REDACTED

NORTHERN UTILITIES, INC.
DG 21-104
PETITION FOR RATE INCREASE

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Unitil

August 2, 2021

BY E-MAIL

Dianne Martin, Chair
New Hampshire Public Utilities Commission
21 S. Fruit St, Suite 10
Concord, N.H. 03301-2429

Re: DG 21-104 Northern Utilities, Inc. - Filing of Rate Schedules

Dear Chairwoman Martin:

Pursuant to N.H. Admin. Rules Puc 1600 *et seq.*, Northern Utilities, Inc. ("Northern" 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, Northern is submitting this filing in electronic form only. The Company's electronic filing complies with Puc 203.03. Northern 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 September 1, 2021 would increase Northern's total annual revenues by $7,782,950, which represents an increase of 8.1 percent above present rates. Northern is also requesting implementation of temporary rates for service rendered on and after October 1, 2021, and until a final order on permanent rates is issued. The requested temporary rates will produce an increase in annual revenues of $3,220,742, or a 3.6 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).

Northern 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.

Patrick H. Taylor
Senior Counsel
taylorp@unitil.com

6 Liberty Lane West
Hampton, NH 03842

T 603.773.6544 www.unitil.com

Sincerely,

Patrick H. Taylor

cc: Donald M. Kreis, Consumer Advocate

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DE 21-104

NORTHERN UTILITIES, INC.

MOTION FOR PROTECTIVE ORDER AND CONFIDENTIAL TREATMENT

NOW COMES Northern Utilities, Inc. ("Northern" 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) sensitive financial and pricing information related to a customer special contract contained in Northern's revenue requirement Workpapers 1.1 and 1.2; (b) a variance analysis containing the results of a discounted cash flow (DCF) analysis as calculated by Northern's proprietary financial model, provided in Schedule CGDN-6 to the prefiled testimony of Christopher Goulding and Daniel Nawazelski; (c) sensitive commercial information contained in a Maine report on Northern's gas supply resource procurement and management, provided in the Volume of Supplemental Filing Requirements pursuant to N.H. Code of Administrative Rules Puc 1604.01(a)(13)**;** and (d) 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). Northern 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, Northern 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. Special Contract Revenue Adjustment (CGDN Workpapers 1.1 and 1.2)

1. As explained in the testimony of Christopher Goulding and Daniel Nawazelski, and set forth in the Company's Schedule RevReq-3-2, the Company made an adjustment to total revenues to reflect certain known and measurable special contract rate increases. Northern's workpapers supporting this Schedule, Workpapers 1.1 and 1.2, are provided with the Company's revenue requirement schedules and contain sensitive and confidential commercial and financial information including pricing and cost information from the Company's special contracts as well as customer usage data. Specifically, Workpapers 1.1

and 1.2 contain confidential special contract rates, including customer charges and monthly fixed charges, customer usage by therm, and special contract revenues.

2. Northern seeks to protect this information from public disclosure in order to protect Northern's competitive position as well as that of the Customer. Release of the above-described confidential information would likely result in harm to the Customer in that it would divulge sensitive and confidential commercial and financial information that the Customer would not otherwise disclose. This information would be of interest to competitor entities and may be utilized to gain a superior competitive position over the Customer. Furthermore, Northern seeks to protect this information from public disclosure in order to protect Northern's competitive position. Release of the above-described confidential information would likely result in harm to Northern in the form of being disadvantaged in price negotiations with customers or potential customers who have alternative options, whether from bypass, alternative fuel supplies, or from direct competitors. Public knowledge of the confidential information would impair Northern's future bargaining positions and thus its ability to obtain the maximum possible contribution to fixed costs. Northern must be able to maximize such contributions to fixed costs as this benefits its firm ratepayers.

3. The Commission has previously evaluated and granted confidential treatment to the information that is similar or identical to the information contained in Workpapers 1.1 and 1.2. See DG 17-070, Order No. 26,129 at 16. The Company urges the Commission to reach the same conclusion in this case.

III. The Epping Discounted Cash Flow Analysis (Schedule CGDN-6)

4. In its Order granting the Company’s request for a franchise to operate in Epping, New Hampshire, the Commission directed Northern to has provide, in the Company’s next rate

case, a variance analysis comparing the original DCF analysis for the Epping franchise (DG 18-094 Hearing Exhibit 8) and a revised DCF analysis using actual costs and revenues and projected future revenues. DG 18-094, Order No. 26,220 at 12 (Feb. 8, 2019). Northern has provided the requested analysis as Schedule CGDN-6.

5. Schedule CGDN-6 contains the original results of the Company's DCF analysis, as well as updated results consistent with the Commission's direction. The DCF analyses are conducted using the Company's proprietary financial model. Northern safeguards this information and does not disclose it to anyone outside of its corporate organization and its authorized representatives. Release of the confidential information contained in Schedule CGDN-6 would likely result in commercial harm to Northern and its customers as the Company's competitors could use the information to Northern's disadvantage. Northern competes against providers of alternative energy suppliers, including fuel oil and propane, as well as other suppliers of natural gas delivered by traditional and non-traditional methods, and disclosure of the Company's confidential analytical information as it relates to the Epping expansion project would impair the Company's competitive position.

6. Northern previously sought, and received, confidential treatment for the results of the DCF analysis as conducted in connection with the Company's Epping expansion efforts. DG 18-094, Order No. 26,220 at 11 (Feb. 8, 2019). The updated DCF analysis is similarly sensitive, and the Commission should extend the same confidential treatment granted in DG 18-094 to the information in Schedule CGDN-6.

IV. Maine Gas Supply Procurement and Management Report

1. Rule Puc 1604.01(a) requires that a public utility filing a rate case provide "the utility's most recent management and financial audits if not previously filed in an adjudicative proceeding."

2. On October 17, 2018, the Maine Public Utilities Commission issued an Order in Maine PUC Docket 2015-00155 indicating an intent to "initiate periodic audits" of all Maine Local Distribution Companies ("LDCs") "to allow for a comprehensive, structured and in-depth examination of LDC gas supply procurement and management decisions and activities." The Commission first conducted an audit of Northern Utilities, Inc.'s Maine Division ("Northern Utilities Maine"). 2018-00300, *Northern Utilities Inc. Review of Gas Supply Procurement and Management Activities*, Notice of Summary Investigation (October 18, 2018). The Maine Commission's third-party consultant, Liberty Consulting Group, issued Confidential and Redacted versions of its Final Report on December 19, 2019. Though the investigation was not a "Management Audit" as that term is defined in 35-A M.R.S. § 113, the Company has provided a copy of the Final Report as an attachment to its response to Puc 1604.01(a)(13).

3. At the outset of the above-referenced Maine docket, the Company sought a protective order applying, *inter alia*, to any confidential, proprietary, and competitively sensitive information regarding the Company's gas supply procurement and management processes contained in the Final Report issued by the Maine Commission's third party consultant. The Commission granted the Company's request and issued a protective order. When the Commission's third party consultant issued its Final Report, the Maine Commission provided it on both a redacted and confidential basis. The redacted version of the Final Report protects the Company's confidential, proprietary, and competitively sensitive information regarding

the Company's gas supply procurement and management processes from public disclosure, but the majority of the document is public.

4. The New Hampshire Commission should grant the same protections that the Maine Commission has granted to this information. Disclosure of such information may be prejudicial to Northern, its counterparties, and its customers. For example, if confidential, proprietary, and commercially sensitive terms of gas supply agreements are disclosed, potential counterparties in future gas resource contracts would be given an unfair advantage with respect to their respective negotiating positions. This could, in turn, result in future transactions that are less favorable to Northern's New Hampshire ratepayers.

5. Moreover, like other parties, Northern and its contractual counterparties enter into these agreements with an understanding that commercial terms will remain confidential. In fact, many of Northern's agreements with counterparties prohibit disclosure of confidential information without prior written counterparty consent or in the absence of an order mandating disclosure. Such confidential terms and information may include, but are not limited to, the prices paid by Northern pursuant to RFPs, price terms, operational provisions, credit terms, other cost information, including commodity, city-gate, and delivered prices, as well as other commercial terms and sensitive material. Disclosure of the terms and substance of such agreements to the marketplace would undercut the reasonable expectations of Northern and its counterparties with respect to sensitive agreements and documents and potentially put Northern in breach of its contractual obligations.

6. The New Hampshire Commission has consistently protected information of this kind from public disclosure. Furthermore, a neighboring Commission has already granted confidential treatment of the information, and posted the confidential and redacted versions

of the report on its web site. The information is confidential, commercial or financial information within the meaning of RSA 91-A:5, IV, and should be granted confidential treatment in this case.

V. Company Officers' Compensation

2. In accordance with Puc 1604.01(a)(14), Northern has submitted documents containing officer compensation and benefit information. The compensation of Northern's officers (the Company's President and Senior Vice Presidents) who are or were also officers of Northern'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 Northern'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.

3. 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.

VI. Conclusion

4. Northern 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 Department of Energy, and that the results of such review will be provided to the Commission for its consideration.

5. Northern 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. Northern requests that the protective order also extend to any discovery, testimony, argument or briefing relative to the confidential information.

WHEREFORE, Northern 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

NORTHERN UTILITIES, INC.

By its Attorney:

Dated: August 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 August 2nd, 2021, a copy of the foregoing Motion was electronically served upon the Office of Consumer Advocate.

Patrick H. Taylor

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THE STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DG 21-104

NORTHERN UTILITIES, INC.

PETITION OF NORTHERN UTILITIES, INC.

NOW COMES Northern Utilities, Inc. ("Northern" 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 September 1, 2021, for gas service at the levels set forth in its proposed revised tariff filed with this Petition; (2) replace certain pages of the Company's current tariff, NHPUC No. 12, with proposed revised tariff pages; (3) implement a multi-year Rate Plan with three annual step adjustments for certain non-growth capital additions; (4) implement a revenue decoupling mechanism, which the Company has proposed in compliance with Commission Order No. 25,932; (5) implement an Arrearage Management Program; and (6) if the Commission suspends the effective date of the Company's permanent rates, implement temporary rates beginning October 1, 2021 for gas service at rate levels set forth in Supplement No. 1 to NHPUC No. 12. In support of this Petition, the Company states as follows:

A. RATE INCREASE AND REVISED TARIFF

1. On June 30, 2021, pursuant to NH RSA 378:3 and New Hampshire Code of Administrative Rules, Puc 1604.05, the Company filed a Notice of Intent to File Rate Schedules with the Commission.

2. The Company is filing with this Petition revisions to its Tariff NHPUC No. 12 ("the Permanent Rates Tariff"). The revised tariff pages have a proposed effective date of September 1, 2021 and are intended to produce a permanent increase in annual revenues of $7,782,950, which represents an increase of approximately 8.1 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 7.75 percent. The overall rate of return of 7.75 percent includes a requested Return on Equity of 10.30 percent, and a proposed capital structure consisting of 52.47% common equity and 47.53% long-term debt.

3. Pursuant to NH RSA 378:8 and N.H. Admin. Rule Puc 1600 *et seq.*, the Company 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. The Company requests permission to implement a multi-year Rate Plan with three annual step adjustments to recover the revenue requirement associated with certain non-growth capital additions to rate base. These projects are necessary in order to maintain the Company's ability to provide safe and reliable gas 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 August 1, 2023, and a third capital project step adjustment will be implemented on August 1, 2024.

5. The Commission has previously authorized the Company to implement a similar series of step adjustments. *See Northern Utilities, Inc.*, DG 17-070, Order No. 26,129 at 14-15, 16 (May 2, 2018); *Northern Utilities, Inc.*, DG 13-086, Order No. 25,653 at 9-11 (April 21, 2014). In support of its request for a long-term Rate Plan, the Company 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 the Company 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). The Company filed its last rate case prior to the end of the first EERS triennium, and thus this is the first time that the Company is proposing a decoupling mechanism.

7. In compliance with the Commission's directive, the Company proposes a full Revenue Decoupling Mechanism ("RDM") that reconciles monthly actual and authorized revenues per customer by rate class. The Company proposes that the authorized revenues per customer be adjusted annually to reflect the three step increases on August 1, 2022, August 1, 2023, and August 1, 2024. The proposed RDM will be applicable to the Company's Residential Heating and Non-Heating Service (Schedules R-

5 and R-10 combined, and R-6) and Commercial and Industrial Service (Schedules G-40, G-50, G-41, G-42, G-51, and G-52) customer classes. The RDM 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 August through July; second, the Company will file the applicable RDM adjustment factor on 45 days before the proposed effective date of November 1. The proposed RDM is described at length and supported by the direct testimony of Timothy Lyons of ScottMadden, Inc.

D. ARREARAGE MANAGEMENT PROGRAM

8. The Company is also proposing an Arrearage Management Program ("AMP") for residential financial hardship customers who are struggling to pay their natural gas bills. The AMP will offer qualifying residential customers of the Company 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 the Company's proposed AMP.

E. TEMPORARY RATES

9. Pursuant to NH RSA 378:6, the Commission may suspend the effective date of Northern'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 the Company's permanent rates Tariff, the Company 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.

10. The Company requests that if such temporary rates are set, they be established at the levels set forth in Supplement No. 1 to NHPUC No. 12, commencing with service rendered on October 1, 2021 and until the date a final, non-appealable order establishing permanent rates is issued. The requested temporary rates represent an increase of $3,220,742 in annual revenues, or 3.6 percent above present revenues. The Company proposes to recover this increase on a uniform per therm basis from all rate classes. In support of this request, the Company notes that since the second calendar quarter of 2019 (when the last step adjustment approved under DG 17-070 became effective), the Company's earned Return on Equity has remained well below the 9.50 percent return authorized in that case. In fact, by the fourth quarter of 2020, Northern under-earned its authorized return on equity by approximately 170 basis points. Absent rate relief, the Company's earnings will continue to erode.

11. The Company 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, the Company 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, the Company 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 Northern Utilities, Inc. to implement such proposed rates and tariffs as permanent effective for service rendered on and after September 1, 2021;

C. If the Commission suspends the Company'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. 1 to NHPUC No. 12 for service rendered on and after October 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 the Company to collect the difference from customers;

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

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

Respectfully submitted,

NORTHERN UTILITIES, INC.

By its Attorneys:

Patrick H. Taylor
Senior Counsel
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842-1720

Dated: August 2, 2021

Certificate of Service

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

Patrick H. Taylor

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NHPUC No. 12 – Gas
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.

SUPPLEMENT NO. 1

SUPPLEMENT NO. 1
TEMPORARY RATES

A temporary rate delivery charge of $0.0846 per therm shall be billed by the Company to all customers taking service under Rate Schedules (R-5, R-6 and R-10) of this tariff.

A temporary rate delivery charge of $0.0279 per therm shall be billed by the Company to all customers taking service under Rate Schedules (R-40, R-41, R-42, R-50, R-51 and R-52) of this tariff.

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II. GENERAL TERMS AND CONDITIONS

4. Application and Contract

Application for service may be made through the Company's website or by contacting the Company by phone. Whether or not a signed application for service is made by the Customer and accepted by the Company, the rendering of the service by the Company and its use by the Customer shall be deemed a contract between the parties and subject to all provisions of the Tariff, as in effect from time to time, applicable to the service. Application for service to a multi-unit dwelling which is supplied through a single meter, must be made by the building owner who will be the customer of record.

The application or the depositing of any sum of money by the applicant shall not require the Company to render service until the expiration of such time as may be reasonably required by the Company to determine if the applicant has complied with the provisions of these Terms and Conditions and as may reasonably be required by the Company to install the required service facilities.

The Company shall not be required to serve any applicant if the distance of the premises to be served from an existing suitable distribution main, or the difficulty of access thereto, is such that the estimated income (revenue excluding gas costs) from the service applied for is insufficient to yield a reasonable return to the Company unless such application is accompanied by a cash payment or an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time or both.

Where service under the Rate Schedules is to be used for temporary purposes only, the Customer may be required to pay the cost of installation and removal of equipment required to render service in addition to payments for gas consumed. Said costs of installation and removal may be required to be paid in advance of any construction by the Company. If, in the Company's sole judgment, any such installation presents unusual difficulties as to metering the service supplied, the Company may estimate consumption for purposes of applying the Rate Schedule, and the Company will notify the Customer prior to turn-on of the estimated amount to be billed.

5. Assignment of Rate Schedule

Rates are available for various classes of Customers. The conditions under which they are applicable are set forth in the Rate Schedules in this Tariff.

Upon application for service or upon request, the applicant or Customer shall be assigned the applicable rate schedule according to its estimated requirements. The Company shall not be held responsible for inaccurate estimates of Customer's requirements and will not refund the difference in charge(s) under different rate schedules.

II. GENERAL TERMS AND CONDITIONS

omission or circumstances occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, unforeseeable or unusual weather conditions, washouts, arrests and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, temporary failure of gas supply, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause except willful default or neglect, whether of the kind herein enumerated, or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or any other person or concern not a party thereto, not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the party claiming suspension.

12. Meter Reading, Billing and Payment

The Company's filed rates for service are predicated on the sale and/or Delivery of natural gas, as far as practicable, for a thirty (30) day period. Bills for service will be rendered at regular intervals. The Company may, however, at its option, read some or all meters in alternate months, and render a bi-monthly or monthly bill. If a monthly bill is rendered in the intervening months it shall be based upon an estimated consumption of gas, which bill will be due and payable when rendered. When a meter reading is obtained and an actual quantity of gas is determined, that quantity previously billed the Customer on an estimated basis will be deducted from the total quantity used during the period and a bill rendered for the remaining quantity.

In the event a meter reading cannot be obtained at the regularly scheduled time, a reading will be estimated until access can be obtained. Bills rendered for service on an estimated basis shall have the same force and effect as those based upon actual meter readings.

Bills are due and payable upon presentation. A late payment charge shall be assessed at a rate of one percent per month or fraction thereof on balances unpaid within thirty days after the billing date. When bills are paid by remittance through the mail, the postmark on the envelope will be considered as the date of payment.

When a residential customer is unable to pay the total arrearage due, but such customer

IV. COST OF GAS CHARGE

NHPUC. The table below lists approved costs and amounts:

VARIABLE	DESCRIPTION	CURRENTLY APPROVED AMOUNTS
MISC	Miscellaneous Overhead Costs	\$611,875
PS	Production and Storage Capacity Costs	\$214,538
WCA%	Working Capital Allowance Percentage	9.3 supply related net lag days / 365 days x WCCCR

Where: WCCCR=Working Capital Carrying Charge Rate

6.2 COGC Formulas

The COGC Formulas shall be computed on an annual basis for the Company's three (3) groups of customer classes as shown in the table below. The computations will use forecasts of seasonal gas costs, carrying charges, sendout volumes, credits and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

GROUP	CUSTOMER CLASSES
Residential	R-5, R-6 and R-10
Commercial and Industrial: Low Winter	G-50, G-51 and G-52
Commercial and Industrial: High Winter	G-40, G-41 and G-42

COGC will be calculated on a seasonal basis. The Winter Season COGC will be effective November 1st and Summer Season COGC will be effective on May 1st.

VI. RATE SCHEDULES

RATE SCHEDULE R-5 - RESIDENTIAL HEATING SERVICE

CHARACTER OF SERVICE

Natural Gas or its equivalent having a nominal heat content of 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping, Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

Service hereunder is available under this rate at single, domestic locations for all purposes in individual private dwellings and individual apartments including condominiums and their facilities which use gas as the principal household heating fuel or at locations which are otherwise deemed ineligible for non-heating service based on availability.

RATE – MONTHLY

Customer Charge				$27.84 per month
Summer	-	All therms	@	$0.8491 per therm
Winter	-	All therms	@	$0.8491 per therm

MINIMUM BILL

The minimum monthly bill for gas service will be the Customer Charge Per Month.

COST OF GAS FACTOR AND LOCAL DELIVERY ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Charge, Part IV, and the Local Delivery Adjustment Charge, Part V, apply to gas sold under this rate schedule.

VI. RATE SCHEDULES

RATE SCHEDULE R-10 - LOW INCOME RESIDENTIAL HEATING SERVICE
(continued)

RATE – MONTHLY

Customer Charge				$27.84 per month
Summer	-	All therms	@	$0.8491 per therm
Winter	-	All therms	@	$0.8491 per therm

LOW INCOME DISCOUNT ADJUSTMENT

Effective November 1, 2020, customers taking service under this rate schedule will receive a 45% discount off the customer charge as well as the distribution rate and cost of gas rate during the winter period. The discount does not apply during the summer period and does not apply to the Local Delivery Adjustment Charge.

MINIMUM BILL

The minimum monthly bill for gas service will be the Customer Charge Per Month.

COST OF GAS FACTOR AND LOCAL DELIVERY ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Charge, Part IV, and the Local Delivery Adjustment Charge, Part V, apply to gas sold under this rate schedule.

DEFINITIONS

Summer - Defined as being the Company's billing cycles May through October.

Winter - Defined as being the Company's billing cycles November through April.

TERMS OF PAYMENT

VI. RATE SCHEDULES

RATE SCHEDULE R-6 - RESIDENTIAL NON-HEATING SERVICE

CHARACTER OF SERVICE

Natural Gas or its equivalent having a nominal heat content of 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company

AVAILABILITY

Service hereunder is available for any residential purpose other than for use as the principal heating fuel except that this rate is not available at locations where usage in the six winter months of November through April is greater than or equal to 80% of annual usage and usage exceeds 100 therms in any winter month.

RATE - MONTHLY

Customer Charge				$27.84 per month
Summer	-	All therms	@	$1.1208 per therm
Winter	-	All therms	@	$1.1208 per therm

VI. RATE SCHEDULES

RATE SCHEDULE G-40 - COMMERCIAL AND INDUSTRIAL SERVICE
(Low Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing one thousand (1,000) Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$80.00 per month
Summer	-	All therms	@	$0.2518 per therm
Winter	-	All therms	@	$0.2518 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-41 - COMMERCIAL AND INDUSTRIAL SERVICE
(Medium Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$225.00 per month
Summer	-	All therms	@	$0.2860 per therm
Winter	-	All therms	@	$0.2860 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

CHARACTERISTICS OF CUSTOMER

A Customer receiving service under this schedule must have annual usage of greater than 8,000 therms but less than or equal to 80,000 therms and peak period usage greater than or equal to 67% of annual usage, as determined by the Company's records and procedures.

VI. RATE SCHEDULES

RATE SCHEDULE G-42 - COMMERCIAL AND INDUSTRIAL SERVICE
(High Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$1,350.00 per month
Summer	-	All therms	@	$0.2167 per therm
Winter	-	All therms	@	$0.2167 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

CHARACTERISTICS OF CUSTOMER

A Customer receiving service under this schedule must have annual usage greater than 80,000 therms and peak period usage greater than or equal to 67% of annual usage, as determined by the Company's records and procedures.

VI. RATE SCHEDULES

RATE SCHEDULE G-50 - COMMERCIAL AND INDUSTRIAL SERVICE
(Low Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$80.00 per month
Summer	-	All therms	@	$0.2232 per therm
Winter	-	All therms	@	$0.2232 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-51 - COMMERCIAL AND INDUSTRIAL SERVICE
(Medium Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$225.00 per month
Summer	-	All therms	@	$0.1718 per therm
Winter	-	All therms	@	$0.1718 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-52 - COMMERCIAL AND INDUSTRIAL SERVICE
(High Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$1,350.00 per month
Summer	-	All therms	@	$0.1121 per therm
Winter	-	All therms	@	$0.1720 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

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NORTHERN UTILITIES, INC.

Tenth Revised Page 85
Superseding Ninth Page 85

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON RESIDENTIAL RATES

	Winter Season November 2020 - April 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**			
	Monthly Customer Charge	$27.84	**$27.84**	**$27.84**
	All Usage	$0.8491	**$0.9456**	**$1.6727**
	LDAC	**$0.0965**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7271**		
Residential Heating	**Tariff Rate R 10:**			
Low Income	Monthly Customer Charge	$27.84	**$27.84**	**$27.84**
	All Usage	$0.8491	**$0.9456**	**$1.6727**
	LDAC	**$0.0965**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7271**		
45% Low Income Discount	Monthly Customer Charge	($12.53)	**($12.53)**	**($12.53)**
45% Low Income Discount	All Usage	($0.3821)	**($0.3821)**	**($0.7093)**
No Discount	**LDAC**	$0.0000		
	Gas Cost Adjustment:			
45% Low Income Discount	Cost of Gas	($0.3272)		
Residential Non-Heating	**Tariff Rate R 6:**			
	Monthly Customer Charge	$27.84	**$27.84**	**$27.84**
	All Usage	$1.1208	**$1.2173**	**$1.9444**
	LDAC	**$0.0965**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7271**		

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Effective: With Service Rendered On and After September 1, 2021

Issued by: Robert B. Hevert
Title: Senior Vice Presiden

Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

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NORTHERN UTILITIES, INC. | **Superseding Eleventh Revised Page 86**

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER SEASON RESIDENTIAL RATES

	Summer Season May 2021 - October 2021	Tariff Rates		Total Delivery Rates (Includes LDAC)		Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**					
	Monthly Customer Charge	$27.84		**$27.84**		**$27.84**
	All Usage	$0.8491	**$0.9456**		**$1.4429**	
	LDAC	**$0.0965**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.4973**				
Residential Heating	**Tariff Rate R 10:**					
Low Income	Monthly Customer Charge	$27.84		**$27.84**		**$27.84**
	All Usage	$0.8491	**$0.9456**		**$1.4429**	
	LDAC	**$0.0965**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.4973**				
No Discount*	Monthly Customer Charge	$0.00		**$0.00**		**$0.00**
No Discount*	All Usage	$0.0000	**$0.0000**		**$0.0000**	
No Discount	**LDAC**	$0.0000				
	Gas Cost Adjustment:					
No Discount*	Cost of Gas	$0.0000				
Residential Non-Heating	**Tariff Rate R 6:**					
	Monthly Customer Charge	$27.84		**$27.84**		**$27.84**
	All Usage	$1.1208	**$1.2173**		**$1.7146**	
	LDAC	**$0.0965**				
	Gas Cost Adjustment:					
	Cost of Gas	**$0.4973**				

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Effective: With Service Rendered On and After September 1, 2021 | **Title:** **Senior Vice President**

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NHPUC No. 12 - Gas | **Ninth Revised Page 87**
NORTHERN UTILITIES, INC. | **Superseding Eighth Revised Page 87**

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON C & I RATES

	Winter Season November 2020 - April 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$80.00	**$80.00**	**$80.00**
	All Usage	$0.2518	**$0.2952**	**$1.0345**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7393**		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$80.00	**$80.00**	**$80.00**
	All Usage	$0.2232	**$0.2666**	**$0.9077**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.6411**		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$225.00	**$225.00**	**$225.00**
	All Usage	$0.2860	**$0.3294**	**$1.0687**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7393**		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$225.00	**$225.00**	**$225.00**
	All Usage	$0.1718	**$0.2152**	**$0.8563**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.6411**		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$1,350.00	**$1,350.00**	**$1,350.00**
	All Usage	$0.2167	**$0.2601**	**$0.9994**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.7393**		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$1,350.00	**$1,350.00**	**$1,350.00**
	All Usage	$0.1720	**$0.2154**	**$0.8565**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.6411**		

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NHPUC No. 12 - Gas | **Eleventh Revised Page 88**
NORTHERN UTILITIES, INC. | **Superseding Tenth Revised Page 88**

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER SEASON C&I RATES

	Summer Season May 2021 - October 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	$80.00	**$80.00**	**$80.00**
	All Usage	$0.2518	**$0.2952**	**$0.8246**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5294**		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	$80.00	**$80.00**	**$80.00**
	All Usage	$0.2232	**$0.2666**	**$0.7170**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4504**		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	$225.00	**$225.00**	**$225.00**
	All Usage	$0.2860	**$0.3294**	**$0.8588**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5294**		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	$225.00	**$225.00**	**$225.00**
	All Usage	$0.1718	**$0.2152**	**$0.6656**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4504**		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	$1,350.00	**$1,350.00**	**$1,350.00**
	All Usage	$0.2167	**$0.2601**	**$0.7895**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.5294**		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	$1,350.00	**$1,350.00**	**$1,350.00**
	All Usage	$0.1121	**$0.1555**	**$0.6059**
	LDAC	**$0.0434**		
	Gas Cost Adjustment:			
	Cost of Gas	**$0.4504**		

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Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)

Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Part VII, Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer. If the customer requests or if an existing phone line is not providing adequate service, the Company may provide communication via cell modem technology for a monthly charge as listed in Appendix A.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Part VII,

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.71 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$ 64.53 per MMBtu** per MDPQ per month for November 2020 through April 2021. Provided on Page 6 of Schedule 21-FXW.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: **1.30% -** Provided in Schedule 18-FXW

IV. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

V. Meter Read Charge: $78.00 when customer phone line is not reporting daily data

VI. Meter Read via Cellular Service: $20.00 per month

Issued: August 2, 2021 Issued by: Robert B. Hevert
Effective: September 1, 2021 Senior Vice President
Authorized by NHPUC Order No. __________ in Docket No. DG 21-104, dated______________.

IX. 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 Residential Service (Rates R-5, R-6, R-10) and Commercial/ Industrial Service (Rates G-40, G-50, G-41, G-42, G-51, G-52) customers.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. Actual Base Revenues is the revenue billed for a Customer Class through the Company’s customer charge and distribution charges plus the change in unbilled revenues. This excludes revenues billed 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 November 1, 2023 to October 31, 2024. Each subsequent Adjustment Period shall be the twelve months November 1 through October 31.

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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: Residential Heating (Rates R-5 and R-10), Residential Non-Heating (Rate R-6), Low Annual Use, High Peak Use Commercial & Industrial (Rate G-40), Low Annual Use, Low Peak Use C&I (Rate G-50), Medium Annual Use, High Peak Use C&I (Rate G-41), Medium Annual Use, Low Peak Use C&I (Rate G-51), High Annual Use, High Peak Use C&I (Rate G-42), and High Annual Use, Low Peak Use C&I (Rate G-52).
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 August 1, 2022 to July 31, 2023. Each subsequent Measurement Period shall be the twelve months August 1 through July 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

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 the prime interest rate as reported by the Wall Street Journal on the first business day of the month preceding the first month of the quarter. Following the end of each Measurement Period, 45 days before the effective date of November 1, 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)

$$\mathrm{MRV}_i^{CC} = \left(\mathrm{ARPC}_i^{CC} - \mathrm{AURPC}_i^{CC}\right) \text{ x } \mathrm{ACUST}_i^{CC}$$

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:

$$\mathrm{ARPC}_i^{CC} = \frac{\text{Actual Month i Revenue for Customer Class}}{\text{Actual Month i Bills for Customer Class}}$$

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

$$\mathrm{AURPC}_i^{CC} = \frac{\text{Authorized Month i Revenue for Customer Class}}{\text{Authorized Month i Bills for Customer Class}}$$

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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

i: The twelve Months of the Measurement Period (August through July)

2. Revenue Decoupling Adjustment (RDA)

$$\mathrm{RDA} = [\textstyle\sum_{\mathrm{CC}=1}^{8}[\sum_{\mathrm{i}=1}^{12} \mathrm{MRV}_{\mathrm{i}}^{\mathrm{CC}} + \mathrm{CarryingCosts}_{\mathrm{i}}^{\mathrm{CC}}]] + \mathrm{REC}_{\mathrm{P}}$$

Where:

$\mathrm{CarryingCosts}_{\mathrm{i}}^{\mathrm{CC}}$: Carrying Costs on the deferral account balance calculated at the prime interest rate for month i for applicable Customer Class.

$\mathrm{REC}_{\mathrm{P}}$: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

3. RDA Allocation, subject to Adjustment Cap

$\mathrm{IF: RDA} < 0$
$\mathrm{AND\ IF:} |\mathrm{RDA}| > \mathrm{RDC}$

$$\mathrm{THEN: RDA^{CC}} = \mathrm{RDC} \times \frac{\mathrm{AURV^{CC}}}{\sum_{\mathrm{CC}=1}^{\mathrm{CC}=8}[\mathrm{AURV^{CC}}]}$$

$$\mathrm{AND: REC_C} = \mathrm{RDA} - \mathrm{RDC}$$

$$\mathrm{OTHERWISE: RDA^{CC}} = \mathrm{RDA} \times \frac{\mathrm{AURV^{CC}}}{\sum_{\mathrm{CC}=1}^{\mathrm{CC}=8}[\mathrm{AURV^{CC}}]}$$

Where:

$|\mathrm{RDA}|$: Absolute Value of RDA

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

$AURV^{CC}$: 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, August to July, 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 therm Sales for the Adjustment Period for the applicable customer class

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per therm) shall be calculated to the nearest one one-thousandth of a cent and will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 interest 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, August to July with revenue for externally supplied customers being adjusted by imputing the Company's cost of gas 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, Local Delivery Adjustment Clause ("LDAC"), 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 interest rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually with the Commission 45 days before November 1 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.

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NHPUC No. 12 – Gas
Northern Utilities, Inc.

NORTHERN UTILITIES, INC.

SUPPLEMENT NO. 1

SUPPLEMENT NO. 1

TEMPORARY RATES

A temporary rate delivery charge of $0.0846 per therm shall be billed by the Company to all customers taking service under Rate Schedules (R-5, R-6 and R-10) of this tariff.

A temporary rate delivery charge of $0.0279 per therm shall be billed by the Company to all customers taking service under Rate Schedules (R-40, R-41, R-42, R-50, R-51 and R-52) of this tariff.

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II. GENERAL TERMS AND CONDITIONS

4. Application and Contract

Application for service may be made ~~at any business office of the Company~~through the Company's website or by contacting the Company by phone. Whether or not a signed application for service is made by the Customer and accepted by the Company, the rendering of the service by the Company and its use by the Customer shall be deemed a contract between the parties and subject to all provisions of the Tariff, as in effect from time to time, applicable to the service. Application for service to a multi-unit dwelling which is supplied through a single meter, must be made by the building owner who will be the customer of record.

The application or the depositing of any sum of money by the applicant shall not require the Company to render service until the expiration of such time as may be reasonably required by the Company to determine if the applicant has complied with the provisions of these Terms and Conditions and as may reasonably be required by the Company to install the required service facilities.

The Company shall not be required to serve any applicant if the distance of the premises to be served from an existing suitable distribution main, or the difficulty of access thereto, is such that the estimated income (revenue excluding gas costs) from the service applied for is insufficient to yield a reasonable return to the Company unless such application is accompanied by a cash payment or an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time or both.

Where service under the Rate Schedules is to be used for temporary purposes only, the Customer may be required to pay the cost of installation and removal of equipment required to render service in addition to payments for gas consumed. Said costs of installation and removal may be required to be paid in advance of any construction by the Company. If, in the Company's sole judgment, any such installation presents unusual difficulties as to metering the service supplied, the Company may estimate consumption for purposes of applying the Rate Schedule, and the Company will notify the Customer prior to turn-on of the estimated amount to be billed.

5. Assignment of Rate Schedule

Rates are available for various classes of Customers. The conditions under which they are applicable are set forth in the Rate Schedules in this Tariff.

Upon application for service or upon request, the applicant or Customer shall be assigned the applicable rate schedule according to its estimated requirements. The Company shall not be held responsible for inaccurate estimates of Customer's requirements and will

II. GENERAL TERMS AND CONDITIONS

not refund the difference in charge(s) under different rate schedules.

II. GENERAL TERMS AND CONDITIONS

omission or circumstances occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, unforeseeable or unusual weather conditions, washouts, arrests and restraint of rulers and peoples, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, line freeze-ups, temporary failure of gas supply, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause except willful default or neglect, whether of the kind herein enumerated, or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or any other person or concern not a party thereto, not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the party claiming suspension.

12. Meter Reading, Billing and Payment

The Company's filed rates for service are predicated on the sale and/or Delivery of natural gas, as far as practicable, for a thirty (30) day period. Bills for service will be rendered at regular intervals. The Company may, however, at its option, read some or all meters in alternate months, and render a bi-monthly or monthly bill. If a monthly bill is rendered in the intervening months it shall be based upon an estimated consumption of gas, which bill will be due and payable when rendered. When a meter reading is obtained and an actual quantity of gas is determined, that quantity previously billed the Customer on an estimated basis will be deducted from the total quantity used during the period and a bill rendered for the remaining quantity.

In the event a meter reading cannot be obtained at the regularly scheduled time, ~~whether monthly or in alternate months, postcards (postage pre-paid) may be used by the Company to obtain the reading. If the Customer marks the card accurately and returns it in the time described thereon, the pertinent bill will be based on the card reading; otherwise, it~~ a reading will be estimated until access can be obtained. Bills rendered for service on an estimated basis shall have the same force and effect as those based upon actual meter readings.

Bills are due and payable upon presentation. A late payment charge shall be assessed at a rate of one percent per month or fraction thereof on balances unpaid within thirty days after the billing date. When bills are paid by remittance through the mail, the postmark on the envelope will be considered as the date of payment.

II. GENERAL TERMS AND CONDITIONS

When a residential customer is unable to pay the total arrearage due, but such customer

IV. COST OF GAS CHARGE

NHPUC. The table below lists approved costs and amounts:

VARIABLE	DESCRIPTION	CURRENTLY APPROVED AMOUNTS
MISC	Miscellaneous Overhead Costs	$~~580,455~~611,875
PS	Production and Storage Capacity Costs	$~~476,106~~214,538
WCA%	Working Capital Allowance Percentage	~~10.02~~9.3 supply related net lag days / 365 days x WCCCR

Where: WCCCR=Working Capital Carrying Charge Rate

6.2 COGC Formulas

The COGC Formulas shall be computed on an annual basis for the Company's three (3) groups of customer classes as shown in the table below. The computations will use forecasts of seasonal gas costs, carrying charges, sendout volumes, credits and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

GROUP	CUSTOMER CLASSES
Residential	R-5, R-6 and R-10
Commercial and Industrial: Low Winter	G-50, G-51 and G-52
Commercial and Industrial: High Winter	G-40, G-41 and G-42

COGC will be calculated on a seasonal basis. The Winter Season COGC will be effective November 1st and Summer Season COGC will be effective on May 1st.

VI. RATE SCHEDULES

RATE SCHEDULE R-5 - RESIDENTIAL HEATING SERVICE

CHARACTER OF SERVICE

Natural Gas or its equivalent having a nominal heat content of 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping, Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

Service hereunder is available under this rate at single, domestic locations for all purposes in individual private dwellings and individual apartments including condominiums and their facilities which use gas as the principal household heating fuel or at locations which are otherwise deemed ineligible for non-heating service based on availability.

RATE – MONTHLY

Customer Charge				$~~22.20~~27.84 per month
Summer	-	~~First 50~~ All therms	@	$0.~~6099~~ 8491 per therm
		~~Excess 50 therms~~	~~@~~	~~$0.6099 per therm~~
Winter	-	~~First 50~~All therms	@	$0.~~6920~~ 8491 per therm
	~~-~~	~~Excess 50 therms~~	~~@~~	~~$0.6920 per therm~~

MINIMUM BILL

The minimum monthly bill for gas service will be the Customer Charge Per Month.

COST OF GAS FACTOR AND LOCAL DELIVERY ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Charge, Part IV, and the Local Delivery Adjustment Charge, Part V, apply to gas sold under this rate schedule.

VI. RATE SCHEDULES

RATE SCHEDULE R-10 - LOW INCOME RESIDENTIAL HEATING SERVICE

(continued)

RATE – MONTHLY

Customer Charge				$~~22.20~~27.84 per month
Summer	-	~~First 50~~All therms	@	$0.~~6099~~ 8491 per therm
	-	~~Excess 50 therms~~	~~@~~	~~$0.6099 per therm~~
Winter	-	~~First 50~~All therms	@	$0.~~6920~~ 8491 per therm
	-	~~Excess 50 therms~~	~~@~~	~~$0.6920 per therm~~

LOW INCOME DISCOUNT ADJUSTMENT

Effective November 1, 2020, customers taking service under this rate schedule will receive a 45% discount off the customer charge as well as the distribution rate and cost of gas rate during the winter period. The discount does not apply during the summer period and does not apply to the Local Delivery Adjustment Charge.

MINIMUM BILL

The minimum monthly bill for gas service will be the Customer Charge Per Month.

COST OF GAS FACTOR AND LOCAL DELIVERY ADJUSTMENT CLAUSE

The provisions of the Company's Cost of Gas Charge, Part IV, and the Local Delivery Adjustment Charge, Part V, apply to gas sold under this rate schedule.

DEFINITIONS

Summer - Defined as being the Company's billing cycles May through October.

Winter - Defined as being the Company's billing cycles November through April.

VI. RATE SCHEDULES

RATE SCHEDULE R-6 - RESIDENTIAL NON-HEATING SERVICE

CHARACTER OF SERVICE

Natural Gas or its equivalent having a nominal heat content of 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company

AVAILABILITY

Service hereunder is available for any residential purpose other than for use as the principal heating fuel except that this rate is not available at locations where usage in the six winter months of November through April is greater than or equal to 80% of annual usage and usage exceeds 100 therms in any winter month.

RATE - MONTHLY

Customer Charge				$2~~2.20~~27.84 per month
Summer	-	~~First 10~~All therms	@	$~~0.6470~~1.1208 per therm
	~~-~~	~~Excess 10 therms~~	~~@~~	~~$0.6470 per therm~~
Winter	-	~~First 10~~All therms	@	$~~0.6470~~1.1208 per therm
	~~-~~	~~Excess 10 therms~~	~~@~~	~~$0.6470 per therm~~

VI. RATE SCHEDULES

RATE SCHEDULE G-40 - COMMERCIAL AND INDUSTRIAL SERVICE
(Low Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing one thousand (1,000) Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~75.09~~80.00 per month
Summer	-	~~First 75~~All therms	@	$0.~~1865~~ 2518 per therm
	-	~~Excess 75 therms~~	~~@~~	~~$0.1865 per therm~~
Winter	-	~~First 75~~All therms	@	$0.~~1865~~ 2518 per therm
	~~-~~	~~Excess 75 therms~~	~~@~~	~~$0.1865 per therm~~

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-41 - COMMERCIAL AND INDUSTRIAL SERVICE
(Medium Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~222.64~~ 225.00 per month
Summer	-	All therms	@	$0.~~1895~~ 2860 per therm
Winter	-	All therms	@	$0.~~2425~~2860 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

CHARACTERISTICS OF CUSTOMER

A Customer receiving service under this schedule must have annual usage of greater than 8,000 therms but less than or equal to 80,000 therms and peak period usage greater than or equal to 67% of annual usage, as determined by the Company's records and procedures.

VI. RATE SCHEDULES

RATE SCHEDULE G-42 - COMMERCIAL AND INDUSTRIAL SERVICE
(High Annual Use, High Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~1,335.81~~1,350.00 per month
Summer	-	All therms	@	$0.~~1206~~ 2167 per therm
Winter	-	All therms	@	$0.~~1984~~ 2167 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

CHARACTERISTICS OF CUSTOMER

A Customer receiving service under this schedule must have annual usage greater than 80,000 therms and peak period usage greater than or equal to 67% of annual usage, as determined by the Company's records and procedures.

VI. RATE SCHEDULES

RATE SCHEDULE G-50 - COMMERCIAL AND INDUSTRIAL SERVICE
(Low Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~75.09~~80.00 per month
Summer	-	~~First 75~~All therms	@	$0.~~1865~~ 2232 per therm
	-	~~Excess 75 therms~~	~~@~~	~~$0.1865 per therm~~
Winter	-	~~First 75~~All therms	~~@~~	$0.~~1865~~ 2232 per therm
	-	~~Excess 75 therms~~	~~@~~	~~$0.1865 per therm~~

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-51 - COMMERCIAL AND INDUSTRIAL SERVICE
(Medium Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~222.64~~ 225.00per month
Summer	-	~~First 1,000~~All therms	@	$0.~~1337~~ 1718 per therm
	-	~~Excess 1,000 therms~~	~~@~~	~~$0.1087 per therm~~
Winter	-	~~First 1,300~~All therms	@	$0.~~1712~~ 1718 per therm
	-	~~Excess 1,300 therms~~	~~@~~	~~$0.1399 per therm~~

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

VI. RATE SCHEDULES

RATE SCHEDULE G-52 - COMMERCIAL AND INDUSTRIAL SERVICE
(High Annual Use, Low Winter Use)

CHARACTER OF SERVICE

The standard gas unit is defined as 100 cubic feet of gas containing 1,000 Btu per cubic foot.

APPLICABILITY

The towns of Atkinson, Brentwood. Dover, Durham, East Kingston, East Rochester, Epping Exeter, Gonic, Greenland, Hampton, Hampton Falls, Kensington, Kingston, Madbury, Newington, North Hampton, Plaistow, Portsmouth, Rochester, Salem, Seabrook, Somersworth, Stratham and limited areas of Rollinsford and the contiguous territory served by the Company.

AVAILABILITY

This schedule is available at single locations throughout the territory served by the Company to Commercial and Industrial customers having certain characteristics, as defined below, for all purposes when gas is for their exclusive use and not for resale.

RATE - MONTHLY

Customer Charge				$~~1,335.81~~1,350.00 per month
Summer	-	All therms	@	$0.~~0792~~ 1121 per therm
Winter	-	All therms	@	$0.1720 per therm

RATE ADJUSTMENT

The above rate is subject to adjustment according to the provisions of the Cost of Gas Charge, Part IV, if applicable, and the Local Delivery Adjustment Charge, Part V.

NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

~~Ninth~~ Tenth Revised Page 85
Superseding ~~Eighth~~ Ninth Page 85

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION
WINTER SEASON RESIDENTIAL RATES

	Winter Season November 2020 - April 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**			
	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 50 therms~~ All usage	~~$0.6920~~ $0.8491	~~$0.8019~~ $0.9456	~~$1.5334~~ $1.6727
	~~All usage over 50 therms~~	~~$0.6920~~	~~$0.8019~~	~~$1.5334~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7315~~ $0.7271		

Residential Heating	**Tariff Rate R 10:**			
Low Income	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 50 therms~~ All usage	~~$0.6920~~ $0.8491	~~$0.8019~~ $0.9456	~~$1.5334~~ $1.6727
	~~All usage over 50 therms~~	~~$0.6920~~	~~$0.8019~~	~~$1.5334~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7315~~ $0.7271		
45% Low Income Discount	Monthly Customer Charge	~~($9.99)~~ ($12.53)	~~($9.99)~~ ($12.53)	~~($9.99)~~ ($12.53)
45% Low Income Discount	~~First 50 therms~~ All usage	~~($0.3114)~~ ($0.3821)	~~($0.3114)~~ ($0.3821)	~~($0.6406)~~ ($0.7093)
~~45% Low Income Discount~~	~~All usage over 50 therms~~	~~($0.3114)~~	~~($0.3114)~~	~~($0.6406)~~
45% Low Income Discount	LDAC	$0.0000		
	Gas Cost Adjustment:			
45% Low Income Discount	Cost of Gas	~~($0.3292)~~ ($0.3272)		

Residential Non-Heating	**Tariff Rate R 6:**			
	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 10 therms~~ All Usage	~~$0.6470~~ $1.1208	~~$0.7569~~ $1.2173	~~$1.4884~~ $1.9444
	~~All usage over 10 therms~~	~~$0.6470~~	~~$0.7569~~	~~$1.4884~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7315~~ $0.7271		

Issued: ~~November 4, 2020~~ August 2, 2021 | **Issued by: Robert B. Hevert**
Effective: With Service Rendered On and After ~~November 1, 2020~~ September 1, 2021 | **Title: Senior Vice President**

Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

~~Eleventh~~ Twelfth Revised Page 86
Superseding ~~Tenth~~ Eleventh Revised Page 86

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER SEASON RESIDENTIAL RATES

	Summer Season May 2021 - October 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
Residential Heating	**Tariff Rate R 5:**			
	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 50 therms~~ All usage	~~$0.6099~~ $0.8491	~~$0.7198~~ $0.9456	~~$1.2168~~ $1.4429
	~~All usage over 50 therms~~	~~$0.6099~~	~~$0.7198~~	~~$1.2168~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4970~~ $0.4973		
Residential Heating	**Tariff Rate R 10:**			
Low Income	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 50 therms~~ All usage	~~$0.6099~~ $0.8491	~~$0.7198~~ $0.9456	~~$1.2168~~ $1.4429
	~~All usage over 50 therms~~	~~$0.6099~~	~~$0.7198~~	~~$1.2168~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4970~~ $0.4973		
No Discount*	Monthly Customer Charge	$0.00	$0.00	$0.00
No Discount*	~~First 50 therms~~ All usage	$0.0000	$0.0000	$0.0000
~~No Discount*~~	~~All usage over 50 therms~~	~~$0.0000~~	~~$0.0000~~	~~$0.0000~~
No Discount	LDAC	$0.0000		
	Gas Cost Adjustment:			
No Discount*	Cost of Gas	$0.0000		
Residential Non-Heating	**Tariff Rate R 6:**			
	Monthly Customer Charge	~~$22.20~~ $27.84	~~$22.20~~ $27.84	~~$22.20~~ $27.84
	~~First 10 therms~~ All Usage	~~$0.6470~~ $1.1208	~~$0.7569~~ $1.2173	~~$1.2539~~ $1.7146
	~~All usage over 10 therms~~	~~$0.6470~~	~~$0.7569~~	~~$1.2539~~
	LDAC	~~$0.1099~~ $0.0965		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4970~~ $0.4973		

* Discount applicable to winter months April through November only

Issued: ~~November 4, 2020~~ August 2, 2021 | **Issued by:** **Robert B. Hevert**
Effective: With Service Rendered On and After ~~November 1, 2020~~ September 1, 2021 | **Title:** **Senior Vice President**

Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

NHPUC No. 12 - Gas
NORTHERN UTILITIES, INC.

~~Eighth~~ Ninth Revised Page 87
Superseding ~~Seventh~~ Eighth Revised Page 87

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

WINTER SEASON C & I RATES

	Winter Season November 2020 - April 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	~~$75.09~~ $80.00	~~$75.09~~ $80.00	~~$75.09~~ $80.00
	~~First 75 therms~~ All Usage	~~$0.1865~~ $0.2518	~~$0.2337~~ $0.2952	~~$0.9774~~ $1.0345
	~~All usage over 75 therms~~	~~$0.1865~~	~~$0.2337~~	~~$0.9774~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7437~~ $0.7393		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	~~$75.09~~ $80.00	~~$75.09~~ $80.00	~~$75.09~~ $80.00
	~~First 75 therms~~ All Usage	~~$0.1865~~ $0.2232	~~$0.2337~~ $0.2666	~~$0.8802~~ $0.9077
	~~All usage over 75 therms~~	~~$0.1865~~	~~$0.2337~~	~~$0.8802~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6465~~ $0.6411		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	~~$222.64~~ $225.00	~~$222.64~~ $225.00	~~$222.64~~ $225.00
	All usage	~~$0.2425~~ $0.2860	~~$0.2897~~ $0.3294	~~$1.0334~~ $1.0687
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7437~~ $0.7393		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	~~$222.64~~ $225.00	~~$222.64~~ $225.00	~~$222.64~~ $225.00
	~~First 1,300 therms~~ All usage	~~$0.1712~~ $0.1718	~~$0.2184~~ $0.2152	~~0.8649~~ $0.8563
	~~All usage over 1,300 therms~~	~~$0.1399~~	~~$0.1871~~	~~$0.8336~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6465~~ $0.6411		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00
	All usage	~~$0.1984~~ $0.2167	~~$0.2456~~ $0.2601	~~0.9893~~ $0.9994
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.7437~~ $0.7393		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00
	All usage	$0.1720	~~$0.2192~~ $0.2154	~~0.8657~~ $0.8565
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.6465~~ $0.6411		

Issued: ~~November 4, 2020~~ August 2, 2021 **Issued by: Robert B. Hevert**
Effective: With Service Rendered On and After ~~November 1, 2020~~ September 1, 2021 **Title: Senior Vice President**

Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

NHPUC No. 12 - Gas | **~~Tenth~~ Eleventh Revised Page 88**
NORTHERN UTILITIES, INC. | **Superseding ~~Ninth~~ Tenth Revised Page 88**

NORTHERN UTILITIES - NEW HAMPSHIRE DIVISION

SUMMER SEASON C&I RATES

	Summer Season May 2021 - October 2021	Tariff Rates	Total Delivery Rates (Includes LDAC)	Total Billed Rates Tariff Rates, LDAC Plus Cost of Gas
C&I Low Annual/High Winter	**Tariff Rate G 40:**			
	Monthly Customer Charge	~~$75.09~~ $80.00	~~$75.09~~ $80.00	~~$75.09~~ $80.00
	~~First 75 therms~~ All Usage	~~$0.1865~~ $0.2518	~~$0.2337~~ $0.2952	~~$0.7628~~ $0.8246
	~~All usage over 75 therms~~	~~$0.1865~~	~~$0.2337~~	~~$0.7628~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5294		
C&I Low Annual/Low Winter	**Tariff Rate G 50:**			
	Monthly Customer Charge	~~$75.09~~ $80.00	~~$75.09~~ $80.00	~~$75.09~~ $80.00
	~~First 75 therms~~ All Usage	~~$0.1865~~ $0.2232	~~$0.2337~~ $0.2666	~~$0.6838~~ $0.7170
	~~All usage over 75 therms~~	~~$0.1865~~	~~$0.2337~~	~~$0.6838~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4504		
C&I Medium Annual/High Winter	**Tariff Rate G 41:**			
	Monthly Customer Charge	~~$222.64~~ $225.00	~~$222.64~~ $225.00	~~$222.64~~ $225.00
	All usage	~~$0.1895~~ $0.2860	~~$0.2367~~ $0.3294	~~$0.7658~~ $0.8588
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5294		
C&I Medium Annual/Low Winter	**Tariff Rate G 51:**			
	Monthly Customer Charge	~~$222.64~~ $225.00	~~$222.64~~ $225.00	~~$222.64~~ $225.00
	~~First 1,000 therms~~ All usage	~~$0.1337~~ $0.1718	~~$0.1809~~ $0.2152	~~$0.6310~~ $0.6656
	~~All usage over 1,300 therms~~	~~$0.1087~~	~~$0.1559~~	~~$0.6060~~
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4504		
C&I High Annual/High Winter	**Tariff Rate G 42:**			
	Monthly Customer Charge	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00
	All usage	~~$0.1206~~ $0.2167	~~$0.1678~~ $0.2601	~~$0.6969~~ $0.7895
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.5291~~ $0.5294		
C&I High Annual/Low Winter	**Tariff Rate G 52:**			
	Monthly Customer Charge	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00	~~$1,335.81~~ $1,350.00
	All usage	~~$0.0792~~ $0.1121	~~$0.1264~~ $0.1555	~~$0.5765~~ $0.6059
	LDAC	~~$0.0472~~ $0.0434		
	Gas Cost Adjustment:			
	Cost of Gas	~~$0.4501~~ $0.4504		

Issued: ~~April 22, 2021~~ August 2, 2021 | **Issued by:** | **Robert B. Hevert**
Effective: With Service Rendered On and After ~~May 1, 2021~~ September 1, 2021 | **Title:** | **Senior Vice President**

Authorized by NHPUC Order No. ________ in Docket No. DG 21-104, dated ______________

VII. DELIVERY SERVICE TERMS AND CONDITIONS (continued)

the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Part VII, Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer. If the customer requests or if an existing phone line is not providing adequate service, the Company may provide communication via cell modem technology for a monthly charge as listed in Appendix A.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Part VII,

VII. DELIVERY SERVICE TERMS AND CONDITIONS

APPENDIX A

Schedule of Administrative Fees and Charges

I. Supplier Balancing Charge: **$0.71 per MMBtu** of Daily Imbalance Volumes

- Updated effective every November 1 to reflect the Company's latest balancing resources and associated capacity costs.
- Daily Imbalance Volumes represent the difference between ATV and ATV adjusted for actual EDDs.

II. Peaking Service Demand Charge: **$ 64.53 per MMBtu** per MDPQ per month for November 2020 through April 2021. Provided on Page 6 of Schedule 21-FXW.

- Updated effective every November 1 to reflect the Company's Peaking resources and associated costs.

III. Company Allowance Calculation: **1.30% -** Provided in Schedule 18-FXW

IV. Supplier Services and Associated Fees:

SERVICE	PRICING
Pool Administration (required) **Non-Daily Metered Pools only**	• $0.10/month/customer billed @ marketer level
Standard Passthrough Billing (required)	• $0.60/customer/month billed @ marketer level
Standard Complete Billing (optional – Passthrough Billing fee not required if this service is elected)	• $1.50/customer/month billed @ marketer level
Customer Administration (required)	• $10/customer/switch billed @ marketer level

V. Meter Read Charge: $78.00 when customer phone line is not reporting daily data

VI. Meter Read via Cellular Service: $20.00 per month

Issued: ~~November 4, 2020~~ August 2, 2021 Issued by: Robert B. Hevert

Effective: ~~November 1, 2020~~ September 1, 2021 Senior Vice President

Authorized by NHPUC Order No. __________ in Docket No. DG 21-104, dated_______________.

IX. 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 a semi-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 Residential Service (Rates R-5, R-6, R-10) and Commercial/ Industrial Service (Rates G-40, G-50, G-41, G-42, G-51, G-52) customers.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. *Actual Base Revenues is the revenue billed for a Customer Class through the Company's customer charge and distribution charges plus the change in unbilled revenues. This excludes revenues billed through the RDAF. If a special contract customer as included as part of the Company's most recent base rate case moves to service under one of the Company's firm Rate Schedules, their associated billed revenue shall be excluded from Actual Base Revenue.*
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. If a special contract customer as presented as part of the Company's most recent base rate case moves to service under one of the Company's firm Rate Schedules, they shall be excluded from the Actual Number of Customers.*
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 six-month Peak or Off-Peak period for which the RDAF will be applied for each applicable customer class. The first Adjustment Period shall be the six-month period beginning November 1, 2023. Each subsequent Adjustment Period shall be the six month period beginning May 1 and November 1 of each year.*

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 monthly variance amounts by comparing actual base revenues per customer and authorized base revenues per customer, and defined as follows: Residential Heating (Rates R-5 and R-10), Residential Non-Heating (Rate R-6), Low Annual Use, High Peak Use Commercial & Industrial (Rate G-40), Low Annual Use, Low Peak Use C&I (Rate G-50), Medium Annual Use, High Peak Use C&I (Rate G-41), Medium Annual Use, Low Peak Use C&I (Rate G-51), High Annual Use, High Peak Use C&I (Rate G-42), and High Annual Use, Low Peak Use C&I (Rate G-52).*
9. *Measurement Period is the six-month Peak or Off-Peak 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 begin August 1, 2022. Each subsequent Measurement Period shall be the six month periods beginning November 1 and May 1 of each year.*
10. *Off-Peak Period is the continuous period from May 1st through October 31st.*
11. *Peak Period is the continuous period from November 1st through April 30th.*
12. *Rate Class Group is the combination of Customer Classes into four groups (1) Residential Heating (R-5 and R-10); (2) Residential Non-Heating (R-6); (3) C&I High Load Factor (G-50, G-51, G-52); (4) C&I Low Load Factor (G-40, G-41, G-42).*
13. *Revenue Decoupling Adjustment ("RDA") is the cumulative monthly revenue variances, carrying costs and reconciliation amount for each Measurement Period and each Rate Class Group. The RDA forms the basis for RDAF.*

Authorized by NHPUC Order No. ___ in Case No. DG 21-104 Dated__________

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

5.0 CALCULATION OF REVENUE DECOUPLING ADJUSTMENT FACTOR

i. Description of RDAF Calculation

For each month within the applicable 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. For each month within the applicable Measurement Period, the revenue variance for each Customer Class will be combined by Rate Class Group, and recorded in a deferral account with carrying costs accrued monthly at the prime interest rate as reported by the Wall Street Journal on the first business day of the month preceding the first month of the quarter. Following the end of each six-month Measurement Period, the monthly variances in the applicable Measurement Period shall be totaled by Rate Class Group and combined with carrying costs and any prior period deferral to form the basis for the RDA by group.

The Company will file for implementation of the RDAF 45 days before November 1. The filing will provide the proposed RDAF for the Peak period, for effect November 1, and subsequent Off-Peak period, for effect May 1. The RDA for the Peak period will reflect actual data for the entire six month period while the RDA for the Off-Peak period will reflect actual data for the first three months of the period and estimated data for the remaining three months. The first Off-Peak RDAF will become effective May 1, 2024, thus it will include the initial RDA for August 1, 2022 through October 31, 2022 and the RDA for May 1, 2023 through October 31, 2023. The filing shall include the RDA by Rate Class Group, including prior period reconciliation and calculation of the RDAF. The RDAF shall be calculated as a dollar per therm charge or credit based on the RDA for each group divided by the projected therm sales for each group over the prospective six-month Adjustment Period. The RDAF shall be charged or credited to customer bills during the applicable Adjustment Period.

ii. RDAF Calculation

1. Monthly Revenue Variance (MRV)

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

Where:

Authorized by NHPUC Order No. ___ in Case No. DG 21-104 Dated__________

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

$ACUST_i^{CC}$: 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 eight Customer Classes as defined in Section 4.0.

i: The six months of each Measurement Period

2. Revenue Decoupling Adjustment (RDA)

$$RDA^{RCG} = [\sum_{i=1}^{6} MRV_i^{RCG} + CarryingCosts_i^{RCG}] + REC_p^{RCG}$$

Where:

RCG: The Rate Class Groups as defined in Section 4.0.

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

REC_p^{RCG}: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

Authorized by NHPUC Order No. ___ in Case No. DG 21-104 Dated__________

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

3. *RDA subject to Adjustment Cap*

$$IF: |RDA^{RCG}| > RDC^{RCG}$$

$$THEN: RDA^{RCG} = RDC^{RCG}$$

$$AND: REC_C^{RCG} = RDA^{RCG} - RDC^{RCG}$$

Where:

$|RDA^{RCG}|$: *Absolute Value of RDA for each Rate Class Group.*

RDC^{RCG}: *The Revenue Decoupling Cap that equals four and one-quarter (4.25) percent of approved distribution revenues for each Rate Class Group over the relevant Measurement Period(s).*

REC_C^{CG}: *RDAC Reconciliation Balance for current period as defined in Section 7.0.*

iii. *RDAF Calculation*

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

Where:

FS^{RCG}: *The forecasted therm Sales for the Adjustment Period for the applicable Rate Class Group*

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent and will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 5.0, 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 interest rate.

8.0 Revenue Decoupling Adjustment Cap

The RDA for each Adjustment Period, determined in accordance with Section 5.0, may not exceed four and one-quarter percent (4.25%) of approved distribution revenues as established in the Company's most recent base rate case, including any adjustment due to a step. The cap shall be determined separately for each Rate Class Group over the relevant Measurement Period and shall apply to over- and under-recoveries. To the extent that the application of the RDA cap results in a RDA for a Rate Class Group 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 interest rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually with the Commission 45 days before November 1 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 for each Rate Class Group.*
3. *Calculation of the Revenue Decoupling Adjustment Factors for each Rate Class Group, to be utilized in the upcoming applicable Adjustment Period. If distribution rates change during a Measurement Period, the monthly revenue per customer for the remaining months of the Measurement Period will be revised and filed with the Commission.*

State of New Hampshire
Public Utilities Commission
Concord
Report of Proposed Rate Changes ($000)

Northern Utilities, Inc. -- New Hampshire Division
Tariff No. 12

Date Filed: August 2, 2021
Effective Date: September 1, 2021

(A) Class of Service	(B) Effect of Proposed Change	(C) Average Number of Customers	(D) Total Current Revenue	(E) Proposed Distribution, COGC, and LDAC Revenue Changes	(F) Total Revenue Under Proposed Rates	(G) Proposed Change Revenue	(H) Percent Change Revenue
Residential Heating - R5	Increase	26,171	$35,467	$4,811	$40,278	$4,811	13.6%
Residential Low Income Heating - R10	Increase	644	$845	$115	$959	$115	13.6%
Residential Non-Heating - R6	Increase	1,277	$664	$195	$859	$195	29.4%
Subtotal Residential	Increase	28,091	$36,976	$5,120	$42,096	$5,120	13.8%
Commercial & Industrial Low Annual & High Winter Use G-40	Increase	5,234	$14,808	$937	$15,745	$937	6.3%
Commercial & Industrial Medium Annual & High Winter Use G-41	Increase	704	$15,728	$685	$16,414	$685	4.4%
Commercial & Industrial High Annual & High Winter Use G-42	Increase	31	$5,681	$192	$5,873	$192	3.4%
Commercial & Industrial Low Annual & Low Winter Use G-50	Increase	831	$1,844	$94	$1,938	$94	5.1%
Commercial & Industrial Medium Annual & Low Winter Use G-51	Increase	267	$4,091	$111	$4,202	$111	2.7%
Commercial & Industrial High Annual & Low Winter Use G-52	Increase	33	$11,547	$166	$11,713	$166	1.4%
Subtotal Commercial & Industrial	Increase	7,101	$53,698	$2,186	$55,884	$2,186	4.1%
Total	Increase	35,192	$90,674	$7,307	$97,981	$7,307	8.1%

(D) Revenue under previous permanent seasonal rates assuming all customers take Company supplied gas service.
(E) Distribution revenue change reflecting COGC Indirect Gas Costs, LDAC Regulatory Assessment Costs and Energy Efficiency Lost Base Revenue Costs
Totals may differ slightly from other schedules due to rate rounding.
(F) Column D + Column E
(G) Column F - Column D
(H) Column G / Column D

Signed by: *Robert B. Hevert*
Title: Sr. Vice President

NORTHERN UTILITIES, INC.
DG 21-104

Statement to Customers
Pursuant to PUC 1203.02(c)

On August 2, 2021, Northern Utilities, Inc. ("Unitil") filed with the New Hampshire Public Utilities Commission a proposed increase of approximately 8.1% 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 3.6% to become effective October 1, 2021 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/2021/21-104.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.

RESIDENTIAL SERVICE CUSTOMERS (SCHEDULES R5, R6 AND R10)
Based on Unitil's requested temporary rate increase, residential heating customers with R5 service would see an average increase of 4.7% effective October 1, 2021. Residential non-heating customers with R6 service would see an average increase of 3.0% effective October 1, 2021. The proposed projected average increase in monthly bills at the conclusion of the rate proceeding would be 13.6% for residential heating customers with R5 service and 29.4% for residential non-heating customers with R6 service. Low income customers served under rate R10 will see similar impacts to the R5 rate class, but overall bills will remain lower due to discounts provided in the R10 rate class.

COMMERCIAL AND INDUSTRIAL SERVICE CUSTOMERS (SCHEDULES G40, G41, G42, G50, G51 AND G52)
Based on Unitil's requested temporary rate increase, proposed for effect on October 1, 2021, the projected average increase to the total bill for general service customers with G40 Sales Service is 2.1%; for customers with G41 Sales Service, the increase is 2.6%; for customers with G42 Sales Service, the increase is 2.9%; for customers with G50 Sales Service, the increase is 2.2%; for customers with G51 Sales Service, the increase is 3.2%; and for customers with G52 Sales Service, the increase is 4.0%. The proposed projected average increase in monthly bills at the conclusion of the rate proceeding is as follows: G40 Sales Service: 6.3%; G41 Sales Service: 4.4%; G42 Sales Service: 3.4%; G50 Sales Service: 5.1%; G51 Sales Service: 2.7%; and G52 Sales Service: 1.4%. The proposed projected average increases for Commercial and Industrial customers with Delivery Service are comparable to those listed above if the customer's supply rate is the same as Unitil's.

If you are unsure of your customer rate class or rate schedule, please refer to the rate class indicated on your bill.

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Attestation

I affirm, based on my personal knowledge, information and belief, that the cost and revenue statements and the supporting data submitted which purport to reflect the books and records of Northern Utilities, Inc. do in fact set forth the results shown by such books and records and that all differences between the books and the test year data and any changes in the manner of recording an item on the books of Northern Utilities, Inc. during the test year have been expressly noted.

8/2/21
Date

Robert B. Hevert
Robert B. Hevert
Senior Vice President
Northern Utilities, Inc.

State of New Hampshire
County of Rockingham ss.

Subscribed and sworn to this 2nd of August, 2021, before me

Sandra L. Whitney
Notary Public

My Commission Expires: 1/22/25

Sandra L. Whitney
NOTARY PUBLIC
State of New Hampshire
My Commission Expires January 22, 2025

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NORTHERN UTILITIES. INC.

DIRECT TESTIMONY

OF

ROBERT B. HEVERT, CFA

EXHIBIT RBH-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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 Senior Vice President for each of Unitil Corporation's operating utility subsidiaries, including Northern Utilities, Inc. ("Northern", or the "Company"), and Unitil Service Corporation. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

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 325 proceedings across numerous jurisdictions, including the New Hampshire Public Utilities Commission (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 Unitil-RBH-2.

Q. What is the purpose of your Direct Testimony?

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

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

A. Yes, they were.

II. <u>EXECUTIVE SUMMARY</u>

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

A. This is a pivotal time for the utility industry, including Northern. Technology is rapidly evolving, public policies addressing climate change are quickly advancing, the need for enhanced physical and cyber security is growing, and system reliability and safety remain paramount. Unitil Corporation's objective has been to support and enable those changes while providing the safe, 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.

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 and safety metrics, 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 support infrastructure improvement and modernization efforts. 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 shared 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 largely by unrecovered costs associated with non-revenue producing capital investments. Because the fundamental factors driving our application in this case are similar to those underlying Northern's recent rate filings, we have proposed a comparable multi-year structure. Our application in this proceeding includes a permanent rate request of approximately $7.8 million, proposed temporary rates of about $3.2 million, and a series of three step adjustments to recover costs associated with non-growth related capital investments made during the calendar years 2021, 2022, and 2023.

Also consistent with prior multi-year rate plans, our application includes certain customer protection provisions, including a Rate Cap limiting the cumulative revenue increase to

$10.50 million; a Stay Out provision under which the Company would not seek base rate adjustments through calendar year 2024, subject to certain exogenous events and a 7.00 percent floor on its earned equity return; and an Earnings Sharing provision that would allocate earnings above 11.00 percent equally between distribution customers and the Company, with the Company retaining the risk of earnings below our proposed 10.30 percent ROE.

In addition to those measures, we deferred seeking rate relief until the second half of 2021, even though our earned return had fallen nearly 170 basis points below our 9.50 percent authorized Return on Equity. Further, we propose an ROE of 10.30 percent, toward the lower end of the 10.02 percent to 11.64 percent range recommended by our expert. Those decisions, together with the provisions summarized above and our commitment to operating and capital cost management, intend to mitigate the rate effect on our 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 the obligation to provide our customers with exemplary service, and our responsibility to meet their evolving needs in an increasingly complex environment. If approved, our multi-year rate plan will enable us to continue doing both.

III. OVERVIEW OF THE COMPANY'S OPERATIONS

Q. Please briefly summarize Unitil Corporation's structure, and Northern'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: Northern, which provides natural gas service to approximately 69,400 customers in southeastern New Hampshire, and portions of southern and central Maine; Unitil Energy Systems, Inc. ("UES"), 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; and Granite State Gas Transmission, Inc., 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[1]; Unitil Realty Corp., which owns and manages Unitil Corporation's corporate headquarters in Hampton, New Hampshire; and Unitil Resources, Inc., which

[1] 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 Unitil Corporation divested in 2019.[2]

Q. Are Unitil's utility operations geographically contiguous?

A. Although Northern and UES serve common communities in the seacoast region, Northern 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.

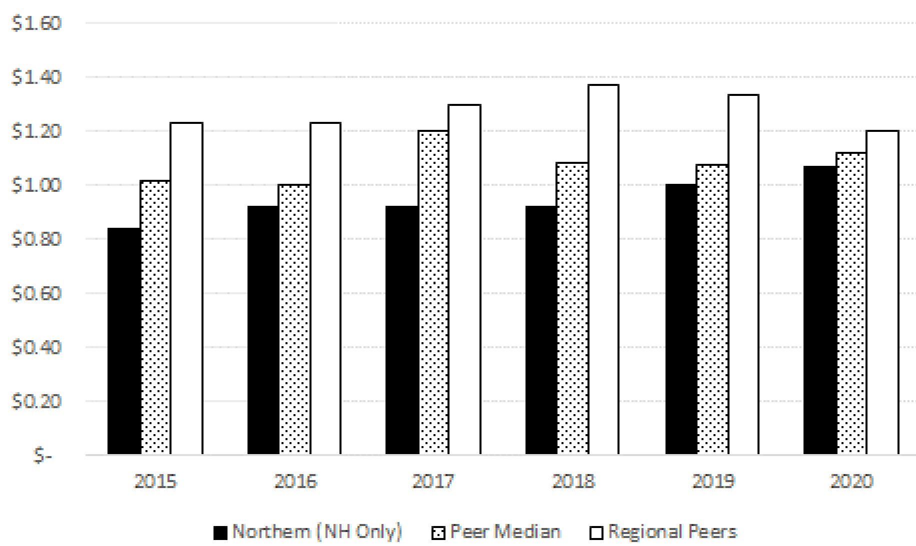
Q. Has the Company's focus on operating and capital cost control benefited its customers?

A. Yes, in the form of competitive rates. From 2015 through 2020 (the most recent period for which comparative data is available), Northern's average residential delivery rate

[2] 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.

($/therm) consistently remained below the median rate for other gas distribution utilities (see Chart 1, below).

Chart 1: Residential Revenue Per Therm [3]



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

A. Yes, Unitil Corporation believes customer satisfaction is integrally related to cost, safety, and system reliability. 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,

[3] Source: S&P Global Market Insight and Company data. Peer group includes Atmos Energy Corp, Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Virginia, Florida Public Utilities Company, Kansas Gas Service Company, New Jersey Natural Gas, Northern Indiana Public Service Company, Northwest Natural Gas Company, Oklahoma Natural Gas Company, South Jersey Gas Company, Spire Gulf Inc, Spire Mississippi, Spire Missouri, Texas Gas Service Company. Regional peer group includes Bangor Gas Company, LLC, Boston Gas Company, Central Hudson Gas & Electric Corporation, Colonial Gas Company, Connecticut Natural Gas Corporation, Fitchburg Gas and Electric Light Company, Liberty Utilities (EnergyNorth Natural Gas) Corp., Liberty Utilities (New England Natural Gas Company) Corp., Maine Natural Gas, New York State Electric & Gas Corporation, NSTAR Gas Company, Rochester Gas and Electric Co and Yankee Gas Services Company

and tenth of 114 utilities nationally.[4] Although we take pride in our customer satisfaction and industry recognition, we take neither for granted. Rather, we continuously focus on the operational excellence our customers expect.

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:

- 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.[5]

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

[4] 2020 Escalent CSAT Survey
[5] Based on survey results among non-collective bargaining employees.

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 maintained our focus on operating and capital cost management and achieved record high levels of customer and employee satisfaction.

Q. Lastly, was the COVID-19 pandemic a factor considered in determining when Northern 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 considerably 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 stable utility, and further deferring rate relief would put increasing pressure on the Company's credit profile.

On balance, we determined it was in our stakeholders' best interests to defer our rate application to the second half of 2021 even though by the end of 2020, Northern had earned well below its authorized return. Given that earnings attrition and the importance of our planned capital investments, we could not defer the filing date beyond 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 and reliable distribution system.

IV. FACTORS UNDERLYING THE COMPANY'S RATE APPLICATION

A. The Company's 2017 Rate Application

Q. Are the factors underlying the Company's application in this case similar to those in DG 17-070?

A. Yes, our request in this case is driven by factors that likewise motivated our 2017 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 improve and grow the distribution system; and (3) ratepayer protection provisions intended to temper the rate effect on our customers.

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

A. The Company's most recent application, docketed as DG 17-070, was filed on June 5, 2017. In that case, Northern requested a base rate increase of approximately $4.7 million, with a proposed temporary rate increase of about $2.0 million (subject to refund or recoupment). Similar to the multi-year structure included in its 2013 filing (DG 13-086), in its 2017 case the Company proposed a series of three step adjustments that would become effective on July 1st of 2018, 2019, and 2020 reflecting eligible investments made during calendar years 2017, 2018, and 2019.[6] The revenue requirement associated with those step adjustments included only the pre-tax rate of return, depreciation, and property taxes on eligible capital invested each rate year.[7] As measures of customer benefits and protection, the multi-year plan included a cumulative cap on revenue increases under the Rate Plan of $7.1 million, an Earnings Sharing Mechanism, and a Stay Out provision restricting the Company from filing a general rate case before 2021.[8]

On July 31, 2017, 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 $1.6 million, effective August 1, 2017.[9]

In April 2018, the Company, the OCA, and Staff entered into a comprehensive settlement agreement resolving all contested issues in the case (the "Settlement").[10] Among other things, the Settlement provided a permanent distribution rate increase of approximately $2.6 million, an offsetting annual revenue decrease of $1.7 million to reflect the effect of the Federal Tax Cuts and Jobs Act of 2017, and one revenue step increase effective May 1, 2018, with an option to the Company for a second step increase effective May 1, 2019 (subject to an revenue requirement cap of $2.2 million on those investments).[11] If the Company opted to implement the second step increase, its next distribution base rate case

6 *See*, Docket DG 17-070, Settlement Agreement on Permanent Delivery Rates, April 6, 2018, at 2.
7 Docket No. 17-070, Direct Testimony of David L. Chong, at 45.
8 Docket No. 17-070, Direct Testimony of David L. Chong, at 46.
9 Docket No. 17-070, Order No. 26,043 at 3, 5.
10 Docket No. 17-070, Settlement Agreement on Permanent Delivery Rates.
11 Docket No. 17-070, Settlement Agreement on Permanent Delivery Rates, at 7.

would be based on an historical test year no earlier than the twelve months ended December 31, 2020.[12] On May 2, 2018, the Commission approved the Settlement.[13]

Q. Did the Company's filing in Docket DG 17-070 explain the factors underlying its need to seek rate relief?

A. Yes, Northern explained that although the step adjustments approved in DG 13-086 helped moderate earnings attrition, it continued to invest capital beyond 2015, the rate year for the final step adjustment in that docket. Northern continued making investments to enhance the safety and reliability of its existing gas distribution system, and to expand the system to serve the growing demand for natural gas in New Hampshire.[14] Those continuing investments caused Northern's 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. If not addressed through rate relief, the resulting earnings attrition would have eroded the Company's ability to maintain its financial profile and credit quality and, therefore, its ability to access capital at reasonable terms.[15]

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[12] Docket No. 17-070, Settlement Agreement on Permanent Delivery Rates, at 6.
[13] *See*, Docket No. 17-070, Order No. 26,129, dated May 2, 2018.
[14] *See*, Docket No. 17-070, Direct Testimony of David L. Chong, at 9.
[15] *See*, Docket No. 17-070, Direct Testimony of David L. Chong, at 9-10.

B. Continuing Earnings Attrition

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

A. In general, earnings attrition is the decline in returns that occurs when revenues do not keep pace with costs. Like all utilities, Northern is capital-intensive, 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.[16]

As with financial leverage, operating leverage tends to magnify the effect of changes in revenue on operating income. Intuitively, if revenues remain steady or fall, the larger portion of a utility's cost structure, its fixed costs, will grow with increased investments, and its earnings will fall at a faster rate. Even if the customer count increases and operating costs are well-managed, revenue may not 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, reflects the need for timely recovery of invested capital.

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[16] *See, e.g.,* J. Fred Weston, Eugene F. Brigham, Essentials of Managerial Finance, 9th Ed., The Dryden Press, 1990, at 371 – 373. *See also*, Testimony of Ronald J. Amen, at 13 – 14.

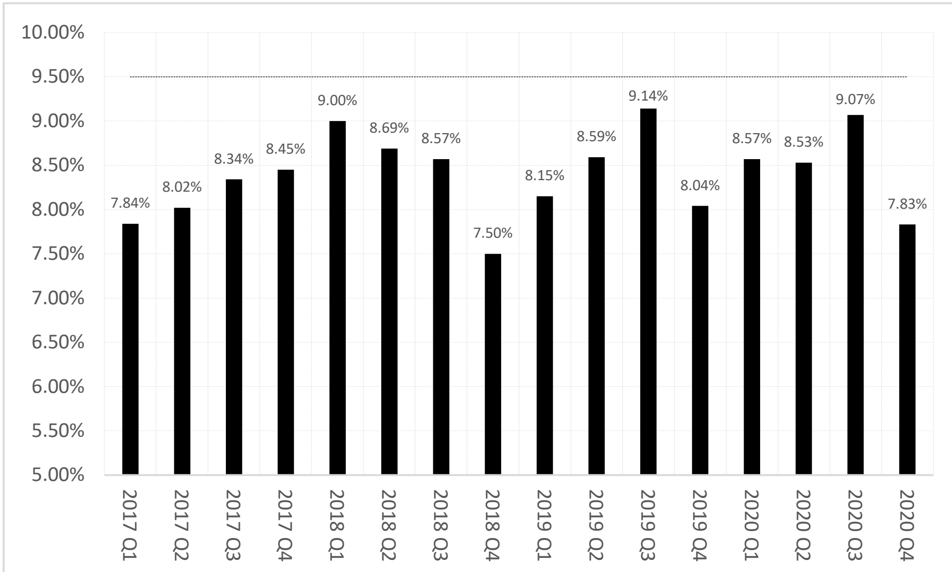
Here too, the reasoning is intuitive - absent timely recovery, revenue will not be sufficient to cover incremental costs, leading to earnings attrition.

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

A. Yes, our 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, and investments made since 2018, the last rate year reflected in those adjustments. Since the Company's filing in DG 17-070, which included a *pro forma* 2016 test year, Northern's New Hampshire Division has invested approximately $89.19 million in its distribution system. Although the multi-year rate filing approved in that case provided a measure of cost recovery, about $64.73 million of those investments (approximately 73.00 percent) have not been recovered under any rate mechanism.

Since the second calendar quarter of 2019 (when the last step adjustment approved under DG 17-070 became effective), the Company's earned Return on Equity has remained well below the 9.50 percent return authorized in that case. In fact, by the fourth quarter of 2020, Northern under-earned its authorized return by about 170 basis points (see Chart 2 below).

Chart 2: Northern Earned ROE (2017 – 2020)[17]



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

A. Northern 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 2016, increased at an annual average rate of 2.14 percent.[18] As a point of reference, over the same period the average annual (regional) inflation rate was about 2.19 percent.[19]

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[17] Provided in Company NH PUC 509.01 Quarterly Filing.

[18] Refers to Northern NH O&M expense. Excludes Total Production Expense, Total Transmission Expense, and Customer Assistance Expenses.

[19] 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, as noted earlier 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 gas 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.[20]

C. Revenue Decoupling Proposal

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 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."[21]

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

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[20] *See also*, Direct Testimony of Kevin E. Sprague and Christopher J. LeBlanc at 9.
[21] Docket DE 15-137, Order No. 25,932, at 60. *See also*, Testimony of Timothy S. Lyons, at 4-5.

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.[22] 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.[23]

Whereas consumption-based pricing structures may create a financial 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,[24] supporting policy objectives regarding energy conservation.

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 $7.8 million based on the calendar year 2020 test year; (2) a temporary rate increase of $3.2 million, effective October 1,

[22] *See*, Docket DE 15-137, Order No. 25,932, at 26-27.
[23] Docket DE 15-137, Order No. 25,932, at 59. *See also*, Direct Testimony of Timothy S. Lyons, at 7-8.
[24] *See*, Direct Testimony of Timothy S. Lyons, at 10.

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 heating customer using 62 therms per month would see a 13.5 percent increase in their total bill after accounting for changes to other reconciling mechanisms.

Our calculated revenue deficiency is based on a test year ended December 31, 2020, adjusted for known and measurable changes for ratemaking purposes. The revenue requirement reflects a rate base of $188.72 million, and an overall Rate of Return of 7.75 percent, including a Return on Equity of 10.30 percent. Of note, the total rate base includes approximately $57.03 million of gross plant additions since December 2018, the rate year for the last step adjustment provided in DG 17-070.[25]

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. To that end, our proposed temporary rates are based on the Company's year-end rate base, with limited known and measurable changes,[26] combined with an overall Rate of Return of 7.33 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 7.59 percent return approved in DG 17-070,[27] our temporary rate

[25] Compares Pro Forma December 31, 2020 Utility Plant in Service of $301,245,498 as shown on Schedule RevReq-5, Column 7, Line 1 to Gross Utility Plant of $244,211,724 as shown on the Company's 2018 Annual Report to the Commission (Form F-16 G) NHPUC Page 10a, New Hampshire Division Utility Plant, December 2018).

[26] *See*, Testimony of Christopher Goulding and Daniel Nawazelski Schedule CGDN-3, Schedule RevReq-3, for known and measurable changes included in temporary rates.

[27] Docket No. 17-070, Settlement Agreement on Permanent Delivery Rates.

request is not based on our currently authorized overall return. Rather, the proposed 7.33 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 DG 17-070 (rather than the 10.30 percent Cost of Equity proposed in this case).

Q. Please also summarize the proposed annual step adjustments.

A. Similar to the structure proposed in DG 17-070, our proposal in this proceeding includes a series of 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 about 76.57 percent of all forecasted investments during the three calendar years ended 2023.[28]

Each March 31st (beginning 2022), the Company will make a compliance filing 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 August 1st and ending July 31st of the following year. Under that structure, the Company would make its first compliance filing on or before March 31, 2022, identifying the revenue requirement associated with eligible investments made during calendar year 2021, to be recovered over the rate year August 1, 2022 through July 31, 2023.[29]

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28 *See*, Testimony of Kevin E. Sprague and Christopher J. LeBlanc at 16.

29 Messrs. Goulding and Nawazelski present the proposed step adjustments in their direct testimony, see Exhibit CGDN-2.

B. Rate Effect Mitigation and Customer Protection Measures

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

A. First, as discussed earlier, Northern remains committed to both operating and capital cost control. Second, and as also explained above, the Company chose to defer its filing into the second half of 2021, even though we had meaningfully under-earned our authorized return. Third, although we understand that by some measures New Hampshire recently has fared better than many other parts of the country,[30] we are mindful of the continuing unease in the region. We therefore request a Return on Equity of 10.30 percent, toward the lower end of the 10.02 percent to 11.64 percent range recommended by our expert.[31]

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.[32] 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, even as long-term interest rates have been unstable.[33]

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30 For example, as June 2021, New Hampshire's 2.90 percent unemployment rate was the third lowest in the United States. Source: U.S. Bureau of Labor Statistics, https://www.bls.gov/web/laus/laumstrk.htm, accessed July 27, 2021.

31 Direct Testimony of John Cochrane, at 3.

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

33 *See*, Testimony of John Cochrane, at 21.

We also propose a Revenue Requirement Cap, which limits the three-year step adjustment cumulative revenue increase to $10.50 million. 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 on an equal basis between customers and shareholders. The Company would retain the downside risk of earnings below 10.30 percent, although if its earned Return on Equity falls below 7.00 percent during the Stay Out period, the Company may file a request for base rate relief.[34]

C. <u>Revenue Decoupling Mechanism</u>

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. 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 the twelve-month measurement period ended July 31st. 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

[34] *See*, Testimony of Christopher Goulding and Daniel Nawazelski, Schedule CGDN-1.

proposed adjustments would be filed with the Commission 45 days before the effective date of November 1, for effect over the twelve-month period ended October 31st.

Lastly, the Revenue Decoupling Adjustment in any given year would not exceed 2.50 percent of the total revenue from delivered sales over the twelve month period ended July 31st. As Mr. Lyons explains, the cap would be applicable only to revenue shortfalls, providing a further means of mitigating potential customer bill impacts.[35]

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, Manager, Revenue Requirements*, 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

[35] *See*, Direct Testimony of Timothy S. Lyons, at 16.

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. Kevin Sprague*, *Vice President of Engineering*, *and Mr. Christopher LeBlanc, Vice President of Gas Operations* address the Company's annual planning and capital investment plan reflected in the proposed step adjustments under the multi-year rate plan.
- *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, Northern's Treasurer and Director of Finance, and Andre Francoeur, Senior Financial Analysts II,* supports the Company's proposed capital structure, and explains the importance of maintaining Northern's financial strength and integrity,
- *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; the Coronavirus Aid, Relief, and Economic Security Act; and the Families Fist Coronavirus Response Act on Northern's accounting for income taxes and how those effects are presented in the current rate case cost of service schedules.
- *Mr. Ronald Amen and Mr. John Taylor of Atrium Economics* present the Company's allocated cost of service and marginal cost of service studies, revenue apportionment and revenue targets by rate class, rate design, and bill impacts.
- *Mr. Timothy Lyons, Partner, ScottMadden, Inc.* provides the Company's proposed revenue decoupling structure.
- *Mr. John Cochrane, Senior Managing Director, FTI Consulting, Inc.*, 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. SUMMARY AND CONCLUSIONS

Q. Please now summarize your testimony.

A. Over the past several years, the Company has focused on delivering safe, reliable, and affordable service while investing in the assets to support growth and improve the system. We are proud of our past accomplishments and we look forward to further supporting New Hampshire's policy objectives. The multi-year plan we propose in this application will allow Northern to continue investing in the assets needed to provide the safe and reliable service our customers require, and the rate mechanisms we propose will ensure just and reasonable rates with a reasonable opportunity to earn its authorized rate of return without the need to file frequent rate cases.

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 gas delivered by a stable, financially healthy utility will be well-served.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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Summary

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 range of financial, strategic, regulatory, and economic matters on over 325 occasions before regulatory commissions at the state, Provincial (Canada), and U.S. Federal (FERC) levels, U.S. Federal District Courts, and American Arbitration Association panels.

Prior to joining Unitil in July 2020, 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. During his career, Bob has worked with numerous energy companies, regulatory commissions, 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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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.	6/21	Northern Utilities, Inc.	Docket No. 2021-00022	Investigation of inclusion of CIS implementation costs in rates
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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	Financing Plan
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Financing Plan
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	Docket No. DE 21-030	Overall Policy Witness
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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)
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)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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)

Sponsor	Date	Case/Applicant	Docket No.	Subject
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

CHRISTOPHER J. GOULDING

AND

DANIEL T. NAWAZELSKI

EXHIBIT CGDN-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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Schedule CGDN-2	Illustrative Revenue Requirement – 2021 Rate Plan
Schedule CGDN-3	Computation of Revenue Requirement for Temporary Rates
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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 Northern Utilities, Inc. ("Northern" or the "Company"). My responsibilities include all rate and regulatory filings related to the financial requirements of Northern 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 Manager of Revenue Requirements 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, progressing to the role of Manager of Revenue Requirements in 2021. 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 Northern 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. We also discuss the Company's other regulatory proposals and considerations regarding waived late payment charges, special contract revenues, the treatment of certain mains extensions projects and an update to the Company's expansion in Epping, New Hampshire. Next, we explain the transition to decoupling from the current lost revenue recovery mechanism. Finally, we provide proposed tariff changes and 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 $7,782,950 or approximately 8.1 percent over the Company's total base revenue under present rates after accounting for changes to other reconciling mechanisms. These changes roll certain items, such as lost base revenue and regulatory assessments, 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 7.75 percent that includes a return of equity ("ROE") of 10.30 percent.

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

A. The Company currently collects costs for lost base revenue and regulatory assessments 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 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 a net base revenue increase of $7,307,632 as summarized in Table 1 below.

Table 1: Net Revenue Deficiency Increase

Description	Reference	Amount
Revenue Deficiency	Schedule RevReq-1, Line 7	$ 7,782,950
Cost Recovery Movement		
Lost Base Revenue	RevReq Workpaper – Flowthrough Detail	$ (359,089)
Regulatory Assessments	Schedule RevReq-3-9, Line 3	$ (116,230)
Net Revenue Deficiency		$ 7,307,632

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 Northern 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 Northern.

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 August 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 Northern with sufficient revenues to continue to ensure safe, reliable and cost-effective delivery service for Northern customers and to provide a reasonable opportunity for Northern to earn its authorized rate of return. Northern 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 Northern 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-6 through 6-7. The Adjustments to Test Year specified in Section Puc 1604.09 have been provided in Schedules RevReq-3 through 3-21.

Q. Has Northern 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 $7,782,950 based on an overall rate of return on rate base of 7.75 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 Northern in the test year are presented in Schedule RevReq-1 through RevReq-7 and Workpapers supporting the revenue requirement schedules. The pro forma operating income for Northern in the test year is presented in Schedule RevReq-2, pages 1 and 2. In page 1, the “per books” revenues, operating expenses and net operating income are set forth in column (2), labeled “Test Year 12 Months Ended 12/31/2020.” Column (3), labeled “Cost of Gas Excluding Prod. & OH.”, contains test year revenue and operating expenses associated with the Company’s cost of gas mechanism, excluding its allowance for production and related overhead. We will discuss the exclusion of production and related overhead in the next Q&A. Column (4), labeled “Other Flowthrough” contains revenue and operating expenses from the Company’s non-base rate mechanisms including energy efficiency, environmental response costs, residential low income assistance, rate case costs, recoupment, lost base revenue and on-bill financing. Column (5), labeled “Test Year Distribution, Prod. & OH.” reflects base revenues and expenses and is calculated by subtracting Columns (3) and (4) from Column (2). In 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, Prod. & OH”, to obtain the adjusted revenues and operating expenses in column (4), labeled “Test Year Distribution, Prod. & OH. Pro Forma.” 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, page 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 on Line 7 of Schedule RevReq-1.

Q. Please describe the exclusion of production and related overhead allowances in the cost of gas mechanism as shown in column (3) of page 1 of Schedule RevReq-2.

A. During the test year, the Company collected $1,057,890 for production and related overhead through the Company's cost of gas mechanism as shown in Workpaper – Cost of Gas. This revenue relates to the revenue requirement last approved for the Company's gas production facilities in Docket DG 17-070. Excluding this amount from column (3) causes it to be included as a component of revenues in column (5) of Schedule RevReq-2, page 1. This component of the revenue requirement is later functionalized as production-related by witnesses Ron Amen and John Taylor and appropriately assigned for recovery through the cost of gas mechanism consistent with the current ratemaking.

Q. Please describe the pro forma adjustments that are shown in column (3) of page 2 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 & Cash Working Capital

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 balance sheet and detailed plant and accumulated depreciation information. Schedule RevReq-5 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-6 provides the calculations showing the Company's requested return on rate base of 7.75 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:

- Weather Normalization
- New Customer Revenue Annualization
- Residential Low Income
- Unbilled Revenue
- Non-Distribution Bad Debt
- Miscellaneous Revenue Adjustment
- Late Fees
- Billed Accuracy Adjustment
- Special Contract Customer Revenue

1. WEATHER NORMALIZATION

Q. Please explain the weather normalization adjustment.

A. The weather normalization adjustment normalizes the effect of actual weather experienced during the test year. Normal weather is based on 20-year historical average temperatures. In 2020, net temperatures were warmer than normal; therefore the test year operating revenues were lower than would occur under normal weather conditions. Schedule RevReq-3-1 provides for a pro forma adjustment to increase base distribution revenue by $1,994,374. This adjustment was calculated and supported in the testimony of Ron Amen and John Taylor.

2. NEW CUSTOMER REVENUE ANNUALIZATION

Q. Please explain the new customer revenue annualization adjustment.

A. The Company has adjusted test year operating revenues to annualize for sales growth associated with year-end customers. Schedule RevReq-3-2, Line 2 provides for a pro forma adjustment to increase base distribution revenue by $278,301. This adjustment was calculated and supported in the testimony of Ron Amen and John Taylor.

3. RESIDENTIAL LOW INCOME

Q. Please explain the residential low income adjustment.

A. We increased distribution revenues by $264,523 to reflect that residential low income costs are collected through a separate flow-through rate recovery mechanism, but should be attributed to the Company's cost of service. This adjustment is shown in Schedule RevReq-3-2, Line 4.

4. UNBILLED REVENUE

Q. Please explain the unbilled revenue adjustment.

A. The Company books unbilled revenue to account for the difference between the amount of gas delivered to customers during the test year and the amount billed to customers during the same period. Because the test year sales are based on weather-normalized sales, the accrual for the amount of unbilled sales was removed from the test year. This adjustment increases revenue by $294,543 as shown in Schedule RevReq-3-2, Line 6.

5. NON-DISTRIBUTION BAD DEBT

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

A. Total revenues have been decreased by $97,468 to remove accrued revenue associated with non-distribution bad debt. A similar adjustment was made to decrease operating expenses by $97,468, which is the provision for non-distribution bad debt in operating expenses. These adjustments are summarized in Schedule RevReq-3-2, Lines 7-9. Overall, there is no impact on the revenue requirement since both the revenue and operating expenses are adjusted by the same amount.

6. MISCELLANEOUS REVENUE ADJUSTMENT

Q. Please explain the miscellaneous revenue adjustment.

A. The Company booked a miscellaneous revenue adjustment to clear remaining rate case expense and recoupment balances during the 2020 test year. To remove this nonrecurring entry we have increased total revenues by $4,788 as shown in Schedule RevReq-3-2, Line 11.

7. LATE FEE REVENUE

Q. Please explain the late fee revenue adjustment.

A. The Company has increased test year revenue by $40,013 as shown in Schedule RevReq-3-2, Lines 12-15, 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 prohibited the Company from collecting these revenues?

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

8. BILLED ACCURACY ADJUSTMENT

Q. Please explain the billed accuracy adjustment.

A. The billed accuracy adjustment increases revenue by $367 and reflects the difference between what the Company booked in the test year versus what witnesses Ron Amen and John Taylor calculated using test year billing determinants and distribution rates. This adjustment is shown in Schedule RevReq-3-2, Lines 17.

9. SPECIAL CONTRACT CUSTOMER REVENUE

Q. Please explain the special contract customer revenue adjustment.

A. We increased total revenues by $17,968 as shown in Schedule RevReq-3-2, Lines 18-21 to reflect known and measurable special contract rate increases that occurred in December 2020 and March 2021. Test year billing determinants for these two customers were calculated at their respective 2021 special contract rates and then reduced by the customer's test year actual revenues to calculate the net revenue adjustment.

Q. Is the Company proposing anything else with respect to special contract revenue?

A. Yes. The Company is proposing to exclude special contract revenue from decoupling. 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 Northern's per books Operating & Maintenance Expense?

A. In the test year, Northern incurred $13,580,391 of Operating & Maintenance ("O&M") Expense related to Distribution and Production Related Overhead, as shown on Schedule RevReq-2, Page 2, Column 2, Lines 6 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:

- Production Expense
- Non-Distribution Bad Debt
- Distribution Bad Debt
- Payroll
- Medical & Dental Insurances
- Pension, Postemployment Benefits Other than Pension, Supplemental Executive Retirement Plan, 401K, and Deferred Compensation Plan Expense
- Property & Liability Insurance

- Commission Regulatory Assessment
- Dues and Subscriptions
- Pandemic Costs
- Severance
- Rent Expense
- Arrearage Management Program ("AMP") Implementation Cost
- Inflation Allowance

We will discuss each adjustment individually in the following section.

1. PRODUCTION EXPENSE

Q. Please explain the adjustment for production expense.

A. This adjustment allocates production facility operation and maintenance expenses between Northern Utilities' Maine (ME) and New Hampshire (NH) divisions by the Fixed Demand factor as filed in the Company's cost of gas filings. The Fixed Demand factor as of December 31, 2020 was 40.88% (NH) and 59.12% (ME). This allocation results in an increase of expense of $76,191 to the NH division as shown in Schedule RevReq 3-3.

2. PAYROLL

Q. What adjustment was made to payroll?

A. The payroll adjustment, as reflected on Schedule RevReq-3-4 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 September 6, 2021 and that are projected to occur on January 1, 2022 and September 6, 2022.

These adjustments have been made to the payroll for both Northern 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 $554,442 as shown on Schedule RevReq-3-4 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. 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-3-5. 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 $88,160.

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 because the write off activity in 2020 was not reflective of a normal year's level. This was due to the disconnection moratorium that was implemented beginning in March 2020 pursuant to the Governor's Executive Order 2020-04 and Emergency Order #3, and Commission Order No. 26,343.

Q. How is the Company proposing to address the write off activity that will occur now that the disconnection moratorium has been lifted?

A. To ensure that the Company is recovering a representative level of bad debt expense in distribution rates, the Company proposes to track the actual delivery write offs against the level in distribution rates and to recover the difference annually through the Company's proposed Regulatory Cost Adjustment Mechanism ("RCAM") as part of the Local Delivery Adjustment Charge ("LDAC"). The Company does not expect actual write-offs to return to pre-pandemic levels for some time.

Q. Has the Commission issued an order in Docket IR No. 20-089 regarding the recovery of incremental bad debt expense?

A. Yes. In Order No. 26,495 (July 7, 2021) the Commission declined to authorize New Hampshire's public distribution utilities to establish a regulatory asset for incremental bad debt expense or waived late payment fees related to the Covid-19 pandemic. However, the Order states: "recovery of these expenses is best addressed in the context of each utility's next rate case when such costs (to the extent they remain relevant under test year based rate-setting) can be appropriately considered in the context of each company's full revenue requirement and overall rate of return." Order at 9 (July 7, 2021).

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 described 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 Company's proposed RCAM as a component of the LDAC.

Q. Why is it necessary for the Company to handle the bad debt in this manner?

A. Due to the pandemic and the disconnection moratorium, and the timing of the moratorium terminating, it is anticipated that it will be a multi-year process before Unitil experiences a normal level of write off activity. On June 30, 2020 Emergency Order #3 terminated and Emergency Order #58 was enacted that further provided that the New Hampshire utilities "shall offer payment arrangements, refrain from charging late fees, and begin normal collection activity and disconnections consistent with an agreement between a utility or utilities and the Commission's Consumer Services and External Affairs Division, subsequent order of the Commission, and/or rules adopted by the Commission pursuant to RSA 541-A". In complying with Emergency Order #58, on September 10, 2020, the Utilities along with the New Hampshire Public Utilities Staff, Office of the

Consumer Advocate, New Hampshire Legal Assistance and LISTEN filed a settlement[1] extending the shut off and disconnection moratorium until April 1, 2021 and subsequent amendment to the settlement extending the date to May 31, 2021. The shut off and disconnection moratorium has led to an abnormal increase in past due account receivables which have the potential to lead to higher than historic bad debt expense levels.

4. 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-3-2.

5. 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 $404,594. This adjustment is shown on Schedule RevReq-3-6, and includes amounts allocable to the Company 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

[1] Settlement was approved in Docket No. IR 20-089 by Secretarial Letter issued on October 5, 2020.

presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

6. 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-3-7 which shows a pension decrease of $2,185, a decrease to PBOP expense of $19,749 and increases to SERP, 401(k) and deferred compensation expense of $58,798, $30,095 and $44,415, 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.

7. PROPERTY & LIABILITY INSURANCE

Q. Please describe Northern'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. Northern'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-3-8, the pro forma adjustment for property and liability insurances is an increase of $60,699 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 4.3 include actual costs for 2021 insurance policies. The Company will provide 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 peer companies 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.

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 and through its Gas Assistance Program and Regulatory Assessment ("GAPRA") mechanism. The proposed adjustment shown in Schedule RevReq-3-9 moves all recovery into base rates, with any incremental changes to be recovered or refunded through the RCAM. The adjustment increases expenses by $116,230 and is necessary to comply with the requirements in RSA 363-A:6,II. 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 GAPRA 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 $1,774 in Schedule RevReq-3-10 to remove the lobbying portion of the Company's annual membership dues to the American Gas Association 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-3-11, this adjustment removes $107,125 of pandemic related costs that were charged during the 2020 test year. The Company believes that these costs were anomalous and should not be included on a forward looking basis for ratemaking purposes.

11. 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 $29,947. 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.

12. RENT EXPENSE

Q. Please explain the adjustment related to rent expense.

A. The Company has increased test year rent expense by $51,913 for estimated rent expense due to Unitil Service for use of the new Exeter Distribution Operating Center. The Company intends to update this amount for actual 2021 rent expense during the pendency of this case, but does not expect the amount to materially change from its estimate.

13. ARRERAGE 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 Ms. Carole Beaulieu. The $92,480 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 split between the Company and Unitil Corp.’s New Hampshire electric distribution operating company, Unitil Energy Systems, as well as the annual program forgiveness costs.

Q. What happens if the program cost are greater or less than the $92,480 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 $92,480 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 RCAM.

14. 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 Northern, 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 5.12 percent over a 25-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 August 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 $165,684 as shown on Schedule RevReq-3-15 page 1, line 19.

III. DEPRECIATION EXPENSE

Q. Is Northern 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 $469,003.

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. DG 17-070.

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, increases the test year depreciation expense by $1,847,988. 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 $189,288. 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 Mr. 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 $308,218, 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 $617,939. 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.

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 31 of Schedule RevReq-3-19 an amount of $688 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. 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 RCAM.

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 $42,415 was prepared to pro form the amount of Northern 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 $95,258 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 revenues and 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 Northern?

A. Yes, we have provided Assets & Deferred Charges and Stockholder's Equity and Liabilities in Schedules RevReq-4-1 and 4-2, respectively. We have also provided detailed plant and accumulated depreciation information in Schedules RevReq-4-3 and 4-4, respectively.

Q. Please summarize the information you have provided to support the rate base used to determine Northern's revenue requirements.

A. Schedule RevReq-5 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 $182.9 million, the "5 Quarter Average" of $179.0 million, the "Rate Base at December 31, 2020" of $188.0 million, and the "Pro Forma Rate Base at December 31, 2020" of $188.7 million. The pro forma rate base at December 31, 2020, was used to determine Northern'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 Northern 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, Northern 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 three base distribution rate cases in Docket DG 11-069, Docket DG 13-086 and Docket DG 17-070, and we believe it is appropriate to continue this practice.

Q. Since the Company's last base rate proceeding, has Northern added utility plant to its operations?

A. Yes. Pro Forma Distribution Utility Plant in Service has grown from $212,059,659 in pro forma 2016 (the Company's most recent rate case test year) to $301,245,498 in pro forma 2020 (a 42.1 percent increase). Adjusting these amounts by the 2016 and 2020 Reserves for Depreciation and Amortization, Net Utility Plant has grown from $145,142,807 in pro forma 2016 to $211,872,045 in pro forma 2020 (a 46.0 percent increase). Refer to Docket No. 17-070 Settlement Agreement, Exhibit 1, Page 45 of 95 for pro forma 2016 information and Schedule RevReq-5, column 7 for pro forma 2020 information.]

Q. Please describe the component of rate base information on Schedule RevReq-5-1.

A. Schedule RevReq-5-1 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-5-2.

A. The calculation of cash working capital in rate base is detailed in this schedule. The calculation consists of a 36.49 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. Northern proposes to include $2,008,385 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 Northern 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 Northern's customers. Pursuant to Commission precedent, cash working capital is an addition to Northern'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 and Prepayments have all been added to rate base. These items are shown on Schedule RevReq-5 and RevReq 5-1.

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-5 and 5-1.

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 $6,572,092 was recognized to be returned to customers in future rates and is shown in Schedule RevReq-5 and Schedule RevReq-5-1.

Q. Please explain Schedule RevReq-5-3 which contains the Supplemental Plant Pro Forma Adjustment.

A. This schedule contains plant in service and accumulated depreciation for the Company's production facilities, including a LNG plant located in Maine. This schedule allocates these production plant and depreciation balances to either New Hampshire or Maine based on the Company's Fixed Demand factor (40.88% NH and 59.12% ME). The Company allocates the production facilities based on this methodology because the Company manages a combined system where the costs are allocated among the states based on relative gas usage. This methodology was approved in the Stipulation and Settlement approved by the Maine Commission in Docket No. 2005-00273 and by the New Hampshire Commission in Docket DG 05-080.

Q. Please explain Schedule RevReq-5-4 which contains a deferred income tax adjustment.

A. In Docket DG 08-048 and DG 08-079, the Company agreed to hold ratepayers harmless from the tax impact of Unitil Corp's acquisition of the Company. In this acquisition, a 338(h)(10) election was made which eliminated the Company's historical accumulated deferred income taxes. In the Stipulation approved by the Commission in Docket DG 08-048 and DG 08-079, the Company agreed to maintain pro forma accounting for regulatory purposes of the historical deferred income tax balance assuming the acquisition had not occurred. This historical deferred income tax balance is then used for ratemaking purposes until such time that the newly acquired deferred income tax balance equals or exceeds the historical balance. This schedule provides both the historical and newly acquired deferred income tax balances and utilizes the historical balance for ratemaking purposes. The Schedule shows that the acquired deferred income tax balance exceeds the historical balance as calculated on Schedule RevReq-5-4, Line 3. The Schedule then incorporates deferred income tax balances as a result of capital spending post-acquisition and deferred taxes due to net operating losses. The deferred taxes associated with net operating losses have been adjusted to reflect losses attributable to rate base. Since the Company's post acquisition deferred income tax balance exceeds the historical balance an adjustment is no longer necessary as shown on Schedule RevReq-5-4, Line 8.

IX. RATE OF RETURN

Q. What rate of return have you used for ratemaking purposes?

A. As shown on Schedule RevReq-6, Northerns's weighted cost of capital is calculated to be 7.75 percent. As described in the prefiled testimony of Messrs. Todd Diggins and Andre Francoeur, 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 7.75 percent, as shown on Schedule RevReq-6. We have applied this weighted cost of capital to the rate base of $188,719,257, shown on Schedule RevReq-1, to calculate the return on the rate base. The result is a total required return on rate base of $14,621,110 as shown on Schedule RevReq-1, line 3.

Q. Is there anything else you would like to add regarding the rate of return?

A. Yes. As described in the testimony of Mr. Robert Hevert and Messrs. Diggins and Francoeur, the Company has requested a Return on Equity of 10.30 percent, which is toward the lower end of the Return on Equity range recommended by our expert Mr. John Cochrane. The Company's decision to request a Return on Equity of 10.30 percent is described in greater detail in the prefiled testimony of Mr. Hevert.

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 non-growth capital additions to rate base. The 2021 Rate Plan is outlined in detail in Schedule CGDN-1.

Q. What additions to plant will be eligible for recovery?

A. As more fully described in the prefiled testimony of Messrs. Sprague and Leblanc, eligible Non-Growth Plant Additions are defined as capital spending related to pipe replacement programs, other replacement programs, system improvements, highway projects, asphalt restoration, farm tap replacement, the Rochester Reinforcement project, and other non-growth related projects.

Q. For what years will the 2021 Rate Plan apply and what is the timing for filings with the Commission and rate implementation?

A. The plan will encompass three annual step adjustments to recover the revenue requirement. The step adjustments would take place in August 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 March for the prior year's additions. Then, the resulting rate changes would go into effect August 1. For example, the filing for investment year 2021 additions would be filed with the Commission by March 31, 2022 with rates going into effect August 1, 2022, coinciding with the permanent rates from this proceeding.

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 Messrs. Sprague and Leblanc. 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 Rate Base on page 1 of Schedule CGDN-2.

A. Rate Base is calculated by sourcing lines 1 and 2 from the Company's plant accounting records to arrive at the 2021 Rate Plan Non-Growth Capital Expenditures as shown on line 3. Accumulated Depreciation is calculated on line 4 by taking 50% of the calculated Depreciation Expense. Next, Accumulated Depreciation is removed from the 2021 Rate Plan Non-Growth Capital Expenditures to derive Net Utility Plant as shown on line 5. Then Accumulated Deferred Income Taxes (ADIT) is calculated on line 6 by applying the Effective Income Tax Rate to the difference between Book and Tax Depreciation as shown on lines 18-26. Lastly, ADIT is deducted from Net Utility Plant to get the Rate Base associated with 2021 Rate Plan Non-Growth Capital Expenditures as shown on line 7. While Schedule CGDN-2 formulaically derives Rate Base based on the capital budget provided in this proceeding, the intent of the Company is to source Non-Growth Capital Expenditures 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. As described above, once Rate Base is calculated it is multiplied by the Pre-Tax Rate of Return on line 9 to derive the Return and Related Income Taxes on line 10. Next, Depreciation Expense associated with eligible Non-Growth Plant

Additions is calculated on lines 18-20 based on a composite depreciation rate of 3.73 percent, which is calculated in Line 39 Column 3 from Schedule RevReq-3-16, Page 2. Then, State Property Taxes are calculated on Net Utility Plant on line 12 using a property tax rate of 0.66%, which corresponds to the statutory tax rate in RSA 83-F:2, currently $6.60 per $1,000 of investment. The Company would update this rate annually based on the latest property tax rates. Finally, Return and Related Income Taxes, Depreciation and Property Taxes are added together to arrive at the Revenue Requirement on line 13.

Q. What schedules support Schedule CGDN-2, Page 1?

A. Schedule CGDN-2, Page 2 presents the capital budget by year for Non-Growth Capital Expenditures for illustrative purposes. Again, actual plant accounting records will be used in calculating 2021 Rate Plan Non-Growth Capital Expenditures. Schedule CGDN-2, Page 3 shows the calculation of the pre-tax rate of return.

Q. Please describe the impact of New Hampshire House Bill ("HB") 700 on the Company.

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.

Q. Did HB 700 allow for increases in all property taxes to be recovered?

A. No, HB 700 allowed for the recovery of increases in property taxes associated with "Utility company Assets" defined as:

> "Utility company assets" means the following property not exempt under RSA 72:23:
>
> (2) For a gas company providing gas service to retail customers: distribution pipes, fittings, meters, pressure reducing stations, buildings, contributions in aid of construction (CIAC), construction works in progress (CWIP), and land rights including use of the public rights of way, easements on private land owned by third parties, and land owned in fee by the gas company.

Q. How does the Company intend to incorporate the impact of New Hampshire House Bill ("HB") 700?

A. The Company recently made a filing in Docket No. DG 21-123 on June 21, 2021. 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 RCAM on November 1 of each year. The amount included in base distribution rates for property tax expense shall be $5,346,199[2]

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[2] Amount will be updated during the pendency of this proceeding to reflect the final 2021 tax bills.

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 RCAM 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 RCAM 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. DG 21-123, the RCAM shall recover any over- or under- recoveries beginning on November 1 of each year.

Q. Is the Company's property tax recovery proposal in Docket No. DG-123 limited to the recovery of increases associated with local – utility plant assets only?

A. No. For administrative efficiencies and simplified reconciliation, the Company has proposed that the annual recovery includes the reconciliation of all local property taxes (local building and utility plant assets).

Q. How does the Company propose to address the change in state related property taxes?

A. The Company is proposing to exclude the changes in the state related property taxes from the recovery proposal consistent with the language of HB 700. Recovery of the state portion of the property taxes would be recovered on Non-

Growth Utility Plant, as described above during the term of the 2021 Rate Plan and thereafter would continue to occur as it does now as part of the normal rate case process.

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 $3.1 million (in investment year 2021 and 2022) to $3.2 million (in investment year 2023) depending on the level of plant investments in a given forecast year. The step adjustments represent 4.7 percent to 4.8 percent of test year operating revenue. Again, these revenue requirement results are forecasts based on the Company's capital budget. Actual Non-Growth Plant Additions will vary from this forecast.

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 revenue requirement cap of $10,500,000 which is the sum of the revenue requirements for investment years 2021-2023 plus an increase of approximately 10%. The additional approximate 10% is to accommodate unknown conditions, such as municipal projects that may arise in the future but are not known today. 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, 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 $3,220,742 on an annualized basis to become effective on October 1, 2021. The development of the temporary rate amount is detailed in Schedule CGDN-3.

Q. Please explain how the temporary rate amount of $3,220,742 was derived?

A. In general, the Company 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. 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-6. 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 Schedule RevReq-1 of Schedule-CGDN-3, this results in an overall cost of capital of 7.33 percent. The test year net operating income was adjusted to reflect a handful of pro forma adjustments, as shown in Schedule RevReq-3 of Schedule CGDN-3, and also portrays a weather-normal 2020 distribution test year. In general, the pro forma adjustments selected were confined to the 2020 test year, such as depreciation annualization to bring depreciation levels up to year-end balances, and property taxes to reflect the most recent annualized 2020 property tax bills. No adjustments pertaining to 2021 and beyond were incorporated.

Q. Please describe the derivation of the proposed temporary delivery charge per therm.

A. The calculation of the annualized proposed temporary rate increase of $0.0876 per therm for rates R5, R6 and R10 and $0.0279 per therm for rates G40, G50, G41, G51, G42, G52 is provided in Schedule CGDN-4. The temporary rates were calculated for residential and commercial and industrial customers by first proportionally allocating the proposed temporary revenue requirement by adjusted 2020 test year revenue. Next, the proposed temporary delivery charge per therm was determined by dividing the residential or commercial and industrial proportioned increase by the test year adjusted weather-normalized delivery volumes rounded to four decimals. The temporary rate surcharge will not be applied to special contract customers.

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 therm, applied to all rate schedules, and included in the LDAC.

VI. OTHER REGULATORY PROPOSALS AND CONSIDERATIONS

Q. What other proposals and considerations is the Company making?

A. The Company is proposing and presenting information regarding the following areas:

1. Waived Late Payment Charge Revenues for the period April 2020 through March 2021
2. Special Contract Revenues
3. Mains Extension Project Updates
4. Epping Franchise Expansion

We will discuss each adjustment individually in the following section.

1. WAIVED LATE PAYMENT CHARGES

Q. 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, Northern was not able to apply late fees to customer's accounts beginning in March of 2020. For the calendar year 2020, the Company charged $36,803 in late payment fees to customers, which is well below the amount that was included when distribution rates were last set in Docket No. DG 17-070 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. DG 17-070, 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 $104,863. This amount was equal to the actual late payment charge revenues for 2016.

Q. How much late payment fees did the Company waive in 2020?

A. Northern waived $133,719 of late payment fees for the 9 month period of April through December 2020 and is $183,462 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
Northern Utilities, Inc.

LPC Revenues	Docket No. DE 17-070 2016 (TY)	2020	Moratorium Period 2020	Moratorium Period 2020/2021	Comment
January	$ 7,985	$ 14,196			Charged - Actual
February	9,423	15,930			Charged - Actual
March*	16,764	6,677			Charged - Actual
April	13,105		$ 16,052	$ 16,052	Waived - Actual
May	14,749		21,297	21,297	Waived - Actual
June	11,837		20,319	20,319	Waived - Actual
July	7,393		15,693	15,693	Waived - Actual
August	7,909		14,976	14,976	Waived - Actual
September	3,037		12,047	12,047	Waived - Actual
October	4,033		12,473	12,473	Waived - Actual
November	4,036		10,239	10,239	Waived - Actual
December	4,592		10,623	10,623	Waived - Actual
January				13,688	Waived - Actual
February				16,386	Waived - Actual
March				19,669	Waived - Actual
Total LPC Revenues	$ 104,863	$ 36,803	$ 133,719	$ 183,462	

*Moratorium began in March 2020 and ended March 2021

Q. Is the $183,462 of waived late payment fees material to Northern?

A. Yes, the amount is material to Northern. For 2020, this amount represents roughly 2 percent of the Distribution Operating Income and 0.43 percent of the 2020 Test Year weather normalized distribution revenues.

Q. What is the Company proposing related to recovery of the $183,462 of waived late payment fees for the 12 month period ended March 31, 2021?

A. For the 12 months ended March 31, 2021, the Company is proposing to recover $104,863, which is the amount included in rates in Docket No. DG 17-070. This amount is lower than the actual waived late payment fees amount of $183,462. The Company would propose that the $104,863 be recovered as part of the Company's proposed RCAM.

2. SPECIAL CONTRACT REVENUES

Q. Is the Company proposing to include special contract revenue in decoupling?

A. No. As detailed in the testimony of Mr. Tim Lyons, the special contract revenue is being proposed to be exlcuded from the decoupling mechanism.

Q. Is the Company proposing any special treatment associated with the special contracts?

A. Yes. The Company is proposing that any change in special contract revenue from the test year adjusted amount of $1,197,813 that is included in the revenue requirement be reconcilled annually and any over or under recovery would be included in the RCAM.

3. MAINS EXTENSION ANALYSIS

Q. Please explain the Commission's decision to temporarily disallow investment related to two projects in the Company's most recent step increase in Docket No DG 17-070.

A. In the Company's last rate case, DG 17-070, the Commission approved a settlement agreement allowing a permanent increase in distribution rates (effective May 1, 2018) as well as an initial step increase (also effective May , 2018) and the option for a second step increase (effective May 1, 2019). DG 17-170, Northern Utilities, Inc., Order No. 26,129 at 14-15 (May 2, 2018). Northern filed a request for a step increase on February 28, 2019. During the course of the proceeding Staff recommended two disallowances to the step adjustment (and permanent rate base) related to projects involving customer CIACs ("Contributions in Aid of Construction"). Staff argued that the Company did not collect sufficient CIACs on two specific projects, 201 Atlantic Avenue, North Hampton and 10 Hampshire Road, Salem. The Commission adopted the Staff's recommended disallowance for the purposes of the step adjustment, but allowed the Company to make a presentation in its next rate case demonstrating why the full cost of the main extensions should be included in rate base. DG 17-070, Northern Utilities, Inc., Order No. 26,246 at 7 (May 2, 2019).

Q. Is this Company seeking to include the full cost of main extension projects at 201 Atlantic Avenue in North Hampton and 10 Hampshire Road in Salem?

A. Yes.

Q. How does the Company determine the CIAC amount to charge to a customer prior to undertaking a main extension project?

A. Any extension of gas main is treated on the basis that the project will have to meet the Company's rate of return criterion. A project may consist of a single building or a group of buildings, so long as the buildings are in close geographic proximity and will be served by a contiguous gas main infrastructure. In cases where the Company's rate of return criterion is met, the Company will provide the extension of gas main at no charge. In cases where this criterion is not met, the customer will be required to make up the capital deficiency (a "Contribution in Aid of Construction" or "CIAC") to meet the Company's rate of return criterion. The Company has developed a rate of return model ("Model") to be used for this analysis. The underlying rate of return criterion requires that each new installation project create sufficient revenues to earn the Company its after-tax weighted-average cost of capital to provide recovery of Incremental Project Costs (capital expenditures for services and/or main extensions, net of fixed General and Engineering and Operations overhead expenses) over a period of 20 years or less for residential and municipal projects and over a period of 10 years or less for commercial and industrial projects. (The recovery periods are considered 'dynamic' in the sense of commencing after the last year of construction, which may be appropriate to larger, multi-year construction projects.) If a project yields a rate of return equal to or greater than the benchmark rate of return over the benchmark recovery period, the project passes the rate of return test and no customer contribution is required. If a project fails the rate of return test, the Model calculates a CIAC required for the project to pass the rate of return test over the recovery period. Customer revenues used to calculate the Company's rate of return include distribution revenues only.

Q. Is calculating a CIAC an exact science?

A. It is not, although the Company is confident that the Model it uses to calculate a CIAC is a sound and conservative estimating tool that facilitates prudent decision-making. For reasons beyond the Company's control, circumstances may change during project construction in a manner that affects assumptions underlying the CIAC calculation. For example, the Company may encounter ledge when installing the extension, increasing the construction budget. In such a situation, a remodeling of the project economics might result in a higher CIAC than was collected from the customer. This was the case with the Atlantic Avenue and Hampshire Road projects. However, it is also the case that some extension projects result in better project economics than originally modeled which results in additional benefit to existing ratepayers.

Q. When the economics of a project change in a way that would result in a higher CIAC if the project were remodeled, does the Company request an additional CIAC amount from the customer?

A. The Company may do so, but believes it is important to be able to exercise judgment and discretion when remodeling a project results in a higher CIAC than was originally collected from the customer. In some circumstances – for example, if decisions unilaterally made by the customer change the project economics – then requesting an additional CIAC may be appropriate. But there may be other situations in which circumstances beyond the control of the Company and the customer cause a project to be less economic than originally modeled. Such circumstances may include unanticipated field conditions, or regulatory, State, or municipal requirements that could not reasonably be foreseen. When this is the case, the Company should have the flexibility to forego seeking an additional CIAC amount or, alternatively, negotiate an additional CIAC amount, as not all customers will have the financial ability to pay an additional CIAC amount, or requesting an additional CIAC may be unfairly burdensome to the customer in light of the customer's settled expectations.

When considered in the context of a portfolio of projects that returns net benefits to all customers, it is appropriate and reasonable to allow the Company full recovery of projects that may not be, in hindsight, as economically beneficial as anticipated. It would not be reasonable to subject the Company to a disallowance when it makes a prudent investment decision, encounters circumstances beyond its control, and determines that it would be unfairly burdensome to the customer to request an additional CIAC.

Q. Please briefly describe the Atlantic Avenue and Hampshire Road projects.

A. The School Administrative Unit 21 (SAU 21) requested gas service to the N. Hampton Elementary School which serves grades K-8th for the town of N.

Hampton. The SAU wanted to replace old inefficient oil boilers with new high-efficient natural gas boilers. To provide gas service the Company needed to install 3,200 feet of 6”8 HDPE gas main to the North Hampton Elementary School. This was tied into an existing 6” IP main in Atlantic Ave. The original IRR modeling for this project required a CIAC ($110,841) from the SAU. The town of N. Hampton was required to put this cost before the town in the form of a Warrant Article. The Article was passed and the project moved forward.

The Hampshire Road project was a new storage facility being constructed at 10 Hampshire Road in Salem, NH in which the customer requested natural gas to be extended enabling a new service connection to the site. To serve the property, the Company needed to install 300 feet of new 6” HDPE gas main to a point where a service could be extended onto the property. The new gas main was connected to the existing 6” IP main in Hampshire Road. The original modeling review for this project passed the necessary hurdle rate and required no CIAC from the customer.

Q. Did the Company remodel the Atlantic Avenue and Hampshire Road projects for this filing?

A. Yes, please see Schedule CGDN-5 for summary of the original model results and the revised model results. The additional projects included in this schedule will be explained later in our testimony.

Q. Did the Company update the results?

A. For the Atlantic Avenue project, modeling based on actual cost, currently connected customers, customers under contract, and the initial CIAC charged and collected returns a negative Net Present Value of ($110,276). However, there are an additional 21 potential customers (5 commercial, 16 residential) along the main extension that may connect over the coming years which would further improve the project economics. The revised modeling for the Hampshire Road project results in a Net Present Value of ($38,502). However, there are two more potential customers (1 commercial, 1 residential) that may connect along this main route and would improve the project economics in the future.

Q. What were the circumstances that caused the actual costs to be higher than originally estimated for the Atlantic Avenue project?

A. The cost increased due to ledge removal and additional cut backs and paving required by the New Hampshire Depart of Transportation ("NHDOT"). Ledge removal and the close proximity of the installed main to the edge of pavement undermined the pavement, and the NHDOT required the Company to cut the trench back one foot and repave. This requirement necessitated more paving and ledge removal than estimated.

Q. What were the circumstances that caused the actual costs to be higher than originally estimated for the Hampshire Road project?

A. The cost increased due to costs associated with additional ledge incurred at the street crossing. Although the Company originally planned to bore under the roadway, the ledge encountered in the street prevented that approach and required that the Company to open cut the street, remove ledge and cutback and pave the trench. This added additional traffic detail costs as well.

Q. Please explain why the full cost of the two main extension projects temporarily disallowed in the previous step filing should now be included in the Company's rate base.

A. The Company believes that main extension projects, when viewed in aggregate, will generally provide a benefit to the existing customer base. The Company relies on estimates that are reasonable and made in good-faith when analyzing the economics of a project during the planning process. Moreover, the planning process is designed to benefit rate payers. That is, if a project is not expected to meet or exceed the Company's hurdle rate during the planning phase, a CIAC is calculated to offset the capital costs and bring the economics in line. Conversely, if the project economics exceeds the Company's hurdle rate the benefit will be recognized by the existing rate payers as the Company's fixed costs are spread over a larger customer base. These two scenarios illustrate that there is a strong rate payer protection built into the main extension policy that allows existing customers to reap the benefit of projects while mitigating the risk of weaker projects with a CIAC. This built in rate payer protection ensures that extension projects, in aggregate, will benefit the existing rate payers.

Schedule CGDN-5 summarizes the original and revised net present value of the nine main extension projects included in the Company's 2019 step filing, and illustrates that the projects, when reviewed in aggregate, benefit the existing customer base. The Company updated the original models for actual capital costs, actual customer additions, and updated estimated usage based on recent billing data. This was a conservative update process as the Company did not update for distribution rates that have increased, nor did the Company update for the lower hurdle rate as a result of declining cost of debt. This Schedule illustrates that the total projects return a favorable Net Present Value of $914,129, an increase of $562,718 over the original estimates. While some projects are not as strong as originally estimated, in aggregate, the main extensions provided a significant net benefit to existing customers of over $0.9 million.

Q. Does the Company believe it is appropriate to continue to disallow rate base denied in the previous step adjustment?

A. No. The Company's gas extension projects proposed for recovery in the prior step filing have proven to be beneficial to existing rate payers, demonstrating the Company's prudent judgement and discretion during the project evaluation phase. By penalizing the Company on a project by project basis the Commission would markedly increase the financial risk of the Company's expansion projects, which provide a net benefit to all rate payers. The Company's main extension projects are properly planned and prudent investments that warrant a fair return on invested capital.

4. EPPING FRANCHISE EXPANSION

Q. Has the Company provided a variance analysis comparing the results of the DCF analysis of the Company's Epping Franchise Expansion (Docket No DG 18-094) to an updated DCF analysis?

A. Yes. Please see Schedule CGDN-6. As directed by the Commission in Docket No DG 18-094, the Company has provided a variance analysis comparing the original DCF analysis for the Epping franchise (DG 18-094 Hearing Exhibit 8) and a revised DCF analysis using actual costs and revenues and projected future revenues. DG 18-094, Order No. 26,220 at 12 (Feb. 8, 2019).

Q. Please explain the update process for the Revised DCF model.

A. The Company updated the original model referenced as Exhibit 8 for actual project costs and actual customer additions. The Company maintained its previous assumptions for total market size and customer conversion rate. The remaining modeling logic for revenue, expense, and the cash flow discounting methodology is also unchanged.

Q. Please compare the results of the original and revised DCF model.

A. Actual capital costs are similar to the original cost estimates, increasing less than 4.0%. The revised 10-year and 20-year net present values have been provided in Schedule CGDN-6.

Q. Will Northern's expansion into Epping be beneficial for its existing customers in New Hampshire?

A. Yes. The Company is pleased with the development of the project and believes the project will benefit existing rate payers and the town of Epping. The 20-year net present value is very strong, emphasizing that this project will benefit rate payers for decades to come. The town of Epping has experienced impressive commercial growth over the past decade, and the Company expects development in the area to further support the economics of the expansion. Furthermore, the pipelines installed in Epping have sufficient capacity to serve other communities should the Company continue to expand its distribution network.

VII. TRANSITION TO DECOUPLING

Q. How will the Company transition from Lost Base Revenue Recovery as part of the Lost Revenue Rate ("LRR") to Decoupling?

A. At the start of the proposed decoupling period of August 1, 2022, the Company will stop accruing Lost Base Revenue ("LBR") associated with Energy Efficiency savings. Up until that time, the Company will 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 July 31, 2022, assuming a start date of decoupling of August 1, 2022. Table 3 below outlines how the transition will work based on the proposed temporary rates, permanent rates and decoupling start period of August 1, 2022 timeline. The Company is not proposing any change to the LRR at this time and instead will make all required changes, including reconciliations in subsequent LRR filings as appropriate.

Table 3: Transition from LBR to Decoupling

October 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 August 1, 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
August 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 therms annually, the impact on the 2020 test year sales would only reflect a reduction of 10 therms kWh (120 / 12 months * 1 month). The remaining 110 therms 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 4 below shows an illustrative example of how the calculation would work based on the 145,178 therms of actual annual 2020 savings installed in 2020. The 2020 test year would reflect a reduction in sales of 65,169 therms with the remaining reduction of 80,008 therms of savings reduction occurring in 2021.

Table 4: Illustrative 2020 Savings Annualization

Northern Utilities, Inc.
2020 Residential Installed Therm 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 Therm Savings***	**-**	**16,204**	**15,242**	**7,355**	**918**	**4,876**	**3,827**	**30,944**	**14,644**	**24,534**	**7,203**	**19,430**	**145,176**
2														
3	**Monthly Residential Therms Savings**													
4	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
5	February 2020		1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	14,853
6	March 2020			1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	12,702
7	April 2020				613	613	613	613	613	613	613	613	613	5,516
8	May 2020					76	76	76	76	76	76	76	76	612
9	June 2020						406	406	406	406	406	406	406	2,844
10	July 2020							319	319	319	319	319	319	1,913
11	August 2020								2,579	2,579	2,579	2,579	2,579	12,893
12	September 2020									1,220	1,220	1,220	1,220	4,881
13	October 2020										2,044	2,044	2,044	6,133
14	November 2020											600	600	1,201
15	December 2020												1,619	1,619
16	**Total 2020 Therm Savings Realized in 2020**	**-**	**1,350**	**2,621**	**3,233**	**3,310**	**3,716**	**4,035**	**6,614**	**7,834**	**9,879**	**10,479**	**12,098**	**65,169**
17														
18	**2020 Residential Therm Savings Realized in 2021**	**-**	**1,350**	**2,540**	**1,839**	**306**	**2,031**	**1,913**	**18,051**	**9,762**	**18,400**	**6,003**	**17,811**	**80,008**
	*Per DE 17-136 Northern Utilities, Inc 2020 Energy Efficiency Revised Annual Report filed on June 29, 2021 Page 1 of 18(Revised)													

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, as presented in the prefiled testimony of Ron Amen and 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 proposed RCAM tariff, which is a component of the LDAC; (4) proposed Temporary Rate surcharge; and (5) changes to the Company's delivery service terms and conditions as supported by Mark Lambert.

Q. What changes is the Company proposing to the Company's proposed RCAM tariff?

A. The Company is proposing changes to its proposed RCAM tariff to address the following:

1. As described above in Section III. C. ii. 3, 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 year's RCAM.
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 RCAM. This is described in greater detail in Section III. C. ii. 13 above.
3. As described in Section VI. 1 above, the Company is proposing to 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 RCAM.
4. As described in Section VI. 1, the Company is proposing to refund or collect the change in special contract revenues from the amount included in base distribution rates through the subsequent year's RCAM.

Finally, the Company is not proposing any change to the RCAM rate at this time, and instead will make all required changes, including reconciliations in subsequent RCAM filings as appropriate. The Company has provided an illustrative RCAM tariff, which is a component of the LDAC in Schedule CGDN-7 to reflect the changes from the RCAM tariff proposed in Docket No. DG 21-123.

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. Northern will file a rate case surcharge rate 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. Northern 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-7.

Q. How do you propose to structure the rate case expenses surcharge?

A. The rate case expenses surcharge will be a charge per therm, applied to all rate schedules, and included in the LDAC. 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 $735,000 and are detailed on Schedule RevReq-7.

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 will be prepared to provide the Commission 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 with its review.

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.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
NEW HAMPSHIRE FILING REQUIREMENT SCHEDULES
TABLE OF CONTENTS

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE - COMPUTATION OF REVENUE DEFICIENCY
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)
LINE NO.	DESCRIPTION	REFERENCE	AMOUNT
1	Rate Base	Schedule RevReq-5	$ 188,719,257
2	Rate of Return	Schedule RevReq-6	7.75%
3	Income Required	Line 1 * Line 2	14,621,110
4	Adjusted Net Operating Income	Schedule RevReq-2	8,946,016
5	Deficiency	Line 3 - Line 4	5,675,094
6	Income Tax Effect	Line 7 - Line 5	2,107,856
7	Revenue Deficiency	1.3714 (Schedule RevReq-1-1) * Line 5	$ 7,782,950

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 1 - OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR 12 MONTHS ENDED 12/31/2020	(3) LESS COST OF GAS EXCLUDING PROD. & OH. (1)	(4) LESS OTHER FLOWTHROUGH (2)	(5) TEST YEAR DISTRIBUTION, PROD. & OH.	(6) TEST YEAR DISTRIBUTION	(7) TEST YEAR PROD. & OH.	(8) CALENDAR YEAR 2019 (3)	(9) CALENDAR YEAR 2018 (3)
1	Operating Revenues:								
2	Total Sales	$ 65,455,125	$ 22,701,750	$ 3,458,228	$ 39,295,147	$ 38,237,257	$ 1,057,890	$ 72,009,468	$ 78,261,307
3	Total Other Operating Revenues	1,228,348	120,656	-	1,107,692	1,107,692	-	841,893	380,541
4	Total Operating Revenues	$ 66,683,473	$ 22,822,406	$ 3,458,228	$ 40,402,839	$ 39,344,949	$ 1,057,890	$ 72,851,361	$ 78,641,848
5	Operating Expenses:								
6	Production	$ 23,544,860	$ 22,696,215	$ 398,908	$ 449,736	$ 449,736	$ -	$ 28,226,731	$ 36,699,896
7	Transmission	63,829	-	-	63,829	63,829	-	72,713	54,452
8	Distribution	3,733,377	-	-	3,733,377	3,733,377	-	3,509,448	3,547,813
9	Customer Accounting	2,608,189	99,544	-	2,508,645	2,508,645	-	2,768,758	2,548,545
10	Customer Service	2,341,706	(0)	2,268,632	73,074	73,074	-	2,319,375	1,946,672
11	Sales Expense	69,178	-	-	69,178	69,178	-	64,467	62,224
12	Administrative & General	6,740,777	-	58,225	6,682,552	6,682,552	-	7,679,291	7,670,327
13	Depreciation	8,876,582	-	-	8,876,582	8,876,582	-	8,166,463	7,482,080
14	Amortizations	816,977	-	-	816,977	816,977	-	838,480	196,816
15	Taxes Other Than Income	4,867,774	-	-	4,867,774	4,867,774	-	4,306,298	4,242,098
16	Federal Income Tax	(30,211)	-	-	(30,211)	(30,211)	-	52,380	(353,526)
17	State Income Tax	(384,644)	-	-	(384,644)	(384,644)	-	(309,547)	(463,245)
18	Deferred Federal & State Income Taxes	2,600,179	-	-	2,600,179	2,600,179	-	2,975,683	3,341,111
19	Interest on Customer Deposits	9,258	-	-	9,258	9,258	-	14,374	18,486
20	Total Operating Expenses	$ 55,857,829	$ 22,795,759	$ 2,725,765	$ 30,336,305	$ 30,336,305	$ -	$ 60,684,915	$ 66,993,749
21	Net Operating Income	$ 10,825,644	$ 26,647	$ 732,463	$ 10,066,533	$ 9,008,643	$ 1,057,890	$ 12,166,447	$ 11,648,100

Notes
(1) Refer to Workpaper - Cost of Gas
(2) Refer to Workpaper - Flowthrough Detail. Consists of Energy Efficiency, Environmental Response Costs, Residential Low Income Assistance, Rate Case Costs, Recoupment, Lost Revenue, and On Bill Financing
(3) Calendar Years 2019 and 2018 represents Total Company (i.e., Flowthrough and Distribution).

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 1 ATTACHMENT - SUMMARY OF ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) CLASSIFICATION	(3) SCHEDULE NO.	(4) AMOUNT
1	Revenue Adjustments			
2	Weather Normalization	Dist Rev	Schedule RevReq-3-1	$ 1,994,374
3	New Customer Revenue Annualization	Dist Rev	Schedule RevReq-3-2	278,301
4	Residential Low Income	Dist Rev	Schedule RevReq-3-2	264,523
5	Unbilled Revenue	Dist Rev	Schedule RevReq-3-2	294,543
6	Non-Distribution Bad Debt	Dist Rev	Schedule RevReq-3-2	(97,468)
7	Misc. Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	4,788
8	Late Fee Adjustment	Oth Rev	Schedule RevReq-3-2	40,013
9	Billed Accuracy Adjustment	Dist Rev	Schedule RevReq-3-2	367
10	Special Contract Customer Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	17,968
11	Total Revenue Adjustments			$ 2,797,410
12	Operating & Maintenance Expense Adjustments			
13	Production Expense (O&M)	Prod	Schedule RevReq-3-3	$ 76,191
14	Payroll	Dist	Schedule RevReq-3-4	554,442
15	Distribution Bad Debt	Cust Acct	Schedule RevReq-3-5	88,160
16	Non-Distribution Bad Debt	Cust Acct	Schedule RevReq-3-2	(97,468)
17	Medical & Dental Insurances	A&G	Schedule RevReq-3-6	404,594
18	Pension	A&G	Schedule RevReq-3-7	(2,185)
19	PBOP	A&G	Schedule RevReq-3-7	(19,749)
20	SERP	A&G	Schedule RevReq-3-7	58,798
21	401K	A&G	Schedule RevReq-3-7	30,095
22	Deferred Comp Expense	A&G	Schedule RevReq-3-7	44,415
23	Property & Liability Insurances	A&G	Schedule RevReq-3-8	60,699
24	NH PUC Assessment	A&G	Schedule RevReq-3-9	116,230
25	Dues & Subscriptions	A&G	Schedule RevReq-3-10	(1,774)
26	Pandemic Costs	A&G	Schedule RevReq-3-11	(107,125)
27	Severance Expense	A&G	Schedule RevReq-3-12	(29,947)
28	Rent Expense	A&G	Schedule RevReq-3-13	51,913
29	Arrearage Management Program (AMP) Implementation Cost	Cust Acct	Schedule RevReq-3-14	92,480
30	Inflation Allowance	A&G	Schedule RevReq-3-15	165,684
31	Total Operating & Maintenance Expense Adjustments			$ 1,485,451
32	Depreciation And Amortization Expense Adjustments			
33	Depreciation Annualization	Depr	Schedule RevReq-3-16 P1	$ 469,003
34	Proposed Depreciation Rates	Depr	Schedule RevReq-3-16 P2	1,847,988
35	Production Expense (Depreciation)	Depr	Schedule RevReq-3-3	37,865
36	Software Amortization	Amort	Schedule RevReq-3-17	189,288
37	Excess ADIT Flowback	Amort	Schedule RevReq-3-18	(308,218)
38	Total Depreciation And Amortization Expense Adjustments			$ 2,235,925
39	Taxes Other Than Income Adjustments			
40	Property Taxes	Oth Tax	Schedule RevReq-3-19	$ 617,939
41	Payroll Taxes - Wage Increases	Oth Tax	Schedule RevReq-3-20 P1	42,415
42	Payroll Taxes - Employee Retention Credit	Oth Tax	Schedule RevReq-3-20 P2	95,258
43	Total Taxes Other Than Income Adjustments			$ 755,611
44	Income Taxes Adjustments			
45	Federal Income Tax	FIT	Schedule RevReq-3-21 P1	$ (405,701)
46	NH State Tax	SIT	Schedule RevReq-3-21 P1	(161,167)
47	Remove Prior Year Federal Income Tax	FIT	Schedule RevReq-3-21 P4	(49,634)
48	Remove Prior Year State Income Tax	SIT	Schedule RevReq-3-21 P4	(834,820)
49	Remove Prior Year Deferred Federal Income Tax	DIT	Schedule RevReq-3-21 P4	57,442
50	Remove Prior Year Deferred State Income Tax	DIT	Schedule RevReq-3-21 P4	834,820
51	Total Income Taxes Adjustments			$ (559,060)
52	Rate Base Adjustments			
53	NH Supplemental Plant Adjustment	Plant	Schedule RevReq-5-3	$ 1,873,246
54	NH Supplemental Plant Adjustment	Acc Depr	Schedule RevReq-5-3	1,350,190
55	DIT Settlement Adjustment	RB DIT	Schedule RevReq-5-4	-
56	Cash Working Capital (Due To Pro Forma Adjustments)	CWC	Schedule RevReq-5-2	235,191
57	Total Rate Base Adjustments			$ 758,247

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 1A - PROPERTY TAXES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	MUNICIPALITY & STATE	LOCAL TAX RATE	ASSESSED VALUATION	TOTAL ANNUALIZED TAXES [1]
1	Atkinson	$ 16.24	$ 1,564,100	$ 25,401
2	Brentwood	21.36	1,489,600	31,818
3	Brentwood	23.19	400	9
4	Dover	24.85	1,200	30
5	Dover	22.92	37,150,600	851,492
6	Durham	25.73	7,742,400	199,212
7	East Kingston	20.50	746,700	15,307
8	Epping	23.64	1,079,900	25,529
9	Exeter	22.50	13,803,800	310,586
10	Greenland	14.58	733,400	10,693
11	Hampton--Class 4000	13.93	18,884,700	263,064
12	Hampton--Class 5000	14.43	9,301,400	134,219
13	Hampton Falls	19.33	36,400	704
14	Kensington	18.61	1,442,400	26,843
15	Madbury	23.41	347,000	8,123
16	Newington	8.02	2,848,900	22,848
17	North Hampton	14.80	1,822,800	26,977
18	Plaistow	19.60	9,849,580	193,052
19	Portsmouth	12.80	47,562,000	608,794
20	Rochester	22.67	26,840,200	608,468
21	Rollinsford	22.57	194,600	4,392
22	Rollinsford	24.68	20,000	494
23	Salem	19.82	9,478,700	187,867
24	Seabrook	13.90	12,142,100	168,775
25	Somersworth	25.91	9,713,200	251,669
26	Somersworth	27.85	62,000	1,727
27	Stratham	17.14	497,200	8,522
28	State Of NH [2]			1,359,585
29	Total			$ 5,346,199
30	Test Year Property Taxes [3]			$ 4,728,948
31	Less: Test Year Property Tax Abatements [4]			688
32	Total Test Year Property Tax Expense			$ 4,728,260
33	Total Property Tax Increase (Line 29 - Line 32)			$ 617,939

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) Test Year Property Taxes adjusted to exclude Greenland 2019 bill correction of $317

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 1B - PAYROLL
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)
			NuNH		FROM	
LINE NO.	DESCRIPTION	NONUNION	UNION	SUBTOTAL	USC	TOTAL
1	Test Year Payroll, Adjusted for Target Incentive Compensation	$ 946,912	$ 3,475,844	$ 4,422,756	$ 6,330,920	$ 10,753,676
2	2020 Rate Increase, Annualized [(1)]	-	57,071	57,071	-	57,071
3	Payroll Annualized for 2020 Union Wage Increase	946,912	3,532,915	4,479,827	6,330,920	10,810,747
4	2021 Salary & Wage Increase [(2)]	29,544	105,987	135,531	278,560	414,091
5	Payroll Proformed for 2020 and 2021 Wage Increases	976,456	3,638,903	4,615,358	6,609,480	11,224,838
6	2022 Salary & Wage Increase [(3)]	30,465	109,167	139,632	290,817	430,449
7	Payroll Proformed for 2020, 2021 and 2022 Wage Increases	1,006,921	3,748,070	4,754,991	6,900,297	11,655,288
8	Less Amounts Chargeable to Capital [(4)]	470,131	1,749,974	2,220,105	2,243,977	4,464,082
9	O&M Payroll Proformed	536,790	1,998,096	2,534,886	4,656,320	7,191,206
10	Less: Test Year O&M Payroll [(5)]			2,364,660	4,272,105	6,636,764
11	Increase in O&M Payroll due to Annual Salary and Wage Increases			170,226	384,216	554,442
12	Incentive Compensation Target Adjustment [(6)]			$ -	-	-
13	Net Adjustment to O&M Payroll / Compensation			170,226	384,216	554,442

Notes
(1) NuNH Union increase of 3.0% effective June 1, 2020
(2) NuNH Non-union increase of 3.12% effective January 1, 2021, Union increase of 3.0% effective September 6, 2021 and USC increase of 4.40% effective January 1, 2021
(3) NuNH Non-union increase of 3.12% effective January 1, 2022, Union increase of 3.0% effective September 6, 2022 and USC increase of 4.40% effective January 1, 2022
(4) Test Year Payroll Capitalization Rates:

NuNH	46.69%
USC	32.52%

(5) Refer to Workpaper 2.2 and Schedule RevReq-3-4, page 2.
(6) Refer to Workpaper 2.4

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 1C - NORMALIZATIONS
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)
LINE NO.	DESCRIPTION	TOTAL
1	To Increase Test Year Base Revenue to Normalize for the Effect of Warmer than Normal Weather [1]	$ 1,994,374
2	To Increase Test Year Base Revenue for 2020 Customer Growth [2]	$ 278,301
3	Pro Forma Adjustment to Remove Unbilled Revenue [2]	$ 294,543

Notes
(1) See Schedule RevReq 3-1
(2) See Schedule RevReq 3-2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 2 - ASSETS & DEFERRED CHARGES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
LINE NO.	Category	New Hampshire	Maine	Common	Consolidated December 31, 2020	Consolidated December 31, 2019	Consolidated December 31, 2018
1	Gas Plant						
2	In Service	$ 299,372,252	$ 390,755,625	$ -	$ 690,127,877	$ 623,207,033	$ 560,519,339
3	Construction Work in Progress	6,411,145	6,890,804	-	13,301,949	12,576,742	11,064,887
4	Less: Reserve for Depreciation	(88,023,262)	(87,391,662)	-	(175,414,925)	(143,066,942)	(131,806,854)
5	Total Gas Plant	217,760,135	310,254,767	-	528,014,901	492,716,833	439,777,371
6	Other Property						
7	Total Other Net Property	-	86,855	-	86,855	29,819	(24,914)
8	Total Other & Non Operating Plant	-	86,855	-	86,855	29,819	(24,914)
9	Current Assets						
10	Cash	1,500	250	370,260	372,010	341,847	672,243
11	Accounts Receivable - Gas	9,102,182	14,492,785	-	23,594,967	21,416,443	28,512,317
12	Accounts Receivable - Other	181,592	14,495	3,377	199,464	154,773	34,597
13	Uncollectible Accounts	(294,933)	(863,075)	-	(1,158,008)	(441,588)	(836,962)
14	Notes Receivable	-	-	8,913,185	8,913,185	5,559,766	3,137,369
15	Material and Supplies	2,416,575	2,048,155	-	4,464,730	4,162,206	3,892,225
16	Stores Expense Undistributed	356,883	351,217	-	708,100	655,826	481,856
17	Inventory	267,731	40,348	-	308,079	448,104	391,250
18	Prepayments	963,040	1,128,283	70,044	2,161,367	4,450,029	3,400,561
19	Accrued Revenue	3,803,680	4,731,203	-	8,534,883	9,587,864	8,319,787
20	Miscellaneous Current Assets	4,530,525	93,747	-	4,624,272	5,666,176	7,622,013
21	Total Current Assets	21,328,775	22,037,408	9,356,866	52,723,049	52,001,444	55,627,256
22	Deferred Charges						
23	Unamortized Debt Expense	-	-	1,359,851	1,359,851	1,208,586	1,092,517
24	Other - Deferred Debits	13,872,478	20,353,943	98,736	34,325,157	27,066,138	32,928,903
25	Total Deferred Charges	13,872,478	20,353,943	1,458,587	35,685,008	28,274,724	34,021,420
26	Total Assets & Deferred Charges	$ 252,961,387	$ 352,732,973	$ 10,815,453	$ 616,509,813	$ 573,022,820	$ 529,401,133

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 2A - STOCKHOLDERS EQUITY & LIABILITIES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) Category	(2) New Hampshire	(3) Maine	(4) Common	(5) Consolidated December 31, 2020	(6) Consolidated December 31, 2019	(7) Consolidated December 31, 2018
1	Capitalization						
2	Common Stock	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000
3	Paid in Capital	-	-	207,074,000	207,074,000	200,699,000	175,199,000
4	Earned Surplus	6,096,270	8,643,131	9,713,702	24,453,103	24,380,042	22,032,465
5	Stockholders Equity	6,096,270	8,643,131	216,788,702	231,528,103	225,080,042	197,232,465
6	Long Term Debt						
7	Bonds and Notes	-	-	230,000,000	230,000,000	198,200,000	166,600,000
8	Total	-	-	230,000,000	230,000,000	198,200,000	166,600,000
9	Current and Accrued Liabilities						
10	Accounts Payable	639,411	538,256	6,001,159	7,178,826	8,651,894	10,471,212
11	Notes Payable to Associated Co.	-	-	26,747,022	26,747,022	28,494,680	58,154,005
12	A/P to Associated Co's	-	-	7,400,409	7,400,409	6,497,178	3,145,273
13	Customer Deposits	249,677	342,624	-	592,301	640,562	738,651
14	Taxes Accrued	67,648	(4,613)	-	63,035	292,534	14,450
15	Interest Accrued	-	-	2,094,467	2,094,467	1,824,919	1,503,714
16	Dividends Declared	-	-	3,666,585	3,666,585	3,304,600	1,229,300
17	Other Tax Liabilities	750,955	(609,964)	33,532	174,523	94,759	130,422
18	Other Current and Accrued Liabilities	811,427	576,546	7,636,657	9,024,630	11,636,693	15,472,163
19	Total Current and Accrued Liabilities	2,519,118	842,849	53,579,831	56,941,798	61,437,819	90,859,190
20	Deferred Credits						
21	Other Deferred Credits	18,639,799	21,537,277	-	40,177,076	35,921,434	27,893,528
22	Other Regulatory Liabilities	6,608,392	8,917,471	-	15,525,863	15,874,493	15,992,896
23	Accumulated Deferred Income Taxes	16,892,861	25,444,116	-	42,336,977	36,509,031	30,823,054
24	Total Deferred Credits	42,141,052	55,898,864	-	98,039,916	88,304,958	74,709,478
25	Total Stockholders Equity & Liabilities	$ 50,756,440	$ 65,384,844	$ 500,368,533	$ 616,509,817	$ 573,022,819	$ 529,401,133

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 2B - MATERIALS & SUPPLIES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
LINE NO.	DESCRIPTION	DECEMBER 31 2019	MARCH 31 2020	JUNE 30 2020	SEPTEMBER 30 2020	DECEMBER 31 2020	5 QUARTER AVERAGE
1	Material and Supplies	$ 2,268,328	$ 2,387,075	$ 2,514,326	$ 2,569,166	$ 2,416,575	$ 2,431,094
2	Stores Expense Undistributed	300,515	417,170	334,238	285,865	356,883	338,934
3	Total M&S Inventories	$ 2,568,843	$ 2,804,245	$ 2,848,563	$ 2,855,032	$ 2,773,457	$ 2,770,028

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 3 - RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(6)	(7)	(8)
LINE NO.	DESCRIPTION	TEST YEAR AVERAGE (1)	5 QUARTER AVERAGE	RATE BASE AT DECEMBER 31, 2020
1	Utility Plant In Service	$ 289,824,481	$ 286,491,423	$ 299,372,252
2	Less: Reserve for Depreciation	85,085,831	85,651,383	88,023,262
3	Net Utility Plant	204,738,650	200,840,040	211,348,990
4	Add: M&S Inventories	2,671,150	2,770,028	2,773,457
5	Prepayments	740,275	1,213,708	64,895
6	Cash Working Capital (2)	1,773,194	1,773,194	1,773,194
7	Sub-Total	5,184,619	5,756,930	4,611,547
8	Less: Net Deferred Income Taxes	$ 20,221,877	$ 20,784,379	$ 21,177,756
9	Excess Deferred Income Taxes	6,572,092	6,572,092	6,572,092
10	Customer Advances	-	-	-
11	Customers Deposits	269,548	264,461	249,677
12	Sub-Total	27,063,517	27,620,932	27,999,526
13	Rate Base	$ 182,859,752	$ 178,976,038	$ 187,961,010
14	Net Operating Income Applicable To Rate Base	$ 10,066,533	$ 10,066,533	$ 10,066,533
15	Rate of Return	5.51%	5.62%	5.36%

Notes
(1) Two Point Average
(2) Computed Working Capital Based on Test Year O&M Expenses. Refer to Schedule RevReq-5-2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SCHEDULE 3A - WORKING CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)
LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR ACTUAL	PRO FORMA ADJUSTMENTS	TEST YEAR PRO FORMA
1	Distribution O&M Expense	Schedule RevReq-2	$ 13,332,381	$ 946,840	$ 14,279,221
2	Tax Expense	Schedule RevReq-2	4,452,919	1,412,146	5,865,065
3	Total		$ 17,785,300	$ 2,358,986	$ 20,144,286
4	Cash Working Capital Requirement:				
5	Other O&M Expense Days Lag (1) / 366	36 days	9.97%	9.97%	9.97%
6	Total Cash Working Capital	Line 5 X Line 3	$ 1,773,194	$ 235,191	$ 2,008,385

Notes
(1) Refer to Lead-Lag Study in Direct Testimony of Daniel Hurstak

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
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	$ 299,372,252	$ 1,873,246	$ 301,245,498
2	Less: Reserve for Depreciation	88,023,262	1,350,190	89,373,452
3	Net Utility Plant	211,348,990	523,056	211,872,045
4	Add: M&S Inventories	$ 2,773,457	$ -	$ 2,773,457
5	Prepayments	64,895	-	64,895
6	Cash Working Capital [(1)]	1,773,194	235,191	2,008,385
7	Sub-Total	4,611,547	235,191	4,846,738
8	Less: Net Deferred Income Taxes	$ 21,177,756	$ -	$ 21,177,756
9	Excess Deferred Income Taxes	6,572,092	-	6,572,092
10	Customer Advances	-	-	-
11	Customers Deposits	249,677	-	249,677
12	Sub-Total	27,999,526	-	27,999,526
13	Rate Base	$ 187,961,010	$ 758,247	$ 188,719,257
14	Net Operating Income Applicable To Rate Base	$ 10,066,533		$ 8,946,016
15	Rate of Return	5.36%		4.74%

Notes
(1) Computed Working Capital Based on Test Year O&M Expenses. Refer to Schedule RevReq-5-2

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DOCKET DG 21-104
REVENUE REQUIREMENT SCHEDULES AND WORKPAPERS

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
REVENUE REQUIREMENT TABLE OF CONTENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-TOC

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
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-5	$ 188,719,257
2	Rate of Return	Schedule RevReq-6	7.75%
3	Income Required	Line 1 * Line 2	14,621,110
4	Adjusted Net Operating Income	Schedule RevReq-2	8,946,016
5	Deficiency	Line 3 - Line 4	5,675,094
6	Income Tax Effect	Line 7 - Line 5	2,107,856
7	Revenue Deficiency	1.3714 (Schedule RevReq-1-1) * Line 5	$ 7,782,950

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-1-1
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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	Northern Effective Tax Rate	(Line 1 + Line 2 + Line 3)	0.2708
5	Gross-Up Factor	(1 / 1 - Line 4)	1.3714

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-2
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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			LESS						
LINE NO.	DESCRIPTION	TEST YEAR 12 MONTHS ENDED 12/31/2020	COST OF GAS EXCLUDING PROD. & OH.[1]	OTHER FLOWTHROUGH[2]	TEST YEAR DISTRIBUTION, PROD. & OH.	TEST YEAR DISTRIBUTION	TEST YEAR PROD. & OH.	CALENDAR YEAR 2019[3]	CALENDAR YEAR 2018[3]
1	Operating Revenues:								
2	Total Sales	$ 65,455,125	$ 22,701,750	$ 3,458,228	$ 39,295,147	$ 38,237,257	$ 1,057,890	$ 72,009,468	$ 78,261,307
3	Total Other Operating Revenues	1,228,348	120,656	-	1,107,692	1,107,692	-	841,893	380,541
4	Total Operating Revenues	$ 66,683,473	$ 22,822,406	$ 3,458,228	$ 40,402,839	$ 39,344,949	$ 1,057,890	$ 72,851,361	$ 78,641,848
5	Operating Expenses:								
6	Production	$ 23,544,860	$ 22,696,215	$ 398,908	$ 449,736	$ 449,736	$ -	$ 28,226,731	$ 36,699,896
7	Transmission	63,829	-	-	63,829	63,829	-	72,713	54,452
8	Distribution	3,733,377	-	-	3,733,377	3,733,377	-	3,509,448	3,547,813
9	Customer Accounting	2,608,189	99,544	-	2,508,645	2,508,645	-	2,768,758	2,548,545
10	Customer Service	2,341,706	(0)	2,268,632	73,074	73,074	-	2,319,375	1,946,672
11	Sales Expense	69,178	-	-	69,178	69,178	-	64,467	62,224
12	Administrative & General	6,740,777	-	58,225	6,682,552	6,682,552	-	7,679,291	7,670,327
13	Depreciation	8,876,582	-	-	8,876,582	8,876,582	-	8,166,463	7,482,080
14	Amortizations	816,977	-	-	816,977	816,977	-	838,480	196,816
15	Taxes Other Than Income	4,867,774	-	-	4,867,774	4,867,774	-	4,306,298	4,242,098
16	Federal Income Tax	(30,211)	-	-	(30,211)	(30,211)	-	52,380	(353,526)
17	State Income Tax	(384,644)	-	-	(384,644)	(384,644)	-	(309,547)	(463,245)
18	Deferred Federal & State Income Taxes	2,600,179	-	-	2,600,179	2,600,179	-	2,975,683	3,341,111
19	Interest on Customer Deposits	9,258	-	-	9,258	9,258	-	14,374	18,486
20	Total Operating Expenses	$ 55,857,829	$ 22,795,759	$ 2,725,765	$ 30,336,305	$ 30,336,305	$ -	$ 60,684,915	$ 66,993,749
21	Net Operating Income	$ 10,825,644	$ 26,647	$ 732,463	$ 10,066,533	$ 9,008,643	$ 1,057,890	$ 12,166,447	$ 11,648,100

Notes
(1) Refer to Workpaper - Cost of Gas
(2) Refer to Workpaper - Flowthrough Detail. Consists of Energy Efficiency, Environmental Response Costs, Residential Low Income Assistance, Rate Case Costs, Recoupment, Lost Revenue, and On Bill Financing
(3) Calendar Years 2019 and 2018 represents Total Company (i.e., Flowthrough and Distribution).

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRO FORMA DISTRIBUTION OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR DISTRIBUTION, PROD. & OH.	(3) PRO FORMA ADJUSTMENTS	(4) TEST YEAR DISTRIBUTION, PROD. & OH. PRO FORMA	(5) PROOF REVENUE REQUIREMENT	(6) PROOF PRO FORMA RATE RELIEF
1	Operating Revenues:					
2	Total Sales	$ 39,295,147	$ 2,757,397	$ 42,052,544	$ 7,782,950	$ 49,835,494
3	Total Other Operating Revenues	1,107,692	40,013	1,147,705	-	1,147,705
4	Total Operating Revenues	$ 40,402,839	$ 2,797,410	$ 43,200,249	$ 7,782,950	$ 50,983,199
5	Operating Expenses:					
6	Production	$ 449,736	$ 76,191	$ 525,927	$ -	$ 525,927
7	Transmission	63,829	-	63,829	-	63,829
8	Distribution	3,733,377	554,442	4,287,819	-	4,287,819
9	Customer Accounting	2,508,645	83,172	2,591,817	-	2,591,817
10	Customer Service	73,074	-	73,074	-	73,074
11	Sales Expense	69,178	-	69,178	-	69,178
12	Administrative & General	6,682,552	771,645	7,454,197	-	7,454,197
13	Depreciation	8,876,582	2,354,856	11,231,438	-	11,231,438
14	Amortizations	816,977	(118,930)	698,046	-	698,046
15	Taxes Other Than Income	4,867,774	755,611	5,623,385	-	5,623,385
16	Federal Income Tax	(30,211)	(455,335)	(485,546)	1,508,569	1,023,023
17	State Income Tax	(384,644)	(995,987)	(1,380,631)	599,287	(781,343)
18	Deferred Federal & State Income Taxes	2,600,179	892,262	3,492,441	-	3,492,441
19	Interest on Customer Deposits	9,258	-	9,258	-	9,258
20	Total Operating Expenses	$ 30,336,305	$ 3,917,927	$ 34,254,233	$ 2,107,856	$ 36,362,089
21	Net Operating Income	$ 10,066,533	$ (1,120,517)	$ 8,946,016	$ 5,675,094	$ 14,621,110

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SUMMARY OF ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3
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LINE NO.	(1) DESCRIPTION	(2) CLASSIFICATION	(3) SCHEDULE NO.	(4) AMOUNT
1	Revenue Adjustments			
2	Weather Normalization	Dist Rev	Schedule RevReq-3-1	$ 1,994,374
3	New Customer Revenue Annualization	Dist Rev	Schedule RevReq-3-2	278,301
4	Residential Low Income	Dist Rev	Schedule RevReq-3-2	264,523
5	Unbilled Revenue	Dist Rev	Schedule RevReq-3-2	294,543
6	Non-Distribution Bad Debt	Dist Rev	Schedule RevReq-3-2	(97,468)
7	Misc. Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	4,788
8	Late Fee Adjustment	Oth Rev	Schedule RevReq-3-2	40,013
9	Billed Accuracy Adjustment	Dist Rev	Schedule RevReq-3-2	367
10	Special Contract Customer Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	17,968
11	Total Revenue Adjustments			$ 2,797,410
12	Operating & Maintenance Expense Adjustments			
13	Production Expense (O&M)	Prod	Schedule RevReq-3-3	$ 76,191
14	Payroll	Dist	Schedule RevReq-3-4	554,442
15	Distribution Bad Debt	Cust Acct	Schedule RevReq-3-5	88,160
16	Non-Distribution Bad Debt	Cust Acct	Schedule RevReq-3-2	(97,468)
17	Medical & Dental Insurances	A&G	Schedule RevReq-3-6	404,594
18	Pension	A&G	Schedule RevReq-3-7	(2,185)
19	PBOP	A&G	Schedule RevReq-3-7	(19,749)
20	SERP	A&G	Schedule RevReq-3-7	58,798
21	401K	A&G	Schedule RevReq-3-7	30,095
22	Deferred Comp Expense	A&G	Schedule RevReq-3-7	44,415
23	Property & Liability Insurances	A&G	Schedule RevReq-3-8	60,699
24	NH PUC Assessment	A&G	Schedule RevReq-3-9	116,230
25	Dues & Subscriptions	A&G	Schedule RevReq-3-10	(1,774)
26	Pandemic Costs	A&G	Schedule RevReq-3-11	(107,125)
27	Severance Expense	A&G	Schedule RevReq-3-12	(29,947)
28	Rent Expense	A&G	Schedule RevReq-3-13	51,913
29	Arrearage Management Program (AMP) Implementation Cost	Cust Acct	Schedule RevReq-3-14	92,480
30	Inflation Allowance	A&G	Schedule RevReq-3-15	165,684
31	Total Operating & Maintenance Expense Adjustments			$ 1,485,451
32	Depreciation And Amortization Expense Adjustments			
33	Depreciation Annualization	Depr	Schedule RevReq-3-16 P1	$ 469,003
34	Proposed Depreciation Rates	Depr	Schedule RevReq-3-16 P2	1,847,988
35	Production Expense (Depreciation)	Depr	Schedule RevReq-3-3	37,865
36	Software Amortization	Amort	Schedule RevReq-3-17	189,288
37	Excess ADIT Flowback	Amort	Schedule RevReq-3-18	(308,218)
38	Total Depreciation And Amortization Expense Adjustments			$ 2,235,925
39	Taxes Other Than Income Adjustments			
40	Property Taxes	Oth Tax	Schedule RevReq-3-19	$ 617,939
41	Payroll Taxes - Wage Increases	Oth Tax	Schedule RevReq-3-20 P1	42,415
42	Payroll Taxes - Employee Retention Credit	Oth Tax	Schedule RevReq-3-20 P2	95,258
43	Total Taxes Other Than Income Adjustments			$ 755,611
44	Income Taxes Adjustments			
45	Federal Income Tax	FIT	Schedule RevReq-3-21 P1	$ (405,701)
46	NH State Tax	SIT	Schedule RevReq-3-21 P1	(161,167)
47	Remove Prior Year Federal Income Tax	FIT	Schedule RevReq-3-21 P4	(49,634)
48	Remove Prior Year State Income Tax	SIT	Schedule RevReq-3-21 P4	(834,820)
49	Remove Prior Year Deferred Federal Income Tax	DIT	Schedule RevReq-3-21 P4	57,442
50	Remove Prior Year Deferred State Income Tax	DIT	Schedule RevReq-3-21 P4	834,820
51	Total Income Taxes Adjustments			$ (559,060)
52	Rate Base Adjustments			
53	NH Supplemental Plant Adjustment	Plant	Schedule RevReq-5-3	$ 1,873,246
54	NH Supplemental Plant Adjustment	Acc Depr	Schedule RevReq-5-3	1,350,190
55	DIT Settlement Adjustment	RB DIT	Schedule RevReq-5-4	-
56	Cash Working Capital (Due To Pro Forma Adjustments)	CWC	Schedule RevReq-5-2	235,191
57	Total Rate Base Adjustments			$ 758,247

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
WEATHER NORMALIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-1
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LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	To Increase Test Year Base Revenue to Normalize for the Effect of Warmer than Normal Weather [1]	$ 1,994,374

Notes
(1) Refer to Direct Testimony of Ron Amen & John Taylor

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
REVENUE ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-2
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LINE NO.	(1) DESCRIPTION		(2) TOTAL
1	Customer Growth Revenue Adjustment		
2	To Increase Test Year Base Revenue for 2020 Customer Growth (1)	$	278,301
3	Residential Low Income Assistance Revenue Adjustment		
4	To Reflect Recovery Of The Low Income Discount Through the LDAC (2)	$	264,523
5	Unbilled Revenue Adjustment		
6	Remove Unbilled Revenue	$	294,543
7	Non Distribution Bad Debt Adjustment (Revenue & Expense)		
8	Remove: Accrued Revenue - Non Dist Bad Debt	$	(97,468)
9	Remove: Provision For Doubtful Accts - Non-Dist - NH	$	(97,468)
10	Misc. Revenue Adjustment		
11	Clear Remaining Rate Case Expense And Recoupment Balances	$	4,788
12	Late Payment Revenue Adjustment		
13	Normalized Late Payment Revenue (3)	$	76,773
14	Test Year Late Payment Revenue		36,761
15	Late Payment Revenue Adjustment	$	40,013
16	Billed Accuracy Adjustment		
17	Booked to Calculated Bill Adjustment (1)	$	367
18	Special Contract Customer Revenue Adjustment		
19	Full Year Special Contract Customer Revenue at Special Contract Rate (4)	$	1,197,813
20	Test Year Special Contract Customer Actual Revenue (4)		1,179,845
21	Net Special Contract Customer Revenue Adjustment	$	17,968

Notes
(1) Refer to Direct Testimony of Ron Amen & John Taylor
(2) See Workpaper - Flowthrough Detail
(3) Normalized Late Payment Revenue based on 2019 calendar year activity
(4) Refer to Workpaper 1.1 and Workpaper 1.2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRODUCTION EXPENSE ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-3
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LINE NO.	(1) DESCRIPTION	(2) NH	(3) ME	(4) TOTAL	(5) NH PR ALLOC. 40.88%	(6) ME PR ALLOC. 59.12%	(7) NH REVREQ ADJUST.	(8) ME REVREQ ADJUST.
1	Operation & Maintenance Expense							
2	Liquefied Propane Gas Production							
3	Operation Expense							
4	710 - Operation Supervision and Engineering	$ -	$ 29,447	$ 29,447	$ 12,038	$ 17,409		
5	717 - Production Operation Labor	-	24,228	24,228	9,904	14,324		
6	735 - Production Operation Miscellaneous	-	59,588	59,588	24,360	35,228		
7	Total Operation Expense	-	113,263	113,263	46,302	66,961		
8	Maintenance							
9	740 - Production Maintenance Supervision	-	29,447	29,447	12,038	17,409		
10	741 - Maintenance of Plant	-	8,464	8,464	3,460	5,004		
11	742 - Maint of Equipment	-	28,588	28,588	11,687	16,901		
12	Total Maintenance Expense	-	66,499	66,499	27,185	39,314		
13	769 - Maint of Scada - Product	-	6,615	6,615	2,704	3,911		
14	Total Manuf Gas Prod Exp	$ -	$ 186,377	$ 186,377	$ 76,191	$ 110,186	$ 76,191	$ (76,191)
15	Depreciation Expense							
16	Production Plant							
17	305 - Structures	$ -	$ 2,277	$ 2,277	$ 931	$ 1,346		
18	Total Production Plant	-	2,277	2,277	931	1,346		
19	Other Storage Plant							
20	361 - Structures & Improve	-	11,705	11,705	4,785	6,920		
21	362 - Gas Holders	-	78,642	78,642	32,149	46,493		
22	Total Other Storage Plant	-	90,347	90,347	36,934	53,413		
23	Total Depreciation & Amortization	$ -	$ 92,624	$ 92,624	$ 37,865	$ 54,759	$ 37,865	$ (37,865)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)
LINE NO.	DESCRIPTION	NuNH NONUNION	NuNH UNION	NuNH SUBTOTAL	FROM USC	TOTAL
1	Test Year Payroll, Adjusted for Target Incentive Compensation	$ 946,912	$ 3,475,844	$ 4,422,756	$ 6,330,920	$ 10,753,676
2	2020 Rate Increase, Annualized [(1)]	-	57,071	57,071	-	57,071
3	Payroll Annualized for 2020 Union Wage Increase	946,912	3,532,915	4,479,827	6,330,920	10,810,747
4	2021 Salary & Wage Increase [(2)]	29,544	105,987	135,531	278,560	414,091
5	Payroll Proformed for 2020 and 2021 Wage Increases	976,456	3,638,903	4,615,358	6,609,480	11,224,838
6	2022 Salary & Wage Increase [(3)]	30,465	109,167	139,632	290,817	430,449
7	Payroll Proformed for 2020, 2021 and 2022 Wage Increases	1,006,921	3,748,070	4,754,991	6,900,297	11,655,288
8	Less Amounts Chargeable to Capital [(4)]	470,131	1,749,974	2,220,105	2,243,977	4,464,082
9	O&M Payroll Proformed	536,790	1,998,096	2,534,886	4,656,320	7,191,206
10	Less: Test Year O&M Payroll [(5)]			2,364,660	4,272,105	6,636,764
11	Increase in O&M Payroll due to Annual Salary and Wage Increases			170,226	384,216	554,442
12	Incentive Compensation Target Adjustment [(6)]			$ -	-	-
13	Net Adjustment to O&M Payroll / Compensation			170,226	384,216	554,442

Notes
(1) NuNH Union increase of 3.0% effective June 1, 2020
(2) NuNH Non-union increase of 3.12% effective January 1, 2021, Union increase of 3.0% effective September 6, 2021 and USC increase of 4.40% effective January 1, 2021
(3) NuNH Non-union increase of 3.12% effective January 1, 2022, Union increase of 3.0% effective September 6, 2022 and USC increase of 4.40% effective January 1, 2022
(4) Test Year Payroll Capitalization Rates:

NuNH	46.69%
USC	32.52%

(5) Refer to Workpaper 2.2 and Schedule RevReq-3-4, page 2.
(6) Refer to Workpaper 2.4

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
UNITIL SERVICE CORP PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)
LINE NO.	DESCRIPTION	TOTAL
1	Test Year USC Labor Charges to Northern Utilities - New Hampshire Division [1]	$ 6,330,920
2	2021 Salary & Wage Increase %[2]	4.40%
3	Payroll Increase	278,560
4	Proforma Payroll for 2019 Increase	6,609,480
5	2022 Salary & Wage Increase %[2]	4.40%
6	Payroll Increase	290,817
7	Proforma Payroll for 2019 and 2020 Increase	6,900,297
8	Payroll Capitalization Ratio for 2021 and 2022 Increase	32.52%
9	Proforma Payroll Capitalization	2,243,977
10	Proforma Amount to O&M Expense	4,656,320
11	Test Year O&M Payroll Amount of USC Charge	4,272,105
12	O&M Payroll Increase	$ 384,216

Notes
(1) Includes Incentive Compensation at Target of $688,442
(2) Average Increase of 4.40% Effective January 1, 2021 and Average Increase of 4.40% Effective January 1, 2022

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DISTRIBUTION BAD DEBT ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-5
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	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	Calendar Year 2019 Write-Offs as a % of Retail Delivery Billed Revenue [1]	0.71%
2	Per Books Based Distribution Billed Revenue - Calendar Year 2019 [1]	$ 39,254,737
3	Revenue Increase from Rate Case	7,782,950
4	2020 Total Normalized Delivery Retail Billed Revenue	$ 47,037,687
5	Uncollectible Delivery Revenue	$ 336,170
6	Less: Test Year Bad Debt Expense	$ 248,010
7	Increase in Bad Debt Expense	$ 88,160

Notes

(1) Normalized write offs and per books base distribution billed revenue by using 2019 calendar year activity

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
MEDICAL AND DENTAL INSURANCE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-6
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TOTAL	NuNH [1]	UNITIL SERVICE CORP. [2]
1	Proformed Medical and Dental O&M Expense	$ 871,431	$ 318,565	$ 552,866
2	Less: Test Year Medical And Dental Insurance O&M Expense	466,837	182,055	284,783
3	Proformed 2021 And 2022 O&M Increase	$ 404,594	$ 136,510	$ 268,083

Notes
(1) See Workpapers W3.1
(2) See Workpapers W3.2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
Pension, PBOP, SERP, 401(K) and Deferred Compensation Expense
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-7
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TOTAL	NuNH	UNITIL SERVICE CORP.
1	Test Year Pension Expense, as Pro-Formed	$ 690,223	$ 250,740	$ 439,483
2	Test Year PBOP Expense, as Pro-Formed	389,446	204,698	184,748
3	Test Year SERP Expense, as Pro-Formed	320,475	-	320,475
4	Test Year 401K Expense, as Pro-Formed	394,059	98,571	295,488
5	Test Year Deferred Comp Expense, as Pro-Formed	52,717	-	52,717
6	Total Test Year Pension, PBOP, SERP and 401K Expense, as Pro-Formed	1,846,920	554,009	1,292,911
7	Test Year Pension Expense	$ 692,409	$ 280,117	$ 412,291
8	Test Year PBOP Expense	409,195	203,878	205,317
9	Test Year SERP Expense	261,677	-	261,677
10	Test Year 401K Expense	363,965	92,859	271,106
11	Test Year Deferred Comp Expense	8,302	-	8,302
12	Total Test Year Pension, PBOP, SERP and 401K Expense	1,735,547	576,854	1,158,693
13	Test Year Pension Expense, Pro-Forma Adjustment (1)	(2,185)	(29,377)	27,192
14	Test Year PBOP Expense, Pro-Forma Adjustment (2)	(19,749)	819	(20,569)
15	Test Year SERP Expense, Pro-Forma Adjustment (3)	58,798	-	58,798
16	Test Year 401K Expense, Pro-Forma Adjustment (4)	30,095	5,712	24,382
17	Test Year Deferred Comp Expense, Pro-Forma Adjustment (5)	44,415	-	44,415
18	Total Test Year Retirement Costs Pro-Forma Adjustment	$ 111,373	$ (22,845)	$ 134,218

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

Schedule RevReq-3-8
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PROPERTY & LIABILITY INSURANCE
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TOTAL	(3) NuNH [1]	(4) UNITIL SERVICE CORP. [2]
1	Proformed Property & Liability Insurances O&M Expense	$ 319,949	$ 289,097	$ 30,851
2	Less: Test Year Property & Liability Insurances O&M Expense	259,250	241,873	17,377
3	Proformed 2021 And 2022 O&M Increase	$ 60,699	$ 47,224	$ 13,475

Notes
(1) Refer to Workpaper 5.1
(2) Refer to Workpaper 5.2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
NH PUC ASSESSMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-9
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	2021 NH PUC Assessment [1]	$ 485,194
2	Test Year Total PUC Assessment Recovered Through Base Rates	368,964
3	Adjustment for 2021 NH PUC Assessment	$ 116,230

Notes
(1) Company will update assessment for fiscal year 2022 during pendency of case

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DUES & SUBSCRIPTION ADJUSTEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-10
Table of Contents

	(1)	(2)	
LINE NO.	DESCRIPTION	AMOUNT	
1	AGA Membership Dues	$	84,145
2	Amount allocated to NuNH		34%
3	Test Year NuNH Dues & Subscriptions		28,609
4	Adjustment to remove lobbying portion of Dues & Subscriptions [1]		(1,774)

Notes
(1) The portion of 2020 membership that is allocable to lobbying is 6.2%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PANDEMIC COST ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-11
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) AMOUNT
1	Pandemic Cost Adjustment - NuNH	$	100,284
2	Unitil Service Expense Allocated to NuNH		
3	Total Unitil Service Pandemic Costs	$	49,496
4	NuNH Apportionment		20.18%
5	Expense Apportioned to NuNH	$	9,988
6	Capitalization Rate		31.51%
7	NuNH Capitalization		3,147
8	NuNH Net O&M Medical Expense	$	6,841
9	Removal of Total Pandemic Costs from Test Year	$	(107,125)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SEVERANCE EXPENSE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-12
Table of Contents

	(1)	(2)	
LINE NO.	DESCRIPTION	AMOUNT	
1	Test year severance normalization [1]	$	(29,947)

Notes
(1) Normalized using 5-year historical amounts

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RENT EXPENSE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-13
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	(1)	(2)	
LINE NO.	DESCRIPTION	AMOUNT	
1	Rent Expense Charged to Unitil Service Corp.	$	381,843
2	NuNH Apportionment		19.85%
3	Expense Apportioned to NuNH	$	75,796
4	Capitalization Rate		31.51%
5	NuNH Capitalization		23,883
6	NuNH Net O&M Rent Expense	$	51,913

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE **Schedule RevReq-3-14**
ARREARAGE MANGAEMENT PROGRAM (AMP) IMPLEMENTATION ADJUSTMENT **Table of Contents**
12 MONTHS ENDED DECEMBER 31, 2020

	(1)		(2)
LINE NO.	DESCRIPTION		AMOUNT
1	Required AMP Full Time Employee	$	84,000
2	Allocable to NuNH		22%
3	Expense Allocable to NuNH	$	18,480
4	Annual AMP Forgiveness (1)		74,000
5	Total AMP Implementation Costs	$	92,480

Notes
(1) Annual over/under recovery of AMP forgiveness to be reconciled through Company's proposed Regulatory Cost Adjustment Mechanism as a component of the Local Delivery Adjustment Charge

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-15
Page 1 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) AMOUNT AS FILED
1	Test Year Distribution O&M Expenses	$	13,580,391
	Less Normalizing Adjustments Items:		
2	Payroll	$	6,636,764
3	Medical and Dental Insurance		466,837
4	401K Costs		363,965
5	Property & Liability Insurance		259,250
6	PUC Assessment		368,964
7	Total Normalizing Adjustment Items	$	8,095,780
	Less Items not Subject to Inflation:		
8	Pension	$	692,409
9	Postemployment Benefits Other than Pensions		409,195
10	Supplemental Executive Retirement Plan		261,677
11	Deferred Comp Expense		8,302
12	Bad Debts		345,477
13	Postage		135,037
14	Amortizations - USC Charge		75,914
15	Facility Leases - USC Charge		320,591
16	Total Items not Subject to Inflation	$	2,248,602
17	Residual O&M Expenses	$	3,236,009
18	Projected Inflation Rate[1]		5.12%
19	Increase in Other O&M Expense for Inflation	$	165,684

Notes
(1) Refer to Schedule RevReq-3-15, Page 2 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

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	113.6
3	July 1, 2020 (Midpoint of Test Year) Index	113.3
	GDPIPD Index Value at date of permanent rates :	
4	July 2022 Index-GDP	119.0
5	August 2022 Index-GDP	119.2
6	August 1, 2022 (Date of Permanent Rates) Index	119.1
7	Projected Inflation Rate	5.12%

Notes
(1) Refer to Workpaper 6.1 for GDPIPD Indices

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
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) CURRENT DEPRECIATION RATES	(4) ANNUAL DEPRECIATION EXPENSE
1	Amortizable Plant:			
2	303 Misc Intangible Plant	$ 12,826,347	N/A	N/A
3	Total Amortizable Plant	12,826,347	N/A	-
4	Mfg. Gas Produc. Plant:			
5	304.2 Land & Rights - Mfg Gas Prod. Pl	6,816	N/A	N/A
6	305 Struct. And Improvements	-	N/A	N/A
7	320 Other Equipment	-	N/A	N/A
8	321 LNG Equipment	-	N/A	N/A
9	Total Mfg Gas Prod. Plant	6,816	N/A	-
10	Distribution Plant:			
11	374.4 Land Rgts, Other Distr Sy	89,111	N/A	N/A
12	374.5 Land Rgts, Rights Of Way	17,911	N/A	N/A
13	375.2 Structures - City Gate Meas & Reg	43,350	1.43%	620
14	375.7 Structures - Other Dist Sys	3,217,521	1.43%	46,011
15	376.2 Mains - Coated/Wrapped	29,746,227	2.66%	791,250
16	376.3 Mains - Bare Steel	190,837	N/A	N/A
17	376.4 Mains - Plastic	120,342,184	2.87%	3,453,821
18	376.5 Mains - Joint Seals	542,145	N/A	N/A
19	376.6 Mains - Cathodic Protection	1,082,739	4.17%	45,150
20	376.8 Mains - Cast Iron	28,455	N/A	N/A
21	378.2 Mea & Reg Station Eq, Regulating	7,288,982	3.50%	255,114
22	379 Mea & Reg Ta-G	39,266	3.50%	1,374
23	380 Services	82,837,047	3.67%	3,040,120
24	381 Meters	4,624,610	3.33%	154,000
25	382 Meter Installations	26,001,685	3.33%	865,856
26	383 House Regulators	733,550	3.33%	24,427
27	386 Water Heaters/Conversion Burners	1,978,895	7.41%	146,636
28	Total Distribution Plant	278,804,516	3.17%	8,824,379
29	General Plant:			
30	389.1 Land	232,947	N/A	N/A
31	391.10 Off Furn & Eq.- Unspecified	508,135	8.70%	44,208
32	393 Stores Equipment	31,520	N/A	N/A
33	394.10 Tools, Garage & Service Equipment	1,430,421	5.26%	75,240
34	396 Power Operated Equipment	75,266	N/A	N/A
35	397 Communication Equipment	1,873,480	9.09%	170,299
36	397.25 Metscan Communication Equip	112,656	N/A	N/A
37	397.35 ERT Automatic Reading Dev	3,470,146	6.67%	231,459
38	Total General Plant	7,734,572	7.16%	521,206
39	Total Plant in Service	$ 299,372,252	3.28%	$ 9,345,585
40	Test Year Expense			$ 8,876,582
41	Increase In Depreciation Expense			$ 469,003

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PROPOSED DEPRECIATION RATES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	PLANT BALANCE 12/31/2020	PROPOSED DEPRECIATION RATES	PROPOSED DEPRECIATION EXPENSE
1	Amortizable Plant:			
2	303 Misc Intangible Plant	$ 12,826,347	N/A	N/A
3	Total Amortizable Plant	12,826,347	N/A	-
4	Mfg. Gas Produc. Plant:			
5	304.2 Land & Rights - Mfg Gas Prod. Pl	6,816	N/A	N/A
6	305 Struct. And Improvements	-	N/A	N/A
7	320 Other Equipment	-	N/A	N/A
8	321 LNG Equipment	-	N/A	N/A
9	Total Mfg Gas Prod. Plant	6,816	N/A	-
10	Distribution Plant:			
11	374.4 Land Rgts, Other Distr Sy	89,111	N/A	N/A
12	374.5 Land Rgts, Rights Of Way	17,911	N/A	N/A
13	375.2 Structures - City Gate Meas & Reg	43,350	2.74%	1,188
14	375.7 Structures - Other Dist Sys	3,217,521	2.74%	88,160
15	376.2 Mains - Coated/Wrapped	29,746,227	3.78%	1,124,407
16	376.3 Mains - Bare Steel	190,837	N/A	N/A
17	376.4 Mains - Plastic	120,342,184	2.88%	3,465,855
18	376.5 Mains - Joint Seals	542,145	N/A	N/A
19	376.6 Mains - Cathodic Protection	1,082,739	4.64%	50,239
20	376.8 Mains - Cast Iron	28,455	N/A	N/A
21	378.2 Mea & Reg Station Eq, Regulating	7,288,982	4.87%	354,973
22	379 Mea & Reg Ta-G	39,266	4.87%	1,912
23	380 Services	82,837,047	4.41%	3,653,114
24	381 Meters	4,624,610	5.34%	246,954
25	382 Meter Installations	26,001,685	4.23%	1,099,871
26	383 House Regulators	733,550	3.32%	24,354
27	386 Water Heaters/Conversion Burners	1,978,895	11.36%	224,802
28	Total Distribution Plant	278,804,516	3.72%	10,335,829
29	General Plant:			
30	389.1 Land	232,947	N/A	N/A
31	391.10 Off Furn & Eq.- Unspecified	508,135	6.67%	33,893
32	393 Stores Equipment	31,520	N/A	N/A
33	394.10 Tools, Garage & Service Equipment	1,430,421	3.67%	52,496
34	396 Power Operated Equipment	75,266	N/A	N/A
35	397 Communication Equipment	1,873,480	5.36%	100,419
36	397.25 Metscan Communication Equip	112,656	N/A	N/A
37	397.35 ERT Automatic Reading Dev	3,470,146	3.18%	110,351
38	Total General Plant	7,734,572	4.08%	297,159
39	Total Plant in Service	$ 299,372,252	3.73%	$ 10,632,988
40	Reserve Adjustment For Amortization (1)			
41	391.10 Off Furn & Eq.- Unspecified			(3,628)
42	394.10 Tools, Garage & Service Equipment			(27,132)
43	397 Communication Equipment			(80,592)
44	397.35 ERT Automatic Reading Dev			(35,960)
45	Total Reserve Adjustment for Amortization			(147,312)
46	Leak Prone Pipe (1)			
47	376.3 Mains - Bare Steel			464,724
48	376.8 Mains - Cast Iron			243,173
49	Total Leak Prone Pipe Amortization			707,897
50	Total Pro Forma Depreciation Expense (Line 39 + Line 45 + Line 49)			11,193,573
51	Annualized Test Year Expense (2)			$ 9,345,585
52	Increase in Depreciation Expense			$ 1,847,988

Notes
(1) Refer to testimony and schedules of Mr. Allis
(2) Refer to Schedule RevReq-3-16, Page 1 of 2, Line 39

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
AMORTIZATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-17
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LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	NU-NH Rate Year Software Amortization [1]	$ 669,511
2	USC Allocated Rate Year Software Amortization[2]	118,959
3	Total Rate Year Software Amortization	788,470
4	NU-NH Test Year Software Amortization[3]	$ 522,006
5	USC Allocated Test Year Software Amortization[4]	77,176
6	Total 2020 Test Year Software Amortization	599,182
7	Test Year Amortization Expense Adjustment (Line 3 - Line 7)	$ 189,288

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

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
EXCESS ACCUMULATED DEFERRED INCOME TAX ("ADIT") FLOW BACK
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-18
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Annual Amortization Expense Reduction Related to Excess ADIT Flowback [1]	$ (308,218)

Notes
(1) Refer to Exhibit JAG-6

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PROPERTY TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-19
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	(1)	(2)		(3)	(4)		(5)
LINE NO.	MUNICIPALITY & STATE	TAXATION PERIOD		LOCAL TAX RATE	ASSESSED VALUATION		TOTAL TAXES[1]
1	Atkinson	4/1 - 3/31	$	16.24	1,564,100		25,401
2	Brentwood	4/1 - 3/31	$	21.36	1,489,600		31,818
3	Brentwood	4/1 - 3/31	$	23.19	400		9
4	Dover	4/1 - 3/31	$	24.85	1,200		30
5	Dover	4/1 - 3/31	$	22.92	37,150,600		851,492
6	Durham	4/1 - 3/31	$	25.73	7,742,400		199,212
7	East Kingston	4/1 - 3/31	$	20.50	746,700		15,307
8	Epping	4/1 - 3/31	$	23.64	1,079,900		25,529
9	Exeter	4/1 - 3/31	$	22.50	13,803,800		310,586
10	Greenland	4/1 - 3/31	$	14.58	733,400		10,693
11	Hampton--Class 4000	4/1 - 3/31	$	13.93	18,884,700		263,064
12	Hampton--Class 5000	4/1 - 3/31	$	14.43	9,301,400		134,219
13	Hampton Falls	4/1 - 3/31	$	19.33	36,400		704
14	Kensington	4/1 - 3/31	$	18.61	1,442,400		26,843
15	Madbury	4/1 - 3/31	$	23.41	347,000		8,123
16	Newington	4/1 - 3/31	$	8.02	2,848,900		22,848
17	North Hampton	4/1 - 3/31	$	14.80	1,822,800		26,977
18	Plaistow	4/1 - 3/31	$	19.60	9,849,580		193,052
19	Portsmouth	4/1 - 3/31	$	12.80	47,562,000		608,794
20	Rochester	4/1 - 3/31	$	22.67	26,840,200		608,468
21	Rollinsford	4/1 - 3/31	$	22.57	194,600		4,392
22	Rollinsford	4/1 - 3/31	$	24.68	20,000		494
23	Salem	4/1 - 3/31	$	19.82	9,478,700		187,867
24	Seabrook	4/1 - 3/31	$	13.90	12,142,100		168,775
25	Somersworth	4/1 - 3/31	$	25.91	9,713,200		251,669
26	Somersworth	4/1 - 3/31	$	27.85	62,000		1,727
27	Stratham	4/1 - 3/31	$	17.14	497,200		8,522
28	State Of NH [2]	4/1 - 3/31					1,359,585
29	Total			$	215,355,280	$	5,346,199
30	Test Year Property Taxes [3]					$	4,728,948
31	Less: Test Year Property Tax Abatements [4]						688
32	Total Test Year Property Tax Expense					$	4,728,260
33	Total Property Tax Increase (Line 29 - Line 32)					$	617,939

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) Test Year Property Taxes adjusted to exclude Greenland 2019 bill correction of $317

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PAYROLL TAX ADJUSTMENT - WAGE INCREASES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	SOCIAL SECURITY	MEDICARE	TOTAL
1	Increase in O&M Payroll / Compensation due to Annual Rate Increases [1]	$ 554,442	$ 554,442	
2	Payroll Tax Rates	6.20%	1.45%	
3	Increase in Payroll Taxes	$ 34,375	$ 8,039	$ 42,415

Notes
(1) Refer to Schedule RevReq-3-4, Page 1 of 2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PAYROLL TAX ADJUSTMENT - EMPLOYEE RETENTION CREDIT
EMPLOYEE RETENTION CREDIT ("ERC") & FAMILY FIRST CORONAVIRUS RESPONSE ACT ("FFCRA")
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-20
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LINE NO.	(1) DESCRIPTION	(2) SOCIAL SECURITY
1	ERC & FFCRA - NuNH	$ (107,364)
2	Capitalization Rate	46.69%
3	Capitalized Amount	(50,128)
4	Net Expense - NuNH	(57,236)
5	Unitil Service ERC Allocated to NuNH	
6	Total Unitil Service ERC	$ (279,213)
7	NUNH Apportionment	20.18%
8	Expense Apportioned to NuNH	$ (56,345)
9	Capitalization Rate	32.52%
10	NuNH Capitalization	(18,323)
11	NuNH Net ERC	$ (38,022)
12	Removal of Total ERC & FFCRA from Test Year	$ 95,258

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-21
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LINE NO.	(1) DESCRIPTION		(2) Amount
1	Increases / (Decreases) To Revenue		
2	Weather Normalization	$	1,994,374
3	New Customer Revenue Annualization		278,301
4	Residential Low Income		264,523
5	Unbilled Revenue		294,543
6	Non-Distribution Bad Debt		(97,468)
7	Misc. Revenue Adjustment		4,788
8	Late Fee Adjustment		40,013
9	Billed Accuracy Adjustment		367
10	Special Contract Customer Revenue Adjustment		17,968
11	Total Revenue Adjustments	$	2,797,410
12	Increases / (Decreases) To Expenses		
13	Production Expense (O&M)	$	76,191
14	Payroll		554,442
15	Medical & Dental Insurances		404,594
16	Distribution Bad Debt		88,160
17	Non-Distribution Bad Debt		(97,468)
18	Pension		(2,185)
19	PBOP		(19,749)
20	SERP		58,798
21	401K		30,095
22	Deferred Comp Expense		44,415
23	Property & Liability Insurances		60,699
24	NH PUC Assessment		116,230
25	Dues & Subscriptions		(1,774)
26	Pandemic Costs		(107,125)
27	Severance Expense		(29,947)
28	Rent Expense		51,913
29	Arrearage Management Program (AMP) Implementation Cost		92,480
30	Inflation Allowance		165,684
31	Depreciation Annualization		469,003
32	Proposed Depreciation Rates		1,847,988
33	Production Expense (Depreciation)		37,865
34	Software Amortization		189,288
35	Excess ADIT Flowback		(308,218)
36	Property Taxes		617,939
37	Payroll Taxes - Wage Increases		42,415
38	Payroll Taxes - Employee Retention Credits		95,258
39	Flowthrough Net Operating Income		759,111
40	Change In Interest Exp (Refer To Schedule RevReq 3-21 Page 2)		(345,611)
41	Total Expense Adjustments	$	4,890,487
42	Increase / (Decrease) In Taxable Income	$	(2,093,077)
43	Effective Federal Income Tax Rate(1)		19.38%
44	NH State Tax Rate(2)		7.70%
	Federal Income & NH State Tax		
45	Effective Federal Income Tax	$	(405,701)
46	NH State Tax		(161,167)
47	Increase (Decrease) In Income Taxes	$	(566,868)
	Notes		
48	Federal Income Tax Rate		21.00%
49	Federal Benefit of State Tax - (Line 48 * Line 51)		-1.62%
50	(1) Effective Federal Income Tax Rate		19.38%
51	(2) State Income Tax Rate		7.70%
52	Northern New Hampshire Tax Rate (Line 50 + Line 51)		27.08%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
CHANGE IN INTEREST EXPENSE APPLICABLE TO INCOME TAX COMPUTATION
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) AMOUNT
1	Ratemaking Interest Synchronization	
2	Rate Base[1]	$ 188,719,257
3	Cost Of Debt In Proposed Rate Of Return[2]	2.34%
4	Interest Expense for Ratemaking	$ 4,422,286
5	Test Year Interest Expense	
6	Interest Charges (427-431)	$ 4,767,897
7	Increase / (Decrease) in Interest Expense	$ (345,611)

Notes
(1) Refer to Schedule RevReq-5
(2) Refer to Schedule RevReq-6

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO	(1) DESCRIPTION	(2) TEST YEAR ACTUAL	(3) PRO-FORMA ADJUSTMENTS	(4) TEST YEAR UTILITY
1	Net Income	$ 6,096,270	$ -	$ 6,096,270
2	Federal Income Tax-Current	(19,629)	-	(19,629)
3	NH State Income Tax-Current	(380,440)	-	(380,440)
4	NH State Business Enterprise Credit Against NH BPT	63,600	-	63,600
5	Deferred Federal Income Tax	1,637,521	-	1,637,521
6	Deferred State Income Tax	962,658	-	962,658
7	Net Income Before Income Taxes	8,359,980	-	8,359,980
8	*Permanent Items*			
9	Lobbying	22,225	-	22,225
10	Parking Lot Disallowance	2,543	-	2,543
11	Penalties	2,500	-	2,500
12	Total Permanent Items	27,268	-	27,268
13	*Temporary Differences*			
14	Accrued Revenue	(3,295,760)	-	(3,295,760)
15	Bad Debt	81,370	-	81,370
16	FASB 87-Pensions	(211,016)	-	(211,016)
17	PBOP SFAS 106	96,936	-	96,936
18	Remediation	267,789	-	267,789
19	Utility Plant Differences	(5,924,514)	-	(5,924,514)
20	Total Temporary Differences	(8,985,195)	-	(8,985,195)
21	*Federal And State Tax Differences*			
22	Tax Depreciation	(2,123,819)	-	(2,123,819)
23	Total Federal And State Tax Differences	(2,123,819)	-	(2,123,819)
24	State Taxable Base Income	(2,721,766)	-	(2,721,766)
25	State Business Profits Tax - Current	(209,576)	-	(209,576)
26	Less: Business Enterprise Tax	63,600	-	63,600
27	Total State Tax Expense	(273,176)	-	(273,176)
28	Federal Taxable Income Base Before Federal And State Tax Differences	(2,512,190)	-	(2,512,190)
29	Less: Federal And State Tax Differences	(2,123,819)	-	(2,123,819)
30	Federal Taxable Income Base	(388,371)	-	(388,371)
31	Federal Income Tax-Current	(81,558)	-	(81,558)
32	*Summary Of Utility Income Taxes:*			
33	Federal Income Tax-Current	(92,140)	-	(92,140)
34	Federal Income Tax-Prior	49,634	-	49,634
35	Federal Income Tax-NOL	12,295	-	12,295
36	Federal Amount To Non-Distribution Operations	10,582	(10,582)	-
37	State Business Profits Tax-Current	(277,380)	-	(277,380)
38	State Business Profits Tax-Prior	834,820	-	834,820
39	State Business Profits Tax-NOL	(942,084)		(942,084)
40	State Amount To Non-Distribution Operations	4,204	(4,204)	-
41	Deferred Federal Income Tax	1,707,258	-	1,707,258
42	Deferred Federal Income Tax-Prior	(57,442)	-	(57,442)
43	Deferred Federal Income Tax-NOL	(12,295)	-	(12,295)
44	Deferred State Business Profits Tax	855,394	-	855,394
45	Deferred State Business Profits Tax-Prior	(834,820)	-	(834,820)
46	Deferred State Business Profits Tax-NOL	942,084		942,084
47	Total Income Taxes	$ 2,200,110	$ (14,786)	$ 2,185,324

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRIOR YEAR INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)
LINE NO	DESCRIPTION	ACTUAL
1	Remove Prior Year Federal Income Taxes	$ (49,634)
2	Remove Prior Year State Income Taxes	(834,820)
3	Remove Prior Year Deferred Federal Income Taxes	57,442
4	Remove Prior Year Deferred State Income Taxes	834,820
5	Total	$ 7,808

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
ASSETS & DEFERRED CHARGES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-1
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LINE NO.	(1) Category	(3) New Hampshire	(2) Maine	(4) Common	(5) Consolidated December 31, 2020	(6) Consolidated December 31, 2019	(7) Consolidated December 31, 2018
1	Gas Plant						
2	In Service	$ 299,372,252	$ 390,755,625	$ -	$ 690,127,877	$ 623,207,033	$ 560,519,339
3	Construction Work in Progress	6,411,145	6,890,804	-	13,301,949	12,576,742	11,064,887
4	Less: Reserve for Depreciation	(88,023,262)	(87,391,662)	-	(175,414,925)	(143,066,942)	(131,806,854)
5	Total Gas Plant	217,760,135	310,254,767	-	528,014,901	492,716,833	439,777,371
6	Other Property						
7	Total Other Net Property	-	86,855	-	86,855	29,819	(24,914)
8	Total Other & Non Operating Plant	-	86,855	-	86,855	29,819	(24,914)
9	Current Assets						
10	Cash	1,500	250	370,260	372,010	341,847	672,243
11	Accounts Receivable - Gas	9,102,182	14,492,785	-	23,594,967	21,416,443	28,512,317
12	Accounts Receivable - Other	181,592	14,495	3,377	199,464	154,773	34,597
13	Uncollectible Accounts	(294,933)	(863,075)	-	(1,158,008)	(441,588)	(836,962)
14	Notes Receivable	-	-	8,913,185	8,913,185	5,559,766	3,137,369
15	Material and Supplies	2,416,575	2,048,155	-	4,464,730	4,162,206	3,892,225
16	Stores Expense Undistributed	356,883	351,217	-	708,100	655,826	481,856
17	Inventory	267,731	40,348	-	308,079	448,104	391,250
18	Prepayments	963,040	1,128,283	70,044	2,161,367	4,450,029	3,400,561
19	Accrued Revenue	3,803,680	4,731,203	-	8,534,883	9,587,864	8,319,787
20	Miscellaneous Current Assets	4,530,525	93,747	-	4,624,272	5,666,176	7,622,013
21	Total Current Assets	21,328,775	22,037,408	9,356,866	52,723,049	52,001,444	55,627,256
22	Deferred Charges						
23	Unamortized Debt Expense	-	-	1,359,851	1,359,851	1,208,586	1,092,517
24	Other - Deferred Debits	13,872,478	20,353,943	98,736	34,325,157	27,066,138	32,928,903
25	Total Deferred Charges	13,872,478	20,353,943	1,458,587	35,685,008	28,274,724	34,021,420
26	Total Assets & Deferred Charges	$ 252,961,387	$ 352,732,973	$ 10,815,453	$ 616,509,813	$ 573,022,820	$ 529,401,133

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
STOCKHOLDERS EQUITY & LIABILITIES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-2
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LINE NO.	(1) Category	(3) New Hampshire	(2) Maine	(4) Common	(5) Consolidated December 31, 2020	(6) Consolidated December 31, 2019	(7) Consolidated December 31, 2018
1	Capitalization						
2	Common Stock	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000
3	Paid in Capital	-	-	207,074,000	207,074,000	200,699,000	175,199,000
4	Earned Surplus	6,096,270	8,643,131	9,713,702	24,453,103	24,380,042	22,032,465
5	Stockholders Equity	6,096,270	8,643,131	216,788,702	231,528,103	225,080,042	197,232,465
6	Long Term Debt						
7	Bonds and Notes	-	-	230,000,000	230,000,000	198,200,000	166,600,000
8	Total	-	-	230,000,000	230,000,000	198,200,000	166,600,000
9	Current and Accrued Liabilities						
10	Accounts Payable	639,411	538,256	6,001,159	7,178,826	8,651,894	10,471,212
11	Notes Payable to Associated Co.	-	-	26,747,022	26,747,022	28,494,680	58,154,005
12	A/P to Associated Co's	-	-	7,400,409	7,400,409	6,497,178	3,145,273
13	Customer Deposits	249,677	342,624	-	592,301	640,562	738,651
14	Taxes Accrued	67,648	(4,613)	-	63,035	292,534	14,450
15	Interest Accrued	-	-	2,094,467	2,094,467	1,824,919	1,503,714
16	Dividends Declared	-	-	3,666,585	3,666,585	3,304,600	1,229,300
17	Other Tax Liabilities	750,955	(609,964)	33,532	174,523	94,759	130,422
18	Other Current and Accrued Liabilities	811,427	576,546	7,636,657	9,024,630	11,636,693	15,472,163
19	Total Current and Accrued Liabilities	2,519,118	842,849	53,579,831	56,941,798	61,437,819	90,859,190
20	Deferred Credits						
21	Other Deferred Credits	18,639,799	21,537,277	-	40,177,076	35,921,434	27,893,528
22	Other Regulatory Liabilities	6,608,392	8,917,471	-	15,525,863	15,874,493	15,992,896
23	Accumulated Deferred Income Taxes	16,892,861	25,444,116	-	42,336,977	36,509,031	30,823,054
24	Total Deferred Credits	42,141,052	55,898,864	-	98,039,916	88,304,958	74,709,478
25	Total Stockholders Equity & Liabilities	$ 50,756,440	$ 65,384,844	$ 500,368,533	$ 616,509,817	$ 573,022,819	$ 529,401,133

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
UTILITY PLANT IN SERVICE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-3
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LINE NO.	(1) Account Name	(2) CAPITAL 1/1	(3) ADDITIONS	(4) RETIREMENTS	(5) TRANSFER ADJ	(6) PLANT IN SERVICE 12/31	(7) COMPLETED CONSTRUCTION NOT CLASSIFIED 12/31
1	Amortizable Plant:						
2	303 Misc Intangible Plant	$ 11,262,452	$ 960,046	$ -	$ -	$ 12,222,498	$ 603,849
3	Total Amortizable Plant	11,262,452	960,046	-	-	12,222,498	603,849
4	Mfg. Gas Produc. Plant:						
5	304.2 Land & Rights - Mfg Gas Prod. Pl	6,816	-	-	-	6,816	-
6	305 Struct. And Improvements	161,860	-	(75,459)	(86,401)	-	-
7	320 Other Equipment	7,640	-	(7,006)	(634)	-	-
8	321 LNG Equipment	84,156	-	(84,156)	-	-	-
9	Total Mfg Gas Prod. Plant	260,472	-	(166,621)	(87,035)	6,816	-
10	Distribution Plant:						
11	374.4 Land Rgts, Other Distr Sy	89,111	-	-	-	89,111	
12	374.5 Land Rgts, Rights Of Way	17,911	-	-	-	17,911	-
13	375.2 Structures - City Gate Meas & Reg	45,256	-	(1,906)	-	43,350	-
14	375.7 Structures - Other Dist Sys	3,124,357	4,495	-	87,035	3,215,887	1,634
15	376.2 Mains - Coated/Wrapped	24,602,506	5,182,813	(78,525)	-	29,706,795	39,433
16	376.3 Mains - Bare Steel	190,837	-	-	-	190,837	-
17	376.4 Mains - Plastic	104,050,393	9,284,825	(600,390)	-	112,734,828	7,607,356
18	376.5 Mains - Joint Seals	542,145	-	-	-	542,145	-
19	376.6 Mains - Cathodic Protection	1,005,475	54,885	-	-	1,060,360	22,380
20	376.8 Mains - Cast Iron	28,455	-	-	-	28,455	-
21	378.2 Mea & Reg Station Eq, Regulating	4,400,294	3,002,141	(279,719)	-	7,122,716	166,266
22	379 Mea & Reg Ta-G	39,266	-	-	-	39,266	-
23	380 Services	74,470,438	5,463,157	(87,804)	-	79,845,791	2,991,256
24	381 Meters	4,086,446	493,715	(241,099)	-	4,339,063	285,548
25	382 Meter Installations	23,126,115	2,038,526	(1,108,186)	-	24,056,455	1,945,231
26	383 House Regulators	685,777	43,536	-	-	729,313	4,237
27	386 Water Heaters/Conversion Burners	1,823,459	159,350	(88,909)	-	1,893,900	84,996
28	Total Distribution Plant	242,328,242	25,727,443	(2,486,538)	87,035	265,656,182	13,148,334
29	General Plant:						
30	389-1 Land	232,947	-	-	-	232,947	-
31	391.10 Off Furn & Eq.- Unspecified	431,834	65,465	-	-	497,299	10,836
32	393 Stores Equipment	31,520	-	-	-	31,520	-
33	394.10 Tools, Garage & Service Equipment	1,314,945	54,709	-	-	1,369,654	60,767
34	396 Power Operated Equipment	75,266	-	-	-	75,266	-
35	397 Communication Equipment	1,639,792	237,572	(37,264)	-	1,840,100	33,380
36	397.25 Comm EQ, Metscan/Telemet	112,656	-	-	-	112,656	-
37	397.35 ERT Automatic Reading Dev-G	3,126,899	212,363	-	-	3,339,262	130,884
38	Total General Plant	6,965,859	570,110	(37,264)	-	7,498,705	235,867
39	Total Plant in Service	$ 260,817,025	$ 27,257,599	$ (2,690,423)	$ (0)	$ 285,384,202	$ 13,988,050

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
ACCUMULATED DEPRECIATION & AMORTIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-4
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LINE NO.	(1) Account Name	(2) RESERVE BALANCE 1/1	(3) RETIREMENTS	(4) TRANSFER ADJ	(5) COST OF REMOVAL	(6) SALVAGE	(7) DEPRECIATION	(8) RESERVE BALANCE 12/31
1	Amortizable Plant:							
2	303 Misc Intangible Plant	$ 4,080,484	$ -	$ -	$ -	$ -	$ 816,977	$ 4,897,461
3	Total Amortizable Plant	4,080,484	-	-	-	-	816,977	4,897,461
4	Mfg. Gas Produc. Plant:							
5	305 Struct. And Improvements	129,465	(75,459)	(54,380)	-	-	-	(374)
6	320 Other Equipment	2,756	(7,006)	(188)	-	-	-	(4,438)
7	321 LNG Equipment	56,611	(84,156)	-	-	-	-	(27,544)
8	Total Mfg Gas Prod. Plant	188,832	(166,621)	(54,568)	-	-	-	(32,357)
9	Distribution Plant:							
10	375.2 Structures - City Gate Meas & Reg	23,676	(1,906)	-	(144,400)	-	636	(121,994)
11	375.7 Structures - Other Dist Sys	618,738	-	54,568	-	-	44,850	718,156
12	376.2 Mains - Coated/Wrapped	3,615,660	(78,525)	-	(96,639)	-	783,669	4,224,164
13	376.3 Mains - Bare Steel	(2,132,784)	-	-	-	-	-	(2,132,784)
14	376.4 Mains - Plastic	33,956,974	(600,390)	-	(220,844)	-	3,247,143	36,382,883
15	376.5 Mains - Joint Seals	542,145	-	-	-	-	-	542,145
16	376.6 Mains - Cathodic Protection	638,564	-	-	-	-	44,096	682,660
17	376.8 Mains - Cast Iron	(1,187,409)	-	-	-	-	-	(1,187,409)
18	378.2 Mea & Reg Station Eq, Regulating	988,517	(279,719)	-	(272,577)	-	230,155	666,376
19	379 Mea & Reg Ta-G	5,058	-	-	-	-	1,374	6,432
20	380 Services	25,894,274	(87,804)	-	(227,967)	-	2,900,993	28,479,497
21	381 Meters	1,376,120	(241,099)	-	(52,894)	-	144,485	1,226,613
22	382 Meter Installations	7,216,618	(1,108,186)	-	(94,033)	-	844,898	6,859,297
23	383 House Regulators	188,268	-	-	-	-	24,134	212,402
24	386 Water Heaters/Conversion Burners	941,396	(88,909)	-	(13,917)	11,358	109,637	959,565
25	Total Distribution Plant	72,685,816	(2,486,538)	54,568	(1,123,270)	11,358	8,376,070	77,518,004
26	General Plant:							
27	391.10 Off Furn & Eq.- Unspecified	256,028	-	-	-	-	42,050	298,078
28	393 Stores Equipment	31,511	-	-	-	-	-	31,511
29	394.10 Tools, Garage & Service Equipment	713,214	-	-	-	-	72,528	785,741
30	396 Power Operated Equipment	75,266	-	-	-	-	-	75,266
31	397 Communication Equipment	1,453,916	(37,264)	-	(5,020)	-	158,970	1,570,602
32	397.25 Comm EQ, Metscan/Telemet	112,656	-	-	-	-	-	112,656
33	397.35 Comm EQ, Itron Equip	2,550,675	-	-	(11,340)	-	226,965	2,766,299
34	Total General Plant	5,193,266	(37,264)	-	(16,360)	-	500,512	5,640,154
4	Total Accumulated Depreciation & Amortization	$ 82,148,399	$ (2,690,423)	$ -	$ (1,139,630)	$ 11,358	$ 9,693,559	$ 88,023,263

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5
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LINE NO.	DESCRIPTION (1)	TEST YEAR AVERAGE [1] (3)	5 QUARTER AVERAGE (4)	RATE BASE AT DECEMBER 31, 2020 (5)	PRO FORMA ADJUSTMENTS (6)	PRO FORMA RATE BASE AT DECEMBER 31, 2020 (7)
1	Utility Plant In Service	$ 289,824,481	$ 286,491,423	$ 299,372,252	$ 1,873,246	$ 301,245,498
2	Less: Reserve for Depreciation	85,085,831	85,651,383	88,023,262	1,350,190	89,373,452
3	Net Utility Plant	204,738,650	200,840,040	211,348,990	523,056	211,872,045
4	Add: M&S Inventories	2,671,150	2,770,028	2,773,457	-	2,773,457
5	Prepayments	740,275	1,213,708	64,895	-	64,895
6	Cash Working Capital [2]	1,773,194	1,773,194	1,773,194	235,191	2,008,385
7	Sub-Total	5,184,619	5,756,930	4,611,547	235,191	4,846,738
8	Less: Net Deferred Income Taxes	$ 20,221,877	$ 20,784,379	$ 21,177,756	$ -	$ 21,177,756
9	Excess Deferred Income Taxes	6,572,092	6,572,092	6,572,092	-	6,572,092
10	Customer Advances	-	-	-	-	-
11	Customers Deposits	269,548	264,461	249,677	-	249,677
12	Sub-Total	27,063,517	27,620,932	27,999,526	-	27,999,526
13	Rate Base	$ 182,859,752	$ 178,976,038	$ 187,961,010	$ 758,247	$ 188,719,257
14	Net Operating Income Applicable To Rate Base	$ 10,066,533	$ 10,066,533	$ 10,066,533		$ 8,946,016
15	Rate of Return	5.51%	5.62%	5.36%		4.74%

Notes
(1) Two Point Average
(2) Computed Working Capital Based on Test Year O&M Expenses. Refer to Schedule RevReq-5-2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE BASE ITEMS
QUARTERLY BALANCES

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
1	Utility Plant in Service						
2	Plant In Service	$ 260,817,025	$ 266,498,877	$ 269,468,172	$ 272,008,852	$ 285,384,202	$ 270,835,426
3	Completed Construction not Classified	19,459,684	16,390,088	14,114,541	14,327,620	13,988,050	15,655,997
4	Total Utility Plant in Service	280,276,709	282,888,965	283,582,713	286,336,471	299,372,252	286,491,423
5	Depreciation Reserve	$ (82,148,399)	$ (84,295,016)	$ (86,310,091)	$ (87,480,144)	$ (88,023,262)	$ (85,651,383)
6	Add:						
7	M&S Inventories						
8	Material and Supplies	$ 2,268,328	$ 2,387,075	$ 2,514,326	$ 2,569,166	$ 2,416,575	$ 2,431,094
9	Stores Expense Undistributed	300,515	417,170	334,238	285,865	356,883	338,934
10	Total M&S Inventories	$ 2,568,843	$ 2,804,245	$ 2,848,563	$ 2,855,032	$ 2,773,457	$ 2,770,028
11	Prepayments	$ 1,415,655	$ 1,415,655	$ 1,415,655	$ 1,756,682	$ 64,895	$ 1,213,708
12	Cash Working Capital	$ 1,773,194	$ 1,773,194	$ 1,773,194	$ 1,773,194	$ 1,773,194	$ 1,773,194
13	Less:						
14	Total Deferred Income Taxes						
15	Def Inc Tax - Accel Depr	$ 20,062,817	$ 22,388,845	$ 22,014,104	$ 21,283,095	$ 22,009,122	$ 21,551,597
16	Def Inc Tax - FAS 87 / 106	(775,910)	(788,563)	(774,047)	(591,877)	(788,419)	(743,763)
17	` Def Inc Tax - Bad Debt	(19,095)	(26,052)	(10,935)	(10,989)	(41,133)	(21,641)
18	Def Inc Tax - Def Rate Case Costs	0	0	0	0	0	-
19	Def Inc Tax - Insurance Claim	(1,814)	(1,814)	(1,814)	(1,814)	(1,814)	(1,814)
20	Total Deferred Income Taxes	$ 19,265,998	$ 21,572,415	$ 21,227,308	$ 20,678,415	$ 21,177,756	$ 20,784,379
21	Less: Excess Deferred Income Taxes	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092
22	Less: Customer Advances	$ -	$ -	$ -	$ -	$ -	$ -
23	Less: Customer Deposits	$ 289,419	$ 269,680	$ 263,516	$ 250,011	$ 249,677	$ 264,461
24	Rate Base	$ 177,758,493	$ 176,172,855	$ 175,247,118	$ 177,740,716	$ 187,961,010	$ 178,976,038

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
CASH WORKING CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-2
Table of Contents

	(1)	(2)	(3)	(4)	(5)
LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR ACTUAL	PRO FORMA ADJUSTMENTS	TEST YEAR PRO FORMA
1	Distribution O&M Expense	Schedule RevReq-2	$ 13,332,381	$ 946,840	$ 14,279,221
2	Tax Expense	Schedule RevReq-2	4,452,919	1,412,146	5,865,065
3	Total		$ 17,785,300	$ 2,358,986	$ 20,144,286
4	Cash Working Capital Requirement:				
5	Other O&M Expense Days Lag (1) / 366	36 days	9.97%	9.97%	9.97%
6	Total Cash Working Capital	Line 5 X Line 3	$ 1,773,194	$ 235,191	$ 2,008,385

Notes
(1) Refer to Lead-Lag Study in Direct Testimony of Daniel Hurstak

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SUPPLEMENTAL PLANT PRO FORMA ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-3
Table of Contents

LINE NO.	(1) DESCRIPTION			(2) BALANCE 12/31/2020
1	Plant In Service:			
2	New Hampshire			
3	304 Land - Barberry Lane		$	6,816
4	Total NH		$	6,816
5	Maine			
6	360 Land - Lewiston		$	58,301
7	361 Structures & Improvements			568,201
8	362 Gas Holders			3,878,347
9	363 Other Equipment			87,313
10	Total ME		$	4,592,161
11	Total Plant In Service NH And ME		$	4,598,977
12	NH Allocation Via Annual Proportional Responsibility Factor	40.88%	$	1,880,062
13	ME Allocation Via Annual Proportional Responsibility Factor	59.12%	$	2,718,915
14	Depreciation Reserve:			
15	New Hampshire			
16	Total NH		$	-
17	Maine			
18	361 Structures & Improvements		$	267,178
19	362 Gas Holders			2,943,652
20	363 Other Equipment			91,983
21	Total ME		$	3,302,812
22	Total Depreciation Reserve NH And ME		$	3,302,812
23	NH Allocation Via Annual Proportional Responsibility Factor	40.88%	$	1,350,190
24	ME Allocation Via Annual Proportional Responsibility Factor	59.12%	$	1,952,623
25	Supplemental Plant Adjustment			
26	NH Supplemental Plant Adjustment (Line 12 - Line 4)		$	1,873,246
27	ME Supplemental Plant Adjustment (Line 13 - Line 10)		$	(1,873,246)
28	Supplemental Depreciation Reserve Adjustment			
29	NH Supplemental Plant Adjustment (Line 23 - Line 16)		$	1,350,190
30	ME Supplemental Plant Adjustment (Line 24 - Line 21)		$	(1,350,190)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DEFERRED INCOME TAX PRO FORMA ADJUSTMENT
SETTLEMENT ADJUSTMENT PURSUANT TO DOCKET 2008-155
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-4
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) DECEMBER 31 2020
1	Nisource Original Plant Federal and State DIT Basis	$ 4,053,514
2	Unitil Acquired Plant Federal and State DIT Basis	5,319,173
3	Greater of Line 1 or Line 2 to be Utilized as DIT Basis per Stipulation	$ 5,319,173
4	Post-Acquisition Capital Expenditures Federal and State DIT Basis	$ 29,619,418
5	Net Operating Loss DIT Related to Rate Base at 12/31/20	(12,929,468)
6	Total Plant and Capex Federal and State DIT to be Used in Rate Base (Line 3 + Line 4 + Line 5)	$ 22,009,122
7	Less Test Year: Def Inc Tax - Accel Depr	22,009,122
8	Required Pro Forma Adjustment (Line 6 - Line 7)	$ -

Schedule RevReq-6
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NORTHERN UTILITIES, INC.
WEIGHTED AVERAGE COST OF CAPITAL
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) REFERENCE
1	Common Stock Equity	$ 229,204,938	$ -	$ 229,204,938	52.47%	10.30%	5.40%	Schedule RevReq 6-1 and 6-2
2	Preferred Stock Equity	-	-	-	0.00%	0.00%	0.00%	Schedule RevReq 6-1 and 6-3
3	Long Term Debt	207,640,000	-	207,640,000	47.53%	4.93%	2.34%	Schedule RevReq 6-1 and 6-4
4	Short Term Debt	-	-	-	0.00%	1.69%	0.00%	Schedule RevReq 6-1 and 6-5
5	Total	$ 436,844,938	$ -	$ 436,844,938	100.00%		7.75%	

NORTHERN UTILITIES, INC.
CAPITAL STRUCTURE FOR RATEMAKING PURPOSES
5-QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-6-1
Table of Contents

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(3)	(8)
LINE NO.	DESCRIPTION	DECEMBER 31 2019	MARCH 31 2020	JUNE 30 2020	SEPTEMBER 30 2020	DECEMBER 31 2020	5 QUARTER AVERAGE	PROFORMA ADJUSTMENT	PROFORMA AMOUNT
1	Common Stock Equity								
2	Common Stock	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ -	$ 1,000
3	Misc. Paid In Capital	200,699,000	200,699,000	205,699,000	205,699,000	207,074,000	203,974,000	-	203,974,000
4	Retained Earnings	24,380,042	29,943,726	26,634,154	20,738,662	24,453,104	25,229,938	-	25,229,938
5	Total Common Stock Equity	225,080,042	230,643,726	232,334,154	226,438,662	231,528,104	229,204,938	-	229,204,938
6	Preferred Stock Equity	-	-	-	-	-	-	-	-
7	Long-Term Debt	198,200,000	190,000,000	190,000,000	230,000,000	230,000,000	207,640,000	-	207,640,000
8	Short-Term Debt (1)	-	-	-	-	-	-	-	-
9	Total	$ 423,280,042	$ 420,643,726	$ 422,334,154	$ 456,438,662	$ 461,528,104	$ 436,844,938	$ -	$ 436,844,938
10	Capital Structure Ratios								
11	Common Stock Equity	53.18%	54.83%	55.01%	49.61%	50.17%	52.47%		52.47%
12	Preferred Stock Equity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
13	Long-Term Debt	46.82%	45.17%	44.99%	50.39%	49.83%	47.53%		47.53%
14	Short-Term Debt (1)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
15	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

NORTHERN UTILITIES, INC.
COST OF COMMON EQUITY CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-6-2
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THE INFORMATION CONCERNING THE COST OF COMMON EQUITY CAPITAL IS PROVIDED IN THE TESTIMONY AND EXHIBITS OF MR. JOHN COCHRANE

NORTHERN UTILITIES, INC.
WEIGHTED AVERAGE COST OF PREFERRED STOCK
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-6-3
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NORTHERN UTILITIES, INC. DOES NOT HAVE PREFERRED STOCK OUTSTANDING

NORTHERN UTILITIES, INC.
WEIGHTED AVERAGE COST OF LONG-TERM DEBT
DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-6-4
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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
LINE NO.		ISSUE	DATE ISSUED	TERM	FACE VALUE	OUTSTANDING AMOUNT	PROFORMA ADJUSTMENT	PROFORMED OUTSTANDING AMOUNT	ISSUANCE COSTS	NET PROCEEDS RATIO [(5)-(9)/(5)]	UNAMORTIZED ISSUANCE COSTS	NET PROCEEDS OUTSTANDING (8)-(11)	ANNUAL ISSUANCE COST	ANNUAL INTEREST COST Rate * (8)	TOTAL ANNUAL COST (13)+(14)	COST RATE BASED ON NET PROCEEDS (15)/[(8)-(11)]
1	7.72%	Sr. Notes	12/3/2008	30 Yrs	$ 50,000,000	$ 50,000,000	$ -	$ 50,000,000	$ 435,899	99.13%	$ 260,401	$ 49,739,599	$ 14,534	$ 3,860,000	$ 3,874,534	7.79%
2	4.42%	Sr. Notes	10/15/2014	30 Yrs	50,000,000	50,000,000	-	50,000,000	482,981	99.03%	383,031	49,616,969	16,099	2,210,000	2,226,099	4.49%
3	3.52%	Sr. Notes	11/1/2017	10 Yrs	20,000,000	20,000,000	-	20,000,000	148,352	99.26%	101,374	19,898,626	14,835	704,000	718,835	3.61%
4	4.32%	Sr. Notes	11/1/2017	30 Yrs	30,000,000	30,000,000	-	30,000,000	222,528	99.26%	199,039	29,800,961	7,418	1,296,000	1,303,418	4.37%
5	4.04%	Sr. Notes	9/12/2019	30 Yrs	40,000,000	40,000,000	-	40,000,000	208,040	99.48%	225,229	39,774,771	6,954	1,616,000	1,622,954	4.08%
6	3.78%	Sr. Notes	9/15/2020	20 Yrs	40,000,000	40,000,000	-	40,000,000	227,434	99.43%	190,778	39,809,222	11,372	1,512,000	1,523,372	3.83%
7		Total			$ 230,000,000	$ 230,000,000	$ -	$ 230,000,000	$ 1,725,233		$ 1,359,851	$ 228,640,149	$ 71,212	$ 11,198,000	$ 11,269,212	4.93%

NORTHERN UTILITIES, INC.
COST OF SHORT-TERM DEBT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-6-5
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	(1)	(2)	(3)	(4)	(5)
LINE NO.	MONTH	MONTH-END AMOUNT OUTSTANDING	AVERAGE DAILY BORROWINGS	MONTHLY SHORT-TERM INTEREST	INTEREST RATE(1)
1	January 2020	28,666,840	$ 25,109,148	$ 60,854	2.86%
2	February 2020	24,794,114	23,351,619	52,155	2.82%
3	March 2020	28,316,841	27,127,612	49,312	2.15%
4	April 2020	27,939,753	25,053,060	39,502	1.92%
5	May 2020	26,822,898	25,283,108	29,299	1.37%
6	June 2020	25,298,270	24,327,028	26,512	1.33%
7	July 2020	33,152,219	29,181,116	32,655	1.32%
8	August 2020	37,754,315	34,429,766	38,141	1.31%
9	September 2020	4,906,721	20,504,100	21,844	1.30%
10	October 2020	18,132,923	9,559,681	10,476	1.29%
11	November 2020	22,751,664	19,566,665	20,656	1.29%
12	December 2020	26,747,022	24,606,907	27,020	1.30%
13	Average for the Year		24,008,317		1.69%

Notes
(1) The Interest Rate is calculated as follows: [Column (4) / # of days in month * 366] / Column (3).

NORTHERN UTILITIES, INC.
HISTORICAL CAPITAL STRUCTURE
DECEMBER 31, 201X

Schedule RevReq-6-6
Table of Contents

	(1)	(2)	(3)	(4)	(5)	(6)
LINE NO.	DESCRIPTION	2015	2016	2017	2018	2019
1	Common Stock Equity	$ 123,556,063	$ 155,183,729	$ 191,323,791	$ 197,232,465	$ 225,080,042
2	Preferred Stock Equity	-	-	-	-	-
3	Long-Term Debt	155,000,000	145,000,000	185,000,000	166,600,000	198,200,000
4	Total	$ 278,556,063	$ 300,183,729	$ 376,323,791	$ 363,832,465	$ 423,280,042
5	Short-Term Debt (Year-End)	17,820,632	36,977,214	2,994,930	58,154,005	28,494,680

NORTHERN UTILITIES, INC.
HISTORICAL CAPITALIZATION RATIOS
DECEMBER 31, 201X

Schedule RevReq-6-7
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) 2015	(3) 2016	(4) 2017	(5) 2018	(6) 2019
1	Common Stock Equity	44.36%	51.70%	50.84%	54.21%	53.18%
2	Preferred Stock Equity	0.00%	0.00%	0.00%	0.00%	0.00%
3	Long-Term Debt	55.64%	48.30%	49.16%	45.79%	46.82%
4	Total	100.00%	100.00%	100.00%	100.00%	100.00%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE CASE EXPENSE COSTS
PROJECTED THROUGH THE COMPLETION OF THE CASE

Schedule RevReq-7
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) AMOUNT
1	Cost Studies and Rate Design	$ 200,000
2	Decoupling	45,000
3	Depreciation Study	75,000
4	Return On Equity	110,000
5	Administration and Miscellaneous Expenses	5,000
6	Commission Costs	300,000
7	Total	735,000

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NORTHERN UTILITIES, 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 Northern Utilities, Inc. ("Northern" or the "Company"), subject to the jurisdiction of the New Hampshire Public Utilities Commission (the "Commission"), to provide annual revenue step increases recovering 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 August 1 of the following year with a compliance filing due by the last day of March as outlined below:

Investment Year	Rate Year	Compliance Filing Due
January 1-December 31, 2021	August 1, 2022-July 31, 2023	March 31, 2022[1]
January 1-December 31, 2022	August 1, 2023-July 31, 2024	March 31, 2023
January 1-December 31, 2023	August 1, 2024-July 31, 2025	March 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 all Non-Growth Plant Additions.

[1] The Company proposes to present Investment Year 2021 during the rate case proceeding for effect with permanent rates on August 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 Rate Base associated with capital spending related to Non-Growth Plant Additions;
- Depreciation Expense on Non-Growth Plant Additions; and
- Property Taxes on the Net Utility Plant related to Non-Growth Plant Additions.

4.0 CUSTOMER PROTECTIONS

4.1 Revenue Requirement Cap

The cumulative Revenue Requirement related to Eligible Facilities is subject to a cap of $10,500,000.

4.2 Earnings Sharing

Earnings sharing will be triggered if return on equity as submitted in its annual PUC 509.01 F-1 filing exceeds 11.00%. If return on equity exceeds 11.00%, then excess earnings will be shared equally between the distribution ratepayers and the Company.

4.3 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 509.01 F-1 filing, then the Company may petition the Commission for a distribution base rate adjustment before 2024.

4.4 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.

5.0 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. DG 21-104. The increase shall be collected through customer or energy charges as applicable for all rate classes.

For earnings sharing and exogenous events in section 4.0 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. DG 21-104. The charge or credit shall be made through energy usage charges for all rate classes. There will be no change in the customer charge.

6.0 DEFINITIONS

1) Accumulated Depreciation is the cumulative net credit balance arising from the provision for Depreciation Expense.

2) Accumulated Deferred Income Taxes is the timing difference between book Depreciation Expense and tax depreciation expense utilizing the modified accelerated cost recovery system. The timing difference is multiplied by the federal and statutory effective income tax rate to determine the liability balance.

3) Cost of Removal is the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto.

4) Depreciation Expense is established at 3.73% and is based on the average depreciation rate provided in Docket No. DG 21-104.

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) Net Utility Plant is the "per books" utility Non-Growth Plant Additions for plant in service after Accumulated Depreciation is deducted and Cost of Removal is added.

9) Non-Growth Plant Additions are the capitalized costs of non-growth plant placed in service as recorded on the Company's books during the Investment Year.

10) Pre-Tax Rate of Return is 9.75% which is established based on the cost of capital and a tax gross up on common stock equity per Docket No. DG 21-104.

11) Property Taxes shall include State utility property taxes for all Non-Growth Plant Additions, calculated using the statutory tax rate in RSA 83-F:2, currently \$6.60 per \$1,000 of investment. Local property taxes shall not be included in the calculation and will be recovered through the proposed Regulatory Cost Adjustment Mechanism.

12) Rate Base is Non-Growth Plant Additions plus Cost of Removal less Accumulated Depreciation less Accumulated Deferred Income Taxes.

13) Rate Year is the annual period August 1 through July 31, following the Investment Year.

14) 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.

15) 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.

Northern Utilities, Inc. - New Hampshire
Rate Plan Capital Expenditures - Non-Growth Plant Additions
For Calendar Years 2021-2023

Northern Utilities, Inc.
Docket No. DG 21-104
Schedule CGDN-2
Page 1 of 3

Line No.	Description	Investment Year 2021	Investment Year 2022	Investment Year 2023
	Rate Effective Date	8/1/2022	8/1/2023	8/1/2024
	Rate Base:			
1	Utility Plant Additions	$ 20,770,248	$ 20,810,532	$ 21,389,700
2	Cost of Removal	2,307,805	2,312,281	2,376,633
3	Capital Expenditures - Non-Growth Plant Additions	23,078,053	23,122,814	23,766,334
4	Accumulated Depreciation	387,365	388,116	398,918
5	Net Utility Plant	22,690,688	22,734,697	23,367,416
6	Accumulated Deferred Income Taxes (ADIT)	1,125	1,127	1,159
7	Rate Base	$ 22,689,563	$ 22,733,570	$ 23,366,257
	Revenue Requirement:			
8	Rate Base	$ 22,689,563	$ 22,733,570	$ 23,366,257
9	Pre-Tax Rate of Return	9.75%	9.75%	9.75%
10	Return and Related Income Taxes	2,213,321	2,217,614	2,279,331
11	Depreciation Expense	774,730	776,233	797,836
12	Property Taxes (1)	149,759	150,049	154,225
13	Revenue Requirement	$ 3,137,810	$ 3,143,896	$ 3,231,392
	Rate Cap Limit:			
14	Revenue Requirement	$ 3,137,810	$ 3,143,896	$ 3,231,392
15	Cumulative Revenue Requirement	3,137,810	6,281,705	9,513,097
16	Revenue Requirement Cap	10,500,000	10,500,000	10,500,000
17	Allowable Revenue Requirement	$ 3,137,810	$ 3,143,896	$ 3,231,392
	Supporting Calculations			
	Book Depreciation			
18	Utility Plant Additions	$ 20,770,248	$ 20,810,532	$ 21,389,700
19	Book Depreciation Rate(2)	3.73%	3.73%	3.73%
20	Book Depreciation	774,730	776,233	797,836
	Tax Depreciation			
21	Utility Plant Additions	20,770,248	20,810,532	21,389,700
22	Tax Depreciation Rate	3.75%	3.75%	3.75%
23	Tax Depreciation	778,884	780,395	802,114
24	Tax-Book Timing Difference	4,154	4,162	4,278
25	Income Tax Rate	27.08%	27.08%	27.08%
26	Accumulated Deferred Income Taxes (ADIT)	1,125	1,127	1,159
27	Accumulated Depreciation = Book Depreciation * 0.5	$ 387,365	$ 388,116	$ 398,918

Notes:
(1) Property Taxes shall include State utility property taxes for all Non-Growth Plant Additions, calculated using the statutory tax rate in RSA 83-F:2, currently $6.60 per $1,000 of investment. Local property taxes shall not be included in the calculation and will be recovered through the proposed Regulatory Cost Adjustment Mechanism
(2) Book Depreciation Rate Based on the Average Depreciation Rate in Docket No. DG 21-104

Northern Utilities, Inc. - New Hampshire
2021-2023 Non-Growth Capital Expenditures Project Detail
$'s in Thousands

Northern Utilities, Inc.
Docket No. DG 21-104
Schedule CGDN-2
Page 2 of 3

			Investment Year 2021				Investment Year 2022				Investment Year 2023			
Line No.	Budget Category	Work Order	Install	Removal (1)	Total	In Service Date	Install	Removal (1)	Total	In Service Date	Install	Removal (1)	Total	In Service Date
1	Non-Growth Capital Expenditures													
2	[Code Number]	Exhibit KES-2	$ 20,770	$ 2,308	$ 23,078	MM/YYYY	$ 20,811	$ 2,312	$ 23,123	MM/YYYY	$ 21,390	$ 2,377	$ 23,766	MM/YYYY
3	[Code Number]	Work Order Name	-	-	-	MM/YYYY	-	-	-	MM/YYYY	-	-	-	MM/YYYY
4	[Code Number]	Work Order Name	-	-	-	MM/YYYY	-	-	-	MM/YYYY	-	-	-	MM/YYYY
5	Total Non-Growth Capital Expenditures		$ 20,770	$ 2,308	$ 23,078		$ 20,811	$ 2,312	$ 23,123		$ 21,390	$ 2,377	$ 23,766	

Notes:
(1) Estimated Cost of Removal Percentage for Illustrative Purposes. Actual Cost of Removal will be used. 10%

Northern Utilities, Inc. - New Hampshire
Pre Tax Rate of Return
5 Quarter Average Ended December 31, 2020 Pro Forma

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Amount	Weight	Cost of Capital	Weighted Cost of Capital	Tax Factor	Pre-Tax Cost
1	Common Stock Equity	$229,204,938	52.47%	10.30%	5.40%	1.3714	7.41%
2	Long Term Debt	207,640,000	47.53%	4.93%	2.34%		2.34%
3	Short Term Debt	-	0.00%	1.69%	0.00%		0.00%
4	Total	$ 436,844,938	100.00%		7.75%		9.75%

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DOCKET DG 21-104
COMPUTATION OF REVENUE REQUIREMENT FOR TEMPORARY RATES

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
REVENUE REQUIREMENT TABLE OF CONTENTS
12 MONTHS ENDED DECEMBER 31, 2020

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF REVENUE DEFICIENCY AND REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) REFERENCE	(3) AMOUNT
1	Rate Base	Schedule RevReq-5	$ 187,852,245
2	Rate of Return	Schedule RevReq-6	7.33%
3	Income Required	Line 1 * Line 2	13,765,436
4	Adjusted Net Operating Income	Schedule RevReq-2	11,416,967
5	Deficiency	Line 3 - Line 4	2,348,469
6	Income Tax Effect	Line 7 - Line 5	872,274
7	Revenue Deficiency	1.3714 (Schedule RevReq-1-1) * Line 5	$ 3,220,742

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

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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	Northern Effective Tax Rate	(Line 1 + Line 2 + Line 3)	0.2708
5	Gross-Up Factor	(1 / 1 - Line 4)	1.3714

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

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LINE NO.	(1) DESCRIPTION	(2) TEST YEAR 12 MONTHS ENDED 12/31/2020	(3) LESS COST OF GAS EXCLUDING PROD. & OH.(1)	(4) LESS OTHER FLOWTHROUGH(2)	(5) TEST YEAR DISTRIBUTION, PROD. & OH.	(6) TEST YEAR DISTRIBUTION	(7) TEST YEAR PROD. & OH.	(8) CALENDAR YEAR 2019(3)	(9) CALENDAR YEAR 2018(3)
	Operating Revenues:								
1	Total Sales	$ 65,455,125	$ 22,701,750	$ 3,458,228	$ 39,295,147	$ 38,237,257	$ 1,057,890	$ 72,009,468	$ 78,261,307
2	Total Other Operating Revenues	1,228,348	120,656	-	1,107,692	1,107,692	-	841,893	380,541
3	Total Operating Revenues	$ 66,683,473	$ 22,822,406	$ 3,458,228	$ 40,402,839	$ 39,344,949	$ 1,057,890	$ 72,851,361	$ 78,641,848
	Operating Expenses:								
4	Production	$ 23,544,860	$ 22,696,215	$ 398,908	$ 449,736	$ 449,736	$ -	$ 28,226,731	$ 36,699,896
5	Transmission	63,829	-	-	63,829	63,829	-	72,713	54,452
6	Distribution	3,733,377	-	-	3,733,377	3,733,377	-	3,509,448	3,547,813
7	Customer Accounting	2,608,189	99,544	-	2,508,645	2,508,645	-	2,768,758	2,548,545
8	Customer Service	2,341,706	(0)	2,268,632	73,074	73,074	-	2,319,375	1,946,672
9	Sales Expense	69,178	-	-	69,178	69,178	-	64,467	62,224
10	Administrative & General	6,740,777	-	58,225	6,682,552	6,682,552	-	7,679,291	7,670,327
11	Depreciation	8,876,582	-	-	8,876,582	8,876,582	-	8,166,463	7,482,080
12	Amortizations	816,977	-	-	816,977	816,977	-	838,480	196,816
13	Taxes Other Than Income	4,867,774	-	-	4,867,774	4,867,774	-	4,306,298	4,242,098
14	Federal Income Tax	(30,211)	-	-	(30,211)	(30,211)	-	52,380	(353,526)
15	State Income Tax	(384,644)	-	-	(384,644)	(384,644)	-	(309,547)	(463,245)
16	Deferred Federal & State Income Taxes	2,600,179	-	-	2,600,179	2,600,179	-	2,975,683	3,341,111
17	Interest on Customer Deposits	9,258	-	-	9,258	9,258	-	14,374	18,486
18	Total Operating Expenses	$ 55,857,829	$ 22,795,759	$ 2,725,765	$ 30,336,305	$ 30,336,305	$ -	$ 60,684,915	$ 66,993,749
19	Net Operating Income	$ 10,825,644	$ 26,647	$ 732,463	$ 10,066,533	$ 9,008,643	$ 1,057,890	$ 12,166,447	$ 11,648,100

Notes
(1) Refer to Workpaper - Cost of Gas
(2) Refer to Workpaper - Flowthrough Detail. Consists of Energy Efficiency, Environmental Response Costs, Residential Low Income Assistance, Rate Case Costs, Recoupment, Lost Revenue, and On Bill Financing
(3) Calendar Years 2019 and 2018 represents Total Company (i.e., Flowthrough and Distribution).

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRO FORMA DISTRIBUTION OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR DISTRIBUTION, PROD. & OH.	(3) PRO FORMA ADJUSTMENTS	(4) TEST YEAR DISTRIBUTION, PROD. & OH. PRO FORMA	PROOF (5) REVENUE REQUIREMENT	PROOF (6) PRO FORMA RATE RELIEF
	Operating Revenues:					
1	Total Sales	$ 39,295,147	$ 2,820,216	$ 42,115,363	$ 3,220,742	$ 45,336,105
2	Total Other Operating Revenues	1,107,692	-	1,107,692	-	1,107,692
3	Total Operating Revenues	$ 40,402,839	$ 2,820,216	$ 43,223,055	$ 3,220,742	$ 46,443,797
	Operating Expenses:					
4	Production	$ 449,736	$ 76,191	$ 525,927	$ -	$ 525,927
5	Transmission	63,829	-	63,829	-	63,829
6	Distribution	3,733,377	-	3,733,377	-	3,733,377
7	Customer Accounting	2,508,645	(97,468)	2,411,177	-	2,411,177
8	Customer Service	73,074	-	73,074	-	73,074
9	Sales Expense	69,178	-	69,178	-	69,178
10	Administrative & General	6,682,552	-	6,682,552	-	6,682,552
11	Depreciation	8,876,582	506,868	9,383,450	-	9,383,450
12	Amortizations	816,977	-	816,977	-	816,977
13	Taxes Other Than Income	4,867,774	617,939	5,485,713	-	5,485,713
14	Federal Income Tax	(30,211)	206,901	176,690	624,276	800,966
15	State Income Tax	(384,644)	(732,910)	(1,117,554)	247,997	(869,557)
16	Deferred Federal & State Income Taxes	2,600,179	892,262	3,492,441	-	3,492,441
17	Interest on Customer Deposits	9,258	-	9,258	-	9,258
18	Total Operating Expenses	$ 30,336,305	$ 1,469,783	$ 31,806,088	$ 872,274	$ 32,678,361
19	Net Operating Income	$ 10,066,533	$ 1,350,434	$ 11,416,967	$ 2,348,469	$ 13,765,436

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SUMMARY OF ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2016

Schedule RevReq-3
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LINE NO.	(1) DESCRIPTION	(2) CLASSIFICATION	(3) SCHEDULE NO.	(4) AMOUNT
1	Revenue Adjustments			
2	Weather Normalization	Dist Rev	Schedule RevReq-3-1	$ 1,994,374
3	New Customer Revenue Annualization	Dist Rev	Schedule RevReq-3-2	
4	Residential Low Income	Dist Rev	Schedule RevReq-3-2	264,523
5	Unbilled Revenue	Dist Rev	Schedule RevReq-3-2	294,543
6	Non-Distribution Bad Debt	Dist Rev	Schedule RevReq-3-2	(97,468)
7	Misc. Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	4,788
8	Late Fee Adjustment	Oth Rev	Schedule RevReq-3-2	
9	Billed Accuracy Adjustment	Dist Rev	Schedule RevReq-3-2	367
10	Lost Base Revenue Moved from FT to Base	Dist Rev	WP - FT Detail	359,089
11	Special Contract Customer Revenue Adjustment	Dist Rev	Schedule RevReq-3-2	
12	Total Revenue Adjustments			$ 2,820,216
13	Operating & Maintenance Expense Adjustments			
14	Production Expense (O&M)	Prod	Schedule RevReq-3-3	$ 76,191
15	Payroll	Dist	Schedule RevReq-3-4	
16	Distribution Bad Debt	Cust Acct	Schedule RevReq-3-5	
17	Non-Distribution Bad Debt	Cust Acct	Schedule RevReq-3-2	(97,468)
18	Medical & Dental Insurances	A&G	Schedule RevReq-3-6	
19	Pension	A&G	Schedule RevReq-3-7	
20	PBOP	A&G	Schedule RevReq-3-7	
21	SERP	A&G	Schedule RevReq-3-7	
22	401K	A&G	Schedule RevReq-3-7	
23	Deferred Comp Expense	A&G	Schedule RevReq-3-7	
24	Property & Liability Insurances	A&G	Schedule RevReq-3-8	
25	NH PUC Assessment	A&G	Schedule RevReq-3-9	
26	Dues & Subscriptions	A&G	Schedule RevReq-3-10	
27	Pandemic Costs	A&G	Schedule RevReq-3-11	
28	Severance Expense	A&G	Schedule RevReq-3-12	
29	Rent Expense	A&G	Schedule RevReq-3-13	
30	Arrearage Management Program (AMP) Implementation Cost	Cust Acct	Schedule RevReq-3-14	
31	Inflation Allowance	A&G	Schedule RevReq-3-15	
32	Total Operating & Maintenance Expense Adjustments			$ (21,277)
33	Depreciation And Amortization Expense Adjustments			
34	Depreciation Annualization	Depr	Schedule RevReq-3-16 P1	$ 469,003
35	Proposed Depreciation Rates	Depr	Schedule RevReq-3-16 P2	
36	Production Expense (Depreciation)	Depr	Schedule RevReq-3-3	37,865
37	Software Amortization	Amort	Schedule RevReq-3-17	
38	Excess ADIT Flowback	Amort	Schedule RevReq-3-18	
39	Total Depreciation And Amortization Expense Adjustments			$ 506,868
40	Taxes Other Than Income Adjustments			
41	Property Taxes	Oth Tax	Schedule RevReq-3-19	$ 617,939
42	Payroll Taxes - Wage Increases	Oth Tax	Schedule RevReq-3-20 P1	
43	Payroll Taxes - Employee Retention Credit	Oth Tax	Schedule RevReq-3-20 P2	
44	Total Taxes Other Than Income Adjustments			$ 617,939
45	Income Taxes Adjustments			
46	Federal Income Tax	FIT	Schedule RevReq-3-21 P1	$ 256,535
47	NH State Tax	SIT	Schedule RevReq-3-21 P1	101,910
48	Remove Prior Year Federal Income Tax	FIT	Schedule RevReq-3-21 P4	(49,634)
49	Remove Prior Year State Income Tax	SIT	Schedule RevReq-3-21 P4	(834,820)
50	Remove Prior Year Deferred Federal Income Tax	DIT	Schedule RevReq-3-21 P4	57,442
51	Remove Prior Year Deferred State Income Tax	DIT	Schedule RevReq-3-21 P4	834,820
52	Total Income Taxes Adjustments			$ 366,253
53	Rate Base Adjustments			
54	NH Supplemental Plant Adjustment	Plant	Schedule RevReq-5-3	$ 1,873,246
55	NH Supplemental Plant Adjustment	Acc Depr	Schedule RevReq-5-3	1,350,190
56	DIT Settlement Adjustment	RB DIT	Schedule RevReq-5-4	-
57	Cash Working Capital (Due To Pro Forma Adjustments)	CWC	Schedule RevReq-5-2	(23,564)
58	Total Rate Base Adjustments			$ 499,492

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
WEATHER NORMALIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-1
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LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	To Increase Test Year Base Revenue to Normalize for the Effect of Warmer than Normal Weather[1]	$ 1,994,374

Notes
(1) Refer to Direct Testimony of Ron Amen & John Taylor

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
REVENUE ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-2
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LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Customer Growth Revenue Adjustment	
2	To Increase Test Year Base Revenue for 2020 Customer Growth [(1)]	
3	Residential Low Income Assistance Revenue Adjustment	
4	To Reflect Recovery Of The Low Income Discount Through the LDAC [(2)]	$ 264,523
5	Unbilled Revenue Adjustment	
6	Remove Unbilled Revenue	$ 294,543
7	Non Distribution Bad Debt Adjustment (Revenue & Expense)	
8	Remove: Accrued Revenue - Non Dist Bad Debt	$ (97,468)
9	Remove: Provision For Doubtful Accts - Non-Dist - NH	$ (97,468)
10	Misc. Revenue Adjustment	
11	Clear Remaining Rate Case Expense And Recoupment Balances	$ 4,788
12	Late Payment Revenue Adjustment	
13	Normalized Late Payment Revenue [(3)]	
14	Test Year Late Payment Revenue	
15	Late Payment Revenue Adjustment	$ -
16	Billed Accuracy Adjustment	
17	Booked to Calculated Bill Adjustment [(1)]	$ 367
18	Special Contract Customer Revenue Adjustment	
19	Full Year Special Contract Customer Revenue at Special Contract Rate [(4)]	
20	Test Year Special Contract Customer Actual Revenue [(4)]	
21	Net Special Contract Customer Revenue Adjustment	$ -

Notes
(1) Refer to Direct Testimony of Ron Amen & John Taylor
(2) See Workpaper - Flowthrough Detail
(3) Normalized Late Payment Revenue based on 2019 calendar year activity
(4) Refer to Workpaper 1.1 and Workpaper 1.2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRODUCTION EXPENSE ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-3
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LINE NO.	(1) DESCRIPTION	(2) NH	(3) ME	(4) TOTAL	(5) NH PR ALLOC. 40.88%	(6) ME PR ALLOC. 59.12%	(7) NH REVREQ ADJUST.	(8) ME REVREQ ADJUST.
1	Operation & Maintenance Expense							
2	Liquefied Propane Gas Production							
3	Operation Expense							
4	710 - Operation Supervision and Engineering	$ -	$ 29,447	$ 29,447	$ 12,038	$ 17,409		
5	717 - Production Operation Labor	-	24,228	24,228	9,904	14,324		
6	735 - Production Operation Miscellaneous	-	59,588	59,588	24,360	35,228		
7	Total Operation Expense	-	113,263	113,263	46,302	66,961		
8	Maintenance							
9	740 - Production Maintenance Supervision	-	29,447	29,447	12,038	17,409		
10	741 - Maintenance of Plant	-	8,464	8,464	3,460	5,004		
11	742 - Maint of Equipment	-	28,588	28,588	11,687	16,901		
12	Total Maintenance Expense	-	66,499	66,499	27,185	39,314		
13	769 - Maint of Scada - Product	-	6,615	6,615	2,704	3,911		
14	Total Manuf Gas Prod Exp	$ -	$ 186,377	$ 186,377	$ 76,191	$ 110,186	$ 76,191	$ (76,191)
15	Depreciation Expense							
16	Production Plant							
17	305 - Structures	$ -	$ 2,277	$ 2,277	$ 931	$ 1,346		
18	Total Production Plant	-	2,277	2,277	931	1,346		
19	Other Storage Plant							
20	361 - Structures & Improve	-	11,705	11,705	4,785	6,920		
21	362 - Gas Holders	-	78,642	78,642	32,149	46,493		
22	Total Other Storage Plant	-	90,347	90,347	36,934	53,413		
23	Total Depreciation & Amortization	$ -	$ 92,624	$ 92,624	$ 37,865	$ 54,759	$ 37,865	$ (37,865)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DEPRECIATION ANNUALIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-16
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LINE NO.	(1) DESCRIPTION	(2) PLANT BALANCE 12/31/2020	(3) CURRENT DEPRECIATION RATES	(4) ANNUAL DEPRECIATION EXPENSE
1	Amortizable Plant:			
2	303 Misc Intangible Plant	$ 12,826,347	N/A	N/A
3	Total Amortizable Plant	12,826,347	N/A	-
4	Mfg. Gas Produc. Plant:			
5	304.2 Land & Rights - Mfg Gas Prod. Pl	6,816	N/A	N/A
6	305 Struct. And Improvements	-	N/A	N/A
7	320 Other Equipment	-	N/A	N/A
8	321 LNG Equipment	-	N/A	N/A
9	Total Mfg Gas Prod. Plant	6,816	N/A	-
10	Distribution Plant:			
11	374.4 Land Rgts, Other Distr Sy	89,111	N/A	N/A
12	374.5 Land Rgts, Rights Of Way	17,911	N/A	N/A
13	375.2 Structures - City Gate Meas & Reg	43,350	1.43%	620
14	375.7 Structures - Other Dist Sys	3,217,521	1.43%	46,011
15	376.2 Mains - Coated/Wrapped	29,746,227	2.66%	791,250
16	376.3 Mains - Bare Steel	190,837	N/A	N/A
17	376.4 Mains - Plastic	120,342,184	2.87%	3,453,821
18	376.5 Mains - Joint Seals	542,145	N/A	N/A
19	376.6 Mains - Cathodic Protection	1,082,739	4.17%	45,150
20	376.8 Mains - Cast Iron	28,455	N/A	N/A
21	378.2 Mea & Reg Station Eq, Regulating	7,288,982	3.50%	255,114
22	379 Mea & Reg Ta-G	39,266	3.50%	1,374
23	380 Services	82,837,047	3.67%	3,040,120
24	381 Meters	4,624,610	3.33%	154,000
25	382 Meter Installations	26,001,685	3.33%	865,856
26	383 House Regulators	733,550	3.33%	24,427
27	386 Water Heaters/Conversion Burners	1,978,895	7.41%	146,636
28	Total Distribution Plant	278,804,516	3.17%	8,824,379
29	General Plant:			
30	389.1 Land	232,947	N/A	N/A
31	391.10 Off Furn & Eq.- Unspecified	508,135	8.70%	44,208
32	393 Stores Equipment	31,520	N/A	N/A
33	394.10 Tools, Garage & Service Equipment	1,430,421	5.26%	75,240
34	396 Power Operated Equipment	75,266	N/A	N/A
35	397 Communication Equipment	1,873,480	9.09%	170,299
36	397.25 Metscan Communication Equip	112,656	N/A	N/A
37	397.35 ERT Automatic Reading Dev	3,470,146	6.67%	231,459
38	Total General Plant	7,734,572	7.16%	521,206
39	Total Plant in Service	$ 299,372,252	3.28%	$ 9,345,585
40	Test Year Expense			$ 8,876,582
41	Increase In Depreciation Expense			$ 469,003

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PROPERTY TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-19
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	(1)	(2)	(3)		(4)		(5)
LINE NO.	MUNICIPALITY & STATE	TAXATION PERIOD	LOCAL TAX RATE		ASSESSED VALUATION		TOTAL TAXES[1]
1	Atkinson	4/1 - 3/31	$	16.24	1,564,100		25,401
2	Brentwood	4/1 - 3/31	$	21.36	1,489,600		31,818
3	Brentwood	4/1 - 3/31	$	23.19	400		9
4	Dover	4/1 - 3/31	$	24.85	1,200		30
5	Dover	4/1 - 3/31	$	22.92	37,150,600		851,492
6	Durham	4/1 - 3/31	$	25.73	7,742,400		199,212
7	East Kingston	4/1 - 3/31	$	20.50	746,700		15,307
8	Epping	4/1 - 3/31	$	23.64	1,079,900		25,529
9	Exeter	4/1 - 3/31	$	22.50	13,803,800		310,586
10	Greenland	4/1 - 3/31	$	14.58	733,400		10,693
11	Hampton--Class 4000	4/1 - 3/31	$	13.93	18,884,700		263,064
12	Hampton--Class 5000	4/1 - 3/31	$	14.43	9,301,400		134,219
13	Hampton Falls	4/1 - 3/31	$	19.33	36,400		704
14	Kensington	4/1 - 3/31	$	18.61	1,442,400		26,843
15	Madbury	4/1 - 3/31	$	23.41	347,000		8,123
16	Newington	4/1 - 3/31	$	8.02	2,848,900		22,848
17	North Hampton	4/1 - 3/31	$	14.80	1,822,800		26,977
18	Plaistow	4/1 - 3/31	$	19.60	9,849,580		193,052
19	Portsmouth	4/1 - 3/31	$	12.80	47,562,000		608,794
20	Rochester	4/1 - 3/31	$	22.67	26,840,200		608,468
21	Rollinsford	4/1 - 3/31	$	22.57	194,600		4,392
22	Rollinsford	4/1 - 3/31	$	24.68	20,000		494
23	Salem	4/1 - 3/31	$	19.82	9,478,700		187,867
24	Seabrook	4/1 - 3/31	$	13.90	12,142,100		168,775
25	Somersworth	4/1 - 3/31	$	25.91	9,713,200		251,669
26	Somersworth	4/1 - 3/31	$	27.85	62,000		1,727
27	Stratham	4/1 - 3/31	$	17.14	497,200		8,522
28	State Of NH [2]	4/1 - 3/31					1,359,585
29	Total				$ 215,355,280	$	5,346,199
30	Test Year Property Taxes [3]					$	4,728,948
31	Less: Test Year Property Tax Abatements [4]						688
32	Total Test Year Property Tax Expense					$	4,728,260
33	Total Property Tax Increase (Line 29 - Line 32)					$	617,939

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) Test Year Property Taxes adjusted to exclude Greenland 2019 bill correction of $317

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-21
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LINE NO.	(1) DESCRIPTION	(2) Amount
1	Increases / (Decreases) To Revenue	
2	Weather Normalization	$ 1,994,374
3	New Customer Revenue Annualization	-
4	Residential Low Income	264,523
5	Unbilled Revenue	294,543
6	Non-Distribution Bad Debt	(97,468)
7	Misc. Revenue Adjustment	4,788
8	Late Fee Adjustment	-
9	Billed Accuracy Adjustment	367
10	Lost Base Revenue Moved from FT to Base	359,089
11	Special Contract Customer Revenue Adjustment	-
12	Total Revenue Adjustments	$ 2,820,216
13	Increases / (Decreases) To Expenses	
14	Production Expense (O&M)	$ 76,191
15	Payroll	-
16	Medical & Dental Insurances	-
17	Distribution Bad Debt	(97,468)
18	Non-Distribution Bad Debt	-
19	Pension	-
20	PBOP	-
21	SERP	-
22	401K	-
23	Deferred Comp Expense	-
24	Property & Liability Insurances	-
25	NH PUC Assessment	-
26	Dues & Subscriptions	-
27	Pandemic Costs	-
28	Severance Expense	-
29	Rent Expense	-
30	Arrearage Management Program (AMP) Implementation Cost	-
31	Inflation Allowance	-
32	Depreciation Annualization	469,003
33	Proposed Depreciation Rates	-
34	Production Expense (Depreciation)	37,865
35	Software Amortization	-
36	Excess ADIT Flowback	-
37	Property Taxes	617,939
38	Payroll Taxes - Wage Increases	-
39	Payroll Taxes - Employee Retention Credits	-
40	Flowthrough Net Operating Income	759,111
41	Change In Interest Exp (Refer To Schedule RevReq 3-21 Page 2)	(365,928)
42	Total Expense Adjustments	$ 1,496,713
43	Increase / (Decrease) In Taxable Income	$ 1,323,504
44	Effective Federal Income Tax Rate(1)	19.38%
45	NH State Tax Rate(2)	7.70%
	Federal Income & NH State Tax	
46	Effective Federal Income Tax	$ 256,535
47	NH State Tax	101,910
48	Increase (Decrease) In Income Taxes	$ 358,445
	Notes	
49	Federal Income Tax Rate	21.00%
50	Federal Benefit of State Tax -(Line 49 * Line 52)	-1.62%
51	(1) Effective Federal Income Tax Rate	19.38%
52	(2) State Income Tax Rate	7.70%
53	Northern New Hampshire Tax Rate (Line 51 + Line 52)	27.08%

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
CHANGE IN INTEREST EXPENSE APPLICABLE TO INCOME TAX COMPUTATION
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) AMOUNT
1	Ratemaking Interest Synchronization	
2	Rate Base[(1)]	$ 187,852,245
3	Cost Of Debt In Proposed Rate Of Return[(2)]	2.34%
4	Interest Expense for Ratemaking	$ 4,401,969
5	Test Year Interest Expense	
6	Interest Charges (427-431)	$ 4,767,897
7	Increase / (Decrease) in Interest Expense	$ (365,928)

Notes
(1) Refer to Schedule RevReq-5
(2) Refer to Schedule RevReq-6

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO	(1) DESCRIPTION	(2) TEST YEAR ACTUAL	(3) PRO-FORMA ADJUSTMENTS	(4) TEST YEAR UTILITY
1	Net Income	$ 6,096,270	$ -	$ 6,096,270
2	Federal Income Tax-Current	(19,629)	-	(19,629)
3	NH State Income Tax-Current	(380,440)	-	(380,440)
4	NH State Business Enterprise Credit Against NH BPT	63,600	-	63,600
5	Deferred Federal Income Tax	1,637,521	-	1,637,521
6	Deferred State Income Tax	962,658	-	962,658
7	Net Income Before Income Taxes	8,359,980	-	8,359,980
8	*Permanent Items*			
9	Lobbying	22,225	-	22,225
10	Parking Lot Disallowance	2,543	-	2,543
11	Penalties	2,500	-	2,500
12	Total Permanent Items	27,268	-	27,268
13	*Temporary Differences*			
14	Accrued Revenue	(3,295,760)	-	(3,295,760)
15	Bad Debt	81,370	-	81,370
16	FASB 87-Pensions	(211,016)	-	(211,016)
17	PBOP SFAS 106	96,936	-	96,936
18	Remediation	267,789	-	267,789
19	Utility Plant Differences	(5,924,514)	-	(5,924,514)
20	Total Temporary Differences	(8,985,195)	-	(8,985,195)
21	*Federal And State Tax Differences*			
22	Tax Depreciation	(2,123,819)	-	(2,123,819)
23	Total Federal And State Tax Differences	(2,123,819)	-	(2,123,819)
24	State Taxable Base Income	(2,721,766)	-	(2,721,766)
25	State Business Profits Tax - Current	(209,576)	-	(209,576)
26	Less: Business Enterprise Tax	63,600	-	63,600
27	Total State Tax Expense	(273,176)	-	(273,176)
28	Federal Taxable Income Base Before Federal And State Tax Differences	(2,512,190)	-	(2,512,190)
29	Less: Federal And State Tax Differences	(2,123,819)	-	(2,123,819)
30	Federal Taxable Income Base	(388,371)	-	(388,371)
31	Federal Income Tax-Current	(81,558)	-	(81,558)
32	*Summary Of Utility Income Taxes:*			
33	Federal Income Tax-Current	(92,140)	-	(92,140)
34	Federal Income Tax-Prior	49,634	-	49,634
35	Federal Income Tax-NOL	12,295	-	12,295
36	Federal Amount To Non-Distribution Operations	10,582	(10,582)	-
37	State Business Profits Tax-Current	(277,380)	-	(277,380)
38	State Business Profits Tax-Prior	834,820	-	834,820
39	State Business Profits Tax-NOL	(942,084)		(942,084)
40	State Amount To Non-Distribution Operations	4,204	(4,204)	-
41	Deferred Federal Income Tax	1,707,258	-	1,707,258
42	Deferred Federal Income Tax-Prior	(57,442)	-	(57,442)
43	Deferred Federal Income Tax-NOL	(12,295)	-	(12,295)
44	Deferred State Business Profits Tax	855,394	-	855,394
45	Deferred State Business Profits Tax-Prior	(834,820)	-	(834,820)
46	Deferred State Business Profits Tax-NOL	942,084		942,084
47	Total Income Taxes	$ 2,200,110	$ (14,786)	$ 2,185,324

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PRIOR YEAR INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO	(1) DESCRIPTION	(2) ACTUAL
1	Remove Prior Year Federal Income Taxes	$ (49,634)
2	Remove Prior Year State Income Taxes	(834,820)
3	Remove Prior Year Deferred Federal Income Taxes	57,442
4	Remove Prior Year Deferred State Income Taxes	834,820
5	Total	$ 7,808

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
UTILITY PLANT IN SERVICE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-3
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LINE NO.	(1) Account Name	(2) CAPITAL 1/1	(3) ADDITIONS	(4) RETIREMENTS	(5) TRANSFER ADJ	(6) PLANT IN SERVICE 12/31	(7) COMPLETED CONSTRUCTION NOT CLASSIFIED 12/31
1	Amortizable Plant:						
2	303 Misc Intangible Plant	$ 11,262,452	$ 960,046	$ -	$ -	$ 12,222,498	$ 603,849
3	Total Amortizable Plant	11,262,452	960,046	-	-	12,222,498	603,849
4	Mfg. Gas Produc. Plant:						
5	304.2 Land & Rights - Mfg Gas Prod. Pl	6,816	-	-	-	6,816	-
6	305 Struct. And Improvements	161,860	-	(75,459)	(86,401)	-	-
7	320 Other Equipment	7,640	-	(7,006)	(634)	-	-
8	321 LNG Equipment	84,156	-	(84,156)	-	-	-
9	Total Mfg Gas Prod. Plant	260,472	-	(166,621)	(87,035)	6,816	-
10	Distribution Plant:						
11	374.4 Land Rgts, Other Distr Sy	89,111	-	-	-	89,111	-
12	374.5 Land Rgts, Rights Of Way	17,911	-	-	-	17,911	-
13	375.2 Structures - City Gate Meas & Reg	45,256	-	(1,906)	-	43,350	-
14	375.7 Structures - Other Dist Sys	3,124,357	4,495	-	87,035	3,215,887	1,634
15	376.2 Mains - Coated/Wrapped	24,602,506	5,182,813	(78,525)	-	29,706,795	39,433
16	376.3 Mains - Bare Steel	190,837	-	-	-	190,837	-
17	376.4 Mains - Plastic	104,050,393	9,284,825	(600,390)	-	112,734,828	7,607,356
18	376.5 Mains - Joint Seals	542,145	-	-	-	542,145	-
19	376.6 Mains - Cathodic Protection	1,005,475	54,885	-	-	1,060,360	22,380
20	376.8 Mains - Cast Iron	28,455	-	-	-	28,455	-
21	378.2 Mea & Reg Station Eq, Regulating	4,400,294	3,002,141	(279,719)	-	7,122,716	166,266
22	379 Mea & Reg Ta-G	39,266	-	-	-	39,266	-
23	380 Services	74,470,438	5,463,157	(87,804)	-	79,845,791	2,991,256
24	381 Meters	4,086,446	493,715	(241,099)	-	4,339,063	285,548
25	382 Meter Installations	23,126,115	2,038,526	(1,108,186)	-	24,056,455	1,945,231
26	383 House Regulators	685,777	43,536	-	-	729,313	4,237
27	386 Water Heaters/Conversion Burners	1,823,459	159,350	(88,909)	-	1,893,900	84,996
28	Total Distribution Plant	242,328,242	25,727,443	(2,486,538)	87,035	265,656,182	13,148,334
29	General Plant:						
30	389-1 Land	232,947	-	-	-	232,947	-
31	391.10 Off Furn & Eq.- Unspecified	431,834	65,465	-	-	497,299	10,836
32	393 Stores Equipment	31,520	-	-	-	31,520	-
33	394.10 Tools, Garage & Service Equipment	1,314,945	54,709	-	-	1,369,654	60,767
34	396 Power Operated Equipment	75,266	-	-	-	75,266	-
35	397 Communication Equipment	1,639,792	237,572	(37,264)	-	1,840,100	33,380
36	397.25 Comm EQ, Metscan/Telemet	112,656	-	-	-	112,656	-
37	397.35 ERT Automatic Reading Dev-G	3,126,899	212,363	-	-	3,339,262	130,884
38	Total General Plant	6,965,859	570,110	(37,264)	-	7,498,705	235,867
39	Total Plant in Service	$ 260,817,025	$ 27,257,599	$ (2,690,423)	$ (0)	$ 285,384,202	$ 13,988,050

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5
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LINE NO.	(1) DESCRIPTION	(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	$ 289,824,481	$ 286,491,423	$ 299,372,252	$ 1,873,246	$ 301,245,498
2	Less: Reserve for Depreciation	85,085,831	85,651,383	88,023,262	1,350,190	89,373,452
3	Net Utility Plant	204,738,650	200,840,040	211,348,990	523,056	211,872,045
4	Add: M&S Inventories	2,671,150	2,770,028	2,773,457	-	2,773,457
5	Prepayments	740,275	1,213,708	64,895	-	64,895
6	Cash Working Capital (1)	1,164,937	1,164,937	1,164,937	(23,564)	1,141,373
7	Sub-Total	4,576,362	5,148,673	4,003,290	(23,564)	3,979,726
8	Less: Net Deferred Income Taxes	$ 20,221,877	$ 20,784,379	$ 21,177,756	$ -	$ 21,177,756
9	Excess Deferred Income Taxes	6,572,092	6,572,092	6,572,092	-	6,572,092
10	Customer Advances	-	-	-	-	-
11	Customers Deposits	269,548	264,461	249,677	-	249,677
12	Sub-Total	27,063,517	27,620,932	27,999,526	-	27,999,526
13	Rate Base	$ 182,251,495	$ 178,367,781	$ 187,352,753	$ 499,492	$ 187,852,245

Notes
(1) Computed Working Capital Based on Test Year O&M Expenses. Refer to Schedule RevReq-5-2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE BASE ITEMS
QUARTERLY BALANCES

Schedule RevReq-5-1
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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	Plant In Service	$ 260,817,025	$ 266,498,877	$ 269,468,172	$ 272,008,852	$ 285,384,202	$ 270,835,426
3	Completed Construction not Classified	19,459,684	16,390,088	14,114,541	14,327,620	13,988,050	15,655,997
4	Total Utility Plant in Service	280,276,709	282,888,965	283,582,713	286,336,471	299,372,252	286,491,423
5	Depreciation Reserve	$ (82,148,399)	$ (84,295,016)	$ (86,310,091)	$ (87,480,144)	$ (88,023,262)	$ (85,651,383)
6	Add:						
7	M&S Inventories						
8	Material and Supplies	$ 2,268,328	$ 2,387,075	$ 2,514,326	$ 2,569,166	$ 2,416,575	$ 2,431,094
9	Stores Expense Undistributed	300,515	417,170	334,238	285,865	356,883	338,934
10	Total M&S Inventories	$ 2,568,843	$ 2,804,245	$ 2,848,563	$ 2,855,032	$ 2,773,457	$ 2,770,028
11	Prepayments	$ 1,415,655	$ 1,415,655	$ 1,415,655	$ 1,756,682	$ 64,895	$ 1,213,708
12	Cash Working Capital	$ 1,164,937	$ 1,164,937	$ 1,164,937	$ 1,164,937	$ 1,164,937	$ 1,164,937
13	Less:						
14	Total Deferred Income Taxes						
15	Def Inc Tax - Accel Depr	$ 20,062,817	$ 22,388,845	$ 22,014,104	$ 21,283,095	$ 22,009,122	$ 21,551,597
16	Def Inc Tax - FAS 87 / 106	(775,910)	(788,563)	(774,047)	(591,877)	(788,419)	(743,763)
17	` Def Inc Tax - Bad Debt	(19,095)	(26,052)	(10,935)	(10,989)	(41,133)	(21,641)
18	Def Inc Tax - Def Rate Case Costs	0	0	0	0	0	-
19	Def Inc Tax - Insurance Claim	(1,814)	(1,814)	(1,814)	(1,814)	(1,814)	(1,814)
20	Total Deferred Income Taxes	$ 19,265,998	$ 21,572,415	$ 21,227,308	$ 20,678,415	$ 21,177,756	$ 20,784,379
21	Less: Excess Deferred Income Taxes	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092	$ 6,572,092
22	Less: Customer Advances	$ -	$ -	$ -	$ -	$ -	$ -
23	Less: Customer Deposits	$ 289,419	$ 269,680	$ 263,516	$ 250,011	$ 249,677	$ 264,461
24	Rate Base	$ 177,150,236	$ 175,564,598	$ 174,638,861	$ 177,132,459	$ 187,352,753	$ 178,367,781

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
CASH WORKING CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-2
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	(1)	(2)	(3)	(4)	(5)
LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR ACTUAL	PRO FORMA ADJUSTMENTS	TEST YEAR PRO FORMA
1	Distribution O&M Expense	Schedule RevReq-2	$ 13,332,381	$ (1,323,953)	$ 12,008,428
2	Tax Expense	Schedule RevReq-2	4,452,919	964,203	5,417,122
3	Total		$ 17,785,300	$ (359,749)	$ 17,425,551
4	Cash Working Capital Requirement:				
5	Other O&M Expense Days Lag (1) / 366	24 days	6.55%	6.55%	6.55%
6	Total Cash Working Capital	Line 5 X Line 3	$ 1,164,937	$ (23,564)	$ 1,141,374

Notes
(1) Based On Lead-Lag Study in Docket 17-070

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SUPPLEMENTAL PLANT PRO FORMA ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-3
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LINE NO.	(1) DESCRIPTION			(2) BALANCE 12/31/2020
1	Plant In Service:			
2	New Hampshire			
3	304 Land - Barberry Lane		$	6,816
4	Total NH		$	6,816
5	Maine			
6	360 Land - Lewiston		$	58,301
7	361 Structures & Improvements			568,201
8	362 Gas Holders			3,878,347
9	363 Other Equipment			87,313
10	Total ME		$	4,592,161
11	Total Plant In Service NH And ME		$	4,598,977
12	NH Allocation Via Annual Proportional Responsibility Factor	40.88%	$	1,880,062
13	ME Allocation Via Annual Proportional Responsibility Factor	59.12%	$	2,718,915
14	Depreciation Reserve:			
15	New Hampshire			
16	Total NH		$	-
17	Maine			
18	361 Structures & Improvements		$	267,178
19	362 Gas Holders			2,943,652
20	363 Other Equipment			91,983
21	Total ME		$	3,302,812
22	Total Depreciation Reserve NH And ME		$	3,302,812
23	NH Allocation Via Annual Proportional Responsibility Factor	40.88%	$	1,350,190
24	ME Allocation Via Annual Proportional Responsibility Factor	59.12%	$	1,952,623
25	Supplemental Plant Adjustment			
26	NH Supplemental Plant Adjustment (Line 12 - Line 4)		$	1,873,246
27	ME Supplemental Plant Adjustment (Line 13 - Line 10)		$	(1,873,246)
28	Supplemental Depreciation Reserve Adjustment			
29	NH Supplemental Plant Adjustment (Line 23 - Line 16)		$	1,350,190
30	ME Supplemental Plant Adjustment (Line 24 - Line 21)		$	(1,350,190)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DEFERRED INCOME TAX PRO FORMA ADJUSTMENT
SETTLEMENT ADJUSTMENT PURSUANT TO DOCKET 2008-155
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-4
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	(1)	(2)
LINE NO.	DESCRIPTION	DECEMBER 31 2020
1	Nisource Original Plant Federal and State DIT Basis	$ 4,053,514
2	Unitil Acquired Plant Federal and State DIT Basis	5,319,173
3	Greater of Line 1 or Line 2 to be Utilized as DIT Basis per Stipulation	$ 5,319,173
4	Post-Acquisition Capital Expenditures Federal and State DIT Basis	$ 29,619,418
5	Net Operating Loss DIT Related to Rate Base at 12/31/20	(12,929,468)
6	Total Plant and Capex Federal and State DIT to be Used in Rate Base (Line 3 + Line 4 + Line 5)	$ 22,009,122
7	Less Test Year: Def Inc Tax - Accel Depr	22,009,122
8	Required Pro Forma Adjustment (Line 6 - Line 7)	$ -

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NORTHERN UTILITIES, INC.
WEIGHTED AVERAGE COST OF CAPITAL
5 QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

	(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	$ 229,204,938	$ -	$ 229,204,938	52.47%	9.50%	4.98%	Schedule RevReq 6-1 and 6-2
2	Preferred Stock Equity	-	-	-	0.00%	0.00%	0.00%	Schedule RevReq 6-1 and 6-3
3	Long Term Debt	207,640,000	-	207,640,000	47.53%	4.93%	2.34%	Schedule RevReq 6-1 and 6-4
4	Short Term Debt	-	-	-	0.00%	1.69%	0.00%	Schedule RevReq 6-1 and 6-5
5	Total	$ 436,844,938	$ -	$ 436,844,938	100.00%		7.33%	

NORTHERN UTILITIES, INC.
CAPITAL STRUCTURE FOR RATEMAKING PURPOSES
5-QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(3)	(8)
LINE NO.	DESCRIPTION	DECEMBER 31 2019	MARCH 31 2020	JUNE 30 2020	SEPTEMBER 30 2020	DECEMBER 31 2020	5 QUARTER AVERAGE	PROFORMA ADJUSTMENT	PROFORMA AMOUNT
1	Common Stock Equity								
2	Common Stock	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ -	$ 1,000
3	Misc. Paid In Capital	200,699,000	200,699,000	205,699,000	205,699,000	207,074,000	203,974,000	-	203,974,000
4	Retained Earnings	24,380,042	29,943,726	26,634,154	20,738,662	24,453,104	25,229,938	-	25,229,938
5	Total Common Stock Equity	225,080,042	230,643,726	232,334,154	226,438,662	231,528,104	229,204,938	-	229,204,938
6	Preferred Stock Equity	-	-	-	-	-	-	-	-
7	Long-Term Debt	198,200,000	190,000,000	190,000,000	230,000,000	230,000,000	207,640,000	-	207,640,000
8	Short-Term Debt (1)	-	-	-	-	-	-	-	-
9	Total	$ 423,280,042	$ 420,643,726	$ 422,334,154	$ 456,438,662	$ 461,528,104	$ 436,844,938	$ -	$ 436,844,938
10	Capital Structure Ratios								
11	Common Stock Equity	53.18%	54.83%	55.01%	49.61%	50.17%	52.47%		52.47%
12	Preferred Stock Equity	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
13	Long-Term Debt	46.82%	45.17%	44.99%	50.39%	49.83%	47.53%		47.53%
14	Short-Term Debt (1)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
15	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

NORTHERN UTILITIES, INC.
WEIGHTED AVERAGE COST OF LONG-TERM DEBT
DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-6-4
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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	7.72%	Sr. Notes	12/3/2008	30 Yrs	$ 50,000,000	$ 50,000,000	$ -	$ 50,000,000	$ 435,899	99.13%	$ 260,401	$ 49,739,599	$ 14,534	$ 3,860,000	$ 3,874,534	7.79%
2	4.42%	Sr. Notes	10/15/2014	30 Yrs	50,000,000	50,000,000	-	50,000,000	482,981	99.03%	383,031	49,616,969	16,099	2,210,000	2,226,099	4.49%
3	3.52%	Sr. Notes	11/1/2017	10 Yrs	20,000,000	20,000,000	-	20,000,000	148,352	99.26%	101,374	19,898,626	14,835	704,000	718,835	3.61%
4	4.32%	Sr. Notes	11/1/2017	30 Yrs	30,000,000	30,000,000	-	30,000,000	222,528	99.26%	199,039	29,800,961	7,418	1,296,000	1,303,418	4.37%
5	4.04%	Sr. Notes	9/12/2019	30 Yrs	40,000,000	40,000,000	-	40,000,000	208,040	99.48%	225,229	39,774,771	6,954	1,616,000	1,622,954	4.08%
6	3.78%	Sr. Notes	9/15/2020	20 Yrs	40,000,000	40,000,000	-	40,000,000	227,434	99.43%	190,778	39,809,222	11,372	1,512,000	1,523,372	3.83%
7		Total			$ 230,000,000	$ 230,000,000	$ -	$ 230,000,000	$ 1,725,233		$ 1,359,851	$ 228,640,149	$ 71,212	$ 11,198,000	$ 11,269,212	4.93%

NORTHERN UTILITIES, INC.
COST OF SHORT-TERM DEBT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-6-5
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	(1)	(2)	(3)	(4)	(5)
LINE NO.	MONTH	MONTH-END AMOUNT OUTSTANDING	AVERAGE DAILY BORROWINGS	MONTHLY SHORT-TERM INTEREST	INTEREST RATE[1]
1	January 2020	28,666,840	$ 25,109,148	$ 60,854	2.86%
2	February 2020	24,794,114	23,351,619	52,155	2.82%
3	March 2020	28,316,841	27,127,612	49,312	2.15%
4	April 2020	27,939,753	25,053,060	39,502	1.92%
5	May 2020	26,822,898	25,283,108	29,299	1.37%
6	June 2020	25,298,270	24,327,028	26,512	1.33%
7	July 2020	33,152,219	29,181,116	32,655	1.32%
8	August 2020	37,754,315	34,429,766	38,141	1.31%
9	September 2020	4,906,721	20,504,100	21,844	1.30%
10	October 2020	18,132,923	9,559,681	10,476	1.29%
11	November 2020	22,751,664	19,566,665	20,656	1.29%
12	December 2020	26,747,022	24,606,907	27,020	1.30%
13	Average for the Year		24,008,317		1.69%

Notes
(1) The Interest Rate is calculated as follows: [Column (4) / # of days in month * 366] / Column (3).

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
WORKPAPERS SUPPORTING REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

Northern Utilities, Inc.
Gas Inc Stmt - NH - YTD
R_NU_4_BF_NH

Workpaper - Income Statement
Schedule 4 NH
4/20/2021
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For Periods Ending December 31, 2020

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	2019 Base	2019 Flowthru	Total	2020 Base	2020 Flowthru	Total
OPERATING REVENUES						
Sales:						
Residential (480)	19,612,987	14,904,240	34,517,227	19,232,153	10,809,182	30,041,335
General Service (481)	11,028,771	17,278,063	28,306,834	10,623,702	11,698,198	22,321,900
Firm Transport Revenues (484, 489) (External Sup)	8,612,979	1,216,889	9,829,867	8,583,266	1,156,548	9,739,814
Sales for Resale (483)	-	2,870,979	2,870,979	-	1,107,459	1,107,459
Other Sales (495)	236,169	(3,751,608)	(3,515,439)	(201,864)	2,446,481	2,244,617
Total Sales	39,490,906	32,518,563	72,009,468	38,237,257	27,217,869	65,455,125
Other Operating Revenues:						
Late Charge (487)	76,773	-	76,773	36,761	-	36,761
Misc. Service Revenues (488)	875,755	-	875,755	852,304	-	852,304
Rent from Property (493 & 457)	200,952	-	200,952	218,628	-	218,628
Other Revenues	-	(311,587)	(311,587)	-	120,656	120,656
Total Other Operating Revenues	1,153,480	(311,587)	841,893	1,107,692	120,656	1,228,348
TOTAL OPERATING REVENUES	40,644,386	32,206,975	72,851,361	39,344,949	27,338,525	66,683,473
OPERATING EXPENSES						
Operation & Maint. Expenses:						
Production (710-813)	477,446	27,749,285	28,226,731	449,736	23,095,124	23,544,860
Transmission (850-857)	72,713	-	72,713	63,829	-	63,829
Distribution (870-894) (586)	3,509,448	-	3,509,448	3,733,377	-	3,733,377
Cust. Accounting (901-905)	2,580,251	188,507	2,768,758	2,508,645	99,544	2,608,189
Cust. Service & Info (906-910)	71,870	2,247,505	2,319,375	73,074	2,268,632	2,341,706
Sales Expenses (911-916)	64,467	-	64,467	69,178	-	69,178
Admin. & General (920-935)	7,607,751	71,540	7,679,291	6,682,552	58,225	6,740,777
Total O & M Expenses	14,383,947	30,256,837	44,640,784	13,580,391	25,521,524	39,101,915
Other Operating Expenses:						
Deprtn. & Amort. (403-407)	8,884,559	120,384	9,004,943	9,693,559	(0)	9,693,559
Taxes-Other Than Inc. (408)	4,306,298	-	4,306,298	4,867,774	-	4,867,774
Federal Income Tax (409)	52,380	-	52,380	(30,211)	-	(30,211)
State Franchise Tax (409)	(309,547)	-	(309,547)	(384,644)	-	(384,644)
Def. Income Taxes (410,411)	2,975,683	-	2,975,683	2,600,179	-	2,600,179
Total Other Operating Expenses	15,909,373	120,384	16,029,757	16,746,657	(0)	16,746,657
TOTAL OPERATING EXPENSES	30,293,320	30,377,221	60,670,541	30,327,047	25,521,524	55,848,571
NET UTILITY OPERATING INCOME	10,351,066	1,829,755	12,180,820	9,017,901	1,817,001	10,834,902
OTHER INCOME & DEDUCTIONS						
Other Income:						
AFUDC - Other Funds (41901)	-	-	-	-	-	-
Other (415- 421)	280,289	(37,502)	242,787	231,700	(25,362)	206,339
Other Income Deduc. (425, 426)	232,636	-	232,636	151,744	-	151,744
Taxes Other than Income Taxes:						
Income Tax, Other Inc & Ded	2,752	-	2,752	14,786	-	14,786
Net Other Income (Deductions)	44,901	(37,502)	7,400	65,170	(25,362)	39,809
GROSS INCOME	10,395,967	1,792,253	12,188,220	9,083,072	1,791,639	10,874,711
Interest Charges (427 - 432)	4,670,265	3,717	4,673,982	4,777,155	1,286	4,778,441
NET INCOME	5,725,702	1,788,536	7,514,238	4,305,917	1,790,353	6,096,270

Northern Utilities, Inc.
Gas Inc Stmt - NH - YTD
R_NU_4_B_FTxM_NH

Workpaper - Flowthrough Detail
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For Periods Ending December 31, 2020
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	Commodity Demand COG	Working Capital	Bad Debt	Residential Low Income Assistance	Energy Efficiency	Environ Response Costs	Rate Case Exp	Recoup	Lost Revenue	On-Bill Financing	Total Flowthru	Total Base	Total New Hampshire Division	Cost of Gas Total	LDAC Flowthrough Total
OPERATING REVENUES															
Sales:															
Residential (480)	$ 9,402,656	$ 6,775	$ 66,784	$ 15,479	$ 977,734	$ 103,733	$ 0	$ (0)	$ 236,021	$ -	$ 10,809,182	$ 19,232,153	$ 30,041,335	$ 9,476,216	$ 1,332,967
General Service (481)	10,833,043	7,005	75,810	77,272	542,605	119,301	(25)	11	43,177	-	11,698,198	10,623,702	22,321,900	10,915,858	782,341
Firm Transport Revenues (484, 489) (External Sup)	-	-	-	114,130	802,535	175,875	25	(11)	63,995	-	1,156,548	8,583,266	9,739,814	0	1,156,548
Sales for Resale (483)	1,107,459	-	-	-	-	-	-	-	-	-	1,107,459	-	1,107,459	1,107,459	-
Other Sales (495)	2,291,577	11,582	(43,051)	115,868	41,657	-	-	-	15,896	12,952	2,446,481	(201,864)	2,244,617	2,260,108	186,373
Total Sales	23,634,735	25,362	99,544	322,748	2,364,531	398,908	(0)	-	359,089	12,952	27,217,869	38,237,257	65,455,125	23,759,640	3,458,228
Other Operating Revenues:															
Late Charge (487)	-	-	-	-	-	-	-	-	-	-	-	36,761	36,761	-	-
Misc. Service Revenues (488)	-	-	-	-	-	-	-	-	-	-	-	852,304	852,304	-	-
Rent from Property (493 & 457)	-	-	-	-	-	-	-	-	-	-	-	218,628	218,628	-	-
Other Revenues	120,656	-	-	-	-	-	-	-	-	-	120,656	-	120,656	120,656	-
Total Other Operating Revenues	120,656	-	-	-	-	-	-	-	-	-	120,656	1,107,692	1,228,348	120,656	-
TOTAL OPERATING REVENUES	23,755,391	25,362	99,544	322,748	2,364,531	398,908	(0)	-	359,089	12,952	27,338,525	39,344,949	66,683,473	23,880,296	3,458,228
OPERATING EXPENSES															
Operation & Maint. Expenses:															
Production (710-813)	22,696,215	-	-	-	-	398,908	-	-	-	-	23,095,124	449,736	23,544,860	22,696,215	398,908
Transmission (850-857)	-	-	-	-	-	-	-	-	-	-	-	63,829	63,829	-	-
Distribution (870-894) (586)	-	-	-	-	-	-	-	-	-	-	-	3,733,377	3,733,377	-	-
Cust. Accounting (901-905)	-	-	99,544	-	-	-	-	-	-	-	99,544	2,508,645	2,608,189	99,544	-
Cust. Service & Info (906-910)	-	-	-	-	2,255,679	-	-	-	-	12,952	2,268,632	73,074	2,341,706	(0)	2,268,632
Sales Expenses (911-916)	-	-	-	-	-	-	-	-	-	-	-	69,178	69,178	-	-
Admin. & General (920-935)	-	-	-	58,225	-	-	-	-	-	-	58,225	6,682,552	6,740,777	-	58,225
Total O & M Expenses	22,696,215	-	99,544	58,225	2,255,679	398,908	-	-	-	12,952	25,521,524	13,580,391	39,101,915	22,795,759	2,725,765
Other Operating Expenses:															
Deprtn. & Amort. (403-407)	-	-	-	-	-	-	(0)	-	-	-	(0)	9,693,559	9,693,559	-	(0)
Taxes-Other Than Inc. (408)	-	-	-	-	-	-	-	-	-	-	-	4,867,774	4,867,774	-	-
Federal Income Tax (409)	-	-	-	-	-	-	-	-	-	-	-	(30,211)	(30,211)	-	-
State Franchise Tax (409)	-	-	-	-	-	-	-	-	-	-	-	(384,644)	(384,644)	-	-
Def. Income Taxes (410,411)	-	-	-	-	-	-	-	-	-	-	-	2,600,179	2,600,179	-	-
Total Other Operating Expenses	-	-	-	-	-	-	(0)	-	-	-	(0)	16,746,657	16,746,657	-	(0)
TOTAL OPERATING EXPENSES	22,696,215	-	99,544	58,225	2,255,679	398,908	(0)	-	-	12,952	25,521,524	30,327,047	55,848,571	22,795,759	2,725,765
NET UTILITY OPERATING INCOME	1,059,176	25,362	-	264,523	108,852	-	-	-	359,089	-	1,817,001	9,017,901	10,834,902	1,084,537	732,463
OTHER INCOME & DEDUCTIONS															
Other Income:															
Other (415- 421)	-	(25,362)	-	-	-	-	-	-	-	-	(25,362)	231,700	206,339	(25,362)	-
Other Income Deduc. (425, 426)	-	-	-	-	-	-	-	-	-	-	-	151,744	151,744	-	-
Taxes Other than Income Taxes:															
Income Tax, Other Inc & Ded	-	-	-	-	-	-	-	-	-	-	-	14,786	14,786	-	-
Net Other Income (Deductions)	-	(25,362)	-	-	-	-	-	-	-	-	(25,362)	65,170	39,809	(25,362)	-
GROSS INCOME	1,059,176	-	-	264,523	108,852	-	-	-	359,089	-	1,791,639	9,083,072	10,874,711	1,059,176	732,463
Interest Charges (427 - 432)	1,286	-	-	-	-	-	-	-	-	-	1,286	4,777,155	4,778,441	1,286	-
NET INCOME	$ 1,057,890	$ -	$ -	$ 264,523	$ 108,852	$ -	$ -	$ -	$ 359,089	$ -	$ 1,790,353	$ 4,305,917	$ 6,096,270	$ 1,057,890	$ 732,463

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COST OF GAS OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper - Cost of Gas
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	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TEST YEAR COST OF GAS	LESS: INDIRECT PRODUCTION & O.H.	COST OF GAS EXCL. PROD. & O.H.
	OPERATING REVENUES			
1	TOTAL SALES	23,759,640	1,057,890	22,701,750
2	TOTAL OTHER OPERATING REVENUES	120,656	-	120,656
3	TOTAL OPERATING REVENUES	23,880,296	1,057,890	22,822,406
4	OPERATING EXPENSES:			
5	PRODUCTION	22,696,215	-	22,696,215
6	TRANSMISSION	-	-	-
7	DISTRIBUTION	-	-	-
8	CUSTOMER ACCOUNTING	99,544	-	99,544
9	CUSTOMER SERVICE	(0)	-	(0)
10	SALES EXPENSE	-	-	-
11	ADMINISTRATIVE & GENERAL	-	-	-
12	DEPRECIATION	-	-	-
13	AMORTIZATIONS	-	-	-
14	TAXES OTHER THAN INCOME	-	-	-
15	FEDERAL INCOME TAX	-	-	-
16	STATE INCOME TAX	-	-	-
17	DEFERRED FEDERAL & STATE INCOME TAXES	-	-	-
18	INTEREST ON CUSTOMER DEPOSITS	-	-	-
19	TOTAL OPERATING EXPENSES	22,795,759	-	22,795,759
20	NET OPERATING INCOME	1,084,537	1,057,890	26,647

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SUMMARY OF ALLOCATORS
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper Allocators

	Allocation Factor
USC Labor & OH Charged to NuNH (Payroll)	20.18%
USC Labor & OH Charged to NuNH (Benefits)	19.85%
Capitalization Rates	
NuNH Payroll	46.69%
NuNH Benefits	48.76%
USC Labor & OH Charged to Construction (Payroll)	32.52%
USC Labor & OH Charged to Construction (Benefits)	31.51%
Incentive Compensation - NuNH	84.00%

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Northern Utilities, Inc.
Calculation of Temporary Rate Adjustment

Line No.	Description		2020 Adjusted Base Year Revenue [(1)]		Allocated Temporary Rate Increase [(2)]	2020 Adjusted Billing Determinant (therms) [(3)]		Temporary Rate Factor $ per therm
1	Residential	$	21,225,409		1,717,764	20,304,525	$	0.0846
2	Commercial & Industrial		18,571,431		1,502,979	53,847,584	$	0.0279
3	Total	$	39,796,840	$	3,220,742	74,152,109		

Notes:
(1) Reference Amen/Taylor Schedule RAJT-11, Pages 1 through 3, Col I
(2) Reference Schedule CGDN-3 for total temporary rate increase. Allocated proportionally by 2020 adjusted base year revenue
(3) Reference Amen/Taylor Schedule RAJT-11, Pages 1 through 3, Col H

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DG 21-104
Schedule CGDN-5
Page 1 of 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
DISCOUNTED CASH FLOW RESULTS
2018 GAS MAIN EXTENSIONS

		Original		Revised	
Line No.	**Project Location**	**CIAC**	**NPV**	**CIAC**	**NPV**
1	201 Atlantic Ave, North Hampton NH *	$ 112,542	$ (49,707)	$ 110,481	$ (110,276)
2	113, 114, 115 & 117 Batchelder Rd, Seabrook NH *		55,245		105,971
3	104 Washington St, Dover NH *		214,880		289,431
4	10 Hampshire Rd, Salem NH		6,616		(38,502)
5	121 Corporate Drive, Portsmouth NH		13,247		104,187
6	140 Wakefield St, Rochester NH *	50,566	(2,086)	50,566	22,736
7	109 Towle Farm Rd, Hampton NH	29,416	-	29,146	(42,617)
8	0 Borthwick Ave, Portsmouth NH	38,125	-	38,125	(71,150)
9	101 International Drive, Portsmouth, NH		113,217		654,349
10			$ 351,411		$ 914,129

11 ** Denotes residential or municipal projects that are analyzed based on a 20 year period. All other project results are based on a 10 year period.*

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DG 21-104
Schedule CGDN-6
Page 1 of 1

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
EPPING FRANCHISE DCF VARIANCE
ORIGINAL MODEL VS REVISED MODEL
REDACTED

Capital Cost			10-Year NPV			20-Year NPV		
Original	Revised	Variance	Original	Revised	Variance	Original	Revised	Variance
[redacted]			[redacted]			[redacted]		

Notes:
Original Model results are referenced as Exhibit 8 in Order No. 26,220 of DG 18-094
Revised Model updated Original Model for actual incremental capital costs and actual customer additions

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V. LOCAL DELIVERY ADJUSTMENT CHARGE

Section

1. Purpose

The purpose of this clause is to establish procedures that allow Northern Utilities ("Northern" or the "Company") subject to the jurisdiction of the State of New Hampshire Public Utilities Commission ("PUC" or "NHPUC"), to adjust, on an annual basis, its rates for firm gas Sales and firm Delivery Services in order to recover Energy Efficiency program costs , recover lost revenue related to the Energy Efficiency programs, recover environmental response costs, return interruptible transportation margin credits, recover revenue shortfall associated with customer participation in the Gas Assistance Program, recover the non-distribution portion of the annual NHPUC regulatory assessment, recover rate case expenses, recover and return the reconciliation of revenues related to permanent changes in delivery rates and recover property tax expense increases associated with RSA 72:8-d and -e, recover or return the actual delivery write offs compared to the level in distribution rates, recover or return the actual annual cost of the Arrearage Management Program ("AMP") compared to the level in distribution rates, recover waived late payment revenues and recover or return the amount of special contract revenues as determined in Docket DG 21-104.

2. Applicability

This Local Delivery Adjustment Charge ("LDAC") shall be applicable in whole or part to all of Northern's firm Sales and firm Delivery Services customers as shown on the table below. The application of the clause may, for good cause shown, be modified by the NHPUC. See Part V, Section 13, "Other Rules."

V. LOCAL DELIVERY ADJUSTMENT CHARGE

Applicability	EE V.3.	LR V.4	ERC V.5.	ITM V.6.	GAP V.7.	RCE V.8.	RPC V.9.	RCAM V.10.
Residential Non-Heating	X	X	X	X	X	X	X	X
Residential Heating	X	X	X	X	X	X	X	X
Small C&I	X	X	X	X	X	X	X	X
Medium C&I	X	X	X	X	X	X	X	X
Large C&I	X	X	X	X	X	X	X	X
No Previous Sales Service	X	X	X	X	X	X	X	X

Notes:

1 N/A - Not applicable
2 X - Applicable to all
3 Specific EEC and LR Rates for Residential Heating and Non-Heating
4 Specific EEC and LR Rates for All C&I classes

3. Energy Efficiency Program Costs Allowable for LDAC

3.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern, subject to the jurisdiction of the NHPUC, to adjust on an annual basis, the Energy Efficiency Charge applicable to firm gas Sales and firm Delivery Services throughput in order to recover from firm ratepayers Energy Efficiency program costs and performance incentives.

3.2 Applicability

An Energy Efficiency Charge ("EEC") shall be applied to firm Sales and firm Delivery Services throughput of the Company as determined in accordance with the provisions of Part V, Section 3 of this clause. Such EEC shall be determined annually by the Company, separately for each Rate Category defined below, subject to review and approval by the NHPUC as provided for in this clause.

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For purposes of applying the respective EEC each "Rate Category" shall be as follows:

Residential	Rates R-5, R-6, R-10,
Commercial/Industrial (including multi-family)	Rates G-40, G-50, G-41, G-42, G-51, G-52

Special contract customers are exempt from the EEC.

3.3 Reporting

The Company shall submit monthly and annual reports by Rate Category to the Commission reconciling any difference between the actual Energy Efficiency costs and actual revenues collected under this rate schedule. The difference, whether positive or negative, will be carried forward, with interest, into the EEC for the next recovery period. Annual reports shall be filed with the Commission at least 45 days prior to the effective date of the next subsequent twelve-month period.

3.4 Effective Date of EEC

Forty-five ("45") days prior to November 1 of each year, the Company will file with the NHPUC for its consideration and approval, the Company's request for a change in the EEC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

3.5 Calculation of the EEC

The EEC for each Rate Category will be derived by dividing the projected annual EE costs, including performance incentives, plus the reconciliation balance, by forecast firm annual throughput. The reconciliation balance shall reflect both actual and projected data, as necessary, through October of the prior rate period.

3.6 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between EEC revenues collected and actual Energy Efficiency program costs and performance incentives, plus carrying charges calculated on the average monthly balance and then added or credited to the end-of-month balance. Interest shall be calculated based on 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

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month preceding the calendar quarter; if more than one rate is reported the average of the reported rates shall be used.

3.7 Application of EEC Rate to Bills

The EEC Rate ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales volumes and transportation throughput.

3.8 Information to be Filed with the NHPUC

An annual EEC filing will be required forty-five (45) days prior to the effective date of November 1, containing the calculation of the new annual EEC to become effective November 1. The calculation will reflect the forecast of EEC annual costs, the updated annual EEC reconciliation balance and throughput forecast for the upcoming period. Monthly and annual reconciliation reports will be filed in accordance with Section 3.3 above.

4. Lost Revenue Allowable for LDAC

4.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern, subject to the jurisdiction of the NHPUC, to adjust on an annual basis, the Lost Revenue Rate applicable to firm gas Sales and firm Delivery Services throughput in order to recover from firm ratepayers lost revenue related to Energy Efficiency programs, pursuant to Order No. 25,932 in Docket DE 15-137, Energy Efficiency Resource Standard.

4.2 Applicability

Effective January 1, 2017, a Lost Revenue Rate (“LRR”) shall be applied to firm Sales and firm Delivery Services throughput of the Company as determined in accordance with the provisions of Part V, Section 4 of this clause. Such LRR shall be determined annually by the Company, separately for each Rate Category defined below, subject to review and approval by the NHPUC as provided for in this clause.

For purposes of applying the respective LRR each "Rate Category" shall be as follows:

Residential	Rates R-5, R-6, R-10

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Commercial/Industrial (including multi-family) Rates G-40, G-50, G-41, G-42, G-51, G-52

Special contract customers are exempt from the LRR.

4.3 Effective Date of the LRR

Forty-five ("45") days prior to November 1 of each year, the Company will file with the NHPUC for its consideration and approval, the Company's request for a change in the LRR applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

4.4 Calculation of the LRR

The LRR for each Rate Category will be derived by dividing the projected annual lost revenue, plus the reconciliation balance and projected interest, by forecast firm annual throughput. The reconciliation balance shall reflect both actual and projected data, as necessary, through October of the prior rate period.

4.5 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between LRR revenues collected and actual costs, plus carrying charges calculated on the average monthly balance and then added or credited to the end-of-month balance. Interest shall be calculated based on 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 rate is reported the average of the reported rates shall be used.

4.6 Application of LRR to Bills

The LRR ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales volumes and transportation throughput.

4.7 Information to be Filed with the NHPUC

An annual LRR filing will be required forty-five (45) days prior to the effective date of November 1, containing the calculation of the new annual LRR to become effective November 1. The calculation will reflect the forecast of LRR annual costs, the updated annual LRR reconciliation balance and throughput forecast for

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the upcoming period.

5. Environmental Response Costs Allowable for LDAC

5.1 Purpose
In order to recover Environmental Response Cost ("ERC") expenditures associated with former manufactured gas plants, there shall be an ERC Rate applied to all firm gas Sales and firm Delivery Services throughput billed under the Company's sales and delivery service rate schedules.

5.2 Applicability

An annual ERC Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ERC Rate shall be filed with the Company's Annual Cost of Gas Charge ("COGC") filing and be subject to review and approval by the Commission. The annual ERC Rate will be applied to firm Sales and to firm Delivery Services throughput as a separate surcharge. Special contract customers are exempt from the ERC.

5.3 Environmental Response Cost Allowable

All approved environmental response costs associated with manufactured gas plants shall be included in the ERC Rate.

The total annual charge to the Company's ratepayers for environmental response costs during any annual ERC recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and Delivery Service throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ERC expenditures to be in effect for the upcoming twelve month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ERC Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted each quarter using the prime interest rate as reported by the Wall Street Journal on the first date of the month preceding the first month of the quarter.

5.4 Effective Date

Forty-five ("45") days prior to November 1 of each year, the Company will file with the NHPUC for its consideration and approval, the Company's request for a

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change in the ERC applicable to all firm sales and firm delivery service throughput for the subsequent twelve month period commencing with the calendar month of November.

5.5 Definitions

Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas plant sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. ERCs shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the company as a result of such claims.

5.6 Reconciliation Adjustments

Prior to the Annual COGC filing, the Company will calculate the difference between (a) the revenues derived by multiplying firm sales and Delivery Service throughput by the ERC Rate through October 31, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ERC Recovery Period. This cumulative difference will be recorded in Account 173. The Company shall file the reconciliation along with its COG filing forty-five (45) days prior to the beginning of the annual period.

5.7 Calculation of the ERC

The ERC Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and Delivery Service throughput for the upcoming twelve months of November 1 through October 31.

5.8 Application of ERC to Bills

The annual ERC Rate shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm gas sales by being included in the determination of the semiannual COGC, and also will be applied to the

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monthly firm Delivery throughput of each firm Delivery customer's bill.

6. Interruptible Transportation Margins Allowable for LDAC

6.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern subject to the jurisdiction of the NHPUC to adjust the Interruptible Transportation Margin Credit (“ITMC”) applicable to firm gas Sales and firm Delivery Services throughput in order to return the Interruptible Transportation margins allocated to the local distribution firm ratepayers.

6.2 Applicability

An Interruptible Transportation Margin Credit (“ITMC”) shall be applied to all firm Sales and firm Delivery Services throughput of the Company subject to the jurisdiction of the NHPUC as determined in accordance with the provisions of Part V, Section 6 of this clause. Such ITMC shall be determined annually by the Company as defined below, subject to review and approval by the NHPUC as provided for in this clause. The ITMC is not applied to the bills of special contract customers.

The application of this provision may, for good cause shown, be modified by the NHPUC. See Part V, Section 13, "Other Rules."

6.3 Effective Date of Interruptible Transportation Margin

The ITMC shall become effective on November 1 as designated by the Company.

6.4 Interruptible Transportation Margins

The ITMC shall be computed annually based on a forecast of Interruptible Transportation margins and firm sales and firm delivery service throughput volumes.

6.5 Annual ITM Credit Formula

The annual ITM Credit shall be calculated according to the following formulas:

$$ITMC = \frac{ITM}{A{:}TPvol} + RF_{ITM}$$

and:

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$$RF_{ITM} = \frac{R_{ITM}}{A{:}TP_{vol}}$$

Where:

$A : TP_{vol}$	Forecast annual firm sales and firm delivery service throughput.
ITMC	Annual Interruptible Transportation Margin Credit.
ITM	Interruptible Transportation margins
RF_{ITM}	Annual Interruptible Transportation margin reconciliation adjustment factor applicable to total firm sales and firm delivery service throughput.
R_{ITM}	Reconciliation costs - interruptible Transportation margins, Account 173 balance, inclusive of the associated Account 173 interest.

6.6 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between annual, interruptible Transportation margins returned toward the local distribution function, as calculated by multiplying the interruptible Transportation margin credit (ITMC) times monthly firm sales and firm delivery service throughput during the year, and the actual margins for the year.

See Part V, Section 6.5 for Reconciliation formulas.

6.7 Application of ITMC to Bills

The ITMC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm by period and will be applied to the monthly firm sales and firm delivery service throughput.

6.8 Information to be Filed with the NHPUC

Information pertaining to the Interruptible Transportation Margins will be filed with the NHPUC along with the gas cost information as required pursuant to the LDAC and COGC. Required filings include an annual report providing actual data and resulting updated projection of the end-of-period reconciliation balance, as well as an annual calculation of the ITM credit, which shall be included in an annual LDAC filing. Also, the annual ITM reconciliation balances shall be filed along with the other reconciliation balances included in the LDAC.

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7. Gas Assistance Program ("GAP") Costs Allowable for LDAC

7.1 Purpose:

The purpose of this provision is to allow Northern Utilities, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Gas Assistance Program, as well as the associated administrative costs, pursuant to DG 20-013. Such costs shall be recovered by applying the GAP Rate to all firm gas Sales and firm Delivery Services throughput billed under the Company's sales and delivery service rate schedules.

7.2 Applicability:

The GAP Rate shall be applied to all firm Sales and Delivery Services customers with the exception of special contract customers who are exempt from the LDAC. The GAP Rate shall be determined annually by the Company as defined below, subject to review and approval by the NHPUC as provided in this clause.

7.3 Gas Assistance Program Costs ("GAPC") Allowable for LDAC

The amount of Gas Assistance Program costs is comprised of the revenue discounts given to customers enrolled under the Gas Assistance Program plus the associated administrative costs The revenue discount and administrative costs shall be the amount approved by the NHPUC.

7.4 Effective Date of Gas Assistance Program Rate

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Forty five (45) days prior to November 1 of each year, the Company will file with the NHPUC for its consideration and approval, the Company's request for a change in the GAP Rate applicable to all consumption of tariff customers eligible to receive delivery service for the subsequent twelve month period commencing with billings for gas consumed on and after November 1.

7.5 Definitions:

Gas Assistance Program Costs are the discounts in delivery and cost of gas service revenues (excluding LDAC revenues) generated from customers participating in the Gas Assistance Program. Participating customers receive a 45% discount on the regular Residential Low Income Heating R-10 rate schedule during the Winter period. Also, these costs include the associated administrative costs, which include associated Information Technology and start-up costs.

7.6 Gas Assistance Program ("GAP") Rate Formula:

$$\textbf{GAP Rate} = \frac{\textbf{GAPC}_{\textbf{GAP}}}{\textbf{A:TPvol}}$$

and:

GAPC = (Cust x DCust$)+(Cust x Avgthm x Dbr)+(Cust x Avgthm x Dcog) + AdminC

Where:

AdminC	Costs associated with administering the Gas Assistance Program, including IT and start-up costs.
Avgthm	Estimated average therm use per customer for period determined from most recent historical therm use under the Company's Gas Assistance Program, or Residential Heating, rate schedules.
Cust	Estimated number of customers participating in the

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	Gas Assistance Program.
Dbr	Difference between the Residential Low Income Heating R-10 and discounted Residential Low Income Heating Service R-10 base rate charges.
Dcog	Difference between the Residential Low Income Heating R-10 and discounted Residential Low Income Heating Service R-10 cost of gas charges.
DCust$	Difference between the Residential Low Income Heating R-10 and discounted Residential Low Income Heating Service R-10 monthly customer charge.
GAPC	Costs, comprised of the revenue discounts associated with customer participation in the Gas Assistance Program, plus associated administrative costs, as defined in section 7.5.
RA_{GAP}	Reconciliation Adjustment associated with Gas Assistance Program Costs and revenues - Account 173 balance, inclusive of the associated interest, as outlined in Section 7.7
A:TPvol	Forecast annual firm sales and firm delivery service throughput.

7.7 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between revenues toward Gas Assistance Program costs as calculated by multiplying the (GAP) Rate times monthly firm throughput volumes and actual GAPC, comprised of the revenue shortfall and administrative costs, allowed as defined in Section 7.5, plus carrying charges calculated on the average monthly balance using the Federal Reserve Statistical Release prime lending rate and then added to the end-of-month balance.

7.8 Application of GAP Rate to Bills

The GAP Rate ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales volumes and transportation throughput.

7.9 Information to be Filed with the NHPUC

Information pertaining to the Gas Assistance Program (GAP) costs and revenue shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GAP filing will be required forty-five

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(45) days prior to the effective date of November 1, containing the calculation of the new annual GAP Rate to become effective November 1. The calculation will reflect the forecast of GAP annual costs, the updated annual GAP reconciliation balance and throughput forecast for the upcoming annual period.

8. Expenses Related to Rate Cases Allowable for LDAC

8.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern Utilities to adjust its rates for the recovery of NHPUC-approved rate case expenses.

8.2 Applicability

The Rate Case Expenses ("RCE") shall be applied to all firm tariffed customers with the exception of special contract customers. The RCE will be determined by the Company, as defined below.

8.3 Rate Case Expenses Allowable for LDAC

The total amount of the RCE will be equal to the amount approved by the Commission.

8.4 Rate Case Expenses Allowable for LDAC

The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

8.5 Definition

The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees, processing expenses, and other approved expenses.

8.6 Rate Case Expense (RCE) Factor Formulas

The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion

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of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

8.7 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor (RCEF) times the appropriate monthly volumes and Rate Case Expense allowed.

At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8.8 Application of RCE to Bills

The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales and firm delivery service throughput of tariffed customers.

8.9 Information to be Filed with the NHPUC

Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

9. Reconciliation of Permanent Changes in Distribution Rates

9.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern Utilities to adjust its rates for the reconciliation of revenues related to a permanent change in the Company’s distribution service rates implemented subsequent to the effective date of such change. This provision includes the reconciliation for the difference in revenues charged under temporary versus permanent rates.

9.2 Applicability

The factor to reconcile the revenues resulting from a permanent rate change (“RPC”) shall be applied to all firm tariffed customers. The Company will determine the RPC, as defined in this section.

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9.3 Amount of RPC Allowable for LDAC

The amount of the RPC will be equal to the amount approved by the Commission.

9.4 Effective Date of RPC Charge

The effective date of the RPC Charge will be determined by the NHPUC on a case by case basis.

9.5 Definition

The RPC is a surcharge mechanism, which allows Northern Utilities to adjust its rates for the reconciliation of revenues generated under delivery service rates that have been permanently changed.

9.6 Formulas to Reconcile Revenues Resulting From a Permanent Rate Change

The RPC will be calculated according to the Commission Order issued in an individual proceeding.

9.7 Reconciliation Adjustment Account

Account 173 shall contain the accumulated difference between revenues toward reconciliation expenses as calculated by multiplying the reconciliation of the permanent changes in delivery rate charge (RPC) times the appropriate monthly volumes and reconciliation amount allowed.

9.8 Application of RPC Charge to Bills

The RPC charge ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales and firm delivery service throughput of tariffed customers.

9.9 Information to be Filed with the NHPUC

Information pertaining to the RPC will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RPC filing will contain the calculation of the new RPC charge and will include the updated RPC reconciliation balance.

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10. Regulatory Cost Adjustment Mechanism (“RCAM”)

10.1 Purpose

The purpose of this provision is to establish a procedure that allows Northern Utilities to recover the increase in local property tax expense associated with HB 700 and RSA 72:8-d and -e. This rate shall also recover~~y~~ the change in the Company’s annual NHPUC regulatory assessment. Also, as approved in Docket DG 21-104, the RCAM shall include the over- or under- collection of the following costs compared to the level included in distribution rates: (1) actual delivery write offs compared to the level in distribution rates (2) the annual cost of the AMP (3) special contract revenues. Finally, the rate shall recover waived late payment revenues as determined in Docket DG. 21-104.

10.2 Applicability

The RCAM Rate shall be applied to all Firm Sales and Delivery Service customers with the exception of special contract customers who are exempt from the LDAC. The RCAM Rate shall be determined annually by the Company as defined below, subject to review and approval by the NHPUC as provided in this clause.

10.3 ~~Regulatory Costs Adjustment Mechanism Costs (“~~RCAM~~”)~~ Allowable for LDAC

The amount of Property Tax Expense costs is the increase in local property tax expense related to HB 700 beginning in 2020 above the amount of local property tax expense recovery in base rates of $3,492,961 established in Docket DG 17-070 and two subsequent Step increases.

Effective October~~July~~ 1~~5~~, 2021~~17~~, the amount of the NH PUC regulatory assessment to be charged, or credited, through this clause shall be calculated by taking the total assessment minus the amount in base rates of $485,194~~368,964~~ established in Docket DG 21~~17~~-104~~070~~.

The amount of delivery write offs to be charged, or credited, through this clause shall be calculated by taking the amount of actual delivery write offs minus the amount in base rates of $336,170 established in Docket DG 21-104.

The amount of AMP costs to be charged, or credited, through this clause shall be calculated by taking the annual AMP costs for the 12 months ended July 31 minus the amount in base rates of $92,480 established in Docket DG. 21-104.

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The amount of waived late payment revenues to be charged, through this clause shall be $104,863 as established in Docket DG 21-104.

Effective October 1, 2021, the amount of special contract revenues to be charged, or credited, through this clause shall be calculated by taking the actual annual special contract revenues minus the amount in base rates of $1,197,813 established in Docket DG. 21-104.

10.4 Effective Date of RCAM~~egulatory Cost Adjustment Mechanism~~ Rate

Forty five (45) days prior to November 1 of each year, the Company will file with the NHPUC for its consideration and approval, the Company's request for a change in the RCAM Rate applicable to all consumption of tariff customers eligible to receive delivery service for the subsequent twelve month period commencing with billings for gas consumed on and after November 1.

10.5 ~~Regulatory Cost Adjustment Mechanism ("~~RCAM~~")~~ Formula:

$$\textbf{RCAM Rate} = \frac{\textbf{RCAMC} + \textbf{RA}_{\textbf{RCAM}}}{\textbf{A:TP}_{\textbf{vol}}}$$

and:

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RCAMC = ~~Property Tax Expense + Regulatory Assessment~~Costs as defined in Section 10.3

Where:

RCAMC Costs, ~~comprised of the property tax expense~~ as defined in Ssection 10.3~~, and the non-distribution portion of the annual NHPUC regulatory assessment.~~

RARCAM Reconciliation Adjustment ~~associated with Property Tax Expense and Regulatory Assessment Costs and revenues~~ - Account 173 balance, inclusive of the associated interest, as outlined in Section 10.6

A:TPvol Forecast annual firm sales and firm delivery service throughput.

10.6 Reconciliation Adjustments

Account 173 shall contain the accumulated difference between revenues toward ~~Property Tax Expense and Regulatory Assessment~~ costs, as defined in Section 10.3, as calculated by multiplying the RCAM Rate times monthly firm throughput volumes and actual RCAMC, comprised of the ~~property tax expense,~~ costs allowed, as defined in Section 10.3, ~~plus the non-distribution portion of the annual NHPUC regulatory assessment,~~ plus carrying charges calculated on the average monthly balance using the Federal Reserve Statistical Release prime lending rate and then added to the end-of-month balance.

10.7 Application of RCAM Rate to Bills

The RCAM Rate ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm sales volumes and transportation throughput.

10.8 Information to be Filed with the NHPUC

Information pertaining to the ~~Regulatory Cost Adjustment Mechanism (~~RCAM~~)~~ costs and revenue shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual RCAM filing will be required forty-five (45) days prior to the effective date of November 1, containing the calculation of the new annual RCAM Rate to become effective November 1. The calculation will reflect the incremental property tax expense for the prior calendar year and forecasted regulatory assessment annual costs, the updated annual RCAM reconciliation balance and throughput forecast for the upcoming annual period.

11. Effective Date of LDAC

The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

12. LDAC Formulas

The LDAC shall be calculated on an annual basis, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = EEC^{x} + LBR^{x} + ERC - ITMC + GAPRA + RCEF^{x} + RPC^{x} + RCAM$$

Where:

EEC^{x}	Annualized class specific Energy Efficiency Charge
LR^{x}	Annualized class specific Lost Revenue Rate
$LDAC^{x}$	Annualized class specific Local Delivery Adjustment Clause
ITMC	Annualized Interruptible Transportation Margin Credit
ERC	Total firm annualized Environmental Response Charge
$RCEF^{x}$	Annualized class specific Rate Case Expense Factor
GAP	Gas Assistance ProgramRate
RPC^{x}	Reconciliation of Permanent Changes in Delivery Rates
RCAM	Regulatory Cost Adjustment Mechanism Rate

13. Application of LDAC to Bills

The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and will be applied to the monthly firm Sales and firm Delivery Services throughput in accordance with the table shown in Part V, Section 2.

14. Other Rules

(1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may

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determine to be in the public interest.

(2) Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

(3) The Company may implement an amended LDAC with the NHPUC approval at any time.

(4) The NHPUC may, at any time, require the Company to file an amended LDAC.

(5) The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

15. Amendments to Uniform System of Accounts

173 Interruptible Transportation Margin Reconciliation Adjustment for LDAC

This account shall be used to record the cumulative difference between annual Interruptible Transportation margin returns and annual Interruptible Transportation margins. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 6.

173 Energy Efficiency Reconciliation Adjustment

This account shall be used to record the cumulative difference between the sum of Energy Efficiency program costs and performance incentives and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 3.

173 Environmental Response Costs Reconciliation Adjustment

This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ERC times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 5.

173 Rate Case Expense Reconciliation Adjustment
This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with

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recovery and actual amounts of third party incremental expense associated with the Company's Rate Case initiatives. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 8.

173 Reconciliation of Permanent Changes in Delivery Rates
This account shall be used to record the cumulative differences between the recovery or refund and actual amount of the reconciliation of permanent changes in delivery rates. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 9.

173 Gas Assistance Program Reconciliation Adjustment

This account shall be used to record the cumulative difference between the recovery and actual Gas Assistance Program and Regulatory Assessment Costs. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 7.

173 Lost Revenue Reconciliation Adjustment

This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 4.

173 Regulatory Cost Adjustment Mechanism Reconciliation Adjustment

This account shall be used to record the cumulative difference between the recovery and actual ~~Property Tax Expense and Regulatory Assessment~~ c~~C~~osts as defined in Section 10.3 above. Entries to this account shall be determined as outlined in the Local Delivery Adjustment Charge, Part V, Section 7.

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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
WORKPAPERS SUPPORTING REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper - Income Statement
Schedule 4 NH
4/20/2021
10:26:24 AM
For Periods Ending December 31, 2020

Northern Utilities, Inc.
Gas Inc Stmt - NH - YTD
R_NU_4_BF_NH

Table of Contents

	2019 Base	2019 Flowthru	Total	2020 Base	2020 Flowthru	Total
OPERATING REVENUES						
Sales:						
Residential (480)	19,612,987	14,904,240	34,517,227	19,232,153	10,809,182	30,041,335
General Service (481)	11,028,771	17,278,063	28,306,834	10,623,702	11,698,198	22,321,900
Firm Transport Revenues (484, 489) (External Sup)	8,612,979	1,216,889	9,829,867	8,583,266	1,156,548	9,739,814
Sales for Resale (483)	-	2,870,979	2,870,979	-	1,107,459	1,107,459
Other Sales (495)	236,169	(3,751,608)	(3,515,439)	(201,864)	2,446,481	2,244,617
Total Sales	39,490,906	32,518,563	72,009,468	38,237,257	27,217,869	65,455,125
Other Operating Revenues:						
Late Charge (487)	76,773	-	76,773	36,761	-	36,761
Misc. Service Revenues (488)	875,755	-	875,755	852,304	-	852,304
Rent from Property (493 & 457)	200,952	-	200,952	218,628	-	218,628
Other Revenues	-	(311,587)	(311,587)	-	120,656	120,656
Total Other Operating Revenues	1,153,480	(311,587)	841,893	1,107,692	120,656	1,228,348
TOTAL OPERATING REVENUES	40,644,386	32,206,975	72,851,361	39,344,949	27,338,525	66,683,473
OPERATING EXPENSES						
Operation & Maint. Expenses:						
Production (710-813)	477,446	27,749,285	28,226,731	449,736	23,095,124	23,544,860
Transmission (850-857)	72,713	-	72,713	63,829	-	63,829
Distribution (870-894) (586)	3,509,448	-	3,509,448	3,733,377	-	3,733,377
Cust. Accounting (901-905)	2,580,251	188,507	2,768,758	2,508,645	99,544	2,608,189
Cust. Service & Info (906-910)	71,870	2,247,505	2,319,375	73,074	2,268,632	2,341,706
Sales Expenses (911-916)	64,467	-	64,467	69,178	-	69,178
Admin. & General (920-935)	7,607,751	71,540	7,679,291	6,682,552	58,225	6,740,777
Total O & M Expenses	14,383,947	30,256,837	44,640,784	13,580,391	25,521,524	39,101,915
Other Operating Expenses:						
Deprtn. & Amort. (403-407)	8,884,559	120,384	9,004,943	9,693,559	(0)	9,693,559
Taxes-Other Than Inc. (408)	4,306,298	-	4,306,298	4,867,774	-	4,867,774
Federal Income Tax (409)	52,380	-	52,380	(30,211)	-	(30,211)
State Franchise Tax (409)	(309,547)	-	(309,547)	(384,644)	-	(384,644)
Def. Income Taxes (410,411)	2,975,683	-	2,975,683	2,600,179	-	2,600,179
Total Other Operating Expenses	15,909,373	120,384	16,029,757	16,746,657	(0)	16,746,657
TOTAL OPERATING EXPENSES	30,293,320	30,377,221	60,670,541	30,327,047	25,521,524	55,848,571
NET UTILITY OPERATING INCOME	10,351,066	1,829,755	12,180,820	9,017,901	1,817,001	10,834,902
OTHER INCOME & DEDUCTIONS						
Other Income:						
AFUDC - Other Funds (41901)	-	-	-	-	-	-
Other (415- 421)	280,289	(37,502)	242,787	231,700	(25,362)	206,339
Other Income Deduc. (425, 426)	232,636	-	232,636	151,744	-	151,744
Taxes Other than Income Taxes:						
Income Tax, Other Inc & Ded	2,752	-	2,752	14,786	-	14,786
Net Other Income (Deductions)	44,901	(37,502)	7,400	65,170	(25,362)	39,809
GROSS INCOME	10,395,967	1,792,253	12,188,220	9,083,072	1,791,639	10,874,711
Interest Charges (427 - 432)	4,670,265	3,717	4,673,982	4,777,155	1,286	4,778,441
NET INCOME	5,725,702	1,788,536	7,514,238	4,305,917	1,790,353	6,096,270

Northern Utilities, Inc.
Gas Inc Stmt - NH - YTD
R_NU_4_B_FTxM_NH

Workpaper - Flowthrough Detail
4/20/2021
10:21:09 AM
For Periods Ending December 31, 2020
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	Commodity Demand COG	Working Capital	Bad Debt	Residential Low Income Assistance	Energy Efficiency	Environ Response Costs	Rate Case Exp	Recoup	Lost Revenue	On-Bill Financing	Total Flowthru	Total Base	Total New Hampshire Division	Cost of Gas Total	LDAC Flowthrough Total
OPERATING REVENUES															
Sales:															
Residential (480)	$ 9,402,656	$ 6,775	$ 66,784	$ 15,479	$ 977,734	$ 103,733	$ 0	$ (0)	$ 236,021	$ -	$ 10,809,182	$ 19,232,153	$ 30,041,335	$ 9,476,216	$ 1,332,967
General Service (481)	10,833,043	7,005	75,810	77,272	542,605	119,301	(25)	11	43,177	-	11,698,198	10,623,702	22,321,900	10,915,858	782,341
Firm Transport Revenues (484, 489) (External Sup)	-	-	-	114,130	802,535	175,875	25	(11)	63,995	-	1,156,548	8,583,266	9,739,814	0	1,156,548
Sales for Resale (483)	1,107,459	-	-	-	-	-	-	-	-	-	1,107,459	-	1,107,459	1,107,459	-
Other Sales (495)	2,291,577	11,582	(43,051)	115,868	41,657	-	-	-	15,896	12,952	2,446,481	(201,864)	2,244,617	2,260,108	186,373
Total Sales	23,634,735	25,362	99,544	322,748	2,364,531	398,908	(0)	-	359,089	12,952	27,217,869	38,237,257	65,455,125	23,759,640	3,458,228
Other Operating Revenues:															
Late Charge (487)	-	-	-	-	-	-	-	-	-	-	-	36,761	36,761	-	-
Misc. Service Revenues (488)	-	-	-	-	-	-	-	-	-	-	-	852,304	852,304	-	-
Rent from Property (493 & 457)	-	-	-	-	-	-	-	-	-	-	-	218,628	218,628	-	-
Other Revenues	120,656	-	-	-	-	-	-	-	-	-	120,656	-	120,656	120,656	-
Total Other Operating Revenues	120,656	-	-	-	-	-	-	-	-	-	120,656	1,107,692	1,228,348	120,656	-
TOTAL OPERATING REVENUES	23,755,391	25,362	99,544	322,748	2,364,531	398,908	(0)	-	359,089	12,952	27,338,525	39,344,949	66,683,473	23,880,296	3,458,228
OPERATING EXPENSES															
Operation & Maint. Expenses:															
Production (710-813)	22,696,215	-	-	-	-	398,908	-	-	-	-	23,095,124	449,736	23,544,860	22,696,215	398,908
Transmission (850-857)	-	-	-	-	-	-	-	-	-	-	-	63,829	63,829	-	-
Distribution (870-894) (586)	-	-	-	-	-	-	-	-	-	-	-	3,733,377	3,733,377	-	-
Cust. Accounting (901-905)	-	-	99,544	-	-	-	-	-	-	-	99,544	2,508,645	2,608,189	99,544	-
Cust. Service & Info (906-910)	-	-	-	-	2,255,679	-	-	-	-	12,952	2,268,632	73,074	2,341,706	(0)	2,268,632
Sales Expenses (911-916)	-	-	-	-	-	-	-	-	-	-	-	69,178	69,178	-	-
Admin. & General (920-935)	-	-	-	58,225	-	-	-	-	-	-	58,225	6,682,552	6,740,777	-	58,225
Total O & M Expenses	22,696,215	-	99,544	58,225	2,255,679	398,908	-	-	-	12,952	25,521,524	13,580,391	39,101,915	22,795,759	2,725,765
Other Operating Expenses:															
Deprtn. & Amort. (403-407)	-	-	-	-	-	-	(0)	-	-	-	(0)	9,693,559	9,693,559	-	(0)
Taxes-Other Than Inc. (408)	-	-	-	-	-	-	-	-	-	-	-	4,867,774	4,867,774	-	-
Federal Income Tax (409)	-	-	-	-	-	-	-	-	-	-	-	(30,211)	(30,211)	-	-
State Franchise Tax (409)	-	-	-	-	-	-	-	-	-	-	-	(384,644)	(384,644)	-	-
Def. Income Taxes (410,411)	-	-	-	-	-	-	-	-	-	-	-	2,600,179	2,600,179	-	-
Total Other Operating Expenses	-	-	-	-	-	-	(0)	-	-	-	(0)	16,746,657	16,746,657	-	(0)
TOTAL OPERATING EXPENSES	22,696,215	-	99,544	58,225	2,255,679	398,908	(0)	-	-	12,952	25,521,524	30,327,047	55,848,571	22,795,759	2,725,765
NET UTILITY OPERATING INCOME	1,059,176	25,362	-	264,523	108,852	-	-	-	359,089	-	1,817,001	9,017,901	10,834,902	1,084,537	732,463
OTHER INCOME & DEDUCTIONS															
Other Income:															
Other (415- 421)	-	(25,362)	-	-	-	-	-	-	-	-	(25,362)	231,700	206,339	(25,362)	-
Other Income Deduc. (425, 426)	-	-	-	-	-	-	-	-	-	-	-	151,744	151,744	-	-
Taxes Other than Income Taxes:															
Income Tax, Other Inc & Ded	-	-	-	-	-	-	-	-	-	-	-	14,786	14,786	-	-
Net Other Income (Deductions)	-	(25,362)	-	-	-	-	-	-	-	-	(25,362)	65,170	39,809	(25,362)	-
GROSS INCOME	1,059,176	-	-	264,523	108,852	-	-	-	359,089	-	1,791,639	9,083,072	10,874,711	1,059,176	732,463
Interest Charges (427 - 432)	1,286	-	-	-	-	-	-	-	-	-	1,286	4,777,155	4,778,441	1,286	-
NET INCOME	$ 1,057,890	$ -	$ -	$ 264,523	$ 108,852	$ -	$ -	$ -	$ 359,089	$ -	$ 1,790,353	$ 4,305,917	$ 6,096,270	$ 1,057,890	$ 732,463

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
COST OF GAS OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper - Cost of Gas
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TEST YEAR COST OF GAS	LESS: INDIRECT PRODUCTION & O.H.	COST OF GAS EXCL. PROD. & O.H.
	OPERATING REVENUES			
1	TOTAL SALES	23,759,640	1,057,890	22,701,750
2	TOTAL OTHER OPERATING REVENUES	120,656	-	120,656
3	TOTAL OPERATING REVENUES	23,880,296	1,057,890	22,822,406
4	OPERATING EXPENSES:			
5	PRODUCTION	22,696,215	-	22,696,215
6	TRANSMISSION	-	-	-
7	DISTRIBUTION	-	-	-
8	CUSTOMER ACCOUNTING	99,544	-	99,544
9	CUSTOMER SERVICE	(0)	-	(0)
10	SALES EXPENSE	-	-	-
11	ADMINISTRATIVE & GENERAL	-	-	-
12	DEPRECIATION	-	-	-
13	AMORTIZATIONS	-	-	-
14	TAXES OTHER THAN INCOME	-	-	-
15	FEDERAL INCOME TAX	-	-	-
16	STATE INCOME TAX	-	-	-
17	DEFERRED FEDERAL & STATE INCOME TAXES	-	-	-
18	INTEREST ON CUSTOMER DEPOSITS	-	-	-
19	TOTAL OPERATING EXPENSES	22,795,759	-	22,795,759
20	NET OPERATING INCOME	1,084,537	1,057,890	26,647

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SPECIAL CONTRACT REVENUE ADJUSTMENT - CUSTOMER 1
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 1.1
REDACTED
Table of Contents

Confidential Special Contract Rates
Effective March 1, 2021

[redacted]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2016
Meters	1	1	1	1	1	1	1	1	1	1	1	1	12
Customer Charge	[redacted]												
Customer Charge Revenue													
Monthly Fixed Charge for First 200,000 Therms or Less													
Therms - First Step													
Consumption Charge - First Step													
Excess (1) - For Gas Use between 200,000 and 300,000 Therms													
Therms - Excess (1)													
Consumption Charge - Excess (1)													
Consumption Charge Revenue - Excess (1)													
Excess (2) - For Gas Use between 300,000 and 400,000 Therms													
Therms - Excess (2)													
Consumption Charge - Excess (2)													
Consumption Charge Revenue - Excess (2)													
Excess (3) - For Gas Use Over 400,000 Therms													
Therms - Excess (3)													
Consumption Charge - Excess (3)													
Consumption Charge Revenue - Excess (3)													
2021 Proforma Revenue													
Less: 2020 Actual Revenue													
Net Revenue Adjustment													

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SPECIAL CONTRACT REVENUE ADJUSTMENT - CUSTOMER 2
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 1.2
REDACTED
Table of Contents

Confidential Special Contract Rates
Effective December 1, 2020

[redacted]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2016
Meters	1	1	1	1	1	1	1	1	1	1	1	1	12
Customer Charge	[redacted]												
Customer Charge Revenue													
Therms													
Consumption Charge													
Consumption Charge Revenue													
2021 Proforma Revenue													
Less: 2020 Actual Revenue													
Net Revenue Adjustment													

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
UNION PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.1
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	TOTAL
1	Payroll - Five Months Ended May 31, 2020	$ 1,902,372
2	2020 Salary & Wage Increase [1]	3.00%
3	Union Payroll Annualization	$ 57,071

Notes
(1) Average Union increase of 3% effective June 1, 2020

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
UNION AND NONUNION PAYROLL/COMPENSATION (1)
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.2
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LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Union Weekly Payroll (1)	$ 3,475,844
2	Total Nonunion Payroll (1)	946,912
3	Total Payroll (2)	4,422,757
4	Payroll Capitalization (3)	(2,058,097)
5	Test Year O&M Payroll	$ 2,364,660

Notes
(1) Payroll Allocation to Union and Non-Union based on ADP 2020 Year End Payroll Registers
(2) Includes Incentive Compensation at Target of $58,992
(3) Refer to Workpaper 2.3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PAYROLL SUMMARY
FOR COMPUTATION OF PAYROLL BENEFIT RELATED OVERHEADS

Workpaper 2.3
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) 2020 INCENTIVE COMP AT TARGET
1	O&M PAYROLL:	
2	OPERATIONS	1,325,952
3	MAINTENANCE	168,179
4	TOTAL O&M PAYROLL	1,494,131
5	CONSTRUCTION PAYROLL:	
6	DIRECT	687,402
7	INDIRECT	1,007,550
8	TOTAL CONSTRUCTION PAYROLL	1,694,952
9	OTHER PAYROLL:	
10	JOBBING	18,867
11	CLEARING ACCOUNTS	193,033
12	UNPRODUCTIVE TIME	165,091
13	MOBILE DATA SYSTEMS (MDS)	816,759
14	INCENTIVE COMPENSATION at TARGET	58,992
15	OTHER	23,646
16	TOTAL OTHER PAYROLL	1,276,387
17	TOTAL PAYROLL	4,465,470
18	O&M PAYROLL:	
19	OPERATIONS	1,325,952
20	MAINTENANCE	168,179
21	ALLOCATED CLEARING	54,513
22	ALLOCATED UNPRODUCTIVE	26,415
23	ALLOCATED MDS	780,163
24	ALLOCATED INCENTIVE COMPENSATION	9,439
25	TOTAL O&M PAYROLL	2,364,660
26	CONSTRUCTION PAYROLL:	
27	DIRECT	687,402
28	INDIRECT	1,007,550
29	ALLOCATED CLEARING	138,521
30	ALLOCATED UNPRODUCTIVE	138,676
31	ALLOCATED MDS	36,395
32	ALLOCATED INCENTIVE COMPENSATION	49,553
33	TOTAL CONSTRUCTION PAYROLL	2,058,097
34	TOTAL PAYROLL, NET OF OTHER PAYROLL	4,422,757
35	TOTAL OTHER PAYROLL:	
36	JOBBING	18,867
37	BELOW THE LINE MDS	201
38	OTHER	23,646
39	TOTAL OTHER PAYROLL	42,713
40	TOTAL PAYROLL, WITH INCENTIVE COMP ADJ TO TARGET	4,465,470

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PAYROLL - INCENTIVE COMPENSATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.4
Table of Contents

LINE NO.	(1) Description		(2) Amount
1	Northern Utilities, Inc. Payroll:		
2	Adjustment to reflect Incentive Compensation at Target		
3	Test Year Accrued Incentive Compensation		$ 58,992
4	Incentive Compensation at Target		58,992
5	Test Year Accounting Adjustment to reflect Incentive Compensation at Target		-
6	Capitalized Incentive Compensation at	84.00%	-
7	Test Year Incentive Comp Accounting Adjustment to O&M		-
8	USC Payroll, Allocated to Northern Utilities, Inc. - NH Division:		
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 NuNH In 2020	20.18%	688,571
12	Incentive Compensation at Target		688,571
13	Test Year Accounting Adjustment to reflect Incentive Compensation at Target		-
14	Capitalized Incentive Compensation at	32.52%	-
15	Test Year Incentive Comp Accounting Adjustment to O&M		-

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
MEDICAL AND DENTAL INSURANCE
FOR THE 12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.1
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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	5	11	-	$ 792.45	$ 1,090.53	$ 46.56	$ 45.21	$ 4,755	$ 5,453	$ 512	$ -	$ 10,720
2	Two Person	2	8	11	-	1,362.76	1,966.94	83.34	80.82	2,726	15,736	917	-	19,378
3	Family	9	9	20	-	1,849.91	2,714.18	147.21	141.43	16,649	24,428	2,944	-	44,021
4	Total	17	22	42	-					24,129	45,616	4,373	-	74,118
5	2021 Annual Cost Based on Employee Enrollments at December 31, 2020									289,553	547,389	52,477	-	889,420
6	Employee Contribution [3]									(57,911)	(109,478)	(10,495)	-	(177,884)
7	Net Cost									231,642	437,912	41,982	-	711,536
8	Plus: Company Contribution to HSA									14,000	-	-	-	14,000
9	Payments to Employees to Opt out									11,840	4,900	-	-	16,740
10	Total HSA and Opt out Payments									25,840	4,900	-	-	30,740
11	Proformed 2021 Medical Cost									257,482	442,812	41,982	-	742,276
12	Projected Increase in Premium Rates Effective January 1, 2022 [4]									21,913	39,853	1,679	-	63,446
13	Proformed 2021 and 2022 Medical and Dental Cost									279,396	482,665	43,661	-	805,721
14	Amount Chargeable to Capital [5]									(167,012)	(293,533)	(26,611)	-	(487,156)
15	Total Pro-formed Medical and Dental Insurance O&M Expense													318,565
16	Less Test Year O&M Expense [6]													182,055
17	Total O&M Medical & Dental Insurance Adjustment													$ 136,510

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: 48.76%
(6) Refer to Workpaper 3.2

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
MEDICAL INSURANCE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.2
Table of Contents

LINE NO.	(1) Description		(2) Amount
1	Medical Insurance Expense		$ 665,259
2	Benefits Cost Capitalized at	48.76%	(324,380)
3	Subtotal Medical Costs		340,879
4	Employee Contribution		(160,868)
5	Drug Subsidy		(10,252)
6	Subtotal		(171,121)
7	Net Test Year Medical Insurance Expense		169,758
8	Dental Insurance Expense		44,042
9	Benefits Cost Capitalized at	48.76%	(21,475)
10	Subtotal Dental Costs		22,567
11	Employee Contribution		(10,270)
12	Net Test Year Dental Costs		12,297
13	Net Test Year Medical & Dental Costs		$ 182,055

Workpaper 3.3
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NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
MEDICAL AND DENTAL INSURANCE - UNITIL SERVICE CORP
FOR THE 12 MONTHS ENDED DECEMBER 31, 2020

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 NuNH at 20.18%									715,134	9,342	49,999	32,745	807,221
13	Amount Chargeable to Capital at 31.51%									(225,339)	(2,944)	(15,755)	(10,318)	(254,355)
14	Total Pro-formed Medical and Dental Insurance O&M Expense													552,866
15	Less Test Year O&M Expense [5]													284,783
16	Total O&M Medical & Dental Insurance Adjustment													$ 268,083

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
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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	NuNH Apportionment at	19.85%	19.85%	19.85%
6	Expense Apportioned to NuNH	367,243	48,559	415,802
7	Capitalization Rate at	31.51%	31.51%	31.51%
8	NuNH Capitalization	(115,718)	(15,301)	(131,019)
9	Net USC Test Year Medical & Dental Costs Allocated to NuNH	$ 251,525	$ 33,258	$ 284,783

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PENSION EXPENSE
2020 ACTUAL EXPENSE RECORDED AND 2021 FORECAST EXPENSE

Workpaper 4.1
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	2020 TEST YEAR	2021 FORECAST EXPENSE	PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to NU-NH	19.85%	19.85%	
A2	NU-NH Capitalization Rates	48.76%	48.76%	
A3	USC Labor & Overhead to Construction	31.51%	31.51%	
A4	Total USC Pension Expense	$ 3,032,609	$ 3,232,617	
	Calculation of Pension Expense, net of Amounts Chargeable to Construction			
	A. NU-NH Pension Expense, net:			
1	NU-NH Pension Expense	$ 546,677	$ 489,345	$ (57,332)
2	Less: Amounts Chargeable to Construction	(266,560)	(238,605)	27,955
3	NU-NH Pension Expense, net	$ 280,117	$ 250,740	$ (29,377)
	B. Unitil Service Pension Expense Allocated to NU-NH, net:			
4	Unitil Service Pension Expense	$ 601,973	$ 641,674	$ 39,702
5	Less: Amounts Chargeable to Construction	(189,682)	(202,192)	(12,510)
6	Total Unitil Service Pension Expense Allocated to NU-NH, net	$ 412,291	$ 439,483	$ 27,192
7	Total NU-NH Pension Expense	$ 692,409	$ 690,223	$ (2,185)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PBOP EXPENSE
2020 ACTUAL EXPENSE RECORDED AND 2021 FORECAST EXPENSE

Workpaper 4.2
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LINE NO.	(1) DESCRIPTION	(2) 2020 TEST YEAR	(3) 2021 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to NU-NH	19.85%	19.85%	
A2	NU-NH Capitalization Rates	48.76%	48.76%	
A3	USC Labor & Overhead to Construction	31.51%	31.51%	
A4	Total USC PBOP Expense	$ 1,510,206	$ 1,358,914	
	Calculation of PBOP Expense, net of Amounts Chargeable to Construction			
	A. NU-NH PBOP Expense, net:			
1	NU-NH PBOP Expense	$ 397,889	$ 399,488	$ 1,599
2	Less: Amounts Chargeable to Construction	(194,011)	(194,790)	(780)
3	NU-NH PBOP Expense, net	$ 203,878	$ 204,698	$ 819
	B. Unitil Service PBOP Expense Allocated to NU-NH, net:			
4	Unitil Service PBOP Expense	$ 299,776	$ 269,744	$ (30,031)
5	Less: Amounts Chargeable to Construction	(94,459)	(84,996)	9,463
6	Total Unitil Service PBOP Expense Allocated to NU-NH, net	$ 205,317	$ 184,748	$ (20,569)
7	Total NU-NH PBOP Expense	$ 409,195	$ 389,446	$ (19,749)

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
SERP EXPENSE
2020 ACTUAL EXPENSE RECORDED AND 2021 FORECAST EXPENSE

Workpaper 4.3
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	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	2020 TEST YEAR	2021 FORECAST EXPENSE	PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to NU-NH	19.85%	19.85%	
A2	NU-NH Capitalization Rates	48.76%	48.76%	
A3	USC Labor & Overhead to Construction	31.51%	31.51%	
A4	Total USC SERP Expense	$ 1,924,767	$ 2,357,253	
	Calculation of SERP Expense, net of Amounts Chargeable to Construction			
	A. NU-NH SERP Expense, net:			
1	NU-NH SERP Expense	$ -	$ -	$ -
2	Less: Amounts Chargeable to Construction	-	-	-
3	NU-NH SERP Expense, net	$ -	$ -	$ -
	B. Unitil Service SERP Expense Allocated to NU-NH, net:			
4	Unitil Service SERP Expense	$ 382,066	$ 467,915	$ 85,848
5	Less: Amounts Chargeable to Construction	(120,389)	(147,440)	(27,051)
6	Total Unitil Service SERP Expense Allocated to NU-NH, net	$ 261,677	$ 320,475	$ 58,798
7	Total NU-NH SERP Expense	$ 261,677	$ 320,475	$ 58,798

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
401(K) EXPENSE
2020 ACTUAL EXPENSE RECORDED AND 2021 FORECAST EXPENSE

Workpaper 4.4
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LINE NO.	(1) DESCRIPTION	(2) 2020 TEST YEAR	(3) 2017 & 2018 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to NU-NH	19.85%	19.85%	
A2	NU-NH Capitalization Rates	48.76%	48.76%	
A3	USC Labor & Overhead to Construction	31.51%	31.51%	
A4	Total USC 401k Expense (1)	$ 1,994,120	$ 2,081,861	
	Calculation of 401k Expense, net of amounts chargeable to construction			
	A. Northern 401k Expense, net:			
1	Northern-401k Expense 2021 Proformed (2)	$ 181,223	$ 186,714	$ 5,491
2	NU-NH 401(k) Expense Adjusted for 2022 Wage Increase(2)	-	5,657	5,657
3	Total NU-NH 401(k) Expense - Proformed	181,223	192,371	11,148
4	Less: Amounts Chargeable to Construction	(88,364)	(93,800)	(5,436)
5	Northern 401k Expense, net	$ 92,859	$ 98,571	$ 5,712
	B. Unitil Service 401k Expense Allocated to Northern, net:			
6	Unitil Service 401K Expense 2021 Proformed	$ 395,833	$ 413,250	$ 17,417
7	Unitil Service 401K Adjusted for 2022 Wage Increase (1)	-	18,183	18,183
8	Total USC 401(k) Expense - Proformed	395,833	431,432	35,600
9	Less: Amounts Chargeable to Construction	(124,727)	(135,944)	(11,217)
10	Unitil Service 401k Expense Allocated to Northern, net	271,106	295,488	24,382
11	Total Northern 401k Expense	$ 363,965	$ 394,059	$ 30,095

Notes
(1) Unitil Service Corp. - Average 2020/2021 Payroll Increase of 4.40%
(2) See Workpaper 3.5

Workpaper 4.5
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401K ADJUSTMENT
2020 & 2021 WEIGHTED AVERAGE PAY INCREASE

	(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	$ 946,912	3.12%	0.66%	3.12%	0.66%
2	Union	3,532,915	3.00%	2.37%	3.00%	2.37%
3	Total	$ 4,479,827		3.03%		3.03%

Notes
(1) Refer to Schedule RevReq-3-4, Page 1 of 2 for 2021 Payroll Increases
(2) Refer to Schedule RevReq-3-4, Page 1 of 2 for 2022 Payroll Increase

Workpaper 4.6
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DEFERRED COMPENSATION PLAN EXPENSE
2020 ACTUAL EXPENSE RECORDED AND 2021 & 2022 FORECAST EXPENSE

Line No.	(1) Description	(2) 2020 TEST YEAR	(3) 2021 & 2022 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to NU-NH	19.85%	19.85%	
A2	NU-NH Capitalization Rates	48.76%	48.76%	
A3	USC Labor & Overhead to Construction	31.51%	31.51%	
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. NU-NH Deferred Compensation Expense, net:			
1	NU-NH Deferred Comp Expense 2021 Proformed	$ -	$ -	$ -
2	NU-NH Deferred Comp Expense adjusted for 2022 wage increase	-	-	-
3	Total NU-NH Deferred Comp Expense - Proformed	-	-	-
4	Less: Amounts chargeable to capital	-	-	-
5	Total NU-NH Deferred Comp Expense, net	$ -	$ -	$ -
	B. Unitil Service Deferred Comp Expense allocated to NU-NH, net:			
6	Unitil Service 2020 Deferred Comp. Expense	$ 36,951	$ 280,214	$ 243,263
7	Unitil Service Deferred Comp Expense Allocated to NU-NH	7,335	55,622	48,287
8	Unitil Service Deferred Incentive Compensation Expense	24,109	95,220	71,111
9	Unitil Service Deferred Incentive Compensation Expense Allocated to NU-NH	4,786	18,901	14,115
10	Unitil Service Deferred Comp. Adjusted for 2021 Wage Increase (1)	-	2,447	2,447
11	Total Unitil Service Deferred Comp Expense Allocated to NU-NH - Proformed	12,121	76,970	64,849
12	Less: Amounts Chargeable to Construction	(3,819)	(24,253)	(20,434)
13	Unitil Service Deferred Comp Expense Allocated to NU-NH, net	$ 8,302	$ 52,717	$ 44,415
14	Total NU-NH Deferred Comp Expense	$ 8,302	$ 52,717	$ 44,415

Notes
(1) Unitil Service Corp - Estimated 2020 Average Payroll Increase of 4.40%

Workpaper 5.1
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PROPERTY AND LIABILITY INSURANCES ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	DESCRIPTION	AMOUNT [1]
	Current Coverage Periods	
	Property:	
1	All Risk	$ 18,989
2	Crime	3,256
3	K&E	285
4	Total Property	$ 22,531
	Liability:	
5	Workers' Compensation	$ 53,618
6	Excess	355,650
7	Cyber	17,698
8	Automobile	43,038
9	Directors & Officers	74,021
10	Fiduciary	5,044
11	Total Liability	$ 549,069
12	Total NuNH Property & Liability Insurances	571,600
13	Less: Amounts Chargeable to Capital	282,502
14	Amount to O&M Expense	289,097
15	Less Test Year O&M Expense	241,873
16	O&M Property and Liability Insurance Increase	$ 47,224

Notes
(1) Refer to Workpaper 5.3

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
PROPERTY AND LIABILITY INSURANCES ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.2
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LINE NO.	DESCRIPTION	UNITIL SERVICE CORP. TOTAL (1)	AMOUNT TO NuNH (2)	NuNH TOTAL
1	USC Cost For Current Coverage Periods			
2	Property:			
3	All Risk	$ 6,952		$ 1,403
4	Crime	968		195
5	K&E	124		25
6	Total Property	$ 8,044	20.18%	$ 1,623
7	Liability:			
8	Workers' Compensation	$ 62,142		$ 12,540
9	Excess	113,172		22,838
10	Automobile	8,799		1,776
11	Directors and Officers	23,554		4,753
12	Cyber	5,898		1,190
13	Fiduciary	1,605		324
14	Total Liability	$ 215,170	20.18%	$ 43,421
15	Total USC Property & Liability Insurances			45,045
16	Less Amount Chargeable to Capital		31.51%	14,194
17	Total Property & Liability Insurances to O&M Expense			30,851
18	Less Test Year O&M Expense (3)			17,377
19	O&M Property and Liability Insurance Increase			$ 13,475

Notes
(1) Refer to Workpaper 5.3
(2) Refer to Workpaper 5.1
(2) Refer to Workpaper 5.4

Casualty & Property Insurance

Workpaper 5.3
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		CASUALTY												PROPERTY				
		AL (prem)	NH-WC (prem)	XL* (prem)	XL (brkr) (2)	XL Surplus Tax	Cyber (prem)	FL (prem)	D&O (prem)	D&O Surplus Tax	D&O (brkr) (2)	D&O Side A	CASUALTY TOTAL	ARP (prem)	CRIME (prem)	K&E (prem)	TOTAL PROP	TOTAL
NuNH	2018a	26,696	90,284	239,335	7,351	7,180	8,376	3,481	34,907	1,047	4,420	-	423,077	10,171	1,468	255	11,894	434,971
	2019a	29,196	84,634	273,415	8,843	8,202	8,399	3,876	35,820	1,093	4,544	-	458,024	8,778	1,503	266	10,547	468,571
	2020a	33,155	66,093	285,336	13,321	8,560	10,467	3,876	42,690	1,281	-	-	464,779	12,588	1,520	266	14,373	479,152
	2021a	40,175	50,051	309,521	13,184	9,286	17,698	4,709	51,976	1,559	-	15,561	513,720	17,726	3,039	266	21,032	534,752
	2022e (1)	43,038	53,618	331,579	14,124	9,947		5,044	55,680	1,670	-	16,670	549,069	18,989	3,256	285	22,531	571,600
	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
USC	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	9,206	65,019	110,396	4,702	3,312	5,898	1,679	18,538	556	-	5,550	224,857	7,274	1,013	130	8,416	233,273
	2022e (1)	8,799	62,142	105,512	4,494	3,165		1,605	17,718	532	-	5,305	215,170	6,952	968	124	8,044	223,214

Notes

(1) Estimated 2022 premiums reflect annual growth rate from 2018 to 2021. All 2022 policies, except for Cyber will updated with actuals during pendency of case

(2) In 2020 the Company changed brokers and now the D&O broker fee is included in the XL broker fee

UNITIL SERVICE CORP.
PROPERTY & LIABILITY INSURANCE TEST YEAR COSTS
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.4
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LINE NO.	DESCRIPTION	TOTAL
	USC O&M Test Year	
1	12-30-08-00-9240100 PROPERTY INSURANCE	$ 5,519
2	12-30-08-00-9250100 INJURIES & DAMAGES	120,204
3	Total	$ 125,723
4	NuNH Apportionment	20.18%
5	NuNH Amount	$ 25,371
6	Capitalization Rate	31.51%
7	Capitalization Amount	$ 7,994
8	O&M Expense Amount	17,377

NuNH - OPERATING FACILITY
COMPUTATION OF BUILDING OVERHEAD
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.5
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SQUARE FOOTAGE OF SERVICE CENTER UPDATED: DESCRIPTION	SQ FT	Dec-20 %	ALLOCATION OF SERVICE CENTER OVERHEADS
SERVICE CENTER ALLOCATED:			
General Area Capitalized (184.00.00)	13,864	54.51%	6,384
Ratio of Payroll Capitalized			48.76%
General Area Capitalized (184.00.01)			3,113
Stock Area Capitalized (163.00.00)	5,741	22.57%	2,643
Ratio of Stock Capitalized			90.00%
Stock Area Capitalized			2,379
Garage Area Capitalized:			
Auto-184.01.00	-	0.00%	-
Light Truck-184.02.00	-	0.00%	-
Heavy Truck-184.03.00	-	0.00%	-
Sub-Total Garage Area	-	0.00%	-
Ratio of Garage Area Capitalized			48.76%
Garage Area Capitalized			-
Total Service Center to DOC	19,605	77.09%	5,492
Non-DOC Space:			
Exclude: USC & Usource	5,827	22.91%	2,683
Ratio of Non-DOC Space Capitalized			0.00%
Non-DOC Space Capitalized			-
TOTAL SERVICE CENTER	25,432	100.00%	5,492

(b) DETERMINATION OF SERVICE CENTER PROPERTY INSURANCE:

BUDGETED ALL RISK PROPERTY INSURANCE	11,723
RATIO OF SERVICE CENTER TO TOTAL PROPERTY	99.89%
TOTAL SERVICE CENTER PROPERTY INSURANCE	11,710
Service Center Property Insurance Capitalization Ratio	46.90%

	Asset 1000c or Asset 1020		
	SERVICE CENTER	ALL STRUCTURE	SERVICE RATIO
GAS STRUCTURES - DIST. ACCT. 375.20	39,504	45,256	
STRUCTURES-OTHER DIST SYS 375.70	3,128,853	3,128,853	
GENERAL PLANT - (TOTAL LESS COMMUN. EQ)	1,923,719	1,923,719	
(ACCT. 391,393,394,395,396,398)	-	-	
TOTAL COST	5,092,075	5,097,827	99.89%

VEHICLE CLEARING ACCOUNT
TOTAL CHARGES & TOTAL CLEARINGS TO EXPENSE & CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.6
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Total Clearings from Clearing Account:

	Expense	Capital	NuNH Total GL	Total Sch 12	Variance
Jan-20	28,022	47,758	75,780	75,780	-
Feb-20	29,141	31,696	60,837	60,837	-
Mar-20	29,755	29,979	59,735	59,735	-
Apr-20	26,484	25,236	51,719	51,719	-
May-20	30,248	31,224	61,473	61,473	-
Jun-20	36,093	51,333	87,427	87,427	-
Jul-20	23,989	40,521	64,510	64,510	-
Aug-20	20,998	29,112	50,111	50,111	-
Sep-20	25,188	32,644	57,832	57,832	-
Oct-20	83,045	146,259	229,304	229,304	-
Nov-20	1,576	4,394	5,970	5,970	-
Dec-20	1,505	4,908	6,413	6,413	-
	336,045	475,064	811,109	811,109	
Capitalization Rate		58.57%			

VEHICLE CLEARING ACCOUNT
AUTO LIABILITY INSURANCE

Auto Liability Insurance Payments into Clearing Account [1]

Jan-20	3,316
Feb-20	3,316
Mar-20	3,316
Apr-20	3,316
May-20	3,316
Jun-20	3,316
Jul-20	3,316
Aug-20	
Sep-20	
Oct-20	
Nov-20	8,035
Dec-20	4,018
Total	35,261

(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

	NuNH
Gross Amount	35,261
Cap. Rates	58.57%
Cap. Amount	20,652
O&M Amount	14,609

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 6.1
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Source: Energy Information Administration
Short-Term Energy Outlook
Publication Date: June 8, 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 2009 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	18,328	18,637	18,825	18,714	18,791	18,878
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	-4.1	-2.6	-1.9	-2.9	-2.5	-1.8
GDP Implicit Price Deflator (Index, 2005=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	113.6	113.9	114.1	114.1	114.4	114.7
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	1.0	1.1	1.2	1.1	1.2	1.4
Real Disposable Personal Income (billion chained 2005 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	16,204	15,636	15,715	15,574	15,349	15,378
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	9.2	4.9	5.2	4.3	2.3	2.8
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	100.7	100.6	102.1	103.1	104.0
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	-5.4	-4.7	-2.8	-2.8	-2.2
Weather																								
U.S. Heating Degree-Days	859	719	632	288	158	34	5	10	41	254	589	715	739	652	483	359	156	25	5	7	58	247	421	749
U.S. Cooling Degree-Days	9	18	18	42	130	227	373	336	243	75	16	14	15	13	43	43	105	247	398	357	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 2009 dollars - SAAR)	18,976	19,084	19,203	19,375	19,505	19,629	19,728	19,848	19,971	20,128	20,237	20,329	20,389	20,454	20,512	20,560	20,603	20,639	20,660	20,689	20,718	20,744	20,773	20,803
Percent change from prior year	-1.7	0.1	2.9	11.2	13.5	13.5	7.6	6.5	6.1	7.6	7.7	7.7	7.4	7.2	6.8	6.1	5.6	5.1	4.7	4.2	3.7	3.1	2.6	2.3
GDP Implicit Price Deflator (Index, 2005=100)	115.1	115.5	116.0	116.2	116.5	116.7	116.9	117.0	117.2	117.4	117.5	117.7	117.8	118.0	118.2	118.4	118.6	118.8	119.0	119.2	119.4	119.6	119.8	120.0
Percent change from prior year	1.5	1.9	2.4	3	3.3	3.3	2.9	2.8	2.7	2.8	2.7	2.6	2.4	2.1	1.8	1.9	1.8	1.8	1.8	1.8	1.9	1.9	2	2
Real Disposable Personal Income (billion chained 2005 dollars - SAAR)	17,114	15,725	19,336	16,406	16,100	15,908	15,969	15,895	15,829	15,726	15,706	15,724	15,843	15,894	15,939	15,971	16,006	16,038	16,070	16,096	16,117	16,121	16,143	16,170
Percent change from prior year	13.6	3.7	29.3	-5.1	-2.1	-1.5	-1.5	1.7	0.7	1	2.3	2.3	-7.4	1.1	-17.6	-2.6	-0.6	0.8	0.6	1.3	1.8	2.5	2.8	2.8
Manufacturing Production Index (Index, 2012=100)	105.2	100.9	104.2	104.6	104.8	105.5	106.2	107.0	107.8	109.0	109.8	110.4	110.9	111.4	111.8	112.1	112.4	112.6	112.6	112.7	112.8	112.9	113.0	113.1
Percent change from prior year	-0.9	-4.9	3.3	23.3	19	11	7.2	6.3	7.1	6.8	6.4	6.2	5.4	10.4	7.3	7.2	7.2	6.7	6	5.4	4.6	3.6	2.9	2.4
Weather																								
U.S. Heating Degree-Days	802	791	505	305	147	28	7	10	55	243	490	777	848	685	558	312	137	30	7	11	55	243	490	777
U.S. Cooling Degree-Days	10	12	28	37	116	244	355	331	184	67	22	11	11	12	23	41	124	243	353	326	184	67	22	11

Notes: Prices are not adjusted for inflation.
The approximate break between historical and forecast values is shown with estimates and forecasts in italics.
Historical data: Latest data available from Energy Information Administration databases supporting the following reports: Petroleum Supply Monthly , DOE/EIA-0109;
Petroleum Supply Annual , DOE/EIA-0340/2; Weekly Petroleum Status Report , DOE/EIA-0208; Petroleum Marketing Monthly , DOE/EIA-0380; Natural Gas Monthly , DOE/EIA-0130;
Electric Power Monthly , DOE/EIA-0226; Quarterly Coal Report , DOE/EIA-0121; and International Petroleum Monthly , DOE/EIA-0520.
Minor discrepancies with published historical data are due to independent rounding.
Projections: EIA Regional Short-Term Energy Model. Macroeconomic projections are based on Global Insight Model of the U.S. Economy.
Weather projections from National Oceanic and Atmospheric Administration.

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
INFLATION ADJUSTMENT - TEST YEAR USC AMORTIZATIONS
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 6.2
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LINE NO.	(1) DESCRIPTION	(2) 2020
1	12-30-10-00-404-03-00 SOFTWARE AMORT - OTHER	$ 343,313
2	12-30-10-00-404-04-00 FINANCIAL REPORT WRITER AMORTIZATION	7,350
3	12-30-10-00-404-23-00 POWER TAX SYSTEM AMORT	30,284
4	12-30-10-00-404-25-00 AMORTIZATION - PAYMENT SYSTEM	1,492
5	Total	$ 382,438
6	NuNH Allocation	19.85%
7	Amount Billed to NuNH	75,914

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
INFLATION ADJUSTMENT - TEST YEAR FACILITY LEASES
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 6.3
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) 2020
1	12-30-10-00-9310100 BUILDING RENT	$	1,252,284
2	12-30-10-00-9310700 CALL CENTER RENT		158,796
3	12-30-10-00-9310800 PORTSMOUTH RENT EXPENSE		203,988
4	Total	$	1,615,068
5	NuNH Allocation		19.85%
6	Amount Billed to NuNH		320,591

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
TEST YEAR AMORTIZATION EXPENSE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 7.1
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LINE NO.	(1) DESCRIPTION	(2) BEGINNING UNAMORTIZED BALANCE 2020(1)	(3) 2020 AMORTIZATION EXPENSE	(4) ENDING UNAMORTIZED BALANCE 2020
1	Northern Utilities 303-Intangible Plant:			
2	Power Plant	$ 36,832	$ 15,785	$ 21,047
3	Power Plan Upgrade	15,843	4,045	11,798
4	Meter Data Management	1,093,248	138,095	955,154
5	2019 Voice System Repl	239,694	23,321	214,318
6	2019 Interface Enhancements	13,177	1,355	11,706
7	Customer Facing Enhancements	232,484	23,543	207,039
8	CIS Billing Integration	202,420	69,401	133,018
9	2014 Infrastructure	586	586	-
10	2014 Desktop Client Mgmt	76	76	-
11	2014 Enhance Critical Financial	769	769	-
12	2014 CMS Rewrite	1,113	1,113	-
13	Gen Software enhancements	160	160	-
14	2014 EETS Enhancements	58	58	-
15	Gas Construction Estimating Model	4,875	4,875	-
16	Electronic Large Vol. Meter Form	1,868	1,868	-
17	2014 AMI/SCADA Cyber Project	3,235	3,235	-
18	AMI Vers Updt PLX Functionality	1,837	1,837	-
19	Milsoft IVR Upgrade	186	186	-
20	2015 Infrastructure	6,105	4,884	1,221
21	SalesForce App for Gas Sales	12,609	7,964	4,645
22	First Responder - iRestore	26,280	13,140	13,140
23	General Software Enhancements	2,792	1,289	1,503
24	2016 IT Infrastructure	15,367	6,830	8,537
25	Gas Inspections	5,264	2,339	2,924
26	CMS 2015 Rewrite	7,397	3,288	4,110
27	2015 Cyber Security Enhancements	99	44	55
28	2016 Cyber Security Enhancements	144	64	80
29	Unify Workforce Management System	4,046	1,798	2,248
30	2016 General Software Enhancements	2,274	1,011	1,264
31	Verotrack Upgrade to myWorld	8,985	3,267	5,718
32	Itron MVRS Upgrade	1,262	459	803
33	New Century Dist Risk Alg. Upgrade	5,340	1,942	3,398
34	EETS Enhancements	11,139	3,819	7,320
35	CMS NH/ME Isolation	1,410	484	927
36	Power Plant Upgrade 2016.1	37,818	12,966	24,852
37	LocusView GPS/GIS Track & Trace	75,602	23,262	52,340
38	2017 Cyber Security Enhancements	1,291	387	903
39	2017 IT Infrastructure	5,831	1,749	4,081
40	SalesForce for Gas Sales Phase II	31,670	9,269	22,401
41	Electronic Time Sheet - Phase One	3,504	978	2,526
42	2017 General Software Enhancements	6,778	1,891	4,886
43	UPC/GEM Enhancements	11,339	3,164	8,175
44	Upgrade to MyWorld Insepction	9,754	2,601	7,153
45	Meter Data Archiving Plan	1,566	408	1,157
46	Sales Force Application	12,770	3,331	9,438
47	OMS Web Page Upgrade	3,103	760	2,343
48	Power Plan License Update	45,014	11,024	33,990
49	GIS Version Upgrade	44,529	10,477	34,052
50	IS Project Tracker Replacement	4,233	996	3,237
51	Comp Mgmt Sys Enhncmnts	27,228	6,407	20,821
52	Legacy Interface Job Rewrite	2,337	550	1,787
53	Gen. Software Enhancements 2018	11,362	2,673	8,689
54	TESS Replacement	3,716	874	2,842
55	Salesforce App for Gas Sales	13,714	3,227	10,487
56	UPS Reporting	558	131	427
57	2018 IT Infrastructure	24,422	5,529	18,892
58	WebOps Replacement - Year 1 of 3	11,750	2,564	9,186
59	2018 Cyber Security Enhancements	3,787	826	2,961
60	DEV Staging Refresh	5,309	1,098	4,211
61	Microsoft Exchange Upgrade	2,425	502	1,923
62	Electronic Timesheet - Phase 2	13,540	2,801	10,738
63	CMS Data Reports	1,616	334	1,282
64	ODI Plant Records - GIS Recon	2,323	481	1,843
65	Metersense Upgrade 4.2 to 4.3	267	55	212
66	FCS Upgrade	770	155	615
67	FCS Upgrade	451	75	376
68	FCS Upgrade	9,038	847	8,191
69	MARS/GEM Enhancements	25,798	2,150	23,648
70	General Software Enchancements 2019	11,825	2,209	9,476
71	WebOps Replacement	13,547	2,408	10,948
72	2019 Reporting Blanket	22,028	1,836	20,193
73	Infrastructure PC & Network 2019	196,345	39,585	154,000
74	2019 Regulatory Work Blanket	5,608	467	5,140
75	LocusView Mobile Data Collections	10,880	907	9,973
76	Compliancy Mgmt Sys Enhancements	17,992	3,246	14,625
77	GIS Enhancements	3,998	333	3,665
78	Gas SCADA-Historical Database	5,219	435	4,784
79	Metersense Upgrade 2020	6,725	112	6,613
80	Power Plan Upgrade	68,580	1,143	67,437
81	Cyber Security Enhancements	21,917	365	21,552
82	2020 IT Infrastructure Budget	301,181	5,020	296,162
83	2020 Customer Facing Enhancements	138,605	2,310	136,295
84	2020 Interface Enhancements	29,156	486	28,670
85	2020 General Software Enhancements	829	14	815
86	Reporting Blanket	26,585	443	26,142
87	Pipeline Compliance Syst. Integ.	71,157	1,186	69,971
88	EE Tracking & Reporting System	36,085	601	35,483
89	MV-90xi Upgrade v 4.5 to 6.0	9,579	160	9,419
90	MV-90 Comm Bank Module	3,327	577	2,715
91	Salesforce Gas Sales Reporting	15,123	252	14,871
92	LocusView Paperless Work Flows	26,180	436	25,744
93	Total NuNH Amortization Expense for Account 303	$ 3,456,660	$ 522,006	$ 2,927,332

NOTES
(1) Projects Installed in 2020 Reflect Total Project Cost

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE YEAR AMORTIZATION EXPENSE

Workpaper 7.2
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LINE NO.	(1) DESCRIPTION	(2) TOTAL PROJECT COST	(3) ANNUAL AMORTIZATION EXPENSE
1	Northern Utilities 303-Intangible Plant:		
2	Power Plant	$ 157,853	$ 15,785
3	Power Plan Upgrade	40,449	4,045
4	Meter Data Management	1,380,945	138,095
5	2019 Voice System Repl	239,694	24,036
6	2019 Interface Enhancements	13,177	1,313
7	Customer Facing Enhancements	232,484	23,219
8	CIS Billing Integration	902,212	69,401
9	2015 Infrastructure	24,419	4,884
10	SalesForce App for Gas Sales	39,818	7,964
11	First Responder - iRestore	65,700	13,140
12	General Software Enhancements	6,443	1,289
13	2016 IT Infrastructure	34,149	6,830
14	Gas Inspections	11,697	2,340
15	CMS 2015 Rewrite	16,438	3,288
16	2015 Cyber Security Enhancements	220	44
17	2016 Cyber Security Enhancements	321	64
18	Unify Workforce Management System	8,991	1,798
19	2016 General Software Enhancements	5,054	1,011
20	Verotrack Upgrade to myWorld	16,336	3,267
21	Itron MVRS Upgrade	2,295	459
22	New Century Dist Risk Alg. Upgrade	9,709	1,942
23	EETS Enhancements	19,095	3,819
24	CMS NH/ME Isolation	2,418	484
25	Power Plant Upgrade 2016.1	64,831	12,966
26	LocusView GPS/GIS Track & Trace	116,310	23,262
27	2017 Cyber Security Enhancements	1,936	387
28	2017 IT Infrastructure	8,746	1,749
29	SalesForce for Gas Sales Phase II	46,347	9,269
30	Electronic Time Sheet - Phase One	4,890	978
31	2017 General Software Enhancements	9,457	1,891
32	UPC/GEM Enhancements	15,822	3,164
33	Upgrade to MyWorld Insepction	13,005	2,601
34	Meter Data Archiving Plan	2,042	408
35	Sales Force Application	16,656	3,331
36	OMS Web Page Upgrade	3,800	760
37	Power Plan License Update	55,120	11,024
38	GIS Version Upgrade	52,387	10,477
39	IS Project Tracker Replacement	4,980	996
40	Comp Mgmt Sys Enhncmnts	31,938	6,407
41	Legacy Interface Job Rewrite	2,749	550
42	Gen. Software Enhancements 2018	13,313	2,673
43	TESS Replacement	4,372	874
44	Salesforce App for Gas Sales	16,134	3,227
45	UPS Reporting	657	131
46	2018 IT Infrastructure	27,627	5,529
47	WebOps Replacement - Year 1 of 3	12,818	2,564
48	2018 Cyber Security Enhancements	4,131	826
49	DEV Staging Refresh	5,492	1,098
50	Microsoft Exchange Upgrade	2,508	502
51	Electronic Timesheet - Phase 2	14,006	2,801
52	CMS Data Reports	1,672	334
53	ODI Plant Records - GIS Recon	2,403	481
54	Metersense Upgrade 4.2 to 4.3	277	55
55	FCS Upgrade	779	157
56	FCS Upgrade	451	90
57	FCS Upgrade	9,038	1,927
58	MARS/GEM Enhancements	25,798	5,160
59	General Software Enchancements 2019	11,825	2,230
60	WebOps Replacement	13,547	2,479
61	2019 Reporting Blanket	22,028	4,406
62	Infrastructure PC & Network 2019	196,345	39,319
63	2019 Regulatory Work Blanket	5,608	1,122
64	LocusView Mobile Data Collections	10,880	2,176
65	Compliancy Mgmt Sys Enhancements	17,992	3,510
66	GIS Enhancements	3,998	800
67	Gas SCADA-Historical Database	5,219	1,044
68	Metersense Upgrade 2020	6,725	1,345
69	Power Plan Upgrade	68,580	14,205
70	Cyber Security Enhancements	21,917	4,383
71	2020 IT Infrastructure Budget	301,181	63,804
72	2020 Customer Facing Enhancements	138,605	28,287
73	2020 Interface Enhancements	29,156	5,831
74	2020 General Software Enhancements	829	166
75	Reporting Blanket	26,585	5,317
76	Pipeline Compliance Syst. Integ.	71,157	14,231
77	EE Tracking & Reporting System	36,085	7,217
78	MV-90xi Upgrade v 4.5 to 6.0	9,579	1,916
79	MV-90 Comm Bank Module	3,327	639
80	Salesforce Gas Sales Reporting	15,123	3,024
81	LocusView Paperless Work Flows	26,180	5,236
82	FCS Upgrade	1,041	174
83	2020 IT Infrastructure Budget	19,607	3,268
84	2020 Customer Facing Enhancements	25,018	4,170
85	2020 Interface Enhancements	1,800	300
86	2020 General Software Enhancements	874	146
87	Reporting Blanket	7,763	1,294
88	Power Plan Upgrade	1,840	307
89	Total NuNH Amortization Expense for Account 303	$ 4,922,826	$ 669,511

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
TEST YEAR USC AMORTIZATION EXPENSE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 7.3
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LINE NO.	(1) DESCRIPTION	(2) BEGINNING UNAMORTIZED BALANCE 2020[(1)]	(3) 2020 AMORTIZATION EXPENSE	(4) 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	NuNH Apportionment		20.18%	
20	Total Billed to NuNH		77,176	

NOTES
(1) Projects Installed in 2020 Reflect Total Project Cost

NORTHERN UTILITIES, INC. - NEW HAMPSHIRE
RATE YEAR USC AMORTIZATION EXPENSE

Workpaper 7.4
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LINE NO.	(1) DESCRIPTION	(2) TOTAL PROJECT COST	(3) 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	NuNH Apportionment		20.18%
20	Total Billed to NuNH		118,959

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

JOHN F. CLOSSON

and

JOSEPH F. CONNEELY

EXHIBIT JCJC-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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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"), including Northern Utilities, Inc.'s New Hampshire division ("Northern" or the "Company"). 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.'s 2016 rate filing.

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

A. I am the Director of Human Resources 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 Compensation Expense.

III. COMPENSATION PROGRAM

Q. What is 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 its 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 Northern 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, Unitil Corporation 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 industry peers. 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 continue 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 has implemented recommendations from Towers Watson 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 Northern effective September 6, 2020. The contract is set to expire on June 7, 2025.

IV. PAYROLL AND RELATED TAXES

Q. **What adjustment was made to payroll?**

A. The payroll adjustment, as reflected on Schedule RevReq 3-4, 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 occurred 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 Northern and Unitil Service.

Q. Please describe the adjustment to Northern's payroll.

A. The payroll adjustment to Northern's test year payroll is shown on Schedule RevReq 3-4, 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 6, 2017.

The wage increases for non-union employees take effect on January 1 each year. On January 1, 2021, the average annual increase was 3.12 percent. For January 1, 2022, the average annual increase for nonunion employees is projected to be the same, 3.12 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 Northern pro forma payroll adjustments for both union and nonunion employees is an increase in O&M of $170,226. See Schedule RevReq 3-4, 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 3-4, pages 1 and 2. The adjustment to the Unitil Service payroll was prepared in a similar manner as the adjustment to Northern'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 Northern 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 Northern is an increase in O&M of $384,216. See Schedule RevReq 3-4, 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 3-4, 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 $554,442 as reflected on Schedule RevReq 3-4, page 1, column 6, line 13.

Q. Have you prepared a payroll tax adjustment?

A. Yes, as shown on Schedule RevReq 3-20, page 1, 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, page 1. The total O&M payroll increase of $554,442 as shown on Schedule RevReq-3-4, page 1, column 6, line 11 was multiplied by the Social Security rate of 6.2 percent, deriving the additional Social Security tax amount of $34,375. To determine the additional Medicare tax, the total O&M payroll increase of $554,442 was multiplied by the Medicare tax rate of 1.45 percent, deriving the additional Medicare tax amount of $8,039. The total of additional Social Security and Medicare taxes is $42,415.

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-3-21, page 2, an adjustment of $95,258 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 Northern 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 3-6, 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 Northern 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 3-6. 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 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 $318,565. 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 $136,510 as reflected on Schedule RevReq 3-6, column 3, line 3.

Q. Please explain the adjustment for the Medical and Dental Insurances that are allocated to Northern through the Unitil Service charge.

A. This adjustment is shown on Schedule RevReq 3-6. Similar to Northern, 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 Northern 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 Northern 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 $268,083. This amount is shown on Schedule RevReq 3-6, 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 Unitil Service, including the employees of Northern. 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 Northern 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 Northern. 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 3-7. 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 decrease in pension expense of ($2,185), a total increase in SERP expense of $58,798 and a total decrease in PBOP expense of ($19,749).

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 3-7, the total 401(k) costs adjustment increases test year expense by $30,095 (column 2, line 16).

Q. Please describe how the 401(k) adjustment was calculated for Northern.

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 $98,571 (Column 3, Line 4). The test year O&M 401(k) cost was then deducted to derive the O&M 401(k) increase of $5,712 (Column 3, Line 16).

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 Northern as shown on Schedule RevReq 3-7. First the test year 401(k) costs apportioned to Northern 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 $295,488 (Column 4, Line 4). The test year O&M 401(k) was then deducted to derive the O&M 401(k) increase of $24,382 (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 $2,447 by the percentage allocated to the Company (19.85 percent). This value is then reduced by the amount chargeable to capital to derive the pro formed deferred compensation pro formed adjustment of $52,717. The test year O&M deferred compensation was then deducted to derive the O&M deferred compensation increase of $44,415. Please see Schedule RevReq Workpaper 4.6.

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY OF

KEVIN E. SPRAGUE

AND

CHRISTOPER J. LEBLANC

EXHIBIT KSCL-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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. ("Unitil Service", which is a subsidiary of Unitil Corporation ("Unitil Corp.") that provides managerial, financial, regulatory and engineering services to Unitil's principal utility subsidiaries, including Northern Utilities, Inc. ("Northern" or the "Company"). In this capacity, I manage all 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 for approximately 25 years. I was originally hired as an Associate Engineer in the 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 Masters 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 Commission, the Maine Public Utilities Commission and the Massachusetts Department of Public Utilities. I also filed testimony in the Company's base rate case proceeding in DG 17-070.

Q. Mr. LeBlanc, please state your names and business addresses.

A. My name is Christopher J. LeBlanc, and my business address is 325 West Road, Portsmouth, New Hampshire.

Q. Mr. LeBlanc, for whom do you work and in what capacity?

A. I am Vice-President of Gas Operations for Unitil Service In this capacity, I am responsible for managing all gas operations for Northern and Unitil's other subsidiaries, including the safe, reliable, and efficient production, transportation and delivery of natural gas service to customers.

Q. Mr. LeBlanc, please summarize your professional and educational background.

A. I have more than 25 years of experience in the utility industry and an extensive background in the operation, maintenance and construction of natural gas distribution systems. I have been Operator Qualified in 84 covered tasks and have had formal industry-specific training at the Gas Technology Institute in Gas

Distribution Operations, Transmission Operations, Pipeline Design and Construction Practices and Regulator Station Design.

I joined Unitil Service in 2000 as a Field Technician and since then have progressed through several positions of increasing responsibility including Project Leader in 2002 and Manager, Gas Operations in 2003. I was promoted to Director, Gas Operations in 2008 and was named Vice-President, Gas Operations on January 1, 2017. Prior to joining Unitil Service, I was employed for nine years at R.H. White Construction Company, where I was responsible for leading and directing field crews in construction and installation of underground utility infrastructure.

I hold a Bachelor of Arts degree in Business Administration from Assumption College and a Master's degree in Business Administration from the same institution. Additionally, I have completed civil engineering course work at the University of Massachusetts, Lowell.

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

A. Yes, I have testified before the Commission on numerous issues related to gas safety and operations. In addition to the Commission, I have also testified before the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission on issues related to gas safety and operations.

Q. Mr. Sprague and Mr. LeBlanc, what is the purpose of your testimony and how is it organized?

A. The purpose of our testimony is to support the Company's capital spending as it relates to Northern's proposed Rate Plan to include annual revenue increases through step adjustments in order to collect costs associated with non-growth related projects. The testimony of Mr. Goulding and Mr. Nawazelski provides support for the proposed Rate Plan. Specifically, we will describe the following: 1) the Company's planning and budgeting process, 2) the authorization and control of capital spending, 3) the five year capital budget forecast from 2021-2025, 4) the actual capital spending from 2017 – 2020 and 5) the Company's approach to cost management.

II. 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. These studies are updated annually with the latest load forecasts 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 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 gas distribution 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 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. Each project is classified into one of six categories, which include annual requirements, gas distribution, gas production, transportation, structures and general equipment. Each category is further broken down into subcategories such as main extensions, pipe replacement, highway projects, distribution system improvements, valve installations, and other specific projects. Blanket authorizations for annual requirements are broken down into subcategories for distribution system improvements, new gas services, corrosion control, gas service upgrades, abandoned services, meter purchase & installation and water heater and burner 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 pressure and capacity where they jeopardize the Company's ability to distribute natural gas, activities to restore service during and 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 gas projects over the period 2021 to 2025.

Table 1 – 2021-2025 Capital Budget Forecast

	Forecast Spending (000's)				
Category	**2021**	**2022**	**2023**	**2024**	**2025**
Growth					
Customer Additions (C)	4,521	4,672	4,756	5,174	5,261
Mains Extensions (M)	2,449	2,492	2,524	2,764	2,779
Subtotal Growth	6,970	7,165	7,280	7,938	8,040
Non-Growth					
Pipe Replacement Programs (P)	0	0	0	0	0
Other Replacement Programs (R)	2,709	2,908	5,238	2,296	6,204
System Improvements (I)	2,733	4,303	2,682	4,623	700
Highway Projects (H)	2,917	2,985	3,026	3,283	3,319
Asphault Restoration (A)	762	790	804	847	869
Farm Tap Replacement (F)	714	508	513	568	568
Rochester Reinforcement (RR)	3,464	3,338	2,894	0	0
Other Non-Growth (O)	9,779	8,291	8,609	10,775	11,442
Subtotal Non-Growth	23,078	23,123	23,766	22,392	23,102
Total	30,048	30,288	31,046	30,330	31,143
% Growth	23%	24%	23%	26%	26%
% Non-Growth	77%	76%	77%	74%	74%

Q. Can you describe the difference between the Growth and Non-Growth categories?

A. Growth projects include customer additions and mains extension projects. Non-growth projects include: pipe replacement programs, other replacement programs, system improvements, highway projects, asphalt restoration, farm tap replacement, Rochester Reinforcement, and other non-growth related projects.

Q. Can you describe each of the subcategories of growth related projects?

A. Customer additions include projects such as new customer additions or services, customer related metering, customer related transformers, and new water heaters and conversion burners. Mains extensions are projects designed to extend mains into areas of the system that are not presently served to provide service to new customers.

Q. Can you describe each of the subcategories of non-growth related projects?

A. Non-growth related projects include the Company's pipe replacement program, other replacement programs, system imprvements, highway projects, asphalt restoration, farm tap replacements, the Rochester Reinforcement project, and other non-growth. The pipe replacement program includes the replacement of cast iron and bare steel mains and services and associated facilities. The Company substantially completed its replacement of all cast iron and bare steel mains and services in 2017. However, the Company continues to identify this as a category in case there are other pipe materials or vintages that will require proactive replacement in the future. The Company has not proposed any spending in this category from 2021 – 2025

Q. What types of projects are included in the other replacement program category?

A. These projects consist of: 1) the proactive replacement of medium density Adyl-A pipe that may be susceptible to brittle stress cracking, 2) the replacement of low pressure mains and services with intermediate pressure mains and services, 3) projects associated with the replacement or rebuild of aging regulator stations and equipment. These projects are all condition-based replacements and are non-growth related. This is not categoried under the pipe replacement category to keep it separate and distinct to the work the Company has completed with respect to cast iron and bare steel mains and services.

Q. What types of projects are in the system improvements category?

A. System improvement projects are designed to increase the capacity or to improve operating pressures to certain portions of the system. These type of projects are similar to the Rochester Reinforcement projects, but on a smaller scale. System improvement projects are not generally associated with known load additions but rather identified through forecasted load growth and network modeling simulations. Unlike mains extensions that are installed to serve known load, system improvements are completed in advance to ensure the system has the capacity required to meet planning criteria. The capacity increase associated with system improvement projects tend to be a lumpy investment, meaning that the amount of capacity is determined based upon standard equipment and materials and is not able to be fine tuned to the amount of load forecasted.

Q. What types of projects are included in the Gas Highway Projects category?

A. Gas Highway Projects covers replacement of facilities caused by forced relocations of gas facilities due to City and State roadway and municipal infrastructure projects (e.g., sewer separation).

Q. Can you describe the asphalt restoration category?

A. Distribution projects within municipal streets require asphalt restoration according to local specifications. This budget item will capture all paving costs for distribution projects over a multi-year time frame based upon the town-by-town requirements to allow time for settlement to occur prior to final paving.

Q. Can you describe what types of projects are included in the Farm Tap Replacement category?

A. Farm Tap Replacements refers to direct-buried regulators to serve rural residential and commercial customers that were installed prior to Unitil's acquisition of Northern.

Q. Can you explain the Rochester Reinforcement category?

A. The Company has identified that in order to continue to expand capacity to the Rochester area of the gas system, a significant reinforcement is required. The Rochester Reinforcement Project includes reinforcement of the Distribution Hi-Line located in Dover as well as mains and regulator station reinforcements required in Rochester. There are several projects supporting the reinforcement of the Rochester portion of the system:

<u>Route 108 Backfeed</u> – With the Rochester IP system (NH #40 – MAOP 45 psig) having a single feed, continuing to grow and already experiencing low end of system pressures Gas Engineering is proposing a 13,500-foot 12-inch coated steel main be installed along Rte. 108 in Rochester from Whitehall Rd. to the end of main on Rte. 108 near Airport Dr. Included in this installation will be a 9000-foot 4-inch HDPE main to be installed parallel from the end of main near Villanova Ln. and Rte. 108 to Airport Dr. The 12 inch CS main extension will become part of the Rochester 150# System (NH #31 – MAOP 150 psig) and will end with a new

regulator station on Whitehall Rd. to become a secondary feed to the Rochester IP system.

<u>Bartlett Avenue/High Street Stations Rebuild</u> - This new station is required to serve increased load in all three systems and will include the addition of pre-heat so as to mitigate gas heat concerns. Based on system analysis results, operational best-practice supports combining both the Bartlett Ave and High Street stations into one site and re-configure them accordingly.

<u>Whitehall Road Vaults-45 PSIG Back-feed-Rochester</u> - This project is for the fabrication and installation of a new set of 45PSIG MAOP regulator station vaults along Whitehall Road in Rochester.

<u>Rochester Reinforcement 99 PSIG Station</u> – This project consists of the design, siting and construction of a new 99PSIG MAOP station, served from the existing 150 PSIG Rochester High line and sited at the existing Route 125 Station in Rochester, NH. A new single feed system operating at a 99PSIG MAOP is required to support this load as the existing Rochester 45PSIG IP system does not have adequate capacity to support this growth

<u>Rochester Reinforcement 99 psig Main</u> – The reinforcement is starting from Washington Street going down Brock Street to Rt. 125, down Rt. 125 to the

existing Route 125/Axe Handle Brook station location for a total footage of 6600' of 8" HDPE.

Q. Can you describe the Other Non-Growth category?

A. Yes. The other non-growth category is a collection of all of the remaining non-growth types of projects. These projects consist of small system improvements, abandoned gas services, gas service upgrades, Company-related meter installations, regulator heater installations, tools and equipment, office equipment, normal improvements to buildings, and allocated Unitil Service. software and IT infrastructure projects.

D. ACTUAL CAPITAL SPENDING 2017-2020

Q. Can you provide the same table as provided in Table 1 but for actual spending from 2017-2020?

A. Yes. Table 2 below categorizes actual spending from 2017-2020.

Table 2 – Actual Capital Spending 2017 – 2020

	Actual Spending (000's)			
Category	**2017**	**2018**	**2019**	**2020**
Growth				
Customer Additions (C)	3,788	4,537	4,054	4,000
Mains Extensions (M)	2,726	3,732	4,096	5,551
Subtotal Growth	6,514	8,268	8,150	9,552
Non-Growth				
Pipe Replacement Programs (P)	6,076	608	68	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,460	1,502
Highway Projects (H)	6,884	8,487	1,576	1,746
Asphault Restoration (A)	0	0	331	757
Farm Tap Replacement (F)	361	310	597	164
Rochester Reinforcement (RR)	859	1,353	2,853	3,982
Other Non-Growth (O)	4,213	4,256	4,594	5,211
Subtotal Non-Growth	18,394	15,014	15,479	13,363
Total	24,908	23,282	23,630	22,915

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%

Q. Can you describe the increase in growth related spending in 2020 as compared to previous years?

A. Yes. The increase in growth related spending in 2020 is related to the mains extension associated with the Epping Expansion. This level of mains extension spending is not forecasted to continue into the future.

Q. What is the relevance of categorizing Tables 1 and 2 into growth and non-growth categories?

A. In times of higher customer expansion, the 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 75% of its capital investment will be on non-growth related projects.

Q. Is the Company proposing special rate treatment for specifically for the non-growth related investments?

A. Yes. The information provided in this testimony is to support the Company's proposal to include the non-growth 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. Has the Company provided a history of actual spending or a forecast of capital spending?

A. Yes. Exhibit KSCL-2 provides a project-by-project history of actual spending for 2017 to 2020 and a project-by-project forecast of capital spending for 2021 to 2025.

Q. Does this information categorize capital spending by non-growth and growth related projects?

A. Yes. The information provided in Exhibit KSCL-2 provides a breakdown of non-growth and growth related spending for 2017 – 2025.

III. COST MANAGEMENT

Q. How does the Company ensure that projects associated with Eligible Facilities are completed as cost effectively as possible?

A. The primary means by which the Company controls costs and ensures the lowest price for its construction is the contracting strategy devised for these activities. Unitil awards multi-year contracts structured as "unit price contracts" through a competitive bidding process. Before awarding the contract, Northern performs analyses to ensure that the winning bidder delivers the lowest overall cost given the actual units of work to be completed.

Q. Please describe the unit price contract.

A. A unit price contract is one under which the Company pays a predetermined price for a defined quantity of work to be performed, including the price charged for labor, construction materials, equipment rental, and associated services. In this way, the cost of construction is "controlled" because the cost is fixed for the duration of the contract and the contractor is only paid for units of work completed. The contractor is incented to work efficiently and complete as many units of work as possible, while the Company and its ratepayers are protected from construction inefficiencies. Through this contracting strategy, the Company accomplishes two key objectives:

1. The objective of ensuring that services (unit prices) are obtained at the

lowest available cost is ensured through competitive solicitation; and

2. The objective of cost control is accomplished through the unit pricing (fixed pricing) in the contract.

Q. Do the Company's project supervisors have incentives for cost containment?

A. Yes. Unitil has a performance management system for setting performance expectations, monitoring progress, measuring results, appraising, rewarding and/or correcting employee performance. In addition, the Company uses project management techniques to manage construction and maintenance activities. The project supervisors have ownership of assigned projects and are responsible for the scope, schedule and budgetary objectives for each project. As part of the Company's performance management system each manager and supervisor receives an annual performance contract. This performance contract covers all aspects of job expectations, including meeting established financial objectives, which are weighted heavily. The performance review process includes, at a minimum, two written performance appraisals (mid-year and year end) and our organizational structure provides the opportunity for continuous feedback. Annual salary increases for established supervisors are merit based, and the financial incentive for project cost control is established through this process.

Q. Does this conclude your testimony?

A. Yes, it does.

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Northern Utilites Capital Spending 2017 - 2025

	Actual Spending ($000's)				Forecast Spending ($000's)				
Category	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Growth									
Customer Additions (C)	3,788	4,537	4,054	4,000	4,521	4,672	4,756	5,174	5,261
Mains Extensions (M)	2,726	3,732	4,096	5,551	2,449	2,492	2,524	2,764	2,779
Subtotal Growth	6,514	8,268	8,150	9,552	6,970	7,165	7,280	7,938	8,040
Non-Growth									
Pipe Replacement Programs (P)	6,076	608	68	-	-	-	-	-	-
Other Replacement Programs (R)	-	-	-	-	2,709	2,908	5,238	2,296	6,204
System Improvements (I)	-	-	5,460	1,502	2,733	4,303	2,682	4,623	700
Highway Projects (H)	6,884	8,487	1,576	1,746	2,917	2,985	3,026	3,283	3,319
Asphault Restoration (A)	-	-	331	757	762	790	804	847	869
Farm Tap Replacement (F)	361	310	597	164	714	508	513	568	568
Rochester Reinforcement (RR)	859	1,353	2,853	3,982	3,464	3,338	2,894	-	-
Other Non-Growth (O)	4,213	4,256	4,594	5,211	9,779	8,291	8,609	10,775	11,442
Subtotal Non-Growth	18,394	15,014	15,479	13,363	23,078	23,123	23,766	22,392	23,102
Total	24,908	23,282	23,630	22,915	30,048	30,288	31,046	30,330	31,143

% Growth	26%	36%	34%	42%	23%	24%	23%	26%	26%
% Non-Growth	74%	64%	66%	58%	77%	76%	77%	74%	74%
% Eligible Facilities	68%	62%	39%	50%	32%	31%	29%	22%	21%

Eligible Facilities	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Pipe Replacement (P)	6,076	608	68	-	-	-	-	-	-
Mains Extension excl. services (M)	2,726	3,732	4,096	5,551	2,449	2,492	2,524	2,764	2,779
Highway Projects (H)	6,884	8,487	1,576	1,746	2,917	2,985	3,026	3,283	3,319
Farm Tap Replacements (F)	361	310	597	164	714	508	513	568	568
Rochester Reinforcement (RR)	859	1,353	2,853	3,982	3,464	3,338	2,894	-	-
Total	16,907	14,490	9,190	11,444	9,543	9,324	8,958	6,615	6,666

Northern Utilities
Actual Spending by Project and Year 2017 - 2020

Category	Actual Spending 2017	2018	2019	2020
Growth				
Customer Additions (C)	3,788,223	4,536,609	4,054,112	4,000,481
Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

Authorization	Budget Number	Description	Actual Spending 2017	2018	2019	2020	Grand Total	Authorized	Total Project Spending	Category
N-003022	GPC03	2013 Physical security upgrades - Carryover	(3,788)				(3,788)	85,000	-	O
N-004000	MAO16	Gas Distribution System Improvements	31				31	180,500	137,392	O
N-004001	MBO16	New Gas Services	(1,719)				(1,719)	2,757,700	2,311,717	C
N-004004	MEO16	Gas Service Upgrades	449				449	749,644	620,731	P
N-004059	ECO01	Gas Inspections	(444)				(444)	51,480	11,697	O
N-005000	MAO17	Gas Distribution System Improvements	(1,312)	(20,745)			(22,057)	461,323	389,874	O
N-005003	MDO16	Abandoned Gas Services	(0)				(0)	209,972	105,257	O
N-005004	MEO17	Gas Service Upgrades	(11,431)	(29,689)			(41,120)	1,103,054	1,199,327	P
N-005011	MMO16	Gas Distribution Improvements - Systems Operations	(180)				(180)	85,427	93,241	O
N-005016	ECO04	GIS Version Upgrade & Data Model Consolidation	15,119	9,511			24,631	250,000	52,387	O
N-005017	EAG02	Normal add & replace- tools & equipment - EM&C	2,040	(2,040)			-	5,000	80	O
N-005039	ECO06	General Software Enhancements	(8,668)				(8,668)	30,000	6,443	O
N-005054	ECO02	Young St Station Telemetry		(24,918)			(24,918)	48,859	-	O
N-005061	JAO03	Bartlett Ave Housing Somersworth NH	(95)				(95)	57,009	-	C
N-005072	ECO08	EETS Enhancements 2015	69				69	100,500	19,095	O
N-005077	ECO10	SalesForce for Gas Sales Phase II project	12,783	160			12,943	137,200	46,347	O
N-006000	MAC17	Gas Distribution System Improvements	(100,257)	0		(108)	(100,364)	345,809	295,648	O
N-006001	MBC17	New Gas Services	136,536	(217)			136,319	1,886,297	2,133,375	C
N-006002	MCO17	Corrosion Control	1,319				1,319	70,600	61,025	O
N-006003	MDC17	Abandoned Gas Services	(317)	(1,292)			(1,609)	213,334	193,674	O
N-006004	MEC17	Gas Service Upgrades	(79,984)	(10,189)			(90,173)	1,569,436	1,651,812	P
N-006005	MHO17	Gas Meter Purchase - Company	115				115	228,000	231,877	O
N-006006	MFC17	Gas Meter Installations - Company	28,832				28,832	735,095	696,946	O
N-006007	MIO17	Gas Meter Purchases - Customer	12,965				12,965	244,400	278,621	C
N-006008	MGC17	Gas Meter Installations - Customer	22,504				22,504	555,923	633,823	C
N-006009	MKC17	Gas C/B Replacements	(3,302)				(3,302)	90,000	47,984	O
N-006010	MJC17	New C/B Installations	2,395				2,395	108,000	47,473	C
N-006011	MMO17	Gas Distribution System Improvements - Systems Operatio	12,636				12,636	108,888	106,693	O
N-006014	GPO01	Normal Improvements to Portsmouth Facility	2,280				2,280	15,000	18,050	O
N-006015	EDO01	Office Furniture and Equipment-Replacements	1,379				1,379	5,000	6,674	O
N-006017	EAO01	Portsmouth Tools	4,958				4,958	31,061	35,811	O
N-006020	JCO01	NH Main Replacement Program	13,454				13,454	7,402,461	7,441,245	P
N-006027	JPO01	Regulator Station Vent Installations	(3,101)				(3,101)	179,511	85,304	O
N-006028	ECO11	Verotrack Upgrade to myWorld Inspection & Service	320				320	56,926	16,336	O
N-006029	ECO12	2016 IT Infrastructure	4,142				4,142	442,199	34,149	O
N-006030	JAC02	100 Farmington Rd Rochester	(125,562)				(125,562)	1,799,613	1,617,761	M
N-006031	JAC03	Bramber Valley 128 Post Rd Greenland	123,750	3,423			127,173	535,414	398,401	M
N-006036	ECO13	First Responder - Municipal Trouble Reporting App	55,800				55,800	362,000	65,700	O
N-006038	JAC06	6-8 Broad St Somersworth NH	11,797	699			12,496	250,000	135,001	M
N-006039	JAC07	Emerald Ln/Indian Ridge Dover	118,726	(1,854)			116,872	660,448	543,545	M
N-006040	JHC05	Central Ave/ Birchwood/ Stark Dover	4,820				4,820	768,288	867,216	H
N-006041	JAC08	Red Barn Dr Dover NH	13				13	57,935	18,108	M
N-006043	ECO15	New Century Distribution Risk Algorithms Upgrade	2,909				2,909	36,055	9,709	O
N-006044	ECO16	Unify Workforce Management System	330				330	56,000	8,991	O
N-006046	JAC09	263 Drakeside Rd Hampton NH	(4,121)				(4,121)	156,484	133,777	M
N-006052	JAC12	181 Silver St (Silver Square) Dover	(2,567)				(2,567)	132,932	117,511	M
N-006053	ECO18	General Software Enhancements	3,250				3,250	204,686	5,054	O
N-006055	JAC14	920 Bld2 Lafayette Rd Seabrook NH	(648)				(648)	59,050	-	M
N-006056	JAC15	Concord Pl / McKay Dr Exeter NH	107,749	(13,921)			93,828	204,686	123,749	M
N-006057	JAC16	Indian Ridge/66 Rochester Hill Rd	2,002				2,002	88,514	11,673	M
N-006060	ECO20	CMS NH/ME Isolation	2,418				2,418	10,000	2,418	O
N-006061	JPO05	Dover Point Catalytic Heaters	5				5	7,632	5,523	O
N-007000	MAB17	Gas Distribution System Improvements	302,888	(150,093)			152,795	278,585	152,795	O
N-007001	MBB17	New Gas Services	2,493,048	(111,060)	(1,278)		2,380,710	2,168,250	2,380,710	C
N-007002	MCB17	Corrosion Control	34,448	1			34,449	85,883	34,449	O
N-007003	MDB17	Abandoned Gas Services	114,695	4,289			118,984	134,577	118,984	O

Northern Utilities
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Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
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Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
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% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

Authorization	Budget Number	Description	Actual Spending 2017	2018	2019	2020	Grand Total	Authorized	Total Project Spending	Category
N-007004	MEB17	Gas Service Upgrades	1,200,091	(53,271)	(16)		1,146,803	1,047,302	1,146,803	P
N-007005	MHB17	Gas Meter Purchases - Company	486,362	23,449			509,811	485,432	509,811	O
N-007006	MFB17	Gas Meter Installations - Company	966,269	6,816			973,085	888,654	973,085	O
N-007007	MIB17	Gas Meter Purchases - Customer	417,505	7,816			425,321	256,250	425,321	C
N-007008	MGB17	Gas Meter Installations - Customers	626,912	6,709			633,621	611,518	633,621	C
N-007009	MKB17	Gas Water Heater Replacements	56,653	2,561			59,214	100,000	59,214	O
N-007010	MJB17	New Water Heater Installations	78,171	5,121			83,292	108,000	83,292	C
N-007011	MMB17	Gas Distribution System Improvements - System Operatior	113,178	8,370			121,549	127,206	121,549	O
N-007013	JAB01	407 Old Dover Rd Rochester	1,322,545	40,571			1,363,116	1,297,121	1,363,116	M
N-007014	JHB01	Whittier St Bridge Dover NH	744,817	(39,611)			705,207	926,574	705,207	H
N-007015	EAG03	Normal add & replace- tools & equipment - EM&C	1,596				1,596	5,000	1,596	O
N-007016	GPB01	Normal Improvements Portsmouth DOC	13,215				13,215	15,000	13,215	O
N-007017	JCB01	Spring St Dover NH	4,953,860	(3,176)			4,950,684	4,366,875	4,950,684	P
N-007018	EAG01	Portsmouth Tools	25,506	30			25,536	25,186	25,536	O
N-007019	EAG04	Vehicle Metthane Detector VMD	20,821				20,821	20,000	20,821	O
N-007020	EDG01	Office Furniture and Equipment	4,365				4,365	4,750	4,365	O
N-007022	JHB02	Congress St/ Fleet St/ Vaughn Mall Portsmouth NH	838,595				838,595	959,222	838,595	H
N-007023	JAB02	Indian Ridge Rochester NH	44,070	(8,492)			35,578	88,514	35,578	M
N-007024	ECN01	UPC/GEMS Enhancements 2017	17,066	(1,244)			15,822	55,000	15,822	O
N-007025	ECN02	Meter data archiving plan	1,684	359			2,042	28,000	2,042	O
N-007028	JPB10	Strafford Ave Station Modification	34,314				34,314	29,813	34,314	O
N-007029	JPN01	5 Andrews East Kingston	36,337				36,337	36,356	36,337	F
N-007030	JPN02	282 Durham Dover	49,925				49,925	43,772	49,925	F
N-007032	JPN04	356 Rt 108 Madbury	42,207				42,207	42,258	42,207	F
N-007033	ECN05	Electronic Time Sheet-Phase One	2,623	2,266			4,890	85,000	4,890	O
N-007034	ECN06	LocusView GPS/GIS Tracking & Traceability	116,310				116,310	355,000	116,310	O
N-007035	ECN07	2017 Cyber Security Scheduled Replacements	1,012	924			1,936	152,143	1,936	O
N-007036	ECN08	Power Plant Upgrade 10.4 to 2016.1	64,831				64,831	381,000	64,831	O
N-007037	GPB04	Replace Chillers	32,650				32,650	33,000	32,650	O
N-007038	EAG02	Tools: Normal Additions and Replacements - Systems Ope	8,689	266			8,955	6,000	8,955	O
N-007039	JPB09	Regulator Vent Installations	91,923	88,590			180,513	157,695	180,513	O
N-007040	JHB03	Islington St / Bartlett St Portsmouth NH	2,958,681	74,935			3,033,616	2,841,828	3,033,616	H
N-007041	JHB04	Lafayette Rd Seabrook NH	260,228				260,228	228,227	260,228	H
N-007042	JAB03	Gas main extensions <$30K	236,196	2,465	1,057		239,718	250,000	239,718	M
N-007044	ECN10	2017 IT Infrastructure	11,335	(2,589)			8,746	423,300	8,746	O
N-007045	JHB05	Dover Point Rd Crossing Dover NH	237,041	16,321			253,361	286,478	253,361	H
N-007046	JHB06	Wakefield St Rochester NH	637,717	(1,557)			636,160	899,243	636,160	H
N-007047	ECN11	2017 SalesForce Application for Gas Sales - Phase 2	4,467	12,189			16,656	50,000	16,656	O
N-007048	JHB07	16-30 High St Exeter	176,837				176,837	218,072	176,837	H
N-007050	JHB08	Court St HDD Exeter	179,612	5,440			185,052	167,193	185,052	H
N-007051	JAB04	77 Farmington Rd Rochester NH	119,443	(1,065)			118,378	117,940	118,378	M
N-007052	JAB05	Tuscan Village Project/Pleasant St	455,007	503,727	(36,584)		922,150	1,006,455	922,150	M
N-007054	JPN06	PLV mini dist regulator	232,481	173,138			405,619	376,637	405,619	F
N-007056	JAB06	Stonebridge Estates Salem NH	16,841	4,276			21,117	331,637	21,117	M
N-007057	JAB07	Sierra Dr Dover NH	17,999	14,302	825		33,126	31,307	33,126	M
N-007058	JHB09	Tanner,Parker,Sudbury,Brewster,McDonough, Hanover Sts	779,656	(105,465)			674,191	604,483	674,191	H
N-007059	JPB08	Rochester Reinforcement	858,633	(10,050)			848,583	812,149	848,583	RR
N-007060	ECN12	2017 General Software Enhancements	4,587	4,871			9,457	-	9,457	O
N-007061	JPN08	Kerotest Valve Replacement	235,923	(8,384)			227,538	364,524	227,538	O
N-007062	JAB08	920 Lafayette Rd Seabrook NH	72,284	(90)			72,194	69,558	72,194	M
N-007063	JAB09	80 Lawrence Rd Salem (Granite Woods)	37,977	(37,977)			-	525,986	-	M
N-007064	JAB10	Sweetbriar Ln Hampton NH	44,090				44,090	65,227	44,090	M
N-007065	JAB11	788-794 Portland St (Carole Ct) Rochester NH	20,645				20,645	68,361	20,645	M
N-007066	ECN13	IS Project Tracker Replacement	1,059	3,920			4,980	30,000	4,980	O
N-007067	JAB12	20 Garrison Rd (Wolcott Dr) Dover NH	14,331	4,241			18,572	57,021	18,572	M
N-007068	JAB13	206 Green St Somersworth NH	66,857	(48)			66,809	148,454	66,809	M

Northern Utilities
Actual Spending by Project and Year 2017 - 2020

	Actual Spending			
Category	**2017**	**2018**	**2019**	**2020**
Growth				
Customer Additions (C)	3,788,223	4,536,609	4,054,112	4,000,481
Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	**(000'S)**	**(000'S)**	**(000'S)**	**(000'S)**
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

			Actual Spending							
Authorization	**Budget Number**	**Description**	**2017**	**2018**	**2019**	**2020**	**Grand Total**	**Authorized**	**Total Project Spending**	**Category**
N-007069	JHB10	Chestnut St Portsmouth NH	11,153				11,153	30,050	11,153	H
N-007070	JHB11	Third St Dover NH	55,222	(371)			54,851	57,859	54,851	H
N-007071	JAB14	50 Pine Rd Brentwood NH	26,684	1,259			27,943	39,376	27,943	M
N-007073	GPC01	Physical Security Upgrades & Additions	34,700	62,631			97,332	85,000	97,332	O
N-007074	JAB15	1 Depot Rd Seabrook NH		56,940			56,940	64,363	56,940	M
N-007075	JAB16	17D Farmington Rd Rochester		5,035			5,035	42,700	5,035	M
N-007076	JAB17	54 Weare Rd Seabrook		51,366			51,366	49,966	51,366	M
N-007078	ECN15	Meter Data Management	1,380,945				1,380,945	36,643,252	1,380,945	O
N-008000	MAB18	Gas Distribution System Improvements		604,670	(177,707)		426,963	592,434	426,963	O
N-008001	MBB18	New Gas Services		2,900,187	182,592	(6,154)	3,076,626	2,950,000	3,076,626	C
N-008002	MCB18	Corrosion Control		76,427	505		76,932	79,427	76,932	O
N-008003	MDB18	Abandoned Gas Services		178,829	1,092	(2,334)	177,586	210,880	177,586	O
N-008004	MEB18	Gas Service Upgrades		1,414,464	(103,121)		1,311,343	1,782,345	1,311,343	O
N-008005	MHB18	Gas Meter Purchases - Company		342,881			342,881	537,577	342,881	O
N-008006	MFB18	Gas Meter Installations - Company		496,519	5,908		502,427	594,890	502,427	O
N-008007	MIB18	Gas Meter Purchases - Customer		559,077			559,077	628,539	559,077	C
N-008008	MGB18	Gas Meter Installations - Customer		924,918	26,087		951,006	946,700	951,006	C
N-008011	MIM18	Gas Distribution System Improvements - System Operations		105,232	13,523		118,755	118,627	118,755	O
N-008016	MKB18	Gas Water Heater Replacements		103,775	(9,087)		94,687	103,000	94,687	O
N-008017	MJB18	New Water Heater Installations		74,161	5,891		80,052	108,000	80,052	C
N-008018	EDG01	Office Furniture and Equipment		5,942			5,942	4,750	5,942	O
N-008019	EAG02	Tools Portsmouth Division		23,716	3,394		27,110	25,942	27,110	O
N-008020	JCB01	Various Locations Paving for 2017 work		704,753			704,753	800,000	704,753	P
N-008021	GPB01	Normal Improvements to Portsmouth Facility		24,049			24,049	25,000	24,049	O
N-008022	EAG01	Normal add & replace- tools & equipment - Metering		675	1,318		1,993	5,000	1,993	O
N-008023	ECN01	2018 IT Infrastructure		20,647	6,980		27,627	542,326	27,627	O
N-008024	GPB02	Roof Replacement & Building Envelope Improvements		276,455	(23,757)		252,699	400,000	252,699	O
N-008025	GPB03	Physical Security Facility Upgrades & Additions 2018		24,182	3,734		27,916	41,500	27,916	O
N-008026	EAG03	Gas System Operations Tools		8,502			8,502	6,000	8,502	O
N-008027	ECN02	2018 Interface Enhancements		91,132	(91,132)		-	654,571	-	O
N-008028	ECN03	2018 Customer Facing Enhancements		103,815	(103,815)		-	849,856	-	O
N-008029	ECN04	2018 MeterSense Enhancements		36,823	(36,823)		-	345,573	-	O
N-008030	JHB01	Whitehouse Rd Rochester NH		6,572,621			6,572,621	6,874,485	6,572,621	H
N-008031	ECN05	Compliancy Management System Enhancements		26,434	5,504		31,938	100,000	31,938	O
N-008032	ECN06	Dev / Staging Refresh			5,492		5,492	42,148	5,492	O
N-008033	ECN07	MARS/GEM Enhancements		17,455	8,343		25,798	94,000	25,798	O
N-008034	ECN08	Legacy Interface Job Rewrite		2,079	671		2,749	15,000	2,749	O
N-008035	ECN09	WebOps Replacement - Year 1 of 3		14,837	(2,019)		12,818	66,300	12,818	O
N-008036	ECN10	General Software Enhancements - 2018		11,776	1,537		13,313	60,000	13,313	O
N-008037	ECN11	TESS Replacement			4,372		4,372	27,000	4,372	O
N-008038	ECN12	2018 Cyber Security Enhancements		4,662	(531)		4,131	138,275	4,131	O
N-008039	ECN13	Upgrade to myWorld Inspection and Survey		13,005			13,005	39,000	13,005	O
N-008040	JHB02	Barberry Ln / Green St Portsmouth		466,235			466,235	442,680	466,235	H
N-008041	JAB01	Gas main ext < $30K		252,896	11,550		264,446	250,000	264,446	M
N-008042	JHB03	Stark St Bridge Portsmouth		271,400		(2,689)	268,711	254,045	268,711	H
N-008043	JPB01	Distribution High Line Dover Phase 1		1,363,214	2,280,690	165,099	3,809,004	3,451,446	3,809,004	RR
N-008045	JHB04	828 Central Ave Dover NH		168,874			168,874	164,633	168,874	H
N-008046	JAB02	118 Ledge Rd Seabrook NH		59,679			59,679	59,416	59,679	M
N-008047	JHB05	Woodbury Ave / Piscataqua Dr Newington		351,466			351,466	311,713	351,466	H
N-008048	JAB03	201 Atlantic Ave N Hampton		529,478			529,478	462,579	529,478	M
N-008049	JAB04	113,114,115 &117 Batchelder Rd Seabrook		101,142			101,142	107,447	101,142	M
N-008050	JAB05	104 Washington St Dover NH		154,354	(787)		153,567	146,251	153,567	M
N-008051	JAB06	10 Hampshire Rd Salem NH		112,129			112,129	97,675	112,129	M
N-008052	ECG01	Gas SCADA - cell modem replacements - USC Labor		29,771	6,659		36,430	49,563	36,430	O
N-008053	ECN15	SalesForce Application for Gas Sales - Phase II		16,134			16,134	48,750	16,134	O
N-008054	JAB07	104 Grafton Rd Portsmouth NH		78,496			78,496	71,811	78,496	M

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Customer Additions (C)	3,788,223	4,536,609	4,054,112	4,000,481
Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

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% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

Authorization	Budget Number	Description	Actual Spending 2017	2018	2019	2020	Grand Total	Authorized	Total Project Spending	Category
N-008055	JAB08	1 Wentworth Ter Dover NH		29,051			29,051	31,585	29,051	M
N-008056	JAB09	1 Mall Rd Salem NH		46,640	7,320		53,960	53,058	53,960	M
N-008057	JHB06	Daniel St and Tremont St Exeter		88,789			88,789	81,215	88,789	H
N-008058	ECN16	Microsoft Exchange Upgrade Carry-Over		2,739	(231)		2,508	26,500	2,508	O
N-008059	JHB07	Railroad Ave @ Brickyard Rd Rochester		196,410			196,410	178,824	196,410	H
N-008063	JPN01	Redesiged New Reg Station		69,369			69,369	66,762	69,369	O
N-008064	ECN17	Electronic Time Sheet-Phase Two		12,467	1,540		14,006	85,000	14,006	O
N-008065	JAB10	121 Corporate Dr Portsmouth NH		135,875	18,558		154,433	160,840	154,433	M
N-008066	JAB11	140 Wakefield St Rochester		69,580			69,580	64,061	69,580	M
N-008067	JAB12	13 Newfields Rd Exeter		48,816			48,816	57,617	48,816	M
N-008068	JHB08	Lafayette Rd @ Andrew Jarvis Way Portsmouth		65,241			65,241	60,510	65,241	H
N-008069	JAB13	109 Towle Farm Rd Hampton NH		92,713			92,713	85,495	92,713	M
N-008070	JPN02	New Odorizer & Setup		75,030	5,927		80,957	75,030	80,957	O
N-008071	JAB14	21 Mechanic St Rochester NH		10,292			10,292	34,322	10,292	M
N-008072	JPN03	299 Exeter Rd Hampton		57,728	(1,119)		56,609	49,645	56,609	F
N-008073	ECN18	Universal Payment System (UPS) Reporting			657		657	13,600	657	O
N-008074	ECN19	Compliance Management System (CMS) Data Reports		1,376	296		1,672	11,000	1,672	O
N-008075	ECN20	ODI Plant Records - GIS Reconcilation Report			2,403		2,403	11,000	2,403	O
N-008076	JHB09	Jackson St / Sylvain St		273,550			273,550	266,376	273,550	H
N-008078	JAB16	Country Club Dr Atkinson NH Phase 1		980,374	277,388	13,265	1,271,026	1,438,836	1,271,026	M
N-008079	JAB17	30 Cate St Portsmouth		24,165	28,101	(902)	51,364	72,690	51,364	M
N-008080	JAB18	0 Borthwick Ave Portsmouth		138,164	171		138,335	138,188	138,335	M
N-008081	JPN04	101 International Dr Portsmouth		169,896	2,057		171,953	149,594	171,953	C
N-008083	JAB19	118,122,159,163, 165,167 Mt Vernon St Dover NH		82,015			82,015	122,759	82,015	M
N-008084	JAB20	299 Vaughan St Portsmouth NH		18,929	41,542		60,472	63,172	60,472	M
N-008085	JHB10	Green St Portsmouth NH		59,495			59,495	97,099	59,495	H
N-008087	JHB11	Main St Salem NH		22,895			22,895	149,398	22,895	H
N-008088	JAB22	183 Epping Rd / Ray Farm Exeter		9,397	73,751	(2,567)	80,581	90,685	80,581	M
N-008089	JAB23	2075 Lafayette Rd Portsmouth		0	18,565	21	18,587	42,485	18,587	M
N-008090	JAB24	31A,31B & 35 Wortley Ave Seabrook		22,012			22,012	30,206	22,012	M
N-008091	JAB25	139 Folly Mill Rd Seabrook NH		41,398	4,105		45,502	42,879	45,502	M
N-008093	JPN05	62 Whitehouse Rd Bottom out replacement			73,260		73,260	80,000	73,260	O
N-008094	JPN06	47 Weare Rd Seabrook NH		78,690			78,690	81,000	78,690	F
N-008095	JAB27	106-114 Mt Vernon ST Dover		58,983	1,089		60,072	57,137	60,072	M
N-008096	JAB28	50-56 Lovell St Portsmouth		10,449	13,668		24,116	30,083	24,116	M
N-008102	ECN22	Upgrade OMS web page			3,800		3,800	-	3,800	O
N-019000	MAB19	Gas Distribution System Improvements			312,088	(18,135)	293,953	375,920	293,953	O
N-019001	MBB19	New Gas Services			2,241,162	85,877	2,327,039	2,282,591	2,327,039	C
N-019002	MCB19	Corrosion Control			41,885	(1,244)	40,641	52,302	40,641	O
N-019003	MDB19	Abandoned Gas Services		271	164,749	3,496	168,516	150,965	168,516	O
N-019004	MEB19	Gas Service Upgrades			927,956	13,532	941,488	1,311,508	941,488	O
N-019005	MHB19	Gas Meter Purchases - Company			474,636	56,204	530,840	853,305	530,840	O
N-019006	MFB19	Gas Meter Installations - Company			567,700	5,165	572,865	667,345	572,865	O
N-019007	MIB19	Gas Meter Purchases - Customer			765,446	224,586	990,032	1,080,750	990,032	C
N-019008	MGB19	Gas Meter Installations - Customer			770,573	(7,502)	763,071	756,629	763,071	C
N-019009	MKB19	Gas C/B Replacements			85,715	5,013	90,728	106,090	90,728	O
N-019010	MJB19	New C/B Installations			61,581	5,883	67,465	100,000	67,465	C
N-019011	MMB19	Gas Distribution System Improvements - Operations			141,424	3,877	145,302	146,682	145,302	O
N-019013	EAG01	Tool: Normal Addtions and Replacements			29,912	2,474	32,386	28,420	32,386	O
N-019014	GPB01	Normal Improvements to Portsmouth Facility			4,495		4,495	18,000	4,495	O
N-019015	EDG01	Office Furniture and Equipment Replacements			7,108		7,108	4,750	7,108	O
N-019016	EDG02	Chair Replacement Year 1			11,756		11,756	9,500	11,756	O
N-019017	EAG03	Normal add & replace- tools & equipment - Meter and FS			1,524		1,524	5,050	1,524	O
N-019018	ECN01	2019 Voice System Replacement			246,672	(6,978)	239,694	1,100,000	239,694	O
N-019019	ECN02	Pipeline Compliance System integration			60,753	10,404	71,157	196,250	71,157	O
N-019020	ECN03	General Software Enhancements - 2019			8,454	3,372	11,825	21,350	11,825	O

Northern Utilities
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Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

Authorization	Budget Number	Description	Actual Spending 2017	2018	2019	2020	Grand Total	Authorized	Total Project Spending	Category
N-019021	ECN04	WebOps Replacement - Year 2 of 3			11,456	2,090	13,547	75,000	13,547	O
N-019022	ECN05	Reporting Blanket			20,110	1,919	22,028	99,919	22,028	O
N-019023	ECN06	Powerplan Updated License			55,120		55,120	275,600	55,120	O
N-019024	GPB02	Audio Video Additions			29,136		29,136	26,500	29,136	O
N-019025	GPB03	Replace Server Rm AC Split Units			17,824		17,824	15,000	17,824	O
N-019026	JPN02	12 Olde Rd Hampton			40,509		40,509	41,000	40,509	F
N-019027	JPN03	30 Fox Run Rd Newington			57,239		57,239	58,000	57,239	O
N-019028	JPN04	432 Central Ave Dover			68,150		68,150	70,000	68,150	P
N-019029	JPB01	Farm Tap Replacement			516,519	5,597	522,116	534,679	522,116	F
N-019030	EAG04	Nitrogen Purge Equipment			5,086	1,613	6,698	11,000	6,698	O
N-019031	JPB02	Rochester Reinforcement Phase 2 - 99psig Main			572,212		572,212	1,847,256	572,212	RR
N-019032	JPB07	Asphalt Restoration 2018 Projects			330,731		330,731	300,000	330,731	A
N-019033	JPB06	Plaistow Route 125 Bridge Crossing Remediation			67,877	211,237	279,114	306,525	279,114	O
N-019034	ECN07	Metersense Upgrade 4.2 to 4.3			277		277	14,325	277	O
N-019035	EAG02	Tools: Normal Additions and Replacements-System Operations			20,440		20,440	20,500	20,440	O
N-019036	JPB09	Gulf Road Heater Installation			874,440	24,005	898,445	785,300	898,445	O
N-019037	JPB10	Epping Road Station Tie-in to Exeter IP system			514,762	225,997	740,758	755,500	740,758	I
N-019040	JPN05	37 East Rd East Kingston NH			40,998		40,998	42,000	40,998	F
N-019041	ECN08	2019 Infrastructure PC & Network			165,649	30,696	196,345	1,289,231	196,345	O
N-019042	ECN09	EE Tracking & Reporting System			24,256	11,829	36,085	216,000	36,085	O
N-019044	ECN11	Regulatory Work Blanket			1,316	4,292	5,608	37,000	5,608	O
N-019045	JHB01	South Broadway Salem NH			75,053	(2,344)	72,708	72,485	72,708	H
N-019046	JHB02	Newfields Rd Exeter NH			363,493	21,494	384,987	437,837	384,987	H
N-019047	JAB01	Epping Expansion Project			1,102,091	1,815,311	2,917,402	2,908,956	2,917,402	M
N-019050	JHB03	Woodbury Ave Bridge Portsmouth			142,957		142,957	234,733	142,957	H
N-019051	JAB03	Main Extensins under $40k			427,099	234,564	661,663	417,114	661,663	M
N-019052	JHB04	Rt 1 By-Pass Hodgson Brook Portsmouth			33,099	449	33,548	114,369	33,548	H
N-019053	JAB04	Tuscan Village Phase 2			365,967	8,359	374,326	411,259	374,326	M
N-019054	JPB03	Forrest Street-Plaistow 492PSIG to 99PSIG			1,348,364	65,104	1,413,469	1,242,000	1,413,469	I
N-019055	ECN12	2019 Interface Enhancements			13,846	(669)	13,177	60,207	13,177	O
N-019056	ECN13	2019 Customer Facing Enhancements			228,291	4,193	232,484	1,107,769	232,484	O
N-019057	JHB05	Broadway Dover Relocate			175,683	349	176,032	180,207	176,032	H
N-019058	JPB05	Plaistow System Improvement			2,624,277	477,689	3,101,967	2,856,591	3,101,967	I
N-019059	JAB05	160 Corporate Dr Portsmouth			155,451	3,459	158,910	147,843	158,910	M
N-019060	JAB06	114 Rochester Hill Rd Rochester			65,561		65,561	83,088	65,561	M
N-019061	JAB07	6,6A,8 & 10 Danville Rd Plaistow			108,058		108,058	95,002	108,058	M
N-019062	JHB06	Vaughan St Portsmouth			169,351		169,351	159,491	169,351	H
N-019063	JAB08	206 Green St Somersworth			20,898	15,936	36,834	90,207	36,834	M
N-019064	JAB09	Atkinson CC phase 2 on site mains and services			46,821	25,509	72,331	241,603	72,331	M
N-019065	JAB10	410-430 Islington St Portsmouth			26,954	1,783	28,737	62,476	28,737	M
N-019066	JAB11	97 Grafton Dr Portsmouth NH			81,951	(16,857)	65,094	66,581	65,094	M
N-019067	JPN06	323 Gonic Rd Rochester NH			84,080	400	84,480	96,813	84,480	O
N-019068	JPB08	Gas SCADA - Replace Telephone Landline Services			9,368	255	9,623	26,455	9,623	O
N-019069	JAB12	236 Winnicunnet Rd Hampton aka Vineyard Place			36,616	7,444	44,060	116,670	44,060	M
N-019070	JHB07	Railroad Ave Rochester			560,576	12,819	573,395	780,325	573,395	H
N-019071	JAB13	Kingston Expansion - Benevento Agregates			823,754	(316,695)	507,059	502,637	507,059	M
N-019072	JPN07	Regulator Station Modifications			182,518	95,862	278,380	258,000	278,380	O
N-019073	JHB08	Whidden St Portsmouth NH			55,991	202	56,193	73,861	56,193	H
N-019074	ECN14	MV-90xi Upgrade v4.5 to 6.0			573	9,006	9,579	118,850	9,579	O
N-019075	ECN15	FCS Upgrade			546	9,723	10,269	76,615	10,269	O
N-019076	ECN16	Compliancy Management System Enhancements			7,278	10,714	17,992	80,000	17,992	O
N-019077	JAB14	653 Exeter Rd Hampton aka Labrador Ln			18,950		18,950	88,571	18,950	M
N-019078	JAB15	36 Rochester Neck Rd Rochester			109,671	16,847	126,518	101,304	126,518	M
N-019079	ECN17	GIS Enhancements			3,998		3,998	21,350	3,998	O
N-019080	ECN18	Replace MV-90 communication bank modules			2,093	1,234	3,327	54,940	3,327	O
N-019081	JPB04	Dover system reinforcement			678,803	(56,358)	622,444	556,576	622,444	I

Northern Utilities
Actual Spending by Project and Year 2017 - 2020

Category	Actual Spending 2017	2018	2019	2020
Growth				
Customer Additions (C)	3,788,223	4,536,609	4,054,112	4,000,481
Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

Authorization	Budget Number	Description	Actual Spending 2017	2018	2019	2020	Grand Total	Authorized	Total Project Spending	Category
N-019082	ECN19	LocusView Mobile Data Collection Enhancements			10,880		10,880	33,375	10,880	O
N-019083	JAB16	8 Chase Park Rd Seabrook NH			1,427	(1,427)	-	82,407	-	M
N-019084	JPB11	Borthwick Ave Reinforcement Portsmouth			293,786	3,843	297,629	481,655	297,629	I
N-019086	JAB18	2 Heritage Ln Atkinson			2,468	11,574	14,042	76,496	14,042	M
N-019087	JAB19	Cottage Park Dr Dover			14,279	40,891	55,170	76,269	55,170	M
N-019088	ECN20	Gas SCADA - Historical Database Addition			5,219		5,219	25,000	5,219	O
N-019089	JAB20	2 Tri-City Rd Somersworth			157,456	(2,318)	155,138	151,352	155,138	M
N-019092	JAB22	69 Main St Exeter NH			27,364	232	27,595	48,323	27,595	M
N-019093	JAB23	58 New Rochester Rd Dover			43,143	434	43,577	54,171	43,577	M
N-020000	MAB20	Gas Distribution System Improvements				278,758	278,758	520,795	278,758	O
N-020001	MBB20	New Gas Services				2,261,495	2,261,495	2,262,790	2,261,495	C
N-020002	MCB20	Corrosion Control				93,941	93,941	196,767	93,941	O
N-020003	MDB20	Abandoned Gas Services				96,985	96,985	198,687	96,985	O
N-020004	MEB20	Gas Service Upgrades				1,821,296	1,821,296	1,611,560	1,821,296	O
N-020005	MHB20	Gas Meter Purchases - Comapny				288,250	288,250	534,820	288,250	O
N-020006	MFB20	Gas Meter Installations - Company				759,829	759,829	572,597	759,829	O
N-020007	MIB20	Gas Meter Purchases - Customer				614,909	614,909	712,604	614,909	C
N-020008	MGB20	Gas Meter Installations - Customer				737,992	737,992	790,635	737,992	C
N-020009	MKB20	Gas Water Heater Replacements				68,743	68,743	109,273	68,743	O
N-020010	MJB20	New Water Heater Installations				22,244	22,244	110,000	22,244	C
N-020011	MMB20	Gas Distribution System Improvements - Operations				279,893	279,893	270,000	279,893	O
N-020013	JPB47	Rochester Reinforcement-99 PSIG Station				577,094	577,094	1,116,935	577,094	RR
N-020014	JPB42	Cyber Security Compliant Contractor Laptop for field telemetry				14,354	14,354	73,464	14,354	O
N-020015	GPB01	Normal Improvements to Portsmouth Facility				1,634	1,634	18,000	1,634	O
N-020016	EAG01	Tools: Normal Additions and Replacements				36,332	36,332	32,522	36,332	O
N-020017	EDG01	Office Furniture & Equipment Normal Additions & Replacements				858	858	4,750	858	O
N-020018	EDG02	Chair Replacement - Year 2 of 3 Year Replacement				9,978	9,978	9,500	9,978	O
N-020019	ECN01	2020 IT Infrastructure Budget				301,181	301,181	1,748,027	301,181	O
N-020020	ECN02	2020 Customer Facing Enhancements				138,605	138,605	874,202	138,605	O
N-020021	ECN03	Metersense Upgrade 2020				6,725	6,725	15,850	6,725	O
N-020022	ECN04	2020 Interface Enhancements				29,156	29,156	216,313	29,156	O
N-020023	ECN05	Regulatory Work Blanket				9,426	9,426	47,244	9,426	O
N-020025	ECN07	2020 General Software Enhancements				829	829	50,000	829	O
N-020026	ECN08	Reporting Blanket				26,585	26,585	125,000	26,585	O
N-020028	ECN10	Universal Payment System Enhancements				745	745	75,000	745	O
N-020029	ECN11	DevOps Implementation Project				32,941	32,941	232,500	32,941	O
N-020032	EAG02	Gas System Operations Tools				17,008	17,008	17,000	17,008	O
N-020033	EAG03	Normal Add / Replace - Metering and FS				729	729	5,000	729	O
N-020034	EAG06	Replace FC300 Handhelds and MC3 Drive By Equipment				51,825	51,825	60,000	51,825	O
N-020035	ECN13	Cyber Security Enhancements				21,917	21,917	110,000	21,917	O
N-020036	ECN14	SalesForce - Gas Sales Reporting				15,123	15,123	45,000	15,123	O
N-020037	ECN15	Cloud Data Warehouse				5,187	5,187	50,000	5,187	O
N-020039	JPB15	Farm Tap Replacement				158,547	158,547	511,485	158,547	F
N-020040	JHB01	Main St @ S. Broadway Salem				376,852	376,852	429,830	376,852	H
N-020041	JPB01	Asphalt Restoration 2019 Projects				757,084	757,084	740,000	757,084	A
N-020042	JAB01	South Village - Tuscan				173,814	173,814	314,182	173,814	M
N-020043	JPB46	Railrod Ave Gonic System Improvement				3,179,004	3,179,004	5,019,772	3,179,004	RR
N-020044	JPB44	Pipeline Safety Management System				53,163	53,163	73,464	53,163	O
N-020045	JAB02	Village at Clark Brook, Rochetser				98,779	98,779	161,729	98,779	M
N-020046	ECN16	Ubisense Custom Enhancements				21,452	21,452	363,159	21,452	O
N-020047	ECN17	LocusView - Paperless Workflows				26,180	26,180	91,000	26,180	O
N-020048	JPB48	Rochester Reinforcement Phase 3 - 99 psig Main				60,510	60,510	1,327,926	60,510	RR
N-020050	JAB03	UNH -6 Leavitt Ln., Durham				157,490	157,490	159,000	157,490	M
N-020051	JHB02	Richmond St City Relocate				123,684	123,684	149,865	123,684	H
N-020052	JHB03	Industrial Way				70,073	70,073	121,075	70,073	H
N-020053	JAB04	Silvergrass Place - 79 Timber Swamp Rd., Hampton				65,667	65,667	403,270	65,667	M

Northern Utilities
Actual Spending by Project and Year 2017 - 2020

	Actual Spending			
Category	**2017**	**2018**	**2019**	**2020**
Growth				
Customer Additions (C)	3,788,223	4,536,609	4,054,112	4,000,481
Mains Extensions (M)	2,726,109	3,731,884	4,096,295	5,551,479
Subtotal Growth	6,514,332	8,268,493	8,150,408	9,551,960
Non-Growth				
Pipe Replacement Programs (P)	6,076,439	608,427	68,134	0
Other Replacement Programs (R)	0	0	0	0
System Improvements (I)	0	0	5,459,992	1,502,499
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Asphault Restoration (A)	0	0	330,731	757,084
Farm Tap Replacement (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Other Non-Growth (O)	4,213,481	4,256,033	4,594,436	5,211,429
Subtotal Non-Growth	18,393,884	15,013,850	15,479,304	13,363,255
Total	24,908,216	23,282,343	23,629,712	22,915,216

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	6,076,439	608,427	68,134	-
Mains Extension excl. services (M)	2,726,109	3,731,884	4,096,295	5,551,479
Highway Projects (H)	6,884,380	8,486,669	1,576,202	1,746,392
Farm Tap Replacements (F)	360,949	309,556	596,908	164,144
Rochester Reinforcement (RR)	858,633	1,353,164	2,852,902	3,981,707
Total	16,906,512	14,489,701	9,190,441	11,443,722

% Growth	26%	36%	34%	42%
% Non-Growth	74%	64%	66%	58%
% Eligible Facilities	68%	62%	39%	50%

			Actual Spending							
Authorization	**Budget Number**	**Description**	**2017**	**2018**	**2019**	**2020**	**Grand Total**	**Authorized**	**Total Project Spending**	**Category**
N-020054	ECN18	Power Plan Upgrade				68,580	68,580	459,678	68,580	O
N-020055	JAB05	Main Extensions Under $40K				288,435	288,435	329,000	288,435	M
N-020057	JPN01	Dover Point Rd. Phase 1				223,106	223,106	180,940	223,106	I
N-020059	JAB06	Black Brook - Main Number				65,726	65,726	167,744	65,726	M
N-020060	JAB07	West End Yards - 428 Route 1 Bypass Portsmouth				215,420	215,420	334,177	215,420	M
N-020062	JHB05	67 Knox Marsh Rd., Dover (Builder Dig)				26,634	26,634	31,337	26,634	H
N-020063	JAB08	1 Princeton Way, Dover				47,375	47,375	69,418	47,375	M
N-020064	JAB09	230 Mill Rd, Hampton (Builder Dig)				27,399	27,399	57,497	27,399	M
N-020065	JAB10	280 Gosling Rd., Portsmouth - Granite Shore Power				184,025	184,025	184,025	184,025	M
N-020067	JPN02	489 Portland Ave., Rollinsford				61,150	61,150	60,688	61,150	C
N-020069	JHB06	Banfield Rd., Portsmouth				985,509	985,509	1,175,314	985,509	H
N-020070	JHB07	Coe Dr., Durham - City Relocate				133,361	133,361	125,150	133,361	H
N-020071	JAB11	53 New Rochester Rd., Dover				52,731	52,731	73,031	52,731	M
N-020072	JAB12	Tuscan Village - Medical Building Access Rd Salem				17,108	17,108	41,235	17,108	M
N-020073	JAB13	Epping Expansion Phase II				1,788,124	1,788,124	2,559,942	1,788,124	M
N-020079	JPN03	Salter St., Portsmouth				97,209	97,209	97,208	97,209	O
N-020080	JAB14	24 Wiley Creek Rd., Exeter (Ray Farm- Bldg B)				34,768	34,768	65,978	34,768	M
N-020081	JPB45	Old Dover Rd System Improvement Rochester				312,043	312,043	253,741	312,043	I
N-020082	JAB15	8 Chase Park., Seabrook				81,326	81,326	81,326	81,326	M
N-020083	JAB16	16 Locke Rd., Hampton				50,760	50,760	45,200	50,760	M
N-020084	JAB17	209 Chestnut Hill Rd., Rochester (New DPW)				213,502	213,502	400,561	213,502	M
N-020085	JPB43	Hampton IP System Improvement				251,076	251,076	385,177	251,076	I
N-020086	JAB18	650 peverly Hill Rd., Portsmouth				32,069	32,069	59,990	32,069	M
N-020087	JAB19	32, 37 and 40 Folly Mill Ter., Seabrook				35,175	35,175	41,409	35,175	M
N-020088	JAB20	207-209 High St., Somersworth				50,696	50,696	49,008	50,696	M
N-020090	ECN20	Customer Experience Mgmt Project Year 1 of 3				27,495	27,495	500,000	27,495	O
N-020091	JAB21	Pointe West - 40 Pointe Place., Dover				16,227	16,227	71,864	16,227	M
N-021000	MAB21	Gas Distribution System Improvements				15,383	15,383	521,045	15,383	O
Grand Total			24,908,216	23,282,343	23,629,712	22,915,216	94,735,487		117,540,511	

Northern Utilities
Forecast Spending by Project and Year 2021-2025

Category	2021	2022	2023	2024	2025
Growth					
Customer Additions (C)	4,521,457	4,672,273	4,756,276	5,173,559	5,260,893
Mains Extensions (M)	2,448,539	2,492,441	2,523,854	2,764,383	2,779,499
Subtotal Growth	6,969,996	7,164,714	7,280,130	7,937,942	8,040,392
Non-Growth					
Pipe Replacement Programs (P)	0	0	0	0	0
Other Replacement Programs (R)	2,708,556	2,907,854	5,237,628	2,296,204	6,204,282
System Improvements (I)	2,733,284	4,302,688	2,681,583	4,622,915	700,217
Highway Projects (H)	2,917,122	2,985,229	3,026,436	3,282,750	3,318,605
Asphault Restoration (A)	762,144	790,372	804,138	847,287	869,038
Farm Tap Replacement (F)	713,802	507,648	513,421	567,753	568,379
Rochester Reinforcement (RR)	3,463,845	3,338,300	2,894,112	0	0
Other Non-Growth (O)	9,779,300	8,290,723	8,609,016	10,775,422	11,441,596
Subtotal Non-Growth	23,078,053	23,122,814	23,766,334	22,392,331	23,102,117
Total	30,048,049	30,287,528	31,046,464	30,330,273	31,142,509

Eligible Facilities	(000'S)	(000'S)	(000'S)	(000'S)	(000'S)
Pipe Replacement (P)	-	-	-	-	-
Mains Extension excl. services (M)	2,448,539	2,492,441	2,523,854	2,764,383	2,779,499
Highway Projects (H)	2,917,122	2,985,229	3,026,436	3,282,750	3,318,605
Farm Tap Replacements (F)	713,802	507,648	513,421	567,753	568,379
Rochester Reinforcement (RR)	3,463,845	3,338,300	2,894,112	-	-
Total	9,543,308	9,323,618	8,957,823	6,614,886	6,666,483

% Growth	23%	24%	23%	26%	26%
% Non-Growth	77%	76%	77%	74%	74%
% Eligible Facilities	32%	31%	29%	22%	21%

Capital Budget 2021 Northern NH								
Code	#	Blankets:Gas	2021	2022	2023	2024	2025	Category
MAB		Distribution System Improvements	572,785	598,685	596,062	650,342	666,422	O
MAC		Distribution System Improvements, Carryover	17,544	18,309	18,555	20,056	20,568	O
MBB		New Gas Services	2,552,884	2,610,527	2,647,121	2,864,362	2,898,495	C
MBC		New Gas Services, Carryover	31,040	32,261	33,520	34,969	35,840	C
MCB		Corrosion Control	151,384	162,424	165,000	175,693	173,263	O
MDB		Abandoned Gas Services	213,404	225,274	227,546	245,843	253,615	O
MDC		Abandoned Gas Services, Carryover	9,603	10,123	10,260	11,050	11,419	O
MEB		Gas Service Upgrades	1,823,722	1,872,781	1,892,883	2,079,125	2,100,924	O
MEC		Gas Service Upgrades, Carryover	11,769	12,328	12,491	13,494	13,876	O
MFB		Meter Installations – Company	817,516	844,043	847,819	942,366	950,866	O
MFC		Meter Installations – Company Carryover	7,545	7,946	8,034	8,798	9,060	O
MGB		Meter Installations – Customer	896,139	912,162	916,489	1,033,355	1,031,336	C
MGC		Meter Installations – Customer	7,545	7,946	8,034	8,798	9,060	C
MHB		Meter Purchases – Company	450,056	845,169	876,588	941,558	984,481	O
MIB		Meter Purchases – Customer	531,618	988,177	1,024,912	1,100,875	1,151,062	C
MMB		Gas System Improve - System Ops	242,791	255,816	264,065	284,156	296,023	O
MMC		GasSystem Improve - System Ops - Carryover	36,286	51,669	53,616	57,660	63,230	O
		Sub-Totals:	8,373,631	9,455,640	9,602,995	10,472,500	10,669,540	
Code	#	Blankets:Water Heater	2021	2022	2023	2024	2025	
MJB		New Water Heaters and Conversion Burners	110,000	120,000	125,000	130,000	133,900	C
MJC		New Water Heaters and Conversion Burners, Carryover	1,160	1,200	1,200	1,200	1,200	C
MKB		Replacement Water Heater & Conversion Burner	110,000	115,928	119,406	122,988	126,677	O
MKC		Replacement Water Heater & Conversion Burner, Carryover	1,160	1,200	1,200	1,200	1,200	O
		Sub-Totals:	222,320	238,328	246,806	255,388	262,977	
Code	#	Communications:Gas	2021	2022	2023	2024	2025	
ECG	1	Replace and Upgrade Gas SCADA Master	22,886	0	0	0	0	O

ECG	2	Provide New Gas SCADA Communications - various locations	11,685	0	0	0	0	O
		Sub-Totals:	34,571	0	0	0	0	
Code	#	Distribution:Gas	2021	2022	2023	2024	2025	
JAB		Main Extensions	2,385,028	2,427,039	2,457,455	2,693,202	2,707,074	M
JAC		Main Extensions, Carryover	63,511	65,402	66,399	71,181	72,425	M
JHB		Gas Highway Projects, Budgeted	2,906,740	2,974,498	3,015,526	3,271,176	3,306,776	H
JHC		Gas Highway Projects, Carryover	10,382	10,731	10,910	11,574	11,829	H
JPB	1	Asphalt Restoration 2020 Projects	762,144	0	0	0	0	A
JPB	1	Asphalt Restoration 2021 Projects	0	790,372	0	0	0	A
JPB	1	Asphalt Restoration 2022 Projects	0	0	804,138	0	0	A
JPB	1	Asphalt Restoration 2023 Projects	0	0	0	847,287	0	A
JPB	1	Asphalt Restoration 2024 Projects	0	0	0	0	869,038	A
JPB	3	Distribution Gas Main Upgrades	429,100	0	0	0	0	R
JPB	3	Distribution Gas Main Upgrades	0	441,090	0	0	0	R
JPB	3	Distribution Gas Main Upgrades	0	0	447,719	0	0	R
JPB	3	Distribution Gas Main Upgrades	0	0	0	480,816	0	R
JPB	3	Distribution Gas Main Upgrades	0	0	0	0	1,465,301	R
JPB	4	Farm Tap Replacement	500,672	0	0	0	0	F
JPB	4	Farm Tap Replacement	0	507,648	0	0	0	F
JPB	4	Farm Tap Replacement	0	0	513,421	0	0	F
JPB	4	Farm Tap Replacement	0	0	0	567,753	0	F
JPB	4	Farm Tap Replacement	0	0	0	0	568,379	F
JPB	5	Regulator Station OPP/Redundancy	238,408	0	0	0	0	O
JPB	10	Unspecified System Improvement	0	695,884	0	0	0	I
JPB	10	Unspecified System Improvement	0	0	687,383	0	0	I
JPB	10	Unspecified System Improvement	0	0	0	421,903	0	I
JPB	11	Unspecified distribution projects	0	0	0	2,812,686	0	O
JPB	11	Unspecified distribution projects	0	0	0	0	1,400,434	O
JPB	12	Exeter Hampton 171 psig Replacement Phase 1	0	1,428,483	0	0	0	I
JPB	12	Exeter Hampton 171 psig Replacement Phase 2	0	0	1,417,966	0	0	I
JPB	14	Rte 108 Back Feed Phase 1	0	1518705	0	0	0	RR
JPB	14	Rte 108 Back Feed Phase 2	0	0	1464623	0	0	RR
JPB	14	Rte 108 Back Feed Phase 3	0	0	123234	0	0	RR
JPB	16	Low Pressure System Replacement	0	470,790	0	0	0	R
JPB	16	Low Pressure System Replacement	0	0	477,684	0	0	R
JPB	17	Regulator Station OPP/Redundancy	0	734655	0	0	0	O
JPB	17	Regulator Station OPP/Redundancy	0	0	1241492	0	0	O
JPB	17	Regulator Station OPP/Redundancy	0	0	0	745987	0	O
JPB	17	Regulator Station OPP/Redundancy	0	0	0	0	743017	O
JPB	21	Heater Replacement - Newfields Station	1075197	0	0	0	0	O
JPB	22	Henry Law Ave Dover Replacement	195827	0	0	0	0	R
JPB	23	Plaistow System Improvement Phase 2	498258	0	0	0	0	I
JPB	24	Bartlett Avenue/High Street Stations Rebuild-PHASE 1	538855	0	0	0	0	RR
JPB	25	Monroe Street Station Upgrade	375174	0	0	0	0	O
JPB	26	Stard Road Mini-DR Station Install	391,071	0	0	0	0	C
JPB	27	Rutland Street Station Rebuild	467,790	0	0	0	0	O
JPB	28	Ashbrook Rd., Exeter	213,130	0	0	0	0	F
JPB	29	Partridge Green Replacement Rochester	875,346	0	0	0	0	R
JPB	30	GIS Data Development - Services & Station Utilities	143,762	0	0	0	0	O
JPB	31	AC Interference Mitigation (NH)	66,445	0	0	0	0	O
JPB	32	Railroad Ave. Rochester	1,208,283	0	0	0	0	R
JPB	33	Borthwick Ave. Footbridge Crossing	276,448	0	0	0	0	O
JPB	34	Middle Road System Improvement	630,410	0	0	0	0	I
JPB	35	Atkinson System Improvement Phase 3	1,375,881	0	0	0	0	I
JPB	40	Hawthorne/Applevale Stations Rebuild	0	1995974	0	0	0	R
JPB	41	Barberry Lane Regulator Station Upgrade	0	1336328	0	0	0	I
JPB	44	Applevale/Hawthorne Distribution Laterals	0	478230	0	0	0	I
JPB	45	Hampton IP System Improvement	0	363763	0	0	0	I
JPB	46	Bartlett Avenue/High Street Stations Rebuild-PHASE 2	0	1819595	0	0	0	RR
JPB	50	Gosling Rd Regulator Station Replacement	0	0	1777593	0	0	R
JPB	51	Stratham Industrial Park Station Replacement-171PSIG to 56PSIG	0	0	1770025	0	0	R
JPB	52	Whitehall Road Vaults-45 PSIG Back-feed-Rochester	0	0	1306255	0	0	RR
JPB	53	CNG Skid-System Maintenance	0	0	756121	0	0	O
JPB	54	Applevale Lateral	0	0	576234	0	0	I
JPB	55	Seabrook Dog Track Station Replacement-New mini-DR	0	0	463427	0	0	R
JPB	56	Gosling Rd. Newington Main Extension to New Station	0	0	142,544	0	0	R
JPB	57	Cross Ridge Estates Replacement	0	0	158,636	0	0	R
JPB	61	Hampton-Seabrook Bridge Improvement	0	0	0	1657508	0	I
JPB	63	Hampton/Seabrook Canal Reinforcement Station	0	0	0	1271752	0	I

JPB	64	Wentworth Ave Vaults-56 PSIG Back-feed-Plaistow	0	0	0	1271752	0	I
JPB	65	Nimble Hill Road Station Replacement-492PSIG to 56PSIG	0	0	0	1815388	0	R
JPB	70	Unspecified system improvement	0	0	0	0	700217	I
JPB	73	Timberswamp Station Hampton-REBUILD	0	0	0	0	1563322	R
JPB	74	Sweet Hill Road Station Plaistow-Regulator run replacement	0	0	0	0	793083	R
JPB	77	East Kingston Station-REBUILD	0	0	0	0	2382576	R
JPB	78	New Heater Installation - Ocean Road Station	0	0	0	0	2332128	O
JPC	1	Rochester Reinforcement - 99 PSIG Station-Carryover	580107	0	0	0	0	RR
JPC	2	Rochester Reinforcement Phase 3 - 99 psig Main Carryover	2344883	0	0	0	0	RR
JPC	3	Atkinson System Improvement Phase 2 Carryover	228735	0	0	0	0	I
		Sub-Totals:	18,781,587	18,059,187	19,678,785	17,939,965	18,915,599	
Code	#	Tools, Shop, Garage:Gas	2021	2022	2023	2024	2025	
EAG	1	Tools: Normal Additions and Replacements	33,497	0	0	0	0	O
EAG	1	Tools: Normal Additions and Replacements	0	34,502	0	0	0	O
EAG	1	Tools: Normal Additions and Replacements	0	0	35,537	0	0	O
EAG	1	Normal add & replace- tools & equipment - Meter and FS	0	0	0	5,050	0	O
EAG	1	Tools: Normal Additions and Replacements	0	0	0	0	37,701	O
EAG	2	Tools: Normal Additions and Replacements - Systems Operations	17,000	0	0	0	0	O
EAG	2	Tools: Normal Additions and Replacements - Systems Operations	0	17,000	0	0	0	O
EAG	2	Tools: Normal Additions and Replacements - Systems Operations	0	0	17,000	0	0	O
EAG	2	Tools: Normal Additions and Replacements	0	0	0	36,603	0	O
EAG	2	Tools: Normal Additions and Replacements - Systems Operations	0	0	0	0	17,000	O
EAG	3	Normal add & replace- tools & equipment - Metering and FS	5,050	0	0	0	0	O
EAG	3	Normal add & replace- tools & equipment - Metering and FS	0	5,050	0	0	0	O
EAG	3	Normal add & replace- tools & equipment - Meter and FS	0	0	5,050	0	0	O
EAG	3	Tools: Normal Additions and Replacements - Systems Operations	0	0	0	17,000	0	O
EAG	3	Normal add & replace- tools & equipment - Metering and FS	0	0	0	0	5,050	O
EAG	4	Mueller Equipment	110,000	0	0	0	0	O
EAG	4	Mueller Equipment	0	110,000	0	0	0	O
EAG	4	Mueller Equipment	0	0	110,000	0	0	O
EAG	5	Emergency Response Trailer	30,000	0	0	0	0	O
EAG	5	Training Equipment/Materials	0	25,000	0	0	0	O
EAG	5	Training Equipment/Materials	0	0	25,000	0	0	O
EAG	5	Training Equipment/Materials	0	0	0	25,000	0	O
EAG	6	TTQM Tools for OQ Training	20,000	0	0	0	0	O
		Sub-Totals:	215,547	191,552	192,587	83,653	59,751	
Code	#	Office:Gas	2021	2022	2023	2024	2025	
EDG	1	Office Furniture & Equipment- Normal Additions & Replacements	5,000	0	0	0	0	O
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	0	5,000	0	0	0	O
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	0	0	5,000	0	0	O
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	0	0	0	5,000	0	O
EDG	1	Office Furniture & Equipment Normal Additions & Replacements	0	0	0	0	5,000	O
EDG	2	Chair Replacement - Year 3 of 3 Year Replacement Program	9,000	0	0	0	0	O
		Sub-Totals:	14,000	5,000	5,000	5,000	5,000	
Code	#	Structures:General	2021	2022	2023	2024	2025	
GPB	1	Normal Improvements to Portsmouth Facility	18,000	0	0	0	0	O
GPB	1	Normal Improvements to Portsmouth Facility	0	18,000	0	0	0	O
GPB	1	Normal Improvements to Portsmouth Facility	0	0	18,000	0	0	O
GPB	1	Normal Improvements to Portsmouth Facility	0	0	0	18,000	0	O
GPB	1	Normal Improvements to Portsmouth Facility	0	0	0	0	18,000	O
GPB	2	HVAC Upgrades	800,000	0	0	0	0	O
GPB	2	Bathroom Renovations	0	150,000	0	0	0	O
GPB	2	Building Systems Upgrades or Replacements	0	0	50,000	0	0	O
GPB	2	Building Systems Upgrades or Replacements	0	0	0	50,000	0	O
GPB	2	Building Systems Upgrades or Replacements	0	0	0	0	50,000	O
GPB	3	Carpet Replacement	0	150,000	0	0	0	O
GPB	4	Facilities Improvements - Portsmouth	300,000	0	0	0	0	O
GPB	4	Upgrade Office & General Lighting	0	120,000	0	0	0	O
GPB	5	Site Improvements	0	500,000	0	0	0	O
		Sub-Totals:	1,118,000	938,000	68,000	68,000	68,000	
Code	#	Transportation:Gas	2021	2022	2023	2024	2025	
FGB	1	#44- Metering- Van	1	0	0	0	0	O
FGB	1	Replace Van #2 - Warehouse	0	1	0	0	0	O
FGB	1	Replace truck #6 Distribution	0	0	1	0	0	O
FGB	1	#40 - Service Dept - Van	0	0	0	1	0	O
FGB	1	#26-Distribution-Street Truck	0	0	0	0	1	O
FGB	2	#58- Manager Gas Operations- SUV	1	0	0	0	0	O
FGB	2	Replace truck #16 Gas Operations	0	1	0	0	0	O
FGB	2	Replace truck #12 Distribution	0	0	1	0	0	O

FGB	2	#39 - Metering - Small Pickup	0	0	0	1	0	O
FGB	2	#35-Distribution- Fitter truck	0	0	0	0	1	O
FGB	3	#13- Service- Weld Truck	1	0	0	0	0	O
FGB	3	Replace #5 - Metering	0	1	0	0	0	O
FGB	3	Replace van #59 Service	0	0	1	0	0	O
FGB	3	#59 - Service Dept - Van	0	0	0	1	0	O
FGB	3	#51- Procurment- Box Truck	0	0	0	0	1	O
FGB	4	#47- Distribution- Backhoe	1	0	0	0	0	O
FGB	4	Replace Van #30 Service	0	1	0	0	0	O
FGB	4	Replace van #60 Service	0	0	1	0	0	O
FGB	4	#21 - Distribution - Small Pickup	0	0	0	1	0	O
FGB	5	Replace pickup #6 Distribution	0	1	0	0	0	O
FGB	5	Replace Van #41 - Service	0	0	1	0	0	O
FGB	5	#60 - Service Dept - Van	0	0	0	1	0	O
FGB	6	Replace pickup #12 Distribution	0	1	0	0	0	O
FGB	6	Replace Van #40 Service	0	0	1	0	0	O
FGB	6	#5 - Metering - Small Pickup	0	0	0	1	0	O
FGB	7	Replace Service Van #62	0	1	0	0	0	O
FGB	8	Replace Van #42 Service	0	1	0	0	0	O
		Totals:	28,759,660	28,887,715	29,794,179	28,824,512	29,980,870	

Unitil Service Corp
Forecast Spending by Project and Year 2021-2025
Allocation to Northern Utilities

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

											NU NH Allocations				
Priority • Status	Code	Item	2021	2022	2023	2024	2025	Sub-Total	Catgory	Division	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	14,250	-	-	-	-
2 • [A] Accepted	GSC04	Reporting Blanket	100,000	0	0	0	0	100,000	S	All	19,000	-	-	-	-
2 • [A] Accepted	GSC05	2021 Regulatory Work Blanket	22,000	0	0	0	0	22,000	S	All	4,180	-	-	-	-
1 • [A] Accepted	GSC06	2021 Customer Facing Enhancements	1,067,465	0	0	0	0	1,067,465	S	All	202,818	-	-	-	-
1 • [A] Accepted	GSC08	Metersense Upgrade 2021	18,800	0	0	0	0	18,800	S	All	3,572	-	-	-	-
1 • [A] Accepted	GSC09	AMI Command Center Upgrade to 8.0	35,000	0	0	0	0	35,000	S	All	6,650	-	-	-	-
2 • [A] Accepted	GSC10	Close - Workflow & Electronic Review	50,000	0	0	0	0	50,000	S	All	9,500	-	-	-	-
1 • [A] Accepted	GSC11	FERC to XBRL	138,000	0	0	0	0	138,000	S	All	26,220	-	-	-	-
3 • [A] Accepted	GSC14	Virtual Payables - Credit Card	3,000	0	0	0	0	3,000	S	All	570	-	-	-	-
2 • [A] Accepted	GSC15	Web Ops Modernization	200,000	0	0	0	0	200,000	S	All	38,000	-	-	-	-
2 • [A] Accepted	GSC16	Advanced Distribution Management System (ADMS) - Grid Mod	1,030,000	0	0	0	0	1,030,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC17	Unitil website upgrade - Year 2 of 2	170,000	0	0	0	0	170,000	S	All	32,300	-	-	-	-
2 • [A] Accepted	GSC19	Modernize GTRAC & CSI	72,000	0	0	0	0	72,000	S	All	13,680	-	-	-	-
2 • [A] Accepted	GSC21	Customer Experience Mgmt Project - Year 2 of 3	2,665,000	0	0	0	0	2,665,000	S	All	506,350	-	-	-	-
1 • [A] Accepted	GSC22	Customer exports used for Gas Engineering CMM Module	20,400	0	0	0	0	20,400	S	Gas	6,528	-	-	-	-
2 • [A] Accepted	GSC25	GTI / Pxio VR Training Project	135,000	0	0	0	0	135,000	S	Gas	43,200	-	-	-	-
1 • [A] Accepted	GSC26	Command Center Upgrade to Cellular	68,000	0	0	0	0	68,000	S	All	12,920	-	-	-	-
1 • [A] Accepted	GSC27	TOU Testing	375,950	0	0	0	0	375,950	S	Electric	-	-	-	-	-
2 • [A] Accepted	GSC28	Cloud Data Warehouse, Carryover	50,000	0	0	0	0	50,000	S	All	9,500	-	-	-	-
2 • [A] Accepted	GSC29	DevOps Implementation Project, Carryover	150,000	0	0	0	0	150,000	S	All	28,500	-	-	-	-
2 • [A] Accepted	GSC30	Damage Assessment Mobile Platform - Grid Mod, Carry Over	125,000	0	0	0	0	125,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC31	Ubisense Custom Enhancements, Carryover	155,059	0	0	0	0	155,059	S	Gas	49,619	-	-	-	-
1 • [A] Accepted	GSC32	USC Time & Billing Upgrade/Replacement, Carryover	50,000	0	0	0	0	50,000	S	All	9,500	-	-	-	-
3 • [A] Accepted	GSC33	ADP Modules - Data Cloud, Time Off and Time Entry, Carryover	141,000	0	0	0	0	141,000	S	All	26,790	-	-	-	-
2 • [A] Accepted	GSC35	Ring Central Phase II	76,600	0	0	0	0	76,600	S	All	14,554	-	-	-	-
2 • [A] Accepted	GSC36	Data Sharing: Unitil Core Platform Design	600,000	0	0	0	0	600,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC37	S&S Oracle Upgrade Test Environment	200,000	0	0	0	0	200,000	S	All	38,000	-	-	-	-
2 • [A] Accepted	GSC38	Data Sharing: Community Aggregation Module	200,000	0	0	0	0	200,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC39	Grid Mod: AMI/OMS Phase 2 Collector Integration	100,000	0	0	0	0	100,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC01	GIS Upgrade to Utility Network	0	395,000	0	0	0	395,000	S	All	-	75,050	-	-	-
3 • [A] Accepted	GSC02	2022 General Software Enhancements	0	217,799	0	0	0	217,799	S	All	-	41,382	-	-	-
2 • [A] Accepted	GSC03	CMS Enhancements - Yr 4 CMS Reporting	0	50,000	0	0	0	50,000	S	All	-	9,500	-	-	-
2 • [A] Accepted	GSC05	Reporting Blanket	0	60,000	0	0	0	60,000	S	All	-	11,400	-	-	-
2 • [A] Accepted	GSC06	Regulatory Work Blanket	0	100,000	0	0	0	100,000	S	All	-	19,000	-	-	-
1 • [A] Accepted	GSC07	2022 Customer Facing Enhancements	0	500,000	0	0	0	500,000	S	All	-	95,000	-	-	-
1 • [A] Accepted	GSC10	MV-90xi Upgrade V6.0 to X.X 2022	0	90,000	0	0	0	90,000	S	Electric	-	-	-	-	-
2 • [A] Accepted	GSC12	Cloud Discovery and Migration Work	0	500,000	0	0	0	500,000	S	All	-	95,000	-	-	-
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	-	13,722	-	-	-
2 • [A] Accepted	GSC13	Web Ops Modernization	0	200,000	0	0	0	200,000	S	All	-	38,000	-	-	-
2 • [A] Accepted	GSC13	TOU and Advanced Rate Design Implementation	0	500,000	0	0	0	500,000	S	Electric	-	-	-	-	-
2 • [A] Accepted	GSC14	Customer Experience Mgmt Project Year 3 of 3	0	1,940,000	0	0	0	1,940,000	S	All	-	368,600	-	-	-
2 • [A] Accepted	GSC15	Distributed Energy Resource Management System (DERMS) - Grid Mod	0	475,000	0	0	0	475,000	G	Electric	-	-	-	-	-
1 • [A] Accepted	GSC16	AMI Command Center Upgrade - 2022	0	92,000	0	0	0	92,000	S	All	-	17,480	-	-	-
2 • [A] Accepted	GSC17	Advanced Distribution Management System (ADMS) - Grid Mod	0	640,000	0	0	0	640,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC18	Flexi Upgrade	0	75,000	0	0	0	75,000	S	All	-	14,250	-	-	-
2 • [A] Accepted	GSC18	Utility Bill Redesign	0	171,575	0	0	0	171,575	S	All	-	32,599	-	-	-
2 • [A] Accepted	GSC19	Smart Speaker Integration	0	150,000	0	0	0	150,000	S	All	-	28,500	-	-	-
1 • [A] Accepted	GSC20	Metersense Upgrade 2022	0	50,000	0	0	0	50,000	S	All	-	9,500	-	-	-
2 • [A] Accepted	GSC21	Payment Alternatives	0	150,000	0	0	0	150,000	S	All	-	28,500	-	-	-
2 • [A] Accepted	GSC24	Construction QA Manager System	0	205,000	0	0	0	205,000	S	Gas	-	65,600	-	-	-

Unitil Service Corp
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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

											NU NH Allocations				
Priority • Status	Code	Item	2021	2022	2023	2024	2025	Sub-Total	Catgory	Division	2021	2022	2023	2024	2025
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	-	9,500	-	-	-
3 • [A] Accepted	GSC47	Capital Budget System	0	450,000	0	0	0	450,000	S	All	-	85,500	-	-	-
2 • [A] Accepted	GSC48	Data Sharing: Behind the Meter Module	0	105,000	0	0	0	105,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC01	Distributed Energy Resource Management System (DERMS) - Grid Mod	0	0	275,000	0	0	275,000	G	Electric	-	-	-	-	-
3 • [A] Accepted	GSC01	Power Plan Upgrade	0	0	295,000	0	0	295,000	S	All	-	-	56,050	-	-
3 • [A] Accepted	GSC02	2023 General Software Enhancements	0	0	250,469	0	0	250,469	S	All	-	-	47,589	-	-
2 • [A] Accepted	GSC02	Work Order Job Scheduler	0	0	350,000	0	0	350,000	S	All	-	-	66,500	-	-
2 • [A] Accepted	GSC03	CMS Enhancements - Yr 5 Inspection Rewrite	0	0	100,000	0	0	100,000	S	Gas	-	-	32,000	-	-
2 • [A] Accepted	GSC04	Reporting Blanket	0	0	48,750	0	0	48,750	S	All	-	-	9,263	-	-
2 • [A] Accepted	GSC05	Regulatory Work Blanket	0	0	100,000	0	0	100,000	S	All	-	-	19,000	-	-
1 • [A] Accepted	GSC06	2023 Customer Facing Enhancements	0	0	1,012,958	0	0	1,012,958	S	All	-	-	192,462	-	-
1 • [A] Accepted	GSC07	Metersense Upgrade 2023	0	0	50,000	0	0	50,000	S	All	-	-	9,500	-	-
1 • [A] Accepted	GSC08	AMI Command Center Upgrade - 2023	0	0	92,000	0	0	92,000	S	All	-	-	17,480	-	-
2 • [A] Accepted	GSC10	Personalized selling / next best action	0	0	500,000	0	0	500,000	s	All	-	-	95,000	-	-
2 • [A] Accepted	GSC11	Cloud Discovery and Migration Work	0	0	600,000	0	0	600,000	S	All	-	-	114,000	-	-
2 • [A] Accepted	GSC12	Web Ops Modernization	0	0	200,000	0	0	200,000	S	All	-	-	38,000	-	-
2 • [A] Accepted	GSC15	DevOps Implementation Project	0	0	232,500	0	0	232,500	S	All	-	-	44,175	-	-
2 • [A] Accepted	GSC16	Customer Experience System Phase 2	0	0	600,000	0	0	600,000	S	All	-	-	114,000	-	-
2 • [A] Accepted	GSC17	Advanced Distribution Management System (ADMS) - Grid Mod	0	0	275,000	0	0	275,000	G	Electric	-	-	-	-	-
3 • [A] Accepted	GSC20	Capital Budget System	0	0	470,000	0	0	470,000	S	All	-	-	89,300	-	-
2 • [A] Accepted	GSC21	Data Sharing: System Data Module	0	0	75,000	0	0	75,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC01	Flexi Upgrade	0	0	0	75,000	0	75,000	S	All	-	-	-	14,250	-
1 • [A] Accepted	GSC03	Metersense Upgrade 2024	0	0	0	50,000	0	50,000	S	All	-	-	-	9,500	-
1 • [A] Accepted	GSC04	AMI Command Center Upgrade - 2024	0	0	0	92,000	0	92,000	S	All	-	-	-	17,480	-
3 • [A] Accepted	GSC05	2024 General Software Enhancements	0	0	0	350,000	0	350,000	S	All	-	-	-	66,500	-
2 • [A] Accepted	GSC06	Reporting Blanket	0	0	0	48,750	0	48,750	S	All	-	-	-	9,263	-
2 • [A] Accepted	GSC08	Web Ops Modernization	0	0	0	500,000	0	500,000	S	All	-	-	-	95,000	-
2 • [A] Accepted	GSC09	Cloud Discovery and Migration Work	0	0	0	500,000	0	500,000	S	All	-	-	-	95,000	-
2 • [A] Accepted	GSC10	DevOps Implementation Project	0	0	0	482,500	0	482,500	S	All	-	-	-	91,675	-
1 • [A] Accepted	GSC12	Artificial Intelligence Enterprise Solution	0	0	0	150,000	0	150,000	G	All	-	-	-	28,500	-
2 • [A] Accepted	GSC14	Customer Engagement Vision Items	0	0	0	200,000	0	200,000	S	All	-	-	-	38,000	-
2 • [A] Accepted	GSC16	Advanced Distribution Management System (ADMS) - Grid Mod	0	0	0	175,000	0	175,000	G	Electric	-	-	-	-	-
2 • [A] Accepted	GSC23	AOC Click to Report System	0	0	0	180,000	0	180,000	S	All	-	-	-	34,200	-
1 • [A] Accepted	GSC45	FCS Upgrade	0	0	0	15,000	0	15,000	S	All	-	-	-	2,850	-
2 • [A] Accepted	GSC46	Locusview Mobile / CMS Integration	0	0	0	30,000	0	30,000	S	Gas	-	-	-	9,600	-
1 • [A] Accepted	GSC47	enQuesta Ver. 6.0 Upgrade	0	0	0	3,281,279	0	3,281,279	S	All	-	-	-	623,443	-
2 • [A] Accepted	GSC48	Regulatory Work Blanket	0	0	0	100,000	0	100,000	S	All	-	-	-	19,000	-
1 • [A] Accepted	GSC02	Metersense Upgrade 2025	0	0	0	0	50,000	50,000	S	All	-	-	-	-	9,500
1 • [A] Accepted	GSC03	AMI Command Center Upgrade - 2025	0	0	0	0	92,000	92,000	S	All	-	-	-	-	17,480
2 • [A] Accepted	GSC07	Regulatory Work Blanket	0	0	0	0	100,000	100,000	S	All	-	-	-	-	19,000
1 • [A] Accepted	GSC22	enQuesta Ver. 6.0 Upgrade	0	0	0	0	1,640,641	1,640,641	S	All	-	-	-	-	311,722
3 • [A] Accepted	GSC23	2025 General Software Enhancements	0	0	0	0	350,000	350,000	S	All	-	-	-	-	66,500
2 • [A] Accepted	GSC24	Reporting Blanket	0	0	0	0	48,750	48,750	S	All	-	-	-	-	9,263
2 • [A] Accepted	GSC25	Web Ops Modernization	0	0	0	0	500,000	500,000	S	All	-	-	-	-	95,000
2 • [A] Accepted	GSC26	Cloud Discovery and Migration Work	0	0	0	0	500,000	500,000	S	All	-	-	-	-	95,000
2 • [A] Accepted	GSC27	DevOps Implementation Project	0	0	0	0	482,500	482,500	S	All	-	-	-	-	91,675
3 • [A] Accepted	GSC28	Blanket Data Project	0	0	0	0	1,000,000	1,000,000	S	All	-	-	-	-	190,000
2 • [A] Accepted	GSC29	Customer Engagement Marketplace	0	0	0	0	250,000	250,000	S	All	-	-	-	-	47,500
2 • [A] Accepted	GSC30	Grid Mod Improvements	0	0	0	0	500,000	500,000	G	Electric	-	-	-	-	-
Sub-Totals:			8,093,274	7,298,094	5,526,677	6,229,529	5,513,891				1,116,201	1,099,138	944,319	1,154,261	952,639
1 • [A] Accepted	GPC01	2021 Cyber Security Enhancements	45,000	0	0	0	0	45,000	N		All	8,550	-	-	-	-

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Category	2021	2022	2023	2024	2025
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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

											NU NH Allocations				
Priority • Status	Code	Item	2021	2022	2023	2024	2025	Sub-Total	Catgory	Division	2021	2022	2023	2024	2025
2 • [**A**] Accepted	GPC02	2021 Infrastructure PC and Network	855,252	0	0	0	0	855,252	N	All	162,498	-	-	-	-
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	1,140	-	-	-	-
1 • [A] Accepted	GPC01	2022 Cyber Security Enhancements	0	100,000	0	0	0	100,000	N	All	-	19,000	-	-	-
2 • [A] Accepted	GPC02	2022 Infrastructure PC and Network	0	1,322,500	0	0	0	1,322,500	N	All	-	251,275	-	-	-
3 • [A] Accepted	GPC03	Network Segmentation	0	160,000	0	0	0	160,000	N	All	-	30,400	-	-	-
1 • [A] Accepted	GPC01	2023 Cyber Security Enhancements	0	0	100,000	0	0	100,000	N	All	-	-	19,000	-	-
2 • [A] Accepted	GPC02	2023 Infrastructure PC and Network	0	0	1,520,875	0	0	1,520,875	N	All	-	-	288,966	-	-
2 • [A] Accepted	GPC01	2024 Infrastructure PC and Network	0	0	0	1,750,000	0	1,750,000	N	All	-	-	-	332,500	-
1 • [A] Accepted	GPC02	2024 Cyber Security Enhancements	0	0	0	100,000	0	100,000	N	All	-	-	-	19,000	-
3 • [A] Accepted	GPC01	2025 Cyber Security Enhancements	0	0	0	0	100,000	100,000	N	All	-	-	-	-	19,000
2 • [A] Accepted	GPC02	2025 Infrastructure PC and Network	0	0	0	0	1,000,000	1,000,000	N	All	-	-	-	-	190,000
Sub-Totals:			906,252	1,582,500	1,620,875	1,850,000	1,100,000	7,059,627			172,188	300,675	307,966	351,500	209,000
Totals:			8,999,526	8,880,594	7,147,552	8,079,529	6,613,891	42,912,819			**1,288,389**	**1,399,813**	**1,252,285**	**1,505,761**	**1,161,639**

2017 Project Support

year	funding_project	quantity	amount
2017	N-003022	0	(3,787.50)
2017	N-004000	-22	31.35
2017	N-004001	7	(1,718.57)
2017	N-004004	-28	449.22
2017	N-004011	0	-
2017	N-004059	0	(444.42)
2017	N-005000	10	(1,311.87)
2017	N-005003	0	(0.18)
2017	N-005004	9	(11,430.77)
2017	N-005011	-10	(180.09)
2017	N-005016	0	15,119.27
2017	N-005017	0	2,040.00
2017	N-005021	0	-
2017	N-005039	0	(8,667.90)
2017	N-005061	0	(95.37)
2017	N-005072	0	69.16
2017	N-005077	0	12,783.16
2017	N-006000	-2456	(100,256.51)
2017	N-006001	10837	136,535.56
2017	N-006002	-8	1,319.13
2017	N-006003	18	(317.14)
2017	N-006004	1270	(79,984.04)
2017	N-006005	0	114.95
2017	N-006006	1522	28,831.85
2017	N-006007	0	12,965.47
2017	N-006008	130	22,504.18
2017	N-006009	0	(3,301.98)
2017	N-006010	0	2,395.00
2017	N-006011	28.5	12,635.94
2017	N-006014	0	2,280.00
2017	N-006015	0	1,378.50
2017	N-006017	0	4,958.30
2017	N-006020	-906	13,453.75
2017	N-006027	0	(3,100.81)
2017	N-006028	0	320.34
2017	N-006029	0	4,141.54
2017	N-006030	5786	(125,561.61)
2017	N-006031	4490	123,749.74
2017	N-006036	0	55,800.00
2017	N-006038	646	11,797.12
2017	N-006039	2572	118,725.80
2017	N-006040	0	4,820.34
2017	N-006041	13	12.93
2017	N-006043	0	2,908.70
2017	N-006044	0	329.94
2017	N-006046	554	(4,121.00)
2017	N-006052	757	(2,566.82)
2017	N-006053	0	3,249.95
2017	N-006054	0	-
2017	N-006055	-646	(647.89)
2017	N-006056	2332	107,748.83
2017	N-006057	1318	2,002.41

2017 Project Support

year	funding_project	quantity	amount
2017	N-006060	0	2,417.98
2017	N-006061	0	4.69
2017	N-007000	4627	302,888.34
2017	N-007001	72604.5	2,493,048.21
2017	N-007002	79	34,447.85
2017	N-007003	1437	114,695.36
2017	N-007004	21396.5	1,200,090.81
2017	N-007005	0	486,361.96
2017	N-007006	16444.5	966,269.19
2017	N-007007	0	417,505.06
2017	N-007008	6464	626,912.47
2017	N-007009	7	56,653.31
2017	N-007010	0	78,170.69
2017	N-007011	419	113,178.23
2017	N-007013	14190.5	1,322,544.78
2017	N-007014	560	744,817.49
2017	N-007015	0	1,595.87
2017	N-007016	0	13,214.74
2017	N-007017	47124.5	4,953,860.16
2017	N-007018	0	25,505.70
2017	N-007019	0	20,820.58
2017	N-007020	0	4,364.84
2017	N-007022	2856	838,595.26
2017	N-007023	2970	44,070.24
2017	N-007024	0	17,066.43
2017	N-007025	0	1,683.70
2017	N-007028	90.5	34,314.36
2017	N-007029	618	36,336.72
2017	N-007030	698	49,924.92
2017	N-007032	709	42,207.07
2017	N-007033	0	2,623.17
2017	N-007034	0	116,310.27
2017	N-007035	0	1,011.87
2017	N-007036	0	64,830.71
2017	N-007037	0	32,650.00
2017	N-007038	0	8,689.21
2017	N-007039	230	91,923.12
2017	N-007040	19268	2,958,680.93
2017	N-007041	1565	260,227.62
2017	N-007042	7160	236,195.86
2017	N-007044	0	11,334.89
2017	N-007045	2964	237,040.82
2017	N-007046	4716	637,717.06
2017	N-007047	0	4,467.12
2017	N-007048	625	176,836.90
2017	N-007050	884	179,612.42
2017	N-007051	652	119,443.14
2017	N-007052	9228	455,007.20
2017	N-007054	3852	232,480.71
2017	N-007056	0	16,840.72
2017	N-007057	1221	17,999.16
2017	N-007058	6355	779,656.09

2017 Project Support

year	funding_project	quantity	amount
2017	N-007059	8285	858,633.41
2017	N-007060	0	4,586.63
2017	N-007061	1783	235,922.78
2017	N-007062	1064	72,283.68
2017	N-007063	4359	37,977.46
2017	N-007064	1022	44,089.88
2017	N-007065	530	20,644.75
2017	N-007066	0	1,059.21
2017	N-007067	567	14,331.04
2017	N-007068	986	66,857.47
2017	N-007069	269	11,153.42
2017	N-007070	385	55,221.95
2017	N-007071	583	26,684.49
2017	N-007073	0	34,700.34
2017	N-007078	0	1,380,945.34
			24,908,215.81
			24,907,700.00
			515.81

2018 Project Support

year	funding_project	quantity	amount
2018	N-005000	0	(20,745.23)
2018	N-005004	0	(29,689.14)
2018	N-005016	0	9,511.46
2018	N-005017	0	(2,040.00)
2018	N-005054	0	(24,918.23)
2018	N-005072	0	-
2018	N-005077	0	160.05
2018	N-006000	0	0.45
2018	N-006001	20	(216.94)
2018	N-006003	-8	(1,291.88)
2018	N-006004	-69	(10,189.07)
2018	N-006031	7253	3,423.09
2018	N-006038	-1017	699.02
2018	N-006039	1516	(1,854.08)
2018	N-006056	593	(13,920.83)
2018	N-007000	339	(150,093.08)
2018	N-007001	12535	(111,059.57)
2018	N-007002	0	1.11
2018	N-007003	109	4,288.63
2018	N-007004	1878	(53,271.31)
2018	N-007005	0	23,449.12
2018	N-007006	44	6,815.88
2018	N-007007	0	7,816.38
2018	N-007008	31	6,708.79
2018	N-007009	0	2,560.77
2018	N-007010	0	5,121.13
2018	N-007011	-7	8,370.36
2018	N-007013	3545.5	40,571.17
2018	N-007014	1076	(39,610.59)
2018	N-007017	354	(3,176.26)
2018	N-007018	0	30.48
2018	N-007023	901	(8,492.01)
2018	N-007024	0	(1,244.34)
2018	N-007025	0	358.55
2018	N-007033	0	2,266.36
2018	N-007035	0	923.83
2018	N-007037	0	-
2018	N-007038	0	265.84
2018	N-007039	164	88,589.65
2018	N-007040	5761	74,935.38
2018	N-007042	669	2,465.34
2018	N-007044	0	(2,589.14)
2018	N-007045	0	16,320.56
2018	N-007046	1390	(1,557.23)
2018	N-007047	0	12,188.84
2018	N-007050	576	5,439.84
2018	N-007051	265	(1,064.79)
2018	N-007052	17062	503,726.89
2018	N-007054	4322	173,137.94
2018	N-007056	1663	4,275.97
2018	N-007057	0	14,302.38
2018	N-007058	4084	(105,465.24)

2018 Project Support

year	funding_project	quantity	amount
2018	N-007059	1933	(10,049.96)
2018	N-007060	0	4,870.60
2018	N-007061	327	(8,384.31)
2018	N-007062	955	(89.62)
2018	N-007063	-4359	(37,977.46)
2018	N-007066	0	3,920.37
2018	N-007067	1317	4,240.94
2018	N-007068	15	(48.34)
2018	N-007069	0	-
2018	N-007070	92	(370.83)
2018	N-007071	217	1,259.00
2018	N-007073	0	62,631.26
2018	N-007074	3214	56,940.14
2018	N-007075	969	5,035.03
2018	N-007076	1394	51,365.53
2018	N-007077	0	-
2018	N-008000	13313	604,670.11
2018	N-008001	74218	2,900,187.33
2018	N-008002	138	76,426.50
2018	N-008003	2188.5	178,828.50
2018	N-008004	16896	1,414,463.89
2018	N-008005	0	342,881.25
2018	N-008006	9440	496,518.69
2018	N-008007	0	559,077.36
2018	N-008008	9095	924,918.42
2018	N-008011	125	105,232.02
2018	N-008016	16	103,774.64
2018	N-008017	0	74,160.62
2018	N-008018	0	5,941.70
2018	N-008019	0	23,715.70
2018	N-008020	0	704,753.22
2018	N-008021	0	24,049.24
2018	N-008022	0	674.76
2018	N-008023	0	20,646.60
2018	N-008024	49	276,455.33
2018	N-008025	0	24,181.69
2018	N-008026	0	8,502.12
2018	N-008027	0	91,131.54
2018	N-008028	0	103,815.46
2018	N-008029	0	36,822.54
2018	N-008030	2583	6,572,621.28
2018	N-008031	0	26,433.75
2018	N-008033	0	17,455.14
2018	N-008034	0	2,078.73
2018	N-008035	0	14,837.24
2018	N-008036	0	11,775.51
2018	N-008038	0	4,661.60
2018	N-008039	0	13,005.00
2018	N-008040	1524	466,235.13
2018	N-008041	9267	252,895.65
2018	N-008042	1014	271,399.88
2018	N-008043	0	1,363,214.42

2018 Project Support

year	funding_project	quantity	amount
2018	N-008045	730	168,874.48
2018	N-008046	689	59,678.97
2018	N-008047	1560	351,465.87
2018	N-008048	3594	529,477.99
2018	N-008049	2032	101,142.09
2018	N-008050	936	154,354.47
2018	N-008051	905	112,128.96
2018	N-008052	52.5	29,770.85
2018	N-008053	0	16,134.42
2018	N-008054	1852	78,495.70
2018	N-008055	689	29,051.37
2018	N-008056	1278	46,639.97
2018	N-008057	974	88,789.44
2018	N-008058	0	2,738.99
2018	N-008059	39	196,409.86
2018	N-008063	12	69,368.63
2018	N-008064	0	12,466.50
2018	N-008065	2436	135,874.76
2018	N-008066	1318	69,579.87
2018	N-008067	1833	48,816.03
2018	N-008068	243	65,241.42
2018	N-008069	2140	92,712.69
2018	N-008070	188	75,030.43
2018	N-008071	455	10,291.92
2018	N-008072	1685	57,727.85
2018	N-008074	0	1,375.51
2018	N-008076	2207	273,550.06
2018	N-008078	28519	980,373.59
2018	N-008079	742	24,165.48
2018	N-008080	2363	138,163.79
2018	N-008081	1649	169,895.64
2018	N-008083	2041	82,015.02
2018	N-008084	701	18,929.43
2018	N-008085	543	59,494.79
2018	N-008087	243	22,895.30
2018	N-008088	19	9,397.41
2018	N-008089	751	0.03
2018	N-008090	675	22,011.86
2018	N-008091	455	41,397.71
2018	N-008094	710	78,689.88
2018	N-008095	873	58,983.01
2018	N-008096	194	10,448.72
2018	N-019003	5	271.36
			23,282,343.33
			23,282,000.00
			343.33

2019 Project Support

year	funding_project	quantity	amount	notes
2019	N-005000	0	-	
2019	N-005004	0	-	
2019	N-006000	0	-	
2019	N-007001	6	(1,278.48)	
2019	N-007004	0	(16.25)	
2019	N-007042	0	1,056.65	Offset with C7003 MDO18
2019	N-007052	2125	(36,583.80)	
2019	N-007057	135	824.90	
2019	N-008000	-530	(177,706.97)	
2019	N-008001	4838	182,592.48	
2019	N-008002	63	505.18	
2019	N-008003	41	1,091.65	
2019	N-008004	-1301	(103,120.76)	
2019	N-008006	149	5,908.07	
2019	N-008008	14	26,087.29	
2019	N-008011	48	13,523.19	
2019	N-008016	0	(9,087.39)	
2019	N-008017	0	5,891.48	
2019	N-008019	0	3,394.37	
2019	N-008020	0	-	
2019	N-008022	0	1,318.36	
2019	N-008023	0	6,980.05	
2019	N-008024	0	(23,756.62)	
2019	N-008025	0	3,733.92	
2019	N-008027	0	(91,131.54)	
2019	N-008028	0	(103,815.46)	
2019	N-008029	0	(36,822.54)	
2019	N-008031	0	5,504.26	
2019	N-008032	0	5,491.93	
2019	N-008033	0	8,342.98	
2019	N-008034	0	670.63	
2019	N-008035	0	(2,018.87)	
2019	N-008036	0	1,537.16	
2019	N-008037	0	4,371.60	
2019	N-008038	0	(530.56)	
2019	N-008041	310	11,549.85	
2019	N-008043	257.5	2,280,690.10	
2019	N-008048	0	-	
2019	N-008050	232	(787.09)	
2019	N-008052	41.5	6,658.69	
2019	N-008056	297	7,320.31	
2019	N-008058	0	(230.77)	
2019	N-008064	0	1,539.97	
2019	N-008065	1489	18,558.27	
2019	N-008070	39	5,926.74	
2019	N-008072	0	(1,118.72)	
2019	N-008073	0	656.97	
2019	N-008074	0	296.08	
2019	N-008075	0	2,403.23	
2019	N-008078	15728.5	277,388.12	
2019	N-008079	166	28,100.88	
2019	N-008080	10	171.05	

2019 Project Support

year	funding_project	quantity	amount	notes
2019	N-008081	15	2,057.19	
2019	N-008084	284	41,542.29	
2019	N-008085	0	-	
2019	N-008088	3942	73,750.56	
2019	N-008089	588	18,565.43	
2019	N-008091	123	4,104.61	
2019	N-008093	329	73,259.74	
2019	N-008095	308	1,088.78	
2019	N-008096	959	13,667.62	
2019	N-008102	0	3,800.00	
2019	N-019000	6540	312,087.80	
2019	N-019001	50829	2,241,161.90	
2019	N-019002	96	41,885.43	
2019	N-019003	2277.5	164,748.57	
2019	N-019004	12675	927,956.02	
2019	N-019005	0	474,635.97	
2019	N-019006	11375	567,699.81	
2019	N-019007	0	765,445.88	
2019	N-019008	6792.5	770,573.47	
2019	N-019009	0	85,714.93	
2019	N-019010	11	61,581.24	
2019	N-019011	647	141,424.46	
2019	N-019013	0	29,912.25	
2019	N-019014	7	4,495.25	
2019	N-019015	0	7,108.23	
2019	N-019016	0	11,755.88	
2019	N-019017	0	1,523.94	
2019	N-019018	0	246,672.27	
2019	N-019019	0	60,753.00	
2019	N-019020	0	8,453.59	
2019	N-019021	0	11,456.44	
2019	N-019022	0	20,109.64	
2019	N-019023	0	55,119.58	
2019	N-019024	0	29,136.01	
2019	N-019025	0	17,824.00	
2019	N-019026	278	40,509.31	
2019	N-019027	836	57,238.50	
2019	N-019028	258	68,150.20	
2019	N-019029	4902	516,519.31	
2019	N-019030	0	5,085.89	
2019	N-019031	2601	572,211.73	
2019	N-019032	0	330,730.67	
2019	N-019033	95	67,877.40	
2019	N-019034	0	276.61	
2019	N-019035	0	20,440.11	
2019	N-019036	1288	874,439.96	
2019	N-019037	385	514,761.66	
2019	N-019040	541	40,998.06	
2019	N-019041	0	165,649.32	
2019	N-019042	0	24,256.06	
2019	N-019044	0	1,315.55	ECO10 Add to Capital Budget
2019	N-019045	728	75,052.50	

2019 Project Support

year	funding_project	quantity	amount	notes
2019	N-019046	4626	363,492.67	
2019	N-019047	296	1,102,090.87	
2019	N-019050	367	142,957.43	
2019	N-019051	12151	427,098.78	
2019	N-019052	203	33,098.74	
2019	N-019053	9542	365,967.03	
2019	N-019054	1104	1,348,364.39	
2019	N-019055	0	13,846.22	
2019	N-019056	0	228,291.28	
2019	N-019057	1066	175,683.10	
2019	N-019058	13545	2,624,277.10	
2019	N-019059	3960	155,451.23	
2019	N-019060	2205	65,560.75	
2019	N-019061	1033	108,057.57	
2019	N-019062	1135	169,350.69	
2019	N-019063	1386	20,898.04	
2019	N-019064	3378	46,821.42	
2019	N-019065	710	26,954.05	
2019	N-019066	2861	81,951.28	
2019	N-019067	1242	84,079.77	
2019	N-019068	0	9,368.07	
2019	N-019069	868	36,615.88	
2019	N-019070	9	560,575.98	
2019	N-019071	5347	823,753.63	
2019	N-019072	353	182,517.89	
2019	N-019073	484	55,990.72	
2019	N-019074	0	573.14	
2019	N-019075	0	545.88	
2019	N-019076	0	7,277.86	
2019	N-019077	1229	18,949.51	
2019	N-019078	1302	109,671.00	
2019	N-019079	0	3,998.00	
2019	N-019080	0	2,092.88	
2019	N-019081	1602	678,802.72	
2019	N-019082	0	10,880.00	
2019	N-019083	1197	1,426.51	
2019	N-019084	3843	293,786.18	
2019	N-019086	0	2,467.96	
2019	N-019087	474	14,278.78	
2019	N-019088	0	5,219.04	
2019	N-019089	2987	157,456.11	
2019	N-019092	646	27,363.61	
2019	N-019093	430	43,143.04	
			23,629,712.01	
			23,629,900.00	
			(187.99)	

2020 Project Support

year	funding_project	quantity	amount	notes
2020	N-006000	0	(108.30)	
2020	N-007004	0	-	
2020	N-008000	0	-	
2020	N-008001	23	(6,153.81)	
2020	N-008003	0	(2,334.22)	
2020	N-008004	0	-	
2020	N-008042	0	(2,689.03)	
2020	N-008043	91.5	165,099.02	
2020	N-008078	1500	13,264.70	
2020	N-008079	493	(902.25)	
2020	N-008088	1402	(2,566.71)	
2020	N-008089	175	21.24	
2020	N-019000	77	(18,135.29)	
2020	N-019001	5326	85,877.24	
2020	N-019002	-12	(1,244.20)	
2020	N-019003	43	3,495.89	
2020	N-019004	968	13,532.10	
2020	N-019005	0	56,203.80	
2020	N-019006	131	5,165.17	
2020	N-019007	0	224,585.76	
2020	N-019008	323	(7,502.34)	
2020	N-019009	0	5,013.33	
2020	N-019010	3	5,883.29	
2020	N-019011	0	3,877.15	
2020	N-019013	0	2,474.06	
2020	N-019018	0	(6,977.80)	
2020	N-019019	0	10,404.29	
2020	N-019020	0	3,371.89	
2020	N-019021	0	2,090.19	
2020	N-019022	0	1,918.58	
2020	N-019029	1260	5,596.67	
2020	N-019030	0	1,612.59	
2020	N-019031	0	-	
2020	N-019033	265	211,236.78	
2020	N-019035	0	-	
2020	N-019036	359	24,005.19	
2020	N-019037	514	225,996.73	
2020	N-019041	0	30,695.68	
2020	N-019042	0	11,828.52	
2020	N-019044	0	4,292.15	
2020	N-019045	236	(2,344.20)	
2020	N-019046	474	21,494.16	
2020	N-019047	453	1,815,311.15	
2020	N-019050	0	-	
2020	N-019051	5941	234,564.22	
2020	N-019052	6	449.16	
2020	N-019053	2378	8,359.05	
2020	N-019054	349	65,104.17	
2020	N-019055	0	(669.05)	
2020	N-019056	0	4,193.16	
2020	N-019057	159	349.21	
2020	N-019058	6402	477,689.47	
2020	N-019059	57	3,458.98	
2020	N-019063	822	15,936.10	
2020	N-019064	1029	25,509.11	

2020 Project Support

year	funding_project	quantity	amount	notes
2020	N-019065	222	1,783.38	
2020	N-019066	764	(16,856.82)	
2020	N-019067	0	400.01	
2020	N-019068	0	254.63	
2020	N-019069	646	7,444.19	
2020	N-019070	170	12,819.27	
2020	N-019071	207	(316,694.81)	
2020	N-019072	248	95,862.21	
2020	N-019073	178	201.85	
2020	N-019074	53.5	9,005.83	
2020	N-019075	166.5	9,723.02	
2020	N-019076	0	10,714.37	
2020	N-019078	429.5	16,847.49	
2020	N-019080	0	1,233.67	
2020	N-019081	55	(56,358.49)	
2020	N-019083	4	(1,426.51)	
2020	N-019084	0	3,842.52	
2020	N-019086	1389	11,573.93	
2020	N-019087	0	40,891.19	JAC20
2020	N-019089	515	(2,317.92)	
2020	N-019092	49	231.87	
2020	N-019093	465	433.72	JAC27
2020	N-020000	12703	278,758.06	
2020	N-020001	39856	2,261,495.49	
2020	N-020002	104	93,940.59	
2020	N-020003	1212.5	96,985.42	
2020	N-020004	15673	1,821,296.45	
2020	N-020005	0	288,249.52	
2020	N-020006	12020	759,828.65	
2020	N-020007	0	614,909.37	
2020	N-020008	6960.5	737,992.42	
2020	N-020009	0	68,743.08	
2020	N-020010	8	22,243.53	
2020	N-020011	639	279,893.16	
2020	N-020013	7706	577,093.56	
2020	N-020014	0	14,353.81	
2020	N-020015	0	1,634.00	
2020	N-020016	0	36,331.51	
2020	N-020017	0	858.11	
2020	N-020018	0	9,977.57	
2020	N-020019	0	301,181.48	
2020	N-020020	0	138,605.18	
2020	N-020021	0	6,725.39	
2020	N-020022	0	29,156.35	
2020	N-020023	0	9,426.30	
2020	N-020025	0	829.30	
2020	N-020026	0	26,584.87	
2020	N-020028	0	744.58	
2020	N-020029	0	32,940.52	
2020	N-020032	0	17,008.29	
2020	N-020033	0	728.91	
2020	N-020034	0	51,824.80	
2020	N-020035	0	21,917.06	
2020	N-020036	0	15,122.57	
2020	N-020037	0	5,186.76	

2020 Project Support

year	funding_project	quantity	amount	notes
2020	N-020039	660	158,546.83	
2020	N-020040	1582	376,851.57	
2020	N-020041	0	757,083.95	
2020	N-020042	7725	173,813.51	
2020	N-020043	107.5	3,179,004.19	
2020	N-020044	0	53,163.03	
2020	N-020045	2675	98,778.95	
2020	N-020046	0	21,451.58	
2020	N-020047	0	26,180.00	
2020	N-020048	0	60,509.84	
2020	N-020050	2328	157,489.78	
2020	N-020051	2587	123,683.55	
2020	N-020052	845	70,072.75	
2020	N-020053	1726	65,666.57	
2020	N-020054	0	68,580.21	
2020	N-020055	8981	288,435.46	
2020	N-020056	0	-	
2020	N-020057	1208	223,105.76	
2020	N-020059	1878	65,725.57	
2020	N-020060	2760	215,419.77	
2020	N-020062	1490	26,633.92	
2020	N-020063	1233	47,375.46	
2020	N-020064	1022	27,399.31	
2020	N-020065	2004	184,024.89	
2020	N-020067	634	61,150.12	
2020	N-020069	5911	985,508.77	
2020	N-020070	1376	133,361.39	
2020	N-020071	1371	52,730.55	
2020	N-020072	48	17,107.73	
2020	N-020073	891	1,788,124.06	
2020	N-020079	512	97,209.25	
2020	N-020080	1485	34,767.60	
2020	N-020081	4030	312,043.05	
2020	N-020082	162	81,325.77	
2020	N-020083	1270	50,759.83	
2020	N-020084	5667	213,501.85	
2020	N-020085	1379	251,076.09	
2020	N-020086	1098	32,069.01	
2020	N-020087	647	35,175.27	
2020	N-020088	478	50,695.90	
2020	N-020090	0	27,494.96	
2020	N-020091	863	16,227.20	
2020	N-021000	0	15,382.70	
			22,915,215.56	
			22,915,000.00	
			215.56	
	N-020049	0	757,629.45	Removed Pension PBOP

2017-2020 Supporting Pivot Table

Sum of amount	Column Labels				
Row Labels	2017	2018	2019	2020	Grand Total
N-003022	(3,787.50)				(3,787.50)
N-004000	31.35				31.35
N-004001	(1,718.57)				(1,718.57)
N-004004	449.22				449.22
N-004059	(444.42)				(444.42)
N-005000	(1,311.87)	(20,745.23)			(22,057.10)
N-005003	(0.18)				(0.18)
N-005004	(11,430.77)	(29,689.14)			(41,119.91)
N-005011	(180.09)				(180.09)
N-005016	15,119.27	9,511.46			24,630.73
N-005017	2,040.00	(2,040.00)			-
N-005039	(8,667.90)				(8,667.90)
N-005054		(24,918.23)			(24,918.23)
N-005061	(95.37)				(95.37)
N-005072	69.16				69.16
N-005077	12,783.16	160.05			12,943.21
N-006000	(100,256.51)	0.45		(108.30)	(100,364.36)
N-006001	136,535.56	(216.94)			136,318.62
N-006002	1,319.13				1,319.13
N-006003	(317.14)	(1,291.88)			(1,609.02)
N-006004	(79,984.04)	(10,189.07)			(90,173.11)
N-006005	114.95				114.95
N-006006	28,831.85				28,831.85
N-006007	12,965.47				12,965.47
N-006008	22,504.18				22,504.18
N-006009	(3,301.98)				(3,301.98)
N-006010	2,395.00				2,395.00
N-006011	12,635.94				12,635.94
N-006014	2,280.00				2,280.00
N-006015	1,378.50				1,378.50
N-006017	4,958.30				4,958.30
N-006020	13,453.75				13,453.75
N-006027	(3,100.81)				(3,100.81)
N-006028	320.34				320.34
N-006029	4,141.54				4,141.54
N-006030	(125,561.61)				(125,561.61)
N-006031	123,749.74	3,423.09			127,172.83
N-006036	55,800.00				55,800.00
N-006038	11,797.12	699.02			12,496.14
N-006039	118,725.80	(1,854.08)			116,871.72
N-006040	4,820.34				4,820.34
N-006041	12.93				12.93
N-006043	2,908.70				2,908.70
N-006044	329.94				329.94
N-006046	(4,121.00)				(4,121.00)
N-006052	(2,566.82)				(2,566.82)
N-006053	3,249.95				3,249.95
N-006055	(647.89)				(647.89)
N-006056	107,748.83	(13,920.83)			93,828.00
N-006057	2,002.41				2,002.41
N-006060	2,417.98				2,417.98
N-006061	4.69				4.69
N-007000	302,888.34	(150,093.08)			152,795.26
N-007001	2,493,048.21	(111,059.57)	(1,278.48)		2,380,710.16
N-007002	34,447.85	1.11			34,448.96
N-007003	114,695.36	4,288.63			118,983.99
N-007004	1,200,090.81	(53,271.31)	(16.25)		1,146,803.25
N-007005	486,361.96	23,449.12			509,811.08
N-007006	966,269.19	6,815.88			973,085.07
N-007007	417,505.06	7,816.38			425,321.44
N-007008	626,912.47	6,708.79			633,621.26
N-007009	56,653.31	2,560.77			59,214.08
N-007010	78,170.69	5,121.13			83,291.82
N-007011	113,178.23	8,370.36			121,548.59
N-007013	1,322,544.78	40,571.17			1,363,115.95
N-007014	744,817.49	(39,610.59)			705,206.90
N-007015	1,595.87				1,595.87
N-007016	13,214.74				13,214.74
N-007017	4,953,860.16	(3,176.26)			4,950,683.90
N-007018	25,505.70	30.48			25,536.18
N-007019	20,820.58				20,820.58
N-007020	4,364.84				4,364.84
N-007022	838,595.26				838,595.26
N-007023	44,070.24	(8,492.01)			35,578.23
N-007024	17,066.43	(1,244.34)			15,822.09
N-007025	1,683.70	358.55			2,042.25
N-007028	34,314.36				34,314.36
N-007029	36,336.72				36,336.72
N-007030	49,924.92				49,924.92
N-007032	42,207.07				42,207.07
N-007033	2,623.17	2,266.36			4,889.53
N-007034	116,310.27				116,310.27
N-007035	1,011.87	923.83			1,935.70
N-007036	64,830.71				64,830.71
N-007037	32,650.00				32,650.00
N-007038	8,689.21	265.84			8,955.05
N-007039	91,923.12	88,589.65			180,512.77
N-007040	2,958,680.93	74,935.38			3,033,616.31
N-007041	260,227.62				260,227.62
N-007042	236,195.86	2,465.34	1,056.65		239,717.85
N-007044	11,334.89	(2,589.14)			8,745.75

2017-2020 Supporting Pivot Table

N-007045	237,040.82	16,320.56			253,361.38
N-007046	637,717.06	(1,557.23)			636,159.83
N-007047	4,467.12	12,188.84			16,655.96
N-007048	176,836.90				176,836.90
N-007050	179,612.42	5,439.84			185,052.26
N-007051	119,443.14	(1,064.79)			118,378.35
N-007052	455,007.20	503,726.89	(36,583.80)		922,150.29
N-007054	232,480.71	173,137.94			405,618.65
N-007056	16,840.72	4,275.97			21,116.69
N-007057	17,999.16	14,302.38	824.90		33,126.44
N-007058	779,656.09	(105,465.24)			674,190.85
N-007059	858,633.41	(10,049.96)			848,583.45
N-007060	4,586.63	4,870.60			9,457.23
N-007061	235,922.78	(8,384.31)			227,538.47
N-007062	72,283.68	(89.62)			72,194.06
N-007063	37,977.46	(37,977.46)			-
N-007064	44,089.88				44,089.88
N-007065	20,644.75				20,644.75
N-007066	1,059.21	3,920.37			4,979.58
N-007067	14,331.04	4,240.94			18,571.98
N-007068	66,857.47	(48.34)			66,809.13
N-007069	11,153.42				11,153.42
N-007070	55,221.95	(370.83)			54,851.12
N-007071	26,684.49	1,259.00			27,943.49
N-007073	34,700.34	62,631.26			97,331.60
N-007074		56,940.14			56,940.14
N-007075		5,035.03			5,035.03
N-007076		51,365.53			51,365.53
N-007078	1,380,945.34				1,380,945.34
N-008000		604,670.11	(177,706.97)		426,963.14
N-008001		2,900,187.33	182,592.48	(6,153.81)	3,076,626.00
N-008002		76,426.50	505.18		76,931.68
N-008003		178,828.50	1,091.65	(2,334.22)	177,585.93
N-008004		1,414,463.89	(103,120.76)		1,311,343.13
N-008005		342,881.25			342,881.25
N-008006		496,518.69	5,908.07		502,426.76
N-008007		559,077.36			559,077.36
N-008008		924,918.42	26,087.29		951,005.71
N-008011		105,232.02	13,523.19		118,755.21
N-008016		103,774.64	(9,087.39)		94,687.25
N-008017		74,160.62	5,891.48		80,052.10
N-008018		5,941.70			5,941.70
N-008019		23,715.70	3,394.37		27,110.07
N-008020		704,753.22			704,753.22
N-008021		24,049.24			24,049.24
N-008022		674.76	1,318.36		1,993.12
N-008023		20,646.60	6,980.05		27,626.65
N-008024		276,455.33	(23,756.62)		252,698.71
N-008025		24,181.69	3,733.92		27,915.61
N-008026		8,502.12			8,502.12
N-008027		91,131.54	(91,131.54)		-
N-008028		103,815.46	(103,815.46)		-
N-008029		36,822.54	(36,822.54)		-
N-008030		6,572,621.28			6,572,621.28
N-008031		26,433.75	5,504.26		31,938.01
N-008032			5,491.93		5,491.93
N-008033		17,455.14	8,342.98		25,798.12
N-008034		2,078.73	670.63		2,749.36
N-008035		14,837.24	(2,018.87)		12,818.37
N-008036		11,775.51	1,537.16		13,312.67
N-008037			4,371.60		4,371.60
N-008038		4,661.60	(530.56)		4,131.04
N-008039		13,005.00			13,005.00
N-008040		466,235.13			466,235.13
N-008041		252,895.65	11,549.85		264,445.50
N-008042		271,399.88		(2,689.03)	268,710.85
N-008043		1,363,214.42	2,280,690.10	165,099.02	3,809,003.54
N-008045		168,874.48			168,874.48
N-008046		59,678.97			59,678.97
N-008047		351,465.87			351,465.87
N-008048		529,477.99			529,477.99
N-008049		101,142.09			101,142.09
N-008050		154,354.47	(787.09)		153,567.38
N-008051		112,128.96			112,128.96
N-008052		29,770.85	6,658.69		36,429.54
N-008053		16,134.42			16,134.42
N-008054		78,495.70			78,495.70
N-008055		29,051.37			29,051.37
N-008056		46,639.97	7,320.31		53,960.28
N-008057		88,789.44			88,789.44
N-008058		2,738.99	(230.77)		2,508.22
N-008059		196,409.86			196,409.86
N-008063		69,368.63			69,368.63
N-008064		12,466.50	1,539.97		14,006.47
N-008065		135,874.76	18,558.27		154,433.03
N-008066		69,579.87			69,579.87
N-008067		48,816.03			48,816.03
N-008068		65,241.42			65,241.42
N-008069		92,712.69			92,712.69
N-008070		75,030.43	5,926.74		80,957.17
N-008071		10,291.92			10,291.92
N-008072		57,727.85	(1,118.72)		56,609.13
N-008073			656.97		656.97
N-008074		1,375.51	296.08		1,671.59

2017-2020 Supporting Pivot Table

N-008075		2,403.23		2,403.23
N-008076	273,550.06			273,550.06
N-008078	980,373.59	277,388.12	13,264.70	1,271,026.41
N-008079	24,165.48	28,100.88	(902.25)	51,364.11
N-008080	138,163.79	171.05		138,334.84
N-008081	169,895.64	2,057.19		171,952.83
N-008083	82,015.02			82,015.02
N-008084	18,929.43	41,542.29		60,471.72
N-008085	59,494.79			59,494.79
N-008087	22,895.30			22,895.30
N-008088	9,397.41	73,750.56	(2,566.71)	80,581.26
N-008089	0.03	18,565.43	21.24	18,586.70
N-008090	22,011.86			22,011.86
N-008091	41,397.71	4,104.61		45,502.32
N-008093		73,259.74		73,259.74
N-008094	78,689.88			78,689.88
N-008095	58,983.01	1,088.78		60,071.79
N-008096	10,448.72	13,667.62		24,116.34
N-008102		3,800.00		3,800.00
N-019000		312,087.80	(18,135.29)	293,952.51
N-019001		2,241,161.90	85,877.24	2,327,039.14
N-019002		41,885.43	(1,244.20)	40,641.23
N-019003	271.36	164,748.57	3,495.89	168,515.82
N-019004		927,956.02	13,532.10	941,488.12
N-019005		474,635.97	56,203.80	530,839.77
N-019006		567,699.81	5,165.17	572,864.98
N-019007		765,445.88	224,585.76	990,031.64
N-019008		770,573.47	(7,502.34)	763,071.13
N-019009		85,714.93	5,013.33	90,728.26
N-019010		61,581.24	5,883.29	67,464.53
N-019011		141,424.46	3,877.15	145,301.61
N-019013		29,912.25	2,474.06	32,386.31
N-019014		4,495.25		4,495.25
N-019015		7,108.23		7,108.23
N-019016		11,755.88		11,755.88
N-019017		1,523.94		1,523.94
N-019018		246,672.27	(6,977.80)	239,694.47
N-019019		60,753.00	10,404.29	71,157.29
N-019020		8,453.59	3,371.89	11,825.48
N-019021		11,456.44	2,090.19	13,546.63
N-019022		20,109.64	1,918.58	22,028.22
N-019023		55,119.58		55,119.58
N-019024		29,136.01		29,136.01
N-019025		17,824.00		17,824.00
N-019026		40,509.31		40,509.31
N-019027		57,238.50		57,238.50
N-019028		68,150.20		68,150.20
N-019029		516,519.31	5,596.67	522,115.98
N-019030		5,085.89	1,612.59	6,698.48
N-019031		572,211.73		572,211.73
N-019032		330,730.67		330,730.67
N-019033		67,877.40	211,236.78	279,114.18
N-019034		276.61		276.61
N-019035		20,440.11		20,440.11
N-019036		874,439.96	24,005.19	898,445.15
N-019037		514,761.66	225,996.73	740,758.39
N-019040		40,998.06		40,998.06
N-019041		165,649.32	30,695.68	196,345.00
N-019042		24,256.06	11,828.52	36,084.58
N-019044		1,315.55	4,292.15	5,607.70
N-019045		75,052.50	(2,344.20)	72,708.30
N-019046		363,492.67	21,494.16	384,986.83
N-019047		1,102,090.87	1,815,311.15	2,917,402.02
N-019050		142,957.43		142,957.43
N-019051		427,098.78	234,564.22	661,663.00
N-019052		33,098.74	449.16	33,547.90
N-019053		365,967.03	8,359.05	374,326.08
N-019054		1,348,364.39	65,104.17	1,413,468.56
N-019055		13,846.22	(669.05)	13,177.17
N-019056		228,291.28	4,193.16	232,484.44
N-019057		175,683.10	349.21	176,032.31
N-019058		2,624,277.10	477,689.47	3,101,966.57
N-019059		155,451.23	3,458.98	158,910.21
N-019060		65,560.75		65,560.75
N-019061		108,057.57		108,057.57
N-019062		169,350.69		169,350.69
N-019063		20,898.04	15,936.10	36,834.14
N-019064		46,821.42	25,509.11	72,330.53
N-019065		26,954.05	1,783.38	28,737.43
N-019066		81,951.28	(16,856.82)	65,094.46
N-019067		84,079.77	400.01	84,479.78
N-019068		9,368.07	254.63	9,622.70
N-019069		36,615.88	7,444.19	44,060.07
N-019070		560,575.98	12,819.27	573,395.25
N-019071		823,753.63	(316,694.81)	507,058.82
N-019072		182,517.89	95,862.21	278,380.10
N-019073		55,990.72	201.85	56,192.57
N-019074		573.14	9,005.83	9,578.97
N-019075		545.88	9,723.02	10,268.90
N-019076		7,277.86	10,714.37	17,992.23
N-019077		18,949.51		18,949.51
N-019078		109,671.00	16,847.49	126,518.49
N-019079		3,998.00		3,998.00
N-019080		2,092.88	1,233.67	3,326.55

2017-2020 Supporting Pivot Table

N-019081			678,802.72	(56,358.49)	622,444.23
N-019082			10,880.00		10,880.00
N-019083			1,426.51	(1,426.51)	-
N-019084			293,786.18	3,842.52	297,628.70
N-019086			2,467.96	11,573.93	14,041.89
N-019087			14,278.78	40,891.19	55,169.97
N-019088			5,219.04		5,219.04
N-019089			157,456.11	(2,317.92)	155,138.19
N-019092			27,363.61	231.87	27,595.48
N-019093			43,143.04	433.72	43,576.76
N-020000				278,758.06	278,758.06
N-020001				2,261,495.49	2,261,495.49
N-020002				93,940.59	93,940.59
N-020003				96,985.42	96,985.42
N-020004				1,821,296.45	1,821,296.45
N-020005				288,249.52	288,249.52
N-020006				759,828.65	759,828.65
N-020007				614,909.37	614,909.37
N-020008				737,992.42	737,992.42
N-020009				68,743.08	68,743.08
N-020010				22,243.53	22,243.53
N-020011				279,893.16	279,893.16
N-020013				577,093.56	577,093.56
N-020014				14,353.81	14,353.81
N-020015				1,634.00	1,634.00
N-020016				36,331.51	36,331.51
N-020017				858.11	858.11
N-020018				9,977.57	9,977.57
N-020019				301,181.48	301,181.48
N-020020				138,605.18	138,605.18
N-020021				6,725.39	6,725.39
N-020022				29,156.35	29,156.35
N-020023				9,426.30	9,426.30
N-020025				829.30	829.30
N-020026				26,584.87	26,584.87
N-020028				744.58	744.58
N-020029				32,940.52	32,940.52
N-020032				17,008.29	17,008.29
N-020033				728.91	728.91
N-020034				51,824.80	51,824.80
N-020035				21,917.06	21,917.06
N-020036				15,122.57	15,122.57
N-020037				5,186.76	5,186.76
N-020039				158,546.83	158,546.83
N-020040				376,851.57	376,851.57
N-020041				757,083.95	757,083.95
N-020042				173,813.51	173,813.51
N-020043				3,179,004.19	3,179,004.19
N-020044				53,163.03	53,163.03
N-020045				98,778.95	98,778.95
N-020046				21,451.58	21,451.58
N-020047				26,180.00	26,180.00
N-020048				60,509.84	60,509.84
N-020050				157,489.78	157,489.78
N-020051				123,683.55	123,683.55
N-020052				70,072.75	70,072.75
N-020053				65,666.57	65,666.57
N-020054				68,580.21	68,580.21
N-020055				288,435.46	288,435.46
N-020057				223,105.76	223,105.76
N-020059				65,725.57	65,725.57
N-020060				215,419.77	215,419.77
N-020062				26,633.92	26,633.92
N-020063				47,375.46	47,375.46
N-020064				27,399.31	27,399.31
N-020065				184,024.89	184,024.89
N-020067				61,150.12	61,150.12
N-020069				985,508.77	985,508.77
N-020070				133,361.39	133,361.39
N-020071				52,730.55	52,730.55
N-020072				17,107.73	17,107.73
N-020073				1,788,124.06	1,788,124.06
N-020079				97,209.25	97,209.25
N-020080				34,767.60	34,767.60
N-020081				312,043.05	312,043.05
N-020082				81,325.77	81,325.77
N-020083				50,759.83	50,759.83
N-020084				213,501.85	213,501.85
N-020085				251,076.09	251,076.09
N-020086				32,069.01	32,069.01
N-020087				35,175.27	35,175.27
N-020088				50,695.90	50,695.90
N-020090				27,494.96	27,494.96
N-020091				16,227.20	16,227.20
N-021000				15,382.70	15,382.70
Grand Total	**24,908,215.81**	**23,282,343.33**	**23,629,712.01**	**22,915,215.56**	**94,735,486.71**

year	funding_project	amount

2017-2020 Supporting Pivot Table

2020	N-006000	(108.30)
2020	N-008001	(6,153.81)
2020	N-008003	(2,334.22)
2020	N-008042	(2,689.03)
2020	N-008043	165,099.02
2020	N-008078	13,264.70
2020	N-008079	(902.25)
2020	N-008088	(2,566.71)
2020	N-008089	21.24
2020	N-019000	(18,135.29)
2020	N-019001	85,877.24
2020	N-019002	(1,244.20)
2020	N-019003	3,495.89
2020	N-019004	13,532.10
2020	N-019005	56,203.80
2020	N-019006	5,165.17
2020	N-019007	224,585.76
2020	N-019008	(7,502.34)
2020	N-019009	5,013.33
2020	N-019010	5,883.29
2020	N-019011	3,877.15
2020	N-019013	2,474.06
2020	N-019018	(6,977.80)
2020	N-019019	10,404.29
2020	N-019020	3,371.89
2020	N-019021	2,090.19
2020	N-019022	1,918.58
2020	N-019029	5,596.67
2020	N-019030	1,612.59
2020	N-019033	211,236.78
2020	N-019036	24,005.19
2020	N-019037	225,996.73
2020	N-019041	30,695.68
2020	N-019042	11,828.52
2020	N-019044	4,292.15
2020	N-019045	(2,344.20)
2020	N-019046	21,494.16
2020	N-019047	1,815,311.15
2020	N-019051	234,564.22
2020	N-019052	449.16
2020	N-019053	8,359.05
2020	N-019054	65,104.17
2020	N-019055	(669.05)
2020	N-019056	4,193.16
2020	N-019057	349.21
2020	N-019058	477,689.47
2020	N-019059	3,458.98
2020	N-019063	15,936.10
2020	N-019064	25,509.11
2020	N-019065	1,783.38
2020	N-019066	(16,856.82)
2020	N-019067	400.01
2020	N-019068	254.63
2020	N-019069	7,444.19
2020	N-019070	12,819.27
2020	N-019071	(316,694.81)
2020	N-019072	95,862.21
2020	N-019073	201.85
2020	N-019074	9,005.83
2020	N-019075	9,723.02
2020	N-019076	10,714.37
2020	N-019078	16,847.49
2020	N-019080	1,233.67
2020	N-019081	(56,358.49)
2020	N-019083	(1,426.51)
2020	N-019084	3,842.52
2020	N-019086	11,573.93
2020	N-019087	40,891.19
2020	N-019089	(2,317.92)
2020	N-019092	231.87
2020	N-019093	433.72
2020	N-020000	278,758.06
2020	N-020001	2,261,495.49
2020	N-020002	93,940.59
2020	N-020003	96,985.42
2020	N-020004	1,821,296.45
2020	N-020005	288,249.52
2020	N-020006	759,828.65
2020	N-020007	614,909.37
2020	N-020008	737,992.42
2020	N-020009	68,743.08
2020	N-020010	22,243.53
2020	N-020011	279,893.16
2020	N-020013	577,093.56
2020	N-020014	14,353.81
2020	N-020015	1,634.00
2020	N-020016	36,331.51
2020	N-020017	858.11
2020	N-020018	9,977.57
2020	N-020019	301,181.48
2020	N-020020	138,605.18
2020	N-020021	6,725.39
2020	N-020022	29,156.35
2020	N-020023	9,426.30

2017-2020 Supporting Pivot Table

2020	N-020025	829.30
2020	N-020026	26,584.87
2020	N-020028	744.58
2020	N-020029	32,940.52
2020	N-020032	17,008.29
2020	N-020033	728.91
2020	N-020034	51,824.80
2020	N-020035	21,917.06
2020	N-020036	15,122.57
2020	N-020037	5,186.76
2020	N-020039	158,546.83
2020	N-020040	376,851.57
2020	N-020041	757,083.95
2020	N-020042	173,813.51
2020	N-020043	3,179,004.19
2020	N-020044	53,163.03
2020	N-020045	98,778.95
2020	N-020046	21,451.58
2020	N-020047	26,180.00
2020	N-020048	60,509.84
2020	N-020050	157,489.78
2020	N-020051	123,683.55
2020	N-020052	70,072.75
2020	N-020053	65,666.57
2020	N-020054	68,580.21
2020	N-020055	288,435.46
2020	N-020057	223,105.76
2020	N-020059	65,725.57
2020	N-020060	215,419.77
2020	N-020062	26,633.92
2020	N-020063	47,375.46
2020	N-020064	27,399.31
2020	N-020065	184,024.89
2020	N-020067	61,150.12
2020	N-020069	985,508.77
2020	N-020070	133,361.39
2020	N-020071	52,730.55
2020	N-020072	17,107.73
2020	N-020073	1,788,124.06
2020	N-020079	97,209.25
2020	N-020080	34,767.60
2020	N-020081	312,043.05
2020	N-020082	81,325.77
2020	N-020083	50,759.83
2020	N-020084	213,501.85
2020	N-020085	251,076.09
2020	N-020086	32,069.01
2020	N-020087	35,175.27
2020	N-020088	50,695.90
2020	N-020090	27,494.96
2020	N-020091	16,227.20
2020	N-021000	15,382.70
2019	N-007001	(1,278.48)
2019	N-007004	(16.25)
2019	N-007042	1,056.65
2019	N-007052	(36,583.80)
2019	N-007057	824.90
2019	N-008000	(177,706.97)
2019	N-008001	182,592.48
2019	N-008002	505.18
2019	N-008003	1,091.65
2019	N-008004	(103,120.76)
2019	N-008006	5,908.07
2019	N-008008	26,087.29
2019	N-008011	13,523.19
2019	N-008016	(9,087.39)
2019	N-008017	5,891.48
2019	N-008019	3,394.37
2019	N-008022	1,318.36
2019	N-008023	6,980.05
2019	N-008024	(23,756.62)
2019	N-008025	3,733.92
2019	N-008027	(91,131.54)
2019	N-008028	(103,815.46)
2019	N-008029	(36,822.54)
2019	N-008031	5,504.26
2019	N-008032	5,491.93
2019	N-008033	8,342.98
2019	N-008034	670.63
2019	N-008035	(2,018.87)
2019	N-008036	1,537.16
2019	N-008037	4,371.60
2019	N-008038	(530.56)
2019	N-008041	11,549.85
2019	N-008043	2,280,690.10
2019	N-008050	(787.09)
2019	N-008052	6,658.69
2019	N-008056	7,320.31
2019	N-008058	(230.77)
2019	N-008064	1,539.97
2019	N-008065	18,558.27
2019	N-008070	5,926.74
2019	N-008072	(1,118.72)
2019	N-008073	656.97

2017-2020 Supporting Pivot Table

2019	N-008074	296.08
2019	N-008075	2,403.23
2019	N-008078	277,388.12
2019	N-008079	28,100.88
2019	N-008080	171.05
2019	N-008081	2,057.19
2019	N-008084	41,542.29
2019	N-008088	73,750.56
2019	N-008089	18,565.43
2019	N-008091	4,104.61
2019	N-008093	73,259.74
2019	N-008095	1,088.78
2019	N-008096	13,667.62
2019	N-008102	3,800.00
2019	N-019000	312,087.80
2019	N-019001	2,241,161.90
2019	N-019002	41,885.43
2019	N-019003	164,748.57
2019	N-019004	927,956.02
2019	N-019005	474,635.97
2019	N-019006	567,699.81
2019	N-019007	765,445.88
2019	N-019008	770,573.47
2019	N-019009	85,714.93
2019	N-019010	61,581.24
2019	N-019011	141,424.46
2019	N-019013	29,912.25
2019	N-019014	4,495.25
2019	N-019015	7,108.23
2019	N-019016	11,755.88
2019	N-019017	1,523.94
2019	N-019018	246,672.27
2019	N-019019	60,753.00
2019	N-019020	8,453.59
2019	N-019021	11,456.44
2019	N-019022	20,109.64
2019	N-019023	55,119.58
2019	N-019024	29,136.01
2019	N-019025	17,824.00
2019	N-019026	40,509.31
2019	N-019027	57,238.50
2019	N-019028	68,150.20
2019	N-019029	516,519.31
2019	N-019030	5,085.89
2019	N-019031	572,211.73
2019	N-019032	330,730.67
2019	N-019033	67,877.40
2019	N-019034	276.61
2019	N-019035	20,440.11
2019	N-019036	874,439.96
2019	N-019037	514,761.66
2019	N-019040	40,998.06
2019	N-019041	165,649.32
2019	N-019042	24,256.06
2019	N-019044	1,315.55
2019	N-019045	75,052.50
2019	N-019046	363,492.67
2019	N-019047	1,102,090.87
2019	N-019050	142,957.43
2019	N-019051	427,098.78
2019	N-019052	33,098.74
2019	N-019053	365,967.03
2019	N-019054	1,348,364.39
2019	N-019055	13,846.22
2019	N-019056	228,291.28
2019	N-019057	175,683.10
2019	N-019058	2,624,277.10
2019	N-019059	155,451.23
2019	N-019060	65,560.75
2019	N-019061	108,057.57
2019	N-019062	169,350.69
2019	N-019063	20,898.04
2019	N-019064	46,821.42
2019	N-019065	26,954.05
2019	N-019066	81,951.28
2019	N-019067	84,079.77
2019	N-019068	9,368.07
2019	N-019069	36,615.88
2019	N-019070	560,575.98
2019	N-019071	823,753.63
2019	N-019072	182,517.89
2019	N-019073	55,990.72
2019	N-019074	573.14
2019	N-019075	545.88
2019	N-019076	7,277.86
2019	N-019077	18,949.51
2019	N-019078	109,671.00
2019	N-019079	3,998.00
2019	N-019080	2,092.88
2019	N-019081	678,802.72
2019	N-019082	10,880.00
2019	N-019083	1,426.51
2019	N-019084	293,786.18
2019	N-019086	2,467.96

2017-2020 Supporting Pivot Table

2019 N-019087	14,278.78
2019 N-019088	5,219.04
2019 N-019089	157,456.11
2019 N-019092	27,363.61
2019 N-019093	43,143.04
2018 N-005000	(20,745.23)
2018 N-005004	(29,689.14)
2018 N-005016	9,511.46
2018 N-005017	(2,040.00)
2018 N-005054	(24,918.23)
2018 N-005077	160.05
2018 N-006000	0.45
2018 N-006001	(216.94)
2018 N-006003	(1,291.88)
2018 N-006004	(10,189.07)
2018 N-006031	3,423.09
2018 N-006038	699.02
2018 N-006039	(1,854.08)
2018 N-006056	(13,920.83)
2018 N-007000	(150,093.08)
2018 N-007001	(111,059.57)
2018 N-007002	1.11
2018 N-007003	4,288.63
2018 N-007004	(53,271.31)
2018 N-007005	23,449.12
2018 N-007006	6,815.88
2018 N-007007	7,816.38
2018 N-007008	6,708.79
2018 N-007009	2,560.77
2018 N-007010	5,121.13
2018 N-007011	8,370.36
2018 N-007013	40,571.17
2018 N-007014	(39,610.59)
2018 N-007017	(3,176.26)
2018 N-007018	30.48
2018 N-007023	(8,492.01)
2018 N-007024	(1,244.34)
2018 N-007025	358.55
2018 N-007033	2,266.36
2018 N-007035	923.83
2018 N-007038	265.84
2018 N-007039	88,589.65
2018 N-007040	74,935.38
2018 N-007042	2,465.34
2018 N-007044	(2,589.14)
2018 N-007045	16,320.56
2018 N-007046	(1,557.23)
2018 N-007047	12,188.84
2018 N-007050	5,439.84
2018 N-007051	(1,064.79)
2018 N-007052	503,726.89
2018 N-007054	173,137.94
2018 N-007056	4,275.97
2018 N-007057	14,302.38
2018 N-007058	(105,465.24)
2018 N-007059	(10,049.96)
2018 N-007060	4,870.60
2018 N-007061	(8,384.31)
2018 N-007062	(89.62)
2018 N-007063	(37,977.46)
2018 N-007066	3,920.37
2018 N-007067	4,240.94
2018 N-007068	(48.34)
2018 N-007070	(370.83)
2018 N-007071	1,259.00
2018 N-007073	62,631.26
2018 N-007074	56,940.14
2018 N-007075	5,035.03
2018 N-007076	51,365.53
2018 N-008000	604,670.11
2018 N-008001	2,900,187.33
2018 N-008002	76,426.50
2018 N-008003	178,828.50
2018 N-008004	1,414,463.89
2018 N-008005	342,881.25
2018 N-008006	496,518.69
2018 N-008007	559,077.36
2018 N-008008	924,918.42
2018 N-008011	105,232.02
2018 N-008016	103,774.64
2018 N-008017	74,160.62
2018 N-008018	5,941.70
2018 N-008019	23,715.70
2018 N-008020	704,753.22
2018 N-008021	24,049.24
2018 N-008022	674.76
2018 N-008023	20,646.60
2018 N-008024	276,455.33
2018 N-008025	24,181.69
2018 N-008026	8,502.12
2018 N-008027	91,131.54
2018 N-008028	103,815.46
2018 N-008029	36,822.54
2018 N-008030	6,572,621.28

2017-2020 Supporting Pivot Table

2018 N-008031	26,433.75
2018 N-008033	17,455.14
2018 N-008034	2,078.73
2018 N-008035	14,837.24
2018 N-008036	11,775.51
2018 N-008038	4,661.60
2018 N-008039	13,005.00
2018 N-008040	466,235.13
2018 N-008041	252,895.65
2018 N-008042	271,399.88
2018 N-008043	1,363,214.42
2018 N-008045	168,874.48
2018 N-008046	59,678.97
2018 N-008047	351,465.87
2018 N-008048	529,477.99
2018 N-008049	101,142.09
2018 N-008050	154,354.47
2018 N-008051	112,128.96
2018 N-008052	29,770.85
2018 N-008053	16,134.42
2018 N-008054	78,495.70
2018 N-008055	29,051.37
2018 N-008056	46,639.97
2018 N-008057	88,789.44
2018 N-008058	2,738.99
2018 N-008059	196,409.86
2018 N-008063	69,368.63
2018 N-008064	12,466.50
2018 N-008065	135,874.76
2018 N-008066	69,579.87
2018 N-008067	48,816.03
2018 N-008068	65,241.42
2018 N-008069	92,712.69
2018 N-008070	75,030.43
2018 N-008071	10,291.92
2018 N-008072	57,727.85
2018 N-008074	1,375.51
2018 N-008076	273,550.06
2018 N-008078	980,373.59
2018 N-008079	24,165.48
2018 N-008080	138,163.79
2018 N-008081	169,895.64
2018 N-008083	82,015.02
2018 N-008084	18,929.43
2018 N-008085	59,494.79
2018 N-008087	22,895.30
2018 N-008088	9,397.41
2018 N-008089	0.03
2018 N-008090	22,011.86
2018 N-008091	41,397.71
2018 N-008094	78,689.88
2018 N-008095	58,983.01
2018 N-008096	10,448.72
2018 N-019003	271.36
2017 N-003022	(3,787.50)
2017 N-004000	31.35
2017 N-004001	(1,718.57)
2017 N-004004	449.22
2017 N-004059	(444.42)
2017 N-005000	(1,311.87)
2017 N-005003	(0.18)
2017 N-005004	(11,430.77)
2017 N-005011	(180.09)
2017 N-005016	15,119.27
2017 N-005017	2,040.00
2017 N-005039	(8,667.90)
2017 N-005061	(95.37)
2017 N-005072	69.16
2017 N-005077	12,783.16
2017 N-006000	(100,256.51)
2017 N-006001	136,535.56
2017 N-006002	1,319.13
2017 N-006003	(317.14)
2017 N-006004	(79,984.04)
2017 N-006005	114.95
2017 N-006006	28,831.85
2017 N-006007	12,965.47
2017 N-006008	22,504.18
2017 N-006009	(3,301.98)
2017 N-006010	2,395.00
2017 N-006011	12,635.94
2017 N-006014	2,280.00
2017 N-006015	1,378.50
2017 N-006017	4,958.30
2017 N-006020	13,453.75
2017 N-006027	(3,100.81)
2017 N-006028	320.34
2017 N-006029	4,141.54
2017 N-006030	(125,561.61)
2017 N-006031	123,749.74
2017 N-006036	55,800.00
2017 N-006038	11,797.12
2017 N-006039	118,725.80
2017 N-006040	4,820.34

2017-2020 Supporting Pivot Table

2017	N-006041	12.93
2017	N-006043	2,908.70
2017	N-006044	329.94
2017	N-006046	(4,121.00)
2017	N-006052	(2,566.82)
2017	N-006053	3,249.95
2017	N-006055	(647.89)
2017	N-006056	107,748.83
2017	N-006057	2,002.41
2017	N-006060	2,417.98
2017	N-006061	4.69
2017	N-007000	302,888.34
2017	N-007001	2,493,048.21
2017	N-007002	34,447.85
2017	N-007003	114,695.36
2017	N-007004	1,200,090.81
2017	N-007005	486,361.96
2017	N-007006	966,269.19
2017	N-007007	417,505.06
2017	N-007008	626,912.47
2017	N-007009	56,653.31
2017	N-007010	78,170.69
2017	N-007011	113,178.23
2017	N-007013	1,322,544.78
2017	N-007014	744,817.49
2017	N-007015	1,595.87
2017	N-007016	13,214.74
2017	N-007017	4,953,860.16
2017	N-007018	25,505.70
2017	N-007019	20,820.58
2017	N-007020	4,364.84
2017	N-007022	838,595.26
2017	N-007023	44,070.24
2017	N-007024	17,066.43
2017	N-007025	1,683.70
2017	N-007028	34,314.36
2017	N-007029	36,336.72
2017	N-007030	49,924.92
2017	N-007032	42,207.07
2017	N-007033	2,623.17
2017	N-007034	116,310.27
2017	N-007035	1,011.87
2017	N-007036	64,830.71
2017	N-007037	32,650.00
2017	N-007038	8,689.21
2017	N-007039	91,923.12
2017	N-007040	2,958,680.93
2017	N-007041	260,227.62
2017	N-007042	236,195.86
2017	N-007044	11,334.89
2017	N-007045	237,040.82
2017	N-007046	637,717.06
2017	N-007047	4,467.12
2017	N-007048	176,836.90
2017	N-007050	179,612.42
2017	N-007051	119,443.14
2017	N-007052	455,007.20
2017	N-007054	232,480.71
2017	N-007056	16,840.72
2017	N-007057	17,999.16
2017	N-007058	779,656.09
2017	N-007059	858,633.41
2017	N-007060	4,586.63
2017	N-007061	235,922.78
2017	N-007062	72,283.68
2017	N-007063	37,977.46
2017	N-007064	44,089.88
2017	N-007065	20,644.75
2017	N-007066	1,059.21
2017	N-007067	14,331.04
2017	N-007068	66,857.47
2017	N-007069	11,153.42
2017	N-007070	55,221.95
2017	N-007071	26,684.49
2017	N-007073	34,700.34
2017	N-007078	1,380,945.34
		94,735,486.71

This comes from General Accounting's, "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	
UES	31%
FGE	25%
NU-NH	19%
NU-ME	23%
GRANITE	2%
	100%

ALL COMPANIES SPLIT BY DIVISION	
UES	31%
FGE-E	14%
FGE-G	11%
NU-NH	19%
NU-ME	23%
GRANITE	2%
	100%

Linked to "Special Purpose Allocators" Tab

GAS ONLY WITH GST	
FGE	20%
NU-NH	32%
NU-ME	43%
GRANITE	5%
	100%

GAS ONLY NO GST	
FGE	21%
NU-NH	34%
NU-ME	45%
	100%

JUST ELECTRIC	
UES	69%
FGE	31%
	100%

ALL COMPANIES WITHOUT GRANITE	
UES	32%
FGE	25%
NU-NH	19%
NU-ME	24%
	100%

FGE & UES Only	
FGE	55.36%
UES	44.64%
	100.00%

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

MARK A. LAMBERT

EXHIBIT MAL-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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 Northern Utilities, Inc. ("Northern"). 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

[1] The "Unitil companies" include Unitil Service and its regulated affiliates, Unitil Energy Systems, Inc., Northern Utilities, Inc., and Fitchburg Gas and Electric Light Company, all of which are wholly-owned subsidiaries of Unitil Corporation.

opportunity to head up the Company's government affairs area as the Director, Government Affairs. 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 (referred to as "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 their 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 five years and successfully launched into production across Unitil Corporation's footprint in July 2017.

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 commonsense 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.
- 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.

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. No, recovery of the CIS investment is not currently included in rates.

Q. How much of the CIS project was allocated to Northern?

A. The total cost of the CIS project was $36,832,636. Applying the three-factor allocator, the total cost of the CIS project that was allocated to Northern and has yet to be included for recovery in Northern's rates is $6,998,201 ($36,832,636 x 19%).

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 $5,718,559.

Q. Why does the total project cost not match the amount included in the test year?

A. The difference of $1,279,641 represents the amount that has already been amortized at Northern 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 any issue related to the new CIS.

Q. Have the CIS project costs been included in rates for Northern's affiliate companies?

A. The portion of the CIS project costs allocated to Northern'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 Northern's Maine natural gas affiliate, Northern Utilities, Inc. d/b/a Unitil ("Northern Utilities Maine"), are currently subject to an audit proceeding before the Maine Public Utilities Commission (Docket No. 2021-00022). Northern Utilities Maine is participating actively in that 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. For Unitil Energy Systems, Inc., a portion of the CIS project is currently included in rates as part of a step increase in DE 18-036 and the remaining portion has been included for recovery as part of the current base rate case in DE 21-030.

III. PROPOSED CHANGES TO TERMS AND CONDITIONS FOR DISTRIBUTION SERVICE

Q. Is the Company proposing changes to its General Terms and Conditions and Delivery Service Terms and Conditions?

A. Yes, the proposed changes are reflected in the Company's redline tariffs included with this filing. The changes reflect a few small changes reflecting Company practice.

Q. Does this conclude your testimony?

A. Yes it does.

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

DANIEL J. HURSTAK

EXHIBIT DJH-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

TABLE OF CONTENTS

Exhibits

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 Northern Utilities, Inc. ("Northern" 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 Northern. 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 New Hampshire Public Utilities Commission ("NHPUC") or other regulatory agencies?

A. Yes, I previously provided testimony before the New Hampshire Public Utilities Commission on behalf of Unitil Energy Systems, Inc. in connection with Docket DE 21-030.

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 Northern for its delivery and purchased gas services. Northern has identified its revenue requirements on a pro forma basis and computed 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 gas 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 Northern for the adjusted test year?

A. Yes. Exhibit DJH-2 summarizes the results of the Northern lead-lag study using the pro forma revenue requirements for the test year ending December 31, 2020. As shown on page 1 of Exhibit DJH-2, the rate base addition for the delivery cash working capital is $2,008,385, reflecting a net lag of 36.49 days.

In addition, as shown on page 4 of Exhibit DJH-2, I have also calculated 9.30 net lag days for purchased gas. The results of this study will be used to calculate the purchased gas working capital costs to be recovered through the Cost of Gas Adjustment. This change would become effective on the same date as the base rate change in this proceeding.

Q. What is a lead-lag study?

A. A lead-lag study is an analysis designed to determine the permanent working capital 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 those 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 gas operations for the 12-month pro forma period ending December 31, 2020. Exhibit DJH-2, page 1 of 4, 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 gas 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 4, line 32, column 5, the Company's net lag days are 36.49 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, insurance (general, fiduciary, property), regulatory commission expenses, vehicle leases, 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 posts meter readings daily for billing the next day, and the meter reading is recorded into accounts receivable on the same day. The Northern billing lag was approximately 1.02 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 33.33 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 Northern?

A. Yes, refer to page 2 of Exhibit DJH-2. This page includes other components such as late payment charges, disconnect / reconnect fees, rentals, 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 51.32 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 expense lags. 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, regulatory commission expenses and vehicle leases 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 39.60 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 expenses (referred to as "Other O&M" expenses) paid directly 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 Other O&M expense lags for the Company. The sample produced a lag of 31.70 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: All vouchers greater than $10,000;

Stratum 2: Every 10th voucher less than $10,000 and more than $1,000;

Stratum 3: Every 100th voucher under $1,000.

The resulting sample, which accounted for 22.98% of the dollars in the population, indicated a lag of 31.70 days.

Q. Did you exclude any voucher selections from the calculation of lag days?

A. Yes. Two invoices greater than $10,000 were determined to be outliers and not representative of the Other O&M expense population. These invoices were for IRP related work that was performed in June and July 2019 but not paid until March 2020.

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, Northern recorded an ERC of approximately $87,364.16 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, Northern recorded a FFCRA of approximately $20,000 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. Did you compute the cash working capital requirements on any expenses not recovered in base rates?

A. Yes, I did. The cash working capital requirement was calculated for purchased gas expenses. The purchased gas expenses were analyzed for 2020 for each supplier. The expense lags for each supplier payment were computed as the difference between the payment date and the mid-point of the service period. This analysis resulted in a purchase gas expense lag of 42.09 days, as shown on page 4 of

Exhibit DJH-2. This page also computes the revenue lag of 51.39 days. The resulting net lag is 9.30 days.

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. As mentioned earlier, this study also includes the lag for purchased gas services, which is presented on page 4 of Exhibit DJH-2.

Q. Have you identified the net lag days between revenue and expense for Northern 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 36.49 days (line 32, column 5) which is slightly different than the number included in line 24, 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, Northern's cash working capital requirement for December 31, 2020 test year is $2,008,385, or 9.97%, as shown on page 1, lines 30 and 34, 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.

Northern Utilities - New Hampshire Division
Cash Working Capital Requirements
12 Months Ended Dec 31, 2020
Lead Lag Summary

Line No		Annual Expense (1)	Revenue (Lead) Lag Days (2)	Expense (Lead) Lag Days (3)	Net (Lead) Lag Days (4)	Day Weighted Amount (5)	Source (6)
1	**Total Revenue Lag**		51.32				
2							
3	**Total Expense Lag**						
4	**Operation & Maintenance Expense**						
5	Labor - Direct	$ 2,525,224	51.32	13.62	37.70	$ 95,188,829.88	Page 3 of 4 - Line 2
6	Labor - Incentive	9,439	51.32	223.55	(172.23)	(1,625,668.37)	Page 3 of 4 - Line 3
7	Employee Benefits	417,136	51.32	25.66	25.66	10,704,934.17	Page 3 of 4 - Line 4
8	General Liability & Fiduciary	289,097	51.32	(135.73)	187.05	54,076,625.66	Page 3 of 4 - Line 5
9	Regulatory Commission Expense	485,194	51.32	1.80	49.52	24,026,215.79	Page 3 of 4 - Line 6
10	Vehicle Leases	153,626	51.32	9.78	41.54	6,382,230.31	Page 3 of 4 - Line 7
11	Other O&M Expenses	2,978,679	51.32	31.70	19.62	58,432,726.59	Page 3 of 4 - Line 8
12	Other O&M Exp - Service Company Charges	7,420,826	51.32	39.60	11.72	86,991,945.85	Page 3 of 4 - Line 9
13							
14	**Other Taxes**						
15	Other Taxes Excluding Property Taxes	277,187	51.32	9.54	41.78	11,580,418.32	Page 3 of 4 - Line 20
16	Property Taxes	5,346,199	51.32	(20.91)	72.23	386,179,424.34	Page 3 of 4 - Line 21
17							
18	**Income Taxes**						
19	Federal Income Taxes	1,023,023	51.32	37.50	13.82	14,137,710.01	Page 3 of 4 - Line 25
20	State Income Taxes	(781,343)	51.32	37.50	13.82	(10,797,807.45)	Page 3 of 4 - Line 26
21							
22							
23							
24	**Net of Revenue less Expense Lag**	$20,144,286	51.32	14.82	36.50	**$735,277,585**	Sum of Lines 5 to 20
25	Days					366	
26							
27	**Avg Daily Cash Working Capital Requirements**					**$2,008,385**	Line 34 * Line 24 Col 1
28							
29							
30	**Cash Working Capital Requirements**					**$2,008,385**	Line 27
31							
32	**Base Revenue Net Lag Days**					36.49	(Line 30 / Line 24, Col 1) * 366
33							
34	**Base Revenues Working Capital Percentage**					9.97%	(Line 24, Col 5 / Line 24, Col 1)/366
35							
36							
37							
38							
39							
40							

Northern Utilities - New Hampshire Division
Cash Working Capital Requirements
12 Months Ended Dec 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	
3	Billing Lag				
4	Cycle Read Customers		1.02	Exhibit DJH-3, Pg. 1, Line 3	
6	Collection Lag		33.33	Exhibit DJH-3, Pg. 1, Line 4	
8	Collection to Receipt of Available Funds		1.79	Exhibit DJH-3, Pg. 1, Line 5	
10	Total Sales Revenues	$ 49,835,494	51.39		$ 2,561,004,723
12	Late Payment Charge Revenue	76,773	38.73	See Note 2	2,973,424
14	Reconnect Fees	312,315	51.39	Line 10	16,049,609
16	Pool Administration	1,193	51.39	Line 10	61,282
18	3rd Party Billing	9,186	51.39	Line 10	472,081
20	Customer Telemetering	6,569	51.39	Line 10	337,594
22	Water Heaters & Conversion Burners	523,040	51.39	Line 10	26,878,608
24	UNH Revenue	-	51.39	Line 10	-
26	Rental Revenue	14,640	39.60	See Note 3	579,698
28	Rental Revenue Intercompany	203,988	39.60	See Note 3	8,077,285
31	Total Revenue Lag	$ 50,983,199	51.32		$ 2,616,434,304

Notes:
1. Computed as 366/12/2
2. Fees are assessed on the next billing. Lag is computed as the collection lag on Line 6 plus the average of 5.4 days from due date.
3. Represents Rental Income from Granite and USC. Cash settlement is made at the same time as the service company charges in the following month. Service Company Charges lag is used.

Northern Utilities - New Hampshire Division
Cash Working Capital Requirements
12 Months Ended Dec 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	$ 2,525,224	13.62	Exhibit DJH-3, Pg. 16, Line 7	$ 34,404,487
3	Labor - Incentive	9,439	223.55	Exhibit DJH-3, Pg. 16, Line 16	$ 2,110,059
4	Employee Benefits	417,136	25.66	Exhibit DJH-3, Pg. 53, Line 22	$ 10,702,303
5	General Liability & Fiduciary	289,097	(135.73)	Exhibit DJH-3, Pg. 72, Line 11	$ (39,240,275)
6	Regulatory Commission Expense	485,194	1.80	Exhibit DJH-3, Pg. 77, Line 6	$ 873,717
7	Vehicle Leases	153,626	9.78	Exhibit DJH-3, Pg. 78, Line 14	$ 1,501,780
8	Other O&M Expenses - Direct	2,978,679	31.70	Exhibit DJH-3, Pg. 91	$ 94,431,713
9	Other O&M Exp - Service Company Charges	7,420,826	39.60	Exhibit DJH-3, Pg. 93, Line 32	$ 293,841,430
10	Arrearage Management Program (AMP) Implementation Cost	92,480		Non Cash Item	
11	Distribution Bad Debt	336,170		Non Cash Item	
12	Non-Distribution Bad Debt	(97,468)		Non Cash Item	
13	Retirement	455,438		Non Cash Item	
14					
15	Total Operating & Maintenance Expenses	$ 15,065,841			
16					
17	**Depreciation & Amortization Expense**	$ 11,929,484		Non Cash Item	
18					
19	**Other Taxes**				
20	Other Taxes Excluding Property Taxes	$ 277,187	9.54	Exhibit DJH-3, Pg. 106, Line 9	$ 2,644,668
21	Property Taxes	5,346,199	(20.91)	Exhibit DJH-3, Pg. 107, Line 14	$ (111,814,968)
22	Total Other Taxes	$ 5,623,385			
23					
24	**Income Taxes**				
25	Federal Income Taxes	$ 1,023,023	37.50	Exhibit DJH-3, Pg. 120, Line 12	$ 38,363,371
26	State Income Taxes	(781,343)	37.50	Exhibit DJH-3, Pg. 121, Line 12	$ (29,300,381)
27	Total Income Taxes	$ 241,680			
28					
29	**Provision for Deferred Income Taxes**	$ 3,492,441		Non Cash Item	
30					
31	**Interest on Customer Deposits**	$ 9,258		See Note 1	
32					
33	**Return**	$ 14,621,110			
34					
35	**Total Requirements**	$ 50,983,199			
36					
37	Note:				
38	1. Customer Deposits are included as a deduction from Rate Base and therefore excluded from the lead lag study.				
39					
40					

Northern Utilities - New Hampshire Division
Purchased Gas Net Lag
12 Months Ended Dec 31, 2020

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**		51.39				Page 2 of 4 - Line 10
2							
3	**Total Expense Lag**						
4	Purchased Gas Acct 804	$22,696,215	51.39	42.09	9.30	$211,136,107	Exhibit DJH-3, Pg. 122, Line 23
5	Total Purchased Gas Expenses for CWC	$22,696,215				$211,136,107	
6							
7							
8	**Net of Revenue less Expense Lag**	$22,696,215	51.39	42.09	9.30	**$211,136,107**	
9	Days					366	
10							
11							
12	**Working Capital Percent**					**2.5417%**	Line 8 Col 4 / Line 9
13							
14							
15							
16							
17							
18							
19							
20							

Northern Utilities, Inc. – New Hampshire
Number of Days Delay Between Receipt of Revenue and Distribution Services to Gas Customers
Based on 2020 Data

Line No.	Description	Customers Number of Days Delay
1	Revenue Lag:	
2	Receipt of Gas Service to Meter Reading	15.25 days
3	Meter Reading to Recording of Accounts Receivable	1.02 days
4	Billing to Collection	33.33 days
5	Collection to Receipt of Available Funds	1.79 days
6	Subtotal Revenue Lag Days	51.39 days

Receipt of Gas Service to Meter Reading
Average Days Delay

January 1, 2020 to December 31, 2020	Number of Days
December	
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

Northern Utilities, Inc. – New Hampshire
Meter Reading to Recording of
Accounts Receivable

Month	Average Days
January 2020	1.02
February 2020	1.03
March 2020	1.01
April 2020	1.00
May 2020	1.01
June 2020	1.02
July 2020	1.01
August 2020	1.01
September 2020	1.01
October 2020	1.01
November 2020	1.13
December 2020	1.02
Average	1.02

Northern Utilities, Inc. – New Hampshire
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	33,641	99.34%	1	0.99
2	67	0.20%	2	0.00
3	102	0.30%	3	0.01
4	21	0.06%	4	0.00
5	14	0.04%	5	0.00
6	8	0.02%	6	0.00
7	5	0.01%	7	0.00
8-14	4	0.01%	11	0.00
Over 14	2	0.01%	14	0.00
Total	33,864	100.00%		1.02

February 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	33,770	99.16%	1	0.99
2	38	0.11%	2	0.00
3	61	0.18%	3	0.01
4	82	0.24%	4	0.01
5	47	0.14%	5	0.01
6	34	0.10%	6	0.01
7	16	0.05%	7	0.00
8 to 14	7	0.02%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,055	100.00%		1.03

March 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	34,152	99.68%	1	1.00
2	37	0.11%	2	0.00
3	43	0.13%	3	0.00
4	13	0.04%	4	0.00
5	6	0.02%	5	0.00
6	7	0.02%	6	0.00
7	-	0.00%	7	0.00
8 to 14	4	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,262	100.00%		1.01

**Northern Utilities, Inc. – New Hampshire
Meter Reading to Recording of
Accounts Receivable
Monthly Detail**

April 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	33,996	99.77%	1	1.00
2	36	0.11%	2	0.00
3	15	0.04%	3	0.00
4	14	0.04%	4	0.00
5	8	0.02%	5	0.00
6	4	0.01%	6	0.00
7	-	0.00%	7	0.00
8 to 14	1	0.00%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,074	100.00%		1.00

May 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	33,757	99.84%	1	1.00
2	4	0.01%	2	0.00
3	10	0.03%	3	0.00
4	1	0.00%	4	0.00
5	23	0.07%	5	0.00
6	5	0.01%	6	0.00
7	9	0.03%	7	0.00
8 to 14	3	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	33,812	100.00%		1.01

June 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	33,677	99.42%	1	0.99
2	115	0.34%	2	0.01
3	15	0.04%	3	0.00
4	5	0.01%	4	0.00
5	9	0.03%	5	0.00
6	-	0.00%	6	0.00
7	8	0.02%	7	0.00
8 to 14	45	0.13%	11	0.01
Over 14	-	0.00%	14	0.00
Total	33,874	100.00%		1.02

Northern Utilities, Inc. – New Hampshire
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

July 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	33,771	99.70%	1	1.00
2	17	0.05%	2	0.00
3	34	0.10%	3	0.00
4	6	0.02%	4	0.00
5	8	0.02%	5	0.00
6	25	0.07%	6	0.00
7	3	0.01%	7	0.00
8 to 14	7	0.02%	11	0.00
Over 14	-	0.00%	14	0.00
Total	33,871	100.00%		1.01

August 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	33,804	99.71%	1	1.00
2	20	0.06%	2	0.00
3	17	0.05%	3	0.00
4	23	0.07%	4	0.00
5	19	0.06%	5	0.00
6	3	0.01%	6	0.00
7	2	0.01%	7	0.00
8 to 14	12	0.04%	11	0.00
Over 14	2	0.01%	14	0.00
Total	33,902	100.00%		1.01

September 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	34,044	99.78%	1	1.00
2	20	0.06%	2	0.00
3	21	0.06%	3	0.00
4	15	0.04%	4	0.00
5	3	0.01%	5	0.00
6	6	0.02%	6	0.00
7	5	0.01%	7	0.00
8 to 14	5	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,119	100.00%		1.01

**Northern Utilities, Inc. – New Hampshire
Meter Reading to Recording of
Accounts Receivable
Monthly Detail**

October 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	34,234	99.74%	1	1.00
2	31	0.09%	2	0.00
3	26	0.08%	3	0.00
4	14	0.04%	4	0.00
5	8	0.02%	5	0.00
6	6	0.02%	6	0.00
7	1	0.00%	7	0.00
8 to 14	4	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,324	100.00%		1.01

November 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	30,708	88.51%	1	0.89
2	3,882	11.19%	2	0.22
3	5	0.01%	3	0.00
4	55	0.16%	4	0.01
5	10	0.03%	5	0.00
6	13	0.04%	6	0.00
7	9	0.03%	7	0.00
8 to 14	13	0.04%	11	0.00
Over 14	1	0.00%	14	0.00
Total	34,696	100.00%		1.13

December 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	34,524	98.71%	1	0.99
2	341	0.97%	2	0.02
3	53	0.15%	3	0.00
4	10	0.03%	4	0.00
5	19	0.05%	5	0.00
6	12	0.03%	6	0.00
7	7	0.02%	7	0.00
8 to 14	9	0.03%	11	0.00
Over 14	-	0.00%	14	0.00
Total	34,975	100.00%		1.02

Northern Utilities, Inc. – New Hampshire
Number Of Days Lag In Billing To Collection
Twelve Months Average 1/20 - 12/20

Month	Days in Month	Gas Sales Revenues	Daily Average (1/Days)	Accounts Receivable Gas Sales
		(1)	(2)	(3)
2020				
January	31	9,273,728	299,153	8,021,811
February	29	9,322,298	321,459	9,218,610
March	31	8,196,645	264,408	9,058,246
April	30	6,033,356	201,112	7,696,711
May	31	4,103,034	132,356	5,983,008
June	30	2,525,740	84,191	3,926,062
July	31	2,190,380	70,657	3,262,552
August	31	2,068,981	66,741	2,849,441
September	30	2,342,041	78,068	2,423,533
October	31	2,707,773	87,348	2,943,324
November	30	4,859,199	161,973	4,666,361
December	31	8,479,874	273,544	7,983,794
Total		$ 62,103,048	$ 2,041,010	$ 68,033,453
Average		$ 5,175,254	$ 170,084	$ 5,669,454
Payment Lag Days (3/2)				33.33

Note: Accounts Receivable balances exclude write-offs and include protected receivables.

Revenues and accounts receivable balances are per the CIS Billing system.

Northern Utilities, Inc. – New Hampshire
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 succeeding business day.
Source: Report on Previous Day Data, Citizens Bank

2020	Percent of Funds: Available Same Day 0 Days Lag	1 Day Float 1 Day Lag	2 Day Float 2 Days Lag	Total	Weighted Lag Days: 1 Day	2 Days	Total
January	23%	68%	9%	100%	0.68	0.17	0.85
February	34%	60%	5%	100%	0.60	0.11	0.71
March	29%	62%	9%	100%	0.62	0.19	0.80
April	30%	63%	7%	100%	0.63	0.14	0.77
May	26%	65%	9%	100%	0.65	0.17	0.83
June	30%	61%	9%	100%	0.61	0.17	0.79
July	27%	64%	9%	100%	0.64	0.18	0.81
August	25%	66%	8%	100%	0.66	0.17	0.83
September	29%	64%	7%	100%	0.64	0.14	0.77
October	31%	62%	7%	100%	0.62	0.14	0.76
November	27%	67%	6%	100%	0.67	0.13	0.80
December	33%	60%	7%	100%	0.60	0.13	0.74

Average Weighted Lag Days for Availability of Funds 0.79 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	0.79	days
Total Lag Days from Collection to Availability of Funds:	**1.79**	**days**

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

January, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	304,674	511,864	36,040	
3	57,000	133,874	13,652	
6	252,498	870,238	89,129	
7	533,373	86,435	38,854	
8	132,155	483,735	29,787	
9	628	305,209	19,014	
10	59,125	217,840	16,097	
13	214,319	792,628	80,738	
14	473,102	134,568	29,821	
15	97,850	242,343	6,543	
16	(1,612)	212,262	7,328	
17	120,979	344,564	7,725	
21	65,717	841,747	112,497	
22	283,483	92,983	34,563	
23	(8,186)	393,152	25,067	
24	61,841	430,458	34,808	
27	247,082	829,126	166,017	
28	(62,785)	239,677	32,828	
29	97,866	360,285	107,970	
30	(57,304)	330,628	119,575	
31	(35,283)	390,566	36,189	
	2,836,522	8,244,182	1,044,242	12,124,946
% of Available Funds	23%	68%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.68	0.17	0.85

February, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	877,255	776,994	61,312	
4	(44,091)	136,213	39,756	
5	(7,889)	414,031	34,615	
6	738,306	490,682	11,578	
7	88,630	247,633	20,395	
10	239,321	823,056	59,213	
11	681,974	77,866	31,798	
12	169,646	302,176	18,031	
13	(6,042)	249,247	12,523	
14	117,767	242,852	18,027	
18	10,757	788,698	68,263	
19	685,975	88,451	24,823	
20	(3,950)	388,880	50,500	
21	36,096	249,964	17,210	
24	278,641	974,623	100,070	
25	229,649	146,047	14,389	
26	24,599	378,410	24,045	
27	(4,199)	305,716	25,168	
28	54,385	305,226	27,717	
	4,166,830	7,386,765	659,433	12,213,028
% of Available Funds	34%	60%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.60	0.11	0.71

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

March, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	47,691	829,913	216,289	
3	(202,787)	193,754	73,955	
4	(46,028)	286,321	8,128	
5	540,253	416,510	42,769	
6	(3,017)	318,433	17,820	
9	271,260	825,304	70,169	
10	681,223	78,796	29,463	
11	250,371	310,612	17,154	
12	(2,318)	249,884	23,722	
13	73,070	227,219	12,235	
16	196,453	748,406	70,970	
17	608,392	136,185	24,122	
18	132,984	234,470	38,812	
19	(22,007)	146,220	77,788	
20	23,784	160,721	26,148	
23	160,697	654,953	23,405	
24	670,622	111,519	6,589	
25	108,994	280,495	11,598	
26	44,824	179,738	98,663	
27	(50,223)	316,726	25,415	
30	14,030	512,091	155,584	
31	(6,090)	226,878	54,622	
	3,492,178	7,445,148	1,125,420	12,062,746
% of Available Funds	29%	62%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.62	0.19	0.80

April, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(36,209)	242,463	21,167	
2	(3,199)	187,154	43,448	
3	45,036	276,509	28,754	
6	55,293	771,032	76,400	
7	488,073	94,400	56,422	
8	172,183	266,460	12,458	
9	112	247,195	17,054	
10	51,017	223,464	39,376	
13	185,572	705,585	52,488	
14	627,669	114,329	22,749	
15	166,623	177,385	7,732	
16	(1,091)	153,962	11,262	
17	84,366	373,675	3,855	
20	235,212	728,344	59,483	
21	(54,542)	167,024	48,355	
22	618,548	257,558	6,322	
23	13,620	159,766	45,064	
24	56,017	213,780	15,750	
27	181,499	654,300	18,678	
28	253,045	100,047	32,166	
29	96,155	319,920	17,179	
30	(2,035)	307,075	129,866	
	3,232,965	6,741,427	766,028	10,740,420
% of Available Funds	30%	63%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.63	0.14	0.77

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

May, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(40,555)	291,970	37,844	
4	40,859	727,469	89,438	
5	(77,427)	173,528	34,906	
6	362,073	224,951	72,687	
7	(59,283)	283,916	22,531	
8	46,567	158,774	15,348	
11	165,945	586,487	62,241	
12	488,656	76,700	37,344	
13	93,936	217,039	64,877	
14	(67,161)	212,693	8,246	
15	83,015	100,718	38,432	
18	112,172	598,908	61,586	
19	336,579	78,404	24,374	
20	83,153	163,797	8,464	
21	(4,933)	119,870	7,941	
22	51,592	196,033	26,888	
26	161,524	645,898	41,008	
27	310,968	90,728	19,525	
28	3,390	173,670	21,793	
29	38,048	173,526	11,102	
	2,129,118	5,295,079	706,575	8,130,772
% of Available Funds	26%	65%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.65	0.17	0.83

June, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	27,508	719,958	31,744	
2	(24,404)	36,002	22,574	
3	(5,930)	171,964	20,698	
4	281,195	233,191	87,944	
5	(2,797)	284,714	19,147	
8	137,784	442,767	57,223	
9	359,698	33,404	38,095	
10	96,501	309,977	6,948	
11	11,739	90,853	8,512	
12	38,303	102,303	60,518	
15	632,332	481,380	75,711	
16	235,261	94,063	22,383	
17	60,799	87,625	8,265	
18	2,920	280,721	7,103	
19	31,677	65,557	15,946	
22	5,055	328,747	25,396	
23	224,065	60,286	4,318	
24	92,386	125,362	3,228	
25	6,341	88,735	62,376	
26	(19,054)	135,144	15,819	
29	45,499	327,665	44,041	
30	11,098	63,760	11,649	
	2,247,977	4,564,178	649,638	7,461,793
% of Available Funds	30%	61%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.17	0.79

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

July, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(2,500)	85,581	4,791	
2	5,999	104,177	23,628	
3	14,931	104,265	9,047	
6	17,347	239,765	29,557	
7	160,782	39,978	13,238	
8	74,547	111,527	9,741	
9	188	80,475	15,108	
10	27,272	87,158	10,822	
13	67,272	219,362	17,410	
14	249,756	61,537	22,634	
15	48,268	83,435	16,673	
16	(17,349)	121,162	10,852	
17	28,572	112,839	3,457	
20	78,269	218,488	23,334	
21	(20,694)	30,786	11,132	
22	236,791	84,435	6,087	
23	5,250	99,619	18,074	
24	3,657	182,677	16,112	
27	73,198	316,701	45,414	
28	(41,935)	66,524	4,846	
29	104,766	113,040	2,473	
30	3,976	66,217	2,881	
31	31,113	64,067	52,120	
	1,149,477	2,693,815	369,431	4,212,723
% of Available Funds	27%	64%	9%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.64	0.18	0.81

August, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	(32,479)	283,312	36,745	
4	(33,329)	56,426	49,068	
5	(34,588)	186,946	7,605	
6	17,183	49,378	9,495	
7	168,904	86,190	7,415	
10	62,348	230,390	31,733	
11	180,399	109,636	18,712	
12	76,017	114,735	6,116	
13	(6,497)	129,712	8,144	
14	25,192	98,259	3,775	
17	54,350	277,837	49,233	
18	133,679	78,641	5,073	
19	43,255	63,031	666	
20	2,454	80,547	11,129	
21	113,804	81,191	4,848	
24	60,842	251,491	62,037	
25	140,610	66,537	4,301	
26	34,620	105,853	2,301	
27	4,245	61,113	4,356	
28	30,305	51,079	3,652	
31	12,267	277,923	24,670	
	1,053,582	2,740,227	351,074	4,144,883
% of Available Funds	25%	66%	8%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.66	0.17	0.83

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

September, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	18,029	48,638	8,415	
2	(3,585)	133,736	6,449	
3	(5,670)	65,335	10,030	
4	16,446	81,689	5,409	
8	103,987	248,260	46,826	
9	209,250	39,985	22,363	
10	(15,738)	114,750	1,392	
11	23,605	86,441	2,233	
14	92,905	175,186	22,221	
15	143,676	32,736	4,980	
16	52,714	87,481	6,584	
17	(4,107)	107,697	8,500	
18	27,472	38,342	8,886	
21	41,782	183,977	33,400	
22	132,927	72,351	6,198	
23	75,074	44,398	3,340	
24	3,238	69,135	1,361	
25	15,069	128,347	3,893	
28	35,737	226,125	21,787	
29	22,710	45,954	5,350	
30	6,404	109,821	2,183	
	991,925	2,140,384	231,800	3,364,109
% of Available Funds	29%	64%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.64	0.14	0.77

October, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	2,990	52,699	4,340	
2	24,217	47,560	6,588	
5	17,069	256,459	21,387	
6	71,364	27,879	16,430	
7	45,277	92,295	7,955	
8	(4,312)	77,574	8,658	
9	29,010	92,210	14,222	
13	187,464	257,401	12,080	
14	269,772	21,655	5,781	
15	1,361	88,780	7,709	
16	15,121	68,509	15,009	
19	58,119	228,491	46,497	
20	128,580	93,010	13,080	
21	51,088	72,126	4,848	
22	(678)	102,897	2,816	
23	33,010	129,168	18,209	
26	68,878	318,247	41,005	
27	133,935	50,892	9,647	
28	(1,511)	76,514	2,427	
29	3,970	56,556	4,580	
30	25,875	125,508	7,683	
	1,160,600	2,336,430	270,951	3,767,981
% of Available Funds	31%	62%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.62	0.14	0.76

Northern Utilities, Inc. – New Hampshire
Remittance Accounts

November, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	66,468	294,449	31,914	
3	(30,805)	44,102	17,990	
4	155,297	112,736	4,876	
5	1,097	183,024	8,740	
6	34,208	79,781	10,577	
9	72,867	372,350	13,279	
10	255,874	20,176	15,045	
12	59,284	129,499	18,273	
13	28,684	33,806	8,881	
16	74,685	246,880	44,195	
17	150,947	194,510	6,290	
18	46,327	137,424	3,767	
19	(446)	155,647	8,809	
20	36,391	133,015	4,512	
23	106,509	396,239	51,656	
24	154,245	40,451	21,537	
25	21,031	139,693	3,645	
27	44,763	361,720	19,591	
30	(551)	151,029	18,559	
	1,276,876	3,226,531	312,136	4,815,543
% of Available Funds	27%	67%	6%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.67	0.13	0.80

December, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	124,549	46,693	15,620	
2	(4,101)	230,120	4,367	
3	6,249	114,262	12,736	
4	44,983	98,597	17,975	
7	300,011	442,206	56,115	
8	177,043	66,129	33,832	
9	116,773	170,017	35,727	
10	(25,853)	108,547	5,785	
11	52,903	190,862	12,181	
14	140,080	459,890	18,041	
15	349,711	102,236	21,909	
16	61,157	159,529	24,282	
17	(10,160)	223,935	7,039	
18	47,790	16,127	3,598	
21	123,474	503,962	61,758	
22	236,525	150,012	17,544	
23	7,883	90,540	6,890	
24	28,520	166,310	12,520	
28	52,903	190,862	12,181	
29	295,285	43,709	38,313	
30	(12,799)	222,183	11,256	
31	50,527	148,057	12,130	
	2,163,451	3,944,785	441,799	6,550,035
% of Available Funds	33%	60%	7%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.60	0.13	0.74

Northern Utilities, Inc. - New Hampshire Division
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 & Semi Monthly	$ 882,620	6.18	$ 5,452,573
4				
5	Total Non ADP Weekly & Semi Monthly	209,434	45.01	9,425,944
6				
7	Total Weekly & Semi Monthly Payroll	$ 1,092,055	13.62	$ 14,878,517
8				
9				
10				
11	**Incentive Payroll**			
12	Total ADP Weekly & Semi Monthly	$ 75,305	223.50	$ 16,830,746
13				
14	Total Non ADP Weekly & Semi Monthly	2,071	225.50	466,972
15				
16	Total Weekly & Semi Monthly Payroll	$ 77,376	223.55	$ 17,297,718
17				
18	Total Gross Payroll	$ 1,169,431		
19				
20				

Northern Utilities, Inc. - New Hampshire Division
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	$ 19,095	9.33	$ 178,193
4	401K Tax Deferred	80,151	9.34	748,565
5	Health Insurance Premium	33,157	45.98	1,524,484
6	Health Savings Account	3,010	9.33	28,092
7	Dental Premium	1,881	45.98	86,489
8	Vision Premium	444	30.00	13,330
9	Supplemental Life Premium	8,053	9.34	75,217
10	Supplemental AD&D Premium	71	9.33	659
11	Bonds	-	-	-
12	Stock Purchase	720	9.33	6,720
13	Charity	24	9.33	224
14	PC Purchase Loan	225	(334.58)	(75,415)
15	Activity Prizes	100	9.50	950
16	Award	-	-	-
17	Miscellaneous	(14)	9.50	(137)
18	Union Dues	10,941	9.31	101,866
19	Medical Care Account	276	9.33	2,576
20	Dependent Care	-	-	-
21	Auto Adjustment	10,782	207.28	2,234,898
22	Education	-	-	-
23				
24	Total Weekly Payroll	$ 168,915	29.17	$ 4,926,708
25				
26				
27	**Semi Monthly**			
28	401K Loan	$ 3,814	1.17	$ 4,450
29	401K Tax Deferred	12,398	1.16	14,374
30	Health Insurance Premium	4,440	45.98	204,131
31	Health Savings Account	7,100	0.63	4,450
32	Dental Premium	492	45.98	22,605
33	Vision Premium	89	30.00	2,673
34	Supplemental Life Premium	2,187	1.17	2,552
35	Supplemental AD&D Premium	11	1.17	12
36	Bonds	-	-	-
37	Stock Purchase	300	1.17	350
38	Charity	12	1.17	14
39	PC Purchase Loan	271	(334.58)	(90,652)
40	Activity Prizes	-	-	-
41	Award	-	-	-
42	Miscellaneous	-	-	-
43	Union Dues	-	-	-
44	Medical Care Account	360	1.17	420
45	Dependent Care	-	-	-
46	Auto Adjustment	9,046	479.07	4,333,857
47	Education	-	-	-
48				
49	Total Semi Monthly Payroll	$ 40,520	111.04	$ 4,499,236
50				
51				
52	Total Weekly & Semi Monthly	$ 209,434	45.01	$ 9,425,944
53				
54				
55	**Incentive Pay**			
56	401K Tax Deferred	$ 2,071	225.50	$ 466,972
57				
58	Total Incentive Payroll	$ 2,071	225.50	$ 466,972
59				
60				

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Total Payroll Service

Line No	Payroll Description	Grand Total Amount	Total ADP Payroll Deductions	Total Non ADP Payroll Deductions	Difference
1	**Weekly**				
2					
3	9/26/2020	$ 84,421	$ 71,247	$ 13,174	$ -
4	10/3/2020	78,311	65,401	12,910	-
5	10/10/2020	81,228	67,160	14,068	-
6	10/17/2020	79,462	66,432	13,030	0
7	10/24/2020	81,647	68,186	13,461	-
8	10/31/2020	83,583	70,295	13,288	-
9	11/7/2020	81,817	68,599	13,218	-
10	11/14/2020	85,237	71,886	13,351	-
11	11/21/2020	91,540	67,938	23,602	-
12	11/28/2020	79,467	66,096	13,371	-
13	12/5/2020	78,028	64,875	13,152	-
14	12/12/2020	81,625	69,335	12,290	-
15					
16		$ 986,367	$ 817,452	$ 168,915	$ 0
17					
18					
19	**Semi Monthly**				
20					
21	10/15/2020	$ 30,940	$ 25,747	$ 5,193	$ -
22	10/31/2020	27,817	20,416	7,401	-
23	11/15/2020	29,441	24,180	5,261	-
24	11/30/2020	28,772	23,101	5,671	-
25	12/15/2020	34,214	25,712	8,502	-
26	12/31/2020	32,971	24,481	8,490	-
27					
28		$ 184,157	$ 143,637	$ 40,520	$ -
29					
30					
31	**Incentive Pay**				
32	**February 2020**				
33	Incentive Pay-Weekly	$ 8,181	$ 8,181	$ -	$ -
34	Incentive Pay-Salary	75,148	73,077	2,071	(0)
35		$ 83,328	$ 81,258	$ 2,071	
36					
37					
38	Total	$ 1,253,852	$ 1,042,347	$ 211,505	$ 0
39					
40					

Northern Utilities, Inc. - New Hampshire Division
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	$ 1,407	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 13,364
4	10/3/2020	1,603	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	15,231
5	10/10/2020	1,603	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	15,231
6	10/17/2020	1,603	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	15,231
7	10/24/2020	1,603	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	15,231
8	10/31/2020	1,603	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	15,231
9	11/7/2020	1,603	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	15,231
10	11/14/2020	1,603	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	15,231
11	11/21/2020	1,603	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	12,024
12	11/28/2020	1,603	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	15,231
13	12/5/2020	1,627	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	15,459
14	12/12/2020	1,632	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	15,501
15									
16		$ 19,095						9.33	$ 178,193
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 636	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 636
22	10/31/2020	636	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(318)
23	11/15/2020	636	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	1,271
24	11/30/2020	636	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	1,271
25	12/15/2020	636	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	1,271
26	12/31/2020	636	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	318
27									
28		$ 3,814						1.17	$ 4,450
29									
30									
31									
32									
33	Total	$ 22,909							
34									
35									
36									
37	Payment date indicates the wire release date in Dataview.								
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
401K Tax 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	$ 6,848	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 65,059
4	10/3/2020	6,589	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	62,591
5	10/10/2020	7,593	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	72,135
6	10/17/2020	6,557	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	62,293
7	10/24/2020	6,981	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	66,315
8	10/31/2020	6,793	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	64,537
9	11/7/2020	6,733	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	63,966
10	11/14/2020	6,737	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	63,997
11	11/21/2020	6,434	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	48,254
12	11/28/2020	6,810	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	64,693
13	12/5/2020	6,388	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	60,684
14	12/12/2020	5,689	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	54,041
15									
16		$ 80,151						9.34	$ 748,565
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 2,396	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 2,396
22	10/31/2020	2,304	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(1,152)
23	11/15/2020	2,464	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	4,928
24	11/30/2020	2,201	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	4,402
25	12/15/2020	1,522	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	3,045
26	12/31/2020	1,510	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	755
27									
28		$ 12,398						1.16	$ 14,374
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ -	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	$ -
34	Incentive Pay-Salary	2,071	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	466,972
35		$ 2,071						225.50	$ 466,972
36									
37	Annualized Lag	$ 372,266						9.45	$ 3,518,728
38									
39	Payment date indicates the check date in Dataview.								
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 2,742	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM		45.98	$ 126,059
4	10/3/2020	2,742	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM		45.98	126,059
5	10/10/2020	2,742	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM		45.98	126,059
6	10/17/2020	2,742	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM		45.98	126,059
7	10/24/2020	2,742	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM		45.98	126,059
8	10/31/2020	2,742	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM		45.98	126,059
9	11/7/2020	2,742	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM		45.98	126,059
10	11/14/2020	2,742	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM		45.98	126,059
11	11/21/2020	2,742	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM		45.98	126,059
12	11/28/2020	2,827	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM		45.98	129,984
13	12/5/2020	2,827	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM		45.98	129,984
14	12/12/2020	2,827	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM		45.98	129,984
15									
16		$ 33,157						45.98	$ 1,524,484
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 740	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM		45.98	$ 34,022
22	10/31/2020	740	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM		45.98	34,022
23	11/15/2020	740	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM		45.98	34,022
24	11/30/2020	740	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM		45.98	34,022
25	12/15/2020	740	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM		45.98	34,022
26	12/31/2020	740	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM		45.98	34,022
27									
28		$ 4,440						45.98	$ 204,131
29									
30									
31									
32									
33	Total	$ 37,597						45.98	$ 1,728,614
34									
35									
36									
37	The employee 20 % contribution toward health insurance is an offset to the expense.								
38	NU is self insured.								
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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**								
3	9/26/2020	$ 224	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 2,123
4	10/3/2020	252	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	2,389
5	10/10/2020	252	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	2,389
6	10/17/2020	252	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	2,389
7	10/24/2020	252	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	2,389
8	10/31/2020	252	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	2,389
9	11/7/2020	252	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	2,389
10	11/14/2020	252	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	2,389
11	11/21/2020	252	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	1,886
12	11/28/2020	252	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	2,389
13	12/5/2020	262	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	2,484
14	12/12/2020	262	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	2,484
16		$ 3,010						9.33	$ 28,092
19	**Semi Monthly**								
21	10/15/2020	$ 800	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 800
22	10/31/2020	3,100	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(1,550)
23	11/15/2020	800	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	1,600
24	11/30/2020	800	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	1,600
25	12/15/2020	800	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	1,600
26	12/31/2020	800	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	400
28		$ 7,100						0.63	$ 4,450
33	Total	$ 10,110							
37	Payment date indicates the check date.								

Northern Utilities, Inc. - New Hampshire Division
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	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**							
2								
3	9/26/2020	$ 155	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	45.98	$ 7,129
4	10/3/2020	155	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	45.98	7,129
5	10/10/2020	155	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	45.98	7,129
6	10/17/2020	155	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	45.98	7,129
7	10/24/2020	155	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	45.98	7,129
8	10/31/2020	155	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	45.98	7,129
9	11/7/2020	155	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	45.98	7,129
10	11/14/2020	155	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	45.98	7,129
11	11/21/2020	155	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	45.98	7,129
12	11/28/2020	162	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	45.98	7,442
13	12/5/2020	162	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	45.98	7,442
14	12/12/2020	162	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	45.98	7,442
15								
16		$ 1,881					45.98	$ 86,489
17								
18								
19	**Semi Monthly**							
20								
21	10/15/2020	$ 82	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	45.98	$ 3,767
22	10/31/2020	82	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	45.98	3,767
23	11/15/2020	82	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	45.98	3,767
24	11/30/2020	82	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	45.98	3,767
25	12/15/2020	82	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	45.98	3,767
26	12/31/2020	82	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	45.98	3,767
27								
28		$ 492					45.98	$ 22,605
29								
30								
31								
32								
33	Total	$ 2,373					45.98	$ 109,093
34								
35								
36								
37	The employee contribution toward dental insurance is an offset to the expense.							
38	Lag days are based on health insurance premium.							
39	NU is self insured.							
40								

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Vision 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	$ 36	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM		30.00	$ 1,084
4	10/3/2020	36	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM		30.00	1,084
5	10/10/2020	36	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM		30.00	1,084
6	10/17/2020	36	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM		30.00	1,084
7	10/24/2020	36	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM		30.00	1,084
8	10/31/2020	36	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM		30.00	1,084
9	11/7/2020	36	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM		30.00	1,084
10	11/14/2020	37	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM		30.00	1,117
11	11/21/2020	37	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM		30.00	1,117
12	11/28/2020	39	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM		30.00	1,169
13	12/5/2020	39	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM		30.00	1,169
14	12/12/2020	39	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM		30.00	1,169
15									
16		$ 444						30.00	$ 13,330
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 15	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM		30.00	$ 446
22	10/31/2020	15	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM		30.00	446
23	11/15/2020	15	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM		30.00	446
24	11/30/2020	15	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM		30.00	446
25	12/15/2020	15	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM		30.00	446
26	12/31/2020	15	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM		30.00	446
27									
28		$ 89						30.00	$ 2,673
29									
30									
31									
32									
33	Total	$ 533						30.00	$ 16,003
34									
35									
36	NU is self insured for Vision.								
37	The employee contribution toward vision insurance is an offset to the expense.								
38	The lag until payment is made to the provider is estimated to be 30 days after the payroll deduction.								
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 671	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 6,379
4	10/3/2020	673	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	6,392
5	10/10/2020	673	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	6,389
6	10/17/2020	673	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	6,389
7	10/24/2020	673	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	6,389
8	10/31/2020	673	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	6,389
9	11/7/2020	673	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	6,395
10	11/14/2020	673	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	6,395
11	11/21/2020	643	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	4,824
12	11/28/2020	673	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	6,395
13	12/5/2020	680	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	6,462
14	12/12/2020	675	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	6,417
15									
16		$ 8,053						9.34	$ 75,217
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 365	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 365
22	10/31/2020	365	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(182)
23	11/15/2020	365	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	729
24	11/30/2020	365	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	729
25	12/15/2020	365	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	729
26	12/31/2020	365	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	182
27									
28		$ 2,187						1.17	$ 2,552
29									
30									
31									
32								7.59	$ 77,768
33	Total Weighted Lag	$ 10,240							
34									
35									
36									
37	Payment date indicates the check date								
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 6	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 56
4	10/3/2020	6	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	56
5	10/10/2020	6	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	56
6	10/17/2020	6	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	56
7	10/24/2020	6	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	56
8	10/31/2020	6	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	56
9	11/7/2020	6	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	56
10	11/14/2020	6	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	56
11	11/21/2020	6	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	44
12	11/28/2020	6	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	56
13	12/5/2020	6	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	56
14	12/12/2020	6	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	56
15									
16		$ 71						9.33	$ 659
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 2	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 2
22	10/31/2020	2	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(1)
23	11/15/2020	2	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	4
24	11/30/2020	2	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	4
25	12/15/2020	2	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	4
26	12/31/2020	2	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	1
27									
28		$ 11						1.17	$ 12.25
29									
30									
31								8.28	$ 671
32	Total Weighted Lag	$ 81							
33									
34									
35									
36	Payment date reflects the check date								
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Bonds

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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	1/0/00 12:00 AM		$ -
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	1/0/00 12:00 AM		-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	1/0/00 12:00 AM		-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	1/0/00 12:00 AM		-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	1/0/00 12:00 AM		-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	1/0/00 12:00 AM		-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	1/0/00 12:00 AM		-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	1/0/00 12:00 AM		-
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	1/0/00 12:00 AM		-
12	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	1/0/00 12:00 AM		-
13	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	1/0/00 12:00 AM		-
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	1/0/00 12:00 AM		-
15									
16		$ -						-	$ -
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	1/0/00 12:00 AM		$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	1/0/00 12:00 AM		-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	1/0/00 12:00 AM		-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	1/0/00 12:00 AM		-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	1/0/00 12:00 AM		-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	1/0/00 12:00 AM		-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ -							
34									
35									
36									
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 60	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 570
4	10/3/2020	60	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	570
5	10/10/2020	60	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	570
6	10/17/2020	60	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	570
7	10/24/2020	60	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	570
8	10/31/2020	60	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	570
9	11/7/2020	60	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	570
10	11/14/2020	60	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	570
11	11/21/2020	60	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	450
12	11/28/2020	60	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	570
13	12/5/2020	60	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	570
14	12/12/2020	60	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	570
15									
16		$ 720						9.33	$ 6,720
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 50	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 50
22	10/31/2020	50	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(25)
23	11/15/2020	50	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	100
24	11/30/2020	50	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	100
25	12/15/2020	50	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	100
26	12/31/2020	50	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	25
27									
28		$ 300						1.17	$ 350
29									
30									
31									
32									
33	Total	$ 1,020							
34									
35									
36									
37	Payment date indicates the check date in Dataview- Unitil Corporation - DRP purchases.								
38	Account Number - 30.00.00.00.232.18.00								
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Charity

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	$ 2	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 19
4	10/3/2020	2	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	19
5	10/10/2020	2	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	19
6	10/17/2020	2	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	19
7	10/24/2020	2	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	19
8	10/31/2020	2	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	19
9	11/7/2020	2	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	19
10	11/14/2020	2	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	19
11	11/21/2020	2	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	15
12	11/28/2020	2	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	19
13	12/5/2020	2	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	19
14	12/12/2020	2	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	19
15									
16		$ 24						9.33	$ 224
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 2	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 2
22	10/31/2020	2	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(1)
23	11/15/2020	2	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	4
24	11/30/2020	2	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	4
25	12/15/2020	2	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	4
26	12/31/2020	2	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	1
27									
28		$ 12						1.17	$ 14
29									
30									
31									
32									
33	Total	$ 36							
34									
35									
36									
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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			$ -
4	10/3/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
5	10/10/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
6	10/17/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
7	10/24/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
8	10/31/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
9	11/7/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
10	11/14/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
11	11/21/2020	10,593	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	2,192,751
12	11/28/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
13	12/5/2020	189	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	12/11/20 12:00 AM	223.00	42,147
14	12/12/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
15									
16		$ 10,782						207.28	$ 2,234,898
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			$ -
22	10/31/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
23	11/15/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM			-
24	11/30/2020	673	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	139,270
25	12/15/2020	4,187	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	929,465
26	12/31/2020	4,187	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	988,078
27									
28		$ 9,046						479.07	$ 4,333,857
29									
30									
31									
32									
33	Total	$ 19,828							
34									
35									
36	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.								
37	Employee is responsible for taxes. Earnings are grossed up.								
38	Amount is added to earnings and deductions.								
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
PC Purchase Loan

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	$ 18	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM		(334.58)	$ (5,855)
4	10/3/2020	18	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM		(334.58)	(5,855)
5	10/10/2020	18	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM		(334.58)	(5,855)
6	10/17/2020	18	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM		(334.58)	(5,855)
7	10/24/2020	18	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM		(334.58)	(5,855)
8	10/31/2020	18	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM		(334.58)	(5,855)
9	11/7/2020	18	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM		(334.58)	(5,855)
10	11/14/2020	18	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM		(334.58)	(5,855)
11	11/21/2020	18	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM		(334.58)	(5,855)
12	11/28/2020	18	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM		(334.58)	(5,855)
13	12/5/2020	18	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM		(334.58)	(5,855)
14	12/12/2020	33	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM		(334.58)	(11,008)
15									
16		$ 225						(334.58)	$ (75,415)
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 47	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM		(334.58)	$ (15,561)
22	10/31/2020	47	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM		(334.58)	(15,561)
23	11/15/2020	47	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM		(334.58)	(15,561)
24	11/30/2020	46	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM		(334.58)	(15,501)
25	12/15/2020	43	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM		(334.58)	(14,233)
26	12/31/2020	43	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM		(334.58)	(14,233)
27									
28		$ 271						(334.58)	$ (90,652)
29									
30									
31									
32									
33	Total	$ 496							
34									
35									
36	Average Length of Loan is 22.0 Months.								
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Activity Prizes

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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM			$ -
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM			-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM			-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM			-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM			-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM			-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM			-
10	11/14/2020	100	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	950
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM			-
12	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM			-
13	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM			-
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM			-
15									
16		$ 100						9.50	$ 950
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM			$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM			-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM			-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM			-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM			-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM			-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ 100							
34									
35	Gross pay and the deduction are grossed up for the amount of the prizes. Prizes given during Service period. Use midpoint of service period for payment date.								
36	Weekly:								
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	1/0/00 12:00 AM		$ -
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	1/0/00 12:00 AM		-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	1/0/00 12:00 AM		-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	1/0/00 12:00 AM		-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	1/0/00 12:00 AM		-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	1/0/00 12:00 AM		-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	1/0/00 12:00 AM		-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	1/0/00 12:00 AM		-
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	1/0/00 12:00 AM		-
12	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	1/0/00 12:00 AM		-
13	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	1/0/00 12:00 AM		-
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	1/0/00 12:00 AM		-
15									
16		$ -						-	$ -
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	9/1/09 12:00 AM	9/1/10 12:00 AM	365	3/2/10 12:00 PM	1/0/00 12:00 AM		$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	1/0/00 12:00 AM		-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	1/0/00 12:00 AM		-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	1/0/00 12:00 AM		-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	1/0/00 12:00 AM		-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	1/0/00 12:00 AM		-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ -							
34									
35	Five Year Service Awards. Lags are based on 5 year service period.								
36	Exceptional EE Awards are given out Quarterly during the year. Added to payroll at the end of the year. Lag based on the midpoint of the quarter.								
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM			$ -
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM			-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM			-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM			-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM			-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM			-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM			-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM			-
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM			-
12	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM			-
13	12/5/2020	(14)	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	(137)
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM			-
15									
16		$ (14)						9.50	$ (137)
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM			$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM			-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM			-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM			-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM			-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM			-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ (14)							
34									
35									
36	This was a reissued net payroll check for a stop-payment - Misc category selected by HR.								
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 983	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 9,335
4	10/3/2020	752	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	7,149
5	10/10/2020	906	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	8,608
6	10/17/2020	904	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	8,591
7	10/24/2020	912	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	8,660
8	10/31/2020	926	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	8,797
9	11/7/2020	916	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	8,698
10	11/14/2020	944	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	8,972
11	11/21/2020	1,035	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	7,761
12	11/28/2020	897	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	8,519
13	12/5/2020	885	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	8,403
14	12/12/2020	881	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	8,373
15									
16		$ 10,941						9.31	$ 101,866
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM			$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM			-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM			-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM			-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM			-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM			-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ 10,941							
34									
35									
36									
37	Payment date indicates the check.								
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Medical Care 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	$ 23	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	10/2/20 12:00 AM	9.50	$ 219
4	10/3/2020	23	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/9/20 12:00 AM	9.50	219
5	10/10/2020	23	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/16/20 12:00 AM	9.50	219
6	10/17/2020	23	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/23/20 12:00 AM	9.50	219
7	10/24/2020	23	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/30/20 12:00 AM	9.50	219
8	10/31/2020	23	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/6/20 12:00 AM	9.50	219
9	11/7/2020	23	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/13/20 12:00 AM	9.50	219
10	11/14/2020	23	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/20/20 12:00 AM	9.50	219
11	11/21/2020	23	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/25/20 12:00 AM	7.50	173
12	11/28/2020	23	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/4/20 12:00 AM	9.50	219
13	12/5/2020	23	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/11/20 12:00 AM	9.50	219
14	12/12/2020	23	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/18/20 12:00 AM	9.50	219
15									
16		$ 276						9.33	$ 2,576
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 60	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/9/20 12:00 AM	1.00	$ 60
22	10/31/2020	60	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/23/20 12:00 AM	(0.50)	(30)
23	11/15/2020	60	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/10/20 12:00 AM	2.00	120
24	11/30/2020	60	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/25/20 12:00 AM	2.00	120
25	12/15/2020	60	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/10/20 12:00 AM	2.00	120
26	12/31/2020	60	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/24/20 12:00 AM	0.50	30
27									
28		$ 360						1.17	$ 420
29									
30									
31									
32									
33	Total	$ 636							
34									
35									
36									
37	Payment date indicates the check date.								
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Dependent Care

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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	1/0/00 12:00 AM		$ -
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	1/0/00 12:00 AM		-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	1/0/00 12:00 AM		-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	1/0/00 12:00 AM		-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	1/0/00 12:00 AM		-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	1/0/00 12:00 AM		-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	1/0/00 12:00 AM		-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	1/0/00 12:00 AM		-
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	1/0/00 12:00 AM		-
12	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	1/0/00 12:00 AM		-
13	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	1/0/00 12:00 AM		-
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	1/0/00 12:00 AM		-
15									
16		$ -						-	$ -
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	1/0/00 12:00 AM		$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	1/0/00 12:00 AM		-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	1/0/00 12:00 AM		-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	1/0/00 12:00 AM		-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	1/0/00 12:00 AM		-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	1/0/00 12:00 AM		-
27									
28		$ -						-	$ -
29									
30									
31									
32									
33	Total	$ -							
34									
35									
36									
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Education

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	$ -	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	1/0/00 12:00 AM		$ -
6	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	1/0/00 12:00 AM		-
7	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	1/0/00 12:00 AM		-
8	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	1/0/00 12:00 AM		-
9	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	1/0/00 12:00 AM		-
10	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	1/0/00 12:00 AM		-
11	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	1/0/00 12:00 AM		-
12	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	1/0/00 12:00 AM		-
13	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	1/0/00 12:00 AM		-
14	11/28/2020	-	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	1/0/00 12:00 AM		-
15	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	1/0/00 12:00 AM		-
16	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	1/0/00 12:00 AM		-
17									
18		$ -						-	$ -
19									
20									
21	**Semi Monthly**								
22									
23	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	1/0/00 12:00 AM		$ -
24	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	1/0/00 12:00 AM		-
25	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	1/0/00 12:00 AM		-
26	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	1/0/00 12:00 AM		-
27	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	1/0/00 12:00 AM		-
28	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	1/0/00 12:00 AM		-
29									
30		$ -						-	$ -
31									
32									
33									
34									
35	Total	$ -							
36									
37									
38									
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	$ 568,003	7.50	$ 4,261,528
4	Misc_Garnishment	-	-	-
5	FIT Withholding	109,934	7.50	825,004
6	FICA Employee	54,546	7.49	408,537
7	Medicare Employee	12,757	7.49	95,545
8	ME State W/H	3,519	7.51	26,446
9	MA State W/H	850	7.50	6,377
10				
11	Total Weekly Payroll	$ 749,610	7.50	$ 5,623,438
12				
13				
14	**Semi Monthly**			
15	Net Payroll	$ 96,155	(1.28)	$ (123,356)
16	Misc_Garnishment	6,396	(1.33)	(8,528)
17	FIT Withholding	18,693	(1.28)	(23,937)
18	FICA Employee	8,292	(1.30)	(10,743)
19	Medicare Employee	2,335	(1.25)	(2,907)
20	ME State W/H	-	-	-
21	MA State W/H	1,139	(1.22)	(1,393)
22				
23	Total Bi Monthly Payroll	$ 133,010	(1.28)	$ (170,865)
24				
25				
26	Total Weekly & Semi Monthly	$ 882,620	6.18	$ 5,452,573
27				
28				
29	**Incentive Pay**			
30	Net Payroll	$ 52,206	223.50	$ 11,667,961
31	Misc_Garnishment	-	-	-
32	FIT Withholding	16,594	223.50	3,708,833
33	FICA Employee	4,797	223.50	1,072,201
34	Medicare Employee	1,122	223.50	250,754
35	ME State W/H	357	223.50	79,734
36	MA State W/H	229	223.50	51,264
37				
38	Total Incentive Payroll	$ 75,305	223.50	$ 16,830,746
39				
40				
41				
42		Annual		
43	Employer Payroll Taxes	Expense		
44	Social Security Employer Weekly	$ 217,109	7.49	$ 1,626,080
45	Social Security Employer Semi Monthly	44,007	(1.30)	(57,018)
46	Social Security Employer Incentive	4,797	223.50	1,072,203
47	Medicare Employer Weekly	50,817	7.49	380,603
48	Medicare Employer Semi Monthly	10,688	(1.25)	(13,307)
49	Medicare Employer Incentive	1,122	223.50	250,758
50	FUI Employer Weekly	1,738	7.50	13,040
51	FUI Employer Semi Monthly	378	(1.28)	(486)
52	FUI Employer Incentive	24	223.50	5,315
53	SUI Employer Weekly	1,006	7.50	7,547
54	SUI Employer Semi Monthly	124	(1.28)	(160)
55	SUI Employer incentive	9	223.50	2,065
56				
57	Total Employer Payroll Taxes	$ 331,819	9.90	$ 3,286,641
58				
59				
60	Total FICA Taxes	$ 328,540	9.92	$ 3,259,320
61				
62	Total Federal Unemployment Taxes	$ 2,140	8.35	$ 17,869
63				
64	Total State Unemployment Taxes	$ 1,140	8.29	$ 9,452
65				

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Total Payroll Service

Line No	Payroll Description	Gross Pay Amount	Total ADP Payroll Items	Total Transfer to ADP	Difference	Total Payroll Deductions
1	**Weekly**					
2						
3	9/26/2020	$ 78,321	$ 71,247	$ 71,247	$ -	$ 65,413
4	10/3/2020	72,610	65,401	65,401	-	59,968
5	10/10/2020	75,366	67,160	67,160	-	61,566
6	10/17/2020	73,729	66,432	66,432	-	60,966
7	10/24/2020	75,754	68,186	68,186	-	62,560
8	10/31/2020	77,566	70,295	70,295	-	64,545
9	11/7/2020	75,942	68,599	68,599	-	62,992
10	11/14/2020	79,141	71,886	71,886	-	66,057
11	11/21/2020	84,995	67,938	67,938	-	61,631
12	11/28/2020	73,759	66,096	66,096	-	60,656
13	12/5/2020	72,415	64,875	64,875	-	59,538
14	12/12/2020	75,740	69,335	69,335	-	63,720
15						
16		$ 915,338	$ 817,452	$ 817,452		$ 749,610
17						
18						
19	**Semi Monthly**					
20						
21	10/15/2020	$ 28,670	$ 25,747	$ 25,747	$ -	$ 23,669
22	10/31/2020	25,985	20,416	$ 20,416	-	18,777
23	11/15/2020	27,585	24,180	24,180	-	22,517
24	11/30/2020	26,964	23,101	23,101	-	21,486
25	12/15/2020	32,172	25,712	25,712	-	23,862
26	12/31/2020	30,998	24,481	24,481	(0)	22,700
27						
28		$ 172,374	$ 143,637	$ 143,637		$ 133,010
29						
30						
31	**Incentive Pay**					
32	**February 2020**					
33	Incentive Pay-Weekly	$ 7,570	$ 8,181	$ 8,181	$ -	$ 7,570
34	Incentive Pay-Salary	69,806	73,077	73,077	-	67,735
35						
36		$ 77,376	$ 81,258	$ 81,258		$ 75,305
37						
38						
39	Total	$ 1,165,088	$ 1,042,347	$ 1,042,347		$ 957,926
40						

Northern Utilities, Inc. - New Hampshire Division
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	49,452	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	370,891	10/2/20 12:00 AM
4	10/3/2020	45,570	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	341,773	10/9/20 12:00 AM
5	10/10/2020	46,316	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	347,370	10/16/20 12:00 AM
6	10/17/2020	46,363	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	347,723	10/23/20 12:00 AM
7	10/24/2020	47,297	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	354,726	10/30/20 12:00 AM
8	10/31/2020	48,840	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	366,299	11/6/20 12:00 AM
9	11/7/2020	47,739	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	405,785	11/13/20 12:00 AM
10	11/14/2020	49,888	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	374,157	11/20/20 12:00 AM
11	11/21/2020	46,238	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	300,544	11/25/20 12:00 AM
12	11/28/2020	46,348	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	347,609	12/4/20 12:00 AM
13	12/5/2020	45,506	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	341,297	12/11/20 12:00 AM
14	12/12/2020	48,447	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	363,354	12/18/20 12:00 AM
15										
16		$ 568,003						7.50	$ 4,261,528	
17										
18										
19	**Semi Monthly**									
20										
21	10/15/2020	$ 17,239	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (17,239)	10/9/20 12:00 AM
22	10/31/2020	13,250	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(33,124)	10/23/20 12:00 AM
23	11/15/2020	16,412	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(65,650)	11/10/20 12:00 AM
24	11/30/2020	15,635	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-	11/25/20 12:00 AM
25	12/15/2020	17,234	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	17,234	12/10/20 12:00 AM
26	12/31/2020	16,384	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(24,577)	12/24/20 12:00 AM
27										
28		$ 96,155						(1.28)	$ (123,356)	
29										
30										
31	**Incentive Pay**									
32	**February 2020**									
33	Incentive Pay-Weekly	$ 5,326	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	$ 1,190,265	2/13/20 12:00 AM
34	Incentive Pay-Salary	46,880	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	10,477,696	2/13/20 12:00 AM
35		$ 52,206						223.50	$ 11,667,961	
36										
37										
38	Total	$ 716,364								
39										
40										

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Misc_Garnishment

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	-	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	-
4	10/3/2020	-	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	-
5	10/10/2020	-	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	-
6	10/17/2020	-	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	-
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	-
11	11/21/2020	-	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	-
12	11/28/2020	-	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	-
13	12/5/2020	-	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	-
14	12/12/2020	-	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	-
15									
16		$ -						-	$ -
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 1,066	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (1,066)
22	10/31/2020	1,066	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(2,665)
23	11/15/2020	1,066	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(4,264)
24	11/30/2020	1,066	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	1,066	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	1,066
26	12/31/2020	1,066	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(1,599)
27									
28		$ 6,396						(1.33)	$ (8,528)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ -	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	$ -
34	Incentive Pay-Salary	-	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	-
35		$ -						-	$ -
36									
37									
38	Total	$ 6,396							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FIT Withholding

Line			Service Period		Total	Midpoint	Wire Transfer	(Lead) Lag	Weighted
No	Payroll Description	Amount	Start	End	Days	Service Period	Date	Days	Dollar Days
1	**Weekly**								
2									
3	9/26/2020	9,790	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	73,423
4	10/3/2020	8,718	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	65,386
5	10/10/2020	9,226	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	69,198
6	10/17/2020	8,899	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	66,745
7	10/24/2020	9,332	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	69,994
8	10/31/2020	9,647	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	72,356
9	11/7/2020	9,311	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	79,145
10	11/14/2020	10,032	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	75,244
11	11/21/2020	8,810	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	57,266
12	11/28/2020	8,510	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	63,825
13	12/5/2020	8,376	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	62,818
14	12/12/2020	9,281	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	69,605
15									
16		$ 109,934						7.50	$ 825,004
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 3,112	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (3,112)
22	10/31/2020	2,663	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(6,659)
23	11/15/2020	3,185	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(12,740)
24	11/30/2020	2,990	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	3,475	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	3,475
26	12/31/2020	3,268	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(4,902)
27									
28		$ 18,693						(1.28)	$ (23,937)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 1,665	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	$ 372,224
34	Incentive Pay-Salary	14,929	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	3,336,609
35		$ 16,594						223.50	$ 3,708,833
36									
37									
38	Total	$ 145,221							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FICA Employee

Line			Service Period		Total	Midpoint	Wire Transfer	(Lead) Lag	Weighted
No	Payroll Description	Amount	Start	End	Days	Service Period	Date	Days	Dollar Days
1	**Weekly**								
2									
3	9/26/2020	4,675	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	35,065
4	10/3/2020	4,320	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	32,397
5	10/10/2020	4,490	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	33,678
6	10/17/2020	4,389	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	32,917
7	10/24/2020	4,514	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	33,858
8	10/31/2020	4,627	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	34,701
9	11/7/2020	4,526	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	38,472
10	11/14/2020	4,724	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	35,433
11	11/21/2020	5,087	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	33,068
12	11/28/2020	4,385	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	32,887
13	12/5/2020	4,301	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	32,257
14	12/12/2020	4,507	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	33,804
15									
16		$ 54,546						7.49	$ 408,537
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 1,684	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (1,684)
22	10/31/2020	1,318	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(3,295)
23	11/15/2020	1,285	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(5,140)
24	11/30/2020	1,246	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	1,405	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	1,405
26	12/31/2020	1,353	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(2,030)
27									
28		$ 8,292						(1.30)	$ (10,743)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 469	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	$ 104,900
34	Incentive Pay-Salary	4,328	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	967,301
35		$ 4,797						223.50	$ 1,072,201
36									
37									
38	Total	$ 67,635							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Medicare Employee

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	1,093	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	8,201
4	10/3/2020	1,010	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	7,577
5	10/10/2020	1,050	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	7,876
6	10/17/2020	1,026	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	7,698
7	10/24/2020	1,056	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	7,918
8	10/31/2020	1,082	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	8,116
9	11/7/2020	1,059	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	8,998
10	11/14/2020	1,105	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	8,287
11	11/21/2020	1,190	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	7,734
12	11/28/2020	1,026	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	7,691
13	12/5/2020	1,006	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	7,544
14	12/12/2020	1,054	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	7,906
15									
16		$ 12,757						7.49	$ 95,545
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 394	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (394)
22	10/31/2020	322	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(804)
23	11/15/2020	378	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(1,513)
24	11/30/2020	369	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	445	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	445
26	12/31/2020	428	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(642)
27									
28		$ 2,335						(1.25)	$ (2,907)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 110	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	$ 24,534
34	Incentive Pay-Salary	1,012	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	226,220
35		$ 1,122						223.50	$ 250,754
36									
37									
38	Total	$ 16,214							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
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	312	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	2,343
4	10/3/2020	283	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	2,122
5	10/10/2020	415	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	3,115
6	10/17/2020	218	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	1,636
7	10/24/2020	290	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	2,174
8	10/31/2020	275	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	2,065
9	11/7/2020	289	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	2,459
10	11/14/2020	240	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	1,804
11	11/21/2020	239	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	1,551
12	11/28/2020	321	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	2,404
13	12/5/2020	282	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	2,115
14	12/12/2020	355	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	2,659
15									
16		$ 3,519						7.51	$ 26,446
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020		10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ -
22	10/31/2020		10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	-
23	11/15/2020		11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	-
24	11/30/2020		11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020		12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	-
26	12/31/2020		12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	-
27									
28		$ -						#DIV/0!	$ -
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ -	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	$ -
34	Incentive Pay-Salary	357	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	79,734
35		$ 357						223.50	$ 79,734
36									
37									
38	Total	$ 3,876							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
MA 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	90	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	674
4	10/3/2020	67	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	504
5	10/10/2020	67	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	504
6	10/17/2020	70	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	523
7	10/24/2020	71	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	532
8	10/31/2020	74	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	551
9	11/7/2020	67	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	571
10	11/14/2020	67	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	504
11	11/21/2020	67	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	437
12	11/28/2020	67	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	504
13	12/5/2020	67	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	504
14	12/12/2020	76	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	568
15									
16		$ 850						7.50	$ 6,377
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 174	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (174)
22	10/31/2020	158	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(395)
23	11/15/2020	190	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(760)
24	11/30/2020	178	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	238	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	238
26	12/31/2020	201	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(302)
27									
28		$ 1,139						(1.22)	$ (1,393)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ -	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	$ -
34	Incentive Pay-Salary	229	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	51,264
35		$ 229						223.50	$ 51,264
36									
37									
38	Total	$ 2,219							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	4,675	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	35,064
4	10/3/2020	4,320	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	32,397
5	10/10/2020	4,490	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	33,678
6	10/17/2020	4,389	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	32,917
7	10/24/2020	4,514	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	33,858
8	10/31/2020	4,627	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	34,701
9	11/7/2020	4,526	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	38,472
10	11/14/2020	4,724	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	35,433
11	11/21/2020	5,087	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	33,068
12	11/28/2020	4,385	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	32,887
13	12/5/2020	4,301	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	32,261
14	12/12/2020	4,507	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	33,804
15									
16		$ 54,547						7.49	$ 408,539
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 1,684	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (1,684)
22	10/31/2020	1,318	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(3,295)
23	11/15/2020	1,285	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(5,140)
24	11/30/2020	1,246	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	1,405	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	1,405
26	12/31/2020	1,353	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(2,030)
27									
28		$ 8,292						(1.30)	$ (10,743)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 469	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	$ 104,900
34	Incentive Pay-Salary	4,328	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	967,304
35		$ 4,797						223.50	$ 1,072,203
36									
37									
38	Total	$ 67,636							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	1,093	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	8,201
4	10/3/2020	1,010	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	7,577
5	10/10/2020	1,050	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	7,876
6	10/17/2020	1,026	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	7,698
7	10/24/2020	1,056	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	7,919
8	10/31/2020	1,082	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	8,116
9	11/7/2020	1,059	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	8,998
10	11/14/2020	1,105	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	8,287
11	11/21/2020	1,190	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	7,734
12	11/28/2020	1,026	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	7,691
13	12/5/2020	1,006	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	7,545
14	12/12/2020	1,054	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	7,906
15									
16		$ 12,757						7.49	$ 95,546
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ 394	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ (394)
22	10/31/2020	322	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	(804)
23	11/15/2020	378	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	(1,513)
24	11/30/2020	369	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	445	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	445
26	12/31/2020	428	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	(641)
27									
28		$ 2,335						(1.25)	$ (2,908)
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 110	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	$ 24,534
34	Incentive Pay-Salary	1,012	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	226,224
35		$ 1,122						223.50	$ 250,758
36									
37									
38	Total	$ 16,214							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	15	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	110
4	10/3/2020	10	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	72
5	10/10/2020	9	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	67
6	10/17/2020	6	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	42
7	10/24/2020	-	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	-
8	10/31/2020	-	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	-
9	11/7/2020	-	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	-
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	-
11	11/21/2020	9	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	57
12	11/28/2020	8	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	61
13	12/5/2020	8	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	61
14	12/12/2020	15	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	113
15									
16		$ 79						7.39	$ 584
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	-
27									
28		$ -						-	$ -
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 24	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	$ 5,315
34	Incentive Pay-Salary	-	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	-
35		$ 24						223.50	$ 5,315
36									
37									
38	Total	$ 103							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
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	51	9/19/20 12:00 AM	9/26/20 12:00 AM	7	9/22/20 12:00 PM	9/30/20 12:00 AM	7.50	383
4	10/3/2020	94	9/26/20 12:00 AM	10/3/20 12:00 AM	7	9/29/20 12:00 PM	10/7/20 12:00 AM	7.50	704
5	10/10/2020	45	10/3/20 12:00 AM	10/10/20 12:00 AM	7	10/6/20 12:00 PM	10/14/20 12:00 AM	7.50	340
6	10/17/2020	45	10/10/20 12:00 AM	10/17/20 12:00 AM	7	10/13/20 12:00 PM	10/21/20 12:00 AM	7.50	340
7	10/24/2020	56	10/17/20 12:00 AM	10/24/20 12:00 AM	7	10/20/20 12:00 PM	10/28/20 12:00 AM	7.50	417
8	10/31/2020	41	10/24/20 12:00 AM	10/31/20 12:00 AM	7	10/27/20 12:00 PM	11/4/20 12:00 AM	7.50	306
9	11/7/2020	23	10/31/20 12:00 AM	11/7/20 12:00 AM	7	11/3/20 12:00 PM	11/12/20 12:00 AM	8.50	192
10	11/14/2020	-	11/7/20 12:00 AM	11/14/20 12:00 AM	7	11/10/20 12:00 PM	11/18/20 12:00 AM	7.50	-
11	11/21/2020	22	11/14/20 12:00 AM	11/21/20 12:00 AM	7	11/17/20 12:00 PM	11/24/20 12:00 AM	6.50	142
12	11/28/2020	22	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	164
13	12/5/2020	22	11/28/20 12:00 AM	12/5/20 12:00 AM	7	12/1/20 12:00 PM	12/9/20 12:00 AM	7.50	164
14	12/12/2020	39	12/5/20 12:00 AM	12/12/20 12:00 AM	7	12/8/20 12:00 PM	12/16/20 12:00 AM	7.50	293
15									
16		$ 459						7.50	$ 3,443
17									
18									
19	**Semi Monthly**								
20									
21	10/15/2020	$ -	10/1/20 12:00 AM	10/15/20 12:00 AM	14	10/8/20 12:00 AM	10/7/20 12:00 AM	(1.00)	$ -
22	10/31/2020	-	10/16/20 12:00 AM	10/31/20 12:00 AM	15	10/23/20 12:00 PM	10/21/20 12:00 AM	(2.50)	-
23	11/15/2020	-	11/1/20 12:00 AM	11/15/20 12:00 AM	14	11/8/20 12:00 AM	11/4/20 12:00 AM	(4.00)	-
24	11/30/2020	-	11/16/20 12:00 AM	11/30/20 12:00 AM	14	11/23/20 12:00 AM	11/23/20 12:00 AM	-	-
25	12/15/2020	-	12/1/20 12:00 AM	12/15/20 12:00 AM	14	12/8/20 12:00 AM	12/9/20 12:00 AM	1.00	-
26	12/31/2020	-	12/16/20 12:00 AM	12/31/20 12:00 AM	15	12/23/20 12:00 PM	12/22/20 12:00 AM	(1.50)	-
27									
28		$ -						-	$ -
29									
30									
31	**Incentive Pay**								
32	February 2020								
33	Incentive Pay-Weekly	$ 8	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	$ 1,692
34	Incentive Pay-Salary	2	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	373
35		$ 9						223.50	$ 2,065
36									
37									
38	Total	$ 468							
39									
40									

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Empl Benefits Other
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260600 & 601**

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1									
2	January	$ 5,621	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM		31.70	$ 178,195
3	February	4,216	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM		31.70	133,664
4	March	854	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM		31.70	27,067
5	April	3,849	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM		31.70	122,012
6	May	1,288	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM		31.70	40,837
7	June	2,610	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM		31.70	82,755
8	July	2,490	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM		31.70	78,942
9	August	911	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM		31.70	28,876
10	September	661	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM		31.70	20,956
11	October	1,660	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM		31.70	52,637
12	November	2,923	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM		31.70	92,652
13	December	4,293	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM		31.70	136,109
14									
15		$ 31,376			366			31.70	$ 994,700
16									
17									
18									
19									
20	Misc Employee Benefit expenses representing a number of unrelated expenses.								
21	- Such as Safety Shoes, Doctor Referrals, Coffee & Kitchen supplies, Physicals, Drug Screening, Flu Shots, Cleaning Supplies								
22									
23	Use lag for Other O&M expenses								
24									
25									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Benefits Lead Lag Days
12 Months Ended Dec 31, 2020
Summary of Employee Benefits Acct 926

Line No		Description of Benefit	Amount Expensed	(Lead) Lag Days	Weighted Dollar Days
1		Empl Pension Fund Services	$ 4,915	144.28	$ 709,072
2	Cap	Employee Pension 410K	223,620	9.45	2,113,696
3		401K Capitalized	(109,037)	9.45	(1,030,638)
4	Cap	Health Insurance Medical Only	665,259	45.98	30,587,176
5		Health Ins - Emp Contr - Medical Only	(160,868)	45.98	(7,396,389)
6		Health Insurance - Drug Subsidy	(10,252)	317.50	(3,255,096)
7	Cap	Health Insurance NU-NH (Union)	-		-
8		Health Ins Union - Emp Contr - Medical Only	-		-
9	Cap	Dental Insurance	44,042	45.98	2,024,940
10		Dental Insurance - Emp Contribution	(10,270)	45.98	(472,200)
11		Vision	7,387	30.00	221,603
12		Vision - Employee Contr	(2,329)	30.00	(69,882)
13	Cap	Empl Benefit - Life Insurance	14,063	7.59	106,804
14	Cap	AD&D Insurance	1,487	8.28	12,304
15	Cap	LTD Insurance	21,266	59.00	1,254,586
16		Employee Benefit Accrual Adj	(6,145)	45.55	(279,903)
17		Benefit Cost Capitalized	(361,363)	45.55	(16,460,179)
18		Empl Benefits Other	31,376	31.70	994,700
19					
20		Total Employee Benefits	$ 353,148		$ 9,060,595
21					
22		Total Base Rate Employee Benefits	$ 353,148	25.66	$ 9,060,595
23					
24		Total 401k used for Capitalized Items	$ 223,620	9.45	$ 2,113,696
25					
26		Total Direct Benefits used for Capitalized Items	$ 746,116	45.55	$ 33,985,810
27					
28					
29		Health & Dental Lags	$ 527,909	40.70	$ 21,488,432
30					

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Empl Pension Fund Services
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9261000**

Line No	Vendor	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1									
2	John Hancock Retirement Plan	$ 120	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	2/13/20 12:00 PM	59.00	$ 7,080
3	John Hancock Retirement Plan	70	10/1/19 12:00 AM	11/1/19 12:00 AM	31	10/16/19 12:00 PM	4/16/20 12:00 PM	183.00	12,810
4	John Hancock Retirement Plan	130	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	4/16/20 12:00 PM	122.00	15,860
5	John Hancock Retirement Plan	1,161	7/1/19 12:00 AM	10/1/19 12:00 AM	92	8/16/19 12:00 AM	4/16/20 12:00 PM	244.50	283,784
6	John Hancock Retirement Plan	1,344	10/1/19 12:00 AM	1/1/20 12:00 AM	92	11/16/19 12:00 AM	4/16/20 12:00 PM	152.50	205,001
7	John Hancock Retirement Plan	1,153	1/1/20 12:00 AM	4/1/20 12:00 AM	91	2/15/20 12:00 PM	5/14/20 12:00 PM	89.00	102,573
8	TransAmerica Diversified	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 PM	84.50	76,050
9	John Hancock Retirement Plan	37	4/1/20 12:00 AM	7/1/20 12:00 AM	91	5/16/20 12:00 PM	10/22/20 12:00 PM	159.00	5,915
10									
11		$ 4,915						144.28	$ 709,072
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Employee Pension 410K
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260100**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 22,542	1/1/20 12:00 AM	2/1/20 12:00 AM	31	9.45	$ 213,073
3	February	18,793	2/1/20 12:00 AM	3/1/20 12:00 AM	29	9.45	177,639
4	March	17,010	3/1/20 12:00 AM	4/1/20 12:00 AM	31	9.45	160,778
5	April	19,952	4/1/20 12:00 AM	5/1/20 12:00 AM	30	9.45	188,591
6	May	18,471	5/1/20 12:00 AM	6/1/20 12:00 AM	31	9.45	174,589
7	June	19,476	6/1/20 12:00 AM	7/1/20 12:00 AM	30	9.45	184,088
8	July	21,521	7/1/20 12:00 AM	8/1/20 12:00 AM	31	9.45	203,417
9	August	17,484	8/1/20 12:00 AM	9/1/20 12:00 AM	31	9.45	165,260
10	September	17,520	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9.45	165,602
11	October	21,004	10/1/20 12:00 AM	11/1/20 12:00 AM	31	9.45	198,532
12	November	17,471	11/1/20 12:00 AM	12/1/20 12:00 AM	30	9.45	165,135
13	December	12,377	12/1/20 12:00 AM	1/1/21 12:00 AM	31	9.45	116,993
14							
15		$ 223,620			366	9.45	$ 2,113,696

20 Payments to New York Life for 401K - employee match

22 Lag Days are from Non ADP Payroll Lead Lag.

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
401K Capitalized
12 Months Ended Dec 31, 2020

Acct: **30-40-10-00-9260101**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ (10,992)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	9.45	$ (103,899)
3	February	(9,163)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	9.45	(86,610)
4	March	(8,294)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	9.45	(78,396)
5	April	(9,729)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	9.45	(91,956)
6	May	(9,007)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	9.45	(85,135)
7	June	(9,496)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	9.45	(89,761)
8	July	(10,494)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	9.45	(99,187)
9	August	(8,525)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	9.45	(80,579)
10	September	(8,542)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9.45	(80,745)
11	October	(10,242)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	9.45	(96,808)
12	November	(8,518)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	9.45	(80,513)
13	December	(6,036)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	9.45	(57,049)
14							
15		$ (109,037)			366	9.45	$ (1,030,638)
16							
17							
18							
19							
20	Capitalization of 401K benefits						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Health Insurance Medical Only
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260300**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 109,468	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$ 5,033,124
3	February	95,968	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98	4,412,422
4	March	(52,041)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98	(2,392,743)
5	April	95,968	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98	4,412,422
6	May	95,968	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98	4,412,422
7	June	(98,499)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98	(4,528,769)
8	July	95,968	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98	4,412,422
9	August	21,152	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98	972,545
10	September	20,078	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98	923,153
11	October	124,543	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98	5,726,222
12	November	67,254	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98	3,092,191
13	December	89,429	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98	4,111,764
14							
15		$ 665,259			366	45.98	$ 30,587,176
16							
17							
18							
19							
20	Health Insurance Accruals						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Health Ins - Emp Contr - Medical Only
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260301**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ (15,978)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$ (734,619)
3	February	(12,116)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98	(557,090)
4	March	(13,126)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98	(603,496)
5	April	(13,940)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98	(640,931)
6	May	(11,982)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98	(550,929)
7	June	(13,928)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98	(640,367)
8	July	(13,617)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98	(626,100)
9	August	(12,022)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98	(552,742)
10	September	(13,547)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98	(622,869)
11	October	(14,085)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98	(647,597)
12	November	(12,384)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98	(569,378)
13	December	(14,143)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98	(650,270)
14							
15		$ (160,868)			366	45.98	$ (7,396,389)
16							
17							
18							
19							
20	Employee Contributions (through withholdings) for Medical						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Health Insurance - Drug Subsidy
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260303**

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1									
2	January	$ (802)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	$ (254,705)
3	February	(671)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(213,173)
4	March	(802)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(254,705)
5	April	(758)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(240,608)
6	May	(1,863)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(591,372)
7	June	(758)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(240,786)
8	July	(759)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(240,903)
9	August	(802)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(254,705)
10	September	(802)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(254,705)
11	October	(802)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(254,705)
12	November	(673)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(213,592)
13	December	(759)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/15/21 12:00 PM	317.50	(241,138)
14									
15		$ (10,252)						317.50	$ (3,255,096)

16
17
18
19
20 General Accounting entries to accrue for annual drug subsidy receipts
21
22 Check is received for the prior calendar year.
23
24
25

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Health Insurance NU-NH (Union)
12 Months Ended Dec 31, 2020

Acct:

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January		1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$ -
3	February		2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98	-
4	March		3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98	-
5	April		4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98	-
6	May		5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98	-
7	June		6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98	-
8	July		7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98	-
9	August		8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98	-
10	September		9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98	-
11	October		10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98	-
12	November		11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98	-
13	December		12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98	-
14							
15		$ -			366	#DIV/0!	$ -
16							
17							
18							
19							
20	Health Insurance Accruals						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Health Ins Union - Emp Contr - Medical Only
12 Months Ended Dec 31, 2020

Acct:

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January		1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$ -
3	February		2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98	-
4	March		3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98	-
5	April		4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98	-
6	May		5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98	-
7	June		6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98	-
8	July		7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98	-
9	August		8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98	-
10	September		9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98	-
11	October		10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98	-
12	November		11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98	-
13	December		12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98	-
14							
15		$ -			366	#DIV/0!	$ -
16							
17							
18							
19							
20	Employee Contributions (through withholdings) for Medical						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Dental Insurance
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9261200**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 4,356	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$ 200,270
3	February	4,356	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98	200,270
4	March	(2,187)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98	(100,559)
5	April	4,356	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98	200,270
6	May	4,356	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98	200,270
7	June	6,325	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98	290,806
8	July	4,356	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98	200,270
9	August	4,356	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98	200,270
10	September	748	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98	34,403
11	October	4,356	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98	200,270
12	November	4,309	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98	198,129
13	December	4,356	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98	200,270
14							
15		$ 44,042			366	45.98	$ 2,024,940
16							
17							
18							
19							
20	Dental Insurance Expense						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Dental Insurance - Emp Contribution
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9261201**

Line No	Month		Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days		Weighted Dollar Days
1									
2	January	$	(1,068)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.98	$	(49,104)
3	February		(800)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.98		(36,796)
4	March		(862)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.98		(39,629)
5	April		(867)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.98		(39,847)
6	May		(784)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.98		(36,054)
7	June		(899)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.98		(41,356)
8	July		(849)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.98		(39,054)
9	August		(768)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.98		(35,332)
10	September		(856)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.98		(39,361)
11	October		(864)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.98		(39,714)
12	November		(785)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.98		(36,072)
13	December		(867)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.98		(39,880)
14									
15		$	(10,270)			366	45.98	$	(472,200)
16									
17									
18									
19	Lag Days are from Non ADP Payroll Lead Lag.								
20									
21	Employee contributions (through withholdings) for Dental Insurance								
22									
23	The employee contribution toward vision insurance is an offset to the expense.								
24									
25									

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Vision
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9262400**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 636	1/1/20 12:00 AM	2/1/20 12:00 AM	31	30.00	$ 19,090
3	February	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	30.00	-
4	March	1,857	3/1/20 12:00 AM	4/1/20 12:00 AM	31	30.00	55,702
5	April	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	30.00	-
6	May	894	5/1/20 12:00 AM	6/1/20 12:00 AM	31	30.00	26,833
7	June	(111)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	30.00	(3,317)
8	July	673	7/1/20 12:00 AM	8/1/20 12:00 AM	31	30.00	20,199
9	August	1,053	8/1/20 12:00 AM	9/1/20 12:00 AM	31	30.00	31,578
10	September	407	9/1/20 12:00 AM	10/1/20 12:00 AM	30	30.00	12,217
11	October	1,245	10/1/20 12:00 AM	11/1/20 12:00 AM	31	30.00	37,346
12	November	(12)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	30.00	(362)
13	December	744	12/1/20 12:00 AM	1/1/21 12:00 AM	31	30.00	22,316
14							
15		$ 7,387			366	30.00	$ 221,603
16							
17							
18							
19							
20	Vision expense						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24	The employee contribution toward vision insurance is an offset to the expense.						
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Vision - Employee Contr
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9262401**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ (246)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	30.00	$ (7,382)
3	February	(185)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	30.00	(5,544)
4	March	(197)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	30.00	(5,912)
5	April	(198)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	30.00	(5,953)
6	May	(179)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	30.00	(5,360)
7	June	(203)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	30.00	(6,104)
8	July	(186)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	30.00	(5,565)
9	August	(172)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	30.00	(5,165)
10	September	(190)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	30.00	(5,687)
11	October	(194)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	30.00	(5,826)
12	November	(177)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	30.00	(5,303)
13	December	(203)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	30.00	(6,082)
14							
15		$ (2,329)			366	30.00	$ (69,882)
16							
17							
18							
19							
20	Employee Contribution (through withholdings) for Vision coverage						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Empl Benefit - Life Insurance
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9260400**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 1,280	1/1/20 12:00 AM	2/1/20 12:00 AM	31	7.59	$ 9,720
3	February	1,357	2/1/20 12:00 AM	3/1/20 12:00 AM	29	7.59	10,307
4	March	6,657	3/1/20 12:00 AM	4/1/20 12:00 AM	31	7.59	50,558
5	April	3,090	4/1/20 12:00 AM	5/1/20 12:00 AM	30	7.59	23,463
6	May	(2,675)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	7.59	(20,312)
7	June	(2,582)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	7.59	(19,607)
8	July	1,168	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7.59	8,871
9	August	1,045	8/1/20 12:00 AM	9/1/20 12:00 AM	31	7.59	7,937
10	September	1,127	9/1/20 12:00 AM	10/1/20 12:00 AM	30	7.59	8,559
11	October	1,197	10/1/20 12:00 AM	11/1/20 12:00 AM	31	7.59	9,091
12	November	1,197	11/1/20 12:00 AM	12/1/20 12:00 AM	30	7.59	9,089
13	December	1,202	12/1/20 12:00 AM	1/1/21 12:00 AM	31	7.59	9,127
14							
15		$ 14,063			366	7.59	$ 106,804
16							
17							
18							
19							
20	Life Insurance benefits						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
AD&D Insurance
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9261300**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ 146	1/1/20 12:00 AM	2/1/20 12:00 AM	31	8.28	$ 1,211
3	February	155	2/1/20 12:00 AM	3/1/20 12:00 AM	29	8.28	1,284
4	March	(298)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	8.28	(2,470)
5	April	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	8.28	-
6	May	438	5/1/20 12:00 AM	6/1/20 12:00 AM	31	8.28	3,625
7	June	450	6/1/20 12:00 AM	7/1/20 12:00 AM	30	8.28	3,721
8	July	146	7/1/20 12:00 AM	8/1/20 12:00 AM	31	8.28	1,208
9	August	(217)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8.28	(1,797)
10	September	25	9/1/20 12:00 AM	10/1/20 12:00 AM	30	8.28	207
11	October	358	10/1/20 12:00 AM	11/1/20 12:00 AM	31	8.28	2,963
12	November	142	11/1/20 12:00 AM	12/1/20 12:00 AM	30	8.28	1,173
13	December	142	12/1/20 12:00 AM	1/1/21 12:00 AM	31	8.28	1,179
14							
15		$ 1,487			366	8.28	$ 12,304
16							
17							
18							
19							
20	Payments to LINA (Cigna Group Insurance)						
21							
22	Lag Days are from Non ADP Payroll Lead Lag.						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
LTD Insurance
12 Months Ended Dec 31, 2020

Acct: **30-40-03-00-9261400**

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1									
2	January	$ 1,301	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	2/19/20 12:00 PM	65.00	$ 84,567
3	February	2,482	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	3/16/20 12:00 PM	60.00	148,949
4	March	2,482	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/16/20 12:00 PM	30.00	74,475
5	April	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM		-	-
6	May	2,482	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	6/25/20 12:00 PM	70.50	175,016
7	June	2,482	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	99,300
8	July	1,638	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	10/7/20 12:00 PM	113.50	185,929
9	August	1,638	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	10/7/20 12:00 PM	83.00	135,933
10	September	1,674	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	11/10/20 12:00 PM	86.00	143,936
11	October	1,672	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	11/3/20 12:00 PM	48.50	81,087
12	November	1,705	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	12/7/20 12:00 PM	52.00	88,664
13	December	1,708	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/7/20 12:00 PM	21.50	36,731
14									
15		$ 21,266			366			59.00	$ 1,254,586
16									
17									
18									
19	Payments to LINA (Cigna Group Insurance)								
20									
21									
22									
23									
24									
25									

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Employee Benefit Accrual Adj
12 Months Ended Dec 31, 2020

Acct: **30-40-10-00-9260302**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ (3,258)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.55	$ (148,406)
3	February	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.55	-
4	March	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.55	-
5	April	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.55	-
6	May	-	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.55	-
7	June	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.55	-
8	July	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.55	-
9	August	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.55	-
10	September	-	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.55	-
11	October	-	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.55	-
12	November	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.55	-
13	December	(2,887)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.55	(131,498)
14							
15		$ (6,145)			366	45.55	$ (279,903)
16							
17							
18							
19							
20	YE accrual for late adjustments (after Plant Accounting Close) to expense - separate account to be reclassed in Jan 2020 to normal account						
21	(basis for capitalization entries)						
22							
23	Represents the Additional Pensions & Benefits items that will have capitalization applied to it but not yet classified by Plant Accounting						
24							
25	Lag based on Benefits capitalized						

Northern Utilities, Inc. - New Hampshire Division
Benefits Calculation of (Lead) Lag
Benefit Cost Capitalized
12 Months Ended Dec 31, 2020

Acct: **30-40-10-00-9260500**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1							
2	January	$ (57,140)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	45.55	$ (2,602,763)
3	February	(50,290)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	45.55	(2,290,707)
4	March	37,138	3/1/20 12:00 AM	4/1/20 12:00 AM	31	45.55	1,691,660
5	April	(68,700)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	45.55	(3,129,315)
6	May	(48,317)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	45.55	(2,200,868)
7	June	34,383	6/1/20 12:00 AM	7/1/20 12:00 AM	30	45.55	1,566,152
8	July	(36,247)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	45.55	(1,651,055)
9	August	(17,032)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	45.55	(775,808)
10	September	(28,194)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	45.55	(1,284,258)
11	October	(48,585)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	45.55	(2,213,064)
12	November	(36,390)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	45.55	(1,657,597)
13	December	(41,988)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	45.55	(1,912,556)
14							
15		$ (361,363)			366	45.55	$ (16,460,179)
16							
17							
18							
19							
20	Employee Benefit expense offset for capitalization						
21							
22	Based on Benefits (Health & Dental) Lead Lag from Summary Schedule						
23							
24							
25							

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 31, 2020
Injuries & Damages - Safety

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	**30-40-80-00-9250100 INJURIES & DAMAGES SAFETY - NH**								
3									
4	CINTAS CORP	$ 58	1/8/20 12:00 AM	1/9/20 12:00 AM	1	1/8/20 12:00 PM	2/3/20 12:00 AM	25.50	$ 1,474
5	CINTAS CORP	144	2/3/20 12:00 AM	2/4/20 12:00 AM	1	2/3/20 12:00 PM	2/26/20 12:00 AM	22.50	3,244
6	CINTAS CORP	152	3/3/20 12:00 AM	3/4/20 12:00 AM	1	3/3/20 12:00 PM	3/25/20 12:00 AM	21.50	3,276
7	HAWKINS SAFETY EQUIPMENT	843	5/4/20 12:00 AM	5/5/20 12:00 AM	1	5/4/20 12:00 PM	5/27/20 12:00 AM	22.50	18,966
8	GRAYBAR ELECTRIC CO	40	5/22/20 12:00 AM	5/23/20 12:00 AM	1	5/22/20 12:00 PM	6/2/20 12:00 AM	10.50	421
9	CINTAS CORP	135	6/22/20 12:00 AM	6/23/20 12:00 AM	1	6/22/20 12:00 PM	7/20/20 12:00 AM	27.50	3,719
10	CINTAS CORP	154	3/30/20 12:00 AM	3/31/20 12:00 AM	1	3/30/20 12:00 PM	7/15/20 12:00 AM	106.50	16,399
11	CINTAS CORP	1,262	4/9/20 12:00 AM	4/10/20 12:00 AM	1	4/9/20 12:00 PM	7/15/20 12:00 AM	96.50	121,798
12	CINTAS CORP	183	7/23/20 12:00 AM	7/24/20 12:00 AM	1	7/23/20 12:00 PM	8/19/20 12:00 AM	26.50	4,859
13	GRAYBAR ELECTRIC CO	156	7/31/20 12:00 AM	8/1/20 12:00 AM	1	7/31/20 12:00 PM	8/5/20 12:00 AM	4.50	704
14	CINTAS CORP	142	10/14/20 12:00 AM	10/15/20 12:00 AM	1	10/14/20 12:00 PM	11/9/20 12:00 AM	25.50	3,615
15	STAUFFER GLOVE & SAFETY	233	11/24/20 12:00 AM	11/25/20 12:00 AM	1	11/24/20 12:00 PM	12/21/20 12:00 AM	26.50	6,185
16	CINTAS CORP	248	12/9/20 12:00 AM	12/10/20 12:00 AM	1	12/9/20 12:00 PM	12/28/20 12:00 AM	18.50	4,590
17									
18	Total 2020 Payments - Injuries & Damages Safety	$ 3,752						50.44	$ 189,250
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 31, 2020

Line No	Annual Charges to Acct	Total 2020 Charges	Lag Days	Weighted Dollar Days
1				
2				
3	30-40-08-00-9250000 D & O AND FIDUCIARY-NH	$ 45,810	(173.50)	$ (7,947,978)
4	30-40-08-00-9250200 GENERAL LIABILITY-NH	313,004	(160.86)	(50,349,940)
5	30-40-08-00-9250202 GENERAL LIABILITY CLAIMS-NH	1,887	42.67	80,525
6	30-40-08-00-9250400 WORKERS COMP EXP - NH	77,534	(41.85)	(3,244,970)
7	30-40-80-00-9250100 INJURIES & DAMAGES SAFETY - NH	3,752	50.44	189,250
8	30-40-10-00-9250201 GEN LIABILITY CAPITILIZED - NH	(177,984)	(160.86)	28,630,572
9	30-40-10-00-9250401 WORKERS COMP CAPITILIZED - NH	(33,995)	(41.85)	1,422,769
10				
11	Total Injuries & Damages Acct 925	$ 230,008	(135.73)	$ (31,219,771)
12				
13				
14				
15				
16				
17				
18				
19				
20				

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 31, 2020
General Liability

Expense Initially Charged to
Acct 30-40-00-00-1650101 - 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	**30-40-08-00-9250200 GENERAL LIABILITY-NH**								
3									
4	LOCKTON COMPANIES	$ 285,336	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	1/24/20 12:00 AM	(160.00)	$ (45,653,707)
5	LOCKTON COMPANIES	13,321	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	1/24/20 12:00 AM	(160.00)	(2,131,371)
6	LOCKTON COMPANIES	10,467	9/1/20 12:00 AM	9/1/21 12:00 AM	365	3/2/21 12:00 PM	9/10/20 12:00 AM	(173.50)	(1,815,948)
7	LOCKTON COMPANIES	7,231	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)	(893,083)
8	LOCKTON COMPANIES	13,321	1/1/21 12:00 AM	1/1/22 12:00 AM	365	7/2/21 12:00 PM	12/24/20 12:00 AM	(190.50)	(2,537,664)
9									
10	Total 2020 Payments - GENERAL LIABILITY	$ 329,676						(160.86)	$ (53,031,773)
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 31, 2020
D & O Fiduciary

Expense Initially Charged to
Acct 30-40-00-00-1650101 - 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	**30-40-08-00-9250000 D & O AND FIDUCIARY-NH**								
3									
4	LOCKTON COMPANIES	$ 42,690	4/29/20 12:00 AM	4/29/21 12:00 AM	365	10/28/20 12:00 PM	5/8/20 12:00 AM	(173.50)	$ (7,406,689)
5	LOCKTON COMPANIES	3,904	4/29/20 12:00 AM	4/29/21 12:00 AM	365	10/28/20 12:00 PM	5/8/20 12:00 AM	(173.50)	(677,382)
6									
7	Total 2020 Payments - D&O & FIDUCIARY	$ 46,594						(173.50)	$ (8,084,071)
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 31, 2020
General Liability Claims

Expense Initially Charged to
Acct 30-40-00-00-2423110 - Insurance Claims Reserve-NH

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	**30-40-08-00-9250202 GENERAL LIABILITY CLAIMS-NH**								
3									
4	DAMAGES	$ 205	11/26/19 12:00 AM	11/27/19 12:00 AM	1	11/26/19 12:00 PM	1/23/20 12:00 AM	57.50	$ 11,788
5	DAMAGES	238	12/10/19 12:00 AM	12/11/19 12:00 AM	1	12/10/19 12:00 PM	1/23/20 12:00 AM	43.50	10,331
6	DAMAGES	161	1/21/20 12:00 AM	1/22/20 12:00 AM	1	1/21/20 12:00 PM	3/5/20 12:00 AM	43.50	7,004
7	DAMAGES	92	2/25/20 12:00 AM	2/26/20 12:00 AM	1	2/25/20 12:00 PM	4/9/20 12:00 AM	43.50	4,002
8	DAMAGES	60	4/17/20 12:00 AM	4/18/20 12:00 AM	1	4/17/20 12:00 PM	4/30/20 12:00 AM	12.50	750
9	DAMAGES	160	5/15/20 12:00 AM	5/16/20 12:00 AM	1	5/15/20 12:00 PM	6/4/20 12:00 AM	19.50	3,120
10	DAMAGES	871	7/13/20 12:00 AM	7/14/20 12:00 AM	1	7/13/20 12:00 PM	8/27/20 12:00 AM	44.50	38,760
11	DAMAGES	100	7/31/20 12:00 AM	8/1/20 12:00 AM	1	7/31/20 12:00 PM	9/17/20 12:00 AM	47.50	4,750
12									
13	Total 2020 Payments - GENERAL LIABILITY CLAIMS	$ 1,887						42.67	$ 80,504
14									
15									
16									
17									
18									
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended Dec 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	**30-40-08-00-9250400 WORKERS COMP EXP - NH**								
3									
4	Current Policy Payments	$ 13,219	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	11/15/19 12:00 AM	(138.00)	$ (1,824,179)
5		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	12/3/19 12:00 AM	(120.00)	(793,122)
6		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	1/6/20 12:00 AM	(86.00)	(568,404)
7		7,264	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	1/6/20 12:00 AM	(86.00)	(624,711)
8		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	2/4/20 12:00 AM	(57.00)	(376,733)
9		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	3/3/20 12:00 AM	(29.00)	(191,671)
10		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	4/5/20 12:00 AM	4.00	26,437
11		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	5/5/20 12:00 AM	34.00	224,718
12		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	6/3/20 12:00 AM	63.00	416,389
13		6,609	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	7/7/20 12:00 AM	97.00	641,107
14									
15	Total 2020 Payments - Workmen's Compensation	$ 73,358						(41.85)	$ (3,070,169)
16									
17									
18									
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Acct 928 Regulatory Commission Expense Lead Lag Days
12 Months Ended December 31, 2020
Regulatory Commission Assessment Fees

30-40-01-00-9280100 (Base)
30-49-01-77-9280300 (Flow thru)

Line No	Description of Payment		Total Payments 2020	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Scheduled Payment Date	(Lead) Lag Days		Weighted Dollar Days
1	PUBLIC UTILITIES COMMISSION	$	110,280	7/1/19 12:00 AM	7/1/20 12:00 AM	366.00	12/31/19 12:00 AM	2/6/20 12:00 PM	37.50	$	4,135,500
2	PUBLIC UTILITIES COMMISSION		110,280	7/1/19 12:00 AM	7/1/20 12:00 AM	366.00	12/31/19 12:00 AM	5/7/20 12:00 PM	128.50		14,170,980
3	PUBLIC UTILITIES COMMISSION		93,709	7/1/20 12:00 AM	7/1/21 12:00 AM	365.00	12/30/20 12:00 PM	9/17/20 12:00 PM	(104.00)		(9,745,736)
4	PUBLIC UTILITIES COMMISSION		112,920	7/1/20 12:00 AM	7/1/21 12:00 AM	365.00	12/30/20 12:00 PM	10/22/20 12:00 PM	(69.00)		(7,791,480)
5											
6	Total Public Utility Assessment Expense	$	427,189						1.80	$	769,264
7											
8											
9	Total Base Amt in Acct 928.01	$	368,964								
10											
11	Total Flow thru Amt in Acct 928.03	$	58,225								
12											
13											
14	**Note: Include Base and Flow thru in payment amount.**										
15											
16											
17											
18											
19											
20											

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
Summary of Operating Lease Activity

Line No	Type of Tax	Test Period Charges	(Lead) Lag Days	Weighted Dollar Days
1	January Payments	$ 23,455	15.00	$ 351,826
2	February Payments	23,387	(3.01)	(70,427)
3	March Payments	23,358	3.00	70,073
4	April Payments	23,358	11.50	268,613
5	May Payments	162	(1.00)	(162)
6	June Payments	23,584	7.51	177,103
7	July Payments	51,077	31.69	1,618,854
8	August Payments	26,633	9.02	240,318
9	September Payments	80,975	7.50	607,311
10	October Payments	22,289	5.00	111,445
11	November Payments	21,776	7.50	163,317
12	December Payments	51,024	1.75	89,216
13				
14	Total Lease Payments	$ 371,077	9.78	$ 3,627,488
15				
16	Percent charged to O&M	41.40%		
17				
18				
19	Total Lease Payments for O&M	$ 153,626		
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
January 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	CITIZENS ASSET FINANCE INC	$ 18,602	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	1/31/20 12:00 PM	15.00	$ 279,025
2	CITIZENS ASSET FINANCE INC	4,853	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	1/31/20 12:00 PM	15.00	72,801
7		$ 23,455							$ 351,826

Line No		
10	Total January Payments	$ 23,455
12	Total Weighted Dollar Days	$ 351,826
14	January Payments (Lead) Lag Days	15.00

17 Note: Buyback of vehicles are included with other vehicle clearing account expenses.

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
February 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	CITIZENS ASSET FINANCE INC	$ 18,504	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	2/12/20 12:00 PM	(3.00)	$ (55,513)
2	CITIZENS ASSET FINANCE INC	4,853	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	2/12/20 12:00 PM	(3.00)	(14,560)
3	CITIZENS ASSET FINANCE INC	29	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	2/3/20 12:00 PM	(12.00)	(354)
4									
5									
6									
7									
8		$ 23,387							$ (70,427)
9									
10									
11		Total February Payments				$ 23,387			
12									
13		Total Weighted Dollar Days				$ (70,427)			
14									
15		February Payments (Lead) Lag Days				(3.01)			
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
March 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	CITIZENS ASSET FINANCE INC	$ 18,504	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	3/19/20 12:00 PM	3.00	$ 55,513
2	CITIZENS ASSET FINANCE INC	4,853	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	3/19/20 12:00 PM	3.00	14,560
3									
4									
5									
6									
7		$ 23,358							$ 70,073
8									
9									
10		Total March Payments				$ 23,358			
11									
12		Total Weighted Dollar Days				$ 70,073			
13									
14		March Payments (Lead) Lag Days				3.00			
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
April 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	CITIZENS ASSET FINANCE INC	$ 18,504	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	4/27/20 12:00 PM	11.50	$ 212,799
2	CITIZENS ASSET FINANCE INC	4,853	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	4/27/20 12:00 PM	11.50	55,814
3									
4									
5									
6									
7		$ 23,358							$ 268,613
8									
9									
10		Total April Payments				$ 23,358			
11									
12		Total Weighted Dollar Days				$ 268,613			
13									
14		April Payments (Lead) Lag Days				11.50			
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
May 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	CITIZENS ASSET FINANCE INC	$ 162	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	5/15/20 12:00 PM	(1.00)	$ (162)
2									
3									
4									
5									
6		$ 162							$ (162)
7									
8									
9		Total May Payments				$ 162			
10									
11		Total Weighted Dollar Days				$ (162)			
12									
13		May Payments (Lead) Lag Days				(1.00)			
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
June 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	CITIZENS ASSET FINANCE INC	$ 18,504	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	6/23/20 12:00 PM	7.50	$ 138,782
2	CITIZENS ASSET FINANCE INC	4,853	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	6/23/20 12:00 PM	7.50	36,401
3	CITIZENS ASSET FINANCE INC	226	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	6/24/20 12:00 PM	8.50	1,921
4									
5									
6									
7									
8		$ 23,584							$ 177,103
9									
10									
11		Total June Payments				$ 23,584			
12									
13		Total Weighted Dollar Days				$ 177,103			
14									
15		June Payments (Lead) Lag Days				7.51			
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
July 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	CITIZENS ASSET FINANCE INC	$ 18,504	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	7/16/20 12:00 PM	61.00	$ 1,128,757.42
2	CITIZENS ASSET FINANCE INC	4,853	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	7/16/20 12:00 PM	61.00	296,057
3	CITIZENS ASSET FINANCE INC	19,547	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	7/23/20 12:00 PM	7.00	136,826
4	CITIZENS ASSET FINANCE INC	6,953	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	7/23/20 12:00 PM	7.00	48,672
5	CITIZENS ASSET FINANCE INC	976	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	7/23/20 12:00 PM	7.00	6,834
6	CITIZENS ASSET FINANCE INC	216	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	7/23/20 12:00 PM	7.00	1,512
7	CITIZENS ASSET FINANCE INC	28	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	7/23/20 12:00 PM	7.00	195
8									
9									
10									
11									
12		$ 51,077							$ 1,618,854
13									
14									
15		Total July Payments			$	51,077			
16									
17		Total Weighted Dollar Days			$	1,618,854			
18									
19		July Payments (Lead) Lag Days				31.69			
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
August 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	CITIZENS ASSET FINANCE INC	$ 19,499	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	8/25/20 12:00 PM	9.00	$ 175,491
2	CITIZENS ASSET FINANCE INC	6,825	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	8/25/20 12:00 PM	9.00	61,428
3	CITIZENS ASSET FINANCE INC	309	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	8/27/20 12:00 PM	11.00	3,399
4									
5									
6									
7									
8		$ 26,633							$ 240,318
9									
10									
11		Total August Payments				$ 26,633			
12									
13		Total Weighted Dollar Days				$ 240,318			
14									
15		August Payments (Lead) Lag Days				9.02			
16									
17									
18									
19	Note: Buyback of vehicles are included with other vehicle clearing account expenses.								
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
September 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	CITIZENS ASSET FINANCE INC	$ 19,499	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	9/23/20 12:00 PM	7.50	$ 146,242
2	CITIZENS ASSET FINANCE INC	6,836	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	9/23/20 12:00 PM	7.50	51,268
3	CITIZENS ASSET FINANCE INC	221	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	9/23/20 12:00 PM	7.50	1,659
4	CITIZENS ASSET FINANCE INC	37,527	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	9/23/20 12:00 PM	7.50	281,449
5	CITIZENS ASSET FINANCE INC	16,892	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	9/23/20 12:00 PM	7.50	126,693
6									
7									
8									
9									
10		$ 80,975							$ 607,311
11									
12									
13		Total September Payments				$ 80,975			
14									
15		Total Weighted Dollar Days				$ 607,311			
16									
17		September Payments (Lead) Lag Days				7.50			
18									
19									
20									
21	Note: Buyback of vehicles are included with other vehicle clearing account expenses.								
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
October 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	CITIZENS ASSET FINANCE INC	$ 17,278	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 PM	5.00	$ 86,391
2	CITIZENS ASSET FINANCE INC	4,544	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 PM	5.00	22,722
3	CITIZENS ASSET FINANCE INC	467	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 PM	5.00	2,333
4									
5									
6									
7									
8		$ 22,289							$ 111,445
9									
10									
11		Total October Payments				$ 22,289			
12									
13		Total Weighted Dollar Days				$ 111,445			
14									
15		October Payments (Lead) Lag Days				5.00			
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
November 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	CITIZENS ASSET FINANCE INC	$ 17,278	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 PM	7.50	$ 129,586
2	CITIZENS ASSET FINANCE INC	4,497	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 PM	7.50	33,731
3									
4									
5									
6									
7		$ 21,776							$ 163,317
8									
9									
10		Total November Payments				$ 21,776			
11									
12		Total Weighted Dollar Days				$ 163,317			
13									
14		November Payments (Lead) Lag Days				7.50			
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, NH
Calculation of Operating Lease Lead Lag Days
12 Months Ended Dec 31, 2020
December 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	CITIZENS ASSET FINANCE INC	$ 17,278	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/15/20 12:00 PM	(1.00)	$ (17,278)
2	CITIZENS ASSET FINANCE INC	4,497	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/15/20 12:00 PM	(1.00)	(4,497)
3	CITIZENS ASSET FINANCE INC	846	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/21/20 12:00 PM	5.00	4,230
4	CITIZENS ASSET FINANCE INC	648	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/18/20 12:00 PM	2.00	1,295
5	CITIZENS ASSET FINANCE INC	18,966	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/16/20 12:00 PM	-	-
6	CITIZENS ASSET FINANCE INC	8,789	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/28/20 12:00 PM	12.00	105,466
7									
8									
9									
10									
11		$ 51,024							$ 89,216
12									
13									
14		Total December Payments				$ 51,024			
15									
16		Total Weighted Dollar Days				$ 89,216			
17									
18		December Payments (Lead) Lag Days				1.75			
19									
20									
21									
22									
23									
24									
25									

Northern Utilities, Inc. (NH Division)
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 - All vouchers greater than $10,000	$ 136,725	13	$ 136,725	13	$ 6,127,723	$ 6,127,723	44.82
Stratum 2 - Every 10th voucher from $10,000 down to $1,000	536,591	220	56,936	22	1,848,521	17,421,329.39	32.47
Stratum 3 - Every 100th voucher under $1,000	179,614	1,020	2,368	11	46,022	3,491,009	19.44
	$ 852,930	1,253	$ 196,029	46	$ 8,022,266	$ 27,040,061	31.70

VEND_CODE	VOUCHER_NO	Co	Div	Dept	RM	FERC	Sub1	Sub2	JNL_AMT	INV_DATE	PAY_DATE	Sample Strata	SVC_START_DATE	SVC_END_DATE	SERVICE DAYS LAG	Service Period Midpoint	Lag Days	Weighted Dollars Days	Sample #
AECOM	816996	30	40	22	00	932	01	00	$ 12,075.75	2020-11-06	2020-12-02	1	9/26/2020	10/30/2020	34	10/13/2020	50	$ 603,787.50	1
AECOM	795160	30	40	22	00	932	01	00	$ 11,046.56	2020-05-19	2020-06-17	1	4/4/2020	5/1/2020	27	4/17/2020	61	$ 668,316.88	2
PIERCE AT ME	819536	30	00	01	00	928	02	00	$ 10,700.00	2020-12-09	2020-12-28	1	11/2/2020	11/30/2020	28	11/16/2020	42	$ 449,400.00	3
AECOM	808432	30	40	22	00	932	01	00	$ 10,618.94	2020-09-16	2020-10-13	1	7/25/2020	8/31/2020	37	8/12/2020	62	$ 653,064.81	4
AECOM	813335	30	40	22	00	932	01	00	$ 10,618.94	2020-10-02	2020-10-29	1	9/1/2020	9/25/2020	24	9/13/2020	46	$ 488,471.24	5
KUBRA DATA	802358	30	40	21	00	903	04	00	$ 10,395.89	2020-06-30	2020-08-05	1	6/1/2020	6/30/2020	29	6/15/2020	51	$ 524,992.45	6
KUBRA DATA	786206	30	40	21	00	903	04	00	$ 10,362.91	2020-02-29	2020-03-11	1	2/1/2020	2/29/2020	28	2/15/2020	25	$ 259,072.75	7
KUBRA DATA	812774	30	40	21	00	903	04	00	$ 10,313.84	2020-09-30	2020-10-26	1	9/1/2020	9/30/2020	29	9/15/2020	41	$ 417,710.52	8
KUBRA DATA	782622	30	40	21	00	903	04	00	$ 10,203.07	2019-12-31	2020-02-05	1	12/1/2019	12/31/2019	30	12/16/2019	51	$ 520,356.57	9
KUBRA DATA	791648	30	40	21	00	903	04	00	$ 10,195.78	2020-03-31	2020-05-04	1	3/1/2020	3/31/2020	30	3/16/2020	49	$ 499,593.22	10
KUBRA DATA	784897	30	40	21	00	903	04	00	$ 10,117.38	2020-01-31	2020-02-26	1	1/1/2020	1/31/2020	30	1/16/2020	41	$ 414,812.58	11
KUBRA DATA	793926	30	40	21	00	903	04	00	$ 10,075.76	2020-04-30	2020-05-27	1	4/1/2020	4/30/2020	29	4/15/2020	42	$ 418,144.04	12
HMI TECHNICAL	820063	30	40	80	00	887	03	00	$ 10,000.00	2020-12-17	2021-01-07	1	12/14/2020	12/20/2020	6	12/17/2020	21	$ 210,000.00	13
KUBRA DATA	809058	30	40	21	00	903	04	00	$ 9,941.71	2020-08-31	2020-10-01	2	8/1/2020	8/31/2020	30	8/16/2020	46	$ 457,318.66	14
NEUCO	799478	30	40	80	00	892	00	00	$ 6,462.50	2020-07-06	2020-07-13	2	6/5/2020	6/19/2020	14	6/12/2020	31	$ 200,337.50	15
AECOM	816997	30	40	22	00	932	01	00	$ 4,640.00	2020-11-10	2020-12-02	2	9/26/2020	10/30/2020	34	10/13/2020	50	$ 232,000.00	16
NEUCO	799477	30	40	80	00	892	00	00	$ 3,630.00	2020-07-06	2020-07-13	2	6/5/2020	6/12/2020	7	6/8/2020	35	$ 125,235.00	17
UTILITIES INDUS	803733	30	40	80	00	893	00	00	$ 3,065.68	2020-07-31	2020-08-17	2	7/22/2020	7/31/2020	9	7/26/2020	22	$ 65,912.12	18
KUBRA DATA	802358	30	40	21	00	903	05	04	$ 2,443.65	2020-06-30	2020-08-05	2	6/1/2020	6/30/2020	29	6/15/2020	51	$ 123,404.33	19
KUBRA DATA	797737	30	40	21	00	903	05	04	$ 2,286.82	2020-05-31	2020-06-26	2	5/1/2020	5/31/2020	30	5/16/2020	41	$ 93,759.62	20
KUBRA DATA	815327	30	40	21	00	903	05	04	$ 2,215.60	2020-10-31	2020-11-16	2	10/1/2020	10/31/2020	30	10/16/2020	31	$ 68,683.60	21
NEUCO	806155	30	40	80	00	892	00	00	$ 2,200.00	2020-09-01	2020-09-09	2	8/14/2020	8/15/2020	1	8/14/2020	26	$ 56,100.00	22
PIERCE AT ME	806399	30	40	10	00	923	09	00	$ 2,127.00	2020-08-13	2020-09-09	2	7/6/2020	7/22/2020	16	7/14/2020	57	$ 121,239.00	23
OMARK CONS	794647	30	40	80	00	874	05	00	$ 1,878.89	2020-05-22	2020-06-04	2	5/18/2020	5/23/2020	5	5/20/2020	15	$ 27,243.91	24
JANITECH INC	801228	30	40	80	00	921	16	00	$ 1,844.00	2020-07-05	2020-07-27	2	7/1/2020	7/31/2020	30	7/16/2020	11	$ 20,284.00	25
NEUCO	800699	30	40	80	00	892	00	00	$ 1,760.00	2020-07-17	2020-07-27	2	7/10/2020	7/11/2020	1	7/10/2020	17	$ 29,040.00	26
RAM PRINTING NH	818254	30	40	24	00	913	53	00	$ 1,678.18	2020-12-08	2020-12-16	2	12/8/2020	12/9/2020	1	12/8/2020	8	$ 12,586.35	27
ESSCO CALIBRATI	784499	30	40	80	00	874	07	00	$ 1,581.00	2020-02-13	2020-03-09	2	2/13/2020	2/14/2020	1	2/13/2020	25	$ 38,734.50	28
WB MASON CO	792729	30	40	10	00	930	10	00	$ 1,535.00	2020-05-05	2020-05-27	2	5/5/2020	5/6/2020	1	5/5/2020	22	$ 33,002.50	29
DIG SAFE SYSTEM	795163	30	40	80	00	874	04	00	$ 1,495.23	2020-06-02	2020-06-15	2	6/1/2020	7/1/2020	30	6/16/2020	(1)	$ (1,495.23)	30
POWELL CONTROLS	799042	30	40	80	00	891	00	00	$ 1,419.30	2020-06-30	2020-07-27	2	6/30/2020	7/1/2020	1	6/30/2020	27	$ 37,611.45	31
NEUCO	802924	30	40	80	00	874	00	00	$ 1,259.58	2020-08-05	2020-08-17	2	7/10/2020	7/14/2020	4	7/12/2020	36	$ 45,344.88	32
PIERCE AT ME	801693	30	00	01	00	928	02	00	$ 1,200.00	2020-07-09	2020-07-29	2	6/9/2020	6/30/2020	21	6/19/2020	40	$ 47,400.00	33
YANKEE CLIP	791256	30	40	22	00	932	01	00	$ 1,147.37	2020-04-17	2020-04-29	2	5/1/2020	6/1/2020	31	5/16/2020	(18)	$ (20,078.98)	34
KUBRA DATA	815327	30	40	21	00	903	02	00	$ 1,124.45	2020-10-31	2020-11-16	2	10/1/2020	10/31/2020	30	10/16/2020	31	$ 34,857.95	35
PIKE IND	819899	30	40	80	00	874	00	00	$ 971.12	2020-12-08	2020-12-28	3	12/8/2020	12/9/2020	1	12/8/2020	20	$ 18,936.84	36
ROCHE LOCKSMITH	790557	30	40	10	00	930	10	00	$ 532.00	2020-04-08	2020-04-27	3	4/8/2020	4/9/2020	1	4/8/2020	19	$ 9,842.00	37
STEVENS BUSINES	784153	30	40	21	00	903	05	02	$ 302.44	2020-02-01	2020-02-24	3	1/1/2020	1/31/2020	30	1/16/2020	39	$ 11,795.16	38
COASTAL MI BOX	779471	30	40	80	00	874	00	00	$ 199.00	2019-12-23	2020-01-08	3	1/1/2020	2/1/2020	31	1/16/2020	(9)	$ (1,691.50)	39
RIORDON JAMES	797537	30	40	80	00	926	06	00	$ 133.77	2020-05-27	2020-06-24	3	5/27/2020	5/28/2020	1	5/27/2020	28	$ 3,678.68	40
HUSSEY	801199	30	40	10	00	930	10	00	$ 90.00	2020-07-15	2020-07-23	3	7/12/2020	8/12/2020	31	7/27/2020	(5)	$ (405.00)	41
JOHNSON DEREK	803812	30	40	80	00	878	14	00	$ 49.96	2020-08-13	2020-08-20	3	8/13/2020	8/14/2020	1	8/13/2020	7	$ 324.74	42
UNITIL ENERGY	782773	30	40	80	00	887	03	00	$ 39.68	2020-01-16	2020-02-10	3	12/12/2019	1/14/2020	33	12/28/2019	44	$ 1,726.08	43
STEVENS BUSINES	804040	30	40	21	00	903	05	02	$ 25.87	2020-08-01	2020-08-19	3	7/1/2020	7/31/2020	30	7/16/2020	34	$ 879.58	44
EVERSOURCE	805194	30	40	80	00	891	01	00	$ 17.75	2020-08-12	2020-08-31	3	7/6/2020	8/6/2020	31	7/21/2020	41	$ 718.88	45
EVERSOURCE	816011	30	40	80	00	891	00	00	$ 6.29	2020-11-10	2020-11-19	3	10/1/2020	10/30/2020	29	10/15/2020	35	$ 217.01	46

Northern Utilities, Inc. - New Hampshire Division
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	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 449,736	39.66	$ 17,837,042
3				
4	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	$ 1,658,305	39.59	$ 65,649,276
5				
6	30-40-10-00-8510200 USC- DISPATCH	9,906		369,364
7	30-40-10-00-8510201 USC- DISPATCH - CAP	(7,429)		(277,023)
8	Total Acct 851	$ 2,476	37.29	$ 92,341
9				
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	3,199,713		126,774,816
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(2,299,809)		(91,115,085)
12	Total Acct 880	$ 899,904	39.63	$ 35,659,730
13				
14	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	5,269,393		208,567,523
15	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(1,214,361)		(48,065,615)
16	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	269,239		10,680,446
17	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(34,852)		(1,378,967)
18	Total Acct 923	$ 4,289,420	39.59	$ 169,803,387
19				
20	Total Base before Reclassification	$ 7,299,842	39.60	$ 289,041,777
21				
22	**Reclassification to Acct 926 of expenses included above**			
23				
24	30-40-10-00-9260210/30 FASB 87 - PENSION - USC ALLOC	601,980	39.59	23,830,321
25	30-40-10-00-9260812/30 FASB 87 - PENSION CAPITALIZED - USC ALLOC	(189,684)	39.59	(7,508,938)
26	30-40-10-00-9260910/29 SFAS 106 - PBOP - USC ALLOC	299,784	39.59	11,867,419
27	30-40-10-00-9261712/29 SFAS 106 - PBOP CAPITALIZED - USC ALLOC	(94,464)	39.59	(3,739,505)
28	30-40-10-00-9261110/31 SERP - USC ALLOC	382,066	39.59	15,124,679
29	30-40-10-00-9261812/31 SERP - USC ALLOC - CAPITALIZED	(120,389)	39.59	(4,765,784)
30				
31				
32	Total Charges per General Ledger Excel Acct 926	$ 6,420,549	39.60	$ 254,233,586
33				
34				
35	*Source of Data: Monthly Service Bills and Unitil Cashpool (Cashtran file)*			

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 37,705	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	$ 1,508,197
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	162,915	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	6,516,607
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	437,075	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	17,482,988
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(97,290)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	(3,891,612)
8	30-40-10-00-8510200 USC- DISPATCH		1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	259,600	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	10,383,994
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(187,643)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	(7,505,702)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	13,271	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	530,854
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(2,740)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	(109,581)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	27,887	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	1,115,466
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(3,511)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/25/20 12:00 PM	40.00	(140,432)
16									
17									
18	Total Base	$ 647,269						40.00	$ 25,890,780
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 41,957	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	$ 1,594,385
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	146,307	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	5,559,662
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	474,371	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	18,026,083
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(107,378)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	(4,080,382)
8	30-40-10-00-8510200 USC- DISPATCH		2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	289,593	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	11,004,535
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(206,748)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	(7,856,411)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	19,078	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	724,951
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(3,842)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	(145,991)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	26,064	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	990,421
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(3,511)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/24/20 12:00 PM	38.00	(133,410)
16									
17									
18	Total Base	$ 675,891						38.00	$ 25,683,843
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 49,577	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	$ 2,131,830
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	179,120	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	7,702,158
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	554,683	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	23,851,358
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(127,008)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	(5,461,344)
8	30-40-10-00-8510200 USC- DISPATCH		3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	339,265	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	14,588,384
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(242,993)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	(10,448,679)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	18,406	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	791,475
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(4,870)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	(209,424)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	21,018	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	903,770
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/28/20 12:00 PM	43.00	(124,413)
16									
17									
18	Total Base	$ 784,305						43.00	$ 33,725,115
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 36,676	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	$ 1,485,374
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	146,242	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	5,922,814
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	404,109	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	16,366,432
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(92,829)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	(3,759,586)
8	30-40-10-00-8510200 USC- DISPATCH		4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	253,689	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	10,274,407
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(185,710)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	(7,521,251)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	22,513	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	911,772
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(5,809)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	(235,274)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	15,735	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	637,263
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	(117,180)
16									
17									
18	Total Base	$ 591,723						40.50	$ 23,964,771
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 37,296	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	$ 1,454,546
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	134,668	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	5,252,059
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	414,304	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	16,157,842
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(96,176)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	(3,750,845)
8	30-40-10-00-8510200 USC- DISPATCH		5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	264,800	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	10,327,193
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(192,111)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	(7,492,318)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	21,187	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	826,280
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(5,686)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	(221,770)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	15,781	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	615,466
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/24/20 12:00 PM	39.00	(112,840)
16									
17									
18	Total Base	$ 591,170						39.00	$ 23,055,613
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 31,753	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	$ 1,317,735
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	110,901	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	4,602,380
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	333,184	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	13,827,133
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(70,416)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	(2,922,245)
8	30-40-10-00-8510200 USC- DISPATCH	5,270	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	218,688
9	30-40-10-00-8510201 USC- DISPATCH - CAP	(3,952)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	(164,016)
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	220,153	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	9,136,329
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(161,572)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	(6,705,230)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	26,476	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	1,098,759
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(7,500)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	(311,248)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	18,035	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	748,443
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/27/20 12:00 PM	41.50	(120,073)
16									
17									
18	Total Base	$ 499,438						41.50	$ 20,726,657
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 34,699	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	$ 1,422,647
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	137,582	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	5,640,881
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	383,572	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	15,726,440
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(89,162)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	(3,655,631)
8	30-40-10-00-8510200 USC- DISPATCH		7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	258,202	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	10,586,277
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(184,388)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	(7,559,910)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	23,272	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	954,149
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(6,572)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	(269,451)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	15,450	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	633,447
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	(118,627)
16									
17									
18	Total Base	$ 569,762						41.00	$ 23,360,224
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 34,810	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	$ 1,322,763
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	122,443	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	4,652,829
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	393,577	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	14,955,941
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(93,305)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	(3,545,605)
8	30-40-10-00-8510200 USC- DISPATCH		8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	268,168	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	10,190,373
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(193,913)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	(7,368,711)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	20,664	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	785,215
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(5,194)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	(197,369)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	16,665	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	633,255
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 PM	38.00	(109,947)
16									
17									
18	Total Base	$ 561,020						38.00	$ 21,318,745
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 33,835	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	$ 1,437,973
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	123,230	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	5,237,263
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	377,762	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	16,054,887
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(89,335)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	(3,796,731)
8	30-40-10-00-8510200 USC- DISPATCH		9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	241,203	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	10,251,119
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(174,444)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	(7,413,885)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	17,453	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	741,761
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(4,543)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	(193,063)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	45,459	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	1,932,017
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,893)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/28/20 12:00 PM	42.50	(122,967)
16									
17									
18	Total Base	$ 567,726						42.50	$ 24,128,373
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 35,531	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	$ 1,243,579
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	142,213	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	4,977,449
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	410,277	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	14,359,695
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(96,177)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	(3,366,210)
8	30-40-10-00-8510200 USC- DISPATCH		10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	265,500	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	9,292,513
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(187,967)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	(6,578,836)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	23,743	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	830,990
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(4,883)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	(170,890)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	19,609	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	686,302
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,526)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/20/20 12:00 PM	35.00	(88,396)
16									
17									
18	Total Base	$ 605,320						35.00	$ 21,186,196
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 32,915	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	$ 1,069,731
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	121,928	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	3,962,675
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	391,648	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	12,728,560
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(89,825)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	(2,919,315)
8	30-40-10-00-8510200 USC- DISPATCH	4,636	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	150,676
9	30-40-10-00-8510201 USC- DISPATCH - CAP	(3,477)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	(113,007)
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	234,341	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	7,616,081
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(169,110)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	(5,496,086)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	17,440	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	566,793
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(4,023)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	(130,759)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	24,717	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	803,312
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,526)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/18/20 12:00 PM	32.50	(82,082)
16									
17									
18	Total Base	$ 558,664						32.50	$ 18,156,577
19									
20									

Northern Utilities, Inc. - New Hampshire Division
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	**Base**								
3									
4	30-40-10-00-8130100 USC-GAS PRODUCTION OTHER - NH	$ 42,983	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	$ 1,848,282
5	30-40-10-00-9030600 USC - CUSTOMER ACCOUNTING	130,756	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	5,622,498
6	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	447,482	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	19,241,747
7	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(103,292)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	(4,441,568)
8	30-40-10-00-8510200 USC- DISPATCH		12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	-
9	30-40-10-00-8510201 USC- DISPATCH - CAP		12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	-
10	30-40-10-00-8800200 USC-GAS DISTRIBUTION - NH	305,200	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	13,123,612
11	30-40-10-00-8800201 USC-GAS DISTRIBUTION - NH-CAP	(213,211)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	(9,168,066)
12	30-40-10-00-9230300 OS UNITIL SERVICE CORP-NH	23,847	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	1,025,416
13	30-40-10-00-9230301 OS UNITIL SERVICE CORP-NH-CAP	(6,505)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	(279,721)
14	30-40-10-00-9230305 USC OUTSIDE SERVICES-DIRECT CHGS-NH	22,821	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	981,284
15	30-40-10-00-9230307 DIRECT CHARGES CAPITALIZED	(2,526)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/28/21 12:00 PM	43.00	(108,601)
16									
17									
18	Total Base	$ 647,555						43.00	$ 27,844,883
19									
20									

Line No	Type of Tax	Test Period Expense	(Lead) Lag Days	Weighted Dollar Days	
1					
2	TAXES FICA - NH	$ 331,611	9.92	$ 3,289,793	
3	TAXES FEDERAL UNEMPLOYMENT - NH	1,639	8.35	13,685	
4	TAXES UNEMPLOYMENT - NH	1,135	8.29	9,416	
5	OTHER TAXES	-	9.91	-	
6	NHBET TAX EXP- CURRENT	63,600	37.50	2,385,000	Business Enterprise Tax with four 25% estimated payments.
7	PAYROLL TAXES CAPITALIZED - NH	(161,795)	9.91	(1,602,972)	
8	NH SURPLUS TAX	10,372	(168.00)	(1,742,447)	See Note 1
9	Total Taxes Excluding Property Taxes	$ 246,562	9.54	$ 2,352,474	
10					
11					
12					
13	Property Taxes	$ 4,728,576			
14					
15	Total Taxes Other Than Income Taxes	$ 4,975,138			
16					
17					
18	Note 1: Insurance Policies with NH Surplus Tax are paid in the first month of the annual policy period.				
19	Lag is half of the prepaid annual service period less the 15 days for payment during the mid point of the first month.				
20					

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
Summary of Property Taxes

Line No	Type of Tax	Test Period Charges	(Lead) Lag Days	Weighted Dollar Days
1	January Payments	$ 417,875	107.00	$ 44,712,625
2	February Payments	-	-	-
3	March Payments	-	-	-
4	April Payments	319,311	(174.50)	(55,719,770)
5	May Payments	955,431	(130.16)	(124,359,491)
6	June Payments	1,135,809	(104.50)	(118,692,006)
7	July Payments	-	-	-
8	August Payments	-	-	-
9	September Payments	319,311	(20.50)	(6,545,876)
10	October Payments	-	-	-
11	November Payments	838,893	54.44	45,666,053
12	December Payments	1,364,999	75.47	103,009,906
13				
14	Total Payments	$ 5,351,630	(20.91)	$ (111,928,559)
15				
16				
17				
18				
19				
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34				
35				

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
January Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	417,875	4/1/19 12:00 AM	4/1/20 12:00 AM	366	10/1/19 12:00 AM	1/16/20 12:00 AM	107.00	44,712,625
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM			-
23									
24									
25									
26		$ 417,875							$ 44,712,625
27									
28									
29		Total January Payments				$ 417,875			
30									
31		Total Weighted Dollar Days				$ 44,712,625			
32									
33		January Payments (Lead) Lag Days				107.00			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
February Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM			-
23									
24									
25									
26		$ -							$ -
27									
28									
29		Total February Payments				$ -			
30									
31		Total Weighted Dollar Days				$ -			
32									
33		February Payments (Lead) Lag Days				#DIV/0!			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
March Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM			-
23									
24									
25									
26		$ -							$ -
27									
28									
29		Total March Payments				$ -			
30									
31		Total Weighted Dollar Days				$ -			
32									
33		March Payments (Lead) Lag Days				#DIV/0!			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
April Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	319,311	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	4/9/20 12:00 AM	(174.50)	(55,719,770)
23									
24									
25									
26		$ 319,311							$ (55,719,770)
27									
28									
29		Total April Payments				$ 319,311			
30									
31		Total Weighted Dollar Days				$ (55,719,770)			
32									
33		April Payments (Lead) Lag Days				(174.50)			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
May Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	348,507	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	5/21/20 12:00 AM	(132.50)	(46,177,238)
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	287,613	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	5/21/20 12:00 AM	(132.50)	(38,108,723)
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	319,311	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	5/28/20 12:00 AM	(125.50)	(40,073,531)
23									
24									
25									
26		$ 955,431							$ (124,359,491)
27									
28									
29		Total May Payments				$ 955,431			
30									
31		Total Weighted Dollar Days				$ (124,359,491)			
32									
33		May Payments (Lead) Lag Days				(130.16)			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
June Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ 7,291	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	$ (761,910)
2	Brentwood	6,082	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(635,569)
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	104,754	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(10,946,793)
5	East Kingston	6,022	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(629,299)
6	Exeter	131,897	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(13,783,224)
7	Greenland	7,018	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(733,381)
8	Hampton	197,595	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(20,648,678)
9	Hampton Falls	270	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(28,215)
10	Kensington	13,167	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(1,375,952)
11	Madbury	3,654	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(381,843)
12	Newington	9,822	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(1,026,377)
13	North Hampton	10,211	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(1,067,050)
14	Plaistow	53,798	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(5,621,891)
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	312,460	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(32,652,070)
17	Rollinsford	2,075	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(216,838)
18	Salem	101,201	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(10,575,505)
19	Seabrook	65,340	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(6,828,030)
20	Somersworth	99,599	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(10,408,096)
21	Stratham	3,553	4/1/20 12:00 AM	4/1/21 12:00 AM	365.00	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(371,289)
22	State of New Hampshire	-						-	-
23									
24									
25									
26		$ 1,135,809							$ (118,692,006)
27									
28									
29		Total June Payments				$ 1,135,809			
30									
31		Total Weighted Dollar Days				$ (118,692,006)			
32									
33		June Payments (Lead) Lag Days				(104.50)			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
July Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM			-
23									
24									
25									
26		$ -							$ -
27									
28									
29		Total July Payments				$ -			
30									
31		Total Weighted Dollar Days				$ -			
32									
33		July Payments (Lead) Lag Days				#DIV/0!			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
August Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM			-
23									
24									
25									
26		$ -							$ -
27									
28									
29		Total August Payments				$ -			
30									
31		Total Weighted Dollar Days				$ -			
32									
33		August Payments (Lead) Lag Days				#DIV/0!			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
September Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	319,311	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	9/10/20 12:00 AM	(20.50)	(6,545,876)
23									
24									
25									
26		$ 319,311							$ (6,545,876)
27									
28									
29		Total September Payments				$ 319,311			
30									
31		Total Weighted Dollar Days				$ (6,545,876)			
32									
33		September Payments (Lead) Lag Days				(20.50)			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
October Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Exeter	-			-	1/0/00 12:00 AM			-
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	-			-	1/0/00 12:00 AM			-
14	Plaistow	-			-	1/0/00 12:00 AM			-
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	-			-	1/0/00 12:00 AM			-
18	Salem	-			-	1/0/00 12:00 AM			-
19	Seabrook	-			-	1/0/00 12:00 AM			-
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	-			-	1/0/00 12:00 AM			-
22	State of New Hampshire	-			-	1/0/00 12:00 AM		-	-
23									
24									
25									
26		$ -							$ -
27									
28									
29		Total October Payments				$ -			
30									
31		Total Weighted Dollar Days				$ -			
32									
33		October Payments (Lead) Lag Days				#DIV/0!			
34									
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
November Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ -			-	1/0/00 12:00 AM			$ -
2	Brentwood	25,745	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	1,403,103
3	Dover	-			-	1/0/00 12:00 AM			-
4	Durham	94,458	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	5,147,961
5	East Kingston	-			-	1/0/00 12:00 AM			-
6	Epping	25,529	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	1,391,322
7	Exeter	-			-	1/0/00 12:00 AM			-
8	Greenland	3,675	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	200,288
9	Hampton	199,688	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	10,882,996
10	Hampton Falls	434	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	23,653
11	Kensington	13,676	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	745,342
12	Madbury	4,469	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/12/20 12:00 AM	42.50	189,933
13	Newington	13,026	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	709,938
14	North Hampton	-			-	1/0/00 12:00 AM			-
15	Plaistow	-			-	1/0/00 12:00 AM			-
16	Portsmouth	304,396	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	16,589,582
17	Rochester	-			-	1/0/00 12:00 AM			-
18	Rollinsford	-			-	1/0/00 12:00 AM			-
19	Salem	-			-	1/0/00 12:00 AM			-
20	Seabrook	-			-	1/0/00 12:00 AM			-
21	Somersworth	153,797	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/24/20 12:00 AM	54.50	8,381,937
22	Stratham	-			-	1/0/00 12:00 AM			-
23	State of New Hampshire	-			-	1/0/00 12:00 AM			-
24									
25									
26									
27		$ 838,893							$ 45,666,053
28									
29									
30		Total November Payments				$ 838,893			
31									
32		Total Weighted Dollar Days				$ 45,666,053			
33									
34		November Payments (Lead) Lag Days				54.44			
35									

Northern Utilities, Inc. - New Hampshire Division
Calculation of Property Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
December Payments

Line No	Jurisdiction Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check or EFT Date	(Lead) Lag Days	Weighted Dollar Days
1	Atkinson	$ 18,110	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	$ 1,276,755
2	Brentwood	-			-	1/0/00 12:00 AM			-
3	Dover	425,761	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/22/20 12:00 AM	82.50	35,125,265
4	Durham	-			-	1/0/00 12:00 AM			-
5	East Kingston	9,285	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	654,593
6	Exeter	178,689	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	12,597,548
7	Greenland	-			-	1/0/00 12:00 AM			-
8	Hampton	-			-	1/0/00 12:00 AM			-
9	Hampton Falls	-			-	1/0/00 12:00 AM			-
10	Kensington	-			-	1/0/00 12:00 AM			-
11	Madbury	-			-	1/0/00 12:00 AM			-
12	Newington	-			-	1/0/00 12:00 AM			-
13	North Hampton	16,766	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	1,182,003
14	Plaistow	139,254	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	9,817,407
15	Portsmouth	-			-	1/0/00 12:00 AM			-
16	Rochester	-			-	1/0/00 12:00 AM			-
17	Rollinsford	2,811	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	198,176
18	Salem	187,867	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	13,244,624
19	Seabrook	103,435	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	7,292,168
20	Somersworth	-			-	1/0/00 12:00 AM			-
21	Stratham	4,969	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/10/20 12:00 AM	70.50	350,315
22	State of New Hampshire	278,053	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	21,271,055
23									
24									
25									
26		$ 1,364,999							$ 103,009,906
27									
28									
29		Total December Payments				$ 1,364,999			
30									
31		Total Weighted Dollar Days				$ 103,009,906			
32									
33		December Payments (Lead) Lag Days				75.47			
34									
35									

Northern Utilities - New Hampshire Division
Calculation of Income Taxes Lead Lag Days
12 Months Ended Dec 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	60.00	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	30.00	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	30.50	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	29.50	25.00%	7.38
9									
10									
11									
12	Total			366					37.50
13									
14									
15									
16									
17									
18									
19									
20									

Northern Utilities - New Hampshire Division
Calculation of Income Taxes Lead Lag Days
12 Months Ended Dec 31, 2020
NH 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	60.00	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	30.00	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	30.50	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	29.50	25.00%	7.38
9									
10									
11									
12	Total			366					37.50
13									
14									
15									
16									
17									
18									
19									
20									

Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020
Summary of Gas Purchases

Line No	Supplier	Purchased Gas Expensed	(Lead) Lag Days	Weighted Dollar Days
1				
2	**Acct 804**			
3	Alberta Northeast Gas Limited	$ 46,942	43.06	$ 2,021,372
4	Algonquin Gas Transmission Co., Inc.	202,411	39.04	7,902,439
5	Constellation	661,354	42.57	28,155,038
6	DTE	103,379	43.14	4,459,499
7	Emera Energy Services, Inc.	2,909,994	44.07	128,234,495
8	Emera LP	3,247,777	43.68	141,850,012
9	Iroquois Gas Transmission System	174,353	39.44	6,876,025
10	Maritimes	93,342	36.73	3,428,760
11	Portland NG	3,750,430	39.32	147,454,174
12	Repsol Energy North America Corp	9,960,274	42.34	421,675,390
13	Shell Energy North America (US) LP	1,291,368	43.46	56,128,525
14	Southwestern Energy Services Co.	196,618	36.33	7,142,685
15	Tennessee Gas Pipeline	1,678,299	40.69	68,288,464
16	Texas Eastern Transmission	33,948	39.87	1,353,604
17				
18	Total Acct 804	$ 24,350,487	42.09	$ 1,024,970,480
19				
20				
21	**Acct 808 Demand Costs**	$ 1,238,136	41.97	$ 51,964,303
22				
23	Total Gas Costs	$ 25,588,622	42.09	$ 1,076,934,784
24				
25				

Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Alberta Northeast Gas Limited

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 3,713	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 157,822	WIRE
3	January-20	4,089	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	173,799	WIRE
4	February-20	3,705	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	146,335	WIRE
5	March-20	3,735	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	166,185	WIRE
6	April-20	3,589	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	154,345	WIRE
7	May-20	3,764	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/30/20 12:00 AM	44.50	167,483	WIRE
8	June-20	3,588	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	161,442	WIRE
9	July-20	3,705	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	153,739	WIRE
10	August-20	5,577	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/30/20 12:00 AM	44.50	248,181	WIRE
11	September-20	3,761	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	150,422	WIRE
12	October-20	4,174	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/30/20 12:00 AM	44.50	185,760	WIRE
13	November-20	3,542	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	155,859	WIRE
14										
15		$ 46,942			366			43.06	$ 2,021,372	
16										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Algonquin Gas Transmission Co., Inc.

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 14,191	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 603,136	WIRE
3	January-20	14,177	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/20/20 12:00 AM	34.50	489,100	WIRE
4	February-20	14,196	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	560,746	WIRE
5	March-20	14,209	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/27/20 12:00 AM	41.50	589,671	WIRE
6	April-20	14,212	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 AM	35.00	497,435	WIRE
7	May-20	14,212	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	561,391	WIRE
8	June-20	14,212	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	639,559	WIRE
9	July-20	14,212	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	589,816	WIRE
10	August-20	14,212	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 AM	37.50	532,966	WIRE
11	September-20	36,001	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	1,440,050	WIRE
12	October-20	19,388	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	727,046	WIRE
13	November-20	19,186	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	671,522	WIRE
14										
15		$ 202,411			366			39.04	$ 7,902,439	
16										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Constellation

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 134,934	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 5,734,695	WIRE
3	January-20	134,934	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	5,734,695	WIRE
4	February-20	134,934	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	5,329,893	WIRE
5	March-20	134,934	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	6,004,563	WIRE
6	April-20	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM			-	
7	May-20	-	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM			-	
8	June-20	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM			-	
9	July-20	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM			-	
10	August-20	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM			-	
11	September-20	-	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM			-	
12	October-20	-	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM			-	
13	November-20	121,618	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	5,351,192	WIRE
14										
15		$ 661,354			366			42.57	$ 28,155,038	
16										
17										
18										
19										
20										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: DTE

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 48,436	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 2,058,510	WIRE
3	January-20	-	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM			-	
4	February-20	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM			-	
5	March-20	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM			-	
6	April-20	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM			-	
7	May-20	-	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM			-	
8	June-20	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM			-	
9	July-20	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM			-	
10	August-20	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM			-	
11	September-20	4,127	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	165,065	WIRE
12	October-20	-	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM			-	
13	November-20	50,816	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	2,235,924	WIRE
14										
15		$ 103,379			366			43.14	$ 4,459,499	
16										
17										
18										
19										
20										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Emera Energy Services, Inc.

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 485,205	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/31/20 12:00 AM	45.50	$ 22,076,837	WIRE
3	January-20	330,108	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	14,029,579	WIRE
4	February-20	227,000	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/31/20 12:00 AM	44.50	10,101,484	WIRE
5	March-20	188,612	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	8,393,217	WIRE
6	April-20	570,088	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	24,513,775	WIRE
7	May-20	291,371	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/30/20 12:00 AM	44.50	12,965,997	WIRE
8	June-20	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM			-	
9	July-20	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM			-	
10	August-20	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM			-	
11	September-20	-	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM			-	
12	October-20	357,389	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/30/20 12:00 AM	44.50	15,903,819	WIRE
13	November-20	460,222	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	20,249,788	WIRE
14										
15		$ 2,909,994			366			44.07	$ 128,234,495	
16										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Emera LP

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 276,270	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/31/20 12:00 AM	45.50	$ 12,570,279	WIRE
3	January-20	273,736	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	11,633,789	WIRE
4	February-20	258,452	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/31/20 12:00 AM	44.50	11,501,101	WIRE
5	March-20	260,988	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	11,613,955	WIRE
6	April-20	259,762	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	11,169,776	WIRE
7	May-20	265,694	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/30/20 12:00 AM	44.50	11,823,362	WIRE
8	June-20	272,167	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	12,247,528	WIRE
9	July-20	275,652	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	11,439,548	WIRE
10	August-20	271,881	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/30/20 12:00 AM	44.50	12,098,690	WIRE
11	September-20	259,085	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	10,363,400	WIRE
12	October-20	257,145	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/30/20 12:00 AM	44.50	11,442,954	WIRE
13	November-20	316,946	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	13,945,630	WIRE
14										
15		$ 3,247,777			366			43.68	$ 141,850,012	
16										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Iroquois Gas Transmission System

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 14,890	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 632,841	WIRE
3	January-20	14,890	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 AM	38.50	573,280	WIRE
4	February-20	14,890	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	588,170	WIRE
5	March-20	14,890	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/27/20 12:00 AM	41.50	617,951	WIRE
6	April-20	14,390	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 AM	35.00	503,656	WIRE
7	May-20	14,390	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	568,411	WIRE
8	June-20	14,390	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	647,557	WIRE
9	July-20	14,390	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	597,192	WIRE
10	August-20	14,390	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 AM	37.50	539,631	WIRE
11	September-20	14,390	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	575,606	WIRE
12	October-20	14,390	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	539,631	WIRE
13	November-20	14,060	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	492,100	WIRE
14										
15		$ 174,353			366			39.44	$ 6,876,025	
16										
17										
18										
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23										
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25										

Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Maritimes

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 10,673	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 453,600	WIRE
3	January-20	7,736	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 AM	38.50	297,848	WIRE
4	February-20	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM			-	
5	March-20	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM			-	
6	April-20	30,387	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 AM	35.00	1,063,533	WIRE
7	May-20	10,504	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	414,900	WIRE
8	June-20	43	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	1,922	WIRE
9	July-20	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM			-	
10	August-20	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM			-	
11	September-20	70	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	2,812	WIRE
12	October-20	2,653	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	99,476	WIRE
13	November-20	31,276	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	1,094,668	WIRE
14										
15		$ 93,342			366			36.73	$ 3,428,760	
16										
17										
18										
19										
20										
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22										
23										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Portland NG

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 305,455	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 12,981,834	WIRE
3	January-20	305,455	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 AM	38.50	11,760,014	WIRE
4	February-20	305,455	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	12,065,469	WIRE
5	March-20	305,455	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/27/20 12:00 AM	41.50	12,676,379	WIRE
6	April-20	305,455	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 AM	35.00	10,690,922	WIRE
7	May-20	305,455	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	12,065,469	WIRE
8	June-20	305,455	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	13,745,471	WIRE
9	July-20	305,455	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	12,676,379	WIRE
10	August-20	305,455	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 AM	37.50	11,454,559	WIRE
11	September-20	305,455	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	12,218,196	WIRE
12	October-20	305,455	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	11,454,559	WIRE
13	November-20	390,426	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	13,664,923	WIRE
14										
15		$ 3,750,430			366			39.32	$ 147,454,174	
16										
17										
18										
19										
20										
21										
22										
23										
24										
25										

Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Repsol Energy North America Corp

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 2,001,901	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 85,080,773	WIRE
3	January-20	1,985,004	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	84,362,686	WIRE
4	February-20	2,050,070	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	80,977,753	WIRE
5	March-20	1,137,539	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	50,620,474	WIRE
6	April-20	335,475	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	14,425,444	WIRE
7	May-20	335,475	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/30/20 12:00 AM	44.50	14,928,657	WIRE
8	June-20	335,475	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	15,096,395	WIRE
9	July-20	335,475	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	13,922,231	WIRE
10	August-20	335,475	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/30/20 12:00 AM	44.50	14,928,657	WIRE
11	September-20	405,476	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	16,219,040	WIRE
12	October-20	370,738	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/30/20 12:00 AM	44.50	16,497,857	WIRE
13	November-20	332,169	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	14,615,425	WIRE
14										
15		$ 9,960,274			366			42.34	$ 421,675,390	
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Shell Energy North America (US) LP

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 342,855	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/31/20 12:00 AM	45.50	$ 15,599,909	WIRE
3	January-20	279,022	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	11,858,421	WIRE
4	February-20	188,111	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	7,430,402	WIRE
5	March-20	214,872	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	9,561,802	WIRE
6	April-20	48,342	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	2,078,690	WIRE
7	May-20	-	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM			-	
8	June-20	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM			-	
9	July-20	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM			-	
10	August-20	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM			-	
11	September-20	-	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM			-	
12	October-20	-	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM			-	
13	November-20	218,166	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/30/20 12:00 AM	44.00	9,599,301.80	WIRE
14										
15		$ 1,291,368			366			43.46	$ 56,128,525	
16										
17										
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Southwestern Energy Services Co.

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ -	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM			$ -	
3	January-20	-	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM			-	
4	February-20	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM			-	
5	March-20	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM			-	
6	April-20	27,187	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	1,169,026	WIRE
7	May-20	29,402	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/30/20 12:00 AM	44.50	1,308,384	WIRE
8	June-20	24,531	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	1,103,874	WIRE
9	July-20	20,228	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	839,457	WIRE
10	August-20	24,699	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/30/20 12:00 AM	44.50	1,099,088	WIRE
11	September-20	24,699	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	987,944	WIRE
12	October-20	14,637	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/30/20 12:00 AM	13.50	197,600	WIRE
13	November-20	31,237	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/30/20 12:00 AM	14.00	437,312	WIRE
14										
15		$ 196,618			366			36.33	$ 7,142,685	
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20										
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23										
24										
25										

Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Tennessee Gas Pipeline

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 140,707	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 5,980,037	WIRE
3	January-20	140,872	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/28/20 12:00 AM	42.50	5,987,043	WIRE
4	February-20	140,724	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	5,558,594	WIRE
5	March-20	140,689	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 AM	44.50	6,260,670	WIRE
6	April-20	140,464	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/29/20 12:00 AM	43.00	6,039,954	WIRE
7	May-20	140,367	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	5,544,504	WIRE
8	June-20	140,071	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	6,303,195	WIRE
9	July-20	140,042	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	5,811,727	WIRE
10	August-20	139,889	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 AM	37.50	5,245,833	WIRE
11	September-20	140,034	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	5,601,378	WIRE
12	October-20	140,053	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	5,251,989	WIRE
13	November-20	134,387	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	4,703,540	WIRE
14										
15		$ 1,678,299			366			40.69	$ 68,288,464	
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Northern Utilities, Inc. - New Hampshire Division
Purchased Gas - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Texas Eastern Transmission

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	December-19	$ 3,486	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/28/20 12:00 AM	42.50	$ 148,139	WIRE
3	January-20	3,486	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 AM	38.50	134,197	WIRE
4	February-20	3,466	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 AM	39.50	136,917	WIRE
5	March-20	3,466	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/27/20 12:00 AM	41.50	143,849	WIRE
6	April-20	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM			-	
7	May-20	2,865	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 AM	39.50	113,169	WIRE
8	June-20	2,865	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/31/20 12:00 AM	45.00	128,927	WIRE
9	July-20	2,865	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/27/20 12:00 AM	41.50	118,900	WIRE
10	August-20	2,879	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/23/20 12:00 AM	37.50	107,954	WIRE
11	September-20	2,879	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 AM	40.00	115,151	WIRE
12	October-20	2,879	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 AM	37.50	107,954	WIRE
13	November-20	2,813	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 AM	35.00	98,446	WIRE
14										
15		$ 33,948			366			39.87	$ 1,353,604	
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Northern Utilities, Inc. - New Hampshire Division
Purchased Demand - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020
Summary of Gas Purchases

Line No	Supplier	Purchased Demand Expensed	(Lead) Lag Days	Weighted Dollar Days
1				
2	**Acct 30-49-13-10-8080200 Flowthru**			
3	Tennessee Gas Pipeline	$ 52,151	37.51	$ 1,956,066
4	Emera Energy LP	1,185,984	42.17	50,008,237
5	Total Flowthru	$ 1,238,136	41.97	$ 51,964,303
6				
7				
8	**Acct 30-49-13-10-8080200 Base**			
9				
10				
11				
12	Total Acct 30-49-13-10-8080200	$ 1,238,136		
13				
14	Total Acct 30-49-13-10-8080200, per ledger	$ 1,238,136	*Pulls from Detail worksheet tab*	
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Northern Utilities, Inc. - New Hampshire Division
Purchased Demand - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Tennessee Gas Pipeline

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	January-20	$ 4,362	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/23/20 12:00 PM	38.00	$ 165,758	WIRE
3	February-20	4,362	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	170,120	WIRE
4	March-20	4,362	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/23/20 12:00 PM	37.00	161,396	WIRE
5	April-20	4,362	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/24/20 12:00 PM	39.00	170,120	WIRE
6	May-20	4,362	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/22/20 12:00 PM	36.50	159,215	WIRE
7	June-20	4,362	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/22/20 12:00 PM	37.00	161,396	WIRE
8	July-20	4,362	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/23/20 12:00 PM	37.50	163,577	WIRE
9	August-20	4,362	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/25/20 12:00 PM	40.00	174,482	WIRE
10	September-20	4,362	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/21/20 12:00 PM	36.00	157,034	WIRE
11	October-20	4,362	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/22/20 12:00 PM	36.50	159,215	WIRE
12	November-20	4,362	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/23/20 12:00 PM	38.00	165,758	WIRE
13	December-20	4,169	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/21/20 12:00 PM	35.50	147,996	WIRE
14										
15		$ 52,151			366			37.51	$ 1,956,066	
16										
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23										
24										
25										

Northern Utilities, Inc. - New Hampshire Division
Purchased Demand - Calculation of (Lead) Lag
12 Months Ended Dec 31, 2020

Supplier: Emera Energy LP

Line No	Month	Purchased Gas Expense	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days	Payment Type
1										
2	January-20	$ 99,021	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	1/29/20 12:00 PM	44.00	$ 4,356,939	WIRE
3	February-20	99,021	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/27/20 12:00 PM	42.00	4,158,896	WIRE
4	March-20	99,021	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/27/20 12:00 PM	41.00	4,059,875	WIRE
5	April-20	99,021	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/30/20 12:00 PM	45.00	4,455,960	WIRE
6	May-20	99,021	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/26/20 12:00 PM	40.50	4,010,364	WIRE
7	June-20	99,021	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/29/20 12:00 PM	44.00	4,356,939	WIRE
8	July-20	99,021	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/28/20 12:00 PM	42.50	4,208,408	WIRE
9	August-20	99,021	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/26/20 12:00 PM	41.00	4,059,875	WIRE
10	September-20	99,021	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/28/20 12:00 PM	43.00	4,257,920	WIRE
11	October-20	99,021	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/26/20 12:00 PM	40.50	4,010,364	WIRE
12	November-20	99,021	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/25/20 12:00 PM	40.00	3,960,853	WIRE
13	December-20	96,749	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/28/20 12:00 PM	42.50	4,111,847	WIRE
14										
15		$ 1,185,984			366			42.17	$ 50,008,237	
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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

TODD R. DIGGINS

AND

ANDRE J. FRANCOEUR

EXHIBIT TDAF-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

TABLE OF CONTENTS

SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Todd R. Diggins. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

My name is Andre J. Francoeur. My business address is the same as Mr. Diggins.

Q. Mr. Diggins, 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, accounting, regulatory, engineering and information technology services to Unitil Corp.'s subsidiaries. I am also the Treasurer of Northern Utilities, Inc. ("Northern" or the "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. Mr. Francoeur, what is your position and what are your responsibilities?

A. I am a Senior Financial Analyst for Unitil Service. My responsibilities are primarily in the areas of financial planning and analyses, regulatory projects, investor relations and treasury services.

Q. Please describe your business and educational background.

I have approximately five years of professional experience within the finance and accounting areas. I began working for Unitil Service in 2017 as a Financial Analyst and was promoted to Senior Financial Analyst in 2020. I graduated from the State University of New York at Plattsburgh, receiving magna cum laude recognition, with a Bachelor of Science degree. At this time I am also pursuing a Master's degree in Business Administration from the University of New Hampshire.

Q. Do you hold any professional licenses?

Yes, I am a Certified Management Accountant.

Q. Were both this testimony and exhibits prepared by one of you or under your direct supervision?

A. Yes, they were.

II. SUMMARY AND OVERVIEW OF TESTIMONY

Q. What is the purpose of this testimony?

A. The purpose of this 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 and support the proposed rate of return on rate base. This testimony also discusses rating agency actions and other factors that may affect the Company's ability to efficiently access long-term capital.

Q. Please summarize the Company's proposed capital structure for ratemaking purposes.

A. As detailed on Schedules RevReq-6-1[1], the Company's proposed capital structure consists of 52.47% common equity and 47.53% long-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 Northern is detailed on Schedule RevReq-6-4, which shows the weighted cost rate of 4.93% that was calculated by

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[1] References in this testimony to "Schedule RevReq-6-1" are to the revenue requirement schedules sponsored by Northern witnesses Christopher J. Goulding and Daniel T. Nawazelski.

using the "Net Proceeds" methodology, consistent with New Hampshire Public Utility Commission precedent.

Q. Please summarize the Company's proposed overall Return on Rate Base.

A. As summarized on Schedule RevReq-6, the Company's proposed Return on Rate Base is 7.75%. The components of the proposed Return on Rate Base are discussed in greater detail later in this testimony.

III. CAPITAL STRUCTURE

Q. Please describe the Company's proposed capital structure for ratemaking purposes.

A. As detailed on Schedules RevReq-6-1, the Company's proposed capital structure consists of 52.47% common equity and 47.53% long-term debt. The proposed capital structure represents the five quarter average as of December 31, 2020.

Q. Does the proposed capital structure include short-term debt?

A. No, the proposed capital structure includes only sources of long-term capital that fund the permanent assets included in rate base. Those sources do not include short-term debt. The Company believes it is important to align the long-lived nature of utility assets with similarly termed capital. Short-term debt is used principally to fund seasonal working capital requirements and construction work in process ("CWIP"). 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. Short-term debt is not a permanent element of capital structure and should not be included in the regulatory cost of capital calculation.

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 such as depreciation and amortization and deferred income taxes. Northern supplements internally generated funds through short-term borrowings under the Unitil Corp. Cash Pool, which is supported by bank borrowings under Unitil Corp.'s revolving credit facility. Over time, capital spending and debt retirements will result in short-term debt balances accumulating to levels that can be rolled into long-term financings. Under this financing cycle, short-term debt balances fall, and the capital structure's term is consistent with the long-term nature of utility assets.

Q. Please summarize the Company's recent long-term financings.

A. Please refer to Schedule TDAF-1 which shows the last 5 years of financing history at Northern and the frequency and size of that activity. Over the past 5 years, over $220 million of debt and equity capital has been invested into Northern. 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 utility assets and recapitalizing short-term debt as appropriate.

Q. 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 rather than the point in time capital structure as of December 31, 2020. The point in time capital structure at December 31, 2020 is less indicative of the Company's planned capital structure as a result of the timing of its most recent debt financing completed on September 15, 2020.

Q. How does the proposed capital structure compare to the proxy group?

A. The Company's proposed equity ratio of 52.47% is consistent with the peer group. Please reference Exhibit JC-11 in John Cochrane's testimony for the peer group's equity ratios over the last five years. Over the last five years the peer group's average equity ratio has been 52.93%.

Q. Please explain the primary goals the Company considers when managing its capital structure.

A. The primary goals to consider when managing the capital structure are to minimize the weighted average cost of capital, maintain sufficient equity funding to support the Company's balance sheet and creditworthiness, and provide financial flexibility. 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 appropriately manages its financial risk and supports its existing investment-grade credit ratings. Later in this testimony, credit and market factors that must be considered are discussed further.

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.

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, and consistent with the industry tenet of matching the long-term nature of rate base assets with the appropriate sources of capital.

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 Northern is detailed on Schedule RevReq-6-4, which shows the weighted cost rate of 4.93%.

Q. Please discuss your analysis of the Company's proposed Cost of Debt.

A. Please refer to Schedule TDAF-2 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 average 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 the range of these Utility Bond Indices, we 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-6, the Company's proposed return on rate base is 7.75%. This is the sum of the weighted cost of common equity and the cost of debt.

Q. Please describe how the cost of capital is weighted.

A. The cost of capital is weighted by the Company's proposed capital structure, which is described above.

Q. Please summarize the costs of the various capital components.

A. The Company is proposing a Return on Equity of 10.30 percent, which is toward the lower end of the range recommended and supported in the prefiled testimony of the Company's expert, John Cochrane. The Company proposes a Return on Equity at the lower end of the recommended range to mitigate rate effects on customers. The proposed cost of debt of 4.93% is calculated consistent with New Hampshire Public Utilities Commission precedent.

Q. Do you believe the proposed rate of return on rate base is appropriate?

A. Yes, for the reasons described in this testimony and the testimonies of Mr. Hevert, Messrs. Goulding and Nawazelski and Mr. Cochrane, the Company's proposed rate of return on rate base is reasonable and appropriate.

VI. CREDIT RATINGS AND OTHER MARKET CONSIDERATIONS

Q. Please discuss the Company's current credit ratings.

A. Northern has an issuer rating of BBB+ from Standard & Poor's ("S&P") rating agency and an issuer rating of Baa1 from Moody's. Both ratings are considered "investment-grade." The S&P credit rating is determined based on Unitil Corp's entire suite of subsidiaries while the Moody's credit rating is specific to Northern.

Q. Are the Company's credit ratings consistent with the peer group?

A. Yes. The table below compares the Company's credit ratings to those of the holding companies of the utility peer group introduced in the testimony of Mr. Cochrane. The results reflect that the Company's credit ratings are largely consistent with its peers.

Table 1: Credit Rating Benchmarking

PEER GROUP CREDIT RATINGS				
	(1)	(2)	(3)	(4)
LINE NO.	COMPANY	TICKER	S&P	Moody's
1	Atmos Energy Corporation	ATO	A-	A1
2	Chesapeake Utilities	CPK		
3	NiSource Inc.	NI	BBB+	Baa2
4	New Jersey Resources	NJR	-	A1
5	Northwest Natural	NWN	A+	Baa1
6	ONE Gas, Inc.	OGS	BBB+	A3
7	South Jersey Industries, Inc.	SJI	BBB	A3
8	Southwest Gas Holdings, Inc.	SWX	BBB+	Baa1
9	Spire Inc.	SR	A-	Baa2
10	Northern Utilities, Inc.	UTL	BBB+	Baa1

Q. Have there been any recent changes to the Company's credit ratings?

A. Yes. S&P revised Unitil Corp.'s outlook from stable to negative. Please refer to Schedule TDAF-3 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 stated that Unitil's sales margins have become more uncertain without decoupled revenue mechanisms in place. Historically, credit rating agencies are quick to respond to negative events or elevated risk, but slower to act on positive events. S&P indicated it may downgrade the Company if the funds from operations to debt ratio doesn't improve and consistently achieve at least 16%.

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 critical to Northern continuing to provide exceptional service to the communities it serves at competitive rates. Refinancing maturing debt at desirable terms is determined by the strength of our credit profile, which is directly impacted by regulatory outcomes.

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 TDAF-4 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 Northern) must maintain strong equity ratios 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 is credit supportive as a result of more stable revenues. Finally, by implementing multiyear rate plans the Company can recover capital costs in a timelier fashion, 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. Christopher J. Goulding and Daniel T. Nawazelski. The importance of a multiyear rate plan similar to what the Commission approved in Northern's prior base rate case proceedings cannot be overstated. A multiyear rate plan supports the Company's investment in the distribution system, helps maintain and stabilize its financial health, and provides a reasonable opportunity to earn its authorized rate of return without the need to file frequent rate cases

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[2] See generally Direct Testimony of Timothy S. Lyons.

Q. Are there 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, equity investors and the raising of equity capital.

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. Similarly, Moody's sees Unitil Corp.'s small size and scale as a "credit challenge". Please see Schedule TDAF-5, and Schedule TDAF-6, 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 the utility peer group. Unitil Corp.'s market capitalization is less than half the size of Northwest Natural, the smallest company by market capitalization in the peer group.

Table 2: Market Capitalization Benchmarking

Average Daily Capitalization - 90 Day Average ($ millions)				
Line No.	COMPANY	TICKER	MARKET CAPITALIZATION	
1	Atmos Energy Corporation	ATO	$	12,705
2	NiSource Inc.	NI	$	9,658
3	ONE Gas, Inc.	OGS	$	4,037
4	New Jersey Resources	NJR	$	4,010
5	Southwest Gas Holdings, Inc.	SWX	$	3,915
6	Spire Inc.	SR	$	3,800
7	South Jersey Industries, Inc.	SJI	$	2,576
8	Chesapeake Utilities	CPK	$	2,046
9	Northwest Natural	NWN	$	1,630
10	Unitil Corporation	UTL	$	770

Data as of 06/30/2021

Q. Explain how the smaller relative size increases risk to shareholders.

A. Unitil Corp.’s relatively small market capitalization generally 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. Put another way, investors who would like to materially increase or decrease their positon in a smaller company have greater difficulty doing so without causing price fluctuations. The table below further illustrates that Unitil Corp.’s daily trading volume is notably and consistently 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%	0.45%	0.57%	0.55%	0.72%	0.58%
Peer Group Median	0.56%	0.42%	0.50%	0.50%	0.66%	0.53%

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 Northern, 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. In order to attract and maintain institutional ownership 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. Does Unitil's smaller size impact other aspects of equity capital?

A. Yes. As a result of Unitil's smaller relative size, the flotation costs typically incurred during an equity offering are defrayed by smaller relative issuances. Flotation costs include underwriting, legal, and other expenses realized as a result of issuing equity capital. Attachment JC-9 in Mr. Cochrane's testimony illustrates the flotation costs incurred by both Unitil Corp. and the peer group. Given that Unitil Corp. is smaller than its peers, its equity offerings are predictably smaller than its peers. While certain issuance expenses such as underwriting expense is often negotiated as a percentage of the share price, other issuance expenses, such as legal and audit expense, are somewhat fixed. Consequently, Unitil's flotation costs, expressed as a percentage of proceeds, have been more than 200 basis points higher than the peer group average. On balance, the higher flotation cost warrants a somewhat higher cost of equity.

Q. What consideration should be given in this docket pertaining to Northern's credit metrics, small company size and low liquidity?

A. The pressure on credit metrics as well as the Company's small relative size and relatively low liquidity should all be considered by the Commission with regard to the proposed Cost of Equity and capital structure. Investment-grade credit metrics are essential in order to access capital markets at competitive terms, as are strong financial and regulatory results to limit the inherent pressures that smaller investor-owned utilities are faced with. In Mr. Cochrane's direct testimony he approximates that the small size risk premium, as it relates to the Company's cost of equity, is about 150 basis points relative to the peer group average.

VII. CONCLUSION

Q. Do you believe the proposed capital structure and proposed return on rate base are reasonable?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

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NORTHERN UTILITIES, INC.
HISTORICAL FINANCING PROCEEDS
AS OF DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	YEAR	EQUITY	LONG-TERM DEBT	TOTAL
1	2016	30,000,000	-	30,000,000
2	2017	32,000,000	50,000,000	82,000,000
3	2018	-	-	-
4	2019	25,500,000	40,000,000	65,500,000
5	2020	6,375,000	40,000,000	46,375,000
6	TOTAL	$ 93,875,000	$ 130,000,000	$ 223,875,000

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NORTHERN UTILITIES, INC.
COST OF LONG-TERM DEBT COMPARISON
AS OF DECEMBER 31, 2020

	(1)	(2)	(4)	(5)	(6)	(7)	(10)	(11)
							MOODY'S BOND YIELD	
LINE NO.	ISSUE	ISSUE DATE	COUPON RATE	TENOR	INITIAL OFFERING	AMOUNT OUTSTANDING	UTILITY A-RATED	UTILITY BAA-RATED
1	Sr. Notes	12/3/2008	7.72%	30 Yrs	$ 50,000,000	$ 50,000,000	6.88%	8.43%
2	Sr. Notes	10/15/2014	4.42%	30 Yrs	50,000,000	50,000,000	3.94%	4.57%
3	Sr. Notes	11/1/2017	3.52%	10 Yrs	20,000,000	20,000,000	3.87%	4.20%
4	Sr. Notes	11/1/2017	4.32%	30 Yrs	30,000,000	30,000,000	3.87%	4.20%
5	Sr. Notes	9/12/2019	4.04%	30 Yrs	40,000,000	40,000,000	3.47%	3.81%
6	Sr. Notes	9/15/2020	3.78%	20 Yrs	40,000,000	40,000,000	2.84%	3.16%
7	TOTAL				$ 230,000,000	$ 230,000,000		
8	WEIGHTED AVERAGES		4.87%				4.29%	4.95%

Notes

Sources: Schedule RevReq 6-4 and S&P Global Market Intelligence. Weighted average cost of debt rates do not include transaction costs. Moody's Bond Yield figures are as of the offering date of the relevant Notes.

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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

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%.

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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.

NORTHERN UTILTIIES, 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.

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Unitil Corp.

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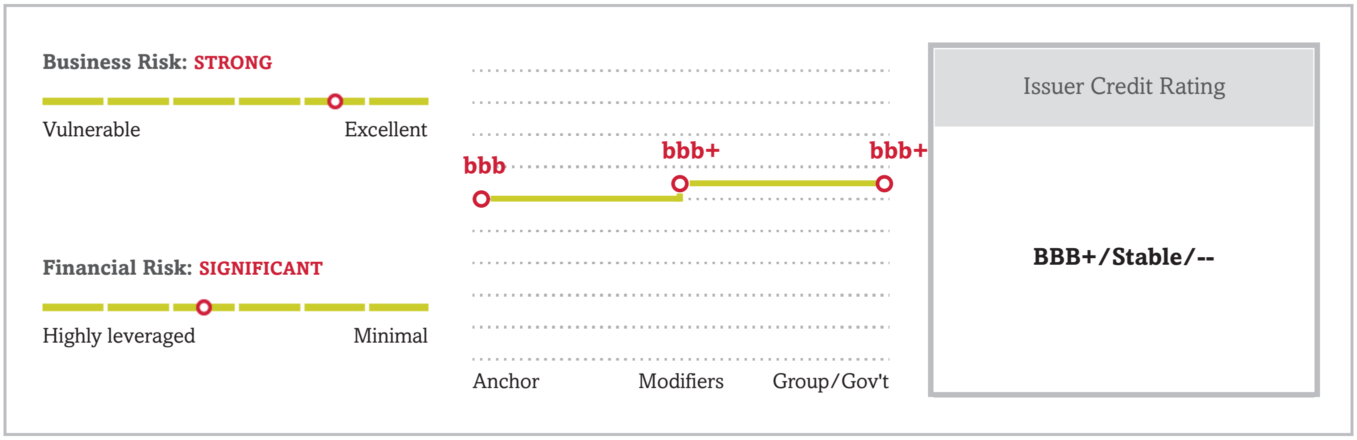
Unitil Corp.



Credit Highlights

Overview

Key strengths	Key risks
Predominantly low-risk electric and natural gas distribution operations.	Smaller customer base and limited scope of operations adds risk to business profile.
Generally constructive regulatory frameworks in three states.	High customer bills in Massachusetts limit rate recovery.
Increasing capital spending to support gas system growth and electric distribution system modernization.	Discretionary cash flow that, when negative, will necessitate external funding.

Earned returns on equity (ROE) in Massachusetts could increase following constructive gas and electric rate settlements. Unitil Corp.-subsidiary, Fitchburg Gas & Electric Co. (FG&E), has historically under-earned as compared to its approved ROEs in Massachusetts, primarily because of regulatory lag. However, in early 2020, FG&E reached constructive rate settlements for both its gas and electric utility operations. On the electric side, state stakeholders agreed to an increase in its current electric capital tracker investment recovery cap to $11 million from $5 million and the recovery of storm-related costs through a storm-related rider, to name a few. While high customer bills in the state limit the size of rate increases, we believe these pre-approved mechanisms could benefit cash flows going forward and lead to higher earned ROEs in the state.

Financial materiality associated with Unitil's long-term contractual agreement with Vineyard Wind LLC is limited. As per MA statute, FG&A along with its electric distribution peers are obligated to purchase power from Vineyard Wind over a 20-year power purchase agreement. However, to limit its financial implications and to compensate the distribution companies for accepting any financial obligation of the long-term contract, the MA Department of Public Utilities (MDPU) approved annual remuneration equal to 2.75% of the annual contractual payments under the contract. This is in addition to a make-whole rider, as the companies will sell into the market any power obtained from the contract.

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. These investments will increase rate base and drive rate relief over the same period.

Outlook: Stable

The stable outlook on Unitil reflects our expectation that the consolidated company will continue to manage regulatory risk effectively, recover project costs through approved mechanisms on a timely basis, and expand its regulated electric and gas distribution operations. Under our base-case scenario, we expect Unitil's core ratios to be around the midpoint of the financial risk profile, with adjusted funds from operations (FFO) to debt in the 17%-18% range.

Downside scenario

We could lower the rating if financial measures weakened below our expectations such that adjusted FFO to debt remains below 16% given the narrow focus and small scale of the company. The weakened financial measures could occur if the company does not receive sufficient and timely cost recovery through the regulatory process, if sales volumes decline significantly, or if there are additional material costs associated with operating as a stand-alone business. Also, we could lower the rating if the utility changes its current utility strategy and materially expands its non-utility operations.

Upside scenario

We could raise the rating if the company maintains its focus around expanding its utility operations in a manner that leads to higher financial measures, such that adjusted FFO to debt is consistently above 23%. This could occur through higher cash flow generation resulting from higher sales and/or lower operating costs, if the company receives greater cost recovery than expected through the regulatory process, or although unlikely, through debt reduction.

Our Base-Case Scenario

Assumptions

- Gross margin growth of about 5% on average per year through 2020 driven by ongoing capital recovery and gas and electric volume growth;
- Annual capital spending of roughly $100 million over the next few years;
- Lower financing costs as the company refinances higher cost debt; and
- Dividend payout ratio to remain in line with historical levels.

Key Metrics

	2019A	2020E	2021E
FFO to debt (%)	16.3	17-18	17-18
FFO cash interest coverage (x)	5.1	5-5.5	5-5.5
Debt to EBITDA (x)	4.6	4.5-5	4-4.5

A--Actual. E--Estimate. FFO--Funds from operations.

Company Description

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, Northern Utilities Inc., and Unitil Energy Systems Inc. Together, these regulated subsidiaries contribute more than 90% of consolidated revenues.

Unitil also operates a FERC-regulated gas transmission pipeline, Granite State Gas Transmission Inc., that provides predominantly Northern Utilities (more than 80% of revenues) and other third-party suppliers with access to domestic and Canadian natural gas.

Business Risk: Strong

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 provides for the company to recover costs, including capital spending, through annual adjustments, multi-year rate plans, and capital tracker mechanisms. Unitil also benefits from electric and natural gas decoupling in Massachusetts. 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.

Serving 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.

Peer comparison

Table 1

Unitil Corp. -- Peer Comparison

Industry Sector: Combo

	Unitil Corp.	Central Maine Power Co.	Central Hudson Gas & Electric Corp.	New York State Electric & Gas Corp.
Ratings as of March 24, 2020	BBB+/Stable/--	A/Stable/A-1	A-/Stable/NR	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2019--	**--Fiscal year ended Dec. 31, 2018--**	**--Fiscal year ended Dec. 31, 2018--**	**--Fiscal year ended Dec. 31, 2018--**
(Mil. $)				
Revenue	438.2	847.8	724.6	1,694.3
EBITDA	128.8	353.4	157.2	381.9
Funds from operations (FFO)	103.7	313.4	130.5	319.6
Interest expense	27.2	60.1	32.5	71.2
Cash interest paid	24.3	48.7	26.7	40.6
Cash flow from operations	106.1	215.5	129.1	408.2
Capital expenditure	119.2	240.7	187.9	522.3
Free operating cash flow (FOCF)	(13.1)	(25.3)	(58.8)	(114.1)

Table 1

Unitil Corp. -- Peer Comparison (cont.)				
Discretionary cash flow (DCF)	(35.2)	(100.3)	(58.8)	(114.1)
Cash and short-term investments	5.2	16.1	39.3	4.9
Debt	620.6	1,237.1	659.1	1,481.3
Equity	376.8	1,917.1	696.3	1,453.9
Adjusted ratios				
EBITDA margin (%)	29.4	41.7	21.7	22.5
Return on capital (%)	7.9	8.2	8.3	8.9
EBITDA interest coverage (x)	4.7	5.9	4.8	5.4
FFO cash interest coverage (x)	5.3	7.4	5.9	8.9
Debt/EBITDA (x)	4.8	3.5	4.2	3.9
FFO/debt (%)	16.7	25.3	19.8	21.6
Cash flow from operations/debt (%)	17.1	17.4	19.6	27.6
FOCF/debt (%)	(2.1)	(2.0)	(8.9)	(7.7)
DCF/debt (%)	(5.7)	(8.1)	(8.9)	(7.7)

Financial Risk: Significant

Our base-case scenario forecast includes adjusted FFO to debt in the 17%-18% range, around the midpoint of the benchmark range. Cash flow from regulated utility operations consistently supports FFO because the company recovers capital investment on a timely basis through base rates and rate surcharges. The supplemental ratio of adjusted FFO cash interest coverage supports this determination because in our base-case scenario we expect the measure to average about 5x. We expect debt leverage, as measured by adjusted debt to EBITDA, to be between 4.0x and 4.5x.

We assess Unitil's financial risk profile using our medial volatility benchmarks, reflecting its lower-risk utility operations and effective regulatory risk management.

Financial summary

Table 2

Unitil Corp. -- Financial Summary				
Industry Sector: Combo				
	--Fiscal year ended Dec. 31--			
	2019	**2018**	**2017**	**2016**
(Mil. $)				
Revenue	438.2	444.1	406.2	383.4
EBITDA	128.8	125.1	130.6	124.0
Funds from operations (FFO)	103.7	99.8	107.4	100.0

Table 2

Unitil Corp. -- Financial Summary (cont.)

Industry Sector: Combo

	--Fiscal year ended Dec. 31--			
	2019	**2018**	**2017**	**2016**
Interest expense	27.2	26.9	27.5	25.0
Cash interest paid	24.3	24.9	23.2	22.3
Cash flow from operations	106.1	79.6	87.3	69.4
Capital expenditure	119.2	102.4	119.3	98.1
Free operating cash flow (FOCF)	(13.1)	(22.8)	(32.0)	(28.7)
Discretionary cash flow (DCF)	(35.2)	(44.6)	(52.4)	(48.7)
Cash and short-term investments	5.2	7.8	8.9	5.8
Gross available cash	5.2	7.8	8.9	5.8
Debt	620.6	572.2	551.7	500.8
Equity	376.8	351.3	336.8	293.1
Adjusted ratios				
EBITDA margin (%)	29.4	28.2	32.2	32.3
Return on capital (%)	7.9	8.1	9.9	9.9
EBITDA interest coverage (x)	4.7	4.6	4.8	5.0
FFO cash interest coverage (x)	5.3	5.0	5.6	5.5
Debt/EBITDA (x)	4.8	4.6	4.2	4.0
FFO/debt (%)	16.7	17.4	19.5	20.0
Cash flow from operations/debt (%)	17.1	13.9	15.8	13.9
FOCF/debt (%)	(2.1)	(4.0)	(5.8)	(5.7)
DCF/debt (%)	(5.7)	(7.8)	(9.5)	(9.7)

Liquidity: Adequate

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	Principal Liquidity Uses
• Cash and liquid investments of about $10 million; • Cash FFO of about $100 million; and • Revolving credit facility availability of about $60 million.	• Maintenance capital spending of about $100 million; • Debt maturities of about $20 million; and • Dividends of about $25 million.

Other Credit Considerations

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.

Environmental, Social, And Governance

Within its electric utility business, Unitil's environmental risk is somewhat lower as the company serves its customers predominantly through electricity from the New England wholesale market, mitigating exposure from compliance-related costs if it owned fossil-fuel-based generation. Within its natural gas operations, vintage gas infrastructure or changes in soil integrity can lead to leaks, potentially inciting an occasional safety incident. Further enhancing the importance of this factor is that although some social risks may not directly affect credit quality, they can influence the regulatory relationship, which would affect credit quality.

Group Influence

Under our group rating methodology, we assess Unitil as the parent of a group. Fitchburg Gas & Electric Light Co., Northern Utilities Inc., Unitil Energy Systems Inc., and Granite State Gas Transmission Inc. are core members to the Unitil group. Unitil's group credit profile is 'bbb+', leading to an issuer credit rating of 'BBB+'.

Reconciliation

Table 3

Reconciliation Of Unitil Corp. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2019--						
Unitil Corp. reported amounts							
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**
	515.6	376.6	125.1	73.1	26.6	128.8	104.9
S&P Global Ratings' adjustments							
Cash taxes paid	--	--	--	--	--	-0.8	--
Cash taxes paid: Other	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	--	-24.1	--
Reported lease liabilities	4.5	--	--	--	--	--	--
Operating leases	--	--	1.4	0.2	0.2	-0.2	1.2

Table 3

Reconciliation Of Unitil Corp. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $) (cont.)

Postretirement benefit obligations/deferred compensation	112.6	--	--	--	0.4	--	--
Accessible cash and liquid investments	-5.2	--	--	--	--	--	--
Share-based compensation expense	--	--	2.3	--	--	--	--
Nonoperating income (expense)	--	--	--	2.7	--	--	--
Noncontrolling interest/minority interest	--	0.2	--	--	--	--	--
Debt: Other	-6.9	--	--	--	--	--	--
Total adjustments	105	0.2	3.7	2.9	0.6	-25.1	1.2

S&P Global Ratings' adjusted amounts

	Debt	Equity	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations
	620.6	376.8	128.8	76	27.2	103.7	106.1

Ratings Score Snapshot

Issuer Credit Rating

BBB+/Stable/--

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

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	**bbb**	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of March 25, 2020)*	
Unitil Corporation	
Issuer Credit Rating	BBB+/Stable/--
Issuer Credit Ratings History	
23-Dec-2014	BBB+/Stable/--
Related Entities	
Fitchburg Gas and Electric Light Co.	
Issuer Credit Rating	BBB+/Stable/--

Ratings Detail (As Of March 25, 2020)*(cont.)	
Granite State Gas Transmission, Inc.	
Issuer Credit Rating	BBB+/Stable/--
Northern Utilities Inc	
Issuer Credit Rating	BBB+/Stable/--
Unitil Energy Systems Inc.	
Issuer Credit Rating	BBB+/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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MOODY'S
INVESTORS SERVICE

CREDIT OPINION
20 July 2021

Update

Rate this Research

RATINGS

Unitil Corporation

Domicile	New Hampshire, United States
Long Term Rating	Baa2
Type	LT Issuer Rating - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Unitil Corporation

Update to credit analysis

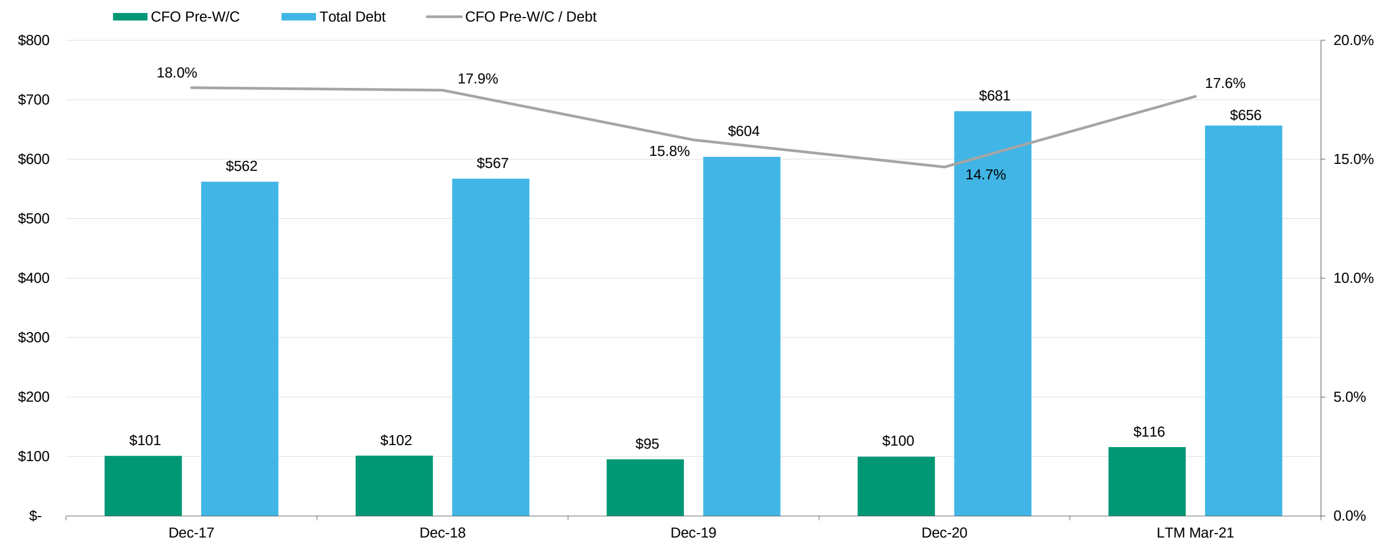
Summary

Unitil Corporation's (Unitil) credit profile reflects the low business risk of its regulated utilities operating in several credit supportive jurisdictions in the New England region. Unitil's business consists primarily of regulated electric transmission and distribution (T&D) utilities and natural gas local distribution companies (LDCs). Unitil's credit also considers structural subordination of its parent level debt compared to that of its operating subsidiaries, with parent long-term debt of about 13% of total consolidated debt as of 31 March 2021, although this is not likely to increase materially over the next several years. Unitil exhibits a stable financial profile, with a consistent ratio of consolidated cash flow from operation before changes in working capital (CFO pre-WC) to debt in the mid to high teens.

Similarly, the credit profiles of subsidiaries Unitil Energy Systems, Inc. (UES, Baa1 stable), Fitchburg Gas & Electric Light Company (FGE, Baa1 stable), and Northern Utilities, Inc. (NU, Baa1 stable) reflects each utility's low risk profile as regulated electric T&Ds or gas LDCs operating in the credit supportive regulatory jurisdictions of Massachusetts, New Hampshire and Maine. UES, FGE and NU benefit from several investment cost recovery and revenue decoupling mechanisms that allow the utilities to generate financial metrics that support their credit quality. We expect each utility's financial profile to remain stable such that UES, FGE and NU's ratios of CFO pre-WC to debt are sustained in the mid to high teens.

Granite State Gas Transmission, Inc.'s (GSGT, Baa2 stable) credit reflects its small size relative to other FERC regulated gas pipelines and solid financial metrics. GSGT operates mostly in and around NU's service territory in northern New England and the credit reflects the pipeline's contracted cash flow, of which about 70% is with NU. The remainder is with mostly unrated utilities and third-party gas marketing suppliers that serve a high demand region. GSGT has limited competition and exhibits a stable financial profile including an FFO to debt ratio in the mid teens.

Exhibit 1
Unitil Corp. Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt ($MM)



Source: Moody's Financial Metrics

Credit Strengths

» Diversified regulated utility holding company with no unregulated business exposure

» Low-risk utilities, primarily electric T&Ds and natural gas LDCs

» Credit supportive regulatory jurisdictions

Credit Challenges

» Small size and scale

» Exposure to commercial and industrial customers

Rating Outlook

Unitil's stable outlook reflects our expectation the company will continue to operate as a low-risk regulated utility holding company and maintain sound financial metrics, including a ratio of CFO pre-WC to debt in the mid to high teens. The stable outlook further incorporates no additional parent level debt in the medium-term.

The stable rating outlooks for Unitil's regulated utility subsidiaries, UES, FGE, NU and GSGT consider their consistent and predictable financial performance, which we expect will continue over the next several years, and their credit supportive regulatory jurisdictions.

Factors that Could Lead to an Upgrade

Unitil's rating could be upgraded if the rating of its largest subsidiaries were to be upgraded or if consolidated CFO pre-WC to debt increased to above 20% on a consistent basis.

UES, FGE and NU's ratings could be upgraded if their respective regulatory jurisdictions become more credit supportive through increased use of reconciling cost and investment recovery mechanisms (e.g., decoupling, forward test years, formula rates). The ratings could also be upgraded if CFO pre-WC to debt increased to above 25% on a sustained basis.

GSGT's rating could be upgraded if there is an improvement in its financial metrics such that its ratio of FFO to debt is sustained at 20%.

Factors that Could Lead to a Downgrade

Unitil's rating could be downgraded if the ratings of any of its largest subsidiaries are downgraded. A rating downgrade could also occur if Unitil's consolidated financial metrics deteriorated, such that its ratio of consolidated CFO pre-WC to debt declined below 14% on a sustained basis or if holding company debt as a percentage of consolidated debt increased to the mid-20% range.

UES, FGE and NU's ratings could be downgraded if their respective regulatory jurisdictions become less credit supportive or if their financial metrics deteriorated such that the ratio of CFO pre-WC to debt declined below 17% on a sustained basis.

GSGT's rating could be downgraded if there is a sustained deterioration in its financial performance, such that FFO to debt ratio declines below 12%. The rating could also be downgraded if there is a material deterioration in the credit quality of either the pipeline's shippers or Unitil.

Key Indicators

Unitil Corporation [1]

	Dec-17	Dec-18	Dec-19	Dec-20	LTM Mar-21
CFO Pre-W/C + Interest / Interest	4.6x	4.4x	4.3x	4.5x	5.0x
CFO Pre-W/C / Debt	18.0%	17.9%	15.8%	14.7%	17.6%
CFO Pre-W/C – Dividends / Debt	14.4%	14.1%	12.1%	11.4%	14.2%
Debt / Capitalization	58.8%	56.3%	56.3%	57.8%	55.9%

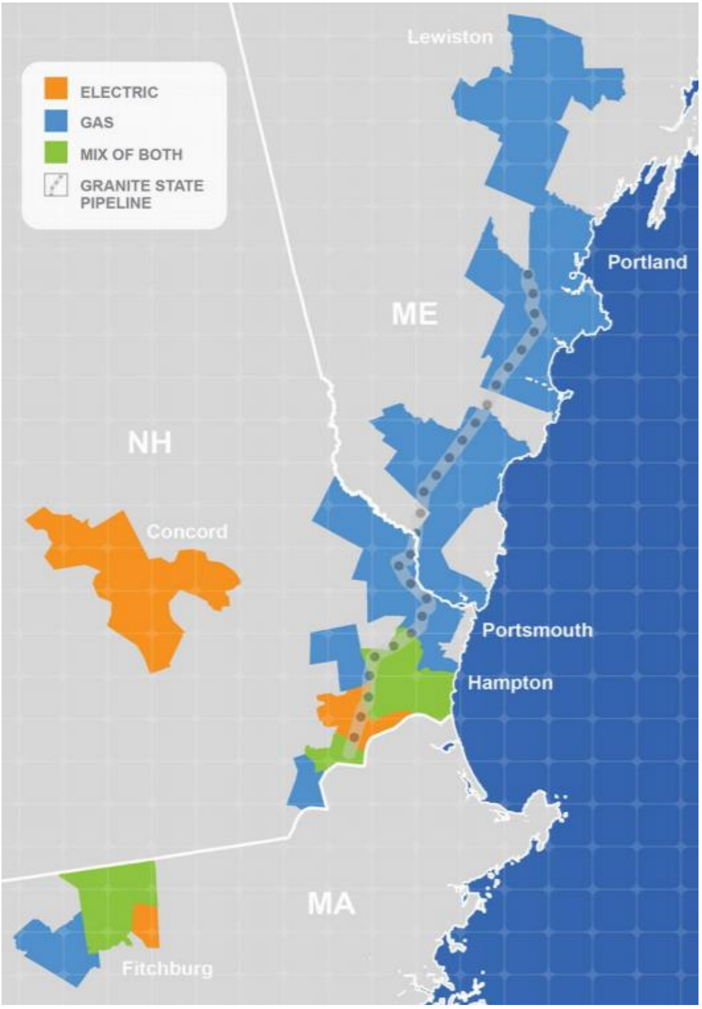
All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for nonfinancial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in Hampton, New Hampshire, Unitil Corporation is a utility holding company that serves close to 193,000 electric and gas customers in the greater northern New England region. Unitil's regulated utility subsidiaries include Unitil Energy Systems, Inc. (UES), an electric T&D that serves over 77,200 customers in New Hampshire; Fitchburg Gas & Electric Light Company (FGE), a gas and electric distribution company that serves approximately 46,000 customers in Massachusetts; Northern Utilities, Inc. (NU), a natural gas local distribution company (LDC) that serves over 69,400 customers in New Hampshire and Maine; and Granite State Gas Transmission, Inc. (GSGT), an 86 mile natural gas pipeline in New Hampshire and Maine.

UES is regulated by the New Hampshire Public Utilities Commission (NHPUC). FGE is regulated by the Massachusetts Department of Public Utilities (MDPU). NU is regulated by the NHPUC and the Maine Public Utilities Commission (MPUC). GSGT is regulated by the Federal Energy Regulatory Commission (FERC). Unitil had about $1.5 billion in assets as of 31 March 2021 and $427 million in revenue for the last twelve months ending 31 March 2021.

Exhibit 3
Unitil's service territory



Source: Company presentation

Detailed Credit Considerations

Low business risk utilities with modest exposure to C&I customers

Unitil's credit profile reflects the structural subordination of the holding company debt holders relative to the indebtedness of its operating utilities. Unitil's credit profile also incorporates the benefits associated with the regulatory and geographic diversification from owning four regulated utilities within the greater New England region.

Three of the four regulated utilities, UES, FGE and NU, are rated Baa1. The fourth regulated utility, a natural gas pipeline, GSGT, is rated Baa2. Unitil's holding company level debt of $69 million represented approximately 13% of the group's consolidated indebtedness. If parent level debt increased significantly from current levels, it could lead to a wider differential between the credit quality of the parent and its operating subsidiaries. However, we do not expect additional parent level debt over the next several years.

Unitil's corporate family of low-risk regulated utilities includes electric T&D's, natural gas LDCs and a FERC regulated natural gas pipeline. The majority of consolidated revenue is derived from utility services while only 2% of revenue is from natural gas transportation services. As shown in Exhibit 4, UES and NU are the largest of the four subsidiaries, which combined produced about 75% of total revenue.

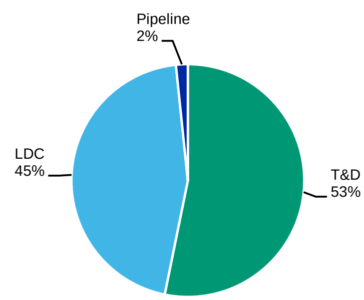
Exhibit 4
Unitil corporate family financial summary

Utility	Segment	State	Revenue	Revenue as % of Consolidated	Long-term Debt	LTD as % of Consolidated	Total Assets	Total Assets as % of Consolidated
Unitil Corporation	HoldCo	NH	$427	100%	$69	13%	$1,475	100%
Unitil Energy Systems, Inc.	T&D	NH	$159	37%	$103	20%	$379	26%
Fitchburg Gas & Electric Light	T&D/LDC	MA	$104	24%	$98	19%	$399	27%
Northern Utilities, Inc.	LDC	NH & ME	$162	38%	$230	45%	$636	43%
Granite State Gas Transmission, Inc.	Pipeline	NH & ME	$7	2%	$15	3%	$45	3%

As of LTM Q1 2021
Source: Unitil Corp filings

When considering a breakdown by segment, Exhibit 5 shows that about 53% of Unitil's revenue is generated by its electric T&D utilities, of which UES makes up close to 70% with FGE the remaining 30%. The LDC segment generates 45% of Unitil's revenue where 81% of this segment's revenue is derived from NU and the remaining 19% from FGE.

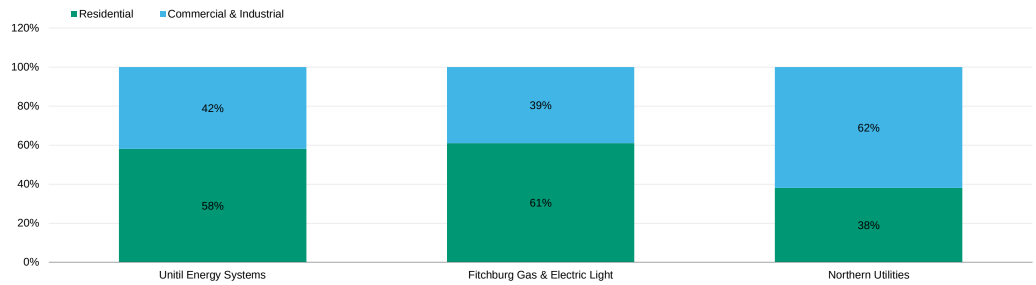
Exhibit 5
Unitil revenue breakdown by segment



Source: Unitil Corp filings

Unitil's material exposure to commercial and industrial (C&I) customers, which account for about 50% of annual revenue, does detract modestly from its low business risk profile (see Exhibit 6). Given the cyclical nature of C&I customer demand, they typically add more volatility to sales volume especially during economic downturns. This volatility can be mitigated with revenue decoupling mechanisms, which are currently only available to FGE in Massachusetts. In the absence of decoupling mechanisms, lower than anticipated volumes can have a negative impact on Unitil's subsidiaries' cash flow. NU has the highest exposure as over 60% of its revenue are from C&I customers, a credit negative. Although the company experienced some declines in C&I sales due to the coronavirus pandemic, residential sales mitigated some of the declines and, as of the first quarter of 2021, the company has seen an improvement given a return to normal economic operations.

Exhibit 6
2020 Revenue breakdown by customer class

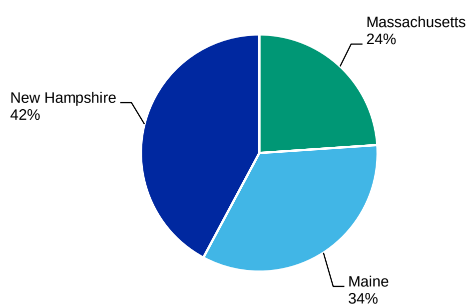


Source: Unitil Corp. Filings

Generally credit supportive regulatory jurisdictions in the New England region

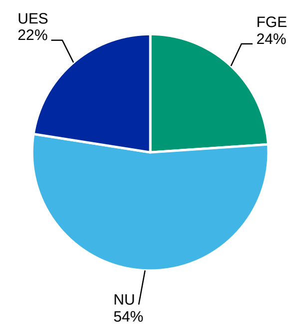
The Unitil family of utilities operate in New Hampshire, Maine and Massachusetts where we view the regulatory environments as credit supportive. The largest share of rate base is located within New Hampshire where NU, UES and GSGT operate (see Exhibit 7 and Exhibit 8). Each company has benefited from generally constructive rate case outcomes that support strong cash flow. Additional support is provided by approved cost recovery mechanisms such as capital investment trackers and decoupling in Massachusetts.

Exhibit 7
Unitil rate base breakdown by state



Source: Unitil Corp. Filings

Exhibit 8
Unitil rate base breakdown by utility



GSGT and NU rate base are combined
Source: Unitil Corp. Filings

Northern Utilities

NU's rate base is largely in Maine (63%) with the smaller portion in New Hampshire. The company filed its latest Maine general rate case in June 2019 and on 26 March 2020, the MPUC approved a base rate revenue increase of $3.6 million based on a 9.48% ROE and an equity ratio of 50%. Although the ROE was lowered slightly from 9.5%, the equity ratio remained the same. NU's rate filing was driven by investments in the system to improve reliability and resiliency as well as to meet customer growth. The company originally requested a $7 million base rate revenue increase based on a 10.5% ROE and 52.9% equity ratio.

Additionally, NU had requested an additional tracker called a Capital Investment Recovery Adjustment (CIRA) that would allow for annual adjustments to base rates for the recovery of capital expenditures for non-growth related infrastructure investments, which was not approved. However, in the previous 2017 general rate case, the MPUC reauthorized the Targeted Infrastructure Adjustment (TIRA), that allows the company recovery on its gas main pipeline replacement program for another eight years.

On 30 June 2021, NU filed a notice of intent to file a rate case in New Hampshire seeking a base rate increase of about $7.7 million premised on a pro forma 2020 test year. The company expects to file in the third quarter. The company's last general rate case in the state concluded in May 2018. The NHPUC authorized an annual revenue increase of $2.6 million and a step increase of $2.3 million to recover post-test year capital investments, which were offset by a $1.7 million revenue reduction associated with tax reform. The NHPUC approved NU's second step increase request of $1.4 million, effective 1 May 2019, to recover eligible capital investments in

2018. Based on the terms of the agreement, the company's next distribution base rate case could be filed until 2021 with a test year no earlier than the last twelve months ended 31 December 2020. In New Hampshire, NU is authorized an ROE of 9.5% and an equity ratio of 51.7%.

Fitchburg Gas & Electric Light

In Massachusetts, FGE uses a revenue decoupling mechanism for its electric and gas segments. Decoupling reconciles the utility's electric and gas distribution revenue, on an annual basis, to a baseline distribution service revenue level established by the MDPU. Decoupling insulates the utility's cash flow from fluctuations in its retail electric and gas sales, thus adding a higher level of stability and predictability, a credit positive. FGE also benefits from a long-term capital expenditure tracker that allows for annual revenue adjustments to recover capital investments for both electric and gas.

On 17 December 2019, FGE filed for a $2.7 million and $7.3 million increase in its electric and gas base revenue decoupling targets, respectively. On 17 April 2020, the MDPU approved a settlement agreement for both electric and gas base rates. The electric base rate settlement allowed for an increase of $1.1 million. The gas base rate settlement allows for an increase of $4.6 million to be phased in over two years. The first year increase totaled $3.7 million effective 1 March 2020 with the remaining $0.9 million increase effective 1 March 2021. Both settlements authorize a 9.7% ROE, lowered slightly from 9.8%, and an equity ratio 52.45%, increased from 52.17%.

As a part of the negotiated terms, FGE cannot seek new rates before 2023 unless there are extraordinary events that meet a certain impact threshold. The latest settlement also provides for the implementation of a major storm reserve fund, whereby FGE may recover the costs of restoration after qualifying storm events. In addition, the agreement provides for the extension of the annual capital cost recovery mechanism, modified to allow the recovery of property tax on cumulative net capital expenditures.

Unitil Energy Systems

On 2 April 2021, UES filed its most recent rate case with the NHPUC requesting a permanent base rate revenue increase of $12 million. UES also requested a temporary base rate revenue increase of $5.8 million to take effect on or after 1 June 2021 and until a final order on permanent rates is issued. The proposed rate increases are based on a 10% ROE and 52.9% equity ratio. On 7 May 2021, a stipulation and settlement was reached with the NHPUC regarding temporary rates with the parties agreeing to a temporary increase of roughly $4.5 million. On 27 May 2021, an order was issued by the NHPUC approving the temporary increase which went into effect on 1 June 2021.

UES' last rate case was settled with a final order by the NHPUC on 20 April 2017. The final order authorized an initial revenue increase of $4.1 million and a three-year rate plan, which included an additional rate increase of $0.9 million in May 2017 and two additional revenue increases covering 80% of UES' change in net plant, property and equipment included in the rate plan. In April 2019, the NHPUC approved UES's final step adjustment representing a revenue increase of about $0.34 million, was effective 1 May 2019. As part of the final order in 2017, UES was granted an authorized ROE of 9.5% based on an equity ratio of 51%.

Granite State Gas Transmission

GSGT's operations are an integral part of NU's operations and service territory. The company's long-term debt outstanding consists of $15 million of notes due November 2027. GSGT accounts for less than 2% of Unitil's consolidated revenue. The FERC regulated interstate natural gas transmission pipeline solely services NU's customer territory in New Hampshire and Maine. GSGT gets natural gas from hubs in the Haverhill, MA area and provides NU with interconnection to three pipelines including the Portland Natural Gas Transmission System, Maritimes and Northeast Pipeline, L.L.C., and the Tennessee Gas Pipeline Company, L.L.C. (Baa2 stable).

GSGT derives approximately 80% of its revenue from gas transportation services provided to investment grade rated LDCs, including 70% from NU, while the remaining 20% of revenue is from third-party gas marketing suppliers. GSGT is highly dependent on NU's growth for future growth projects. GSGT's revenue and operations are regulated by FERC. On 30 November 2020, FERC approved an uncontested rate settlement that resulted in an increase in annual revenue of roughly $1.3 million, effective 1 November 2020. The settlement allowed for the filing of limited rate adjustments for capital cost projects eligible for cost recovery in 2021, 2022 and 2023. It also set a cap of about $14.6 million on the capital costs recoverable under such filings throughout the term of the settlement. The settlement also provided that GSGT not file a general rate case before April 2024.

Consistent cash flow generation resulting in stable financial metrics

Given the low-risk nature and predictable cash flow generation of its utilities, we expect Unitil and the entire family of companies to maintain stable financial profiles. Over the last five years, CFO pre-WC has averaged about $98 million. For the last twelve months ending 31 March 2021, Unitil's consolidated CFO pre-WC was $116 million, which fell short of covering its total capital expenditures of $120 million over the same period, more in line with prior years negative free cash flow levels. Unitil's ratio of consolidated CFO pre-WC to debt was a stronger 17.6% for the period and we expect the ratio to remain in the high teens over the next several years.

For the LTM Q121, UES, FGE and NU's ratios of CFO pre-WC to debt were 20.7%, 17.9% and 19.0%, respectively. We expect all three utilities to sustain stable financial metrics going forward and maintain ratios of CFO pre-WC to debt in the mid teens to 20% range.

GSGT's financial performance improved in recent years driven by a reduction in debt. For the LTM period ending 31 March 2021, FFO to debt reached a high of 19.2% from a low of 15.2% in 2017. We expect GSGT's financial metrics to remain sound ranging from the mid to high teens over the next several years.

ESG considerations

Environmental

Environmental considerations incorporated into our credit analysis for Unitil are primarily related to carbon regulations. Unitil is strongly positioned for carbon transition in the regulated utility sector with strategies and plans in place that substantially mitigate its carbon transition exposure. Moody's framework for assessing carbon transition risk is discussed in "Carbon transition risk for power generation varies widely by issuer" (2 December 2020).

Social

Social risks are primarily related to health and safety, demographic and societal trends, as well as customer relations as the company works to provide reliable and affordable service to customers and safe working conditions to employees. Regarding affordability, Moody's sees the potential for rising social risks associated with the coronavirus pandemic and its effect on Unitil's service territory, should unemployment remain high, making customers less able to absorb rate increases.

Governance

From a governance perspective, financial and risk management policies including a strong financial profile are important characteristics for managing environmental and social risks. We view the governance of Unitil as strong based on our assessment criteria.

Liquidity Analysis

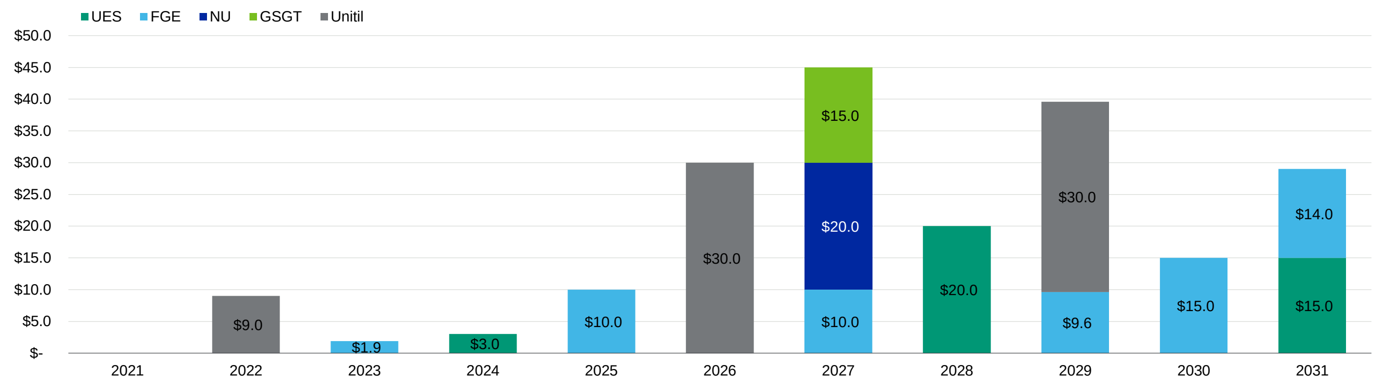
Unitil's adequate liquidity profile is principally supported by the upstreamed dividends from its group of regulated utilities and access to external liquidity sources. Consistent with historical results, Unitil maintained a modest consolidated cash balance of $6.1 million as of 31 March 2021. Dividend distributions from its subsidiaries are the primary source of capital and totaled $27 million for the year ended 31 December 2020, which approximated Unitil's shareholder dividend distribution of $23 million for the same period. Unitil's capital contributions to its subsidiaries were $14 million for the LTM 31 March 2021 period ($8 million went to UES and $6 million went to NU).

Unitil and all of its subsidiaries use a $120 million joint revolving credit facility that expires in July 2023. The revolver includes a $25 million sublimit for the issuance of standby letters of credit. The borrowing limit can be upsized an additional $50 million with lenders approval. The credit agreement has one financial covenant that sets a maximum total debt to capitalization of 65% and is tested quarterly, which Unitil is in compliance with. In addition, borrowings under the facility are subject to a material adverse change clause, which is not a typical clause for revolving credit agreements of investment grade rated companies.

Unitil typically uses its short-term borrowings to help fund its subsidiaries' capex programs, pension contributions, working capital requirements (including any storm related costs) and/or debt repayments until longer term financing is arranged. At 31 March 2021, Unitil had $82.7 million available on the revolver, net of $37.3 million of borrowings and no letters of credit outstanding. Although the subsidiaries have no short-term borrowing limits on the revolver, state regulators establish annual borrowing limits for UES and NU while the board of directors establish annual borrowing limits for FGE and GSGT. UES has a borrowing limit of $37.5 million, FGE's limit is $50 million, NU's limit is about $997.6 million and GSGT's limit is $25 million.

Unitil's $69 million of holding company debt includes unsecured notes due in May 2022, August 2026 and December 2029 (see exhibit 9). We expect that Unitil will continue to fund the group's planned capital investments, ranging from $130 — $140 million over the next three years, with a balanced mix of debt and equity, including internally generated cash flow, short-term borrowings on its revolving credit facility and long-term debt issuances. The subsidiaries' nearest long-term debt maturity is $1.9 million owed at FGE in November 2023.

Exhibit 9
Unitil and subsidiaries debt maturities over the next 10 years



Debt as of year-end 2020
Source: Unitil Corp. Filing

Appendix

Exhibit 10

Cash Flow and Credit Metrics [1]

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	LTM Mar-21
As Adjusted					
FFO	**93**	**92**	**95**	**96**	**102**
+/- Other	8	10	0	4	13
CFO Pre-WC	**101**	**102**	**95**	**100**	**116**
+/- ΔWC	(15)	(10)	13	(23)	(19)
CFO	**87**	**92**	**108**	**77**	**97**
- Div	20	22	22	23	23
- Capex	119	103	124	122	120
FCF	**(53)**	**(33)**	**(38)**	**(68)**	**(46)**
(CFO Pre-W/C) / Debt	18.0%	17.9%	15.8%	14.7%	17.6%
(CFO Pre-W/C - Dividends) / Debt	14.4%	14.1%	12.1%	11.4%	14.2%
FFO / Debt	16.6%	16.1%	15.8%	14.1%	15.6%
RCF / Debt	13.0%	12.3%	12.1%	10.7%	12.1%
Revenue	406	444	438	419	427
Cost of Good Sold	261	298	289	267	269
Interest Expense	28	30	29	29	29
Net Income	29	26	34	33	37
Total Assets	1,248	1,306	1,369	1,476	1,475
Total Liabilities	937	963	1,003	1,088	1,073
Total Equity	311	342	366	388	402

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Peer Comparison Table [1]

	Unitil Corporation Baa2 Stable			Avangrid, Inc. Baa1 Negative			NiSource Inc. Baa2 Stable			DTE Energy Company Baa2 Stable		
(in US millions)	FYE Dec-19	FYE Dec-20	LTM Mar-21	FYE Dec-19	FYE Dec-20	LTM Mar-21	FYE Dec-19	FYE Dec-20	LTM Mar-21	FYE Dec-19	FYE Dec-20	LTM Mar-21
Revenue	438	419	427	6,336	6,320	6,497	5,209	4,682	4,622	12,669	12,177	12,933
CFO Pre-W/C	95	100	116	1,452	1,298	1,412	1,525	1,318	1,339	3,003	3,592	3,624
Total Debt	604	681	656	9,059	12,086	11,784	10,276	10,258	10,279	18,285	20,221	21,221
CFO Pre-W/C / Debt	15.8%	14.7%	17.6%	16.0%	10.7%	12.0%	14.8%	12.8%	13.0%	16.4%	17.8%	17.1%
CFO Pre-W/C – Dividends / Debt	12.1%	11.4%	14.2%	9.3%	6.2%	7.3%	11.7%	9.4%	9.6%	12.2%	13.7%	13.2%
Debt / Capitalization	56.3%	57.8%	55.9%	34.4%	40.6%	39.7%	59.6%	59.9%	58.9%	56.1%	56.4%	57.2%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Rating Methodology and Scorecard Factors

Methodology Scorecard Factors
Unitil Corporation

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.5x	A	4.5x-5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	17.2%	Baa	15% - 17%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	13.5%	Baa	11% - 13%	Baa
d) Debt / Capitalization (3 Year Avg)	55.0%	Baa	53% - 55%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		Baa1
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Scorecard-Indicated Outcome		Baa1		Baa2
b) Actual Rating Assigned		Baa2		Baa2

Methodology Scorecard Factors
Unitil Energy Systems, Inc. — Private

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.8x	A	5.5x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	19.8%	A	17% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	15.3%	A	13% - 16%	Baa
d) Debt / Capitalization (3 Year Avg)	53.4%	Baa	51% - 53%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-1	-1	-1	-1
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

Methodology Scorecard Factors
Northern Utilities, Inc. — Private

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.8x	A	5.2x - 5.6x	A
b) CFO pre-WC / Debt (3 Year Avg)	17.9%	Baa	16.5% - 18.5%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	12.5%	Baa	12% - 14%	Baa
d) Debt / Capitalization (3 Year Avg)	47.5%	A	46% - 48%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		Baa1		Baa1

Methodology Scorecard Factors
Fitchburg Gas & Electric Light Company — Private

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Ba	Ba	Ba	Ba
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.3x	Baa	5.5x - 6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	15.6%	Baa	16% - 18%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	12.9%	Baa	12.5% - 14.5%	Baa
d) Debt / Capitalization (3 Year Avg)	57.3%	Baa	54% - 56%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		Baa1		A3
b) Actual Rating Assigned		Baa1		Baa1

Methodology Scorecard Factors

Granite State Gas Transmission, Inc. — Private

Natural Gas Pipelines Industry Scorecard [1][2]	Current LTM 3/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Market Position (15%)	**Measure**	**Score**	**Measure**	**Score**
a) Demand Growth	Baa	Baa	Baa	Baa
b) Competition	A	A	A	A
c) Volume Risk & Throughput Trend	Baa	Baa	Baa	Baa
Factor 2 : Quality of Supply Source (10%)				
a) Supply Source	A	A	A	A
Factor 3 : Contract Quality (30%)				
a) Firm Revenues	Baa	Baa	Baa	Baa
b) Contract Life	Baa	Baa	Baa	Baa
c) Shipper Quality / Recontracting Risk	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (45%)				
a) (FFO + Interest) / Interest	5.7x	A	6.5x - 7.5x	Aaa
b) FFO / Debt	19.2%	Baa	15.5% - 17.5%	Baa
c) (FFO - Dividends) / Debt	13.5%	Baa	11% - 12%	Ba
Rating:				
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		Baa2		Baa2

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for nonfinancial Corporations.
[2] As of 3/31/2021(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

Ratings

Exhibit 18

Category	Moody's Rating
UNITIL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
GRANITE STATE GAS TRANSMISSION, INC.	
Outlook	Stable
Issuer Rating	Baa2
NORTHERN UTILITIES, INC.	
Outlook	Stable
Issuer Rating	Baa1
UNITIL ENERGY SYSTEMS, INC.	
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
FITCHBURG GAS & ELECTRIC LIGHT COMPANY	
Outlook	Stable
Issuer Rating	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1291090

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

CAROLE A. BEAULIEU

EXHIBIT CAB-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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 Northern Utilities, Inc. ("Northern" 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. I have submitted pre-filed direct testimony in the Unitil Energy Systems, Inc. ("UES") Arrearage Management Program ("AMP") proposal in Docket DE 21-030.

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. Northern is proposing an AMP for residential financial hardship customers who are struggling to pay their gas bill.

Q. Please summarize your testimony.

A. The Company is seeking approval to offer an AMP. The AMP will offer qualifying residential customers of Northern 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 Northern 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 gas 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, Northern 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 Northern'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, Northern'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 that would provide them with the discounted gas rate, and refer them to their local CAP for Fuel Assistance and other 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 Northern, 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 explained that the benefits of such a program include "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." Docket No. 19-197, Noonan Testimony at 6. The Staff also noted that any such program "should also reduce the utility's costs for collections, field visits, disconnections, reconnections, lead lag, carrying costs and uncollectables."

Unitil anticipates being an active participant in a Stakeholder Group with peer NH utilities to discuss shared AMP learnings and ideas for potential program improvements.

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 Northern.
- 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 August 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 estimates the annual cost of arrearage forgiveness to be $74,000. This assumes an average enrollment rate of approximately 75 percent and an annual success rate of approximately 60 percent, based on the current eligible population of over 185 customers. See chart below for supporting calculations:

Forecasted AMP Forgiveness					
Forecasted Number of Eligible Customers	Amount of Eligible Arrears	Max Amount that Could be Forgiven in 12 Months	Forecasted Enrollment Rate	Forecasted Success Rate	Forgiveness Amount
185	$175,441	$163,401	75%	60%	$74,000

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. The Company has proposed a similar AMP for its New Hampshire electric division, UES in Docket DE 21-030. The AMP Coordinator will be in charge of both Northern and UES AMP administration so the Company has allocated 22%, or

$18,480, of the estimated costs associated with the position to Northern based on the Company's estimated amount of enrollees between Northern and UES.

Q. How does the Company propose to recover the costs associated with the AMP?

A. The Company is proposing to recover $92,480[1] ($74,000 + $18,480) in distribution rates. Actual incremental costs directly related to the AMP will be tracked and any difference between the actual costs above or below the amount in distribution rates will be reconciled through the Regulatory Cost Adjustment Mechanism ("RCAM"). This mechanism has been proposed in the Company's recent filing in Docket DG 21-123, which will conclude prior to the Order in this proceeding. The Company will update its cost recovery mechanism proposal as required as a part of that proceeding. 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.

[1] Refer to Schedule RevReq-3-14, Line 5.

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

JONATHAN A. GIEGERICH, CPA

EXHIBIT JAG-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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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 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 Corporation's (the "Company") utility subsidiaries, including Northern Utilities, Inc. ("Northern").

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 the Company and its regulated utility subsidiaries, in litigation regarding property tax assessments in New Hampshire. I have also represented the Company numerous times in federal income tax matters before the Internal Revenue Service (IRS") and I have represented the Company in Maine on state income tax and sales and use taxes audits. Additionally, I have testified before the Main Public Utilities Commission and before the New Hampshire Public Utilities Commission on behalf of the Company.

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 Northern'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 four 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 Northern'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 Northern's cost of service, (3) the effect of other excess ADIT related to reconciling ratemaking mechanisms outside of the cost of service, and (4) the pandemic tax relief provided in the CARES Act and FFCRA. Additionally, the amortization of the excess ADIT Regulatory Liability will reduce Northern'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 report the effect of the TCJA on the Company's cash flow, rate base, and actual return on equity ("ROE"). Finally, I will report the current status of the Company's rate base adjustment for predecessor ADIT as stipulated in *Docket No. DG 08-048 Article 3.5*.

Q. Please briefly explain the economic effect of the TCJA on the Company?

A. 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.

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 most significant corporate effect of the TCJA is reducing the top federal corporate tax rate from 35% to 21%. 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 as part of Northern's settlement agreement in Docket No. DG 17-070. The Company has reflected this change in its annual cost of service, revenue requirements and base rates and in accordance with the principles and requirements contained in the Company's tax sharing agreement, attached as Exhibit JAG-3.

Q. What determines the amount of Accumulated Deferred Income Taxes ("ADIT") reported on Northern'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 its book earnings before income tax or "Pre-Tax Income." At companies that are taking advantage of accelerated tax deductions in the IRC, those companies 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 Net 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 Net 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 Net 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 does now exist and will be properly classified that way in the FERC chart of accounts, *Docket No. AI93-5-000*. Please see Exhibit JAG-4 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 calculated by the Company is $6,572,092. 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 19 years as shown on Exhibit JAG-6.

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 $308,218 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 2019-2020 flow back period?

A. As described the in the prefiled testimony of Messrs. Goulding and Nawazelski, the Company is proposing to offset the 2021 deferral balance of the Company's property taxes associated with House Bill 700. Applying the annual excess ADIT flow back for the years 2019-2020, or $515,202, would materially reduce the Company's property tax deferral balance that would have to be recovered as part of the proposed Regulatory Cost Adjustment Mechanism effective November 1, 2022.

IV. PANDEMIC TAX RELIEF PROVIDED IN THE CARES ACT AND THE FFCRA

Q. Briefly summarize the pandemic tax relief enacted in the CARES Act.

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[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.

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 relief 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 on employment tax form 941. In the third quarter of 2020, Northern and Unitil Service recorded ERCs of approximately $87,364 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 on employment tax form 941. In the fourth quarter of 2020, Northern recorded an FFCRA of approximately $20,000 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 now must also seek additional funding through long term debt or equity contributions for the decreased government benefit realized through accelerated tax deductions on utility plant capital investments. 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 52% of the federal tax benefit in the year the assets were placed in service. Thus, this too 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 52% federal income tax benefit which the Company was previously allowed to deduct in the first year prior to the TCJA?

A. The 52% is a composite rate of the former 50% first year bonus depreciation plus 3.75% of the remaining non-bonus asset basis.

Q. What other effects does the TCJA have on the Company's cash flows and rate base and actual ROE?

A. 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. The Company's actual ROE will deviate negatively from its authorized ROE as rate base increase more quickly due to fewer accelerated tax deductions.

VI. PRO FORMA ADJUSTMENT FOR PREDECESSOR ADIT

Q. Why does the Company make a pro forma adjustment to plant related ADIT?

A. The Company stipulated in Docket No. DG 08-048 and DG 08-079 as part of the purchase agreement of Northern Utilities, Inc. to pro forma the predecessor ADIT offset in rate base until the successor ADIT is greater than the pro formed predecessor ADIT.

Q. How has the Company been completing the predecessor pro forma ADIT calculation?

A. The Company has been annually tracking the predecessor net tax value and predecessor net plant value adjusted for current year retirements and depreciation to calculate a predecessor pro formed ADIT.

Q. How has the Company been tracking the acquired ADIT calculation?

A. The Company tracks all book and tax fixed assets in a software suite developed by PowerPlan. The tax fixed asset module tracks annual tax activity including additions, retirements, depreciation, and accumulated book/tax temporary differences.

Q. Is the acquired ADIT as calculated in PowerPlan greater than the predecessor pro formed ADIT?

A. Yes, the acquired ADIT is now greater than the predecessor pro formed ADIT. This is shown in Exhibit JAG-7. Both predecessor and successor ADIT amounts have been revalued for the effect of the TCJA. The predecessor pro formed ADIT has been decreasing as all pro formed tax additions had already been depreciated through the accelerated portion of the 20 year MACRS tax depreciation schedule at the acquisition date. The acquired ADIT has reached its peak as a result of all acquired tax additions being depreciated in the accelerated portion of the MACRS depreciation rates. Thus, the Company proposes to no longer pro forma the predecessor ADIT offset in rate base as the Settlement stipulation requiring that calculation be maintained has been met and exceeded.

VII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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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

D Unitil

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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.

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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.

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).

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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

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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.

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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.

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.

- **<u>Other Effects & Evaluations</u>**

  - **<u>Securities and Exchange Commission Staff Accounting Bulletin 118 ("SAB 118")</u>**

    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.

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- **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*

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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.

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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.

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.

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.

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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

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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,

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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 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* ***<u>should be flowed back</u>*** *to ratepayers under* ***<u>general ratemaking principles</u>****. 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* ***<u>average rate assumption method</u>*** *when flowing excess ADIT back to customers. Rate-regulated companies must follow this requirement to be considered* ***<u>in compliance with normalization.</u>*** *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.

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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.

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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

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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.

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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.

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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.

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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.

<u>Other Areas of Implementation</u>

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

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(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.

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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

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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

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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.

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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 | Q2 2018 Interim Reporting Update

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

Unitil

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.

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 EDIT Schedule

	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

Unitil

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.

Unitil

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.

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.

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

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

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 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

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

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 2018 Actual YTD	12/31/2017 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	

Unitil

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.

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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.

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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

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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.

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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.

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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

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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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

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[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

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[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. 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

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[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. Discussion

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

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[26] *See generally Indicated RTO Transmission Owners*, 161 FERC ¶ 61,018, at PP 13-14 (2017); *see 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]

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[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]

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[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]

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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]

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[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

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[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

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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

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[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,

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[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

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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

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[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*].**

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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. <u>Order No. 144</u>

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. 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

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[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

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[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. <u>Prior Accounting Guidance for Public Utilities and Natural Gas Pipelines</u>

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

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[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

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[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]

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[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

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[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,

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[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

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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]

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[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

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[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]

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[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

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[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]

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[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.

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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. <u>Consolidated Return Election</u>. 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.

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.

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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

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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. <u>Notice of Inquiry</u>

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. <u>Stated Rates</u>

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*].**

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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. <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. <u>Prior Accounting Guidance for Public Utilities and Natural Gas Pipelines</u>

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. <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. <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. 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

Docket No. DG 21-104

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.

Northern Utilities, Inc.
Excess Deferred Income Tax (EDIT)
At December 31, 2020

COL/LN	(a)	(b)
	Description	**EDIT at 12/31/2020**
1	Utility Plant Differences	$ (6,757,556)
2	SFAS 106 - PBOP	358,242
3	SFAS 87 - Pensions	(74,060)
4	Bad Debt	13,180
5	Prepaid Property Tax	(94,617)
6	Deferred Rate Case & Restructuring	(18,035)
7	Insurance Settlement	754
8	**Total EDIT**	**$ (6,572,092)**

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Northern Utilities, Inc.
Excess Accumulated Deferred Income Tax ARAM Schedule

	(a)	(b)	(c)	(d)	(e)
COL/LN	YEAR	AMOUNT	GROSS-UP	REGULATORY LIABILITY	SOURCE
1	2018	$ -	$ -	$ -	PowerTax Report 257
2	2019	171,526	63,705	235,231	PowerTax Report 257
3	2020	204,150	75,821	279,971	PowerTax Report 257
4	2021	224,747	83,471	308,218	PowerTax Report 257
5	2022	239,502	88,951	328,453	PowerTax Report 257
6	2023	246,758	91,646	338,404	PowerTax Report 257
7	2024	250,949	93,203	344,152	PowerTax Report 257
8	2025	251,226	93,305	344,531	PowerTax Report 257
9	2026	245,354	91,124	336,478	PowerTax Report 257
10	2027	241,988	89,874	331,862	PowerTax Report 257
11	2028	243,656	90,494	334,150	PowerTax Report 257
12	2029	314,707	116,882	431,589	PowerTax Report 257
13	2030	446,645	165,884	612,529	PowerTax Report 257
14	2031	435,585	161,776	597,361	PowerTax Report 257
15	2032	454,479	168,793	623,272	PowerTax Report 257
16	2033	496,291	184,322	680,613	PowerTax Report 257
17	2034	532,685	197,839	730,524	PowerTax Report 257
18	2035	584,985	217,263	802,248	PowerTax Report 257
19	2036	648,333	240,791	889,124	PowerTax Report 257
20	2037	338,528	125,729	464,258	PowerTax Report 257
21	TOTAL	$ 6,572,092	$ 2,440,875	$ 9,012,967	

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Northern Utilities, Inc.
New Hampshire Division
Predecessor ADIT Schedule - Pro Forma

New Hampshire - Predecessor ADIT

LINE NO.		Historical Tax Cost	Current Year Tax Depreciation	Tax Reserve	Net Tax Value = NTV	Utility Plant Book Basis	Current Year Book Depreciation	Book Reserve	Net Book Value = NBV	NTV v. NBV	Deferred Taxes @ 34% / 28.06%
1	12/31/2007			65,571,972		105,792,383		41,497,528		-	-
2	12/31/2008	109,045,091	4,286,754	69,858,726	39,186,365	108,843,169	3,986,929	45,484,457	63,358,712	(24,172,347)	(9,526,322)
3	12/31/2009	106,731,127	4,721,176	72,299,925	34,431,202	106,529,205	3,902,169	48,580,506	57,948,698	(23,517,496)	(9,268,245)
4	12/31/2010	105,912,392	4,271,231	75,991,312	29,921,080	105,710,469	3,872,178	52,129,565	53,580,905	(23,659,825)	(9,324,337)
5	12/31/2011	104,322,850	3,795,195	78,378,305	25,944,544	104,120,927	3,813,953	54,872,031	49,248,897	(23,304,352)	(9,184,245)
6	12/31/2012	103,375,554	3,433,306	80,991,215	22,384,339	103,173,631	3,594,900	57,747,139	45,426,493	(23,042,154)	(9,080,913)
7	12/31/2013	102,465,722	3,181,169	83,364,314	19,101,408	102,263,800	3,563,199	60,572,855	41,690,945	(22,589,537)	(8,902,536)
8	12/31/2014	100,037,684	2,889,138	84,109,950	15,927,734	99,835,762	3,478,598	62,249,501	37,586,260	(21,658,526)	(8,535,625)
9	12/31/2015	98,956,587	2,621,906	85,738,266	13,218,321	98,754,664	3,440,929	64,809,640	33,945,024	(20,726,703)	(8,168,394)
10	12/31/2016	97,911,375	2,364,121	87,110,782	10,800,593	97,709,453	3,404,511	67,314,843	30,394,609	(19,594,016)	(7,722,002)
11	12/31/2017	97,603,792	2,157,648	88,980,313	8,623,479	97,401,869	3,393,793	70,449,277	26,952,593	(18,329,114)	(4,964,074)
12	12/31/2018	96,403,054	1,984,356	90,964,669	5,438,386	96,201,132	3,351,956	73,801,233	22,399,900	(16,961,514)	(4,593,687)
13	12/31/2019	95,163,286	1,913,654	92,878,323	2,284,963	96,201,132	3,351,956	77,153,188	19,047,944	(16,762,981)	(4,539,918)
14	12/31/2020	95,163,286	1,555,979	94,434,302	728,983	96,201,132	3,351,956	80,505,144	15,695,988	(14,967,004)	(4,053,514)
15	12/31/2021	95,163,286	1,072,418	95,506,720	(343,435)	96,201,132	3,351,956	83,857,100	12,344,032	(12,687,467)	(3,436,147)
16	12/31/2022	95,163,286	(343,435)	95,163,286	-	96,201,132	3,351,956	87,209,056	8,992,076	(8,992,076)	(2,435,324)
17	12/31/2023	95,163,286	-	95,163,286	-	96,201,132	3,351,956	90,561,012	5,640,120	(5,640,120)	(1,527,514)
18	12/31/2024	95,163,286	-	95,163,286	-	96,201,132	3,351,956	93,912,968	2,288,165	(2,288,165)	(619,704)
19	12/31/2025	95,163,286	-	95,163,286	-	96,201,132	2,288,165	96,201,132	-	-	-
20	12/31/2026	95,163,286	-	95,163,286	-	96,201,132	-	96,201,132	-	-	-
21	12/31/2027	95,163,286	-	95,163,286	-	96,201,132	-	96,201,132	-	-	-
22	12/31/2028	95,163,286	-	95,163,286	-	96,201,132	-	96,201,132	-	-	-
23	12/31/2029	95,163,286	-	95,163,286	-	96,201,132	-	96,201,132	-	-	-
24	**Totals:**		**39,904,617**				**62,203,015**				

Docket DG 21-104
Exhibit JAG-7
Page 2 of 2

Northern Utilities, Inc.
New Hampshire Division
Predecessor ADIT Schedule - Pro Forma

LINE NO.	Description	12/31/2020	Source
1	Acquired Basis Book/Tax Timing Difference	$ 19,640,264	PowerTax Report 249
2	Acquired Statutory Tax Rate	27.08%	Fed 21% State 7.7%
3	Acquired ADIT	5,319,173	Line 1 * Line 2
4	Predecessory ADIT	4,053,514	JAG - 4 Page 1 Line 14
5	Predecessory Adjustment to Acquired ADIT (Not Less than $0)	$ -	Line 4 - Line 3

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

RONALD J. AMEN

AND

JOHN D. TAYLOR

ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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SCHEDULES

I. INTRODUCTION

Q. Please state your names and business address.

A. Our names are Ronald J. Amen and John D. Taylor. Our business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. We are appearing on behalf of Northern Utilities, Inc. ("Northern" or the "Company"). Northern has retained Atrium to conduct the weather normalization and annualization of its billing determinants; the allocated class cost of service study ("ACOSS"); the marginal class cost of service study ("MCOSS"); the revenue apportionment and revenue targets by class; and the rate design for existing rate classes.

Q. By whom are you employed and in what capacity?

A. We are employed by Atrium Economics, LLC ("Atrium") as Managing Partners.

Q. Have you prepared an Appendix describing your professional qualifications?

A. Yes. Appendix A to our direct testimony presents our professional qualifications.

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. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. We have provided pre-filed direct testimony in Unitil Energy Systems Inc. 2021 general rate case, Docket No. DE 21-030.

Q. Please summarize the topics addressed in your testimony.

A. Atrium analyzed Northern's respective historical actual and normal weather data sourced from the National Oceanographic and Atmospheric Administration ("NOAA") to determine the basis for the establishment of normalized sales and transportation throughput for purposes of determining the Company's weather-normalized pro forma billing determinants and revenues in its general rate case.

Our 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 gas system components.

The ACOSS and MCOSS prepared for this case reveal how Northern 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.

Finally, Atrium will sponsor the Company's proposed revenue requirement apportionment and rate design proposals, and the resulting bill impacts by rate class.

II. WEATHER NORMALIZATION

Q. Please define weather normalization within the context of Northern's rate case filing.

A. Weather normalization is the process of determining a representative level of gas sales and transportation throughput for the Company's 2020 test year under a predefined level of normal weather conditions, which is represented by an historical average level of Effective Degree Days ("EDD"). EDD reflect an adjustment to standard heating degree days for the effect of wind speed on temperature. Northern has consistently relied on EDD for its weather analysis based on its demonstrated high correlation with the Company's gas throughput.

Q. What is the Company's basis for determining normal weather for its New Hampshire gas distribution system?

A. Northern defines normal weather as the average annual EDD over the most recent 20-year period. Based on a 2020 energy industry survey,[1] 20-year normal weather is the most commonly used normal weather period in the energy industry. The Company provided Atrium with daily actual and normal EDD data for the 20-year period ending December 2020.

Q. Please describe the weather normalization method employed by Atrium.

A. Atrium used actual "per books" billing month consumption volumes by customer class to determine actual average use per customer per day. Regression analysis was then performed for this usage data against actual EDD for the most recent five-year period, or 60 months, for each customer class. Resulting base load per customer and heating coefficients per EDD by class were then applied to actual monthly customers and normal EDD, respectively. Our normalization calculations employed an adjusted base load factor statistic from the regression analysis for each winter month to account for the effect of winter weather on base load usage. The monthly weather adjustment resulted from the difference between the normal and actual 2020 monthly therms. In some months, actual weather was warmer than normal while in other months the weather was colder. In total, the weather for test year 2020 was warmer than normal, resulting in a positive net weather adjustment to throughput of approximately five million therms, as shown in column L of Schedule RAJT-2, labeled "WN Therm Adjustment." Two customer classes, G50/T50 (Low Annual,

[1] *Forecast Accuracy Benchmarking Survey and Energy Trends*, Itron, 2020, copyright protected (Proprietary and Confidential).

Low Winter) and G52/T52 (High Annual, Low Winter) were not weather normalized, as the regression results for these classes did not indicate statistically significant heat sensitivity.

Q. Please describe the net revenue adjustment for each customer class resulting from Atrium's weather normalization process.

A. The weather adjustment therms in column L of Schedule RAJT-2 were multiplied by the volumetric block rate components in each rate schedule to derive the weather normalized revenue impact for each class, as shown in column M of Schedule RAJT-2, labeled "WM Revenue Adjustment."

III. PRO FORMA BILLING DETERMINANTS

Q. Please describe the development of the proforma billing determinants and revenues at current rates.

A. A Customer Annualization Adjustment, as shown in Schedule RAJT-2, was performed using the test year-end number of customers by class to determine the Year-End Customer Adjustment (column P) and Annualization Therm Adjustment (column Q) by class. The respective numerical adjustments were priced at the corresponding current customer charges and volumetric block rates to determine the Annualization Revenue Adjustment by class (column T).

Q. Has there been any further adjustments to class billing determinants or proforma revenues?

A. Yes. An annualization adjustment was made for Rate R-10, Residential Heating, Low

Income, to reflect a change in the customer charge for the months of November and December of the test year. This adjustment is shown in column U of Schedule RAJT-2. The Pro Forma Total Therm Adjustments and corresponding Revenue Adjustments by class are shown in columns V and W respectively, of Schedule RAJT-2.

Q. Have the pro forma billing determinants been reflected the Northern's Revenue Proof?

A. Yes. The preceding weather normalization and annualization adjustments are the basis for the pro forma 2020 Adjusted Billing Determinants and 2020 Adjusted Base Year Revenue at Current Rates in the Revenue Proof and Rate Design, Schedule RAJT-11.

Q. Has Atrium provided calendar month consumption information by customer class?

A. Yes. Atrium developed calendarized revenues per customer by class from the monthly billing cycle revenue per customer. Ratios of billing cycle consumption occurring in the same calendar month were used to allocate monthly billing cycle revenues by class to the corresponding calendar month basis. Monthly calendarized revenues per customer by class will be used in Northern's proposed decoupling mechanism, sponsored by witness Mr. Timothy S. Lyons. Schedule RAJT-12 provides a summary of the calendar month revenue per customer analysis by class.

IV. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an embedded ACOSS is a useful tool for determining the allocation of Northern's revenue requirement among its customer classes. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the incremental change in costs associated with a one-unit change in service (or output) provided by the utility. As a result of using an incremental change, capacity additions tend to be lumpy – meaning that they may add more capacity than required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information per unit of demand, customer, and energy developed in the cost of service study to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds the incremental cost of providing service but is less than stand-alone costs ("SAC"). The logic for this concept is that if customers' prices exceed incremental cost, those customers contribute to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of *cost causation*. Cost causation, as alluded to earlier, addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers.

An important element in the selection and development of a reasonable ACOSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off-peak gas service.

Q. Why are the relationships between customer requirements, load profiles and usage characteristics significant to cost causation?

A. The Company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the Company for its sales service customers.

Q. How does one establish the cost and utility service relationships you previously discussed?

A. To establish these relationships, the Company must analyze its gas system design and operations, its accounting records as well as its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

In order to accomplish this, Atrium reviewed Northern's expense and plant accounts, operational data, usage information, and conducted interviews with Northern employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain what you mean by the term "direct assignment."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing an ACOSS, the analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer group to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. What prompts the analyst to elect to perform a special study?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. How do you determine whether to directly assign costs to a particular customer or customer class?

A. Direct assignments of plant and expenses to specific customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. Is it realistic to assume that a large portion of the plant and expenses of a utility can be directly assigned?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the rate classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. Please describe the process of performing an ACOSS analysis?

A. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken: (1) functionalization; (2) classification; and (3) allocation.

The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Northern's primary functional cost categories associated with gas service include production, distribution, onsite, and customer accounts and services. Indirect costs that support these functions, such as intangible plant, general plant, and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost-defining characteristics previously discussed: (1) customer, (2) demand or capacity, and (3) commodity. The final step is the allocation of each functionalized and classified cost element to the individual customer class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors.

From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics and have different costs based on size and type.

Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

Q. Are there factors that can influence the overall cost allocation framework utilized by a gas utility when performing an ACOSS?

A. Yes. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. Why are these considerations relevant to conducting Northern's ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. Please explain why the physical configuration of the system is an important consideration.

A. The particulars of the physical configuration of the distribution system are important, such as whether the distribution system is a centralized or a dispersed one. Other such characteristics are whether the utility has a single city-gate or a multiple city-gate configuration, whether the utility has an integrated transmission and distribution system or a distribution-only operation, and whether the system is a multiple-pressure based or a single pressure-based operation.

Q. How does the availability of data influence an ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. How do state regulatory policies affect a utility's ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

V. NORTHERN'S ALLOCATED COST OF SERVICE STUDY

Q. What was the source of the cost data analyzed in the Company's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. How are the Northern rate classes structured for purposes of conducting its ACOSS?

A. For Northern's ACOSS, eight rate classes were included:

- Residential Heating Service (Rate R-5) and Residential Low Income (R-10)
- Residential Non Heating Service (R-6)
- Commercial & Industrial Service (Low Annual, High Winter) (G-40, T-40)
- Commercial & Industrial Service (Low Annual, Low Winter) (G-50, T-50)
- Commercial & Industrial Service (Medium Annual, High Winter) (G-41, T-41)
- Commercial & Industrial Service (Medium Annual, Low Winter) (G-51, T-51)
- Commercial & Industrial Service (High Annual, High Winter) (G-42, T-42)
- Commercial & Industrial Service (High Annual, Low Winter) (G-52, T-52)

Q. What are the similarities and differences in the cost allocation approach utilized in Northern's ACOSS in this proceeding with that utilized in Northern's previous rate case?

A. With the exception of the classification and allocation of Distribution Mains, the general methods employed in Northern's previous general rate case proceeding, Docket No. DG 17-070 ("2017 Case"), are reflected in the ACOSS methods employed in the current proceeding and described in my testimony. Updated data was utilized to develop the special studies and analyses that inform the calculations and outcome of the ACOSS, but the general approaches used in the current proceeding are in alignment with the 2017 Case. The primary studies are summarized below:

<u>Indirect Production & Overheads Study</u> – The Atrium ACOSS is fully

unbundled; therefore, the costs in this category are captured in the Function of the same name. The prior case had separate cost of service studies for Production only and Delivery only.

LNG Storage – LNG Storage plant and O&M costs are included in the Indirect Production & Overheads function and allocated based on the design day for each class. In the 2017 Case LNG Storage costs were included in the Production only cost of service study and allocated on the ratio of remaining design day demands.

Classification of Distribution Mains – Mains are classified between a customer component and a demand component, as described in more detail below. In the prior rate case, Mains were classified as 100% demand related.

Special Studies – Atrium's ACOSS included special studies for meters, services, other revenue, uncollectible costs, meter reading, and customer deposits. Studies from the prior rate case included meters, services, uncollectible costs, and customer deposits.

Q. How did the Company's ACOSS classify and allocate investment in Distribution Mains?

A. The Company ACOSS classified 34% of the investment in distribution mains as customer related and 66% of the investment as demand related. The customer related portion of the distribution mains investment was then allocated based on the number of customers on Northern's system. The demand related investment was allocated to the customer classes based on their respective contribution to peak day demand under system design weather conditions, in other words, on a "design day" basis.

Q. Please explain the basis for the choice of classification and allocation methods?

A. It is widely accepted that distribution mains are installed to meet both system peak period load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the Company to incur this plant investment or expense are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the gas distribution system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

Q. Is this method used to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and 2) the most commonly installed, minimum-sized unit of plant investment. Under the zero-intercept approach, which is the method relied upon in the Company's cost study, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the Company's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the Company's distribution system, regardless of the customer's peak or annual gas consumption; that is, the installation is unrelated to either peak gas flows or average gas flows. Rather, these distinct costs are related more strongly to the process of extending the distribution mains to connect customers, which is a function of the length of distribution mains and not of the size or diameter of the mains.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. For purposes of determining the customer component of distribution mains to be used in Northern's ACOSS, the minimum system method was employed to test the reasonableness, by comparison, of the results of the zero-intercept method.

Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities.

From an overall regulatory perspective, in its publication entitled, Gas Rate Design Manual, NARUC presents a section which describes the zero-intercept approach as a minimum system method to be used when identifying and quantifying a customer cost component of distribution mains investment.

Clearly, the existence and utilization of a customer component of distribution facilities, specifically for distribution mains, is a fully supportable and commonly used approach in the gas industry.

Q. With respect to Northern's specific operating experience, is there demonstrable evidence to support the use of a customer component of distribution mains?

A. Yes. In developing an appropriate cost allocation basis for distribution mains, the two methods of cost analysis mentioned in the previous response were conducted for the Company's investment in distribution mains, by size and material type of main installed. Applying the regression results of the "zero inch" distribution main, which was $25.21 per foot for plastic mains, to the Company's total footage of distribution mains results in an investment amount equivalent to approximately 34% of the total investment in distribution mains, on a current cost (year 2020) basis. For the purpose of comparison, the most commonly installed, minimum-sized distribution mains analysis focused on 2-inch diameter plastic pipe. The dominant pipe size for new distribution main installations by far is 2-inch plastic, with over 1.2 million feet installed. The 2-inch plastic pipe analysis, adjusted downward to account for its load carrying capacity, yielded a minimum system result of 41.5%. These results are provided in Schedule RAJT-9 - Customer Component of Mains Analysis. Both methods are supportive of the 34% classification of distribution mains as customer related used in the ACOSS model.

Q. Would one expect there to be a strong correlation between the number of customers served by Northern and the length of its system of distribution mains?

A. Yes. Development of the Company's distribution grid over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Northern's distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a minimum system approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Northern represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

Q. How did the ACOSS allocate distribution-related gas operation and maintenance ("O&M") expenses?

A. In general, these expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant accounts, Mains – Account No. 376. With the detailed analyses supporting the assignment or allocation of major plant in service components; where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. Please describe the classification and allocation of Customer Accounts and Customer Service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading) and 904 (Uncollectible Accounts). The allocation factor for meter reading expenses included additional time and effort related to meter reading for manual meter reading activities. Uncollectible accounts expenses are assigned to the classes based on an analysis of bad debt expenses.

Q. How were administrative and general ("A&G") expenses and taxes allocated to each rate class?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant. Regulatory Commission expense was allocated on rate base.

Q. Please describe the method used to allocate the reserve for depreciation as well as depreciation expenses.

A. These items were allocated by function in proportion to their associated plant accounts.

Q. How did the COSS allocate taxes other than income taxes?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with each tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category and can be grouped into the following categories: (1) labor; (2) plant; and (3) rate base. In the Northern COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. How were income taxes allocated to each rate class?

A. Current income taxes were allocated based on each class' net income before taxes. Income taxes for the total revenue requirement were allocated to each class based on the allocation of rate base to each class. Income taxes at proposed revenues by class were allocated to each class based on the income prior to taxes for each class.

Q. Does Northern's COSS include gas commodity costs?

A. No. However, there are indirect production and overhead costs within the COSS which are recovered through the Company's Cost of Gas Adjustment mechanism. The details relating to these costs and the associated revenue requirement of $826,413 are presented in Schedule RAJT-3, Summary of Cost Functionalization.

VI. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. Please summarize the results of Northern's COSS.

A. The following **Table 1** provides a high-level summary of the results of the ACOSS. It shows the rate of return for each rate class based on current rates as well as the system overall return, the revenue deficiency or excess for each rate class at the uniform system rate of return, and the revenue-to-cost ratio for each class.

Table 1

Summary Results of the Company's ACOSS

Rate Class	Class Revenue (Deficiency)/ Excess	Rate of Return on Net Rate Base	Revenue to Cost Ratio
Residential HeatR-5, R-10	(5,235,399)	3.58%	0.82
Residential Non-HeatR-6, R-11	(484,346)	-5.61%	0.54
High Winter SmallG-40, T-40	(1,486,126)	4.48%	0.84
Low Winter Small G-50, T-50	49,432	10.37%	1.05
High Winter MediumG-41, T-41	(1,180,973)	4.81%	0.83
Low Winter MediumG-51, T-51	106,343	11.29%	1.09
High Winter LargeG-42, T-42	(480,404)	3.91%	0.78
Low Winter LargeG-52, T-52	697,045	16.74%	1.35
Total Company	(8,014,427)	4.74%	0.85

Regarding rate class revenue levels, the resulting revenue-to-cost ratios show that all but three classes, Low Winter Small (G-50, T-50), Low Winter Medium (G-51, T-51, and Low Winter Large (G-52, G-T-52) are being charged rates that recover less than their indicated costs of service.

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 Northern 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 V</u>** of this testimony.

Q. Please describe the ACOSS schedules attached to this testimony.

A. Five schedules provide further details of the ACOSS that include the following information:

- Schedule RAJT-4 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 RAJT-5 provides a single page illustration of the process followed to develop the Company's proposed class revenue allocation.

- Schedule RAJT-6 consists of 3 pages and presents the ACOSS unit cost report.
- Schedule RAJ-7 consists of 2 pages and provides the summary of the ACOSS external allocation factors.
- Schedule RAJT-8 consists of 5 pages and provides a description of the functionalization and classification of the USOA accounts.

VII. 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 supply services to retail customers who do not elect an alternate gas commodity supplier.

Q. Please describe the Company's MCOSS.

A. 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.

An example of the latter point is addressed in Northern's system improvement planning process:

"Unlike mains extensions that are installed to serve known load, system improvements are completed in advance to ensure the system has the capacity required to meet planning criteria. The capacity increase associated with system improvement projects tend to be a lumpy investment, meaning that the amount of capacity is determined based upon standard equipment and materials and is not able to be fine-tuned to the amount of load forecasted."[2]

Q. Please discuss the steps followed to prepare a MCOSS for a gas utility such as Northern.

A. To estimate marginal cost, the first step requires determining the change in cost associated with the incremental consumption of natural gas. The increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity cost because gas costs are a pass-through cost element. Essentially, marginal cost requires an understanding of the utility's system planning process. Often however, the planning process does not provide all of the information necessary to develop complete marginal cost estimates.

The second step in the determination of marginal cost relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for the utility's distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution. Gas distribution systems are typically built using engineering design standards that take into consideration customer density and the expected design day demands of those customers. For customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible

[2] Direct Testimony of Kevin E. Sprague and Christopher J. LeBlanc, at 12:9-14.

services, their demands tend to be coincident. 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.

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 distribution system demand and include mains, service lines and meters. The customer component of these facilities 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 means that the demand related cost is often 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 Northern's distribution system?

A. Yes. The distribution engineering and operations personnel at Northern 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. The customer component of distribution mains, which informs the minimum system, is discussed in **<u>Section V</u>**, Northern's Allocated Cost of Service Study. 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 Northern associated with customer and demand related capital expenditures. The economic carrying charge rate uses Northern'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-10, 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 **Table 2** below.

Table 2

Summary of Unit Costs by Class

Rate Class	Unit Customer Costs ($/Month)		Unit Demand Cost ($/DDDth-Month)	
	(B)	(C)	(D)	(E)
	Embedded	Marginal	Embedded	Marginal
Residential HeatR-5, R-10	71.71	56.20	21.04	24.69
Residential Non-HeatR-6, R-11	72.33	56.05	21.04	24.69
High Winter SmallG-40, T-40	86.60	71.71	21.04	24.69
Low Winter Small G-50, T-50	86.76	71.91	21.04	24.69
High Winter MediumG-41, T-41	187.51	159.07	21.04	24.69
Low Winter MediumG-51, T-51	187.21	160.87	21.04	24.69
High Winter LargeG-42, T-42	725.70	720.13	21.04	24.69
Low Winter LargeG-52, T-52	736.61	729.25	21.04	24.69
Total System	78.70	62.94	21.04	24.69

As the table illustrates, the Residential 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 volumetric 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.

VIII. 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,

(2) Efficiency,

(3) Value of Service,

(4) Stability/Gradualism,

(5) Non-Discrimination,

(6) Administrative Simplicity, and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[3]

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of

[3] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed earlier, into practice and is particularly relevant for Northern because of the competitive supply alternatives that cap rates under its flex rates.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal – rates should be equal and, where costs are different – rates should be different.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that was previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. As noted above, there are tensions between cost and value of service principles. There are potential conflicts between simplicity and non-discrimination and between 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.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

IX. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Northern's proposed revenue increase of $7.8 million to its customer classes.

A. As just described, 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 Northern's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Northern's interclass revenue proposal?

A. Yes. Using Northern's proposed revenue increase, and the results of its COSS, Atrium evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Northern personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option evaluated under Northern'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 RAJT-5, Proposed Revenue Allocation by Class, under *Scenario A - 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. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. 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 considered was assigning the increase in revenues to Northern's customer classes based on an equal percentage basis of its current non-gas revenues (see *Scenario B - Equal Percentage Increase*, in Schedule RAJT-5). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS Study results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of Northern'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 Northern's class revenue proposal.

Q. What was the result of this process?

A. After further discussions with Northern, Atrium concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all of Northern's customer classes while the minimum class increase is set to fifty percent of the system average, as shown in Schedule RJA-5 as *Proposed Class Revenues*. In the case of the Residential Heat class (R-5/R-10), the revenue adjustment at 1.25 times the system average ensures their proposed rates will move class revenues closer to the allocated cost of service for the class at 0.95 revenue-to-cost ratio. The proposed revenue increase to the Residential Non-Heat (R-6/R-11) class of twice the system average increase will improve the class' revenue-to-cost ratio from 0.45 to 0.63, below unity (1.00) at the Company's proposed ROR of 7.75%. Proposed increases for the G-40/T-40, G-41/T-41, and G-42/T42 classes were 75% of the system average increase, which brings their revenue-to-cost ratios 0.96, 1.08 and 1.05, respectively. The ACOSS results for the remaining customer classes (G-50/T50, G-51/T-51, G-52/T-52) indicate their respective class rates of return are at or 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-5 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service classes has led us to conclude, in consultation with the Company, to refrain from revenue reductions for these 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. The resulting allocation of the total revenue increase of $7,782,951 to the respective rate classes is presented in **Table 3**, below.

Table 3

Proposed Class Revenue Apportionment

Rate Class	Revenues at Current Rates	Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Revenue to Cost Ratio
Residential HeatR-5, R-10	20,731,783	25,996,394	5,264,611	25.39%	0.95
Residential Non-HeatR-6, R-11	493,626	692,442	198,816	40.28%	0.65
High Winter SmallG-40, T-40	6,745,829	7,764,703	1,018,874	15.10%	0.96
Low Winter Small G-50, T-50	1,024,226	1,127,357	103,131	10.07%	1.10
High Winter MediumG-41, T-41	5,235,691	6,026,477	790,786	15.10%	1.08
Low Winter MediumG-51, T-51	1,396,947	1,537,608	140,661	10.07%	1.27
High Winter LargeG-42, T-42	1,545,114	1,778,485	233,370	15.10%	1.04
Low Winter LargeG-52, T-52	2,623,624	2,887,802	264,177	10.07%	1.75
Special Contracts Revenue	1,197,813	1,197,813	0	0.00%	
Indirect Production & OH Revenue	1,057,890	826,413	-231,477	-21.88%	
Miscellaneous Revenue	1,147,705	1,147,705	0	0.00%	
Total Company	43,200,249	50,983,199	7,782,951	18.02%	1.00

Q. Please summarize the overall benefit provided by your proposed class revenue apportionment.

A. In summary, the preferred revenue allocation approach in Schedule RJA-5, *Scenario C* results in reasonable movement of the Residential and High Winter Small Commercial classes revenue-to-cost ratios toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring varying levels of revenue increase responsibility from the other 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.

X. NORTHERN'S RATE DESIGN

Q. Please summarize the proposed rate design changes.

A. In consultation with Northern, Atrium is proposing changes to monthly customer charges. We are recommending an increase to the Residential (R-5/R-10, R-6) customer charges equal to the percentage revenue increase (25.4%) to the Residential Heat class from $22.20 to $27.84 per month. Modest increases were made to the customer charges for the remaining non-residential rate schedules.

Atrium is also proposing to remove all seasonally differentiated volumetric rates in the rate schedules where the winter/summer rates remain with one exception; that is, Rate Schedule G-52/T-52. While there is no demonstrable cost of service support for the current seasonal differences in the rates, eliminating the winter/summer rate differential will cause disproportionate increases for G-52/T-52 customers with primarily summer season consumption.

Finally, all rate schedules with current multi-block volumetric rates have been reduced to a single flat block, which continues the transition of the volumetric rates from Northern's 2017 rate case. These proposed changes to the volumetric rates will simplify bill calculation and presentation of the information on customer bills, in addition to the monthly revenue per customer by class calculations used in the Company's proposed decoupling mechanism, and provide some winter bill reductions to heating load customers when monthly bills are the highest.

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. Schedule RAJT-11, Revenue Proof and Rate Design, presents summaries by customer class of the proposed revenue increases. This schedule displays the revenues calculated under the present and proposed rates for each customer rate schedule. The proposed revenue increase by class and corresponding percentages are also shown.

XI. CUSTOMER BILL IMPACTS

Q. What are the corresponding bill comparisons for Northern's customers served under its various rate schedules?

A. A presentation of the billing impacts based on class average monthly usage by winter and summer seasons, and presented in deciles of usage, are provided for all rate schedules in Schedule RAJT-13, Customer Bill Impacts.

Q. Has Northern prepared additional bill comparisons for its Residential customers?

A. Yes. The annual bill impacts, as shown on a month-by-month basis, for the Residential rate schedules are provided in Schedule RAJT-14, Residential Customer Bill Impacts.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	WN Therm Adjustment Summer	WN Therm Adjustment Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
1	R-5	Residential Heating	January	(11,181)	2,990,270	2,979,089	25,300	117.748	133.131	3,368,269	389,180		389,180	$269,312
2			February	(1,088)	3,028,644	3,027,557	25,213	120.080	139.422	3,515,228	487,671		487,671	$337,469
3		*Rates*	March	(331)	2,582,100	2,581,769	25,370	101.764	115.348	2,926,418	344,649		344,649	$238,497
4		*Customer*	April	(520)	1,794,556	1,794,035	25,211	71.161	77.829	1,962,150	168,115		168,115	$116,336
5		*$22.20*	May	609,620	675,934	1,285,554	25,458	50.496	44.372	1,129,646	(155,908)	(73,933)	(81,975)	-$101,819
6		*Summer*	June	547,616	(9,388)	538,228	25,363	21.221	25.582	648,829	110,601	110,601		$67,456
7		*$0.6099*	July	356,914	(784)	356,130	25,483	13.975	11.294	287,818	(68,312)	(68,312)		-$41,664
8		*Winter*	August	296,799	(535)	296,265	25,442	11.645	9.396	239,056	(57,209)	(57,209)		-$34,892
9		*$0.6920*	September	383,497	0	383,497	25,600	14.981	13.677	350,119	(33,378)	(33,378)		-$20,357
10			October	540,827	894	541,721	25,795	21.001	26.443	682,104	140,383	140,383		$85,620
11			November	684,892	561,474	1,246,367	26,120	47.718	51.958	1,357,123	110,756	60,862	49,894	$71,646
12			December	(283)	2,258,625	2,258,342	26,171	86.291	100.691	2,635,202	376,860		376,860	$260,787
13				3,406,764	13,881,789	17,288,553		678.081	749.144	19,101,961	1,813,408	79,014	1,734,393	$1,248,391
14	R-10	Res. Heating, Low Income	January	585	77,516	78,101	742	105.309	121.181	89,872	11,771		11,771	$8,145
15			February	1,125	86,314	87,439	817	106.994	130.166	106,377	18,937		18,937	$13,105
16		*Rates*	March	331	70,723	71,054	760	93.463	115.534	87,833	16,779		16,779	$11,611
17		*Customer*	April	441	55,771	56,212	879	63.928	82.227	72,302	16,090		16,090	$11,134
18		*$22.20*	May	16,946	18,090	35,036	794	44.142	46.837	37,175	2,139	1,035	1,104	$1,395
19		*Summer*	June	12,319	9,654	21,973	781	28.148	26.009	20,304	(1,669)	(1,669)		-$1,018
20		*$0.6099*	July	7,455	772	8,226	688	11.954	10.336	7,112	(1,114)	(1,114)		-$679
21		*Winter*	August	6,497	464	6,961	663	10.497	8.367	5,549	(1,412)	(1,412)		-$861
22		*$0.6920*	September	7,994	0	7,994	644	12.409	12.880	8,298	304	304		$185
23		*Rates, Jan-Oct*	October	11,941	1	11,943	641	18.631	27.210	17,442	5,499	5,499		$3,354
24		*$8.88*	November	14,175	14,146	28,321	630	44.977	49.718	31,307	2,985	1,494	1,491	$1,943
25		*$0.2440*	December	296	51,744	52,039	644	80.845	86.220	55,499	3,460		3,460	$2,394
26		*$0.2760*		80,105	385,195	465,300		621.298	716.686	539,069	73,769	4,136	69,633	$50,708
27	R-6	Residential Non-Heating	January	17	29,096	29,113	1,267	22.977	25.217	31,951	2,838		2,838	$1,836
28			February	29	28,355	28,384	1,289	22.021	25.601	32,998	4,614		4,614	$2,985
29		*Rates*	March	0	26,031	26,031	1,295	20.094	21.109	27,347	1,316		1,316	$851
30		*Customer*	April	0	21,269	21,269	1,280	16.619	16.378	20,961	(309)		(309)	-$200
31		*$22.20*	May	8,884	9,778	18,661	1,311	14.238	13.681	17,932	(730)	(347)	(382)	-$472
32		*Summer*	June	14,744	0	14,744	1,331	11.074	11.394	15,170	426	426		$275
33		*$0.6470*	July	12,608	0	12,608	1,354	9.312	9.076	12,289	(319)	(319)		-$206
34		*Winter*	August	11,288	0	11,288	1,355	8.329	8.367	11,340	52	52		$34
35		*$0.6470*	September	14,017	0	14,017	1,358	10.320	9.705	13,181	(836)	(836)		-$541
36			October	12,848	5	12,852	1,347	9.543	10.630	14,317	1,464	1,464		$947
37			November	10,298	7,240	17,538	1,312	13.366	13.709	17,988	450	264	186	$291
38			December	0	25,111	25,111	1,277	19.669	20.978	26,783	1,672		1,672	$1,082
39				84,733	146,885	231,617		177.562	185.845	242,254	10,637	703	9,934	$6,882

Docket No. DG 21-104
Schedule RAJT-2
Summary of Weather Normalized Billing Determinants

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
1	R-5	Residential Heating	January	871	115,908		115,908	$99,536		505,088	$368,849
2			February	958	133,593		133,593	$113,719		621,265	$451,187
3		*Rates*	March	801	92,379		92,379	$81,705		437,027	$320,202
4		*Customer*	April	960	74,721		74,721	$73,021		242,836	$189,356
5		*$22.20*	May	713	31,620	14,994	16,625	$36,470		(124,289)	-$65,349
6		*Summer*	June	809	20,686	20,686		$30,567		131,287	$98,023
7		*$0.6099*	July	688	7,771	7,771		$20,014		(60,541)	-$21,650
8		*Winter*	August	730	6,856	6,856		$20,378		(50,353)	-$14,513
9		*$0.6920*	September	572	7,818	7,818		$17,458		(25,561)	-$2,900
10			October	376	9,944	9,944		$14,413		150,327	$100,032
11			November	51	2,676	1,470	1,205	$2,874		113,432	$74,521
12			December	0	-		-	$0		376,860	$260,787
13				7,528	503,971	69,538	434,432	$510,154		2,317,378	$1,758,545
14	R-10	Res. Heating, Low Income	January	(98)	(11,868)		(11,868)	-$10,387	$42,339	(97)	$40,097
15			February	(174)	(22,589)		(22,589)	-$19,485	$47,204	(3,652)	$40,824
16		*Rates*	March	(117)	(13,464)		(13,464)	-$11,905	$39,668	3,315	$39,375
17		*Customer*	April	(236)	(19,373)		(19,373)	-$18,637	$35,074	(3,283)	$27,572
18		*$22.20*	May	(150)	(7,026)	(3,398)	(3,628)	-$7,914	$24,298	(4,887)	$17,780
19		*Summer*	June	(137)	(3,562)	(3,562)		-$5,212	$18,922	(5,231)	$12,691
20		*$0.6099*	July	(44)	(459)	(459)		-$1,267	$12,215	(1,573)	$10,268
21		*Winter*	August	(20)	(163)	(163)		-$533	$11,404	(1,576)	$10,010
22		*$0.6920*	September	(1)	(7)	(7)		-$16	$11,506	297	$11,675
23		*Rates, Jan-Oct*	October	3	73	73		$104	$12,908	5,572	$16,366
24		*$8.88*	November	14	697	349	348	$764	$9,655	3,682	$12,363
25		*$0.2440*	December	0	-		-	$0	$108	3,460	$2,502
26		*$0.2760*		(958)	(77,743)	(7,168)	(70,575)	-$74,485	$265,302	(3,974)	$241,525
27	R-6	Residential Non-Heating	January	10	244		244	$372		3,081	$2,208
28			February	(12)	(314)		(314)	-$475		4,300	$2,510
29		*Rates*	March	(19)	(396)		(396)	-$673		919	$178
30		*Customer*	April	(3)	(51)		(51)	-$103		(360)	-$302
31		*$22.20*	May	(34)	(465)	(221)	(243)	-$1,055		(1,194)	-$1,527
32		*Summer*	June	(55)	(623)	(623)		-$1,618		(198)	-$1,342
33		*$0.6470*	July	(77)	(701)	(701)		-$2,169		(1,020)	-$2,375
34		*Winter*	August	(79)	(657)	(657)		-$2,168		(605)	-$2,134
35		*$0.6470*	September	(82)	(791)	(791)		-$2,322		(1,628)	-$2,863
36			October	(70)	(745)	(745)		-$2,039		719	-$1,092
37			November	(35)	(485)	(285)	(200)	-$1,100		(36)	-$809
38			December	0	-		-	$0		1,672	$1,082
39				(456)	(4,986)	(4,024)	(962)	-$13,349		5,651	-$6,467

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	WN Therm Adjustment Summer	WN Therm Adjustment Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
40	G-40/T-40	Low Annual, High Winter	January	(9)	1,800,364	1,800,355	5,126	351.2	396.3	2,031,250	230,896		230,896	$43,062
41			February	69	1,761,135	1,761,204	5,124	343.7	408.0	2,090,502	329,298		329,298	$61,414
42		*Rates*	March	6	1,471,715	1,471,721	5,128	287.0	337.4	1,729,963	258,243		258,243	$48,162
43		*Customer*	April	(1)	934,832	934,831	5,081	184.0	216.4	1,099,281	164,450		164,450	$30,670
44		*$75.09*	May	297,681	307,245	604,927	5,099	118.6	117.7	600,046	(4,881)	(2,402)	(2,479)	-$910
45		*Summer*	June	207,272	(24)	207,248	4,953	41.8	59.4	294,140	86,892	86,892		$16,205
46		*$0.1865*	July	116,133	0	116,133	4,905	23.7	16.5	80,797	(35,336)	(35,336)		-$6,590
47		*Winter*	August	99,054	88	99,142	4,924	20.1	11.7	57,787	(41,355)	(41,355)		-$7,713
48		*$0.1865*	September	156,660	0	156,660	4,941	31.7	23.0	113,863	(42,797)	(42,797)		-$7,982
49			October	229,293	(27)	229,266	4,986	46.0	64.2	319,906	90,641	90,641		$16,904
50			November	371,818	331,258	703,076	5,026	139.9	141.1	709,174	6,098	3,225	2,873	$1,137
51			December	(53)	1,360,353	1,360,300	5,234	259.9	287.2	1,503,339	143,039		143,039	$26,677
52				1,477,924	7,966,938	9,444,862		1,847.7	2,078.7	10,630,049	1,185,187	58,867	1,126,319	$221,037
53	G-50/T-50	Low Annual, Low Winter	January	0	162,592	162,592	812	200.3	200.3	162,592	0		-	$0
54			February	0	163,761	163,761	825	198.5	198.5	163,761	0		-	$0
55		*Rates*	March	0	156,891	156,891	826	190.1	190.1	156,891	0		-	$0
56		*Customer*	April	8	98,889	98,897	828	119.5	119.5	98,897	0		-	$0
57		*$75.09*	May	46,723	44,759	91,482	833	109.8	109.8	91,482	0	-	-	$0
58		*Summer*	June	100,996	0	100,996	844	119.6	119.6	100,996	0	-		$0
59		*$0.1865*	July	110,175	0	110,175	857	128.6	128.6	110,175	0	-		$0
60		*Winter*	August	106,021	0	106,021	848	125.0	125.0	106,021	0	-		$0
61		*$0.1865*	September	126,540	0	126,540	848	149.3	149.3	126,540	0	-		$0
62			October	100,562	(48)	100,514	816	123.1	123.1	100,514	0	-		$0
63			November	65,069	49,618	114,688	821	139.8	139.8	114,688	0	-	-	$0
64			December	0	141,206	141,206	831	169.8	169.8	141,206	0		-	$0
65				656,093	817,670	1,473,763		1,773.5	1,773.5	1,473,763	0	0	0	$0
66	G-41/T-41	Med. Annual, High Winter	January	11,142	2,457,584	2,468,726	742	3,326	3,610	2,679,813	211,087		211,087	$51,189
67			February	0	2,407,737	2,407,737	739	3,258	3,694	2,730,344	322,606		322,606	$78,232
68		*Rates*	March	0	2,077,387	2,077,387	736	2,821	3,141	2,312,568	235,182		235,182	$57,032
69		*Customer*	April	1,824	1,333,734	1,335,559	736	1,814	2,034	1,497,721	162,162		162,162	$39,324
70		*$222.64*	May	479,198	448,673	927,870	735	1,263	1,217	894,001	(33,869)	(17,492)	(16,378)	-$7,286
71		*Summer*	June	401,386	0	401,386	729	551	716	521,704	120,318	120,318		$22,800
72		*$0.1895*	July	259,893	0	259,893	726	358	332	241,016	(18,876)	(18,876)		-$3,577
73		*Winter*	August	151,231	0	151,231	721	210	280	201,676	50,445	50,445		$9,559
74		*$0.2425*	September	319,271	(2,303)	316,968	722	439	397	286,497	(30,471)	(30,471)		-$5,774
75			October	490,403	1,490	491,893	723	680	735	531,558	39,664	39,664		$7,516
76			November	513,191	576,140	1,089,331	728	1,497	1,570	1,142,289	52,958	24,949	28,009	$11,520
77			December	0	1,820,964	1,820,964	704	2,586	2,756	1,940,963	119,999		119,999	$29,100
78				2,627,539	11,121,406	13,748,945		18,802	20,482	14,980,151	1,231,206	168,537	1,062,669	$289,635

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
40	G-40/T-40	Low Annual, High Winter	January	108	42,970		42,970	$16,156		273,865	$59,218
41			February	110	44,986		44,986	$16,670		374,285	$78,084
42		*Rates*	March	106	35,861		35,861	$14,670		294,103	$62,832
43		*Customer*	April	154	33,268		33,268	$17,750		197,719	$48,420
44		*$75.09*	May	135	15,869	7,809	8,060	$13,087		10,988	$12,176
45		*Summer*	June	282	16,732	16,732		$24,276		103,624	$40,481
46		*$0.1865*	July	329	5,421	5,421		$25,723		(29,915)	$19,133
47		*Winter*	August	310	3,640	3,640		$23,972		(37,715)	$16,259
48		*$0.1865*	September	293	6,763	6,763		$23,298		(36,034)	$15,316
49			October	248	15,906	15,906		$21,584		106,547	$38,488
50			November	208	29,367	15,530	13,836	$21,106		35,465	$22,243
51			December	0	-		-	$0		143,039	$26,677
52				2,284	250,784	71,802	178,982	$218,291		1,435,971	$439,328
53	G-50/T-50	Low Annual, Low Winter	January	20	3,975		3,975	$2,231		3,975	$2,231
54			February	6	1,277		1,277	$721		1,277	$721
55		*Rates*	March	6	1,134		1,134	$660		1,134	$660
56		*Customer*	April	4	438		438	$357		438	$357
57		*$75.09*	May	(2)	(172)	(172)		-$150		(172)	-$150
58		*Summer*	June	(13)	(1,512)	(1,512)		-$1,231		(1,512)	-$1,231
59		*$0.1865*	July	(25)	(3,224)	(3,224)		-$2,484		(3,224)	-$2,484
60		*Winter*	August	(17)	(2,079)	(2,079)		-$1,637		(2,079)	-$1,637
61		*$0.1865*	September	(16)	(2,428)	(2,428)		-$1,674		(2,428)	-$1,674
62			October	15	1,868	1,868		$1,488		1,868	$1,488
63			November	11	1,533		1,533	$1,109		1,533	$1,109
64			December	0	-		-	$0		-	$0
65				(10)	810	(7,547)	8,357	-$609		810	-$609
66	G-41/T-41	Med. Annual, High Winter	January	(38)	(137,312)		(137,312)	-$41,766		73,775	$9,423
67			February	(35)	(128,568)		(128,568)	-$38,926		194,039	$39,307
68		*Rates*	March	(32)	(100,815)		(100,815)	-$31,594		134,367	$25,437
69		*Customer*	April	(32)	(65,520)		(65,520)	-$23,061		96,642	$16,263
70		*$222.64*	May	(30)	(36,883)	(36,883)		-$13,736		(70,753)	-$21,023
71		*Summer*	June	(25)	(17,678)	(17,678)		-$8,849		102,640	$13,951
72		*$0.1895*	July	(21)	(7,108)	(7,108)		-$6,111		(25,984)	-$9,689
73		*Winter*	August	(17)	(4,781)	(4,781)		-$4,713		45,664	$4,846
74		*$0.2425*	September	(17)	(6,869)	(6,869)		-$5,153		(37,340)	-$10,928
75			October	(19)	(13,797)	(13,797)		-$6,793		25,867	$724
76			November	(24)	(36,988)		(36,988)	-$14,216		15,970	-$2,696
77			December	0	-		-	$0		119,999	$29,100
78				(290)	(556,319)	(87,117)	(469,203)	-$194,920		674,887	$94,715

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]
				Per Books					Weather Normalization					
Line	Rate Class	Description	Month	2020 Therms - Summer	2020 Therms - Winter	2020 Therms - Total	2020 Customers	2020 UPC	Normal UPC	2020 Normal Therms	WN Therm Adjustment	WN Therm Adjustment Summer	WN Therm Adjustment Winter	WN Revenue Adjustment
								[G] / [H]	WNA	[H] x [J]	[K] - [G]	[K] - [G]	[K] - [G]	[M] x Rate + [N] x Rate
79	G-51/T-51	Med. Annual, Low Winter	January	404	573,932	574,336	279	2,057	2,040	569,637	(4,699)		(4,699)	-$657
80			February	0	564,038	564,038	277	2,035	2,076	575,391	11,353		11,353	$1,588
81		*Rates*	March	0	535,718	535,718	278	1,927	1,928	536,049	331		331	$46
82		*Customer*	April	359	307,104	307,462	278	1,106	1,485	412,752	105,290		105,290	$14,730
83		*$222.64*	May	138,093	137,155	275,248	278	989	1,336	371,675	96,428	48,378	48,050	$11,981
84		*Summer*	June	266,334	(3,946)	262,387	277	948	1,267	350,616	88,229	88,229		$9,590
85		*$0.1337*	July	272,663	0	272,663	277	986	1,133	313,453	40,790	40,790		$4,434
86		*$0.1087*	August	256,063	0	256,063	274	934	1,059	290,228	34,165	34,165		$3,714
87			September	310,812	0	310,812	276	1,127	1,190	328,287	17,475	17,475		$1,900
88		*Winter*	October	299,345	411	299,755	279	1,073	1,147	320,330	20,575	20,575		$2,236
89		*$0.1712*	November	202,739	160,794	363,532	278	1,306	1,418	394,656	31,124	17,358	13,766	$3,813
90		*$0.1399*	December	0	447,486	447,486	267	1,679	1,787	476,284	28,798		28,798	$4,029
91				1,746,810	2,722,691	4,469,501		16,168	17,866	4,939,359	469,858	266,970	202,888	$57,404
92	G-42/T-42	High Annual, High Winter	January	0	883,132	883,132	34	25,974	29,522	1,003,732	120,600		120,600	$23,927
93			February	0	842,264	842,264	35	24,065	26,436	925,261	82,997		82,997	$16,467
94		*Rates*	March	0	710,411	710,411	35	20,297	23,699	829,467	119,056		119,056	$23,621
95		*Customer*	April	14,062	516,408	530,470	35	15,156	16,620	581,698	51,228		51,228	$10,164
96		*$1,335.81*	May	302,173	38,889	341,062	35	9,607	10,463	371,433	30,370	26,907	3,463	$3,932
97		*Summer*	June	218,221	0	218,221	35	6,235	7,036	246,274	28,053	28,053		$3,383
98		*$0.1206*	July	184,562	0	184,562	35	5,273	6,112	213,906	29,344	29,344		$3,539
99		*Winter*	August	191,592	0	191,592	35	5,474	6,198	216,926	25,333	25,333		$3,055
100		*$0.1984*	September	243,881	0	243,881	34	7,173	7,488	254,575	10,694	10,694		$1,290
101			October	392,858	11,382	404,240	34	11,889	12,378	420,845	16,606	16,606		$2,003
102			November	42,102	531,834	573,936	34	16,880	18,657	634,352	60,416	4,432	55,984	$11,642
103			December	0	699,750	699,750	31	22,573	25,385	786,923	87,173		87,173	$17,295
104				1,589,451	4,234,069	5,823,520		170,598	189,993	6,485,392	661,872	141,371	520,501	$120,317
105	G-52/T-52	High Annual, Low Winter	January	0	1,285,855	1,285,855	32	40,393	40,393	1,285,855	0	-		$0
106			February	0	1,458,466	1,458,466	32	45,577	45,577	1,458,466	0	-		$0
107		*Rates*	March	0	1,334,531	1,334,531	32	41,704	41,704	1,334,531	0	-		$0
108		*Customer*	April	41,018	1,300,352	1,341,370	32	41,918	41,918	1,341,370	0	-		$0
109		*$1,335.81*	May	1,276,171	5,650	1,281,821	34	38,263	38,263	1,281,821	0	-	-	$0
110		*Summer*	June	1,261,218	12,462	1,273,681	34	37,461	37,461	1,273,681	0		-	$0
111		*$0.0792*	July	1,220,236	0	1,220,236	33	36,977	36,977	1,220,236	0		-	$0
112		*Winter*	August	1,282,733	0	1,282,733	33	38,871	38,871	1,282,733	0		-	$0
113		*$0.1720*	September	1,373,207	0	1,373,207	32	42,913	42,913	1,373,207	0		-	$0
114			October	1,344,057	43,229	1,387,286	32	43,353	43,353	1,387,286	0		-	$0
115			November	28,665	1,354,228	1,382,893	32	42,726	42,726	1,382,893	0	-	-	$0
116			December	0	1,562,138	1,562,138	33	47,338	47,338	1,562,138	0	-		$0
117				7,827,306	8,356,912	16,184,218		497,493	497,493	16,184,218	0	0	0	$0
118		**Total Test Year Adjustment**		**19,496,726**	**49,633,554**	**69,130,280**				**74,576,215**	**5,445,936**	**719,598**	**4,726,338**	**$1,994,374**

Northern Utilities New Hampshire
Weather Normalization and Customer Annualization

[A]	[B]	[C]	[D]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
				Customer Annualization					Rate Change	Pro Forma Adjustment	
Line	Rate Class	Description	Month	Year-End Customer Adjustment	Annualization Therm Adjustment	Annualization Therm Adj. Summer	Annualization Therm Adj. Winter	Annualization Revenue Adjustment	R-10 Rate Change Annualization	Total Therm Adjustment	Test Year Revenue Adjustment
				[H]Dec - [H]	[J] x [P]	[J] x [P]	[J] x [P]	[P]xRt+[R]xRt+[S]xRt	[E]xDif+[H]xDif	[L] + [Q]	[U]+[O]+[T]
79	G-51/T-51	Med. Annual, Low Winter	January	(13)	(25,976)		(25,976)	-$6,987		(30,675)	-$7,645
80			February	(11)	(22,144)		(22,144)	-$5,907		(10,791)	-$4,318
81		*Rates*	March	(12)	(22,175)		(22,175)	-$6,131		(21,844)	-$6,084
82		*Customer*	April	(12)	(17,074)		(17,074)	-$5,417		88,215	$9,313
83		*$222.64*	May	(12)	(15,719)	(15,719)		-$4,623		80,709	$7,358
84		*Summer*	June	(10)	(12,884)	(12,884)		-$3,918		75,345	$5,672
85		*$0.1337*	July	(10)	(11,446)	(11,446)		-$3,745		29,344	$689
86		*$0.1087*	August	(8)	(8,116)	(8,116)		-$2,781		26,050	$933
87			September	(9)	(11,185)	(11,185)		-$3,544		6,290	-$1,644
88		*Winter*	October	(13)	(14,607)	(14,607)		-$4,741		5,967	-$2,505
89		*$0.1712*	November	(12)	(16,734)		(16,734)	-$5,448		14,391	-$1,636
90		*$0.1399*	December	0	-		-	$0		28,798	$4,029
91				(120)	(178,059)	(73,956)	(104,102)	-$53,242		291,799	$4,162
92	G-42/T-42	High Annual, High Winter	January	(3)	(88,565)		(88,565)	-$21,579		32,036	$2,348
93			February	(4)	(105,744)		(105,744)	-$26,323		(22,747)	-$9,856
94		*Rates*	March	(4)	(94,796)		(94,796)	-$24,151		24,260	-$530
95		*Customer*	April	(4)	(66,480)		(66,480)	-$18,533		(15,252)	-$8,369
96		*$1,335.81*	May	(4)	(47,083)	(47,083)		-$11,689		(16,713)	-$7,757
97		*Summer*	June	(4)	(28,146)	(28,146)		-$8,738		(92)	-$5,354
98		*$0.1206*	July	(4)	(24,446)	(24,446)		-$8,291		4,898	-$4,753
99		*Winter*	August	(4)	(24,792)	(24,792)		-$8,333		542	-$5,278
100		*$0.1984*	September	(3)	(22,463)	(22,463)		-$6,716		(11,768)	-$5,427
101			October	(3)	(37,133)	(37,133)		-$8,486		(20,527)	-$6,483
102			November	(3)	(55,973)		(55,973)	-$15,112		4,443	-$3,471
103			December	0	-		-	$0		87,173	$17,295
104				(41)	(595,620)	(184,063)	(411,557)	-$157,951		66,252	-$37,635
105	G-52/T-52	High Annual, Low Winter	January	1	47,125		47,125	$9,664		47,125	$9,664
106			February	1	45,577		45,577	$9,175		45,577	$9,175
107		*Rates*	March	1	41,704		41,704	$8,509		41,704	$8,509
108		*Customer*	April	1	41,917		41,917	$8,546		41,917	$8,546
109		*$1,335.81*	May	(1)	(19,132)	(19,132)		-$2,183		(19,132)	-$2,183
110		*Summer*	June	(1)	(37,461)	(37,461)		-$4,303		(37,461)	-$4,303
111		*$0.0792*	July	0	-	-		$0		-	$0
112		*Winter*	August	0	-	-		$0		-	$0
113		*$0.1720*	September	1	42,913	42,913		$4,734		42,913	$4,734
114			October	1	43,353	43,353		$4,769		43,353	$4,769
115			November	1	27,060		27,060	$5,500		27,060	$5,500
116			December	0	-		-	$0		-	$0
117				5	233,056	29,672	203,384	$44,412		233,056	$44,412
118		**Total Test Year Adjustment**		**7,942**	**(424,106)**	**(192,862)**	**(231,244)**	**$278,301**	**$265,302**	**5,021,830**	**$2,537,977**

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
1	**RATE BASE**							
2	**Plant in Service**							
3	**Intangible Plant**							
4	Miscellaneous Intangible Plant, Plant-related	303	212,619	INT_PLANT	1,424	123,191	88,003	-
5	Miscellaneous Intangible Plant, Customer-related	303	9,041,497	DISTRIBUTION	-	9,041,497	-	-
6	Miscellaneous Intangible Plant, Labor-related	303	3,572,231	INT_LABOR	160,985	1,044,144	1,614,481	752,621
7	Subtotal - Intangible Plant		12,826,347		162,409	10,208,833	1,702,484	752,621
8	**Mfg. Gas Produc. Plant**							
9	Land and Land Rights	304	2,787	PROD_OH	2,787	-	-	-
10	Structures & Improvements	305	-	-	-	-	-	-
11	Other Equipment	320	-	-	-	-	-	-
12	LNG Equipment	321	-	-	-	-	-	-
13	Subtotal - Mfg. Gas Produc. Plant		2,787		2,787	-	-	-
14	**Other Storage Plant**							
15	Land - Lewiston	360	23,833	PROD_OH	23,833	-	-	-
16	Structures & Improvements	361	232,281	PROD_OH	232,281	-	-	-
17	Gas Holders	362	1,585,468	PROD_OH	1,585,468	-	-	-
18	Other Equipment	363	35,693	PROD_OH	35,693	-	-	-
19	Subtotal - Other Storage Plant		1,877,275		1,877,275	-	-	-
20	**Distribution Plant**							
21	Land & Land Rights, Other Distr Sys	374.4	89,111	DISTRIBUTION	-	89,111	-	-
22	Land & Land Rights, Right of Way	374.5	17,911	DISTRIBUTION	-	17,911	-	-
23	Structures & Improvements	375	3,260,871	DISTRIBUTION	-	3,260,871	-	-
24	Mains	376	151,932,588	DISTRIBUTION	-	151,932,588	-	-
25	M&R Station Equip. - Regulating	378	7,288,982	DISTRIBUTION	-	7,288,982	-	-
26	M&R Station Equip. - G	379	39,266	DISTRIBUTION	-	39,266	-	-
27	Services	380	82,837,047	ONSITE	-	-	82,837,047	-
28	Meters	381	4,624,610	ONSITE	-	-	4,624,610	-
29	Meter Installations	382	26,001,685	ONSITE	-	-	26,001,685	-
30	House Regulators	383	733,550	ONSITE	-	-	733,550	-
31	Water Heaters/Conversion Burners	386	1,978,895	ONSITE	-	-	1,978,895	-
32	Subtotal - Distribution Plant		278,804,516			162,628,729	116,175,787	-
33	**General Plant**							
34	Land and Land Rights	389	232,947	INT_PLANT	1,560	134,969	96,417	-
35	Office Furniture & Equipment	391	508,135	INT_LABOR	22,899	148,525	229,653	107,057
36	Stores Equipment	393	31,520	INT_PLANT	211	18,263	13,046	-
37	Tools, Shop & Garage Equip.	394	1,430,421	INT_PLANT	9,581	828,787	592,054	-
38	Power Operated Equip.	396	75,266	INT_PLANT	504	43,609	31,153	-
39	Communication Equip.	397	1,873,480	INT_PLANT	12,549	1,085,495	775,436	-
40	Metscan Communication Equip	397.25	112,656	ONSITE	-	-	112,656	-
41	ERT Automatic Reading Dev	397.35	3,470,146	ONSITE	-	-	3,470,146	-
42	Subtotal - General Plant		7,734,572		47,305	2,259,648	5,320,562	107,057
43	**Total Plant in Service**		301,245,498		2,089,776	175,097,210	123,198,833	859,678

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
44	**Accumulated Depreciation**							
45	**Intangible Plant**							
46	Miscellaneous Intangible Plant, Plant-related	303	(81,184)	INT_PLANT	(544)	(47,038)	(33,602)	-
47	Miscellaneous Intangible Plant, Customer-related	303	(3,452,299)	DISTRIBUTION	-	(3,452,299)	-	-
48	Miscellaneous Intangible Plant, Labor-related	303	(1,363,979)	INT_LABOR	(61,469)	(398,684)	(616,454)	(287,372)
49	Subtotal - Intangible Plant		(4,897,461)		(62,012)	(3,898,020)	(650,057)	(287,372)
50	**Mfg. Gas Produc. Plant**							
51	Land and Land Rights	304	-	-	-	-	-	-
52	Structures & Improvements	305	374	PROD_OH	374	-	-	-
53	Other Equipment	320	4,438	PROD_OH	4,438	-	-	-
54	LNG Equipment	321	27,544	PROD_OH	27,544	-	-	-
55	Subtotal - Mfg. Gas Produc. Plant		32,357		32,357	-	-	-
56	**Other Storage Plant**							
57	Land - Lewiston	360	-	-	-	-	-	-
58	Structures & Improvements	361	(109,222)	PROD_OH	(109,222)	-	-	-
59	Gas Holders	362	(1,203,365)	PROD_OH	(1,203,365)	-	-	-
60	Other Equipment	363	(37,603)	PROD_OH	(37,603)	-	-	-
61	Subtotal - Other Storage Plant		(1,350,190)		(1,350,190)	-	-	-
62	**Distribution Plant**							
63	Land & Land Rights, Other Distr Sys	374.4	-	-	-	-	-	-
64	Land & Land Rights, Right of Way	374.5	-	-	-	-	-	-
65	Structures & Improvements	375	(596,162)	DISTRIBUTION	-	(596,162)	-	-
66	Mains	376	(38,511,660)	DISTRIBUTION	-	(38,511,660)	-	-
67	M&R Station Equip. - Regulating	378	(666,376)	DISTRIBUTION	-	(666,376)	-	-
68	M&R Station Equip. - G	379	(6,432)	DISTRIBUTION	-	(6,432)	-	-
69	Services	380	(28,479,497)	ONSITE	-	-	(28,479,497)	-
70	Meters	381	(1,226,613)	ONSITE	-	-	(1,226,613)	-
71	Meter Installations	382	(6,859,297)	ONSITE	-	-	(6,859,297)	-
72	House Regulators	383	(212,402)	ONSITE	-	-	(212,402)	-
73	Water Heaters/Conversion Burners	386	(959,565)	ONSITE	-	-	(959,565)	-
74	Subtotal - Distribution Plant		(77,518,004)		-	(39,780,631)	(37,737,373)	-
75	**General Plant**							
76	Land & Land Rights	389	-	-	-	-	-	-
77	Office Furniture & Equipment	391	(298,078)	INT_LABOR	(13,433)	(87,127)	(134,717)	(62,801)
78	Stores Equipment	393	(31,511)	INT_PLANT	(211)	(18,258)	(13,042)	-
79	Tools, Shop & Garage Equip.	394	(785,741)	INT_PLANT	(5,263)	(455,259)	(325,220)	-
80	Power Operated Equip.	396	(75,266)	INT_PLANT	(504)	(43,609)	(31,153)	-
81	Communication Equip.	397	(1,570,602)	INT_PLANT	(10,520)	(910,007)	(650,074)	-
82	Metscan Communication Equip	397.25	(112,656)	ONSITE	-	-	(112,656)	-
83	ERT Automatic Reading Dev	397.35	(2,766,299)	ONSITE	-	-	(2,766,299)	-
84	Subtotal - General Plant		(5,640,154)		(29,931)	(1,514,260)	(4,033,162)	(62,801)
85	**Total Accumulated Depreciation**		(89,373,452)		(1,409,777)	(45,192,910)	(42,420,592)	(350,173)

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
86	**Other Rate Base Items**							
87	Material and Supplies	154	2,773,457	INT_DIST_PLANT	-	1,617,778	1,155,679	-
88	Prepayments	165	64,895	INT_DIST_PLANT	-	37,854	27,041	-
89	Cash Working Capital	131	1,773,194	INT_TOTAL_PLANT	12,301	1,030,659	725,174	5,060
90	Cash Working Capital - Pro Forma	131	235,191	INT_TOTAL_PLANT	1,632	136,703	96,185	671
91	Customer Deposits	235	(249,677)	ACCTS_SERVICES	-	-	-	(249,677)
92	Net Deferred Income Taxes	283	(21,177,756)	INT_TOTAL_PLANT	(146,913)	(12,309,449)	(8,660,959)	(60,436)
93	Excess Deferred Income Taxes - Regulatory Liability	254	(8,999,336)	INT_TOTAL_PLANT	(62,429)	(5,230,812)	(3,680,412)	(25,682)
94	Excess Deferred Income Taxes - Gross up	283	2,427,244	INT_TOTAL_PLANT	16,838	1,410,821	992,657	6,927
95	Total Other Rate Base Items		(23,152,788)		(178,572)	(13,306,445)	(9,344,634)	(323,137)
96	**TOTAL RATE BASE**		188,719,257		501,428	116,597,855	71,433,607	186,368
97	**OPERATION AND MAINTENANCE EXPENSE**							
98	**Production, Storage, and Distribution Expense**							
99	**Mfg. Gas Produc. Plant**							
100	Supervision	710	12,038	PROD_OH	12,038	-	-	-
101	Propane Expenses	717	9,904	PROD_OH	9,904	-	-	-
102	Misc. Intangible Plant	735	24,360	PROD_OH	24,360	-	-	-
103	Subtotal - Mfg. Gas Produc. Plant		46,302		46,302	-	-	-
104	**Maintenance Expenses**							
105	Supervision	740	12,038	PROD_OH	12,038	-	-	-
106	Maintenance of Plant	741	3,460	PROD_OH	3,460	-	-	-
107	Maintenance of Equipment	742	11,687	PROD_OH	11,687	-	-	-
108	Maint of Scada - Production	769	2,704	PROD_OH	2,704	-	-	-
109	Subtotal - Maintenance Expenses		29,889		29,889	-	-	-
110	**Other Gas Expenses**							
111	Other Gas Supply Exp	813	290,076	PROD_OH	290,076	-	-	-
112	Other Gas Supp Exp - Del Serv	813	180,290	DISTRIBUTION	-	180,290	-	-
113	Subtotal - Other Gas Expenses		470,367		290,076	180,290	-	-
114	**Operation Expenses**							
115	System Cntl/Load Dispatching	851.02	2,885	DISTRIBUTION	-	2,885	-	-
116	System Cntl/Load Dispatching - Gas Supply	851.0201	-	-	-	-	-	-
117	Communication System Exp	852	62,100	DISTRIBUTION	-	62,100	-	-
118	Subtotal - Operation Expenses		64,985		-	64,985	-	-

Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Functionalization

Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
119	**Distribution Operation Expenses**							
120	Op Superv-Eng-Gas Distr	870	39,588	INT_874-879	-	14,895	24,694	-
121	Mains & Services	874	793,237	INT_MAIN_SVCS	-	513,348	279,889	-
122	Regulator Station Expense	875	320,571	DISTRIBUTION	-	320,571	-	-
123	Meter & House Regulator	878	1,054,382	ONSITE	-	-	1,054,382	-
124	Customer Installation Exp	879	48,280	ONSITE	-	-	48,280	-
125	Operations Exp Other	880	1,139,382	INT_874-879	-	428,678	710,704	-
126	Subtotal - Distribution Operation Expenses		3,395,440		-	1,277,492	2,117,948	-
127	**Distribution Maintenance Expenses**							
128	Maint Supvervision	885	90,410	INT_887-894	-	39,513	50,897	-
129	Structures & Improvements	886	35,514	INT_887-894	-	15,521	19,993	-
130	Mains	887	81,512	DISTRIBUTION	-	81,512	-	-
131	Measuring & Regulating - Atatew EQ	889	64,637	DISTRIBUTION	-	64,637	-	-
132	Measuring & Regulating - EQ Industry	890	5,322	DISTRIBUTION	-	5,322	-	-
133	Measuring & Regulating - EQ City Gate	891	45,328	DISTRIBUTION	-	45,328	-	-
134	Main Distri SCADA	891.01	40,137	DISTRIBUTION	-	40,137	-	-
135	Services	892	142,056	ONSITE	-	-	142,056	-
136	Meters & House Regulators	893	26,058	ONSITE	-	-	26,058	-
137	Other Equipment	894	1,035	INT_887-894	-	452	582	-
138	Water Heaters & Conv Burn	894.01	137,082	ONSITE	-	-	137,082	-
139	Rented Conv Burn		-	-	-	-	-	-
140	Subtotal - Distribution Maintenance Expenses		669,090		-	292,422	376,668	-
141	**Total Production, Storage, and Distribution Expense**		4,676,073		366,267	1,815,190	2,494,616	-
142	**Customer Accounts, Service, and Sales Expense**							
143	**Customer Accounts Expense**							
144	Meter Reading Expense	902	202,880	ACCTS_SERVICES	-	-	-	202,880
145	Cust Records and Col	903	2,052,586	ACCTS_SERVICES	-	-	-	2,052,586
146	Uncollectible Accts	904	437,750	ACCTS_SERVICES	-	-	-	437,750
147	Subtotal - Customer Accounts Expense		2,693,217		-	-	-	2,693,217
148	**Customer Service & Information Expense**							
149	Customer Assistance - other	908	-	-	-	-	-	-
150	Inf and Instruct Expense	909	73,965	ACCTS_SERVICES	-	-	-	73,965
151	Subtotal - Customer Service & Information Expense		73,965		-	-	-	73,965
152	**Sales Expense**							
153	Advertising Expense	913	70,021	ACCTS_SERVICES	-	-	-	70,021
154	Interest on Customer Deposits		9,371	ACCTS_SERVICES	-	-	-	9,371
155	Subtotal - Sales Expense		79,392		-	-	-	79,392
156	**Total Customer Accounts, Service, and Sales Expense**		2,846,573		-	-	-	2,846,573

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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
157	**Administrative and General Expense**							
158	Administrative and General Salaries	920	11,414	INT_LABOR	514	3,336	5,158	2,405
159	Office Supplies and Exp	921	425,018	INT_LABOR	19,154	124,230	192,088	89,546
160	Outside Service Employed	923	3,909,556	INT_LABOR	176,187	1,142,742	1,766,936	823,691
161	Property Insurance	924	2,931	INT_PLANT	20	1,698	1,213	-
162	Injuries and Damages	925	293,510	INT_LABOR	13,227	85,792	132,653	61,839
163	Employee Pension and Benefits	926	2,201,576	INT_LABOR	99,216	643,509	995,009	463,842
164	Regulatory Commission Exp	928	504,386	INT_RATEBASE	1,340	311,629	190,919	498
165	General Advertising Expense	930	42,897	INT_LABOR	1,933	12,539	19,387	9,038
166	Rents Admin and General	931	23,527	INT_LABOR	1,060	6,877	10,633	4,957
167	Maint General Plant - Equip Shared	932	130,652	INT_GEN_PLANT	799	38,170	89,875	1,808
168	Maint of General Plant	935	6,985	INT_GEN_PLANT	43	2,041	4,805	97
169	Subtotal - Administrative and General Expense		7,552,453		313,493	2,372,562	3,408,678	1,457,720
170	**Total Administrative and General Expense**		7,552,453		313,493	2,372,562	3,408,678	1,457,720
171	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		15,075,099		679,760	4,187,752	5,903,294	4,304,293
172	**Depreciation and Amortization Expense**							
173	**Intangible Plant**							
174	Miscellaneous Intangible Plant, Plant-related	303	-	-	-	-	-	-
175	Miscellaneous Intangible Plant, Customer-related	303	-	-	-	-	-	-
176	Miscellaneous Intangible Plant, Labor-related	303	-	-	-	-	-	-
177	Subtotal - Intangible Plant		-		-	-	-	-
178	**Mfg. Gas Produc. Plant**							
179	Land and Land Rights	304	-	-	-	-	-	-
180	Structures & Improvements	305	931	PROD_OH	931	-	-	-
181	Other Equipment	320	-	-	-	-	-	-
182	LNG Equipment	321	-	-	-	-	-	-
183	Subtotal - Mfg. Gas Produc. Plant		931		931	-	-	-
184	**Other Storage Plant**							
185	Land - Lewiston	360	-	-	-	-	-	-
186	Structures & Improvements	361	4,785	PROD_OH	4,785	-	-	-
187	Gas Holders	362	32,149	PROD_OH	32,149	-	-	-
188	Other Equipment	363	-	-	-	-	-	-
189	Subtotal - Other Storage Plant		36,934		36,934	-	-	-

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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
190	**Distribution Plant**							
191	Land & Land Rights, Other Distr Sys	374.4	-	-	-	-	-	-
192	Land & Land Rights, Right of Way	374.5	-	-	-	-	-	-
193	Structures & Improvements	375	89,348	DISTRIBUTION	-	89,348	-	-
194	Mains	376	5,348,398	DISTRIBUTION	-	5,348,398	-	-
195	M&R Station Equip. - Regulating	378	354,973	DISTRIBUTION	-	354,973	-	-
196	M&R Station Equip. - G	379	1,912	DISTRIBUTION	-	1,912	-	-
197	Services	380	3,653,114	ONSITE	-	-	3,653,114	-
198	Meters	381	246,954	ONSITE	-	-	246,954	-
199	Meter Installations	382	1,099,871	ONSITE	-	-	1,099,871	-
200	House Regulators	383	24,354	ONSITE	-	-	24,354	-
201	Water Heaters/Conversion Burners	386	224,802	ONSITE	-	-	224,802	-
202	Subtotal - Distribution Plant		11,043,726		-	5,794,631	5,249,095	-
203	**General Plant**							
204	Land & Land Rights	389	-	-	-	-	-	-
205	Office Furniture & Equipment	391	30,265	INT_LABOR	1,364	8,846	13,678	6,376
206	Stores Equipment	393	-	-	-	-	-	-
207	Tools, Shop & Garage Equip.	394	25,364	INT_PLANT	170	14,696	10,498	-
208	Power Operated Equip.	396	-	-	-	-	-	-
209	Communication Equip.	397	19,827	INT_PLANT	133	11,488	8,206	-
210	Metscan Communication Equip	397.25	-	-	-	-	-	-
211	ERT Automatic Reading Dev	397.35	74,391	ONSITE	-	-	74,391	-
212	Subtotal - General Plant		149,847		1,667	35,030	106,774	6,376
213	**Amortization Expense**							
214	Amortization Expense	404	816,977	INT_INTANGIBLE	10,345	650,254	108,440	47,938
215	Amortization Expense Adjustments	404	189,288	INT_INTANGIBLE	2,397	150,659	25,125	11,107
216	Amortization Rate Case Costs - NH	407	-	-	-	-	-	-
217	Excess ADIT Flow Back	407	(308,218)	INT_RATEBASE	(819)	(190,429)	(116,666)	(304)
218	Subtotal - Amortization Expense		698,046		11,923	610,484	16,899	58,741
219	**Total Depreciation and Amortization Expense**		11,929,484		51,454	6,440,145	5,372,768	65,117
220	**Taxes**							
221	**Taxes Other Than Income**							
222	Payroll Taxes - FICA	408	224,247	INT_LABOR	10,106	65,546	101,349	47,246
223	Payroll Tax Pro Formas	408	137,672	INT_LABOR	6,204	40,241	62,221	29,006
224	Unemployment Tax - Federal	408.04	1,639	INT_LABOR	74	479	741	345
225	Unemployment Tax - State	408.06	1,135	INT_LABOR	51	332	513	239
226	Property Taxes	408.12	4,728,576	INT_TOTAL_PLANT	32,803	2,748,458	1,933,822	13,494
227	Property Taxes Pro Forma	408.12	617,939	INT_TOTAL_PLANT	4,287	359,173	252,715	1,763
228	Payroll Taxes Capitalized	408.1	(161,795)	INT_LABOR	(7,291)	(47,292)	(73,124)	(34,088)
229	Other Taxes	408.02	73,972	INT_RATEBASE	197	45,703	28,000	73
230	Subtotal - Taxes Other Than Income		5,623,385		46,430	3,212,640	2,306,237	58,079

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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
231	**Income Taxes**							
232	Federal Income Tax	409.01	(485,546)	INT_RATEBASE	(1,290)	(299,989)	(183,788)	(479)
233	State Income Tax	409.02	(1,380,631)	INT_RATEBASE	(3,668)	(853,006)	(522,593)	(1,363)
234	Deferred Federal & State Income Taxes	410.01	3,492,441	INT_RATEBASE	9,279	2,157,761	1,321,951	3,449
235	Subtotal - Income Taxes		1,626,264		4,321	1,004,767	615,570	1,606
236	**Total Taxes**		7,249,649		50,751	4,217,407	2,921,807	59,685
237	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**							
238	**Test Year Expenses at Current Rates**		34,254,233	n/a	781,965	14,845,304	14,197,869	4,429,095
239	**Return on Rate Base**		14,621,110	INT_RATEBASE	38,848	9,033,472	5,534,351	14,439
240	**Gross Up Items**							
241	Tax1		2,107,856	INT_RATEBASE	5,601	1,302,313	797,861	2,082
242	ITem2		-	-	-	-	-	-
243	ITem3		-	-	-	-	-	-
244	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**50,983,199**		**826,413**	**25,181,089**	**20,530,081**	**4,445,616**
245	**INTERNAL ALLOCATION FACTORS**							
246	INT_PLANT		280,684,578		1,880,062	162,628,729	116,175,787	0
247	INT_INTANGIBLE		12,826,347		162,409	10,208,833	1,702,484	752,621
248	INT_MAIN_SVCS		234,769,635		0	151,932,588	82,837,047	0
249	INT_887-894		542,132		0	236,936	305,196	0
250	INT_RATEBASE		188,719,257		501,428	116,597,855	71,433,607	186,368
251	INT_REVREQ		48,875,343		820,813	23,878,776	19,732,220	4,443,534
252	INT_LABOR		4,695,390		211,601	1,372,437	2,122,097	989,255
253	INT_TOTAL_PLANT		301,245,498		2,089,776	175,097,210	123,198,833	859,678
254	INT_874-879		2,216,470		0	833,919	1,382,551	0
255	INT_DIST_PLANT		278,804,516		0	162,628,729	116,175,787	0
256	INT_GEN_PLANT		7,734,572		47,305	2,259,648	5,320,562	107,057

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Line No.	Account Description	FERC Account	Account Balance	Allocation Factor	Indirect Production & O.H.	Distribution	Onsite	Customer Accounts & Services
257	**INDIRECT PRODUCTION AND OVERHEAD SUMMARY**							
258	**LNG Production and Storage**							
259	Return on Assets				38,848			
260	O&M Expenses				76,191			
261	Associated A&G and Overheads				99,499			
262	**Total Production and Storage**				214,538			
263	**Other A&G Expenses (Energy Contracts Charges and Overheads)**							
264	Other Gas Supply Expenses (Acct. 813)				290,076			
265	Associated A&G and Overheads				321,799			
266	Total Other A&G Expenses				611,875			
267	**Total Indirect Production and Overhead**				**826,413**			

Docket No. DG 21-104
Schedule RAJT-4
Summary of Allocated Cost of Service Study Results
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Northern Utilities New Hampshire
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Design Day with Customer Component of Mains
Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
1	**Rate Base**									
2	Plant in Service	$ 301,245,498	$ 170,246,732	$ 6,593,386	$ 51,245,369	$ 6,225,067	$ 36,771,567	$ 7,493,599	$ 11,647,303	$ 11,022,474
3	Accumulated Reserve	(89,373,452)	(52,308,017)	(2,111,513)	(15,148,725)	(1,919,028)	(9,769,917)	(2,152,494)	(3,074,609)	(2,889,149)
4	Other Rate Base Items	(23,152,788)	(13,000,952)	(503,394)	(3,962,675)	(497,283)	(2,864,201)	(601,238)	(889,945)	(833,100)
5	**Total Rate Base**	$ 188,719,257	$ 104,937,763	$ 3,978,479	$ 32,133,969	$ 3,808,756	$ 24,137,449	$ 4,739,867	$ 7,682,750	$ 7,300,225
6	**Revenue at Current Rates**									
7	Rate Schedule Revenue	$ 39,796,841	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624
8	Special Contracts	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
9	Indirect Production & OH Revenue	1,057,890	510,076	6,031	238,849	19,474	98,439	101,838	69,962	13,222
10	Late Payment Revenues	76,773	54,649	1,478	8,359	1,627	6,010	2,313	790	1,546
11	Miscellaneous Revenues	1,070,932	848,963	36,804	99,475	13,662	42,047	7,466	11,035	11,481
12	**Total Revenue at Current Rates**	$ 43,200,249	$ 22,839,504	$ 565,562	$ 7,295,080	$ 1,084,321	$ 5,518,329	$ 1,539,199	$ 1,669,111	$ 2,689,143
13	**Expenses at Current Rates**									
14	O&M and A&G Expenses	$ 15,075,099	$ 9,171,694	$ 380,169	$ 2,528,361	$ 335,891	$ 1,440,748	$ 417,071	$ 427,957	$ 373,208
15	Depreciation and Amortization Expense	11,929,484	6,938,809	281,543	2,013,209	253,539	1,348,390	283,695	415,282	395,017
16	Taxes Other Than Income	5,623,385	3,182,191	123,567	956,858	116,545	683,495	140,674	215,969	204,087
17	Income Taxes	1,626,264	903,494	34,220	276,965	32,798	208,445	40,901	66,375	63,067
18	**Total Expenses at Current Rates**	$ 34,254,233	$ 20,196,188	$ 819,499	$ 5,775,393	$ 738,772	$ 3,681,077	$ 882,340	$ 1,125,583	$ 1,035,380
19	**Operating Income at Current Rates**	$ 8,946,016	$ 2,643,315	$ (253,936)	$ 1,519,687	$ 345,548	$ 1,837,252	$ 656,859	$ 543,528	$ 1,653,763
20	**Current Rate of Return**	4.74%	2.52%	-6.38%	4.73%	9.07%	7.61%	13.86%	7.07%	22.65%
21	**Current Revenue at Equal Rates of Return**									
22	Current Rate of Return	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%	4.74%
23	Operating Income at Current Rates - Equal ROR	$ 8,946,016	$ 4,974,452	$ 188,595	$ 1,523,273	$ 180,550	$ 1,144,208	$ 224,688	$ 364,192	$ 346,059
24	Income Taxes - Equal ROR	1,626,264	904,288	34,284	276,910	32,821	208,001	40,845	66,205	62,909
25	Other Expenses - Equal ROR	32,627,968	19,292,694	785,279	5,498,428	705,975	3,472,633	841,439	1,059,208	972,312
26	**Total Revenue @ Equal Rates of Return**	$ 43,200,249	$ 25,171,434	$ 1,008,158	$ 7,298,612	$ 919,346	$ 4,824,842	$ 1,106,972	$ 1,489,605	$ 1,381,280
27	**Current Class (Subsidies)/Excesses**	$ -	$ (2,331,931)	$ (442,595)	$ (3,532)	$ 164,975	$ 693,487	$ 432,227	$ 179,505	$ 1,307,863

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Summary of Cost of Service Study Results

Line No.	Revenue Requirement Summary	Account Balance	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
28	**Revenue Requirement at Equal Rates of Return**									
29	Required Return	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
30	**Required Operating Income**	$ 14,621,110	$ 8,130,101	$ 308,234	$ 2,489,594	$ 295,085	$ 1,870,060	$ 367,223	$ 595,225	$ 565,588
31	**Expenses at Required Return**									
32	O&M and A&G Expenses	$ 15,075,099	$ 9,171,694	$ 380,169	$ 2,528,361	$ 335,891	$ 1,440,748	$ 417,071	$ 427,957	$ 373,208
33	Depreciation and Amortization Expense	11,929,484	6,938,809	281,543	2,013,209	253,539	1,348,390	283,695	415,282	395,017
34	Taxes Other Than Income	5,623,385	3,182,191	123,567	956,858	116,545	683,495	140,674	215,969	204,087
35	Income Taxes	1,626,264	903,494	34,220	276,965	32,798	208,445	40,901	66,375	63,067
36	Gross Up - Income Taxes	2,107,856	1,171,049	44,354	358,983	42,510	270,172	53,013	86,030	81,744
36	Gross Up - Other Items	-	-	-	-	-	-	-	-	-
37	**Total Expenses at Required Return**	$ 36,362,089	$ 21,367,238	$ 863,853	$ 6,134,376	$ 781,283	$ 3,951,249	$ 935,354	$ 1,211,613	$ 1,117,124
38	**Total Revenue Requirement at Equal Rates of Return**	$ 50,983,199	$ 29,497,339	$ 1,172,087	$ 8,623,970	$ 1,076,368	$ 5,821,309	$ 1,302,577	$ 1,806,838	$ 1,682,712
39	Less Other Revenue	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
40	Less Indirect Production & OH Revenue	826,413	398,466	4,711	186,587	15,213	76,899	79,555	54,653	10,329
41	Less Current Miscellaneous Revenue	1,147,705	903,612	38,282	107,835	15,289	48,057	9,779	11,825	13,026
42	**Total Rate Revenue @ Equal Rates of Return**	$ 47,811,268	$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086
43	**Rate Revenue (Deficiency)/Surplus**	$ (8,014,427)	$ (6,769,445)	$ (607,844)	$ (1,381,153)	$ 3,692	$ (324,520)	$ 214,339	$ (153,035)	$ 1,003,538
44	**Total Base Revenue as Proposed**	$ 47,811,268	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802
45	Special Contracts Revenue	1,197,813	694,032	27,624	202,566	25,332	136,142	30,636	42,210	39,271
46	Indirect Production & OH Revenue	826,413	398,466	4,711	186,587	15,213	76,899	79,555	54,653	10,329
47	Miscellaneous Revenue	1,147,705	903,612	38,282	107,835	15,289	48,057	9,779	11,825	13,026
48	**Total Revenue as Proposed**	$ 50,983,199	$ 27,992,505	$ 763,059	$ 8,261,691	$ 1,183,191	$ 6,287,576	$ 1,657,577	$ 1,887,173	$ 2,950,427
49	**Total Distribution Margin Increase as Proposed**	$ 8,014,427	$ 5,264,611	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177
50	Special Contracts Revenue Change	-	-	-	-	-	-	-	-	-
51	Indirect Production & OH Revenue	(231,477)	(111,610)	(1,320)	(52,263)	(4,261)	(21,539)	(22,283)	(15,308)	(2,893)
52	Miscellaneous Revenue Change	-	-	-	-	-	-	-	-	-
53	**Total Revenue Increase as Proposed**	$ 7,782,951	$ 5,153,001	$ 197,496	$ 966,612	$ 98,870	$ 769,247	$ 118,378	$ 218,062	$ 261,284
54	Precent Total Revenue Change	19.56%	24.86%	40.01%	14.33%	9.65%	14.69%	8.47%	14.11%	9.96%
55	**Operating Income at Proposed Rates**									
56	Income Prior to Taxes	$ 18,355,231	$ 8,699,811	$ (22,220)	$ 2,763,263	$ 477,216	$ 2,814,943	$ 816,138	$ 827,964	$ 1,978,115
57	Less Income Taxes	3,734,121	2,074,543	78,574	635,948	75,308	478,617	93,914	152,405	144,811
58	**Operating Income**	$ 14,621,110	$ 6,625,267	$ (100,794)	$ 2,127,315	$ 401,908	$ 2,336,327	$ 722,224	$ 675,560	$ 1,833,304
59	**Proposed Return**	7.75%	6.3%	-2.5%	6.6%	10.6%	9.7%	15.2%	8.8%	25.1%

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Schedule RAJT-5
Proposed Revenue Allocation by Class
Page 1 of 1

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Proposed Revenue Apportionment

Proposed Class Revenues

		Total System	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52	Special Contracts	Indirect Production & OH	Miscellaneous Revenue
1	Current Revenues	$ 43,200,249	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624	$ 1,197,813	$ 1,057,890	$ 1,147,705
2	% Increase		24.2%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%			
3	Targeted Increase	$ 7,528,387	$ 5,010,047	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177	$ -	$ (231,477)	$ -
4	Targeted Revenue	$ 50,728,636	$ 25,741,830	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802	$ 1,197,813	$ 826,413	$ 1,147,705
5	Allocation of Delta	$ 254,564	$ 254,564										
6	Proposed Increase/ (Decrease)	$ 7,782,951	$ 5,264,611	$ 198,816	$ 1,018,874	$ 103,131	$ 790,786	$ 140,661	$ 233,370	$ 264,177	$ -	$ (231,477)	$ -
7	Proposed Revenue	$ 50,983,199	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802	$ 1,197,813	$ 826,413	$ 1,147,705
8	Resulting Increase % (Dist Margin)	19.6%	25.4%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%			
9	Resulting Increase % with Total Revenues	18.0%	25.4%	40.3%	15.1%	10.1%	15.1%	10.1%	15.1%	10.1%	0.0%	-21.9%	0.0%
10	Proposed Distribution Margin	$ 47,811,268	$ 25,996,394	$ 692,442	$ 7,764,703	$ 1,127,357	$ 6,026,477	$ 1,537,608	$ 1,778,485	$ 2,887,802			
11	Proposed Rate of Return	7.75%	6.31%	-2.53%	6.62%	10.55%	9.68%	15.24%	8.79%	25.11%			
12	Proposed Revenue to Cost Ratio		0.95	0.63	0.96	1.10	1.08	1.30	1.05	1.78			
13	Current Revenue to Cost Ratio		0.75	0.45	0.83	1.00	0.94	1.18	0.91	1.62			

		Total System
14	Rate Margin Increase	8,014,427
15	System Increase (Total Revenue)	18.55%
16	System Increase (Total Distribution Margin)	20.14%

		Total System	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52	Special Contracts	Indirect Production & OH	Miscellaneous Revenue
	Under Current Rates												
17	Current Revenues	$ 43,200,249	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624	$ 1,197,813	$ 1,057,890	$ 1,147,705
18	Current Rate Of Return	4.74%	2.52%	-6.38%	4.73%	9.07%	7.61%	13.86%	7.07%	22.65%			
19	Current Relative Rate of Return	1.00	0.53	(1.35)	1.00	1.91	1.61	2.92	1.49	4.78			
20	Current Revenue to Cost Ratio		0.75	0.45	0.83	1.00	0.94	1.18	0.91	1.62			
21	**Scenario A - Equalized Rate of Return**												
22	Equalized Rate of Return	$ 50,983,199	$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086	$ 1,197,813	$ 826,413	$ 1,147,705
23	Equalized Rate of Return Increase		$ 6,769,445	$ 607,844	$ 1,381,153	$ (3,692)	$ 324,520	$ (214,339)	$ 153,035	$ (1,003,538)			
24	% Change on Dist Margin (Equalized Rate of Return)		32.7%	123.1%	20.5%	-0.4%	6.2%	-15.3%	9.9%	-38.3%			
25	% Change on Total Revenue (Equalized ROR)		32.7%	123.1%	20.5%	-0.4%	6.2%	-15.3%	9.9%	-38.3%	0.0%	0.0%	0.0%
26	**Scenario B - Proportionate to Distribution Margin**												
27	Resulting Revenues		$ 27,501,228	$ 1,101,470	$ 8,126,982	$ 1,020,534	$ 5,560,210	$ 1,182,608	$ 1,698,150	$ 1,620,086	$ 1,197,813	$ 826,413	$ 1,147,705
28	Distribution Margin	$ 39,796,841	$ 20,731,783	$ 493,626	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624			
29	Increase on Distribution Margin		$ 4,175,039	$ 99,408	$ 1,358,499	$ 206,262	$ 1,054,382	$ 281,322	$ 311,161	$ 528,355			
30	% Change on Dist Margin (equal % on Dist Margin)		20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%	20.1%			
31	Resulting Revenues	$ 50,983,199	$ 24,906,823	$ 593,034	$ 8,104,328	$ 1,230,488	$ 6,290,072	$ 1,678,269	$ 1,856,275	$ 3,151,979	$ 1,197,813	$ 826,413	$ 1,147,705

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Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Functional Rate Base									
1	**Indirect Production & O.H.**									
2	Demand	$ 408,158	$ 196,799	$ 2,327	$ 92,154	$ 7,513	$ 37,980	$ 39,291	$ 26,993	$ 5,101
3	Commodity	$ 93,270	$ 44,971	$ 532	$ 21,058	$ 1,717	$ 8,679	$ 8,979	$ 6,168	$ 1,166
4	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 501,428	$ 241,770	$ 2,859	$ 113,212	$ 9,230	$ 46,659	$ 48,270	$ 33,161	$ 6,267
6	**Distribution**									
7	Demand	$ 76,812,163	$ 27,202,195	$ 264,752	$ 13,568,322	$ 880,793	$ 19,025,955	$ 2,786,965	$ 6,752,549	$ 6,330,633
8	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer	$ 39,785,691	$ 30,314,965	$ 1,443,349	$ 5,917,579	$ 939,999	$ 796,158	$ 301,287	$ 35,046	$ 37,308
10	Subtotal	$ 116,597,855	$ 57,517,160	$ 1,708,101	$ 19,485,902	$ 1,820,792	$ 19,822,113	$ 3,088,251	$ 6,787,595	$ 6,367,941
11	**Onsite**									
12	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Customer	$ 71,433,607	$ 46,882,378	$ 2,252,315	$ 12,538,424	$ 1,991,980	$ 4,342,033	$ 1,632,132	$ 869,667	$ 924,677
15	Subtotal	$ 71,433,607	$ 46,882,378	$ 2,252,315	$ 12,538,424	$ 1,991,980	$ 4,342,033	$ 1,632,132	$ 869,667	$ 924,677
16	**Customer Accounts & Services**									
17	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 186,368	$ 296,455	$ 15,204	$ (3,569)	$ (13,247)	$ (73,355)	$ (28,787)	$ (7,673)	$ 1,340
20	Subtotal	$ 186,368	$ 296,455	$ 15,204	$ (3,569)	$ (13,247)	$ (73,355)	$ (28,787)	$ (7,673)	$ 1,340
31	**Total**									
32	Demand	$ 77,220,321	$ 27,398,994	$ 267,079	$ 13,660,476	$ 888,306	$ 19,063,934	$ 2,826,256	$ 6,779,542	$ 6,335,734
33	Commodity	$ 93,270	$ 44,971	$ 532	$ 21,058	$ 1,717	$ 8,679	$ 8,979	$ 6,168	$ 1,166
34	Customer	$ 111,405,666	$ 77,493,798	$ 3,710,869	$ 18,452,434	$ 2,918,733	$ 5,064,835	$ 1,904,632	$ 897,040	$ 963,325
35	**TOTAL RATE BASE**	$ 188,719,257	$ 104,937,763	$ 3,978,479	$ 32,133,969	$ 3,808,756	$ 24,137,449	$ 4,739,867	$ 7,682,750	$ 7,300,225

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Functional Revenue Requirement									
36	**Indirect Production & O.H.**									
37	Demand	$ 186,350	$ 89,851	$ 1,062	$ 42,074	$ 3,430	$ 17,340	$ 17,939	$ 12,324	$ 2,329
38	Commodity	$ 640,064	$ 308,616	$ 3,649	$ 144,513	$ 11,782	$ 59,559	$ 61,616	$ 42,329	$ 8,000
39	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Subtotal	$ 826,413	$ 398,466	$ 4,711	$ 186,587	$ 15,213	$ 76,899	$ 79,555	$ 54,653	$ 10,329
41	**Distribution**									
42	Demand	$ 16,742,400	$ 5,929,139	$ 57,707	$ 2,957,426	$ 191,982	$ 4,147,001	$ 607,462	$ 1,471,823	$ 1,379,859
43	Commodity	$ 180,290	$ 86,929	$ 1,028	$ 40,706	$ 3,319	$ 16,776	$ 17,356	$ 11,923	$ 2,253
44	Customer	$ 8,258,399	$ 6,292,540	$ 299,599	$ 1,228,324	$ 195,118	$ 165,260	$ 62,539	$ 7,275	$ 7,744
45	Subtotal	$ 25,181,089	$ 12,308,609	$ 358,334	$ 4,226,456	$ 390,419	$ 4,329,038	$ 687,356	$ 1,491,020	$ 1,389,857
46	**Onsite**									
47	**Demand**									
47	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Customer	$ 20,530,081	$ 13,362,790	$ 651,400	$ 3,578,824	$ 568,957	$ 1,341,303	$ 498,865	$ 255,592	$ 272,350
50	Subtotal	$ 20,530,081	$ 13,362,790	$ 651,400	$ 3,578,824	$ 568,957	$ 1,341,303	$ 498,865	$ 255,592	$ 272,350
51	**Customer Accounts & Services**									
52	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	Customer	$ 4,445,616	$ 3,420,336	$ 157,068	$ 632,591	$ 101,567	$ 78,054	$ 37,303	$ 7,095	$ 11,602
55	Subtotal	$ 4,445,616	$ 3,420,336	$ 157,068	$ 632,591	$ 101,567	$ 78,054	$ 37,303	$ 7,095	$ 11,602
66	**Total**									
67	Demand	$ 16,928,750	$ 6,018,990	$ 58,769	$ 2,999,500	$ 195,413	$ 4,164,341	$ 625,401	$ 1,484,146	$ 1,382,189
68	Commodity	$ 820,354	$ 395,545	$ 4,677	$ 185,219	$ 15,101	$ 76,335	$ 78,972	$ 54,253	$ 10,253
69	Customer	$ 33,234,095	$ 23,075,666	$ 1,108,067	$ 5,439,740	$ 865,641	$ 1,584,617	$ 598,707	$ 269,962	$ 291,696
70	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**	$ 50,983,199	$ 29,490,202	$ 1,171,513	$ 8,624,458	$ 1,076,155	$ 5,825,294	$ 1,303,080	$ 1,808,361	$ 1,684,138
71	Demand	33.20%	20.41%	5.02%	34.78%	18.16%	71.49%	47.99%	82.07%	82.07%
72	Energy	1.61%	1.34%	0.40%	2.15%	1.40%	1.31%	6.06%	3.00%	0.61%
73	Customer	65.19%	78.25%	94.58%	63.07%	80.44%	27.20%	45.95%	14.93%	17.32%

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Design Day with Customer Component of Mains
Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
	Unit Costs									
74	**Indirect Production & O.H.**									
75	Demand	$ 2.81	$ 3.83	$ 4.65	$ 3.59	$ 4.51	$ 1.06	$ 7.46	$ 2.11	$ 0.43
76	Commodity	$ 8.63	$ 15.38	$ 15.38	$ 13.28	$ 7.99	$ 4.13	$ 12.94	$ 7.19	$ 0.49
77	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	**Distribution**									
79	Demand	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46
80	Commodity	$ 0.00	$ 4.33	$ 4.33	$ 3.74	$ 2.25	$ 1.16	$ 3.65	$ 2.02	$ 0.14
81	Customer	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56	$ 19.56
82	**Onsite**									
83	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Customer	$ 48.61	$ 41.53	$ 42.52	$ 56.98	$ 57.02	$ 158.72	$ 155.99	$ 687.08	$ 687.75
86	**Customer Accounts & Services**									
87	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	Commodity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	Customer	$ 10.53	$ 10.63	$ 10.25	$ 10.07	$ 10.18	$ 9.24	$ 11.66	$ 19.07	$ 29.30
98	**Total - Distribution**									
99	Demand - Distribution	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46	$ 252.46
100	Commodity - Distribution	$ 0.0024	$ 0.0043	$ 0.0043	$ 0.0037	$ 0.0023	$ 0.0012	$ 0.0036	$ 0.0020	$ 0.0001
101	Customer (per cust month)	$ 78.70	$ 71.71	$ 72.33	$ 86.60	$ 86.76	$ 187.51	$ 187.21	$ 725.70	$ 736.61
102	Customer (Onsite/Metering & Cust Acts)	$ 59.14	$ 52.16	$ 52.77	$ 67.05	$ 67.20	$ 167.96	$ 167.66	$ 706.15	$ 717.05
103	Demand & Customer (per cust month)	$ 118.78	$ 90.42	$ 76.16	$ 134.36	$ 106.34	$ 680.29	$ 382.77	$ 4,715.34	$ 4,226.98
104	**BILLING DETERMINANTS**									
105	Demand	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
106	Commodity	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
107	Customers (Number of Bills)	422,304	321,778	15,320	62,812	9,978	8,451	3,198	372	396

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Northern Utilities New Hampshire
External Class Allocation Factors

Line	Allocation Factor	Description	Total	Residential Heat	Residential Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
				R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
1	**DEMAND ALLOCATION FACTORS**										
2	**Design Day**										
3		Design Peak Day	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
4	DESIGN_DAY	Design Peak Day Percent	100%	35.41%	0.34%	17.66%	1.15%	24.77%	3.63%	8.79%	8.24%
5	**CUSTOMER ALLOCATORS**										
6	**Customer Count**										
7		December 2020 Customer Count	35,192	26,815	1,277	5,234	831	704	267	31	33
8	CUSTOMERS	December 2020 Customer Count Percent	100%	76.20%	3.63%	14.87%	2.36%	2.00%	0.76%	0.09%	0.09%
9	**Telemetry Customers**										
10		2020 Telemetered Customers	73	-	-	1	2	16	3	21	30
11	CUST_TELEMETER	2020 Telemetered Customers Percent	100%	0.00%	0.00%	1.37%	2.74%	21.92%	4.11%	28.77%	41.10%
12	**Customers Excluding Telemetered (ERTs)**										
13		2020 Customers excluding Telemetered	35,119	26,815	1,277	5,233	829	688	264	10	3
14	ERTS	2020 Customers excluding Telemetered Percent	100%	76.35%	3.64%	14.90%	2.36%	1.96%	0.75%	0.03%	0.01%
15	**Customer Meters**										
16		Meter Replacement Cost	21,291,856	12,464,988	593,480	3,963,830	629,649	2,110,810	798,784	353,746	376,568
17	METERS	Meter Replacement Cost Percent	100%	58.54%	2.79%	18.62%	2.96%	9.91%	3.75%	1.66%	1.77%
18	**Services Lines**										
19		Services at Current Costs	163,283,766	111,591,172	5,313,054	28,238,845	4,485,702	7,312,260	2,767,147	1,731,925	1,843,662
20	SERVICES	Services at Current Costs Percent	100%	68.34%	3.25%	17.29%	2.75%	4.48%	1.69%	1.06%	1.13%
21	**Write-offs / Uncollectible, Distribution**										
22		2018-2020 Average Write-offs, Distribution	254,119	214,169	6,803	22,634	4,468	-	4,885	-	1,161
23	DIST_UNCOLLECT	2018-2020 Average Write-offs, Distribution %	100%	84.28%	2.68%	8.91%	1.76%	0.00%	1.92%	0.00%	0.46%
24	**Meter Reading (FERC 902)**										
25		Relative Weighting Factor		1.00	1.00	1.02	1.06	1.30	1.14	10.60	13.86
26		Weighted Customers	36,333	26,815	1,277	5,360	877	915	303	329	457
27	METER_READ	Weighted Customers Percent	100%	73.80%	3.51%	14.75%	2.41%	2.52%	0.83%	0.90%	1.26%
28	**Customer Deposits**										
29		Customer Deposits (12/31/2020)	249,403	33,843	523	68,253	23,565	82,404	32,116	8,699	-
30	CUST_DEPOSITS	Customer Deposits (12/31/2020) Percent	100%	13.57%	0.21%	27.37%	9.45%	33.04%	12.88%	3.49%	0.00%

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Schedule RAJT-7
Summary of ACOSS External Allocation Factors
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Northern Utilities New Hampshire
External Class Allocation Factors

Line	Allocation Factor	Description	Total	Residential Heat	Residential Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
				R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
31	**COMMODITY and REVENUE ALLOCATORS**										
32	**Total Volume**										
33		2020 Adjusted Billing Determinants	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
34	TOTAL_VOLUME	2020 Adjusted Billing Determinants Percent	100%	27.06%	0.32%	14.67%	1.99%	19.45%	6.42%	7.94%	22.14%
35	**Sales Volume (excludes Transportation)**										
36		2020 Adjusted Sales Billing Determinants	41,619,185	20,067,257	237,269	9,396,744	766,130	3,872,741	4,006,477	2,752,408	520,161
37	SALES_VOLUME	2020 Adjusted Sales Billing Determinants Percent	100%	48.22%	0.57%	22.58%	1.84%	9.31%	9.63%	6.61%	1.25%
38	**Sales Volume (excludes Transportation) - Allocation of Indirect Production & Overhead**										
39		2020 Adjusted Sales Billing Determinants	41,619,185	20,067,257	237,269	9,396,744	766,130	3,872,741	4,006,477	2,752,408	520,161
40	IND_PROD_OH	2020 Adjusted Sales Billing Determinants Percent	100%	48.22%	0.57%	22.58%	1.84%	9.31%	9.63%	6.61%	1.25%
38	**Test Year Revenue**										
41		2020 Pro Forma Revenue at Current Rates	39,796,840	20,731,783	493,626	6,745,829	1,024,226	5,235,691	1,396,947	1,545,114	2,623,624
42	BASE_REVENUE	2020 Pro Forma Revenue at Current Rates Percent	100%	52.09%	1.24%	16.95%	2.57%	13.16%	3.51%	3.88%	6.59%
38	**Late Fees**										
43		2018-2020 Avg Late Fees	69,249	49,293	1,334	7,540	1,468	5,421	2,086	713	1,394
44	LATE_FEES	2018-2020 Avg Late Fees Percent	100%	71.18%	1.93%	10.89%	2.12%	7.83%	3.01%	1.03%	2.01%
45	**Miscellaneous Service Revenue**										
46		Other Revenue	852,295	727,388	32,194	62,248	9,249	14,084	1,975	2,134	3,023
47	MISC_REVENUE	Other Revenue Percent	100%	85.34%	3.78%	7.30%	1.09%	1.65%	0.23%	0.25%	0.35%
48	**Water Heater and Burner Conversion Revenue**										
49		Water Heater and Burner Conversion Revenue	249,162	204,026	15,142	18,735	3,119	8,140	-	-	-
50	HEAT_CONV_REV	Water Heater and Burner Conversion Revenue Percent	100%	81.88%	6.08%	7.52%	1.25%	3.27%	0.00%	0.00%	0.00%
51	**Direct Assignment to Low Income**										
52		Customer Deposits	1	1	-	-	-	-	-	-	-
53	RES_LOW_INCOME	Customer Deposits Percent	100%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
54	***FUNCTIONAL PLANT ALLOCATORS***										
55	**Misc. Intangible Plant Split**										
56	Plant Related	Account 303 related to plant	1.7%								
57	Customer Related	Account 303 related to billing, meter reading, customer accounts	70.5%								
58	Labor Related	Account 303 related to operations, IT, finance accounting, employees	27.9%								

Northern Utilities New Hampshire

Description of ACOSS Functionalization and Classification of Accounts

FERC	Description	Functionalization	Classification
Intangible Plant			
301-303	*Intangible Plant*		
303	Miscellaneous Intangible Plant, Plant-related	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
303	Miscellaneous Intangible Plant, Customer-related	Distribution	Customer-related
303	Miscellaneous Intangible Plant, Labor-related	Labor expense	Labor expense
Manufactured Gas Production Plant and Expenses			
304-321	*Other Production Plant*		
304	Land and Land Rights	Indirect Production and OH	Demand-related
305	Structures & Improvements	Indirect Production and OH	Demand-related
320	Other Equipment	Indirect Production and OH	Demand-related
321	LNG Equipment	Indirect Production and OH	Demand-related
710-735	*Manufactured Gas Production Plant Expenses*		
710	Supervision	Indirect Production and OH	Demand-related
717	Propane Expenses	Indirect Production and OH	Demand-related
735	Misc. Intangible Plant	Indirect Production and OH	Demand-related
Other Storage Plant, Other Gas & Operation Expenses			
360-369	*Other Storage Plant*		
360	Land-Lewiston	Indirect Production and OH	Demand-related
361	Structures & Improvements	Indirect Production and OH	Demand-related
362	Gas Holders	Indirect Production and OH	Demand-related
363	Other Equipment	Indirect Production and OH	Demand-related

FERC	Description	Functionalization	Classification
740-769	*Maintenance Expenses*		
740	Supervision	Indirect Production and OH	Demand-related
741	Maintenance of Plant	Indirect Production and OH	Demand-related
742	Maintenance of Equipment	Indirect Production and OH	Demand-related
769	Maintenance of Scada - Production	Indirect Production and OH	Demand-related
800-813	*Other Gas Expenses*		
813	Other Gas Expenses	Indirect Production and OH	Commodity-related
813	Other Gas Supply Expenses – Del Serv	Distribution	Commodity-related
851-852	*Operation Expenses*		
851	System Control/Load Dispatching	Distribution	Demand-related
851	System Control//Load Dispatching – Gas Supply	Indirect Production and OH	Demand-related
852	Communication System Expense	Distribution	Demand-related
Distribution Plant and Expenses			
374-386	*Distribution Plant*		
374	Land and Land Rights	Distribution	Demand-related
375	Structures and Improvements	Distribution	Demand-related
376	Mains	Distribution	Demand and Customer based on zero-intercept analysis
378	M&R Station Equipment - Regulating	Distribution	Demand-related
379	M&R Station Equipment - Gate	Distribution	Demand-related
380	Services	Onsite	Customer-related
381	Meters	Onsite	Customer-related
382	Meter Installations	Onsite	Customer-related
383	House Regulators	Onsite	Customer-related
386	Water Heaters/Conversion Burners	Onsite	Customer-related

FERC	Description	Functionalization	Classification
870-894	*Distribution Expenses*		
870	Op Supervision-Engineering-Gas Distribution	Accts 874-879	Accts 874-879
874	Mains & Services	Mains and Services Plant	Mains and Services Plant
875	Regulator Station Expense	Distribution	Demand-related
878	Meter & House Regulator	Onsite	Customer-related
879	Customer Installation Exp	Onsite	Customer-related
880	Operations Exp Other	Accts 874-879	Accts 874-879
885	Maintenance Supervision	Accts 887-894	Accts 887-894
886	Structures & Improvements	Accts 887-894	Accts 887-894
887	Mains	Distribution	Demand and Customer based on zero-intercept analysis
889	Measuring & Regulating - Atatew EQ	Distribution	Demand-related
890	Measuring & Regulating - EQ Industry	Distribution	Demand-related
891	Measuring & Regulating - EQ City Gate	Distribution	Demand-related
891	Main Distribution SCADA	Distribution	Demand-related
892	Services	Onsite	Customer-related
893	Meters & House Regulators	Onsite	Customer-related
894	Other Equipment	Accts 874-879	Accts 874-879
894	Water Heaters & Conv Burn	Onsite	Customer-related
General Plant			
389-399	*General & Common Plant*		
389	Land & Land Rights	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
391	Office Furniture & Equipment	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
393	Stores Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
394	Tools, Shop & Garage Equip.	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
396	Power Operated Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
397	Communication Equipment	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
397.3	Metscan Communication Equipment	Onsite	Customer-related
397.4	ERT Automatic Reading Devices	Onsite	Customer-related
Depreciation Reserve			
108	Accumulated Depreciation	Corresponding plant accts.	Corresponding plant accts.
Other Rate Base Items			
154	Materials and Supplies	Distribution Plant	Distribution Plant
165	Prepayments	Distribution Plant	Distribution Plant
131	Cash Working Capital	Total plant in service	Total plant in service
235	Customer Deposits	Accounts & Services	Customer-related
283	Net Deferred Income Taxes	Total plant in service	Total plant in service
254	Excess Deferred Income Taxes	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	Accounts & Services	Customer-related
Administrative and General Expenses			
920	Administrative & General Salaries	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
921	Office Supplies & Expenses	Labor expense	Labor expense
923	Outside Services Employed	Labor expense	Labor expense
924	Property Insurance	Production, Storage, and Distribution Plant	Production, Storage, and Distribution Plant
925	Injuries and Damages	Labor expense	Labor expense
926	Employee Pensions and Benefits	Labor expense	Labor expense
928	Regulatory Commission Expenses	Rate Base	Rate Base
930	General/Miscellaneous Expenses	Labor expense	Labor expense
931	Rents	Labor expense	Labor expense
932	Maintenance of General Plant – Equip Shared	General Plant	General Plant
935	Maintenance of General Plant	General Plant	General Plant
Depreciation and Amortization Expenses			
403	Depreciation Expense	Corresponding plant accts.	Corresponding plant accts.
404-407	Amortization Expense	Intangible Plant	Intangible Plant
407	Excess ADIT Flow Back	Rate Base	Rate Base
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	Payroll Taxes - Capitalized	Labor expense	Labor expense
408	Other Taxes	Rate Base	Rate Base
Income Taxes			
409-410	Income Taxes	Rate base	Rate base

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Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Customer Component of Mains

Minimum System Summary

Material	Quantity	Cost 2020	Minimum Size Cost (2020)	Customer Component	Customer Component Percentage
Plastic	2,572,194	$149,782,247	$32.58	$83,795,365	55.9%
Steel	421,064	$70,715,971	$32.58	$13,717,152	19.4%
Total	**2,993,258**	**$220,498,219**		**$97,512,517**	**44.2%**

Zero-Intercept Summary

Material	Quantity	Cost 2020	Zero-Intercept Cost (2020)	Customer Component	Customer Component Percentage
Plastic	2,572,194	$149,782,247	$25.21	$64,845,019	43.3%
Steel	421,064	$70,715,971	$25.21	$10,615,014	15.0%
Total	**2,993,258**	**$220,498,219**		**$75,460,033**	**34.2%**
				Rounded Customer Component	**34%**

ADJUSTED MINIMUM SYSTEM

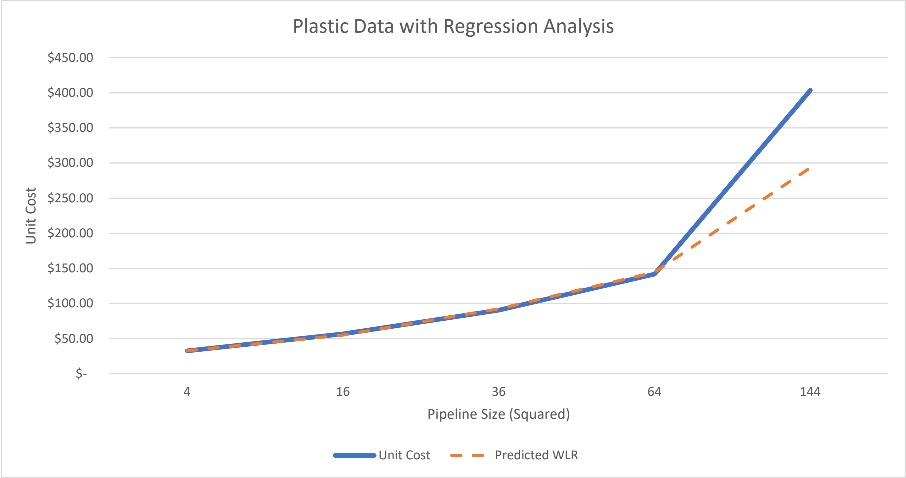
Minimum System Cost	$97,512,517
	x
Minimum System Serving Design Day Demand (%)	6.11%
	=
Minimum System Serving Design Day Demand (Total)	$ 5,954,778.30
Remaining Customer Portion	$ 91,557,738
	/
Total Plastic & Steel Cost	$220,498,219
	=
	41.52%

Description	Amount	
2 Inch Main	2	
Pipe Diameter Squared	4	Line 1 squared
Constant	0.372	
PSIG	40	
Cubic Feet of Capacity per Thousand Feet	59.52	Multiply lines 2 - 4
Feet in Mile (1,000s)	5.28	
Cubic Feet of Capacity per Mile	314.27	Line 5 * Line 6
Hours in Day	24	
Cubic Feet of Capacity per Mile per Day	7,542	Line 7 * Line 8
Total Design Day (in Ccf)	699,920	*Design Day from Company
Total Customers	35,194	
Ccf Per Customer on Design Day	19.89	Line 10 / Line 11
Customers Per Mile	62.10	Line 20
Capacity (Ccf) Required on Design Day per Mile	1235.1	Line 12 * Line 13
Cubic Feet of Capacity per Mile	7,542	Line 9
Ccf of Capacity per Mile	75.42	Line 15 / 100
Portion of Required Capacity Met by 2 Inch Main Capacity	6.11%	Line 16 / Line 14
Miles of Main from 2020 DOT Report	566.69	
Total Customers	35,194	
Customers Per Mile	62.10	

Northern Utilities New Hampshire
12 Months Ended December 31, 2020
Zero-Intercept Mains Study

Plastic Data	Used as X-value for Regression		Weights Used for Regression				Equation: 25.208+1.862x Weighted Linear Regression
Size (Inches)	Size (Inches-Squared)	GIS footage	% Total Footage	Acct. Dollars	2020$	Unit Cost	Predicted WLR
2	4	1,199,189	47.24460%	$ 25,998,228	$ 39,066,445	$ 32.58	32.656
4	16	634,672	25.00426%	$ 25,161,778	$ 36,055,758	$ 56.81	55
6	36	508,384	20.02888%	$ 32,129,456	$ 46,029,660	$ 90.54	92.24
8	64	193,207	7.61182%	$ 24,779,188	$ 27,416,116	$ 141.90	144.376
12	144	2,803	0.11044%	$ 967,760	$ 1,131,176	$ 403.54	293.336
Total		2,538,256	100.00%	$ 109,036,410	$ 149,699,156	$ 725.37	

```
#Weighted Linear Regression Formula
weighted_regression
##
## Call:
## lm(formula = Plastic_UnitCost ~ Size_Squared, data = Plastic_DF,
##     weights = Plastic_Weights)
##
## Coefficients:
##  (Intercept)  Size_Squared
##       25.208         1.862
#Regression Summary
summary(weighted_regression)
##
## Call:
## lm(formula = Plastic_UnitCost ~ Size_Squared, data = Plastic_DF,
##     weights = Plastic_Weights)
##
## Weighted Residuals:
##        1        2        3        4        5
## -0.05539  0.90138 -0.76773 -0.69121  3.66003
##
## Coefficients:
##              Estimate Std. Error t value Pr(>|t|)
## (Intercept)   25.2081     3.1717   7.948 0.004155 **
## Size_Squared   1.8625     0.1229  15.152 0.000624 ***
## ---
## Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
##
## Residual standard error: 2.257 on 3 degrees of freedom
## Multiple R-squared:  0.9871, Adjusted R-squared:  0.9828
## F-statistic: 229.6 on 1 and 3 DF,  p-value: 0.0006242
```



Steel Data	Used as X-value for Regression		Weights Used for Regression				Equation: 19.92+3.37x Weighted Linear Regression
Size (Inches)	Size (Inches-Squared)	GIS footage	% Total Footage	Acct. Dollars	2020$	Unit Cost	Predicted WLR
2	4	37,133	8.94%	$ 1,137,562	$ 5,750,794	$ 154.87	33.39489
4	16	97,838	23.54%	$ 2,743,699	$ 10,973,455	$ 112.16	73.83427
6	36	87,630	21.09%	$ 2,578,887	$ 9,787,549	$ 111.69	141.23322
8	64	175,766	42.30%	$ 11,984,562	$ 30,987,019	$ 176.30	235.59176
10	100	1,853	0.45%	$ 207,703	$ 703,927	$ 379.87	356.90988
12	144	15,326	3.69%	$ 10,690,515	$ 12,450,031	$ 812.36	505.18758
Total		415,545	100.00%	$ 29,342,928	$ 70,652,775	$ 1,747.26	

```
#Weighted Linear Regression Formula
weighted_regression
##
## Call:
## lm(formula = Steel_UnitCost ~ Size_Squared, data = Steel_DF,
##     weights = Steel_Weights)
##
## Coefficients:
##  (Intercept)  Size_Squared
##        19.92          3.37
#Regression Summary
summary(weighted_regression)
##
## Call:
## lm(formula = Steel_UnitCost ~ Size_Squared, data = Steel_DF,
##     weights = Steel_Weights)
##
## Weighted Residuals:
##       1       2       3       4       5       6
##  36.313  18.597 -13.566 -38.563   1.533  58.991
##
## Coefficients:
##              Estimate Std. Error t value Pr(>|t|)
## (Intercept)    19.915     74.113   0.269   0.8014
## Size_Squared    3.370      1.382   2.439   0.0713 .
## ---
## Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
##
## Residual standard error: 41.29 on 4 degrees of freedom
## Multiple R-squared:  0.5979, Adjusted R-squared:  0.4974
## F-statistic: 5.948 on 1 and 4 DF,  p-value: 0.07129
```

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Marginal Cost Summary

A	B	C	D	E	F	G	H	I	J	K	L
Line	FERC A/C	Description	Total System	Residential Heat R-5, R-10	Residentail Non-Heat R-6, R-11	High Winter Small G-40, T-40	Low Winter Small G-50, T-50	High Winter Medium G-41, T-41	Low Winter Medium G-51, T-51	High Winter Large G-42, T-42	Low Winter Large G-52, T-52
1	**MARGINAL COST BASED REVENUE REQUIREMENTS REPORT**										
2		**Demand Related Carrying Costs**									
3	376	Reinforcement/Pipe Replacement	$ 9,985,255	$ 3,536,170	$ 34,417	$ 1,763,824	$ 114,499	$ 2,473,293	$ 362,294	$ 877,803	$ 822,955
4	376	Mains Extension - Demand Component	$ 7,789,012	$ 2,758,394	$ 26,847	$ 1,375,874	$ 89,315	$ 1,929,296	$ 282,608	$ 684,731	$ 641,948
5		Subtotal: Demand Related Carrying Costs	$ 17,774,267	$ 6,294,564	$ 61,263	$ 3,139,698	$ 203,815	$ 4,402,589	$ 644,901	$ 1,562,534	$ 1,464,903
6		**Demand Related O&M Costs**									
7	920-935	A&G Expense - Demand Related	$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
8		Subtotal: Demand O&M Costs	$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
9		**Total: Demand Related Costs**	**$ 19,920,546**	**$ 7,054,645**	**$ 68,661**	**$ 3,518,823**	**$ 228,426**	**$ 4,934,211**	**$ 722,774**	**$ 1,751,213**	**$ 1,641,793**
10		**Customer Related Carrying Costs**									
11	376	Mains Extension - Customer Component	$ 5,171,273	$ 3,940,285	$ 187,604	$ 769,156	$ 122,179	$ 103,483	$ 39,161	$ 4,555	$ 4,849
12	380	Services	$ 15,506,102	$ 10,597,159	$ 504,550	$ 2,681,678	$ 425,981	$ 694,402	$ 262,780	$ 164,471	$ 175,082
13	381-383	Meters, Installations, Regulators	$ 2,944,304	$ 1,723,697	$ 82,068	$ 548,131	$ 87,070	$ 291,889	$ 110,458	$ 48,917	$ 52,073
14		Subtotal: Demand Related Carrying Costs	$ 18,450,406	$ 12,320,857	$ 586,618	$ 3,229,808	$ 513,051	$ 986,292	$ 373,238	$ 213,388	$ 227,155
15		**Customer Related O&M Costs**									
16	902	Meter Reading Expenses	$ 202,880	$ 149,729	$ 7,129	$ 29,930	$ 4,899	$ 5,111	$ 1,694	$ 1,835	$ 2,554
17	903	Customer Records & Collection Expenses	$ 2,052,586	$ 1,563,982	$ 74,464	$ 305,294	$ 48,496	$ 41,075	$ 15,544	$ 1,808	$ 1,925
18	904	Uncollectible Accounts	$ 437,750	$ 368,931	$ 11,718	$ 38,990	$ 7,696	$ -	$ 8,415	$ -	$ 2,000
19	908	Customer Assistance Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	909	Informational and Instructional Advertising Exp.	$ 73,965	$ 56,358	$ 2,683	$ 11,001	$ 1,748	$ 1,480	$ 560	$ 65	$ 69
21	920-935	Customer A&G Costs	$ 5,092,681	$ 3,418,714	$ 166,346	$ 849,158	$ 135,185	$ 304,929	$ 112,969	$ 50,554	$ 54,825
22		Subtotal: Customer O&M Costs	$ 7,859,863	$ 5,557,714	$ 262,341	$ 1,234,374	$ 198,023	$ 352,595	$ 139,182	$ 54,261	$ 61,373
23		**Total: Customer Related Costs**	**$ 26,310,269**	**$ 17,878,570**	**$ 848,959**	**$ 4,464,182**	**$ 711,074**	**$ 1,338,886**	**$ 512,420**	**$ 267,649**	**$ 288,528**
24		**Total LRIC Based Revenue Requirement**	**$ 46,230,815**	**$ 24,933,216**	**$ 917,620**	**$ 7,983,005**	**$ 939,500**	**$ 6,273,097**	**$ 1,235,195**	**$ 2,018,862**	**$ 1,930,321**
25		**Actual Revenue Requirement**	**$ 50,983,199**								
26		**True-up Factor**	**1.1028**								
27		**Allocated Actual Revenue Requirement**	**$ 50,983,199**	**$ 27,496,273**	**$ 1,011,948**	**$ 8,803,633**	**$ 1,036,077**	**$ 6,917,952**	**$ 1,362,169**	**$ 2,226,395**	**$ 2,128,752**
28		**Revenue to Cost Ratio**	0.85	0.83	0.56	0.83	1.05	0.80	1.13	0.75	1.27

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Marginal Cost Summary

A	B	C	D	E	F	G	H	I	J	K	L
				Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
Line	FERC A/C	Description	Total System	R-5, R-10	R-6, R-11	G-40, T-40	G-50, T-50	G-41, T-41	G-51, T-51	G-42, T-42	G-52, T-52
29	**MARGINAL UNIT COST REPORT**										
30		**Demand Related Carrying Costs**									
31	376	Reinforcement/Pipe Replacement	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57	$ 150.57
32	376	Mains Extension - Demand Component	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45	$ 117.45
33		Subtotal: Demand Related Carrying Costs	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02	$ 268.02
34		**Demand Related O&M Costs**									
35	920-935	A&G Expense - Demand Related	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
36		Subtotal: Demand O&M Costs	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
37		**Total: Demand Related Costs**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**	**$ 300.38**
38		Monthly Costs	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**	**$ 25.03**
39		**Customer Related Carrying Costs**									
	376	Mains Extension - Customer Component	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94	$ 146.94
40	380	Services	$ 440.61	$ 395.20	$ 395.20	$ 512.32	$ 512.32	$ 986.04	$ 986.04	$ 5,305.51	$ 5,305.51
41	381-383	Meters, Installations, Regulators	$ 83.66	$ 64.28	$ 64.28	$ 104.72	$ 104.72	$ 414.48	$ 414.48	$ 1,577.97	$ 1,577.97
42		Subtotal: Customer Related Carrying Costs	$ 524.28	$ 459.48	$ 459.48	$ 617.04	$ 617.04	$ 1,400.52	$ 1,400.52	$ 6,883.48	$ 6,883.48
43		**Customer Related O&M Costs**									
44	902	Meter Reading Expenses	$ 5.76	$ 5.58	$ 5.58	$ 5.72	$ 5.89	$ 7.26	$ 6.36	$ 59.18	$ 77.40
45	903	Customer Records & Collection Expenses	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33
46	904	Uncollectible Accounts	$ 12.44	$ 13.76	$ 9.18	$ 7.45	$ 9.26	$ -	$ 31.58	$ -	$ 60.60
47	908	Customer Assistance Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	909	Informational and Instructional Advertising Exp.	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10
49	920-935	Customer A&G Costs	$ 144.71	$ 127.49	$ 130.29	$ 162.23	$ 162.59	$ 432.99	$ 423.90	$ 1,630.76	$ 1,661.37
50		Subtotal: Customer O&M Costs	$ 223.34	$ 207.26	$ 205.48	$ 235.82	$ 238.16	$ 500.68	$ 522.26	$ 1,750.37	$ 1,859.79
51		**Total: Customer Related Costs**	**$ 747.62**	**$ 666.74**	**$ 664.96**	**$ 852.87**	**$ 855.20**	**$ 1,901.20**	**$ 1,922.78**	**$ 8,633.85**	**$ 8,743.27**
52		Monthly Costs	$ 62.30	$ 55.56	$ 55.41	$ 71.07	$ 71.27	$ 158.43	$ 160.23	$ 719.49	$ 728.61

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
Plant Investment

A	B	C	D	E	F	G	H	I	J	K	L	M
No.	FERC A/C	Description	Units	Total	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
1		**Billing Determenants**										
2		No. of Customers		35,192	26,815	1,277	5,234	831	704	267	31	33
3		Design Day Capacity	dt	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466
4		Throughput	therms	74,152,109	20,067,257	237,269	10,880,833	1,474,573	14,423,832	4,761,300	5,889,772	16,417,274
5		Revenue		$ 43,200,249	$ 22,793,730	$ 561,877	$ 7,298,212	$ 1,082,956	$ 5,543,884	$ 1,542,422	$ 1,678,879	$ 2,698,288
6		**Demand Related Additions**										
7	376	Reinforcement/Pipe Replacement										
8		Investment per unit capacity	$/dt		$1,664	$1,664	$1,664	$1,664	$1,664	$1,664	$1,664	$1,664
9		Class investment	$	$ 110,375,535	$39,088,299	$380,437	$19,497,053	$1,265,659	$27,339,419	$4,004,740	$9,703,101	$9,096,828
10		ECCR	%		9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
11		Annual Carrying Charge	$	$ 9,985,255	$3,536,170	$34,417	$1,763,824	$114,499	$2,473,293	$362,294	$877,803	$822,955
12		Unit Annual Carrying Costs	$/dt		$150.57	$150.57	$150.57	$150.57	$150.57	$150.57	$150.57	$150.57
13	376	Mains Extension - Demand Component										
14		Investment per unit capacity	$/dt		$1,298	$1,298	$1,298	$1,298	$1,298	$1,298	$1,298	$1,298
15		Class investment	$	$ 86,098,596	$30,490,884	$296,760	$15,208,705	$987,279	$21,326,153	$3,123,903	$7,568,918	$7,095,994
16		ECCR			9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
17		Annual Carrying Charge	$	$ 7,789,012	$2,758,394	$26,847	$1,375,874	$89,315	$1,929,296	$282,608	$684,731	$641,948
18		Unit Annual Carrying Costs	$/dt		$117.45	$117.45	$117.45	$117.45	$117.45	$117.45	$117.45	$117.45
19		**Customer Related Additions**										
20	376	Mains Extension - Customer Component										
21		Investment per customer	$/Cust		$1,624	$1,624	$1,624	$1,624	$1,624	$1,624	$1,624	$1,624
22		Class investment	$	$ 57,162,494	$43,555,332	$2,073,747	$8,502,142	$1,350,554	$1,143,888	$432,877	$50,353	$53,602
23		ECCR			9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%	9.05%
24		Annual Carrying Charge	$	$ 5,171,273	$3,940,285	$187,604	$769,156	$122,179	$103,483	$39,161	$4,555	$4,849
25		Unit Annual Carrying Costs	$/Cust		$146.94	$146.94	$146.94	$146.94	$146.94	$146.94	$146.94	$146.94
26	380	Services										
27		Investment per customer	$/Cust		$4,161.55	$4,161.55	$5,394.93	$5,394.93	$10,383.29	$10,383.29	$55,868.54	$55,868.54
28		Class investment	$	$ 163,283,766	$111,591,172	$5,313,054	$28,238,845	$4,485,702	$7,312,260	$2,767,147	$1,731,925	$1,843,662
29		ECCR			9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
30		Annual Carrying Charge	$	$ 15,506,102	$10,597,159	$504,550	$2,681,678	$425,981	$694,402	$262,780	$164,471	$175,082
31		Unit Annual Carrying Costs	$/Cust		$395.20	$395.20	$512.32	$512.32	$986.04	$986.04	$5,305.51	$5,305.51
32	381-383	Meters, Installations, Regulators										
33		Investment per customer	$/Cust		$464.85	$464.85	$757.27	$757.27	$2,997.32	$2,997.32	$11,411.16	$11,411.16
34		Class investment	$	$ 21,291,856	$12,464,988	$593,480	$3,963,830	$629,649	$2,110,810	$798,784	$353,746	$376,568
35		ECCR			13.83%	13.83%	13.83%	13.83%	13.83%	13.83%	13.83%	13.83%
36		Annual Carrying Charge	$	$ 2,944,304	$1,723,697	$82,068	$548,131	$87,070	$291,889	$110,458	$48,917	$52,073
37		Unit Annual Carrying Costs	$/Cust		$64.28	$64.28	$104.72	$104.72	$414.48	$414.48	$1,577.97	$1,577.97

Northern Utilities New Hampshire
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Plant Investment

A	B	C	D	E	F	G	H	I	J	K	L	M
No.	FERC A/C	Description	Units	Total	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
38		**General Plant**										
39	389-398	Demand Related General Plant										
40		General Plant - ECOSS Demand Allocation		$ 1,951,305	$ 691,033	$ 6,726	$ 344,684	$ 22,375	$ 483,328	$ 70,799	$ 171,539	$ 160,821
41		Less: Accumulated Depreciation		$ (1,306,916)	$ (462,830)	$ (4,505)	$ (230,857)	$ (14,986)	$ (323,716)	$ (47,419)	$ (114,891)	$ (107,712)
42		Net General Plant - Demand Allocation		$ 644,389	$ 228,203	$ 2,221	$ 113,827	$ 7,389	$ 159,612	$ 23,380	$ 56,648	$ 53,109
43		Return on Ratebase (Pre Tax)			7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
44		Return on Ratebase (Pre Tax)		$ 49,924	$ 17,680	$ 172	$ 8,819	$ 572	$ 12,366	$ 1,811	$ 4,389	$ 4,115
45		Depreciation Expence		$ 30,626	$ 10,846	$ 106	$ 5,410	$ 351	$ 7,586	$ 1,111	$ 2,692	$ 2,524
46		Annual Carrying Charge	$	$ 80,550.43	$ 28,526.06	$ 277.64	$ 14,228.66	$ 923.66	$ 19,951.90	$ 2,922.60	$ 7,081.18	$ 6,638.73
47		Unit Annual Carrying Costs	$/kW		$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21	$1.21
48	389-398	General Plant - Customer Related										
49		General Plant - ECOSS Customer Allocation		$ 5,735,962	$ 4,103,207	$ 196,178	$ 884,617	$ 143,215	$ 209,208	$ 74,270	$ 55,299	$ 69,967
50		Less: Accumulated Depreciation		$ (4,303,307)	$ (3,073,933)	$ (146,885)	$ (655,956)	$ (106,916)	$ (155,768)	$ (54,159)	$ (47,692)	$ (61,999)
51		Net General Plant - Demand Allocation		$ 1,432,655	$ 1,029,274	$ 49,293	$ 228,661	$ 36,299	$ 53,440	$ 20,111	$ 7,607	$ 7,969
52		Return on Ratebase (Pre Tax)			7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%	7.75%
53		Return on Ratebase (Pre Tax)		$ 110,996	$ 79,743	$ 3,819	$ 17,716	$ 2,812	$ 4,140	$ 1,558	$ 589	$ 617
54		Depreciation Expence		$ 117,554	$ 85,854	$ 4,110	$ 18,371	$ 2,916	$ 3,904	$ 1,470	$ 457	$ 473
55		Annual Carrying Charge	$	$ 228,550	$ 165,597	$ 7,929	$ 36,087	$ 5,728	$ 8,045	$ 3,028	$ 1,046	$ 1,091
56		Unit Annual Carrying Costs	$/Cust		$6.18	$6.21	$6.89	$6.89	$11.42	$11.36	$33.74	$33.05

Northern Utilities New Hampshire
2021 Rate Case Gas Marginal Cost of Service Study
O&M Expense

A	B	C	D	E	F	G	H	I	J	K	L	M
No.	FERC A/C	Description	Units	Total	Residential Heat	Residentail Non-Heat	High Winter Small	Low Winter Small	High Winter Medium	Low Winter Medium	High Winter Large	Low Winter Large
1		**Customer Related O&M**										
2	902	Meter Reading Expenses										
3		Meter Reading Expenses			$ 149,729	$ 7,129	$ 29,930	$ 4,899	$ 5,111	$ 1,694	$ 1,835	$ 2,554
4		Expenses per customer			$ 5.58	$ 5.58	$ 5.72	$ 5.89	$ 7.26	$ 6.36	$ 59.18	$ 77.40
5	903	Customer Records & Collection Expenses										
6		Customer Records & Collection Expenses			$ 1,563,982	$ 74,464	$ 305,294	$ 48,496	$ 41,075	$ 15,544	$ 1,808	$ 1,925
7		Expenses per customer			$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33	$ 58.33
8	904	Uncollectible Accounts										
9		Uncollectible Accounts			$ 368,931	$ 11,718	$ 38,990	$ 7,696	$ -	$ 8,415	$ -	$ 2,000
10		Expenses per customer			$ 13.76	$ 9.18	$ 7.45	$ 9.26	$ -	$ 31.58	$ -	$ 60.60
11	908	Customer Assistance Expenses										
12		Customer Assistance Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Expenses per customer			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	909	Informational and Instructional Advertising Exp.										
15		Informational and Instructional Advertising Exp.			$ 56,358	$ 2,683	$ 11,001	$ 1,748	$ 1,480	$ 560	$ 65	$ 69
16		Expenses per customer			$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.10
17	920-935	A&G Expense - Customer Related										
18		A&G Expense - Customer Allocation			$ 3,418,714	$ 166,346	$ 849,158	$ 135,185	$ 304,929	$ 112,969	$ 50,554	$ 54,825
19		Expenses per customer			$ 127.49	$ 130.29	$ 162.23	$ 162.59	$ 432.99	$ 423.90	$ 1,630.76	$ 1,661.37
20		**Demand Related O&M**										
21	920-935	A&G Expense - Demand Related										
22		A&G Expense - Demand Allocation		$ 2,146,279	$ 760,081	$ 7,398	$ 379,125	$ 24,611	$ 531,622	$ 77,873	$ 188,679	$ 176,890
23		Expenses per unit Demand		32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36	$ 32.36
24		**Billing Determinants**										
25		No. of Customers	count	35,192	26,815	1,277	5,234	831	704	267	31	33
26		Design Day Capacity	dt	66,317	23,486	229	11,714	760	16,426	2,406	5,830	5,466

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Northern Utilities New Hampshire
Revenue Proof and Rate Design
Test Year: January 1, 2020 Through December 31, 2020

					Adjustments			Pro Forma at Current Rates		Pro Forma Proposed Rates		
Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Normalization & Annualization Adjustments (bills or therms)	Weather Normalization & Annualization Revenue Adjustment	R-10 Rate Change Annualization	2020 Adjusted Billing Determinants (bills or therms)	2020 Adjusted Base Year Revenue ("Margin")	Projected Billing Determinants (bills or therms)	Proposed Rate	Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D) [B * C]	(E)	(F) [C * E]		(H) [B + E]	(I) [D + F]	(J) [=H]	(K)	(L) [J * K]
1	**R-5: Residential Heating**											
2	Customer Charge	306,525	$22.20	$6,804,865	7,528	$167,116		314,053	$6,971,981	314,053	$27.84	$8,743,241
3	Summer First 50 therms	2,947,284	$0.6099	$1,797,548	148,552	$90,602		3,095,836	$1,888,150	3,095,836	$0.8491	$2,628,674
4	Summer Excess therms	459,480	$0.6099	$280,237	-	$0		459,480	$280,237	459,480	$0.8491	$390,145
5	Winter First 50 therms	6,432,280	$0.6920	$4,451,138	182,063	$125,988		6,614,343	$4,577,125	6,614,343	$0.8491	$5,616,239
6	Winter Excess therms	7,449,509	$0.6920	$5,155,060	1,986,762	$1,374,840		9,436,272	$6,529,900	9,436,272	$0.8491	$8,012,338
7	Total	17,288,553		$18,488,849	2,317,378	$1,758,545		19,605,931	$20,247,394	19,605,931		$25,390,637
8	**R-10: Residential Heating, Low Income**											
9	**January through October**											
10	Customer Charge	7,409	$8.88	$65,795	(972)	($21,587)	$98,692					
11	Summer First 50 therms	60,977	$0.2440	$14,878	(4,875)	($2,973)	$22,311					
12	Summer Excess therms	4,657	$0.2440	$1,136	-	$0	$1,704					
13	Winter First 50 therms	164,671	$0.2760	$45,449	(31,181)	($21,578)	$68,503					
14	Winter Excess therms	154,635	$0.2760	$42,679	24,940	$17,258	$64,328					
15	Total	384,939		$169,938	(11,116)	($28,879)	$255,538					
16	**November, December**											
17	Customer Charge before rate char	335	$8.88	$2,979			$4,468					
18	Customer Charge after rate chang	938	$22.20	$20,822	14	$311						
19	Summer First 50 therms b/f chang	11,932	$0.2440	$2,911	1,843	$1,124	$4,366					
20	Summer Excess therms b/f change	2,539	$0.2440	$620		$0	$929					
21	Winter First 50 therms	40,114	$0.6920	$27,759	701	$485	$0					
22	Winter Excess therms	25,775	$0.6920	$17,836	4,598	$3,182	$0					
23	Total	80,360		$72,927	7,142	$5,102	$9,763					
24	**Test Year**											
25	Customer Charge	8,683		$89,595	(958)	($21,276)	$103,160	7,724	$171,480	7,724	$27.84	$215,045
26	Summer First 50 therms	72,909		$17,790	(3,032)	($1,849)	$26,677	69,877	$42,618	69,877	$0.8491	$59,333
27	Summer Excess therms	7,196		$1,756	-	$0	$2,633	7,196	$4,389	7,196	$0.8491	$6,110
28	Winter First 50 therms	204,785		$73,208	(30,481)	($21,093)	$68,503	174,305	$120,619	174,305	$0.8491	$148,002
29	Winter Excess therms	180,409		$60,515	29,538	$20,441	$64,328	209,948	$145,284	209,948	$0.8491	$178,267
30	Total	465,300		$242,865	(3,974)	($23,777)	$265,302	461,326	$484,389	461,326		$606,756

Northern Utilities New Hampshire
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Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Adjustments: Normalization & Annualization Adjustments (bills or therms)	Adjustments: Weather Normalization & Annualization Revenue Adjustment	Adjustments: R-10 Rate Change Annualization	Pro Forma at Current Rates: 2020 Adjusted Billing Determinants (bills or therms)	Pro Forma at Current Rates: 2020 Adjusted Base Year Revenue ("Margin")	Pro Forma Proposed Rates: Projected Billing Determinants (bills or therms)	Pro Forma Proposed Rates: Proposed Rate	Pro Forma Proposed Rates: Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D)	(E)	(F)		(H)	(I)	(J)	(K)	(L)
				[B * C]		[C * E]		[B + E]	[D + F]	[=H]		[J * K]
31	**R-6: Residential Non-Heating**											
32	Customer Charge	15,776	$22.20	$350,236	(456)	($10,123)		15,320	$340,113	15,320	$27.84	$426,520
33	Summer First 10 therms	51,805	$0.6470	$33,518	(3,321)	($2,149)		48,484	$31,369	48,484	$1.1208	$54,340
34	Summer Excess therms	32,928	$0.6470	$21,304	-	$0		32,928	$21,304	32,928	$1.1208	$36,906
35	Winter First 10 therms	52,602	$0.6470	$34,034	(599)	($388)		52,003	$33,646	52,003	$1.1208	$58,285
36	Winter Excess therms	94,282	$0.6470	$61,001	9,571	$6,193		103,854	$67,193	103,854	$1.1208	$116,399
37	Total	231,617		$500,092	5,651	($6,467)		237,269	$493,626	237,269		$692,451
38	**G-40/T-40: Low Annual, High Winter Use**											
39	Customer Charge	60,528	$75.09	$4,545,034	2,284	$171,520		62,812	$4,716,554	62,812	$80.00	$5,024,961
40	Summer First 75 therms	749,335	$0.1865	$139,751	130,670	$24,370		880,005	$164,121	880,005	$0.2518	$221,585
41	Summer Excess therms	728,589	$0.1865	$135,882	-	$0		728,589	$135,882	728,589	$0.2518	$183,459
42	Winter First 75 therms	1,918,684	$0.1865	$357,835	51,517	$9,608		1,970,201	$367,443	1,970,201	$0.2518	$496,097
43	Winter Excess therms	6,048,253	$0.1865	$1,127,999	1,253,784	$233,831		7,302,037	$1,361,830	7,302,037	$0.2518	$1,838,653
44	Total	9,444,862		$6,306,501	1,435,971	$439,328		10,880,833	$6,745,829	10,880,833		$7,764,755
45	**G-50/T-50: Low Annual, Low Winter Use**											
46	Customer Charge	9,988	$75.09	$749,978	(10)	($760)		9,978	$749,218	9,978	$80.00	$798,208
47	Summer First 75 therms	211,366	$0.1865	$39,420	(7,547)	($1,408)		203,819	$38,012	203,819	$0.2232	$45,492
48	Summer Excess therms	444,727	$0.1865	$82,942	-	$0		444,727	$82,942	444,727	$0.2232	$99,263
49	Winter First 75 therms	216,653	$0.1865	$40,406	3,516	$656		220,169	$41,061	220,169	$0.2232	$49,142
50	Winter Excess therms	601,017	$0.1865	$112,090	4,841	$903		605,858	$112,993	605,858	$0.2232	$135,228
51	Total	1,473,763		$1,024,835	810	($609)		1,474,573	$1,024,226	1,474,573		$1,127,333
52	**G-41/T-41: Medium Annual, High Winter Use**											
53	Customer Charge	8,741	$222.64	$1,946,116	(290)	($64,630)		8,451	$1,881,486	8,451	$225.00	$1,901,430
54	Summer All therms	2,627,539	$0.1895	$497,919	81,420	$15,429		2,708,960	$513,348	2,708,960	$0.2860	$774,762
55	Winter All therms	11,121,406	$0.2425	$2,696,941	593,466	$143,916		11,714,872	$2,840,856	11,714,872	$0.2860	$3,350,453
56	Total	13,748,945		$5,140,976	674,887	$94,715		14,423,832	$5,235,691	14,423,832		$6,026,646
57	**G-51/T-51: Medium Annual, Low Winter Use**											
58	Customer Charge	3,318	$222.64	$738,727	(120)	($26,725)		3,198	$712,003	3,198	$225.00	$719,550
59	Summer First 1,000 therms	1,231,175	$0.1337	$164,608	(61,835)	($8,267)		1,169,340	$156,341	1,169,340	$0.1718	$200,893
60	Summer Excess therms	515,635	$0.1087	$56,050	254,848	$27,702		770,483	$83,752	770,483	$0.1718	$132,369
61	Winter First 1,300 therms	1,677,170	$0.1712	$287,131	(75,660)	($12,953)		1,601,510	$274,178	1,601,510	$0.1718	$275,139
62	Winter Excess therms	1,045,521	$0.1399	$146,268	174,446	$24,405		1,219,967	$170,673	1,219,967	$0.1718	$209,590
63	Total	4,469,501		$1,392,785	291,799	$4,162		4,761,300	$1,396,947	4,761,300		$1,537,541

Northern Utilities New Hampshire
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Test Year: January 1, 2020 Through December 31, 2020

					Adjustments			Pro Forma at Current Rates		Pro Forma Proposed Rates		
Line No.	Rate Description	2020 Billing Units (bills or therms)	Current Rates	Calculated Revenue	Normalization & Annualization Adjustments (bills or therms)	Weather Normalization & Annualization Revenue Adjustment	R-10 Rate Change Annualization	2020 Adjusted Billing Determinants (bills or therms)	2020 Adjusted Base Year Revenue ("Margin")	Projected Billing Determinants (bills or therms)	Proposed Rate	Total Proposed Revenue ("Margin")
	(A)	(B)	(C)	(D) [B * C]	(E)	(F) [C * E]		(H) [B + E]	(I) [D + F]	(J) [=H]	(K)	(L) [J * K]
64	**G-42/T-42: High Annual, High Winter Use**											
65	Customer Charge	413	$1,335.81	$551,022	(41)	($54,100)		372	$496,921	372	$1,350.00	$502,200
66	Summer All therms	1,589,451	$0.1206	$191,688	(42,692)	($5,149)		1,546,759	$186,539	1,546,759	$0.2167	$335,183
67	Winter All therms	4,234,069	$0.1984	$840,039	108,944	$21,614		4,343,013	$861,654	4,343,013	$0.2167	$941,131
68	Total	5,823,520		$1,582,749	66,252	($37,635)		5,889,772	$1,545,114	5,889,772		$1,778,514
69	**G-52/T-52: High Annual, Low Winter Use**											
70	Customer Charge	391	$1,335.81	$521,901	5	$7,080		396	$528,981	396	$1,350.00	$534,600
71	Summer All therms	7,827,306	$0.0792	$619,923	29,672	$2,350		7,856,979	$622,273	7,856,979	$0.1121	$880,767
72	Winter All therms	8,356,912	$0.1720	$1,437,389	203,384	$34,982		8,560,295	$1,472,371	8,560,295	$0.1720	$1,472,371
73	Total	16,184,218		$2,579,212	233,061	$44,412		16,417,274	$2,623,624	16,417,274		$2,887,738
74	**Total**											
75	Customer Charge	414,362		$16,297,475	7,942	$168,102	$103,160	422,304	$16,568,737	422,304		$18,865,756
76	Summer First Block therms	17,308,170		$3,502,164	271,888	$113,930	$26,677	17,580,058	$3,642,771	17,580,058		$5,201,030
77	Summer Excess therms	2,188,556		$578,170	254,848	$27,702	$2,633	2,443,404	$608,505	2,443,404		$848,251
78	Winter First Block therms	34,214,561		$10,218,121	1,036,150	$302,330	$68,503	35,250,711	$10,588,954	35,250,711		$12,406,859
79	Winter Excess therms	15,418,993		$6,662,934	3,458,944	$1,660,611	$64,328	18,877,936	$8,387,873	18,877,936		$10,490,475
80	Total	69,130,280		$37,258,864	5,021,830	$2,272,675	$265,302	74,152,109	$39,796,840	74,152,109		$47,812,371

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Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
1	R-5	Residential Heating	January	26,171	3,484,177	31.0	15.0	48.4%	1,685,892	1,883,263	3,569,155	$ 3,759,173	$ 143.64
2			February	26,171	3,648,821	31.0	15.0	48.4%	1,765,559	1,401,584	3,167,143	$ 3,417,824	$ 130.60
3		*Rates*	March	26,171	3,018,796	28.0	15.0	53.6%	1,617,212	1,051,289	2,668,501	$ 2,994,428	$ 114.42
4		*Customer*	April	26,171	2,036,872	31.0	15.0	48.4%	985,583	580,633	1,566,216	$ 2,058,477	$ 78.65
5		*$27.84*	May	26,171	1,161,265	30.0	15.0	50.0%	580,633	345,556	926,189	$ 1,515,030	$ 57.89
6		*Per Therm*	June	26,171	669,515	31.0	15.0	48.4%	323,959	147,794	471,753	$ 1,129,169	$ 43.15
7		*$0.8491*	July	26,171	295,589	30.0	15.0	50.0%	147,794	126,922	274,716	$ 961,865	$ 36.75
8			August	26,171	245,912	31.0	15.0	48.4%	118,989	184,742	303,731	$ 986,501	$ 37.69
9			September	26,171	357,937	31.0	15.0	48.4%	173,195	346,024	519,219	$ 1,169,472	$ 44.69
10			October	26,171	692,048	30.0	15.0	50.0%	346,024	701,831	1,047,855	$ 1,618,337	$ 61.84
11			November	26,171	1,359,798	31.0	15.0	48.4%	657,967	1,317,601	1,975,568	$ 2,406,058	$ 91.94
12			December	26,171	2,635,202	30.0	15.0	50.0%	1,317,601	1,798,285	3,115,886	$ 3,374,302	$ 128.93
13					19,605,931	365.0	180.00				19,605,931	$ 25,390,637	$ 970.18
14	R-10	Res. Heating, Low Income	January	644	78,003	31.0	15.0	48.4%	37,744	43,245	80,989	$ 86,688	$ 134.67
15			February	644	83,787	31.0	15.0	48.4%	40,542	34,528	75,070	$ 81,663	$ 126.87
16		*Rates*	March	644	74,368	28.0	15.0	53.6%	39,840	27,318	67,158	$ 74,945	$ 116.43
17		*Customer*	April	644	52,929	31.0	15.0	48.4%	25,611	15,074	40,685	$ 52,466	$ 81.51
18		*$27.84*	May	644	30,149	30.0	15.0	50.0%	15,074	8,641	23,715	$ 38,057	$ 59.12
19		*Per Therm*	June	644	16,742	31.0	15.0	48.4%	8,101	3,326	11,427	$ 27,623	$ 42.91
20		*$0.8491*	July	644	6,653	30.0	15.0	50.0%	3,326	2,780	6,106	$ 23,105	$ 35.89
21			August	644	5,386	31.0	15.0	48.4%	2,606	4,279	6,885	$ 23,767	$ 36.92
22			September	644	8,291	31.0	15.0	48.4%	4,012	8,757	12,769	$ 28,763	$ 44.68
23			October	644	17,515	30.0	15.0	50.0%	8,757	16,518	25,275	$ 39,382	$ 61.18
24			November	644	32,003	31.0	15.0	48.4%	15,485	27,750	43,235	$ 54,631	$ 84.87
25			December	644	55,499	30.0	15.0	50.0%	27,750	40,260	68,009	$ 75,667	$ 117.55
26					461,326	365.0	180.00				461,326	$ 606,756	$ 942.62
27	R-6	Residential Non-Heating	January	1,277	32,194	31.0	15.0	48.4%	15,578	16,869	32,447	$ 71,910	$ 56.32
28			February	1,277	32,684	31.0	15.0	48.4%	15,815	12,513	28,328	$ 67,293	$ 52.71
29		*Rates*	March	1,277	26,950	28.0	15.0	53.6%	14,438	10,792	25,230	$ 63,821	$ 49.99
30		*Customer*	April	1,277	20,909	31.0	15.0	48.4%	10,117	8,733	18,851	$ 56,671	$ 44.39
31		*$27.84*	May	1,277	17,467	30.0	15.0	50.0%	8,733	7,508	16,241	$ 53,747	$ 42.10
32		*Per Therm*	June	1,277	14,547	31.0	15.0	48.4%	7,039	5,794	12,833	$ 49,926	$ 39.11
33		*$1.1208*	July	1,277	11,588	30.0	15.0	50.0%	5,794	5,514	11,308	$ 48,217	$ 37.77
34			August	1,277	10,683	31.0	15.0	48.4%	5,169	6,395	11,564	$ 48,504	$ 37.99
35			September	1,277	12,390	31.0	15.0	48.4%	5,995	6,786	12,781	$ 49,868	$ 39.06
36			October	1,277	13,571	30.0	15.0	50.0%	6,786	9,033	15,819	$ 53,273	$ 41.73
37			November	1,277	17,502	31.0	15.0	48.4%	8,469	13,391	21,860	$ 60,044	$ 47.03
38			December	1,277	26,783	30.0	15.0	50.0%	13,391	16,616	30,008	$ 69,176	$ 54.18
39					237,269	365.0	180.00				237,269	$ 692,451	$ 542.38

Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
40	G-40/T-40	Low Annual, High Winter	January	5,234	2,074,220	31.0	15.00	48.4%	1,003,655	1,102,188	2,105,842	$ 948,998	$ 181.30
41			February	5,234	2,135,489	31.0	15.00	48.4%	1,033,301	819,847	1,853,148	$ 885,369	$ 169.15
42		*Rates*	March	5,234	1,765,824	28.0	15.00	53.6%	945,977	584,542	1,530,519	$ 804,131	$ 153.63
43		*Customer*	April	5,234	1,132,550	31.0	15.00	48.4%	548,008	307,957	855,965	$ 634,279	$ 121.18
44		*$80.00*	May	5,234	615,915	30.0	15.00	50.0%	307,957	160,450	468,408	$ 536,692	$ 102.53
45		*Per Therm*	June	5,234	310,873	31.0	15.00	48.4%	150,422	43,109	193,531	$ 467,478	$ 89.31
46		*$0.2518*	July	5,234	86,217	30.0	15.00	50.0%	43,109	31,705	74,813	$ 437,585	$ 83.60
47			August	5,234	61,428	31.0	15.00	48.4%	29,723	62,259	91,982	$ 441,908	$ 84.42
48			September	5,234	120,626	31.0	15.00	48.4%	58,368	167,906	226,274	$ 475,722	$ 90.89
49			October	5,234	335,813	30.0	15.00	50.0%	167,906	381,182	549,088	$ 557,007	$ 106.41
50			November	5,234	738,541	31.0	15.00	48.4%	357,358	751,669	1,109,028	$ 698,000	$ 133.35
51			December	5,234	1,503,339	30.0	15.00	50.0%	751,669	1,070,565	1,822,234	$ 877,585	$ 167.66
52					10,880,833	365.0	180.00				10,880,833	$ 7,764,755	$ 1,483.43
53	G-50/T-50	Low Annual, Low Winter	January	831	166,567	31.0	15.00	48.4%	80,597	85,181	165,778	$ 103,519	$ 124.50
54			February	831	165,038	31.0	15.00	48.4%	79,857	73,369	153,226	$ 100,717	$ 121.13
55		*Rates*	March	831	158,026	28.0	15.00	53.6%	84,657	51,270	135,926	$ 96,856	$ 116.49
56		*Customer*	April	831	99,335	31.0	15.00	48.4%	48,065	45,655	93,720	$ 87,436	$ 105.16
57		*$80.00*	May	831	91,310	30.0	15.00	50.0%	45,655	51,347	97,002	$ 88,168	$ 106.04
58		*Per Therm*	June	831	99,485	31.0	15.00	48.4%	48,138	53,475	101,613	$ 89,197	$ 107.28
59		*$0.2232*	July	831	106,951	30.0	15.00	50.0%	53,475	53,647	107,123	$ 90,427	$ 108.76
60			August	831	103,942	31.0	15.00	48.4%	50,294	64,058	114,352	$ 92,041	$ 110.70
61			September	831	124,112	31.0	15.00	48.4%	60,054	51,191	111,245	$ 91,347	$ 109.86
62			October	831	102,382	30.0	15.00	50.0%	51,191	59,985	111,176	$ 91,332	$ 109.84
63			November	831	116,220	31.0	15.00	48.4%	56,236	70,603	126,839	$ 94,828	$ 114.05
64			December	831	141,206	30.0	15.00	50.0%	70,603	85,970	156,573	$ 101,464	$ 122.03
65					1,474,573	365.0	180.00				1,474,573	$ 1,127,333	$ 1,355.84
66	G-41/T-41	Med. Annual, High Winter	January	704	2,542,501	31.0	15.00	48.4%	1,230,243	1,342,852	2,573,095	$ 894,358	$ 1,269.97
67			February	704	2,601,776	31.0	15.00	48.4%	1,258,924	1,026,886	2,285,810	$ 812,194	$ 1,153.30
68		*Rates*	March	704	2,211,754	28.0	15.00	53.6%	1,184,868	739,200	1,924,069	$ 708,736	$ 1,006.39
69		*Customer*	April	704	1,432,201	31.0	15.00	48.4%	693,000	428,559	1,121,559	$ 479,218	$ 680.48
70		*$225.00*	May	704	857,118	30.0	15.00	50.0%	428,559	260,143	688,701	$ 355,421	$ 504.69
71		*Per Therm*	June	704	504,026	31.0	15.00	48.4%	243,884	116,954	360,838	$ 261,652	$ 371.54
72		*$0.2860*	July	704	233,908	30.0	15.00	50.0%	116,954	101,623	218,577	$ 220,966	$ 313.77
73			August	704	196,895	31.0	15.00	48.4%	95,272	144,324	239,596	$ 226,977	$ 322.30
74			September	704	279,628	31.0	15.00	48.4%	135,304	258,880	394,184	$ 271,189	$ 385.08
75			October	704	517,761	30.0	15.00	50.0%	258,880	570,478	829,358	$ 395,649	$ 561.82
76			November	704	1,105,301	31.0	15.00	48.4%	534,823	970,482	1,505,305	$ 588,970	$ 836.33
77			December	704	1,940,963	30.0	15.00	50.0%	970,482	1,312,259	2,282,740	$ 811,316	$ 1,152.06
78					14,423,832	365.0	180.00				14,423,832	$ 6,026,646	$ 8,557.74

Northern Utilities New Hampshire
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]
				Billing Determinants		Bill Cycle to Calendar Month Conversion			Calendar Month Therms			Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Pro Forma Test Year Normal Therms (Cycle)	Days In Bill Cycle	Days Billed in Current Month	% Calendar Therms Billed in Same Month	Therms Billed in Same Month	Therms Billed in Next Month	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
79	G-51/T-51	Med. Annual, Low Winter	January	267	543,661	31.0	15.00	48.4%	263,062	285,547	548,609	$ 154,213	$ 578.66
80			February	267	553,247	31.0	15.00	48.4%	267,700	238,585	506,285	$ 146,942	$ 551.38
81		*Rates*	March	267	513,874	28.0	15.00	53.6%	275,290	204,221	479,510	$ 142,342	$ 534.12
82		*Customer*	April	267	395,677	31.0	15.00	48.4%	191,457	177,978	369,435	$ 123,431	$ 463.16
83		*$225.00*	May	267	355,957	30.0	15.00	50.0%	177,978	174,313	352,292	$ 120,486	$ 452.11
84		*Per Therm*	June	267	337,732	31.0	15.00	48.4%	163,419	151,004	314,422	$ 113,980	$ 427.69
85		*$0.1718*	July	267	302,008	30.0	15.00	50.0%	151,004	145,606	296,610	$ 110,920	$ 416.21
86			August	267	282,112	31.0	15.00	48.4%	136,506	163,666	300,172	$ 111,532	$ 418.51
87			September	267	317,102	31.0	15.00	48.4%	153,437	152,861	306,298	$ 112,585	$ 422.46
88			October	267	305,723	30.0	15.00	50.0%	152,861	195,057	347,918	$ 119,735	$ 449.29
89			November	267	377,923	31.0	15.00	48.4%	182,866	238,142	421,008	$ 132,292	$ 496.40
90			December	267	476,284	30.0	15.00	50.0%	238,142	280,599	518,741	$ 149,082	$ 559.41
91					4,761,300	365.0	180.00				4,761,300	$ 1,537,541	$ 5,769.39
92	G-42/T-42	High Annual, High Winter	January	31	915,167	31.00	31.00	100.0%	915,167	-	915,167	$ 240,167	$ 7,747.32
93			February	31	819,517	28.00	28.00	100.0%	819,517	-	819,517	$ 219,439	$ 7,078.69
94		*Rates*	March	31	734,670	31.00	31.00	100.0%	734,670	-	734,670	$ 201,053	$ 6,485.58
95		*Customer*	April	31	515,218	30.00	30.00	100.0%	515,218	-	515,218	$ 153,498	$ 4,951.54
96		*$1,350.00*	May	31	324,350	31.00	31.00	100.0%	324,350	-	324,350	$ 112,137	$ 3,617.31
97		*Per Therm*	June	31	218,129	30.00	30.00	100.0%	218,129	-	218,129	$ 89,118	$ 2,874.79
98		*$0.2167*	July	31	189,460	31.00	31.00	100.0%	189,460	-	189,460	$ 82,906	$ 2,674.38
99			August	31	192,134	31.00	31.00	100.0%	192,134	-	192,134	$ 83,485	$ 2,693.08
100			September	31	232,113	30.00	30.00	100.0%	232,113	-	232,113	$ 92,149	$ 2,972.54
101			October	31	383,712	31.00	31.00	100.0%	383,712	-	383,712	$ 125,000	$ 4,032.27
102			November	31	578,379	30.00	30.00	100.0%	578,379	-	578,379	$ 167,185	$ 5,393.06
103			December	31	786,923	31.00	31.00	100.0%	786,923	-	786,923	$ 212,376	$ 6,850.84
104					5,889,772	365.0	365.00				5,889,772	$ 1,778,514	$ 57,371.41
105	G-52/T-52	High Annual, Low Winter	January	33	1,332,981	31.00	31.00	100.0%	1,332,981	-	1,332,981	$ 273,823	$ 8,297.66
106			February	33	1,504,043	28.00	28.00	100.0%	1,504,043	-	1,504,043	$ 303,245	$ 9,189.26
107		*Rates*	March	33	1,376,235	31.00	31.00	100.0%	1,376,235	-	1,376,235	$ 281,262	$ 8,523.10
108		*Customer*	April	33	1,383,288	30.00	30.00	100.0%	1,383,288	-	1,383,288	$ 280,018	$ 8,485.41
109		*$1,350.00*	May	33	1,262,689	31.00	31.00	100.0%	1,262,689	-	1,262,689	$ 186,436	$ 5,649.57
110		*Per Therm Summer*	June	33	1,236,219	30.00	30.00	100.0%	1,236,219	-	1,236,219	$ 183,877	$ 5,572.02
111		*$0.1121*	July	33	1,220,236	31.00	31.00	100.0%	1,220,236	-	1,220,236	$ 181,339	$ 5,495.11
112		*Per Therm Winter*	August	33	1,282,733	31.00	31.00	100.0%	1,282,733	-	1,282,733	$ 188,344	$ 5,707.41
113		*$0.1720*	September	33	1,416,119	30.00	30.00	100.0%	1,416,119	-	1,416,119	$ 203,297	$ 6,160.51
114			October	33	1,430,639	31.00	31.00	100.0%	1,430,639	-	1,430,639	$ 207,514	$ 6,288.30
115			November	33	1,409,953	30.00	30.00	100.0%	1,409,953	-	1,409,953	$ 285,345	$ 8,646.81
116			December	33	1,562,138	31.00	31.00	100.0%	1,562,138	-	1,562,138	$ 313,238	$ 9,492.05
117					16,417,274	365.0	365.00				16,417,274	$ 2,887,738	$ 87,507.22
118		**Test Year Total**			74,152,109						74,152,109	$ 47,812,371	

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Northern Utilities - NH Division
Residential Heating Customer - R5
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	5.91	$31.26	$37.72	$6.46	20.7%
20.0%	22.05	$56.01	$64.73	$8.71	15.6%
30.0%	37.57	$79.81	$90.68	$10.88	13.6%
40.0%	52.37	$102.51	$115.44	$12.94	12.6%
50.0%	67.18	$125.22	$140.22	$15.00	12.0%
60.0%	82.99	$149.46	$166.66	$17.21	11.5%
70.0%	101.23	$177.42	$197.17	$19.75	11.1%
80.0%	124.00	$212.35	$235.27	$22.92	10.8%
90.0%	155.63	$260.84	$288.17	$27.33	10.5%
100.0%	240.82	$391.47	$430.66	$39.20	10.0%
Average	88.98	$158.63	$176.67	$18.04	11.4%
		Distribution Only			
10.0%	5.91	$26.29	$32.86	$6.57	25.0%
20.0%	22.05	$37.46	$46.56	$9.10	24.3%
30.0%	37.57	$48.20	$59.74	$11.54	23.9%
40.0%	52.37	$58.44	$72.31	$13.87	23.7%
50.0%	67.18	$68.69	$84.88	$16.19	23.6%
60.0%	82.99	$79.63	$98.31	$18.68	23.5%
70.0%	101.23	$92.25	$113.79	$21.54	23.4%
80.0%	124.00	$108.01	$133.13	$25.12	23.3%
90.0%	155.63	$129.90	$159.99	$30.09	23.2%
100.0%	240.82	$188.84	$232.32	$43.47	23.0%
Average	88.98	$83.77	$103.39	$19.62	23.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6920	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6920	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Heating Customer - R5
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	1.76	$24.13	$30.16	$6.04	25.0%
30.0%	5.79	$28.53	$35.48	$6.95	24.4%
40.0%	9.28	$32.34	$40.07	$7.74	23.9%
50.0%	12.82	$36.20	$44.74	$8.54	23.6%
60.0%	16.63	$40.36	$49.76	$9.40	23.3%
70.0%	21.15	$45.30	$55.72	$10.42	23.0%
80.0%	27.57	$52.31	$64.18	$11.87	22.7%
90.0%	39.21	$65.02	$79.53	$14.51	22.3%
100.0%	83.07	$112.92	$137.35	$24.42	21.6%
Average	21.73	$45.93	$56.48	$10.55	23.0%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	1.76	$23.28	$29.34	$6.06	26.0%
30.0%	5.79	$25.73	$32.76	$7.03	27.3%
40.0%	9.28	$27.86	$35.72	$7.86	28.2%
50.0%	12.82	$30.02	$38.72	$8.71	29.0%
60.0%	16.63	$32.34	$41.96	$9.62	29.7%
70.0%	21.15	$35.10	$45.80	$10.70	30.5%
80.0%	27.57	$39.01	$51.25	$12.23	31.4%
90.0%	39.21	$46.11	$61.13	$15.02	32.6%
100.0%	83.07	$72.86	$98.37	$25.51	35.0%
Average	21.73	$35.45	$46.29	$10.84	30.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6099	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6099	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Low Income Heating Customer - R10
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	14.96	$25.57	$29.71	$4.14	16.2%
20.0%	31.25	$40.13	$45.40	$5.27	13.1%
30.0%	43.22	$50.82	$56.92	$6.10	12.0%
40.0%	54.61	$61.00	$67.89	$6.89	11.3%
50.0%	65.94	$71.12	$78.79	$7.67	10.8%
60.0%	77.14	$81.13	$89.58	$8.45	10.4%
70.0%	90.21	$92.81	$102.16	$9.36	10.1%
80.0%	108.11	$108.80	$119.40	$10.60	9.7%
90.0%	135.38	$133.16	$145.65	$12.49	9.4%
100.0%	205.88	$196.15	$213.53	$17.38	8.9%
Average	82.67	$86.07	$94.90	$8.83	10.3%
		Distribution Only			
10.0%	14.96	$32.55	$40.54	$7.99	24.5%
20.0%	31.25	$43.83	$54.38	$10.55	24.1%
30.0%	43.22	$52.11	$64.54	$12.43	23.9%
40.0%	54.61	$59.99	$74.21	$14.22	23.7%
50.0%	65.94	$67.83	$83.83	$16.00	23.6%
60.0%	77.14	$75.58	$93.34	$17.76	23.5%
70.0%	90.21	$84.63	$104.44	$19.81	23.4%
80.0%	108.11	$97.02	$119.64	$22.62	23.3%
90.0%	135.38	$115.89	$142.80	$26.91	23.2%
100.0%	205.88	$164.67	$202.66	$37.98	23.1%
Average	82.67	$79.41	$98.04	$18.63	23.5%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6920	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6920	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)
45% Customer Charge Discount ($/customer)	-$9.99	(6)	45% Customer Charge Discount ($/customer)	-$12.53	(6)
45% Therm Discount - First 50 therms ($/thm)	-$0.6400	(6)	45% Therm Discount - All therms ($/thm)	-$0.7100	(6)
45% Therm Discount - Excess 50 therms ($/thm)	-$0.6400	(6)			

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal
(6) Low income customers receive a 45% discount on the customer charge, distribution charges, and COG in the winter period only

Northern Utilities - NH Division
Residential Low Income Heating Customer - R10
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.15	$22.36	$28.03	$5.67	25.4%
20.0%	3.16	$25.65	$32.01	$6.35	24.8%
30.0%	6.95	$29.79	$37.00	$7.21	24.2%
40.0%	10.00	$33.12	$41.02	$7.90	23.9%
50.0%	12.74	$36.11	$44.63	$8.52	23.6%
60.0%	16.06	$39.74	$49.01	$9.27	23.3%
70.0%	20.58	$44.67	$54.96	$10.29	23.0%
80.0%	27.06	$51.76	$63.52	$11.76	22.7%
90.0%	39.85	$65.72	$80.37	$14.65	22.3%
100.0%	80.33	$109.94	$133.74	$23.81	21.7%
Average	21.69	$45.89	$56.43	$10.54	23.0%
		Distribution Only			
10.0%	0.15	$22.29	$27.97	$5.68	25.5%
20.0%	3.16	$24.13	$30.52	$6.40	26.5%
30.0%	6.95	$26.44	$33.74	$7.30	27.6%
40.0%	10.00	$28.30	$36.33	$8.03	28.4%
50.0%	12.74	$29.97	$38.66	$8.69	29.0%
60.0%	16.06	$31.99	$41.47	$9.48	29.6%
70.0%	20.58	$34.75	$45.31	$10.56	30.4%
80.0%	27.06	$38.71	$50.82	$12.11	31.3%
90.0%	39.85	$46.50	$61.68	$15.17	32.6%
100.0%	80.33	$71.19	$96.05	$24.86	34.9%
Average	21.69	$35.43	$46.25	$10.83	30.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 50 therms ($/thm)	$0.6099	(1)	Distribution Charge - All therms ($/thm)	$0.8491	(3)
Distribution Charge - Excess 50 therms ($/thm)	$0.6099	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Non-Heating Customer - R6
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.50	$22.95	$28.81	$5.87	25.6%
30.0%	2.23	$25.53	$32.19	$6.66	26.1%
40.0%	5.44	$30.30	$38.43	$8.12	26.8%
50.0%	9.21	$35.91	$45.76	$9.84	27.4%
60.0%	12.95	$41.48	$53.03	$11.55	27.8%
70.0%	17.13	$47.70	$61.15	$13.45	28.2%
80.0%	23.24	$56.79	$73.02	$16.24	28.6%
90.0%	36.13	$75.98	$98.09	$22.12	29.1%
100.0%	78.37	$138.84	$180.22	$41.38	29.8%
Average	18.52	$49.77	$63.85	$14.09	28.3%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.50	$22.52	$28.40	$5.88	26.1%
30.0%	2.23	$23.65	$30.34	$6.70	28.3%
40.0%	5.44	$25.72	$33.94	$8.22	32.0%
50.0%	9.21	$28.16	$38.17	$10.01	35.5%
60.0%	12.95	$30.58	$42.36	$11.78	38.5%
70.0%	17.13	$33.28	$47.04	$13.76	41.3%
80.0%	23.24	$37.23	$53.88	$16.65	44.7%
90.0%	36.13	$45.58	$68.33	$22.76	49.9%
100.0%	78.37	$72.90	$115.67	$42.77	58.7%
Average	18.52	$34.18	$48.60	$14.42	42.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 10 therms ($/thm)	$0.6470	(1)	Distribution Charge - All therms ($/thm)	$1.1208	(3)
Distribution Charge - Excess 10 therms ($/thm)	$0.6470	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.7315	(2)	COGC ($/thm)	$0.7271	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
Residential Non-Heating Customer - R6
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Present Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.70	$22.99	$28.95	$5.96	25.9%
30.0%	1.96	$24.41	$30.96	$6.54	26.8%
40.0%	3.94	$26.65	$34.11	$7.46	28.0%
50.0%	6.31	$29.32	$37.87	$8.55	29.1%
60.0%	8.51	$31.81	$41.37	$9.56	30.1%
70.0%	10.84	$34.45	$45.08	$10.64	30.9%
80.0%	13.60	$37.55	$49.46	$11.90	31.7%
90.0%	17.92	$42.44	$56.34	$13.90	32.7%
100.0%	37.81	$64.90	$87.96	$23.06	35.5%
Average	10.16	$33.67	$43.99	$10.32	30.7%
		Distribution Only			
10.0%	0.00	$22.20	$27.84	$5.64	25.4%
20.0%	0.70	$22.65	$28.62	$5.97	26.4%
30.0%	1.96	$23.47	$30.04	$6.57	28.0%
40.0%	3.94	$24.75	$32.26	$7.51	30.3%
50.0%	6.31	$26.28	$34.91	$8.63	32.8%
60.0%	8.51	$27.70	$37.38	$9.67	34.9%
70.0%	10.84	$29.22	$39.99	$10.78	36.9%
80.0%	13.60	$31.00	$43.08	$12.08	39.0%
90.0%	17.92	$33.80	$47.93	$14.13	41.8%
100.0%	37.81	$46.66	$70.22	$23.55	50.5%
Average	10.16	$28.77	$39.23	$10.45	36.3%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$22.20	(1)	Customer Charge ($/customer)	$27.84	(3)
Distribution Charge - First 10 therms ($/thm)	$0.6470	(1)	Distribution Charge - All therms ($/thm)	$1.1208	(3)
Distribution Charge - Excess 10 therms ($/thm)	$0.6470	(1)			
LDAC ($/thm)	$0.1099	(1)	LDAC ($/thm)	$0.0965	(4)
COGC ($/thm)	$0.3724	(2)	COGC ($/thm)	$0.3727	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, High Winter Use - G40
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	5.08	$80.05	$85.25	$5.20	6.5%
20.0%	29.08	$103.52	$110.09	$6.57	6.3%
30.0%	58.36	$132.13	$140.38	$8.24	6.2%
40.0%	91.27	$164.29	$174.42	$10.12	6.2%
50.0%	132.07	$204.17	$216.63	$12.45	6.1%
60.0%	183.41	$254.36	$269.75	$15.39	6.0%
70.0%	248.65	$318.12	$337.24	$19.11	6.0%
80.0%	341.54	$408.91	$433.33	$24.42	6.0%
90.0%	491.01	$555.01	$587.97	$32.96	5.9%
100.0%	989.61	$1,042.33	$1,103.78	$61.44	5.9%
Average	257.01	$326.29	$345.88	$19.59	6.0%
		Distribution Only			
10.0%	5.08	$76.04	$81.28	$5.24	6.9%
20.0%	29.08	$80.51	$87.32	$6.81	8.5%
30.0%	58.36	$85.97	$94.70	$8.72	10.1%
40.0%	91.27	$92.11	$102.98	$10.87	11.8%
50.0%	132.07	$99.72	$113.25	$13.53	13.6%
60.0%	183.41	$109.30	$126.18	$16.89	15.5%
70.0%	248.65	$121.46	$142.61	$21.15	17.4%
80.0%	341.54	$138.79	$166.00	$27.21	19.6%
90.0%	491.01	$166.66	$203.64	$36.97	22.2%
100.0%	989.61	$259.65	$329.18	$69.53	26.8%
Average	257.01	$123.02	$144.71	$21.69	17.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2518	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, High Winter Use - G40
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.00	$75.09	$80.00	$4.91	6.5%
30.0%	0.00	$75.09	$80.00	$4.91	6.5%
40.0%	1.02	$75.74	$80.71	$4.97	6.6%
50.0%	5.22	$78.43	$83.66	$5.23	6.7%
60.0%	11.96	$82.74	$88.39	$5.65	6.8%
70.0%	25.29	$91.26	$97.74	$6.47	7.1%
80.0%	49.28	$106.61	$114.56	$7.96	7.5%
90.0%	93.76	$135.05	$145.76	$10.70	7.9%
100.0%	280.68	$254.59	$276.85	$22.26	8.7%
Average	46.72	$104.97	$112.77	$7.80	7.4%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.00	$75.09	$80.00	$4.91	6.5%
30.0%	0.00	$75.09	$80.00	$4.91	6.5%
40.0%	1.02	$75.28	$80.26	$4.98	6.6%
50.0%	5.22	$76.06	$81.32	$5.25	6.9%
60.0%	11.96	$77.32	$83.01	$5.69	7.4%
70.0%	25.29	$79.81	$86.37	$6.56	8.2%
80.0%	49.28	$84.28	$92.41	$8.13	9.6%
90.0%	93.76	$92.58	$103.61	$11.03	11.9%
100.0%	280.68	$127.44	$150.68	$23.24	18.2%
Average	46.72	$83.80	$91.76	$7.96	9.5%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2518	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, Low Winter Use - G50
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	1.04	$76.00	$80.94	$4.94	6.5%
30.0%	6.81	$81.08	$86.19	$5.10	6.3%
40.0%	17.70	$90.67	$96.09	$5.42	6.0%
50.0%	40.86	$111.05	$117.13	$6.08	5.5%
60.0%	78.30	$144.01	$151.15	$7.14	5.0%
70.0%	146.37	$203.92	$213.01	$9.09	4.5%
80.0%	259.74	$303.72	$316.04	$12.32	4.1%
90.0%	406.53	$432.91	$449.42	$16.51	3.8%
100.0%	704.50	$695.19	$720.20	$25.01	3.6%
Average	166.18	$221.37	$231.02	$9.65	4.4%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	1.04	$75.28	$80.23	$4.95	6.6%
30.0%	6.81	$76.36	$81.52	$5.16	6.8%
40.0%	17.70	$78.39	$83.95	$5.56	7.1%
50.0%	40.86	$82.71	$89.12	$6.41	7.7%
60.0%	78.30	$89.69	$97.48	$7.78	8.7%
70.0%	146.37	$102.39	$112.67	$10.28	10.0%
80.0%	259.74	$123.53	$137.97	$14.44	11.7%
90.0%	406.53	$150.91	$170.74	$19.83	13.1%
100.0%	704.50	$206.48	$237.25	$30.77	14.9%
Average	166.18	$106.08	$117.09	$11.01	10.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2232	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Low Annual, Low Winter Use - G50
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.81	$75.55	$80.48	$4.94	6.5%
30.0%	5.32	$78.10	$83.19	$5.09	6.5%
40.0%	12.20	$82.00	$87.31	$5.32	6.5%
50.0%	26.67	$90.20	$95.99	$5.80	6.4%
60.0%	55.97	$106.79	$113.56	$6.77	6.3%
70.0%	110.70	$137.79	$146.37	$8.59	6.2%
80.0%	196.19	$186.20	$197.63	$11.42	6.1%
90.0%	306.05	$248.43	$263.50	$15.07	6.1%
100.0%	521.36	$370.37	$392.59	$22.22	6.0%
Average	123.53	$145.05	$154.06	$9.01	6.2%
		Distribution Only			
10.0%	0.00	$75.09	$80.00	$4.91	6.5%
20.0%	0.81	$75.24	$80.18	$4.94	6.6%
30.0%	5.32	$76.08	$81.19	$5.11	6.7%
40.0%	12.20	$77.37	$82.72	$5.36	6.9%
50.0%	26.67	$80.06	$85.95	$5.89	7.4%
60.0%	55.97	$85.53	$92.49	$6.96	8.1%
70.0%	110.70	$95.74	$104.71	$8.97	9.4%
80.0%	196.19	$111.68	$123.79	$12.11	10.8%
90.0%	306.05	$132.17	$148.31	$16.14	12.2%
100.0%	521.36	$172.32	$196.37	$24.04	14.0%
Average	123.53	$98.13	$107.57	$9.44	9.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$75.09	(1)	Customer Charge ($/customer)	$80.00	(3)
Distribution Charge - First 75 therms ($/thm)	$0.1865	(1)	Distribution Charge - All therms ($/thm)	$0.2232	(3)
Distribution Charge - Excess 75 therms ($/thm)	$0.1865	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, High Winter Use - G41
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	410.78	$647.14	$664.01	$16.87	2.6%
20.0%	855.12	$1,106.32	$1,138.89	$32.57	2.9%
30.0%	1,123.60	$1,383.76	$1,425.82	$42.05	3.0%
40.0%	1,358.83	$1,626.86	$1,677.22	$50.36	3.1%
50.0%	1,592.36	$1,868.19	$1,926.80	$58.61	3.1%
60.0%	1,899.01	$2,185.08	$2,254.53	$69.45	3.2%
70.0%	2,385.06	$2,687.36	$2,773.97	$86.62	3.2%
80.0%	3,120.90	$3,447.78	$3,560.39	$112.61	3.3%
90.0%	4,464.86	$4,836.63	$4,996.72	$160.09	3.3%
100.0%	8,063.23	$8,555.18	$8,842.39	$287.21	3.4%
Average	2,527.37	$2,834.43	$2,926.07	$91.64	3.2%
		Distribution Only			
10.0%	410.78	$322.25	$342.48	$20.23	6.3%
20.0%	855.12	$430.01	$469.56	$39.56	9.2%
30.0%	1,123.60	$495.11	$546.35	$51.24	10.3%
40.0%	1,358.83	$552.16	$613.63	$61.47	11.1%
50.0%	1,592.36	$608.79	$680.42	$71.63	11.8%
60.0%	1,899.01	$683.15	$768.12	$84.97	12.4%
70.0%	2,385.06	$801.02	$907.13	$106.11	13.2%
80.0%	3,120.90	$979.46	$1,117.58	$138.12	14.1%
90.0%	4,464.86	$1,305.37	$1,501.95	$196.58	15.1%
100.0%	8,063.23	$2,177.97	$2,531.08	$353.11	16.2%
Average	2,527.37	$835.53	$947.83	$112.30	13.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - All therms ($/thm)	$0.2425	(1)	Distribution Charge - All therms ($/thm)	$0.2860	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, High Winter Use - G41
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	0.00	$222.64	$225.00	$2.36	1.1%
20.0%	8.12	$227.86	$230.97	$3.12	1.4%
30.0%	50.08	$254.82	$261.83	$7.02	2.8%
40.0%	125.85	$303.50	$317.57	$14.06	4.6%
50.0%	243.55	$379.13	$404.14	$25.01	6.6%
60.0%	375.58	$463.96	$501.25	$37.29	8.0%
70.0%	522.98	$558.66	$609.66	$51.00	9.1%
80.0%	723.73	$687.65	$757.32	$69.67	10.1%
90.0%	1,101.48	$930.36	$1,035.16	$104.80	11.3%
100.0%	2,699.06	$1,956.83	$2,210.21	$253.38	12.9%
Average	585.04	$598.54	$655.31	$56.77	9.5%
		Distribution Only			
10.0%	0.00	$222.64	$225.00	$2.36	1.1%
20.0%	8.12	$224.18	$227.32	$3.14	1.4%
30.0%	50.08	$232.13	$239.32	$7.19	3.1%
40.0%	125.85	$246.49	$260.99	$14.50	5.9%
50.0%	243.55	$268.79	$294.66	$25.86	9.6%
60.0%	375.58	$293.81	$332.42	$38.60	13.1%
70.0%	522.98	$321.74	$374.57	$52.83	16.4%
80.0%	723.73	$359.79	$431.99	$72.20	20.1%
90.0%	1,101.48	$431.37	$540.02	$108.65	25.2%
100.0%	2,699.06	$734.11	$996.93	$262.82	35.8%
Average	585.04	$333.51	$392.32	$58.82	17.6%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - All therms ($/thm)	$0.1895	(1)	Distribution Charge - All therms ($/thm)	$0.2860	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, Low Winter Use - G51
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
			Delivery and Supply		
10.0%	298.97	$481.21	$481.31	$0.10	0.0%
20.0%	665.04	$797.83	$795.16	($2.68)	-0.3%
30.0%	830.71	$941.12	$937.19	($3.93)	-0.4%
40.0%	961.40	$1,054.16	$1,049.24	($4.92)	-0.5%
50.1%	1,110.81	$1,183.38	$1,177.33	($6.05)	-0.5%
60.1%	1,275.37	$1,325.71	$1,318.41	($7.30)	-0.6%
70.0%	1,540.79	$1,547.73	$1,545.96	($1.77)	-0.1%
80.0%	1,950.17	$1,888.99	$1,896.93	$7.94	0.4%
90.0%	2,919.75	$2,697.23	$2,728.18	$30.95	1.1%
100.0%	5,195.70	$4,594.46	$4,679.41	$84.95	1.8%
Average	1,674.87	$1,659.50	$1,660.91	$1.41	0.1%
			Distribution Only		
10.0%	298.97	$273.82	$276.36	$2.54	0.9%
20.0%	665.04	$336.50	$339.25	$2.76	0.8%
30.0%	830.71	$364.86	$367.72	$2.86	0.8%
40.0%	961.40	$387.23	$390.17	$2.94	0.8%
50.1%	1,110.81	$412.81	$415.84	$3.03	0.7%
60.1%	1,275.37	$440.98	$444.11	$3.13	0.7%
70.0%	1,540.79	$478.89	$489.71	$10.82	2.3%
80.0%	1,950.17	$536.16	$560.04	$23.88	4.5%
90.0%	2,919.75	$671.80	$726.61	$54.81	8.2%
100.0%	5,195.70	$990.21	$1,117.62	$127.41	12.9%
Average	1,674.87	$497.64	$512.74	$15.10	3.0%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - First 1,300 therms ($/thm)	$0.1712	(1)	Distribution Charge - All therms ($/thm)	$0.1718	(3)
Distribution Charge - Excess 1,300 therms ($/thm)	$0.1399	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - Medium Annual, Low Winter Use - G51
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.0%	112.57	$280.45	$286.71	$6.26	2.2%
20.0%	415.51	$436.03	$452.77	$16.74	3.8%
30.0%	530.84	$495.26	$515.99	$20.73	4.2%
40.0%	615.04	$538.51	$562.15	$23.64	4.4%
50.0%	707.58	$586.03	$612.87	$26.84	4.6%
60.0%	801.28	$634.15	$664.24	$30.09	4.7%
70.0%	921.82	$696.06	$730.31	$34.26	4.9%
80.0%	1,114.68	$792.23	$836.03	$43.80	5.5%
90.0%	1,569.17	$1,014.29	$1,085.17	$70.89	7.0%
100.0%	3,257.80	$1,839.29	$2,010.83	$171.54	9.3%
Average	1,004.63	$738.47	$775.71	$37.24	5.0%
		Distribution Only			
10.0%	112.57	$237.69	$244.34	$6.65	2.8%
20.0%	415.51	$278.19	$296.38	$18.19	6.5%
30.0%	530.84	$293.61	$316.20	$22.58	7.7%
40.0%	615.04	$304.87	$330.66	$25.79	8.5%
50.0%	707.58	$317.24	$346.56	$29.32	9.2%
60.0%	801.28	$329.77	$362.66	$32.89	10.0%
70.0%	921.82	$345.89	$383.37	$37.48	10.8%
80.0%	1,114.68	$368.81	$416.50	$47.70	12.9%
90.0%	1,569.17	$418.21	$494.58	$76.37	18.3%
100.0%	3,257.80	$601.76	$784.69	$182.93	30.4%
Average	1,004.63	$356.84	$397.60	$40.75	11.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$222.64	(1)	Customer Charge ($/customer)	$225.00	(3)
Distribution Charge - First 1,000 therms ($/thm)	$0.1337	(1)	Distribution Charge - All therms ($/thm)	$0.1718	(3)
Distribution Charge - Excess 1,000 therms ($/thm)	$0.1087	(1)			
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, High Winter Use - G42
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.2%	3,952.46	$5,245.98	$5,300.20	$54.22	1.0%
20.0%	7,213.13	$8,471.76	$8,559.00	$87.24	1.0%
30.2%	9,121.50	$10,359.71	$10,466.28	$106.56	1.0%
40.0%	10,470.29	$11,694.07	$11,814.29	$120.22	1.0%
50.2%	11,571.15	$12,783.15	$12,914.52	$131.37	1.0%
60.0%	13,509.92	$14,701.17	$14,852.17	$151.00	1.0%
70.2%	15,600.24	$16,769.12	$16,941.30	$172.17	1.0%
80.0%	18,555.29	$19,692.56	$19,894.66	$202.10	1.0%
90.2%	24,287.75	$25,363.68	$25,623.83	$260.15	1.0%
100.0%	94,489.70	$94,814.48	$95,785.55	$971.08	1.0%
Average	20,877.14	$21,989.57	$22,215.18	$225.61	1.0%
		Distribution Only			
10.2%	3,952.46	$2,119.98	$2,206.50	$86.52	4.1%
20.0%	7,213.13	$2,766.90	$2,913.09	$146.19	5.3%
30.2%	9,121.50	$3,145.52	$3,326.63	$181.11	5.8%
40.0%	10,470.29	$3,413.12	$3,618.91	$205.80	6.0%
50.2%	11,571.15	$3,631.53	$3,857.47	$225.94	6.2%
60.0%	13,509.92	$4,016.18	$4,277.60	$261.42	6.5%
70.2%	15,600.24	$4,430.90	$4,730.57	$299.67	6.8%
80.0%	18,555.29	$5,017.18	$5,370.93	$353.75	7.1%
90.2%	24,287.75	$6,154.50	$6,613.16	$458.66	7.5%
100.0%	94,489.70	$20,082.57	$21,825.92	$1,743.35	8.7%
Average	20,877.14	$5,477.84	$5,874.08	$396.24	7.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1984	(1)	Distribution Charge - All therms ($/thm)	$0.2167	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.7437	(2)	COGC ($/thm)	$0.7393	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, High Winter Use - G42
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.1%	145.06	$1,419.02	$1,446.64	$27.62	1.9%
20.2%	557.94	$1,655.85	$1,721.71	$65.86	4.0%
29.8%	1,236.71	$2,045.21	$2,173.92	$128.71	6.3%
39.9%	2,019.46	$2,494.20	$2,695.40	$201.20	8.1%
50.0%	2,763.59	$2,921.05	$3,191.16	$270.11	9.2%
60.1%	3,577.05	$3,387.66	$3,733.10	$345.44	10.2%
70.2%	4,914.67	$4,154.94	$4,624.25	$469.31	11.3%
79.8%	6,697.70	$5,177.72	$5,812.14	$634.42	12.3%
89.9%	9,872.70	$6,998.96	$7,927.40	$928.44	13.3%
100.0%	44,000.48	$26,575.22	$30,664.02	$4,088.80	15.4%
Average	7,578.54	$5,682.98	$6,398.98	$715.99	12.6%
		Distribution Only			
10.1%	145.06	$1,353.30	$1,381.44	$28.13	2.1%
20.2%	557.94	$1,403.10	$1,470.91	$67.81	4.8%
29.8%	1,236.71	$1,484.96	$1,618.00	$133.04	9.0%
39.9%	2,019.46	$1,579.36	$1,787.62	$208.26	13.2%
50.0%	2,763.59	$1,669.10	$1,948.87	$279.77	16.8%
60.1%	3,577.05	$1,767.20	$2,125.15	$357.94	20.3%
70.2%	4,914.67	$1,928.52	$2,415.01	$486.49	25.2%
79.8%	6,697.70	$2,143.55	$2,801.39	$657.84	30.7%
89.9%	9,872.70	$2,526.46	$3,489.41	$962.96	38.1%
100.0%	44,000.48	$6,642.27	$10,884.91	$4,242.64	63.9%
Average	7,578.54	$2,249.78	$2,992.27	$742.49	33.0%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1206	(1)	Distribution Charge - All therms ($/thm)	$0.2167	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.4058	(2)	COGC ($/thm)	$0.4061	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, Low Winter Use - G52
Proposed Rates versus Present Rates
Winter

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.3%	821.21	$2,046.73	$2,054.21	$7.48	0.4%
20.0%	8,495.02	$8,689.95	$8,634.71	($55.24)	-0.6%
30.3%	11,712.45	$11,475.28	$11,393.74	($81.54)	-0.7%
40.0%	16,972.72	$16,029.10	$15,904.57	($124.53)	-0.8%
50.3%	23,903.02	$22,028.65	$21,847.48	($181.17)	-0.8%
60.0%	34,186.20	$30,930.80	$30,665.58	($265.22)	-0.9%
70.3%	47,229.91	$42,222.75	$41,850.92	($371.82)	-0.9%
80.0%	56,936.34	$50,625.60	$50,174.44	($451.16)	-0.9%
90.3%	74,244.21	$65,609.02	$65,016.41	($592.61)	-0.9%
100.0%	158,615.50	$138,649.25	$137,367.06	($1,282.19)	-0.9%
Average	43,311.66	$38,830.71	$38,490.91	($339.80)	-0.9%
		Distribution Only			
10.3%	821.21	$1,477.06	$1,491.25	$14.19	1.0%
20.0%	8,495.02	$2,796.95	$2,811.14	$14.19	0.5%
30.3%	11,712.45	$3,350.35	$3,364.54	$14.19	0.4%
40.0%	16,972.72	$4,255.12	$4,269.31	$14.19	0.3%
50.3%	23,903.02	$5,447.13	$5,461.32	$14.19	0.3%
60.0%	34,186.20	$7,215.84	$7,230.03	$14.19	0.2%
70.3%	47,229.91	$9,459.36	$9,473.55	$14.19	0.2%
80.0%	56,936.34	$11,128.86	$11,143.05	$14.19	0.1%
90.3%	74,244.21	$14,105.81	$14,120.00	$14.19	0.1%
100.0%	158,615.50	$28,617.68	$28,631.87	$14.19	0.0%
Average	43,311.66	$8,785.42	$8,799.61	$14.19	0.2%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.1720	(1)	Distribution Charge - All therms ($/thm)	$0.1720	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.6465	(2)	COGC ($/thm)	$0.6421	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - NH Division
General Service - High Annual, Low Winter Use - G52
Proposed Rates versus Present Rates
Summer

Cumulative Percentage of Bills	Average Monthly Usage (Therms)	Monthly Bills @ Present Rates	Monthly Bills @ Proposed Rates	$ Difference	% Difference
		Delivery and Supply			
10.1%	2,623.08	$2,539.98	$2,631.30	$91.32	3.6%
20.1%	8,643.71	$5,303.85	$5,572.20	$268.35	5.1%
30.2%	11,831.46	$6,767.24	$7,129.32	$362.08	5.4%
40.2%	18,488.22	$9,823.14	$10,380.95	$557.81	5.7%
50.3%	25,068.63	$12,843.98	$13,595.29	$751.30	5.8%
59.8%	29,171.12	$14,727.30	$15,599.23	$871.93	5.9%
69.8%	35,448.25	$17,608.92	$18,665.42	$1,056.50	6.0%
79.9%	47,888.13	$23,319.65	$24,741.93	$1,422.28	6.1%
89.9%	70,667.62	$33,776.96	$35,869.04	$2,092.08	6.2%
100.0%	143,682.62	$67,295.71	$71,534.71	$4,239.00	6.3%
Average	39,351.28	$19,400.67	$20,571.94	$1,171.26	6.0%
		Distribution Only			
10.1%	2,623.08	$1,543.56	$1,644.05	$100.49	6.5%
20.1%	8,643.71	$2,020.39	$2,318.96	$298.57	14.8%
30.2%	11,831.46	$2,272.86	$2,676.31	$403.45	17.8%
40.2%	18,488.22	$2,800.08	$3,422.53	$622.45	22.2%
50.3%	25,068.63	$3,321.25	$4,160.19	$838.95	25.3%
59.8%	29,171.12	$3,646.16	$4,620.08	$973.92	26.7%
69.8%	35,448.25	$4,143.31	$5,323.75	$1,180.44	28.5%
79.9%	47,888.13	$5,128.55	$6,718.26	$1,589.71	31.0%
89.9%	70,667.62	$6,932.69	$9,271.84	$2,339.15	33.7%
100.0%	143,682.62	$12,715.47	$17,456.82	$4,741.35	37.3%
Average	39,351.28	$4,452.43	$5,761.28	$1,308.85	29.4%

Present Rates			Proposed Rates		
Customer Charge ($/customer)	$1,335.81	(1)	Customer Charge ($/customer)	$1,350.00	(3)
Distribution Charge - All therms ($/thm)	$0.0792	(1)	Distribution Charge - All therms ($/thm)	$0.1121	(3)
LDAC ($/thm)	$0.0472	(2)	LDAC ($/thm)	$0.0434	(4)
COGC ($/thm)	$0.3327	(2)	COGC ($/thm)	$0.3330	(5)

(1) Current seasonal rates
(2) 6 month average seasonal COG
(3) Proposed Rates, Schedule RAJT-11
(4) Seasonal rates adjusted for changes due to rate proposal
(5) 6 month average seasonal COG adjusted for changes due to rate proposal

Northern Utilities - New Hampshire Division
Typical Residential Heating Bill (R-5)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Residential Heating (R-5)	Nov (1)	Dec (2)	Jan (3)	Feb (4)	Mar (5)	Apr (6)	May (7)	Jun (8)	Jul (9)	Aug (10)	Sep (11)	Oct (12)	Total Peak (13)	Total Off-Peak (14)	Annual Nov-Oct (15)
1	Test Year Monthly Weather Normalized Therms per Custome	52	$101	133	139	115	78	44	26	11	9	14	26	618	131	749
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	TOTAL BILL	$101.87	$176.60	$226.34	$235.99	$199.08	$141.54	$70.66	$50.14	$34.54	$32.46	$37.14	$51.08	$1,081	$276	$1,357
10																
11																
12	**Proposed November - October Rates**															
13	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
14	Distribution	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491			
15	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
16	COGC ($/therm) inc. increment	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
17																
18	TOTAL BILL	$114.75	$196.27	$250.53	$261.05	$220.79	$158.03	$86.33	$61.56	$42.73	$40.23	$45.87	$62.70	$1,201	$339	$1,541
19																
20	**Proposed Bill less Current Bill**															
21	Total Bill increase/(decrease)	$12.88	$19.67	$24.19	$25.06	$21.71	$16.48	$15.67	$11.42	$8.19	$7.76	$8.73	$11.62	$120	$63	$183
22	Percentage increase/(decrease)	12.6%	11.1%	10.7%	10.6%	10.9%	11.6%	22.2%	22.8%	23.7%	23.9%	23.5%	22.7%	11.1%	23.0%	13.5%

Northern Utilities - New Hampshire Division
Typical Low Income Residential Heating Bill (R-10)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Low Income Residential Heating (R-10)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total Peak	Total Off-Peak	Annual Nov-Oct
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Test Year Monthly Weather Normalized Therms per Custome	50	86	121	130	116	82	47	26	10	8	13	27	585	132	717
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6920	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099	$0.6099			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	45% Customer Charge Discount ($/customer)	-$9.99	-$9.99	-$9.99	-$9.99	-$9.99	-$9.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
10	45% Therm Discount - ($/thm)	-$0.3114	-$0.3114	-$0.3114	-$0.3114	-$0.3114	-$0.3114	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
11	45% Therm Discount - Cost of Gas ($/thm)	-$0.3292	-$0.3292	-$0.3292	-$0.3292	-$0.3292	-$0.3292	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
12																
13	TOTAL BILL	$56.60	$89.19	$120.40	$128.43	$115.36	$85.62	$73.35	$50.61	$33.49	$31.34	$36.27	$51.92	$596	$277	$873
14																
15																
16	**Proposed November - October Rates**															
17	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
18	Distribution	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491	$0.8491			
19	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
20	COGC ($/therm)	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
21																
22	45% Customer Charge Discount ($/customer)	-$12.53	-$12.53	-$12.53	-$12.53	-$12.53	-$12.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00			
23	45% Therm Discount - ($/thm)	-$0.3821	-$0.3821	-$0.3821	-$0.3821	-$0.3821	-$0.3821	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
24	45% Therm Discount - Cost of Gas ($/thm)	-$0.3272	-$0.3272	-$0.3272	-$0.3272	-$0.3272	-$0.3272	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000			
25																
26	TOTAL BILL	$63.21	$98.38	$132.06	$140.72	$126.62	$94.53	$89.58	$62.13	$41.46	$38.87	$44.82	$63.71	$656	$341	$996
27																
28	**Proposed Bill less Current Bill**															
29	Total Bill increase/(decrease)	$6.61	$9.19	$11.66	$12.29	$11.26	$8.91	$16.23	$11.52	$7.98	$7.53	$8.55	$11.79	$60	$64	$124
30	Percentage increase/(decrease)	11.7%	10.3%	9.7%	9.6%	9.8%	10.4%	22.1%	22.8%	23.8%	24.0%	23.6%	22.7%	10.1%	23.0%	14.2%

Northern Utilities - New Hampshire Division
Typical Residential Non-Heating Bill (R-6)
Bill Impacts Illustrating Changes on a Monthly Basis
Current Rates and Proposed Rates, using 6 month average COGC

Line No.	Residential Non-Heating (R-6)	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Total Peak	Total Off-Peak	Annual Nov-Oct
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Test Year Monthly Weather Normalized Therms per Custome	14	21	25	26	21	16	14	11	9	8	10	11	123	63	186
2																
3	**Current November - October Rates**															
4	Customer Charge	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20	$22.20			
5	Distribution	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470	$0.6470			
6	LDAC ($/therm)	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099	$0.1099			
7	COGC ($/therm)	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.7315	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724	$0.3724			
8																
9	TOTAL BILL	$42.60	$53.42	$59.73	$60.30	$53.62	$46.58	$37.65	$35.07	$32.45	$31.65	$33.16	$34.20	$316	$204	$520
10																
11																
12	**Proposed November - October Rates**															
13	Customer Charge	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84	$27.84			
14	Distribution	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208	$1.1208			
15	LDAC ($/therm)	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965	$0.0965			
16	COGC ($/therm)	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.7271	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727	$0.3727			
17																
18	TOTAL BILL	$54.50	$68.63	$76.87	$77.62	$68.89	$59.69	$49.59	$45.96	$42.27	$41.14	$43.27	$44.74	$406	$267	$673
19																
20	**Proposed Bill less Current Bill**															
21	Total Bill increase/(decrease)	$11.89	$15.21	$17.14	$17.31	$15.27	$13.11	$11.94	$10.89	$9.82	$9.49	$10.11	$10.54	$90	$63	$153
22	Percentage increase/(decrease)	27.9%	28.5%	28.7%	28.7%	28.5%	28.1%	31.7%	31.1%	30.3%	30.0%	30.5%	30.8%	28.4%	30.8%	29.3%

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

EXHIBIT TSL-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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 Northern Utilities, Inc. ("Northern" 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") 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.
- Section VI summarizes the benefits of the proposed RDM.

III. OVERVIEW OF REVENUE DECOUPLING

Q. What is revenue decoupling?

A. Revenue decoupling breaks or "decouples" the link between utility revenues and 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 Rate ("LRR") within the Local Delivery Adjustment Charge ("LDAC") 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

[1] Docket DE 15-137

example of full revenue decoupling. Variances can be measured on the basis of total revenues, or revenues per customer ("RPC").

Q. Has the Commission approved a revenue decoupling mechanism for New Hampshire gas and electric utilities?

A. Yes. The Commission approved a lost revenue adjustment mechanism ("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:

[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.")

> "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 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 and the revenue decoupling mechanism recently filed by the Company's New Hampshire electric division (Unitil Energy Systems, Inc.)[8].

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. The Company proposes that the authorized RPC be adjusted

[5] Id., p. 60
[6] Docket DE 17-048, Order No. 26,122 at pp. 45-46 ("We applaud Liberty for proposing a decoupling mechanism to replace the LRAM.").
[7] Docket DE 19-064, Order No. 26,376 at pp. 9, 13 (approving a Settlement Agreement supporting the implementation of a decoupling mechanism).
[8] Docket DE 21-030.

annually to reflect three estimated annual step increases on August 1, 2022 of $3.1 million; August 1, 2023 of $3.1 million; and August 1, 2024 of $3.2 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 aggregated over the twelve-month period August through July (the "Measurement Period"). The monthly variances are recorded in a deferred account with carrying costs accrued at the Prime rate.[9] 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 surpluses (actual RPC is greater than authorized RPC) during the Measurement Period will result in a credit or refund for the customers. Conversely, revenue shortfalls (i.e., actual RPC is less than authorized RPC) during the Measurement Period will result in a surcharge to the customers.

In the second step, the Company will file with the Commission the applicable RDAF 45 days in advance of the effective date of November 1. 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.

[9] 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 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 therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the prospective twelve-month period November through October ("RDM Adjustment Period"). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

The tariff for the Company's proposed RDM is included in Schedule TSL-2. Upon implementation of its first RDAF, the Company 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 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. Gas utilities incur three types of costs in providing natural gas service to customers:

- <u>Customer costs</u> – including meter, billing and a portion of distribution costs that generally vary by the number of customers;

- Demand-related costs – including transmission and distribution costs that generally vary by demand; and
- Commodity-related costs – including variable Operating and Maintenance expenses that generally vary by therm sales or natural gas 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 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.

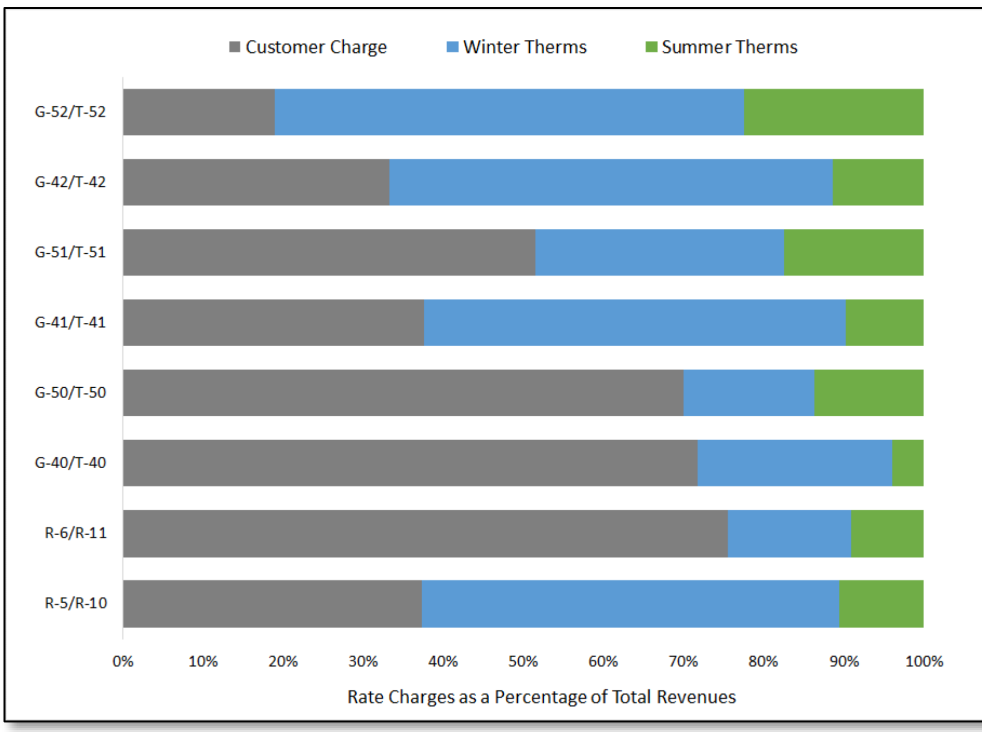
Q. Has the Commission recognized this misalignment between utility rates and costs?

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.”[10]

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 (therm sales) is significant, as shown in Figure 1.

Figure 1: Consumption Revenues as Percentage of Total Revenues[11]



The Figure shows that a significant portion of the Company’s residential and commercial distribution revenues are recovered through usage (therms). For

[10] Docket DE 15-137, Order No 25,932, p. 59
[11] Source: Settlement Agreement in Docket DG 17-070, Exhibit 2.

example, the Figure shows that approximately 60 percent of Residential Heating (R-5 and R-10 rate classes) revenues are recovered through consumption charges.

Q. Please discuss how revenue decoupling supports certain policy objectives.

A. The proposed RDM supports certain policy objectives, such as EE 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]

The RDM removes this financial disincentive, facilitating policies aimed to encourage EE initiatives. The Commission has noted: "Decoupling . . . was designed to sever the link between sales and revenues to remove [a utility's] disincentive to promote energy conservation that is inherent in traditional ratemaking."[13]

Q. Has the utility industry recognized the benefits of RDM in achieving policy objectives?

A. Yes. Revenue decoupling is recognized by the utility industry as an essential tool in promoting EE initiatives. An ACEEE report states: "For energy efficiency to

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[12] National Action Plan for Energy Efficiency (2007): Aligning Utility Incentives with Investment in Energy Efficiency, at p. ES-3

[13] Docket DG 19-145, Order No 26,306 at p. 7.

flourish, the use of decoupling needs to be expanded so that utilities can recover their fixed costs even if sales decline."[14] Moreover, the benefits of revenue decoupling are recognized in regulatory jurisdictions throughout the U.S. Full revenue decoupling is currently in effect in 22 jurisdictions, including New Hampshire. In New England, full revenue decoupling is currently in effect for 20 of 26 electric and gas utilities, as shown in Schedule TSL-3.[15]

IV. NORTHERN'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

[14] ACEEE The Future of the Utility Industry and the Role of Energy Efficiency (June 2014), at p. viii
[15] S&P Global Market Intelligence. Data as of April 12, 2021.

1. <u>Type of RDM</u>

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 better accomplishes the Commission's policy objective to severe the link between volumes and revenues, providing a greater incentive to pursue energy efficiency, as compared to partial or limited revenue decoupling.

Q. What is the primary benefit of the proposed RPC approach?

A. The primary benefit of the proposed RPC approach is the recognition of 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 RPC associated with serving new customers that is used to offset the costs associated with new customers.

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 August 1, 2022 of $3.1 million, August 1, 2023 of $3.1 million, and August 1, 2024 of $3.2 million associated with the 2021, 2022 and 2023 capital investments, as discussed in the testimony of Company witnesses Messrs. Christopher Goulding and Daniel Nawazelski.

Schedule TSL-4 shows derivation of the authorized RPC for the first step increase on August 1, 2022. Specifically, the Schedule shows the authorized RPC is based on the authorized revenues divided by the number of customers included in the authorized rate design. The authorized revenues are based on the target distribution revenues plus the step increase.

For example, the authorized RPC in August 2022 for the residential heating class of $40.49 is based on the authorized revenues of $51,687 divided by the number of customers included in the authorized rate design of 1,277. The authorized revenues of $51,687 are based on the target distribution revenues of $48,504 plus the 2022 step increase of $3,183.

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 Residential Heating and Non-Heating Service (Schedules R-5 and R10 combined, and R-6), Commercial and Industrial Service (Schedules G-40, G-50, G-41, G-42, G-51, and G-52) customer classes. The revenues associated with special contracts will not be included as part of the RDM.

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 surpluses (i.e., actual RPC greater than authorized RPC) during the Measurement Period will result in a credit or refund to customers, while revenue shortfalls (i.e., actual RPC less than authorized RPC) during the Measurement Period will result in a surcharge to customers.

Q. What is the proposed process to establish the RDAF?

A. The Company proposes to file with the Commission the applicable RDAF 45 days before the effective date of November 1. 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 therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the RDM Adjustment Period (prospective 12-month period November through October). 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
August 1 through July 31	Measure and record monthly in a deferred account the revenue variances between actual and authorized RPC
On or about September 17 (45 days before November 1)	File with the Commission the RDAF based on the aggregate monthly revenue variances and monthly carrying costs on the deferred account balances
November 1 through October 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 based on the proportion of authorized revenues in the most recent rate case, including step adjustments.

6. <u>Factor Calculation</u>

Q. How will the RDAF be calculated?

A. The RDAF will be calculated on a dollar per therm basis for each rate class based on the RDA allocated to each rate class divided by the projected class therm sales for the RDM Adjustment Period (November through October). The RDAF will be applied to customer bills during the RDM Adjustment Period.

7. <u>Adjustment Cap</u>

Q. Is the Company proposing any adjustment cap?

A. Northern proposes to limit the RDA to two- and one-half percent (2.5%) of total revenues from delivered sales for the most recent twelve-month period, August through July, with revenue for externally supplied customers being adjusted by imputing the Company's cost of gas charges for that period. To help mitigate customer bill impacts, the cap would be applicable only to revenue shortfalls. 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 August through July (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 surplus (actual revenues are greater than authorized revenues) during the Measurement Period, the RDM will result in a credit or refund to customers. Conversely, 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.

In the second step, the Company files with the Commission the applicable RDAF 45 days before the effective date of November 1. 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 therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the RDM Adjustment

Period (twelve-month period November through October). 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 2 (below).

Figure 2: Monthly Residential Heating Revenue Variance Calculation (Illustrative)[16]

Illustrative Calculation	Actual Residential Heating			Authorized Residential Heating			Variance Over / (Under)	
Variance Over / (Under)	Revenues	Customers	RPC	Revenues	Customers	RPC	RPC	Revenues
August	$ 1,081,951	27,217	$ 39.75	$ 1,076,569	26,815	$ 40.15	$ (0.40)	$ (10,766)
September	1,283,256	27,217	47.15	1,276,871	26,815	47.62	(0.47)	(12,769)
October	1,775,342	27,217	65.23	1,766,509	26,815	65.88	(0.65)	(17,665)
November	2,635,287	27,217	96.82	2,622,176	26,815	97.79	(0.96)	(26,222)
December	3,694,761	27,217	135.75	3,676,379	26,815	137.10	(1.35)	(36,764)
January	4,118,742	27,217	151.33	4,098,251	26,815	152.84	(1.51)	(40,983)
February	3,747,792	27,217	137.70	3,729,146	26,815	139.07	(1.37)	(37,291)
March	3,287,159	27,217	120.78	3,270,805	26,815	121.98	(1.20)	(32,708)
April	2,260,725	27,217	83.06	2,249,478	26,815	83.89	(0.83)	(22,495)
May	1,663,286	27,217	61.11	1,655,011	26,815	61.72	(0.61)	(16,550)
June	1,238,872	27,217	45.52	1,232,709	26,815	45.97	(0.45)	(12,327)
July	1,054,859	27,217	38.76	1,049,611	26,815	39.14	(0.39)	(10,496)
12ME July	$ 27,842,031	326,604		$ 27,703,514	321,778			$ (277,035)

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

[16] The illustrative calculation assumes a 1.00 percent reduction in revenue per customer each month

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 Prime rate, as illustrated for the residential rate class in Figure 3 (below).

Figure 3: Deferred Account Balance (Illustrative)[17]

Illustrative Deferred Account Balance	Deferred Account Starting Balance	Revenue Variance	Carrying Costs Rate	Carrying Costs	Deferred Account Ending Balance
August	$ -	$ (10,766)	0.27%	$ (15)	$ (10,780)
September	(10,780)	$ (12,769)	0.27%	(46)	$ (23,595)
October	(23,595)	$ (17,665)	0.27%	(88)	$ (41,348)
November	(41,348)	$ (26,222)	0.27%	(147)	$ (67,718)
December	(67,718)	$ (36,764)	0.27%	(233)	$ (104,715)
January	(104,715)	$ (40,983)	0.27%	(339)	$ (146,036)
February	(146,036)	$ (37,291)	0.27%	(446)	$ (183,774)
March	(183,774)	$ (32,708)	0.27%	(542)	$ (217,024)
April	(217,024)	$ (22,495)	0.27%	(618)	$ (240,137)
May	(240,137)	$ (16,550)	0.27%	(673)	$ (257,360)
June	(257,360)	$ (12,327)	0.27%	(714)	$ (270,400)
July	(270,400)	$ (10,496)	0.27%	(747)	$ (281,643)
August	(281,643)		0.27%	(763)	$ (282,406)
September	(282,406)		0.27%	(765)	$ (283,171)
October	(283,171)		0.27%	(767)	$ (283,938)
Total		$ **(277,035)**		$ **(6,903)**	$ **(283,938)**

The Figure shows that carrying costs of $6,903 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.[18]

Q. Please discuss the second step in calculating the RDM adjustment.

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[17] The illustrative calculation assumes a Prime Rate of 3.25 percent, or 0.2708 percent monthly
[18] The illustrative calculation shows RDA based on 12 months' ending July balance. However, the Company's proposed RDA filed will also include estimated carrying costs through October 31.

A. In the second step, the Company will file 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 class based on each class's authorized revenues, including step adjustments, as shown in Figure 4 (below).

Figure 4: Decoupling Adjustment Allocation (Illustrative)[19]

Illustrative Revenue Decoupling Adjustment	Authorized Revenues ($)	Authorized Revenues (%)	Allocated RDA ($)
Residential Non-Heating (R-6)	$ 737,886	1.45%	$ (4,112)
Residential Heating (R-5/R-10)	27,702,514	54.37%	(154,385)
C&I Low Annual, High Winter (G-40)	8,274,293	16.24%	(46,112)
C&I Low Annual, Low Winter (G-50)	1,201,344	2.36%	(6,695)
C&I Medium Annual, High Winter (G-41)	6,421,989	12.60%	(35,790)
C&I Medium Annual, Low Winter (G-51)	1,638,520	3.22%	(9,131)
C&I High Annual, High Winter (G-42)	1,895,204	3.72%	(10,562)
C&I High Annual, Low Winter (G-52)	3,077,325	6.04%	(17,150)
Total	$ 50,949,076	100.00%	$ (283,938)

The Figure shows that the Residential Heating class revenues are 54.37 percent of total Company revenues. Accordingly, the deferred account balance allocated to the Residential Heating class is $154,385.

The allocated RDA forms the basis for the calculation of RDAF for each rate class, as shown in Figure 5 (below).

[19] The RDA will be allocated to each rate class based on each class's authorized revenues. For illustrative purpose, Figure 4 currently shows the Company's proposed revenues plus 2022 step increase in the 'Authorized Revenues ($)' column. The illustrative deferred account balance assumes that only the Residential class experienced a revenue change.

Figure 5: Calculation of RDAF (Illustrative)

Illustrative Revenue Decoupling Adjustment	Charge/ (Refund) ($)	Adjusted Test Year Sales	Charge/ (Refund) ($/therm)
Residential Non-Heating (R-6)	$ 4,112	237,269	$ 0.0173
Residential Heating (R-5/R-10)	154,385	20,067,257	0.0077
C&I Low Annual, High Winter (G-40)	46,112	10,880,833	0.0042
C&I Low Annual, Low Winter (G-50)	6,695	1,474,573	0.0045
C&I Medium Annual, High Winter (G-41)	35,790	14,423,832	0.0025
C&I Medium Annual, Low Winter (G-51)	9,131	4,761,300	0.0019
C&I High Annual, High Winter (G-42)	10,562	5,889,772	0.0018
C&I High Annual, Low Winter (G-52)	17,150	16,417,274	0.0010
Total	$ 283,938	74,152,109	

The Figure shows that the RDAF for the Residential Heating class will be $0.0077 per therm. The adjustment factor would be implemented on customer bills during the November through October RDM Adjustment Period.

Q. Please describe how the RDAF will appear on customer bills.

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.

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 rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as 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 and sponsored testimony supporting a 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			
Liberty Utilities (CalPeco Electric)	5/21	Docket No. A 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
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 supporting 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			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
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.

Sponsor	Date	Docket No.	Subject
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
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.
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			
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
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.

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Sponsor	Date	Docket No.	Subject
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			
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
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.

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Sponsor	Date	Docket No.	Subject
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.
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.

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Sponsor	Date	Docket No.	Subject
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.
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.

IX. 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 Residential Service (Rates R-5, R-6, R-10) and Commercial/ Industrial Service (Rates G-40, G-50, G-41, G-42, G-51, G-52) customers.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. Actual Base Revenues is the revenue billed for a Customer Class through the Company's customer charge and distribution charges plus the change in unbilled revenues. This excludes revenues billed 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 November 1, 2023 to October 31, 2024. Each subsequent Adjustment Period shall be the twelve months November 1 through October 31.

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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: Residential Heating (Rate R-5 and R-10), Residential Non-Heating (Rate R-6), Low Annual Use, High Peak Use Commercial & Industrial (Rate G-40), Low Annual Use, Low Peak Use C&I (Rate G-50), Medium Annual Use, High Peak Use C&I (Rate G-41), Medium Annual Use, Low Peak Use C&I (Rate G-51), High Annual Use, High Peak Use C&I (Rate G-42), and High Annual Use, Low Peak Use C&I (Rate G-52).
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 August 1, 2022 to July 31, 2023. Each subsequent Measurement Period shall be the twelve months August 1 through July 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

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 the prime interest rate as reported by the Wall Street Journal on the first business day of the month preceding the first month of the quarter. Following the end of each Measurement Period, 45 days before the effective date of November 1, 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)

$$\mathrm{MRV}_i^{CC} = \left(\mathrm{ARPC}_i^{CC} - \mathrm{AURPC}_i^{CC}\right) \text{ x } \mathrm{ACUST}_i^{CC}$$

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:

$$\mathrm{ARPC}_i^{CC} = \frac{\text{Actual Month i Revenue for Customer Class}}{\text{Actual Month i Bills for Customer Class}}$$

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

$$\mathrm{AURPC}_i^{CC} = \frac{\text{Authorized Month i Revenue for Customer Class}}{\text{Authorized Month i Bills for Customer Class}}$$

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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

i: The twelve Months of the Measurement Period (August through July)

2. Revenue Decoupling Adjustment (RDA)

$$\mathrm{RDA} = [\sum_{\mathrm{CC}=1}^{8}[\sum_{i=1}^{12} \mathrm{MRV}_i^{\mathrm{CC}} + \mathrm{CarryingCosts}_i^{\mathrm{CC}}]] + \mathrm{REC_P}$$

Where:

$\mathrm{CarryingCosts}_i^{\mathrm{CC}}$: Carrying Costs on the deferral account balance calculated at the prime interest rate for month i for applicable Customer Class.

$\mathrm{REC_P}$: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

3. RDA Allocation, subject to Adjustment Cap

IF: $\mathrm{RDA} < 0$
AND IF: $|\mathrm{RDA}| > \mathrm{RDC}$

$$\text{THEN: } \mathrm{RDA^{CC}} = \mathrm{RDC} \times \frac{\mathrm{AURV^{CC}}}{\sum_{\mathrm{CC}=1}^{\mathrm{CC}=8}[\mathrm{AURV^{CC}}]}$$

$$\text{AND: } \mathrm{REC_C} = \mathrm{RDA} - \mathrm{RDC}$$

$$\text{OTHERWISE: } \mathrm{RDA^{CC}} = \mathrm{RDA} \times \frac{\mathrm{AURV^{CC}}}{\sum_{\mathrm{CC}=1}^{\mathrm{CC}=8}[\mathrm{AURV^{CC}}]}$$

Where:

$|\mathrm{RDA}|$: Absolute Value of RDA

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

$AURV^{CC}$: 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, August to July, 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 therm Sales for the Adjustment Period for the applicable customer class

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per therm) shall be calculated to the nearest one one-thousandth of a cent and will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

IX. REVENUE DECOUPLING ADJUSTMENT CLAUSE

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 interest 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, August to July, with revenue for externally supplied customers being adjusted by imputing the Company's cost of gas 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, Local Delivery Adjustment Clause ("LDAC"), 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 interest rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually with the Commission 45 days before November 1 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.

Full Revenue Decoupling Mechanisms in New England

State	Company	Gas/ Electric	Full Decoupling Mechanism
Connecticut	Connecticut Light and Power Co.	Electric	Yes
	Connecticut Natural Gas Co.	Gas	Yes
	Southern Connecticut Gas Co.	Gas	Yes
	United Illuminating Co.	Electric	Yes
	Yankee Gas Services Co.	Gas	Yes
Maine	Central Maine Power Co.	Electric	Yes
	Maine Natural Gas	Gas	No
	Northern Utilities, Inc	Gas	No
	Versant Power Co.	Electric	No
Massachusetts	Bay State Gas Co.	Gas	Yes
	Berkshire Gas Co.	Gas	Yes
	Boston Gas Co./Colonial Gas Co.	Gas	Yes
	Fitchburg Gas & Electric	Electric	Yes
	Fitchburg Gas & Electric	Gas	Yes
	Liberty Utilities (New England Natural Gas Co.) Corp.	Gas	Yes
	Massachusetts Electric Co.	Electric	Yes
	NSTAR Electric Co.	Electric	Yes
	NSTAR Gas Co.	Gas	Yes
New Hampshire	Liberty Utilities Co. (EnergyNorth Natural Gas)	Gas	Yes
	Liberty Utilities Co. (Granite State Electric)	Electric	Yes
	Northern Utilities Inc.	Gas	No
	Public Service Co. of New Hampshire	Electric	No
	Unitil Energy Systems Inc.	Electric	No
Rhode Island	Narragansett Electric Co.	Electric	Yes
	Narragansett Electric Co.	Gas	Yes
Vermont	Green Mountain Power Corp.	Electric	Yes
Total			**20 of 26**

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Revenue per Customer Calculation

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Target Distribution Revenues	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	$ 48,504	$ 1,010,268	$ 441,908	$ 92,041	$ 226,977	$ 111,532	$ 83,485	$ 188,344	$ 2,203,059
September	49,868	1,198,235	475,722	91,347	271,189	112,585	92,149	203,297	2,494,392
October	53,273	1,657,719	557,007	91,332	395,649	119,735	125,000	207,514	3,207,229
November	60,044	2,460,689	698,000	94,828	588,970	132,292	167,185	285,345	4,487,352
December	69,176	3,449,969	877,585	101,464	811,316	149,082	212,376	313,238	5,984,208
January	71,910	3,845,860	948,998	103,519	894,358	154,213	240,167	273,823	6,532,848
February	67,293	3,499,487	885,369	100,717	812,194	146,942	219,439	303,245	6,034,688
March	63,821	3,069,372	804,131	96,856	708,736	142,342	201,053	281,262	5,367,574
April	56,671	2,110,944	634,279	87,436	479,218	123,431	153,498	280,018	3,925,496
May	53,747	1,553,087	536,692	88,168	355,421	120,486	112,137	186,436	3,006,174
June	49,926	1,156,792	467,478	89,197	261,652	113,980	89,118	183,877	2,412,021
July	48,217	984,970	437,585	90,427	220,966	110,920	82,906	181,339	2,157,329
12ME July	$ 692,451	$ 25,997,394	$ 7,764,755	$ 1,127,333	$ 6,026,646	$ 1,537,541	$ 1,778,514	$ 2,887,738	$ 47,812,371

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Step Increase	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	$ 3,183	$ 66,300	$ 29,002	$ 6,041	$ 14,896	$ 7,320	$ 5,479	$ 12,361	$ 144,582
September	3,273	78,636	31,221	5,995	17,797	7,389	6,048	13,342	163,702
October	3,496	108,790	36,556	5,994	25,965	7,858	8,204	13,619	210,483
November	3,941	161,487	45,809	6,224	38,652	8,683	10,972	18,727	294,494
December	4,540	226,410	57,595	6,659	53,244	9,785	13,938	20,558	392,728
January	4,719	252,391	62,281	6,794	58,694	10,121	15,762	17,971	428,734
February	4,416	229,659	58,106	6,610	53,302	9,644	14,401	19,902	396,041
March	4,188	201,432	52,774	6,357	46,512	9,342	13,195	18,459	352,260
April	3,719	138,534	41,627	5,738	31,450	8,101	10,074	18,378	257,621
May	3,527	101,924	35,222	5,787	23,325	7,908	7,359	12,236	197,288
June	3,277	75,916	30,680	5,854	17,172	7,481	5,849	12,068	158,296
July	3,164	64,640	28,718	5,935	14,501	7,280	5,441	11,901	141,581
12ME July	$ 45,444	$ 1,706,120	$ 509,590	$ 73,987	$ 395,512	$ 100,912	$ 116,720	$ 189,524	$ 3,137,810

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Authorized Revenues	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	$ 51,687	$ 1,076,569	$ 470,910	$ 98,081	$ 241,873	$ 118,852	$ 88,964	$ 200,706	$ 2,347,642
September	53,141	1,276,871	506,944	97,342	288,987	119,974	98,196	216,639	2,658,094
October	56,769	1,766,509	593,563	97,326	421,614	127,593	133,204	221,133	3,417,712
November	63,985	2,622,176	743,809	101,051	627,622	140,974	178,157	304,072	4,781,846
December	73,716	3,676,379	935,180	108,124	864,561	158,867	226,314	333,796	6,376,936
January	76,629	4,098,251	1,011,279	110,313	953,052	164,335	255,928	291,794	6,961,582
February	71,709	3,729,146	943,475	107,328	865,496	156,586	233,841	323,148	6,430,729
March	68,009	3,270,805	856,905	103,213	755,249	151,685	214,248	299,722	5,719,835
April	60,391	2,249,478	675,906	93,174	510,668	131,533	163,572	298,396	4,183,117
May	57,274	1,655,011	571,914	93,955	378,746	128,394	119,496	198,672	3,203,462
June	53,203	1,232,709	498,158	95,051	278,824	121,461	94,967	195,945	2,570,317
July	51,381	1,049,611	466,303	96,362	235,467	118,200	88,347	193,240	2,298,910
12ME July	$ 737,895	$ 27,703,514	$ 8,274,345	$ 1,201,320	$ 6,422,158	$ 1,638,453	$ 1,895,234	$ 3,077,262	$ 50,950,181

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Customers in Authorized Rate Design	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	1,277	26,815	5,234	831	704	267	31	33	
September	1,277	26,815	5,234	831	704	267	31	33	
October	1,277	26,815	5,234	831	704	267	31	33	
November	1,277	26,815	5,234	831	704	267	31	33	
December	1,277	26,815	5,234	831	704	267	31	33	
January	1,277	26,815	5,234	831	704	267	31	33	
February	1,277	26,815	5,234	831	704	267	31	33	
March	1,277	26,815	5,234	831	704	267	31	33	
April	1,277	26,815	5,234	831	704	267	31	33	
May	1,277	26,815	5,234	831	704	267	31	33	
June	1,277	26,815	5,234	831	704	267	31	33	
July	1,277	26,815	5,234	831	704	267	31	33	

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial					
Authorized Revenue per Customer	R6	R5-R10	G40	G50	G41	G51	G42	G52
August	$ 40.49	$ 40.15	$ 89.97	$ 117.96	$ 343.46	$ 445.97	$ 2,869.82	$ 6,081.99
September	41.62	47.62	96.85	117.07	410.36	450.18	3,167.63	6,564.83
October	44.47	65.88	113.40	117.05	598.69	478.77	4,296.90	6,701.01
November	50.12	97.79	142.10	121.53	891.21	528.98	5,746.99	9,214.31
December	57.74	137.10	178.66	130.04	1,227.66	596.12	7,300.45	10,115.02
January	60.02	152.84	193.20	132.67	1,353.32	616.64	8,255.76	8,842.24
February	56.17	139.07	180.25	129.08	1,228.99	587.57	7,543.25	9,792.35
March	53.27	121.98	163.71	124.13	1,072.44	569.17	6,911.22	9,082.48
April	47.30	83.89	129.13	112.06	725.14	493.56	5,276.50	9,042.31
May	44.86	61.72	109.26	113.00	537.81	481.78	3,854.71	6,020.36
June	41.67	45.97	95.17	114.32	395.93	455.76	3,063.46	5,937.72
July	40.25	39.14	89.09	115.89	334.36	443.53	2,849.90	5,855.75
Total	$ 577.97	$ 1,033.14	$ 1,580.78	$ 1,444.82	$ 9,119.36	$ 6,148.04	$ 61,136.58	$ 93,250.36

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

JOHN COCHRANE

EXHIBIT JC-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

TABLE OF CONTENTS

ATTACHMENTS

Attachment	Title
JC-1	Resume of John Cochrane
JC-2	Summary of Results
JC-3	Proxy Group Selection
JC-4	Constant Growth DCF Results
JC-5	Multi-Stage DCF Results
JC-6	Proxy Group Betas
JC-7	Expected Market Return Calculation
JC-8	CAPM Results
JC-9	Flotation Costs
JC-10	Small Size Premium
JC-11	Proxy Group Capital Structure

I. INTRODUCTION AND BACKGROUND

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

A. My name is John Cochrane. I am a Senior Managing Director and head the Boston office of the Power & Utilities practice at FTI Consulting, Inc. ("FTI"). My business address is 200 State St, 9th Floor, Boston, Massachusetts.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Northern Utilities, Inc. d/b/a Unitil ("Northern" or "the Company").

Q. Please describe your education and professional experience.

A. I have more than 35 years of experience in utility finance. Prior to joining FTI, I held senior executive positions at National Grid plc ("National Grid"), where I was most recently Executive Vice President of Global Mergers & Acquisitions and Business Development. Prior to holding that position, I was Executive Vice President, Chief Financial Officer, and Treasurer for National Grid's U.S. business. I also serve or have served as a member of the Board of Directors of several utilities and other companies in the energy sector. I hold a Bachelor's degree in Biology from Harvard University and an MBA from Northeastern University. A copy of my resume is provided as Attachment JC-1.

Q. Please describe FTI's Power & Utilities practice.

A. FTI is a worldwide consulting firm dedicated to helping organizations manage change, mitigate risk, and resolve disputes. Our Power & Utilities practice brings these services to firms in regulated and competitive energy industries. The services we provide our utility clients include expert testimony, regulatory advice, support for strategic decision-making, and advice regarding investments and capital allocation. Our team is comprised of former utility executives, regulators, investors, and financial analysts that combine for hundreds of years of experience in the regulated energy space.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have testified before the New Hampshire Public Utilities Commission ("Commission") in several proceedings, most recently in Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities distribution service rate case, Docket No. DG 20-105, and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities distribution service rate case, Docket No. DE 19-064. A list of select testimony is included in Attachment JC-1.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present evidence and provide recommendations regarding the Return on Equity ("ROE") the Company should be allowed to earn on the equity portion of its rate base as well as recommendations regarding the Company's capital costs and capital structure.

Q. Please summarize your conclusions regarding the authorized ROE for the Company.

A. Based on the analyses that I describe in this testimony, I conclude that the reasonable range within which the Commission should authorize Northern's ROE is between 10.02% and 11.64%.

Q. Please summarize how you reached those conclusions.

A. My recommendations regarding the reasonable range of ROE are based on quantitative and qualitative analyses I undertook utilizing analytical approaches that are widely accepted for estimating a utility's cost of capital in New Hampshire and elsewhere. I developed analyses using two variants of the Discounted Cash Flow ("DCF") method, the Constant Growth DCF method and the Multi-Stage DCF method, and I also used the Capital Asset Pricing Model ("CAPM") to arrive at my preliminary estimate of a reasonable range of ROEs for Northern. I then undertook a quantitative analysis to adjust that range to account for the costs that Northern will incur in the issuance of new capital. Finally, I undertook quantitative and qualitative analyses of the Company's risk profile, including a small size premium, and the business environment in which it operates. A summary of the results from these analyses is presented in Attachment JC-2.

Q. What Return on Equity is the Company requesting in this case?

A. The Company requests a 10.30% ROE, which falls in the lower-middle end of the reasonable range. The Company's proposed ROE is discussed further in the testimonies of Robert B. Hevert, Todd Diggins and Andre Francoeur, and Christopher Goulding and Daniel Nawazelski.

Q. What are your recommendations regarding the Company's proposed capital structure and cost of debt?

A. The Company is proposing a capital structure that is comprised of 52.47% common equity and 47.53% long-term debt, details of which are provided in the Testimony of Messrs. Diggins and Francoeur. I find this capital structure is reasonable and consistent with other utility companies in my comparable group. Regarding the cost of debt, the Company proposes to use its actual net cost of debt of 4.93% for long-term debt, which I also find reasonable.

Q. What are your conclusions regarding Northern's total rate of return?

A. I conclude that a total Rate of Return ("ROR") of 7.75% is reasonable, based on an authorized ROE of 10.30%, a long-term debt cost of 4.93%, and a capital structure that includes 52.47% equity.

Table 1. ROR Summary Calculation

Cost of Equity	10.30%	*a*
Capital structure equity weight	52.47%	*b*
Cost of long-term debt	4.93%	*c*
Capital structure long-term debt weight	47.53%	*d*
Overall rate of return	7.75%	$e = a*b + c*d$

Q. How is the remainder of your testimony organized?

A. The remainder of my testimony is organized as follows:

- Section III describes the key regulatory principles underlying the estimation of the cost of capital for a regulated utility;
- Section IV describes the selection and composition of a proxy group of utility companies I used to conduct the analyses that underlie my testimony;
- Section V details the analyses I undertook to estimate Northern's cost of equity;
- Section VI describes the risk factors that justify establishing Northern's ROE in the range of reasonable ROEs;
- Section VII discusses my findings regarding the Company's proposed capital structure;
- Section VIII discusses my findings regarding the Company's proposed cost of debt; and
- Section IX summarizes my conclusions and recommendations.

III. REGULATORY PRINCIPLES

Q. Please describe the guiding principles to which you adhere in estimating the ROE for a regulated utility.

A. The United States Supreme Court established the standards for determining the fairness or reasonableness of a utility's allowed ROE in *Bluefield Water Works and Improvement Co. v. Public Service Commission of Virginia* ("*Bluefield*")[1] and *Federal Power Commission v. Hope Natural Gas Co.* ("*Hope*").[2] In those proceedings, the Court established that a regulated utility's ROE should be sufficient to attract capital and

[1] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923).
[2] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

support the company's credit quality, and that the ROE should be consistent with the returns investors would require in making investments of similar risk.

Q. Did you review any relevant precedents in New Hampshire?

A. Yes, I did. Commission Order No. 24,972 supports the *Hope* and *Bluefield* standards. Specifically, that Order 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 the 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.[3]

Q. Please summarize what these standards require.

A. Based on these standards, the return authorized in this proceeding should afford Northern the opportunity to earn a return that is:

- Adequate to attract capital at reasonable rates, allowing the Company to make the capital investments it requires to provide safe, reliable service;
- Sufficient to ensure the Company's financial integrity; and
- Consistent with returns provided by investments in other utilities with comparable risk profiles.

[3] Order No. 24,972 at 54 (May 29, 2009) (quoting *Appeal of Conservation Law Foundation*, 127 N.H. 606, 635 (1986)).

IV. PROXY GROUP SELECTION

Q. Please briefly describe Northern Utilities.

A. Northern provides gas distribution services to approximately 69,000 customers in southeastern New Hampshire and portions of southern and central Maine.[4] The Company is a subsidiary of Unitil Corporation ("Unitil") based in Hampton, New Hampshire and is traded on the New York Stock Exchange.

Q. Why is it necessary to use a proxy group to estimate Northern's ROE?

A. Northern is not a publicly traded company, which makes it impossible to directly observe its cost of equity. Even if it were publicly traded, anomalous or transitory events may mean that its current ROE is not generally reflective of its economic and financial fundamentals or indicative of investor expectations moving forward. For both reasons, it is standard practice to develop a "proxy group" of comparable, publicly traded companies that can be analyzed and from which inferences regarding Northern's ROE can be drawn.

Q. How did you select the companies in your proxy group?

A. Starting with the list of all companies categorized by Value Line as Gas Utilities, I applied a set of screening guidelines. Specifically, companies were generally included in the proxy group if:

- They received at least 60% of their operating income or net income from regulated gas operations;

[4] Approximately 35,000 customers are in New Hampshire and 34,000 are in Maine.

- They had investment-grade issuer ratings from either Standard & Poor's ("S&P") or Moody's;
- They consistently paid quarterly dividends with no cuts over the past four years;
- They were covered by at least two industry analysts;
- They had positive earnings growth estimates from at least two industry analysts;
- They had not been part of a significant transaction within the past six months.

Q. Have similar criteria been used to select proxy group companies in past proceedings before the Commission?

A. Yes, these criteria are similar to those used in past proceedings before the Commission.

Q. Please identify the companies in your proxy group.

A. The proxy group includes the following nine companies:

Table 2. Proxy Group

Company Name	Stock Ticker
Atmos Energy	ATO
Chesapeake Utilities	CPK
NiSource Inc.	NI
New Jersey Resources	NJR
Northwest Natural	NWN
ONE Gas Inc.	OGS
South Jersey Inds.	SJI
Spire Inc.	SR
Southwest Gas	SWX

Q. Is there any company shown in Table 2 that does not meet every aspect of your screening guidelines?

A. Yes, Chesapeake is not publicly rated by either Moody's or S&P. However, it has a Value Line Financial Strength rating of A, which is comparable to or higher than the rest of the proxy group companies.

Q. Why is neither Northern nor Unitil included in your proxy group of companies?

A. It is typical to not include the firm (nor its parent company) that is the subject of a rate proceeding in the composition of a proxy group in order to avoid any circularity issues that could bias results. In addition, Northern is not publicly traded nor does it make up the entirety of a publicly traded company. Because the cost of equity is a market-based concept and, therefore, readily observable and accessible data must be used, the proxy group cannot include Northern and instead consists of publicly traded companies that are similar in business and financial risks to Northern.

V. <u>COST OF EQUITY ANALYSIS</u>

Q. Please explain the relevance of a regulated utility's ROE in the context of setting retail gas rates.

A. Utilities are provided the opportunity to earn a reasonable return on the capital investments they make to provide for safe and reliable operation of their natural gas systems. Those returns contribute to the utility's cost of service, which are recovered through rates approved by the Commission. Regulators authorize a ROR that utilities are allowed to earn on their investments based on the weighted average cost of debt and cost of equity for investments made. These authorized returns will reimburse investors for the capital they have provided to the utility.

Q. How is a regulated utility's ROE estimated?

A. While a utility's cost of debt can generally be observed directly from market rates paid for newly issued debt, the cost of equity must be estimated using market-based information. Although methods vary, the generally accepted approach for doing so is to identify a group of utility companies with similar risk and operating profiles as the utility in question, apply various methodologies to determine their ROEs, and compile an estimate of the utility's ROE based on the results of those analyses plus any adjustments that are required to account for the specific operating and financial factors applicable to the utility that is the subject of the analysis.

Q. Which methods did you utilize to estimate Northern's ROE?

A. I utilized three different financial models to analyze the proxy group and estimate the Company's ROE. Those models are the Constant Growth DCF, the Multi-Stage DCF, and the CAPM. I used the results of those models to establish a preliminary range of reasonable ROEs. I then adjusted that range to account for the costs that Northern incurs when issuing new common equity to fund investments in its system.

Q. Why did you use three models to estimate Northern's ROE?

A. It is widely accepted practice in New Hampshire and elsewhere to estimate ROE using multiple models, and then synthesize a recommended range from those results, because any given model will necessarily utilize certain assumptions which, under some conditions, could limit the accuracy of the model. Additionally, since the models rely on different data inputs and assumptions, using more than one model reduces the potential for some anomalous market result or transient market condition to have an undue influence on results.

Q. Has the Commission recognized the use of more than one analytical approach for estimating ROE?

A. Yes, it has done so on numerous occasions. In each of the gas and electric rate cases filed before the Commission in the last five years, multiple analytical approaches were used to estimate the filing utility's ROE.

Q. Has the Commission and its Staff commented on the appropriateness of using the Constant Growth DCF and Multi-Stage DCF models in previous proceedings?

A. Yes, they have. The Constant Growth DCF model appears to have widespread support from both the Commission and its Staff. Regarding the Multi-Stage DCF model, the Commission indicated in 2004 that: "Staff testimony supports the view that a three-stage version of the DCF represents a valuable refinement to the DCF method of estimating the cost of capital looking forward over the long term. We agree."[5]

Q. Did you use the three-stage version of the DCF in your analysis?

A. Yes, I did.

[5] *Verizon New Hampshire*, Order No. 24,265 at 65 (Jan. 16, 2004).

A. <u>Constant Growth DCF Method</u>

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF method of estimating a utility's ROE is based on the theory that a company's stock price represents the Present Value ("PV") of all future dividend payments. Dividend payments are assumed to continue at their current level into perpetuity and stock prices can be observed in the market. The discount rate implied by the dividends and the current stock price is equal to the company's cost of equity. Thus, the theory holds that a company's stock price is equal to the following:

$$P_0 = \frac{D}{ROE - g}$$

where P_0 is the current stock price, D is the current dividend, ROE is equal to the discount rate required to yield the observable stock price given expected dividends, and g is the expected growth rate in dividends. By restating the same equation, ROE can be expressed as:

$$ROE = \frac{D}{P_0} + g$$

Q. Please summarize your approach to estimating ROE using the Constant Growth DCF method.

A. The Constant Growth DCF method relies on the assumption that a company's dividend payments, earnings, and book value will grow at a constant rate, and that its current cost of equity, its dividend payout ratio, the ratio between a company's total dividend payments to its net income, and its Price-Earnings Ratio ("PE Ratio"), which is the ratio of its stock price to its earnings, will all remain constant. The Constant Growth DCF method also requires a discount rate that is greater than the expected earnings growth rate. Assuming that each of these assumptions hold true, I calculated the ROE for each of the companies in the proxy group using publicly available data for stock prices and analyst estimates of earnings growth. The ROE estimate for Northern is based on the average of the ROE estimates for each proxy group company. Low, Mid, and High estimates are developed based on which growth estimates are used, as I describe in detail below.

Q. Please explain the stock price data you used in your calculations.

A. Rather than relying on a single stock closing price, I averaged the closing stock prices over three periods: 30, 90, and 180 trading days. The periods I used for each calculation are shown below:

Table 3. Stock Price Averaging Periods

Averaging Period	Start Date	End Date
30-day	April 14, 2021	May 25, 2021
90-day	January 15, 2021	May 25, 2021
180-day	September 8, 2020	May 25, 2021

Q. Why is it necessary to use different averaging periods?

A. I used the multiple averaging periods to reduce any bias that could be introduced by anomalous market conditions if the stock price were based on the results of a single trading day.

Q. Did you make any adjustments to the dividend yield?

A. Yes. To account for the fact that dividends are paid on a quarterly basis and may be increased at different times, I have adjusted the dividend yield by one-half of the expected long-term growth rate. This adjustment has been common practice both in New Hampshire and elsewhere. In particular, the Federal Energy Regulatory Commission ("FERC") has stated:

> For ratemaking purposes, the Commission rearranges the DCF formula to solve for "k", the discount rate, which represents the rate of return that investors require to invest in a company's common stock, and then multiplies the dividend yield by the express (1 + .5g) to account for the fact that dividends are paid on a quarterly basis. Multiplying the dividend yield by (1 + .5g) increases the dividend yield by one half of the growth rate and produces what the Commission refers to as the "adjusted dividend yield."[6]

Q. Please identify the source of the growth expectations assumptions you used in your calculations.

A. For each company in the proxy group, I used the latest earnings growth estimate as reported by Yahoo Finance, Value Line, and Zacks. These sources are widely used in regulatory proceedings in New Hampshire and elsewhere.

Q. Please describe the results of your analysis using the Constant Growth DCF method.

A. Using the stock prices from each of the three averaging periods, I developed three ROE estimates, which vary by the earnings growth estimate on which it relies. My Mid ROE calculation is based on average earnings growth estimates from Yahoo Finance, Value

[6] Opinion No. 531, 147 FERC ¶ 61,234 at p. 9.

Line, and Zacks. The Low ROE and High ROE calculations use the earnings growth estimates that are the lowest and highest, respectively, of the three sources. My calculations are provided in Attachment JC-2 and the results are shown below:

Table 4. Constant Growth DCF Method Calculation Results

Averaging Period	Low	Mid	High
30-day	7.86%	9.62%	11.70%
90-day	8.07%	9.84%	11.91%
180-day	8.23%	9.99%	12.07%

I have averaged the results for each of the three averaging periods to calculate the Low, Mid, and High Estimates shown below in Table 5.

Table 5. Average Constant Growth DCF Results

Low	Mid	High
8.05%	9.82%	11.89%

B. Multi-Stage DCF

Q. What other types of DCF analysis did you utilize to estimate Northern's ROE?

A. I also utilized a Multi-Stage (three stage) DCF method to estimate the ROE.

Q. Please explain the Multi-Stage DCF.

A. Like the Constant Growth DCF, the analytical basis for the Multi-Stage DCF is the assumption that a utility's stock price is equal to the PV of the cash flows that will be received by the stockholder. The Multi-Stage DCF assumes that those cash flows are received in three different periods. Stage 1 includes cash flows from dividend payments received in years 1 through 5 in the future. Stage 2 includes cash flows from dividend payments received in years 6 through 10. Stage 3 includes cash flows received thereafter. As with my calculations using the Constant Growth DCF method, I estimated Northern's ROE using the stock prices from the three averaging periods (30-day, 90-day, and 180-day) and developed a Low, Mid, and High ROE estimate using each averaging period. As I describe earlier in my testimony, the use of Multi-Stage DCF in addition to other models is standard practice in New Hampshire and elsewhere, and the use of a Multi-Stage DCF that includes three stages has specifically been recommended by the Commission for the estimation of utility ROEs.

Q. How did you estimate the dividend payments in Stage 1?

A. In Stage 1, my estimates of dividend payments are based on the earnings growth estimates from Yahoo Finance, Value Line and Zacks. For the Mid ROE estimate, I used the average of the three sources. For the Low and High ROE estimates, I used the lowest and highest, respectively, of those three estimates.

Q. How did you estimate the dividend payments in Stage 3?

A. Beginning 11 years into the future, I assume that dividend payments will grow at the same rate as the long-term growth of the economy, as measured by U.S. Gross Domestic Product ("GDP"). My estimate of long-term GDP growth is based on historical real GDP growth with an adjustment for expected inflation.

Q. How did you calculate the historical GDP?

A. Using quarterly data from the U.S. Bureau of Economic Analysis as reported by the Federal Reserve Bank of St. Louis, I calculated that over the period 1929 to 2020, the U.S. economy grew in real terms at an average rate of 3.14% per year.

Q. How did you develop your estimate of inflation?

A. I averaged three sources. First, I used the average of the last 180 trading days as of May 25, 2021, of the 10-Year Breakeven Inflation Rate reported by the Federal Reserve Bank of St. Louis. The 10-Year Breakeven Inflation Rate represents a measure of expected inflation implied from 10-Year Treasury Constant Maturity Securities. Second, I used the annual growth rate of the Consumer Price Index ("CPI") from 2031–2050 for all urban consumers as projected by the Energy Information Administration ("EIA"). Third, I used the annual growth rate of the GDP chain-type price index from 2031–2050 as reported by the EIA. The inflation measures and the average are shown in Table 6 below.

Table 6. Inflation Assumption

10-Year Breakeven Inflation Rate	2.20%
CPI	2.27%
GDP Chain-Type Price Index	2.37%
Average	2.28%

Q. Please summarize your nominal GDP growth estimate.

A. Combining my real GDP growth estimate with my average inflation rate results in a nominal GDP growth estimate of 5.49%.

Q. How did you estimate earnings growth for Stage 2?

A. Earnings growth in Stage 2 is designed to provide for a gradual transition between Stage 1 and Stage 3. In all cases, there are significant differences between the earnings outlook for Stage 1, which is based on the analysts' earnings outlook, and the long-term GDP outlook. Since there is no reason to believe that there will be a step change in company earnings between years 5 and 6 of the forward-looking period, I assumed that the Stage 2 earnings growth rates would provide a "bridge" between Stages 1 and 3 such that a linear transition occurs in the growth rates between years 5 and 11.

An illustrative example is provided below. Here, the company is assumed to have a Stage 1 growth rate of 6.00%. The Stage 3 growth rate is 5.49%.. Growth rates for years 6-10 provide for a linear transition between Stages 1 and 3.

Table 7. Stage 2 Growth Rates Calculation Illustrative Example

A	*b=(g-a)/6+a*	*c=(g-a)/6+b*	*d=(g-a)/6+c*	*e=(g-a)/6+d*	*f=(g-a)/6+e*	*g*
First Stage *(Year 5)*	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage** *(Year 11)*
6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	**5.49%**

Q. Does setting the Stage 3 growth to your GDP outlook into perpetuity imply that an investor holding a company's stock would hold it into perpetuity?

A. No. The PV of the Stage 3 cash flows is equal to the PV of a series of dividend payments based on the Stage 3 earnings growth rate into perpetuity. In other words, the PV of the Stage 3 cash flows is calculated using the Constant Growth DCF method. As I discuss earlier in my testimony, financial theory indicates that the stock price is equal to the discounted value of the dividend payments. As such, the PV of the Stage 3 cash flows is the same whether the investor sells the stock or holds it into perpetuity.

Q. What are the results of your analysis using the Multi-Stage DCF method?

A. The results of my analysis using the Multi-Stage DCF method are shown in Table 8 and the calculations are provided in Attachment JC-5.

Table 8. Multi-Stage DCF Method Calculation Results

Averaging Period	Low	Mid	High
30-day	8.86%	9.27%	9.83%
90-day	9.09%	9.51%	10.10%
180-day	9.25%	9.69%	10.31%

I have averaged the results for each of the three averaging periods to calculate the Low, Mid, and High estimates shown in Table 9.

Table 9. Multi-Stage DCF Results

Low	Mid	High
9.07%	9.49%	10.08%

Q. What are the results from the Constant Growth and Multi-Stage DCF models?

A. The range of estimates for the Company's ROE, based on the Constant Growth DCF method is 8.05% to 11.89% and the range of estimates for the Company's ROE based on the Multi-Stage DCF method is 9.07% to 10.08%.

C. <u>Capital Asset Pricing Model</u>

Q. Please summarize the CAPM method.

A. CAPM describes the relationship between the price of a security and the return that investors will require to hold it. The analytical basis is that any security is subject to market risk and that investors will require higher returns for holding riskier assets, all else being equal. In the case of a regulated utility stock, the required return is assumed to be equal to the ROE. Analysis of the risk profile and market conditions to which the proxy group is exposed using the CAPM yields an ROE estimate for Northern.

Q. Please provide the analytical form of the CAPM.

A. The CAPM is defined as follows:

$$RR_i = R_f + \beta_i(R_m - R_f)$$

where:

RR_i is the required return of the investment, which is equal to the ROE;

R_f is the risk-free rate;

β_i is the beta coefficient of the investment; and

R_m is the expected return of the securities market as a whole.

Q. Please explain the meaning and significance of the risk-free rate.

A. Investors require compensation for risk and for the time-value of money; the risk-free rate accounts for the latter. The risk-free rate is set at the return that investors could achieve while exposing themselves to zero risk. It is the minimum return any investor will accept since, by definition, taking on more than zero risk will require compensation beyond this amount. It is typical for the risk-free rate to be estimated using yields on U.S. Treasury bonds.

Q. How did you estimate the risk-free rate?

A. I estimated the risk-free rate by taking the average of the yields on 30-year constant maturity U.S. Treasury securities as reported by the U.S. Department of the Treasury over recent trading periods. Specifically, I averaged the yields on the 30-year treasuries for each of 30, 90, and 180 trading days, with each period ending as of May 25, 2021. The results of that analysis are shown below:

Table 10. Average Yields of 30-Year U.S. Treasuries

Period	Average
30-day Average	2.30%
90-day Average	2.21%
180-day Average	1.91%

Q. Why did you use multiple averaging periods to estimate the treasury yields?

A. I chose to utilize multiple averaging periods to estimate the treasury yield input to my CAPM calculations to reduce the possibility of biasing my results by relying on outcomes from what may be transitory market conditions; and I used the same averaging periods as those I used for stock prices.

Q. Please explain the meaning and significance of the beta coefficient.

A. The beta coefficient is a measure of a security's exposure to systematic, or non-diversifiable, risk. It indicates a stock's riskiness (volatility) compared to that of the market as a whole. If a stock has a beta coefficient of 1.0, it is exactly as risky as the market. A higher coefficient indicates that the stock is riskier than the market and, conversely, a lower coefficient means that the security is less risky than the market.

Beta is calculated by analyzing the returns of a security and the returns of the market as a whole over some historical period, and is mathematically defined as:

$$\beta_i = \frac{Covariance\ (R_i, R_m)}{Variance\ (R_m)}$$

where β_i is the beta coefficient of the security, R_i is the return of the security, and R_m is the return of the market as a whole. Calculation of the covariance between R_i and R_m measures the degree to which the returns of the security and market returns move together, while the variance of R_m measures the degree of volatility in the market.

Q. How did you estimate the beta coefficient?

A. The beta coefficient I use in my CAPM analysis is based on the average of the beta coefficients for the companies in my proxy group, which equals 0.88. The proxy group betas which include market information through May 2021 are reported by Value Line. These are shown below in Table 11 and included as Attachment JC-6.

Table 11. Proxy Group Beta Coefficients

Company	Beta
Atmos Energy	0.80
Chesapeake Utilities	0.80
NiSource Inc.	0.85
New Jersey Resources	1.00
Northwest Natural	0.85
ONE Gas Inc.	0.80
South Jersey Inds.	1.05

Spire Inc.	0.85
Southwest Gas	0.95
Average	**0.88**

Q. Please explain the meaning and significance of the expected market return.

A. The primary relevance of the expected market return is that it is used to calculate the Market Risk Premium, which is defined by the term ($R_m – R_f$). This represents the return that investors can expect from the securities market as a whole, above the return that would be provided by a risk-free investment.

Q. How did you calculate the expected market return?

A. I calculated the expected market return by applying the Constant Growth DCF method described earlier in my testimony to the companies in the S&P 500 Index as reported by Value Line. Using this approach, I estimate that the expected market return is 14.02%. My calculations are provided in Attachment JC-7. The expected market risk premiums that result from reducing the expected market return by the risk-free rates I estimated for each of the three trading-day periods of 30, 90, and 180 trading days (the same as for stock prices)[7] is shown below:

Table 12. Calculation of Market Risk Premium

	30-day Average	90-day Average	180-day Average
Expected Market Return	14.02%	14.02%	14.02%
Risk-Free Rate	2.30%	2.21%	1.91%

[7] The 90 trading-day average is January 19, 2021 through May 25, 2021 as the stock market was closed on April 2, 2021 for Good Friday but the Treasury rate was published. Similarly, the 180 trading-day average is September 4, 2020 through May 25, 2021 as the Treasury rate was not published on October 12, 2020 (Columbus Day) and November 11, 2020 (Veterans Day) but the stock market was open each of these days.

Market Risk Premium	11.72%	11.81%	12.11%

Q. What were the results of your CAPM analysis?

A. Based on the three risk-free rate estimates I developed, as well as the beta, and market risk premium calculations I describe above, the CAPM method indicates that Northern's ROE is between 12.61% and 12.65%, with an average ROE of 12.64% based on the three risk-free rates I used. My calculations are summarized below in Table 13, and are also provided in Attachment JC-8.

Table 13. CAPM Results

		30-day Average	**90-day Average**	**180-day Average**
Risk-free rate	*a*	2.30%	2.21%	1.91%
Beta	*b*	0.88	0.88	0.88
Expected market return	*c*	14.02%	14.02%	14.02%
Market risk premium	*d = c - a*	11.72%	11.81%	12.11%
ROE	*e = a + b*d*	12.65%	12.64%	12.61%
Average ROE	*Average of e*	12.64%		

D. Analytical Results and Adjustment for Flotation Costs

Q. Briefly summarize your results using the two DCF and CAPM methods.

A. As I previously described, using the Constant Growth DCF method, I calculated estimates of Northern's ROE that range from 8.05% to 11.89%. Using the Multi-Stage DCF method, I calculated estimates of ROE that range from 9.07% to 10.08%. Using the CAPM method, I estimate Northern's ROE to be 12.64%.

Q. How have you aggregated the estimates you developed using the three models?

A. I aggregated them using simple averaging. As shown in Table 14 below, I developed preliminary Low, Mid, and High ROE estimates using the three methods by averaging the results of the Constant Growth DCF, the Multi-Stage Growth DCF, and the CAPM. The averages yield a range of preliminary ROE estimates for Northern of 9.92% to 11.54%.

Table 14. Aggregation of Preliminary Analytical Results

	Low	Mid	High
Constant Growth DCF	8.05%	9.82%	11.89%
Multi-Stage DCF	9.07%	9.49%	10.08%
CAPM	12.64%	12.64%	12.64%
Average	9.92%	10.65%	11.54%

Q. Have you made any adjustments to your preliminary range?

A. Yes, I have. I have incorporated an adder to account for security flotation costs in my estimate.

Q. What are security flotation costs?

A. Flotation costs are expenses that companies incur when they issue new common stock or other securities. Flotation costs include underwriting, legal expenses, issuance preparation and other expenses.

Q. Should flotation costs be recovered through ROE rather than through operating expenses?

A. Yes, they should. A utility's cost to issue new stock is part of its capital rather than operating costs. If a company cannot recover its flotation costs through ROE, its actual ROE will be less than that required by investors to own the stock. This will, in turn, impair the company's ability to attract the capital required to operate a safe and reliable system. This situation could become particularly problematic if other utilities with whom the Company competes to attract capital are allowed recovery of their flotation costs while Northern is not.

Q. Are flotation costs accounted for in the DCF and CAPM models you used to develop the preliminary estimates shown in Table 14?

A. No, they are not. The DCF and CAPM models are designed to estimate the returns that an investor would require for holding a stock based on expected dividend payments (in the case of the DCF models) and/or has a certain risk profile (in the case of the CAPM). For purposes of this proceeding, that required return is used as a proxy for the Company's ROE since the authorized return must match investor requirements in order for Northern to attract capital. Because neither the DCF nor the CAPM models are primarily designed to estimate the ROE for a regulated utility, neither take flotation costs into consideration.

Q. How did you estimate Northern's flotation cost adjustment?

A. I estimated Northern's flotation costs by examining the costs of issuing equity incurred by the proxy group companies and Unitil in their two most recent common equity issuances. After calculating the average flotation costs for the proxy group and Unitil, I adjusted the Constant Growth DCF model to incorporate a dividend yield that would allow investors to recover costs associated with the issuance of equity. The resulting dividend yield is calculated by dividing the current dividend yield by one minus the weighted average flotation costs of the proxy group companies. The difference between the resulting ROE from the adjusted Constant Growth DCF and the unadjusted Constant Growth DCF is the flotation cost adjustment. My calculations can be found in Attachment JC-9.

Q. What is your estimate of the appropriate adder to Northern's ROE estimate to cover flotation costs?

A. Using this method, I estimate that the ROE adder required to cover flotation costs is 0.10%.

Q. Please update your preliminary ROE range to account for flotation costs.

A. In Table 15, below, I add the flotation costs to the preliminary ROE estimates I previously described.

Table 15. ROE Range

	Low	**Mid**	**High**
Preliminary estimate	9.92%	10.65%	11.54%
Flotation costs	0.10%	0.10%	0.10%
ROE estimate	10.02%	10.75%	11.64%

Based on the information shown in Table 15, I conclude that Northern's authorized ROE should fall within the reasonable range of 10.02% to 11.64%.

E. COVID-19 Impacts

Q. What is the most apparent impact that the economic fallout from the COVID-19 pandemic is having on the economy and financial markets?

A. To date, the impact on financial markets from the economic fallout caused by the COVID-19 pandemic is mixed, demonstrating a high degree of volatility and uncertainty. The U.S. economy reached a monthly economic peak in February 2020, but moved into recession in March 2020 as the onset of the COVID-19 pandemic began to take hold. The unemployment rate spiked from 3.5% in February 2020 to just under 15% in April 2020. Since that time, the national unemployment rate has continued to decline and while it has not returned to a pre-pandemic level, it has significantly abated and as of May 2021 stands at 5.8%. Financial markets reacted to the economic downturn as interest rates trended downward initially with the 30-year treasury rate declining from around 2.3% at the start of 2020 to around 1.3% in early July 2020, due primarily to the unprecedented efforts of the Federal Reserve to counteract the impact of COVID-19. However, over the past 10 months, the 30-year treasury rate has returned to its pre-pandemic level at just over 2.3% as of May 2021. Stock market volatility increased significantly during this time period, spiking in March 2020 to more than four times the level experienced at the start of 2020. The stock market had not experienced that level of volatility since the Great Recession of 2008-2009. Since that time, stock market volatility has generally declined, yet it is still approximately one-third higher than the level of volatility prior to the onset of COVID-19.[8] At the same time that stock market

[8] See for example, CBOE (Chicago Board Options Exchange) S&P 500 3-Month Volatility Index: https://fred.stlouisfed.org/series/VXVCLS

volatility spiked in March 2020, both the S&P 500 index and the Dow Jones Industrial Average index reached relative lows (compared to 2016). Since March 2020, the S&P 500 and the Dow Jones Industrial Average have been on upward trends doubling in value.[9,10] The Dow Jones Utility Average index, which captures the stock price performance of major U.S. utility companies, has experienced a similar upward trajectory, but with more moderated growth of approximately 50 percent from March 2020 to date.[11]

Q. How are these economic and financial market impacts affecting the ROE for utility companies?

A. The improved economic and financial market conditions are affecting the expected returns of the proxy group as economic activity continues to improve and interest rates return to pre-pandemic levels. As noted by Value Line:

> A number of stocks in *Value Line's* Natural Gas Utility Industry have strengthened nicely in price since our last report three months ago. It appears these movements are attributable, to a certain extent, to improved earnings as of late, compared to last year's figures. Indeed the economic environment in the United States is brightening, as state and local governments are easing COVID-related restrictions on businesses and individuals due to declining infection rates (reflecting, no doubt, the ongoing administration of vaccines).[12]

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9 See the S&P 500 Index: https://fred.stlouisfed.org/series/SP500
10 See the DJIA Index: https://fred.stlouisfed.org/series/DJIA
11 See the DJIA Index: https://fred.stlouisfed.org/series/DJUA
12 Value Line Investment Survey, "Natural Gas Utility", May 28, 2021.

These market dynamics suggest that while we experienced a significant decline in economic activity with the onset of the pandemic, we are much closer to a pre-pandemic economic environment today than we were a year ago. While there is still some uncertainty associated with the coronavirus, there is greater optimism today certainly in comparison to a year ago.

Q. Have you made any adjustments to your results to account for impacts attributable to COVID-19?

A. No, I have not made any adjustments to account for these impacts because the economic impact of COVID-19 has now been occurring for over a year and is reflected to that extent in the data used to produce the DCF and CAPM results.

VI. SMALL SIZE PREMIUM AND ROE RECOMMENDATION

Q. Are there any other factors that could impact your recommendation for Northern's ROE?

A. Yes. Northern is considerably smaller than the utilities in the proxy group, a situation that creates risk for the Company's investors for which they will need to be compensated with a higher return.

A. Small Size Premium

Q. Please explain why smaller utilities are riskier than larger ones.

A. There is a broad body of evidence supporting the existence of a "firm size effect" on firms in general, and utilities in particular, that requires smaller companies to provide higher returns than larger companies in the same industries.[13] Smaller utilities have smaller customer bases, have fewer financial resources, and are less diversified in terms of customers and geography.[14] These challenges increase the investors' risks of owning securities in small companies which, in turn, require them to pay a higher return in order to attract capital.

Q. How does Northern compare in size to the other utilities in the proxy group?

A. The Company's operations are significantly smaller than those of the proxy group companies. As shown in Attachment JC-10, Northern has less than a quarter (22%) of the customers of the smallest company by customer count in the proxy group, and only 2% of the median number of customers. Northern's capitalization is significantly smaller than the other proxy group companies. Attachment JC-10 shows the actual market capitalization for the proxy group companies based on recent data and estimates the implied market capitalization for Northern.

Q. How did you estimate Northern's capitalization?

A. Because the Company is not a standalone publicly-traded entity, I have estimated its market capitalization by applying the median market-to-book ratio of the proxy group companies to Northern's equity of $229.2 million.[15] The resulting implied market

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[13] Shannon Pratt and Roger Grabowski, *Cost of Capital: Applications and Examples*, 3rd Edition, New Jersey, John Wiley & Sons, 2008 at Chapter 12; Duff & Phelps, *2018 Cost of Capital: Annual US Guidance and Examples*, 2018 at Chapter 4 pp. 1-7; Rolf W. Banz, "The Relationship between Return and Market Value of Common Stocks", Journal of Financial Economics (March 1981) at pp. 3–18.

[14] Duff & Phelps, *2018 Cost of Capital: Annual US Guidance and Examples*, 2018 at Chapter 4 p. 2.

[15] Shareholder equity is shown on Schedule RevREq-6, Column 4, Line 1.

capitalization for Northern is approximately $415 million, or about 11% of the median market capitalization for the proxy group companies.

Q. What did you conclude regarding a small size premium for Northern's ROE?

A. By calculating an implied market capitalization for the Company, I was able to evaluate the impact of Northern's small size on its ROE relative to the proxy group companies. In its Cost of Capital Navigator, Duff & Phelps calculates size premia associated with deciles of market capitalizations, as well as categorizations of Mid Cap, Low Cap, and Micro Cap.[16] As shown in Attachment JC-10, the mean market capitalization of the proxy group companies of $4.9 billion falls into the fourth decile of market capitalization, corresponding to a size premium of approximately 0.75% and the median market capitalization of $3.8 billion falls just outside the fifth decile, which would correspond to a size premium of approximately 1.09% if in that decile. Northern's implied market capitalization falls in the ninth decile and Micro Cap category. According to the Duff & Phelps data, Northern merits a size premium of 2.29%, which is 1.54% higher than the size premium for the mean of the proxy group and 1.20% higher than the size premium for the median of the proxy group.

Q. Do you propose to adjust your reasonable range to account for the size premium?

A. No, I do not. Estimating the size premium is a complex analysis that lacks the transparency of the calculations on which I relied for other aspects of my testimony.

[16] Duff & Phelps defines Mid Cap companies as companies with market capitalizations between $2,996 million and $13,455.8 million, Low Cap companies as companies with market capitalizations between $730 million and $2,992.3 million, and Micro Cap companies as companies with market capitalizations between $2.5 million and $727.8 million. Northern falls in the MicroCap category, while the majority of companies in the proxy group tend to fall in the Mid Cap range.

While it is clear that Northern is exposed to the small size premium, the magnitude of the impact of this influence is a matter of debate in academic literature and limitations regarding data availability make the estimation less robust. The results of the size premium analysis should be considered as an additional input supporting Northern's proposal that its authorized ROE be set at 10.30% which falls on the middle-lower end of the reasonable range I previously described.

B. Proposed ROE

Q. What does Northern propose for an authorized ROE?

A. As discussed in more detail in the testimonies of Robert Hevert, Todd Diggins and Andre Francoeur, and Christopher Goulding and Daniel Nawazelski, Northern proposed an authorized ROE of 10.30%.

VII. CAPITAL STRUCTURE

Q. What is the Company's proposed capital structure?

A. As described in the joint testimony of Todd Diggins and Andre Francoeur, the Company has proposed a capital structure of 52.47% common equity and 47.53% long-term debt.

Q. Have you compared this proposed capital structure to the other companies in the proxy group?

A. Yes, I have. I calculated the average capital structure for the proxy group companies over the past five years and compared it to Northern's proposed capital structure. As shown in Attachment JC-11, over this period, the capital structure of the proxy group was, on average, comprised of approximately 53% common equity and 47% long-term debt. Over that same period, the maximum average equity weight for the proxy group companies was approximately 65% while the minimum was approximately 37%.

Q. What is your conclusion regarding the Company's proposed capital structure?

A. I conclude that the Company's proposed capital structure is reasonable.

VIII. COST OF DEBT

Q. What is the Company's proposed cost of debt?

A. As described by Messrs. Diggins and Francoeur, the Company proposes a cost of long-term debt of 4.93%.

Q. What is your conclusion regarding the Company's proposed cost of debt?

A. As described in the Company's testimony, the proposed cost of debt is based on Northern's actual cost of debt. I conclude that it is reasonable.

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions

A. I have four primary conclusions. *First*, I conclude that the Company's ROE should fall between the range of 10.02% and 11.64% including a flotation cost adjustment but not one for its small size relative to the peer group. *Second*, I support Northern's proposed authorized ROE of 10.30%, which is within the reasonable range described in my testimony. *Third*, I conclude that the Company's proposed capital structure is reasonable. *Fourth*, I conclude that the Company's proposed cost of debt is reasonable.

Q. Please summarize your recommendations.

A. I recommend that the Commission accept Northern's proposed authorized ROE of 10.30%, that it accept the Company's proposed capital structure and debt costs, and that it authorize a total ROR of 7.75%.

Q. Does this conclude your testimony?

A. Yes.

John Cochrane

Senior Managing Director

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John Cochrane specializes in advising gas and electric utility clients in all economic, regulatory, and financial aspects of the business. Mr. Cochrane has testified in rate matters before the FERC and at the state level, has held C-suite and other senior leadership positions at major U.S. utilities, and served as a member of the board of directors on a variety of energy sector companies, including start-ups.

Education

M.B.A. Northeastern University

B.A. Biology, Harvard University

Board of Directors Memberships

EMERA US Subsidiaries, Member, Board of Directors, 2015 – present

PowerOptions, Board of Directors (Audit and Strategic Planning Committees), 2013 – present

GreenerU, Inc., Member, Board of Directors, 2011 – 2013

National Grid USA, Member, Board of Directors, 2000 – 2013

Mr. Cochrane has more than 30 years of U.S. and international experience working for a utility, which includes all areas within corporate finance, mergers and acquisitions, joint ventures, partnerships, restructurings, federal and state regulation, gas and electric supply, and business development, both domestic and international. He has testified in rate case matters relating to capital structure/cost of capital, mergers and acquisitions, and financings before FERC and various state-level regulatory bodies.

Experience

— **Management audit, National Grid for the MA DPU:** Conducted a management audit of National Grid on behalf of the Massachusetts Department of Public Utilities (“DPU”). The audit covers the areas of strategic planning; staffing and workflow structure; EV infrastructure, IT upgrades and cybersecurity implementation; and analysis of delays in the company’s solar program cluster study. For the audit, Mr. Cochrane wrote the final report’s section on strategic planning after conducting interviews with dozens of National Grid employees, ranging from operational to upper management personnel.

— **Rate case expert testimony, Liberty Utilities:** Providing cost of capital testimony to support the Liberty Utilities’ subsidiaries Granite State Electric and Energy North rate cases before the New Hampshire Public Utilities Commission and Empire Electric before the Missouri Public Service Commission, including analysis of ROE and capital structure.

— **Privatization advisory, P3A:** Advising the Puerto Rico Public Private Partnerships Authority (“P3A”) in the development and evaluation of the solicitation to select a third-party T&D operator as well as several concurrent generation asset solicitations. Advisory support includes structuring the T&D operator contract, evaluating bid submissions, and undertaking financial and operations analysis in support of the solicitation processes, among other tasks.

— **Privatization advisory, JEA:** Provided regulatory advice for the privatization of Jacksonville Electric Authority (“JEA”), a large municipally owned electric and water utility located in Florida. Advisory support includes advising on regulatory financial treatment of generation and transmission assets and development of financial modeling inputs.

— **Underwater transmission ROE methodology, Trans Bay Cable:** Advised Trans Bay Cable, an underwater direct current transmission cable connecting San Francisco, CA to Pittsburg, CA on the reasonableness and methodology of its ROE calculation for the three year rate case reset before FERC; provided analysis and expert advice for testimony development.

— **Offshore wind transmission strategy, confidential client:** Advising a large global offshore wind developer on transmission development strategy across the U.S. in order to facilitate offshore wind projects and to diversify business risks.

— **M&A expert testimony, CCI:** Provided expert testimony pertaining to a purchase price dispute stemming from CCI's acquisition of a portfolio of power plants located in PJM.

— **Rate case strategy, PPL Electric:** Advised PPL Electric Utilities on financial modeling and rate case strategy on the development of transmission projects in PJM.

— **Water utility rate case advisory, confidential client:** Advised a global infrastructure fund on financial modeling and rate case strategy applying to a wholly owned portfolio company, a water utility covering three separate jurisdictions in the U.S. southwest.

— **Executive Vice President – Global Business Development & Mergers and Acquisitions (most recently, among other senior roles):**

- Led all business development, mergers, acquisitions, divestitures and joint ventures globally, including the sale of a wide range of businesses totaling $10 billion.
- Led joint venture negotiations, feasibility studies, project budgets and timelines, and vendor selections for four £1 billion submarine interconnectors between the United Kingdom, Norway, Belgium, France and the Netherlands.
- Led Offshore Wind Transmission ("OFTO") bid submittals in the UK.

— **Executive Vice President, Chief Financial Officer and Treasurer, National Grid USA:**

- Supported regulatory approval filings for several M&A deals completed by National Grid including the sale of New England Electric to National Grid, the purchase of Eastern Utilities by National Grid, the purchase of Niagara Mohawk by National Grid, the purchase of KeySpan Corp by National Grid, the purchase of Rhode Island Gas assets of Southern Union Co by National Grid, helping to create the second largest U.S. utility with a total enterprise value of $27 billion.
- Testified on behalf of National Grid with respect to capital structure in rate cases, in all National Grid state jurisdictions, including New Hampshire, Massachusetts, Rhode Island, New York and before FERC.
- Testified as a witness with respect to ROE for a rate case in New Hampshire on behalf of Granite State Electric.
- Testified on behalf of National Grid with respect to debt and equity financings including first mortgage bonds, bank agreements, private placements, common equity issuances in all National Grid state jurisdictions, including New Hampshire, Massachusetts, Rhode Island, New York and before FERC.
- Managed ROE expert testimony preparation on behalf of National Grid in all National Grid state jurisdictions, including New Hampshire, Massachusetts, Rhode Island, New York and before FERC.
- Managed the preparation of FERC ROE filing for two DC transmission lines from Canada in New Hampshire and Massachusetts.
- Testified in arbitration case involving a new power company, New England Energy and Keystone Shipping over a coal shipping joint venture dispute.
- Testified in arbitration case involving Hydro Quebec and ISO New England over transmission agreements dispute for HQ Phase I and Phase II projects.
- Ran the sale process on behalf of National Grid for Granite State and EnergyNorth, purchased by Liberty Utilities.

  - Led the commercial and regulatory negotiations for the formation of a $3 billion FERC regulated Transco amongst the six New York transmission owners.
  - Key member of deal team closing a $2.5 billion generation portfolio in the U.S. northeast, responsible for portfolio valuation and complementary insights from indicative bid through closing the transaction.
  - Served as a U.S. board member on US/European companies involved in cross-border tax structures including Luxemburg, Ireland, Jersey, Iceland and Malta.

— **Treasurer (most recently, among other senior roles), New England Electric Systems**

Select Testimony

Sponsor	Date	Applicant(s)	Docket/Case	Subject
Missouri Public Service Commission				
The Empire District Electric Company	03/2020	The Empire District Electric Company	ER-2019-0374	Affiliate Transactions / Financing
New Hampshire Public Utilities Commission				
EnergyNorth Natural Gas	07/2020	EnergyNorth Natural Gas	DG 20-105	Cost of Capital
EnergyNorth Natural Gas	11/2019	EnergyNorth Natural Gas	DG 19-161	Cost of Capital
Granite State Electric Company	04/2019	Granite State Electric Company	DG 19-064	Cost of Capital
National Grid USA	08/2006	National Grid USA; EnergyNorth Natural Gas	DG 06-107	Merger
Granite State Electric Company	11/1992	Granite State Electric Company	DF 92-219	Financing
Massachusetts Department of Public Utilities				
New England Power Company	10/1997	USGen New England, Inc; New England Power Company; Massachusetts Electric Company; Nantucket Electric Company	DPU 97-94	Financing
New England Electric System	05/1995	New England Electric System; Nantucket Electric Company	DPU 95-67	Merger

New York Department of Public Service				
National Grid plc	10/2006	National Grid plc; KeySpan Corporation	PSC Case 06-M-0878	Merger
Federal Energy Regulatory Commission				
New England Power Company; Massachusetts Electric Company; The Narragansett Electric Company; Granite State Electric Company	09/1997	New England Power Company; Massachusetts Electric Company; The Narragansett Electric Company; Granite State Electric Company	OA96-74-000	Capital Structure and Cost of Capital
New England Power Company	01/1997	New England Power Company	ER-97-1115	Financing
NEES Transmission Services, Inc.; New England Power Company; Massachusetts Electric Company; The Narragansett Electric Company; Granite State Electric Company	03/1996	NEES Transmission Services, Inc.; New England Power Company; Massachusetts Electric Company; The Narragansett Electric Company; Granite State Electric Company	ER96-1309-000	Capital Structure and Cost of Capital
New England Power Company	09/1995	Tennessee Gas Pipeline Co	RP95-112-000	Return on Equity
New England Power Company	12/1994	New England Power Company	Docket ER95-267	Capital Structure and Cost of Capital

Summary of Results

Constant Growth DCF - Earnings Growth			
Mean	**Low ROE**	**Mid ROE**	**High ROE**
30-Day Average	7.86%	9.62%	11.70%
90-Day Average	8.07%	9.84%	11.91%
180-Day Average	8.23%	9.99%	12.07%
Average	8.05%	9.82%	11.89%

Multi-Stage Growth DCF			
Mean	**Low ROE**	**Mid ROE**	**High ROE**
30-Day Average	8.86%	9.27%	9.83%
90-Day Average	9.09%	9.51%	10.10%
180-Day Average	9.25%	9.69%	10.31%
Average	9.07%	9.49%	10.08%

CAPM	
Current 30-Day Treasury	**CAPM**
30-Day Average	12.65%
90-Day Average	12.64%
180-Day Average	12.61%
Average	12.64%

Flotation Cost Adjustment	0.10%

Zone of Reasonableness			
Method	**Low ROE**	**Mid ROE**	**High ROE**
Constant Growth DCF	8.05%	9.82%	11.89%
Multi-Stage DCF	9.07%	9.49%	10.08%
CAPM	12.64%	12.64%	12.64%
Mean	9.92%	10.65%	11.54%
With Flotation Costs	10.02%	10.75%	11.64%

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Proxy Group Selection Criteria

Company Name	Stock Ticker	[1] Consistently Paid Dividends?	[2] Positive Earnings Growth Estimates From At Least Two Analysts?	[3] Party to Merger or Other Significant Transaction?	[4] S&P Long-Term Issuer Rating	[5] Moody's Long-Term Issuer Rating	[6] Percent of Operating Income or Net Income From Regulated Gas Operations
Atmos Energy	ATO	Yes	Yes	No	A-	A1	100.0%
Chesapeake Utilities	CPK	Yes	Yes	No			81.7%
NiSource Inc.	NI	Yes	Yes	No	BBB+	Baa2	63.5%
New Jersey Resources	NJR	Yes	Yes	No		A1	80.1%
Northwest Natural	NWN	Yes	Yes	No	A+	Baa1	99.5%
ONE Gas Inc.	OGS	Yes	Yes	No	BBB+	A3	100.0%
South Jersey Inds.	SJI	Yes	Yes	No	BBB	A3	92.6%
Spire Inc.	SR	Yes	Yes	No	A-	Baa2	96.3%
Southwest Gas	SWX	Yes	Yes	No	BBB+	Baa1	71.5%

[1] Source: Value Line
[2] Source: Value Line, Zack's, Yahoo Finance
[3] Source: Company 10Ks
[4] Source: S&P Global Market Intelligence
[5] Source: Moody's
[6] Source: Company 10Ks

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Constant Growth Discounted Cash Flow Model
Earnings Growth
30 Day Average Stock Price

Company	Ticker	[1] Indicated Annual Dividend	[2] Weighted-Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] Yahoo Finance Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mid ROE	[11] High ROE
Atmos Energy	ATO	$2.65	$101.26	2.62%	2.71%	7.30%	7.17%	7.00%	7.16%	9.71%	9.87%	10.01%
Chesapeake Utilities	CPK	$1.96	$118.66	1.65%	1.71%	NA	4.74%	8.50%	6.62%	6.43%	8.33%	10.22%
NiSource Inc.	NI	$0.88	$25.69	3.43%	3.54%	6.40%	3.52%	9.50%	6.47%	7.01%	10.01%	13.09%
New Jersey Resources	NJR	$1.33	$42.46	3.13%	3.21%	7.10%	6.00%	2.00%	5.03%	5.16%	8.24%	10.34%
Northwest Natural	NWN	$1.92	$54.40	3.53%	3.61%	3.90%	3.80%	5.50%	4.40%	7.40%	8.01%	9.13%
ONE Gas Inc.	OGS	$2.40	$77.52	3.10%	3.18%	5.00%	5.00%	6.00%	5.33%	8.17%	8.51%	9.19%
South Jersey Inds.	SJI	$1.28	$25.06	5.11%	5.29%	5.40%	4.90%	11.50%	7.27%	10.13%	12.56%	16.90%
Spire Inc.	SR	$2.66	$75.24	3.54%	3.67%	5.50%	7.31%	10.00%	7.60%	9.13%	11.27%	13.71%
Southwest Gas	SWX	$2.42	$69.03	3.51%	3.61%	5.50%	4.00%	9.00%	6.17%	7.58%	9.78%	12.66%
Mean				3.29%	3.39%	5.76%	5.16%	7.67%	6.23%	7.86%	9.62%	11.70%
Median				3.43%	3.54%	5.50%	4.90%	8.50%	6.47%	7.58%	9.78%	10.34%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 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
Earnings Growth
90 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Dividend Yield**	**Expected Dividend Yield**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**Average Earnings Growth**	**Low ROE**	**Mid ROE**	**High ROE**
Atmos Energy	ATO	$2.65	$94.25	2.81%	2.91%	7.30%	7.17%	7.00%	7.16%	9.91%	10.07%	10.21%
Chesapeake Utilities	CPK	$1.96	$111.79	1.75%	1.81%	NA	4.74%	8.50%	6.62%	6.53%	8.43%	10.33%
NiSource Inc.	NI	$0.88	$23.87	3.69%	3.81%	6.40%	3.52%	9.50%	6.47%	7.27%	10.28%	13.36%
New Jersey Resources	NJR	$1.33	$39.82	3.34%	3.42%	7.10%	6.00%	2.00%	5.03%	5.37%	8.46%	10.56%
Northwest Natural	NWN	$1.92	$49.62	3.87%	3.95%	3.90%	3.80%	5.50%	4.40%	7.74%	8.35%	9.48%
ONE Gas Inc.	OGS	$2.40	$74.44	3.22%	3.31%	5.00%	5.00%	6.00%	5.33%	8.30%	8.64%	9.32%
South Jersey Inds.	SJI	$1.28	$23.91	5.35%	5.55%	5.40%	4.90%	11.50%	7.27%	10.38%	12.81%	17.16%
Spire Inc.	SR	$2.66	$70.15	3.79%	3.94%	5.50%	7.31%	10.00%	7.60%	9.40%	11.54%	13.98%
Southwest Gas	SWX	$2.42	$66.26	3.65%	3.77%	5.50%	4.00%	9.00%	6.17%	7.73%	9.93%	12.82%
Mean				3.50%	3.61%	5.76%	5.16%	7.67%	6.23%	8.07%	9.84%	11.91%
Median				3.65%	3.77%	5.50%	4.90%	8.50%	6.47%	7.74%	9.93%	10.56%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 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
Earnings Growth
180 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Dividend Yield**	**Expected Dividend Yield**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**Average Earnings Growth**	**Low ROE**	**Mid ROE**	**High ROE**
Atmos Energy	ATO	$2.65	$94.89	2.79%	2.89%	7.30%	7.17%	7.00%	7.16%	9.89%	10.05%	10.19%
Chesapeake Utilities	CPK	$1.96	$97.62	2.01%	2.07%	NA	4.74%	8.50%	6.62%	6.80%	8.69%	10.59%
NiSource Inc.	NI	$0.88	$23.47	3.75%	3.87%	6.40%	3.52%	9.50%	6.47%	7.34%	10.34%	13.43%
New Jersey Resources	NJR	$1.33	$35.75	3.72%	3.81%	7.10%	6.00%	2.00%	5.03%	5.76%	8.85%	10.95%
Northwest Natural	NWN	$1.92	$48.33	3.97%	4.06%	3.90%	3.80%	5.50%	4.40%	7.85%	8.46%	9.58%
ONE Gas Inc.	OGS	$2.40	$74.23	3.23%	3.32%	5.00%	5.00%	6.00%	5.33%	8.31%	8.65%	9.33%
South Jersey Inds.	SJI	$1.28	$22.98	5.57%	5.77%	5.40%	4.90%	11.50%	7.27%	10.61%	13.04%	17.39%
Spire Inc.	SR	$2.66	$64.87	4.10%	4.26%	5.50%	7.31%	10.00%	7.60%	9.71%	11.86%	14.31%
Southwest Gas	SWX	$2.42	$65.36	3.70%	3.82%	5.50%	4.00%	9.00%	6.17%	7.78%	9.98%	12.87%
Mean				3.65%	3.76%	5.76%	5.16%	7.67%	6.23%	8.23%	9.99%	12.07%
Median				3.72%	3.82%	5.50%	4.90%	8.50%	6.47%	7.85%	9.98%	10.95%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 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])

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Multi-Stage Discounted Cash Flow Model
30 Day Average Stock Price
Low Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	Ticker	Indicated Annual Dividend	Weighted-Average Stock Price	Zacks Earnings Growth	Yahoo Finance Earnings Growth	Value Line Earnings Growth	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
Atmos Energy	ATO	$2.65	$101.26	7.30%	7.17%	7.00%	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.61%
Chesapeake Utilities	CPK	$1.96	$118.66	NA	4.74%	8.50%	4.74%	4.86%	4.99%	5.11%	5.24%	5.36%	5.49%	7.17%
NiSource Inc.	NI	$0.88	$25.69	6.40%	3.52%	9.50%	3.52%	3.85%	4.18%	4.50%	4.83%	5.16%	5.49%	8.79%
New Jersey Resources	NJR	$1.33	$42.46	7.10%	6.00%	2.00%	2.00%	2.58%	3.16%	3.74%	4.33%	4.91%	5.49%	8.20%
Northwest Natural	NWN	$1.92	$54.40	3.90%	3.80%	5.50%	3.80%	4.08%	4.36%	4.64%	4.93%	5.21%	5.49%	8.95%
ONE Gas Inc.	OGS	$2.40	$77.52	5.00%	5.00%	6.00%	5.00%	5.08%	5.16%	5.24%	5.33%	5.41%	5.49%	8.76%
South Jersey Inds.	SJI	$1.28	$25.06	5.40%	4.90%	11.50%	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	10.97%
Spire Inc.	SR	$2.66	$75.24	5.50%	7.31%	10.00%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.36%
Southwest Gas	SWX	$2.42	$69.03	5.50%	4.00%	9.00%	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	8.97%
													Mean	8.86%
													Median	8.79%
													Max	10.97%
													Min	7.17%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals minimum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
30 Day Average Stock Price
Average Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**First Stage Growth**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage Growth**	**ROE**
Atmos Energy	ATO	$2.65	$101.26	7.30%	7.17%	7.00%	7.16%	6.88%	6.60%	6.32%	6.05%	5.77%	5.49%	8.64%
Chesapeake Utilities	CPK	$1.96	$118.66	NA	4.74%	8.50%	6.62%	6.43%	6.24%	6.05%	5.87%	5.68%	5.49%	7.40%
NiSource Inc.	NI	$0.88	$25.69	6.40%	3.52%	9.50%	6.47%	6.31%	6.15%	5.98%	5.82%	5.65%	5.49%	9.47%
New Jersey Resources	NJR	$1.33	$42.46	7.10%	6.00%	2.00%	5.03%	5.11%	5.19%	5.26%	5.34%	5.41%	5.49%	8.80%
Northwest Natural	NWN	$1.92	$54.40	3.90%	3.80%	5.50%	4.40%	4.58%	4.76%	4.94%	5.13%	5.31%	5.49%	9.09%
ONE Gas Inc.	OGS	$2.40	$77.52	5.00%	5.00%	6.00%	5.33%	5.36%	5.39%	5.41%	5.44%	5.46%	5.49%	8.83%
South Jersey Inds.	SJI	$1.28	$25.06	5.40%	4.90%	11.50%	7.27%	6.97%	6.67%	6.38%	6.08%	5.79%	5.49%	11.79%
Spire Inc.	SR	$2.66	$75.24	5.50%	7.31%	10.00%	7.60%	7.25%	6.90%	6.55%	6.19%	5.84%	5.49%	9.90%
Southwest Gas	SWX	$2.42	$69.03	5.50%	4.00%	9.00%	6.17%	6.05%	5.94%	5.83%	5.72%	5.60%	5.49%	9.49%
													Mean	9.27%
													Median	9.09%
													Max	11.79%
													Min	7.40%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals average ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
30 Day Average Stock Price
High Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**First Stage Growth**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage Growth**	**ROE**
Atmos Energy	ATO	$2.65	$101.26	7.30%	7.17%	7.00%	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.67%
Chesapeake Utilities	CPK	$1.96	$118.66	NA	4.74%	8.50%	8.50%	8.00%	7.50%	6.99%	6.49%	5.99%	5.49%	7.65%
NiSource Inc.	NI	$0.88	$25.69	6.40%	3.52%	9.50%	9.50%	8.83%	8.16%	7.49%	6.83%	6.16%	5.49%	10.27%
New Jersey Resources	NJR	$1.33	$42.46	7.10%	6.00%	2.00%	7.10%	6.83%	6.56%	6.29%	6.03%	5.76%	5.49%	9.27%
Northwest Natural	NWN	$1.92	$54.40	3.90%	3.80%	5.50%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.35%
ONE Gas Inc.	OGS	$2.40	$77.52	5.00%	5.00%	6.00%	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	8.97%
South Jersey Inds.	SJI	$1.28	$25.06	5.40%	4.90%	11.50%	11.50%	10.50%	9.50%	8.49%	7.49%	6.49%	5.49%	13.44%
Spire Inc.	SR	$2.66	$75.24	5.50%	7.31%	10.00%	10.00%	9.25%	8.50%	7.74%	6.99%	6.24%	5.49%	10.57%
Southwest Gas	SWX	$2.42	$69.03	5.50%	4.00%	9.00%	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	10.24%
													Mean	9.83%
													Median	9.35%
													Max	13.44%
													Min	7.65%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals maximum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
90 Day Average Stock Price
Low Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**First Stage Growth**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage Growth**	**ROE**
Atmos Energy	ATO	$2.65	$94.25	7.30%	7.17%	7.00%	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.85%
Chesapeake Utilities	CPK	$1.96	$111.79	NA	4.74%	8.50%	4.74%	4.86%	4.99%	5.11%	5.24%	5.36%	5.49%	7.28%
NiSource Inc.	NI	$0.88	$23.87	6.40%	3.52%	9.50%	3.52%	3.85%	4.18%	4.50%	4.83%	5.16%	5.49%	9.05%
New Jersey Resources	NJR	$1.33	$39.82	7.10%	6.00%	2.00%	2.00%	2.58%	3.16%	3.74%	4.33%	4.91%	5.49%	8.39%
Northwest Natural	NWN	$1.92	$49.62	3.90%	3.80%	5.50%	3.80%	4.08%	4.36%	4.64%	4.93%	5.21%	5.49%	9.30%
ONE Gas Inc.	OGS	$2.40	$74.44	5.00%	5.00%	6.00%	5.00%	5.08%	5.16%	5.24%	5.33%	5.41%	5.49%	8.90%
South Jersey Inds.	SJI	$1.28	$23.91	5.40%	4.90%	11.50%	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	11.25%
Spire Inc.	SR	$2.66	$70.15	5.50%	7.31%	10.00%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.65%
Southwest Gas	SWX	$2.42	$66.26	5.50%	4.00%	9.00%	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	9.13%
													Mean	9.09%
													Median	9.05%
													Max	11.25%
													Min	7.28%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals minimum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
90 Day Average Stock Price
Average Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	Ticker	Indicated Annual Dividend	Weighted-Average Stock Price	Zacks Earnings Growth	Yahoo Finance Earnings Growth	Value Line Earnings Growth	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
Atmos Energy	ATO	$2.65	$94.25	7.30%	7.17%	7.00%	7.16%	6.88%	6.60%	6.32%	6.05%	5.77%	5.49%	8.88%
Chesapeake Utilities	CPK	$1.96	$111.79	NA	4.74%	8.50%	6.62%	6.43%	6.24%	6.05%	5.87%	5.68%	5.49%	7.52%
NiSource Inc.	NI	$0.88	$23.87	6.40%	3.52%	9.50%	6.47%	6.31%	6.15%	5.98%	5.82%	5.65%	5.49%	9.78%
New Jersey Resources	NJR	$1.33	$39.82	7.10%	6.00%	2.00%	5.03%	5.11%	5.19%	5.26%	5.34%	5.41%	5.49%	9.03%
Northwest Natural	NWN	$1.92	$49.62	3.90%	3.80%	5.50%	4.40%	4.58%	4.76%	4.94%	5.13%	5.31%	5.49%	9.45%
ONE Gas Inc.	OGS	$2.40	$74.44	5.00%	5.00%	6.00%	5.33%	5.36%	5.39%	5.41%	5.44%	5.46%	5.49%	8.97%
South Jersey Inds.	SJI	$1.28	$23.91	5.40%	4.90%	11.50%	7.27%	6.97%	6.67%	6.38%	6.08%	5.79%	5.49%	12.11%
Spire Inc.	SR	$2.66	$70.15	5.50%	7.31%	10.00%	7.60%	7.25%	6.90%	6.55%	6.19%	5.84%	5.49%	10.22%
Southwest Gas	SWX	$2.42	$66.26	5.50%	4.00%	9.00%	6.17%	6.05%	5.94%	5.83%	5.72%	5.60%	5.49%	9.66%
													Mean	9.51%
													Median	9.45%
													Max	12.11%
													Min	7.52%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals average ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
90 Day Average Stock Price
High Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	Ticker	Indicated Annual Dividend	Weighted-Average Stock Price	Zacks Earnings Growth	Yahoo Finance Earnings Growth	Value Line Earnings Growth	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
Atmos Energy	ATO	$2.65	$94.25	7.30%	7.17%	7.00%	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.91%
Chesapeake Utilities	CPK	$1.96	$111.79	NA	4.74%	8.50%	8.50%	8.00%	7.50%	6.99%	6.49%	5.99%	5.49%	7.78%
NiSource Inc.	NI	$0.88	$23.87	6.40%	3.52%	9.50%	9.50%	8.83%	8.16%	7.49%	6.83%	6.16%	5.49%	10.63%
New Jersey Resources	NJR	$1.33	$39.82	7.10%	6.00%	2.00%	7.10%	6.83%	6.56%	6.29%	6.03%	5.76%	5.49%	9.52%
Northwest Natural	NWN	$1.92	$49.62	3.90%	3.80%	5.50%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.74%
ONE Gas Inc.	OGS	$2.40	$74.44	5.00%	5.00%	6.00%	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.12%
South Jersey Inds.	SJI	$1.28	$23.91	5.40%	4.90%	11.50%	11.50%	10.50%	9.50%	8.49%	7.49%	6.49%	5.49%	13.82%
Spire Inc.	SR	$2.66	$70.15	5.50%	7.31%	10.00%	10.00%	9.25%	8.50%	7.74%	6.99%	6.24%	5.49%	10.94%
Southwest Gas	SWX	$2.42	$66.26	5.50%	4.00%	9.00%	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	10.44%
													Mean	10.10%
													Median	9.74%
													Max	13.82%
													Min	7.78%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals maximum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
180 Day Average Stock Price
Low Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	Ticker	Indicated Annual Dividend	Weighted-Average Stock Price	Zacks Earnings Growth	Yahoo Finance Earnings Growth	Value Line Earnings Growth	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
Atmos Energy	ATO	$2.65	$94.89	7.30%	7.17%	7.00%	7.00%	6.75%	6.50%	6.24%	5.99%	5.74%	5.49%	8.83%
Chesapeake Utilities	CPK	$1.96	$97.62	NA	4.74%	8.50%	4.74%	4.86%	4.99%	5.11%	5.24%	5.36%	5.49%	7.55%
NiSource Inc.	NI	$0.88	$23.47	6.40%	3.52%	9.50%	3.52%	3.85%	4.18%	4.50%	4.83%	5.16%	5.49%	9.11%
New Jersey Resources	NJR	$1.33	$35.75	7.10%	6.00%	2.00%	2.00%	2.58%	3.16%	3.74%	4.33%	4.91%	5.49%	8.74%
Northwest Natural	NWN	$1.92	$48.33	3.90%	3.80%	5.50%	3.80%	4.08%	4.36%	4.64%	4.93%	5.21%	5.49%	9.41%
ONE Gas Inc.	OGS	$2.40	$74.23	5.00%	5.00%	6.00%	5.00%	5.08%	5.16%	5.24%	5.33%	5.41%	5.49%	8.91%
South Jersey Inds.	SJI	$1.28	$22.98	5.40%	4.90%	11.50%	4.90%	5.00%	5.10%	5.19%	5.29%	5.39%	5.49%	11.50%
Spire Inc.	SR	$2.66	$64.87	5.50%	7.31%	10.00%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	10.00%
Southwest Gas	SWX	$2.42	$65.36	5.50%	4.00%	9.00%	4.00%	4.25%	4.50%	4.74%	4.99%	5.24%	5.49%	9.18%
													Mean	9.25%
													Median	9.11%
													Max	11.50%
													Min	7.55%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals minimum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
180 Day Average Stock Price
Average Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**First Stage Growth**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage Growth**	**ROE**
Atmos Energy	ATO	$2.65	$94.89	7.30%	7.17%	7.00%	7.16%	6.88%	6.60%	6.32%	6.05%	5.77%	5.49%	8.86%
Chesapeake Utilities	CPK	$1.96	$97.62	NA	4.74%	8.50%	6.62%	6.43%	6.24%	6.05%	5.87%	5.68%	5.49%	7.82%
NiSource Inc.	NI	$0.88	$23.47	6.40%	3.52%	9.50%	6.47%	6.31%	6.15%	5.98%	5.82%	5.65%	5.49%	9.86%
New Jersey Resources	NJR	$1.33	$35.75	7.10%	6.00%	2.00%	5.03%	5.11%	5.19%	5.26%	5.34%	5.41%	5.49%	9.45%
Northwest Natural	NWN	$1.92	$48.33	3.90%	3.80%	5.50%	4.40%	4.58%	4.76%	4.94%	5.13%	5.31%	5.49%	9.57%
ONE Gas Inc.	OGS	$2.40	$74.23	5.00%	5.00%	6.00%	5.33%	5.36%	5.39%	5.41%	5.44%	5.46%	5.49%	8.98%
South Jersey Inds.	SJI	$1.28	$22.98	5.40%	4.90%	11.50%	7.27%	6.97%	6.67%	6.38%	6.08%	5.79%	5.49%	12.39%
Spire Inc.	SR	$2.66	$64.87	5.50%	7.31%	10.00%	7.60%	7.25%	6.90%	6.55%	6.19%	5.84%	5.49%	10.62%
Southwest Gas	SWX	$2.42	$65.36	5.50%	4.00%	9.00%	6.17%	6.05%	5.94%	5.83%	5.72%	5.60%	5.49%	9.72%
													Mean	9.69%
													Median	9.57%
													Max	12.39%
													Min	7.82%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals average ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
[8] Equals [6] + ([12] - [6]) / 6
[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

Multi-Stage Discounted Cash Flow Model
180 Day Average Stock Price
High Growth Rate

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
								Second Stage Growth						
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**First Stage Growth**	**Year 6**	**Year 7**	**Year 8**	**Year 9**	**Year 10**	**Third Stage Growth**	**ROE**
Atmos Energy	ATO	$2.65	$94.89	7.30%	7.17%	7.00%	7.30%	7.00%	6.70%	6.39%	6.09%	5.79%	5.49%	8.89%
Chesapeake Utilities	CPK	$1.96	$97.62	NA	4.74%	8.50%	8.50%	8.00%	7.50%	6.99%	6.49%	5.99%	5.49%	8.12%
NiSource Inc.	NI	$0.88	$23.47	6.40%	3.52%	9.50%	9.50%	8.83%	8.16%	7.49%	6.83%	6.16%	5.49%	10.72%
New Jersey Resources	NJR	$1.33	$35.75	7.10%	6.00%	2.00%	7.10%	6.83%	6.56%	6.29%	6.03%	5.76%	5.49%	9.99%
Northwest Natural	NWN	$1.92	$48.33	3.90%	3.80%	5.50%	5.50%	5.50%	5.50%	5.49%	5.49%	5.49%	5.49%	9.86%
ONE Gas Inc.	OGS	$2.40	$74.23	5.00%	5.00%	6.00%	6.00%	5.91%	5.83%	5.74%	5.66%	5.57%	5.49%	9.13%
South Jersey Inds.	SJI	$1.28	$22.98	5.40%	4.90%	11.50%	11.50%	10.50%	9.50%	8.49%	7.49%	6.49%	5.49%	14.15%
Spire Inc.	SR	$2.66	$64.87	5.50%	7.31%	10.00%	10.00%	9.25%	8.50%	7.74%	6.99%	6.24%	5.49%	11.38%
Southwest Gas	SWX	$2.42	$65.36	5.50%	4.00%	9.00%	9.00%	8.41%	7.83%	7.24%	6.66%	6.07%	5.49%	10.51%
													Mean	10.31%
													Median	9.99%
													Max	14.15%
													Min	8.12%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Source: Zacks
[4] Source: Yahoo Finance
[5] Source: Value Line
[6] Equals maximum ([3], [4], [5])
[7] Equals [6] + ([12] - [6]) / 6
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[9] Equals [6] + ([12] - [6]) / 6
[10] Equals [6] + ([12] - [6]) / 6
[11] Equals [6] + ([12] - [6]) / 6
[12] Source: Federal Reserve Bank of St. Louis; Energy Information Administration
[13] Equals internal rate of return of cash flows resulting from Excel's goal seek function

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Proxy Group Betas

Company Name	Stock Ticker	Beta [1]
Atmos Energy	ATO	0.80
Chesapeake Utilities	CPK	0.80
NiSource Inc.	NI	0.85
New Jersey Resources	NJR	1.00
Northwest Natural	NWN	0.85
ONE Gas Inc.	OGS	0.80
South Jersey Inds.	SJI	1.05
Spire Inc.	SR	0.85
Southwest Gas	SWX	0.95
Mean		**0.88**

[1] Source: Value Line

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Market Risk Premium Derived from Value Line Long-Term Growth Estimates

[1]	S&P 500 Estimated Required Market Return	14.02%

S&P 500 Index

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Dividend Yield	[5] Long-Term EPS Growth	[6] DCF Result	[7] Weighted DCF Result
Agilent Technologies	A	39,714.00	0.10%	0.60%	11.00%	11.63%	0.0122%
Amer. Airlines	AAL	14,732.40	0.04%	0.00%	0.00%	0.00%	0.0000%
Advance Auto Parts	AAP	12,912.50	0.03%	2.06%	11.00%	13.17%	0.0045%
Apple Inc.	AAPL	2,080,615.40	5.47%	0.71%	14.50%	15.26%	0.8354%
AbbVie Inc.	ABBV	204,552.10	0.54%	4.49%	6.50%	11.14%	0.0599%
AmerisourceBergen	ABC	24,249.80	0.06%	1.52%	7.00%	8.57%	0.0055%
ABIOMED Inc.	ABMD	12,390.70	0.03%	0.00%	10.00%	10.00%	0.0033%
Abbott Labs.	ABT	206,786.30	0.54%	1.55%	11.50%	13.14%	0.0715%
Accenture Plc	ACN	178,744.10	0.47%	1.35%	9.50%	10.91%	0.0513%
Adobe Inc.	ADBE	230,145.10	0.61%	0.00%	14.50%	14.50%	0.0878%
Analog Devices	ADI	56,474.80	0.15%	1.80%	8.50%	10.38%	0.0154%
Archer Daniels Midl'd	ADM	37,134.40	0.10%	2.29%	7.50%	9.88%	0.0096%
Automatic Data Proc.	ADP	81,297.80	0.21%	2.05%	9.00%	11.14%	0.0238%
Autodesk Inc.	ADSK	60,163.80	0.16%	0.00%	18.00%	18.00%	0.0285%
Ameren Corp.	AEE	21,515.70	0.06%	2.66%	6.00%	8.74%	0.0049%
Amer. Elec. Power	AEP	42,895.20	0.11%	3.54%	6.50%	10.16%	0.0115%
AES Corp.	AES	16,616.40	0.04%	2.41%	21.50%	24.17%	0.0106%
Aflac Inc.	AFL	38,611.20	0.10%	2.44%	7.00%	9.53%	0.0097%
Amer. Int'l Group	AIG	43,655.10	0.11%	2.53%	28.50%	31.39%	0.0361%
Assurant Inc.	AIZ	9,105.60	0.02%	1.68%	14.00%	15.80%	0.0038%
Gallagher (Arthur J.)	AJG	28,481.90	0.07%	1.32%	12.50%	13.90%	0.0104%
Akamai Technologies	AKAM	18,437.00	0.05%	0.00%	9.50%	9.50%	0.0046%
Albemarle Corp.	ALB	18,322.40	0.05%	0.99%	6.50%	7.52%	0.0036%
Align Techn.	ALGN	45,225.40	0.12%	0.00%	23.00%	23.00%	0.0274%
Alaska Air Group	ALK	8,627.60	0.02%	0.00%	77.50%	77.50%	0.0176%
Allstate Corp.	ALL	41,249.80	0.11%	2.39%	8.50%	10.99%	0.0119%
Allegion plc	ALLE	12,396.10	0.03%	1.05%	8.50%	9.59%	0.0031%
Alexion Pharmac.	ALXN	38,761.30	0.10%	0.00%	19.50%	19.50%	0.0199%
Applied Materials	AMAT	114,524.10	0.30%	0.77%	11.50%	12.31%	0.0371%
Amcor plc	AMCR	19,444.20	0.05%	3.91%	0.00%	3.91%	0.0020%
Advanced Micro Dev.	AMD	92,619.40	0.24%	0.00%	24.00%	24.00%	0.0585%
AMETEK Inc.	AME	30,372.80	0.08%	0.61%	10.00%	10.64%	0.0085%
Amgen	AMGN	143,036.80	0.38%	2.91%	5.50%	8.49%	0.0319%
Ameriprise Fin'l	AMP	29,259.10	0.08%	1.79%	13.00%	14.91%	0.0115%
Amer. Tower 'A'	AMT	109,436.90	0.29%	2.26%	9.50%	11.87%	0.0342%
Amazon.com	AMZN	1,628,827.10	4.29%	0.00%	28.50%	28.50%	1.2212%
Arista Networks	ANET	24,674.50	0.06%	0.00%	4.50%	4.50%	0.0029%
ANSYS Inc.	ANSS	28,449.70	0.07%	0.00%	8.00%	8.00%	0.0060%
Anthem Inc.	ANTM	96,366.40	0.25%	1.15%	10.00%	11.21%	0.0284%
Aon plc	AON	57,054.40	0.15%	0.81%	7.00%	7.84%	0.0118%
Smith (A.O.)	AOS	11,010.50	0.03%	1.52%	8.50%	10.08%	0.0029%
APA Corp.	APA	7,859.20	0.02%	0.48%	47.00%	47.59%	0.0098%
Air Products & Chem.	APD	66,011.30	0.17%	2.01%	12.00%	14.13%	0.0245%
Amphenol Corp.	APH	39,372.80	0.10%	0.88%	9.00%	9.92%	0.0103%
Aptiv PLC	APTV	37,031.80	0.10%	0.00%	15.50%	15.50%	0.0151%
Alexandria Real Estate	ARE	19,214.00	0.05%	2.52%	13.00%	15.68%	0.0079%
Atmos Energy	ATO	12,819.70	0.03%	2.70%	7.00%	9.79%	0.0033%
Activision Blizzard	ATVI	73,230.00	0.19%	0.50%	12.50%	13.03%	0.0251%
AvalonBay Communities	AVB	27,440.80	0.07%	3.29%	1.00%	4.31%	0.0031%
Broadcom Inc.	AVGO	180,221.80	0.47%	3.26%	27.00%	30.70%	0.1456%
Avery Dennison	AVY	17,942.00	0.05%	1.26%	9.00%	10.32%	0.0049%
Amer. Water Works	AWK	27,595.80	0.07%	1.59%	8.00%	9.65%	0.0070%
Amer. Express	AXP	124,557.70	0.33%	1.16%	8.50%	9.71%	0.0318%
AutoZone Inc.	AZO	32,538.50	0.09%	0.00%	14.50%	14.50%	0.0124%
Boeing	BA	131,163.40	0.35%	0.00%	0.00%	0.00%	0.0000%
Bank of America	BAC	363,074.60	0.96%	1.72%	5.00%	6.76%	0.0646%
Baxter Int'l Inc.	BAX	41,460.80	0.11%	1.36%	8.50%	9.92%	0.0108%
Best Buy Co.	BBY	29,332.00	0.08%	2.46%	8.50%	11.06%	0.0085%
Becton Dickinson	BDX	70,501.50	0.19%	1.40%	7.50%	8.95%	0.0166%
Franklin Resources	BEN	16,875.20	0.04%	3.35%	10.50%	14.03%	0.0062%
Brown-Forman 'B'	BF/B	37,363.60	0.10%	0.92%	11.00%	11.97%	0.0118%
Biogen	BIIB	42,431.60	0.11%	0.00%	1.00%	1.00%	0.0011%
Bio-Rad Labs. 'A'	BIO	17,567.10	0.05%	0.00%	9.00%	9.00%	0.0042%
Bank of New York Mello	BK	44,527.00	0.12%	2.44%	5.00%	7.50%	0.0088%

Booking Holdings	BKNG	93,186.20	0.25%	0.00%	14.00%	14.00%	0.0343%
Baker Hughes	BKR	18,266.50	0.05%	2.85%	0.00%	2.85%	0.0014%
BlackRock Inc.	BLK	127,988.30	0.34%	1.97%	10.00%	12.07%	0.0406%
Ball Corp.	BLL	28,158.70	0.07%	0.70%	20.00%	20.77%	0.0154%
Bristol-Myers Squibb	BMY	146,362.90	0.39%	2.99%	56.50%	60.33%	0.2323%
Broadridge Fin'l	BR	18,460.80	0.05%	1.44%	8.50%	10.00%	0.0049%
Berkshire Hathaway 'B'	BRK/	0.00	0.00%	0.00%	0.00%	0.00%	0.0000%
Boston Scientific	BSX	58,854.30	0.15%	0.00%	17.50%	17.50%	0.0271%
BorgWarner	BWA	11,997.20	0.03%	1.36%	5.50%	6.90%	0.0022%
Boston Properties	BXP	17,041.90	0.04%	3.65%	1.50%	5.18%	0.0023%
Citigroup Inc.	C	159,186.70	0.42%	2.67%	5.00%	7.74%	0.0324%
Conagra Brands	CAG	18,060.40	0.05%	3.00%	5.00%	8.08%	0.0038%
Cardinal Health	CAH	16,278.50	0.04%	3.50%	11.50%	15.20%	0.0065%
Carrier Global	CARR	37,749.30	0.10%	1.11%	0.00%	1.11%	0.0011%
Caterpillar Inc.	CAT	129,748.90	0.34%	1.74%	8.50%	10.31%	0.0352%
Chubb Ltd.	CB	74,866.80	0.20%	1.88%	10.00%	11.97%	0.0236%
Cboe Global Markets	CBOE	11,933.80	0.03%	1.50%	12.00%	13.59%	0.0043%
CBRE Group	CBRE	28,516.10	0.08%	0.00%	8.50%	8.50%	0.0064%
Crown Castle Int'l	CCI	78,559.20	0.21%	3.14%	8.50%	11.77%	0.0243%
Carnival Corp.	CCL	30,558.70	0.08%	0.00%	0.00%	0.00%	0.0000%
Cadence Design Sys.	CDNS	34,037.40	0.09%	0.00%	9.50%	9.50%	0.0085%
CDW Corp.	CDW	23,591.40	0.06%	0.95%	10.00%	11.00%	0.0068%
Celanese Corp.	CE	18,515.70	0.05%	1.65%	6.50%	8.20%	0.0040%
Cerner Corp.	CERN	23,668.10	0.06%	1.12%	8.00%	9.16%	0.0057%
CF Industries	CF	11,357.90	0.03%	2.30%	14.50%	16.97%	0.0051%
Citizens Fin'l Group	CFG	20,849.30	0.05%	3.25%	8.50%	11.89%	0.0065%
Church & Dwight	CHD	21,500.70	0.06%	1.15%	8.00%	9.20%	0.0052%
C.H. Robinson	CHRW	12,975.20	0.03%	2.14%	8.00%	10.23%	0.0035%
Charter Communic.	CHTR	128,226.90	0.34%	0.00%	26.50%	26.50%	0.0894%
Cigna Corp.	CI	93,099.00	0.24%	1.52%	11.00%	12.60%	0.0309%
Cincinnati Financial	CINF	19,248.50	0.05%	2.11%	10.50%	12.72%	0.0064%
Colgate-Palmolive	CL	70,393.10	0.19%	2.16%	4.50%	6.71%	0.0124%
Clorox Co.	CLX	22,466.90	0.06%	2.46%	6.50%	9.04%	0.0053%
Comerica Inc.	CMA	10,762.00	0.03%	3.53%	1.00%	4.55%	0.0013%
Comcast Corp.	CMCS	249,179.40	0.66%	1.84%	11.50%	13.45%	0.0881%
CME Group	CME	75,897.40	0.20%	1.70%	8.00%	9.77%	0.0195%
Chipotle Mex. Grill	CMG	36,809.20	0.10%	0.00%	18.50%	18.50%	0.0179%
Cummins Inc.	CMI	37,900.90	0.10%	2.08%	7.50%	9.66%	0.0096%
CMS Energy Corp.	CMS	18,302.20	0.05%	2.80%	7.50%	10.41%	0.0050%
Centene Corp.	CNC	41,300.50	0.11%	0.00%	9.50%	9.50%	0.0103%
CenterPoint Energy	CNP	13,497.20	0.04%	2.65%	8.00%	10.76%	0.0038%
Capital One Fin'l	COF	71,786.30	0.19%	1.02%	3.50%	4.54%	0.0086%
Cabot Oil & Gas 'A'	COG	7,189.60	0.02%	2.78%	14.50%	17.48%	0.0033%
Cooper Cos.	COO	18,754.70	0.05%	0.02%	13.50%	13.52%	0.0067%
ConocoPhillips	COP	75,000.70	0.20%	3.10%	8.50%	11.73%	0.0231%
Costco Wholesale	COST	168,058.00	0.44%	0.83%	9.50%	10.37%	0.0458%
Campbell Soup	CPB	14,644.40	0.04%	3.06%	5.00%	8.14%	0.0031%
Copart Inc.	CPRT	28,590.80	0.08%	0.00%	10.00%	10.00%	0.0075%
salesforce.com	CRM	203,411.50	0.54%	0.00%	39.50%	39.50%	0.2114%
Cisco Systems	CSCO	221,475.90	0.58%	2.82%	6.00%	8.90%	0.0519%
CSX Corp.	CSX	74,497.90	0.20%	1.14%	8.00%	9.19%	0.0180%
Cintas Corp.	CTAS	35,974.80	0.09%	0.88%	13.50%	14.44%	0.0137%
Catalent Inc.	CTLT	17,093.00	0.04%	0.00%	28.00%	28.00%	0.0126%
Cognizant Technology	CTSH	37,350.70	0.10%	1.36%	6.50%	7.90%	0.0078%
Corteva Inc.	CTVA	33,091.50	0.09%	1.27%	0.00%	1.27%	0.0011%
Citrix Sys.	CTXS	14,236.40	0.04%	1.28%	9.00%	10.34%	0.0039%
CVS Health	CVS	117,132.70	0.31%	2.24%	6.00%	8.31%	0.0256%
Chevron Corp.	CVX	198,679.20	0.52%	5.19%	23.50%	29.30%	0.1531%
Dominion Energy	D	62,045.90	0.16%	3.33%	12.00%	15.53%	0.0253%
Delta Air Lines	DAL	29,514.00	0.08%	0.00%	49.00%	49.00%	0.0380%
DuPont de Nemours	DD	44,823.30	0.12%	1.45%	0.00%	1.45%	0.0017%
Deere & Co.	DE	112,342.80	0.30%	1.00%	14.00%	15.07%	0.0445%
Discover Fin'l Svcs.	DFS	35,087.30	0.09%	1.53%	12.50%	14.13%	0.0130%
Dollar General	DG	49,055.10	0.13%	0.82%	10.50%	11.36%	0.0147%
Quest Diagnostics	DGX	17,120.40	0.05%	1.90%	7.00%	8.97%	0.0040%
Horton D.R.	DHI	32,915.40	0.09%	0.89%	10.50%	11.44%	0.0099%
Danaher Corp.	DHR	177,273.60	0.47%	0.34%	18.00%	18.37%	0.0857%
Disney (Walt)	DIS	301,469.80	0.79%	0.00%	14.00%	14.00%	0.1110%
Discovery Inc.	DISC	16,753.70	0.04%	0.00%	15.50%	15.50%	0.0068%
Discovery Communic. 'C	DISC	16,296.00	0.04%	0.00%	0.00%	0.00%	0.0000%
Dish Network 'A'	DISH	22,754.20	0.06%	0.00%	0.00%	0.00%	0.0000%
Digital Realty Trust	DLR	42,046.30	0.11%	3.13%	7.00%	10.24%	0.0113%
Dollar Tree Inc.	DLTR	25,389.70	0.07%	0.00%	9.50%	9.50%	0.0063%
Dover Corp.	DOV	21,210.50	0.06%	1.34%	6.50%	7.88%	0.0044%
Dow Inc.	DOW	51,206.10	0.13%	4.16%	0.00%	4.16%	0.0056%
Domino's Pizza	DPZ	16,767.40	0.04%	0.88%	13.00%	13.94%	0.0061%
Duke Realty Corp.	DRE	16,856.30	0.04%	2.35%	-2.50%	-0.18%	-0.0001%
Darden Restaurants	DRI	18,312.80	0.05%	2.52%	14.50%	17.20%	0.0083%
DTE Energy	DTE	26,889.30	0.07%	3.22%	6.00%	9.32%	0.0066%

Duke Energy	DUK	77,792.00	0.20%	3.88%	7.00%	11.02%	0.0225%
DaVita Inc.	DVA	13,087.10	0.03%	0.00%	14.50%	14.50%	0.0050%
Devon Energy	DVN	17,064.00	0.04%	1.74%	21.00%	22.92%	0.0103%
DXC Technology	DXC	9,394.60	0.02%	0.00%	1.50%	1.50%	0.0004%
DexCom Inc.	DXCM	32,132.40	0.08%	0.00%	27.50%	27.50%	0.0232%
Electronic Arts	EA	40,059.00	0.11%	0.50%	9.00%	9.52%	0.0100%
eBay Inc.	EBAY	40,717.00	0.11%	1.24%	16.50%	17.84%	0.0191%
Ecolab Inc.	ECL	60,998.90	0.16%	0.90%	9.00%	9.94%	0.0160%
Consol. Edison	ED	26,669.20	0.07%	4.01%	4.00%	8.09%	0.0057%
Equifax Inc.	EFX	28,408.40	0.07%	0.67%	10.50%	11.21%	0.0084%
Edison Int'l	EIX	21,870.50	0.06%	4.68%	23.50%	28.73%	0.0165%
Lauder (Estee)	EL	108,200.90	0.28%	0.74%	11.00%	11.78%	0.0335%
Eastman Chemical	EMN	17,008.20	0.04%	2.21%	9.00%	11.31%	0.0051%
Emerson Electric	EMR	55,964.00	0.15%	2.17%	9.00%	11.27%	0.0166%
Enphase Energy	ENPH	17,730.70	0.05%	0.00%	48.50%	48.50%	0.0226%
EOG Resources	EOG	47,004.00	0.12%	2.11%	12.50%	14.74%	0.0182%
Equinix Inc.	EQIX	64,078.40	0.17%	1.64%	17.00%	18.78%	0.0317%
Equity Residential	EQR	27,364.20	0.07%	3.28%	2.00%	5.31%	0.0038%
Eversource Energy	ES	28,590.90	0.08%	2.94%	5.50%	8.52%	0.0064%
Essex Property Trust	ESS	18,545.50	0.05%	2.93%	1.00%	3.94%	0.0019%
Eaton Corp. plc	ETN	56,889.90	0.15%	2.13%	5.50%	7.69%	0.0115%
Entergy Corp.	ETR	21,068.50	0.06%	3.73%	3.00%	6.79%	0.0038%
Etsy Inc.	ETSY	20,972.90	0.06%	0.00%	27.50%	27.50%	0.0152%
Evergy Inc.	EVRG	14,246.30	0.04%	3.51%	8.00%	11.65%	0.0044%
Edwards Lifesciences	EW	56,384.80	0.15%	0.00%	13.00%	13.00%	0.0193%
Exelon Corp.	EXC	44,492.60	0.12%	3.36%	5.50%	8.95%	0.0105%
Expeditors Int'l	EXPD	20,140.50	0.05%	0.97%	8.50%	9.51%	0.0050%
Expedia Group	EXPE	23,990.80	0.06%	0.00%	0.00%	0.00%	0.0000%
Extra Space Storage	EXR	19,037.70	0.05%	2.76%	3.50%	6.31%	0.0032%
Ford Motor	F	49,760.00	0.13%	0.00%	46.00%	46.00%	0.0602%
Diamondback Energy	FANG	12,318.20	0.03%	2.05%	0.00%	2.05%	0.0007%
Fastenal Co.	FAST	29,829.80	0.08%	2.16%	9.50%	11.76%	0.0092%
Facebook Inc.	FB	890,909.30	2.34%	0.00%	17.00%	17.00%	0.3984%
Fortune Brands Home	FBHS	14,275.60	0.04%	1.01%	10.00%	11.06%	0.0042%
Freep't-McMoRan Inc.	FCX	59,614.10	0.16%	0.79%	32.50%	33.42%	0.0524%
FedEx Corp.	FDX	81,706.80	0.21%	0.84%	11.00%	11.89%	0.0255%
FirstEnergy Corp.	FE	20,341.90	0.05%	4.22%	11.50%	15.96%	0.0085%
F5 Networks	FFIV	10,843.00	0.03%	0.00%	9.00%	9.00%	0.0026%
Fidelity Nat'l Info.	FIS	91,493.40	0.24%	1.06%	34.50%	35.74%	0.0860%
Fiserv Inc.	FISV	75,372.50	0.20%	0.00%	13.00%	13.00%	0.0258%
Fifth Third Bancorp	FITB	29,666.40	0.08%	2.59%	4.00%	6.64%	0.0052%
FLIR Systems	FLIR	7,532.60	0.02%	1.19%	6.50%	7.73%	0.0015%
FleetCor Technologies	FLT	22,674.10	0.06%	0.00%	11.00%	11.00%	0.0066%
FMC Corp.	FMC	15,019.30	0.04%	1.66%	8.50%	10.23%	0.0040%
Fox Corp. 'B'	FOX	0.00	0.00%	1.27%	0.00%	1.27%	0.0000%
Fox Corp. 'A'	FOXA	21,771.00	0.06%	1.23%	0.00%	1.23%	0.0007%
First Republic Bank	FRC	32,345.10	0.09%	0.48%	12.50%	13.01%	0.0111%
Federal Rlty. Inv. Tru	FRT	8,611.80	0.02%	3.81%	-2.00%	1.77%	0.0004%
Fortinet Inc.	FTNT	33,901.10	0.09%	0.00%	19.00%	19.00%	0.0169%
Fortive Corp.	FTV	23,397.10	0.06%	0.41%	13.50%	13.94%	0.0086%
Gen'l Dynamics	GD	53,275.40	0.14%	2.53%	5.00%	7.59%	0.0106%
Gen'l Electric	GE	114,740.30	0.30%	0.31%	14.50%	14.83%	0.0448%
Gilead Sciences	GILD	85,899.00	0.23%	4.15%	15.50%	19.97%	0.0451%
Gen'l Mills	GIS	38,298.70	0.10%	3.31%	3.50%	6.87%	0.0069%
Globe Life Inc.	GL	10,902.80	0.03%	0.75%	8.00%	8.78%	0.0025%
Corning Inc.	GLW	33,040.40	0.09%	2.22%	20.00%	22.44%	0.0195%
Gen'l Motors	GM	80,555.80	0.21%	0.00%	10.50%	10.50%	0.0223%
Generac Holdings	GNRC	21,777.30	0.06%	0.00%	21.00%	21.00%	0.0120%
Alphabet Inc. 'A'	GOOG	1,547,379.90	4.07%	0.00%	18.13%	18.13%	0.7380%
Alphabet Inc.	GOOG	1,558,891.80	4.10%	0.00%	15.00%	15.00%	0.6152%
Genuine Parts	GPC	18,727.50	0.05%	2.52%	7.00%	9.61%	0.0047%
Global Payments	GPN	57,487.90	0.15%	0.42%	16.50%	16.95%	0.0256%
Gap (The) Inc.	GPS	12,693.60	0.03%	1.41%	25.00%	26.59%	0.0089%
Garmin Ltd.	GRMN	26,548.50	0.07%	1.94%	9.00%	11.03%	0.0077%
Goldman Sachs	GS	123,314.30	0.32%	1.39%	7.00%	8.44%	0.0274%
Grainger (W.W.)	GWW	23,773.10	0.06%	1.42%	4.50%	5.95%	0.0037%
Halliburton Co.	HAL	20,038.10	0.05%	0.80%	7.00%	7.83%	0.0041%
Hasbro Inc.	HAS	12,908.90	0.03%	2.90%	12.50%	15.58%	0.0053%
Huntington Bancshs.	HBAN	15,912.20	0.04%	3.84%	4.50%	8.43%	0.0035%
Hanesbrands Inc.	HBI	6,768.90	0.02%	3.09%	6.50%	9.69%	0.0017%
HCA Healthcare	HCA	67,967.50	0.18%	0.94%	10.50%	11.49%	0.0205%
Home Depot	HD	338,662.70	0.89%	2.10%	8.00%	10.18%	0.0907%
Hess Corp.	HES	25,517.00	0.07%	1.21%	0.00%	1.21%	0.0008%
HollyFrontier Corp.	HFC	5,625.40	0.01%	0.00%	2.50%	2.50%	0.0004%
Hartford Fin'l Svcs.	HIG	23,635.20	0.06%	2.12%	5.50%	7.68%	0.0048%
Huntington Ingalls	HII	8,591.20	0.02%	2.14%	3.50%	5.68%	0.0013%
Hilton Worldwide Hldgs	HLT	33,582.10	0.09%	0.00%	26.50%	26.50%	0.0234%
Hologic Inc.	HOLX	16,066.60	0.04%	0.00%	14.50%	14.50%	0.0061%
Honeywell Int'l	HON	153,719.10	0.40%	1.68%	9.50%	11.26%	0.0455%

Hewlett Packard Ent.	HPE	20,964.00	0.06%	2.98%	6.50%	9.58%	0.0053%
HP Inc.	HPQ	39,845.40	0.10%	2.45%	11.50%	14.09%	0.0148%
Hormel Foods	HRL	24,830.60	0.07%	2.17%	9.00%	11.27%	0.0074%
Schein (Henry)	HSIC	11,129.60	0.03%	0.00%	6.50%	6.50%	0.0019%
Host Hotels & Resorts	HST	11,998.90	0.03%	0.00%	8.00%	8.00%	0.0025%
Hershey Co.	HSY	35,656.60	0.09%	1.91%	5.50%	7.46%	0.0070%
Humana Inc.	HUM	57,291.60	0.15%	0.63%	11.00%	11.66%	0.0176%
Howmet Aerospace	HWM	14,578.10	0.04%	0.00%	6.00%	6.00%	0.0023%
Int'l Business Mach.	IBM	127,819.00	0.34%	4.58%	1.50%	6.11%	0.0206%
Intercontinental Exch.	ICE	62,346.60	0.16%	1.19%	8.00%	9.24%	0.0152%
IDEXX Labs.	IDXX	45,084.70	0.12%	0.00%	13.50%	13.50%	0.0160%
IDEX Corp.	IEX	16,532.40	0.04%	0.99%	7.50%	8.53%	0.0037%
Int'l Flavors & Frag.	IFF	35,318.20	0.09%	2.23%	7.50%	9.81%	0.0091%
Illumina Inc.	ILMN	56,461.10	0.15%	0.00%	10.50%	10.50%	0.0156%
Incyte Corp.	INCY	17,963.40	0.05%	0.00%	66.50%	66.50%	0.0314%
IHS Markit	INFO	40,854.20	0.11%	0.78%	10.50%	11.32%	0.0122%
Intel Corp.	INTC	223,543.70	0.59%	2.51%	7.00%	9.60%	0.0564%
Intuit Inc.	INTU	110,294.20	0.29%	0.59%	14.50%	15.13%	0.0439%
Int'l Paper	IP	24,641.80	0.06%	3.26%	11.00%	14.44%	0.0094%
Interpublic Group	IPG	12,814.40	0.03%	3.38%	12.00%	15.58%	0.0053%
IPG Photonics	IPGP	10,678.10	0.03%	0.00%	18.50%	18.50%	0.0052%
IQVIA Holdings	IQV	44,585.30	0.12%	0.00%	13.50%	13.50%	0.0158%
Ingersoll Rand Inc.	IR	20,020.70	0.05%	0.00%	0.00%	0.00%	0.0000%
Iron Mountain	IRM	12,161.20	0.03%	5.89%	11.50%	17.73%	0.0057%
Intuitive Surgical	ISRG	96,728.10	0.25%	0.00%	15.00%	15.00%	0.0382%
Gartner Inc.	IT	19,778.90	0.05%	0.00%	15.50%	15.50%	0.0081%
Illinois Tool Works	ITW	73,361.50	0.19%	1.96%	9.00%	11.05%	0.0213%
Invesco Ltd.	IVZ	12,303.90	0.03%	2.54%	12.00%	14.69%	0.0048%
Jacobs Engineering	J	17,762.00	0.05%	0.62%	12.50%	13.16%	0.0061%
Hunt (J.B.)	JBHT	18,096.20	0.05%	0.71%	8.00%	8.74%	0.0042%
Johnson Ctrls. Int'l p	JCI	45,332.20	0.12%	1.71%	8.50%	10.28%	0.0123%
Henry (Jack) & Assoc.	JKHY	11,406.80	0.03%	1.20%	9.00%	10.25%	0.0031%
Johnson & Johnson	JNJ	447,769.90	1.18%	2.49%	8.50%	11.10%	0.1307%
Juniper Networks	JNPR	8,512.40	0.02%	3.15%	7.00%	10.26%	0.0023%
JPMorgan Chase	JPM	491,294.30	1.29%	2.23%	6.50%	8.80%	0.1138%
Kellogg	K	22,486.40	0.06%	3.53%	3.00%	6.58%	0.0039%
KeyCorp	KEY	22,272.20	0.06%	3.23%	9.50%	12.88%	0.0075%
Keysight Technologies	KEYS	25,737.30	0.07%	0.00%	12.00%	12.00%	0.0081%
Kraft Heinz Co.	KHC	53,286.10	0.14%	3.67%	1.50%	5.20%	0.0073%
Kimco Realty	KIM	8,862.30	0.02%	3.90%	-2.00%	1.86%	0.0004%
KLA Corp.	KLAC	46,588.50	0.12%	1.18%	17.50%	18.78%	0.0230%
Kimberly-Clark	KMB	44,759.00	0.12%	3.44%	5.50%	9.03%	0.0106%
Kinder Morgan Inc.	KMI	41,824.80	0.11%	5.85%	19.00%	25.41%	0.0280%
CarMax Inc.	KMX	18,897.30	0.05%	0.00%	11.00%	11.00%	0.0055%
Coca-Cola	KO	233,526.90	0.61%	3.10%	7.00%	10.21%	0.0627%
Kroger Co.	KR	27,591.20	0.07%	2.14%	5.00%	7.19%	0.0052%
Kansas City South'n	KSU	26,875.80	0.07%	0.73%	10.50%	11.27%	0.0080%
Loews Corp.	L	15,679.40	0.04%	0.43%	21.50%	21.98%	0.0091%
L Brands	LB	18,712.20	0.05%	0.89%	28.50%	29.52%	0.0145%
Leidos Hldgs.	LDOS	14,394.70	0.04%	1.33%	9.50%	10.89%	0.0041%
Leggett & Platt	LEG	7,230.60	0.02%	3.10%	10.00%	13.26%	0.0025%
Lennar Corp.	LEN	29,724.30	0.08%	1.08%	7.00%	8.12%	0.0063%
Laboratory Corp.	LH	26,116.50	0.07%	0.00%	9.50%	9.50%	0.0065%
L3Harris Technologies	LHX	44,061.00	0.12%	1.90%	0.00%	1.90%	0.0022%
Linde plc	LIN	154,018.00	0.41%	1.50%	0.00%	1.50%	0.0061%
LKQ Corp.	LKQ	15,042.90	0.04%	0.00%	10.50%	10.50%	0.0042%
Lilly (Eli)	LLY	188,547.80	0.50%	1.73%	9.00%	10.81%	0.0536%
Lockheed Martin	LMT	107,154.70	0.28%	2.75%	7.50%	10.35%	0.0292%
Lincoln Nat'l Corp.	LNC	13,391.90	0.04%	2.50%	9.00%	11.61%	0.0041%
Alliant Energy	LNT	14,411.70	0.04%	2.79%	5.50%	8.37%	0.0032%
Lowe's Cos.	LOW	139,416.30	0.37%	1.31%	15.50%	16.91%	0.0620%
Lam Research	LRCX	85,877.90	0.23%	0.91%	13.00%	13.97%	0.0316%
Lumen Technologies	LUMN	15,941.80	0.04%	6.93%	2.50%	9.52%	0.0040%
Southwest Airlines	LUV	35,713.30	0.09%	0.00%	33.50%	33.50%	0.0315%
Las Vegas Sands	LVS	42,883.30	0.11%	0.00%	19.00%	19.00%	0.0214%
Lamb Weston Holdings	LW	11,265.40	0.03%	1.23%	2.50%	3.75%	0.0011%
LyondellBasell Inds.	LYB	36,898.10	0.10%	3.81%	4.50%	8.40%	0.0081%
Live Nation Entertain.	LYV	19,032.70	0.05%	0.00%	0.00%	0.00%	0.0000%
MasterCard Inc.	MA	358,092.20	0.94%	0.49%	12.50%	13.02%	0.1227%
Mid-America Apartment	MAA	17,784.70	0.05%	2.63%	0.50%	3.14%	0.0015%
Marriott Int'l	MAR	45,403.80	0.12%	0.00%	16.00%	16.00%	0.0191%
Masco Corp.	MAS	15,592.60	0.04%	1.53%	7.50%	9.09%	0.0037%
McDonald's Corp.	MCD	171,714.90	0.45%	2.29%	10.00%	12.40%	0.0560%
Microchip Technology	MCHP	39,578.20	0.10%	1.12%	9.00%	10.17%	0.0106%
McKesson Corp.	MCK	31,632.80	0.08%	0.85%	9.00%	9.89%	0.0082%
Moody's Corp.	MCO	60,622.70	0.16%	0.77%	8.50%	9.30%	0.0148%
Mondelez Int'l	MDLZ	87,566.30	0.23%	2.17%	8.00%	10.26%	0.0236%
Medtronic plc	MDT	169,336.50	0.45%	1.91%	7.00%	8.98%	0.0400%
MetLife Inc.	MET	57,887.40	0.15%	2.96%	6.50%	9.56%	0.0146%

MGM Resorts Int'l	MGM	19,320.80	0.05%	0.03%	0.00%	0.03%	0.0000%
Mohawk Inds.	MHK	14,489.30	0.04%	0.00%	6.50%	6.50%	0.0025%
McCormick & Co.	MKC	23,982.40	0.06%	1.52%	5.50%	7.06%	0.0045%
MarketAxess Holdings	MKTX	16,841.50	0.04%	0.60%	14.50%	15.14%	0.0067%
Martin Marietta	MLM	22,697.40	0.06%	0.64%	6.00%	6.66%	0.0040%
Marsh & McLennan	MMC	68,297.30	0.18%	1.41%	9.50%	10.98%	0.0197%
3M Company	MMM	117,442.20	0.31%	2.92%	5.00%	7.99%	0.0247%
Monster Beverage	MNST	47,914.20	0.13%	0.00%	11.50%	11.50%	0.0145%
Altria Group	MO	91,551.90	0.24%	6.96%	6.00%	13.17%	0.0317%
Mosaic Company	MOS	13,410.40	0.04%	0.85%	30.00%	30.98%	0.0109%
Marathon Petroleum	MPC	38,767.10	0.10%	3.90%	0.00%	3.90%	0.0040%
Monolithic Power Sys.	MPWR	14,626.70	0.04%	0.75%	17.50%	18.32%	0.0070%
Merck & Co.	MRK	200,884.30	0.53%	3.28%	8.00%	11.41%	0.0603%
Marathon Oil Corp.	MRO	9,160.30	0.02%	1.38%	49.00%	50.72%	0.0122%
Morgan Stanley	MS	155,718.20	0.41%	1.63%	8.50%	10.20%	0.0418%
MSCI Inc.	MSCI	36,891.30	0.10%	0.79%	16.00%	16.85%	0.0164%
Microsoft Corp.	MSFT	1,831,666.00	4.82%	0.92%	15.00%	15.99%	0.7705%
Motorola Solutions	MSI	33,724.50	0.09%	1.43%	7.00%	8.48%	0.0075%
M&T Bank Corp.	MTB	20,815.60	0.05%	2.71%	8.00%	10.82%	0.0059%
Mettler-Toledo Int'l	MTD	29,120.20	0.08%	0.00%	11.50%	11.50%	0.0088%
Micron Technology	MU	89,601.50	0.24%	0.00%	12.50%	12.50%	0.0295%
Maxim Integrated	MXIM	25,312.10	0.07%	0.00%	8.00%	8.00%	0.0053%
Norwegian Cruise Line	NCLH	10,746.60	0.03%	0.00%	0.00%	0.00%	0.0000%
Nasdaq Inc.	NDAQ	26,433.10	0.07%	1.34%	5.00%	6.37%	0.0044%
NextEra Energy	NEE	142,413.60	0.37%	2.12%	10.50%	12.73%	0.0477%
Newmont Corp.	NEM	59,013.60	0.16%	2.99%	14.50%	17.71%	0.0275%
Netflix Inc.	NFLX	216,238.40	0.57%	0.00%	23.50%	23.50%	0.1337%
NiSource Inc.	NI	9,873.80	0.03%	3.49%	9.50%	13.16%	0.0034%
NIKE Inc. 'B'	NKE	209,943.80	0.55%	0.83%	23.50%	24.43%	0.1349%
NortonLifeLock Inc.	NLOK	15,485.10	0.04%	1.89%	7.00%	8.96%	0.0036%
Nielsen Hldgs. plc	NLSN	9,747.50	0.03%	0.88%	0.00%	0.88%	0.0002%
Northrop Grumman	NOC	61,835.30	0.16%	1.69%	7.00%	8.75%	0.0142%
NOV Inc.	NOV	6,445.80	0.02%	0.00%	0.00%	0.00%	0.0000%
ServiceNow Inc.	NOW	90,778.20	0.24%	0.00%	44.50%	44.50%	0.1063%
NRG Energy	NRG	8,402.80	0.02%	3.79%	0.00%	3.79%	0.0008%
Norfolk Southern	NSC	69,929.90	0.18%	1.42%	9.00%	10.48%	0.0193%
NetApp Inc.	NTAP	17,329.30	0.05%	2.68%	5.50%	8.25%	0.0038%
Northern Trust Corp.	NTRS	24,423.10	0.06%	2.39%	5.00%	7.45%	0.0048%
Nucor Corp.	NUE	30,382.00	0.08%	1.60%	2.50%	4.12%	0.0033%
NVIDIA Corp.	NVDA	348,830.60	0.92%	0.11%	14.50%	14.62%	0.1341%
NVR Inc.	NVR	17,392.20	0.05%	0.00%	8.00%	8.00%	0.0037%
Newell Brands	NWL	11,983.50	0.03%	3.27%	0.00%	3.27%	0.0010%
News Corp. 'B'	NWS	14,353.90	0.04%	0.81%	0.00%	0.81%	0.0003%
News Corp. 'A'	NWSA	15,366.30	0.04%	0.77%	0.00%	0.77%	0.0003%
NXP Semi. NV	NXPI	54,675.80	0.14%	1.15%	11.00%	12.21%	0.0176%
Realty Income Corp.	O	23,723.20	0.06%	4.39%	6.00%	10.52%	0.0066%
Old Dominion Freight	ODFL	30,632.20	0.08%	0.30%	9.00%	9.31%	0.0075%
ONEOK Inc.	OKE	23,550.90	0.06%	7.23%	9.50%	17.07%	0.0106%
Omnicom Group	OMC	17,671.10	0.05%	3.47%	6.00%	9.57%	0.0045%
Oracle Corp.	ORCL	227,952.30	0.60%	1.63%	9.50%	11.21%	0.0672%
O'Reilly Automotive	ORLY	37,829.10	0.10%	0.00%	11.00%	11.00%	0.0109%
Otis Worldwide	OTIS	33,242.40	0.09%	1.24%	0.00%	1.24%	0.0011%
Occidental Petroleum	OXY	23,400.80	0.06%	0.48%	36.50%	37.07%	0.0228%
Paycom Software	PAYC	18,474.20	0.05%	0.00%	19.50%	19.50%	0.0095%
Paychex Inc.	PAYX	35,630.10	0.09%	2.67%	6.50%	9.26%	0.0087%
People's United Fin'l	PBCT	8,043.40	0.02%	3.85%	2.50%	6.40%	0.0014%
PACCAR Inc.	PCAR	31,687.10	0.08%	3.62%	5.50%	9.22%	0.0077%
Healthpeak Properties	PEAK	17,902.00	0.05%	3.61%	-13.00%	-9.62%	-0.0045%
Public Serv. Enterpris	PEG	31,237.90	0.08%	3.32%	3.50%	6.88%	0.0057%
Penn Nat'l Gaming	PENN	12,229.70	0.03%	0.00%	27.00%	27.00%	0.0087%
PepsiCo Inc.	PEP	200,984.30	0.53%	2.96%	6.00%	9.05%	0.0478%
Pfizer Inc.	PFE	221,733.60	0.58%	3.92%	9.50%	13.61%	0.0794%
Principal Fin'l Group	PFG	17,786.40	0.05%	3.75%	6.00%	9.86%	0.0046%
Procter & Gamble	PG	334,428.70	0.88%	2.55%	7.00%	9.64%	0.0848%
Progressive Corp.	PGR	59,105.20	0.16%	0.40%	9.00%	9.42%	0.0146%
Parker-Hannifin	PH	39,358.20	0.10%	1.35%	13.00%	14.44%	0.0149%
PulteGroup Inc.	PHM	14,652.90	0.04%	1.03%	7.00%	8.07%	0.0031%
Packaging Corp.	PKG	14,322.20	0.04%	2.65%	5.00%	7.72%	0.0029%
PerkinElmer Inc.	PKI	15,984.00	0.04%	0.20%	11.00%	11.21%	0.0047%
Prologis	PLD	85,287.60	0.22%	2.23%	8.50%	10.82%	0.0243%
Philip Morris Int'l	PM	150,100.40	0.39%	4.98%	6.50%	11.64%	0.0460%
PNC Financial Serv.	PNC	81,978.30	0.22%	2.38%	10.00%	12.50%	0.0270%
Pentair plc	PNR	11,128.80	0.03%	1.20%	11.00%	12.27%	0.0036%
Pinnacle West Capital	PNW	9,632.00	0.03%	4.00%	5.50%	9.61%	0.0024%
Pool Corp.	POOL	17,150.00	0.05%	0.75%	15.00%	15.81%	0.0071%
PPG Inds.	PPG	41,811.00	0.11%	1.23%	10.00%	11.29%	0.0124%
PPL Corp.	PPL	22,598.10	0.06%	5.65%	3.00%	8.73%	0.0052%
Perrigo Co. plc	PRGO	5,956.80	0.02%	2.17%	-2.00%	0.15%	0.0000%
Prudential Fin'l	PRU	42,200.70	0.11%	4.32%	4.50%	8.92%	0.0099%

Public Storage	PSA	48,278.90	0.13%	2.91%	2.50%	5.45%	0.0069%
Phillips 66	PSX	37,538.30	0.10%	4.20%	20.50%	25.13%	0.0248%
PTC Inc.	PTC	14,854.60	0.04%	0.00%	33.50%	33.50%	0.0131%
PVH Corp.	PVH	8,016.80	0.02%	0.00%	12.50%	12.50%	0.0026%
Quanta Services	PWR	12,727.30	0.03%	0.26%	13.50%	13.78%	0.0046%
Pioneer Natural Res.	PXD	25,179.80	0.07%	1.46%	17.50%	19.09%	0.0126%
PayPal Holdings	PYPL	286,706.40	0.75%	0.00%	16.00%	16.00%	0.1207%
Qualcomm Inc.	QCOM	147,515.10	0.39%	2.08%	16.50%	18.75%	0.0728%
Qorvo Inc.	QRVO	19,731.00	0.05%	0.00%	32.00%	32.00%	0.0166%
Royal Caribbean	RCL	21,378.10	0.06%	0.00%	0.00%	0.00%	0.0000%
Everest Re Group Ltd.	RE	10,763.40	0.03%	2.34%	11.00%	13.47%	0.0038%
Regency Centers Corp.	REG	10,521.80	0.03%	3.79%	10.00%	13.98%	0.0039%
Regeneron Pharmac.	REGN	54,417.20	0.14%	0.00%	12.50%	12.50%	0.0179%
Regions Financial	RF	21,779.60	0.06%	2.73%	9.00%	11.85%	0.0068%
Robert Half Int'l	RHI	9,921.70	0.03%	1.76%	7.50%	9.33%	0.0024%
Raymond James Fin'l	RJF	18,149.90	0.05%	1.18%	6.50%	7.72%	0.0037%
Ralph Lauren	RL	9,579.80	0.03%	1.57%	6.00%	7.62%	0.0019%
ResMed Inc.	RMD	28,209.90	0.07%	0.81%	13.50%	14.36%	0.0107%
Rockwell Automation	ROK	29,996.60	0.08%	1.68%	6.50%	8.23%	0.0065%
Rollins Inc.	ROL	17,194.80	0.05%	0.92%	11.50%	12.47%	0.0056%
Roper Tech.	ROP	45,387.50	0.12%	0.52%	8.00%	8.54%	0.0102%
Ross Stores	ROST	44,612.80	0.12%	0.91%	14.00%	14.97%	0.0176%
Republic Services	RSG	34,545.10	0.09%	1.64%	7.50%	9.20%	0.0084%
Raytheon Technologies	RTX	129,100.80	0.34%	2.39%	1.50%	3.91%	0.0133%
SBA Communications	SBAC	31,670.70	0.08%	0.84%	43.50%	44.52%	0.0371%
Starbucks Corp.	SBUX	129,180.30	0.34%	1.78%	16.00%	17.92%	0.0609%
Schwab (Charles)	SCHW	128,602.10	0.34%	1.05%	7.00%	8.09%	0.0274%
Sealed Air	SEE	8,391.90	0.02%	1.45%	13.50%	15.05%	0.0033%
Sherwin-Williams	SHW	74,803.80	0.20%	0.82%	10.00%	10.86%	0.0214%
SVB Fin'l Group	SIVB	29,209.80	0.08%	0.00%	8.00%	8.00%	0.0061%
Smucker (J.M.)	SJM	14,744.70	0.04%	2.72%	4.00%	6.77%	0.0026%
Schlumberger Ltd.	SLB	44,746.60	0.12%	1.56%	8.50%	10.13%	0.0119%
Snap-on Inc.	SNA	13,463.90	0.04%	2.04%	4.50%	6.59%	0.0023%
Synopsys Inc.	SNPS	36,165.10	0.10%	0.00%	12.50%	12.50%	0.0119%
Southern Co.	SO	67,731.10	0.18%	4.13%	5.00%	9.23%	0.0165%
Simon Property Group	SPG	40,164.80	0.11%	4.25%	-0.50%	3.74%	0.0040%
S&P Global	SPGI	89,294.40	0.23%	0.83%	8.50%	9.37%	0.0220%
Sempra Energy	SRE	41,192.90	0.11%	3.27%	10.00%	13.43%	0.0146%
STERIS plc	STE	16,162.80	0.04%	0.85%	10.00%	10.89%	0.0046%
State Street Corp.	STT	29,696.90	0.08%	2.47%	6.50%	9.05%	0.0071%
Seagate Technology plc	STX	22,854.70	0.06%	2.69%	5.50%	8.26%	0.0050%
Constellation Brands	STZ	44,913.90	0.12%	1.31%	6.50%	7.85%	0.0093%
Stanley Black & Decker	SWK	36,900.20	0.10%	1.36%	6.00%	7.40%	0.0072%
Skyworks Solutions	SWKS	27,467.70	0.07%	1.20%	13.00%	14.28%	0.0103%
Synchrony Financial	SYF	26,656.40	0.07%	1.92%	9.50%	11.51%	0.0081%
Stryker Corp.	SYK	95,034.70	0.25%	1.00%	9.00%	10.05%	0.0251%
Sysco Corp.	SYY	41,491.60	0.11%	2.22%	10.00%	12.33%	0.0135%
AT&T Inc.	T	206,770.20	0.54%	7.18%	2.50%	9.77%	0.0531%
Molson Coors Beverage	TAP	11,814.20	0.03%	2.07%	41.00%	43.49%	0.0135%
TransDigm Group	TDG	32,238.60	0.08%	0.00%	9.50%	9.50%	0.0081%
Teledyne Technologies	TDY	14,920.00	0.04%	0.00%	9.00%	9.00%	0.0035%
TE Connectivity	TEL	43,848.50	0.12%	1.51%	8.00%	9.57%	0.0110%
Teradyne Inc.	TER	20,371.30	0.05%	0.33%	13.00%	13.35%	0.0072%
Truist Fin'l	TFC	81,450.30	0.21%	2.98%	5.50%	8.56%	0.0183%
Teleflex Inc.	TFX	18,248.10	0.05%	0.35%	14.50%	14.88%	0.0071%
Target Corp.	TGT	109,697.10	0.29%	1.24%	12.50%	13.82%	0.0399%
TJX Companies	TJX	80,898.50	0.21%	1.54%	10.50%	12.12%	0.0258%
Thermo Fisher Sci.	TMO	179,594.20	0.47%	0.23%	13.00%	13.24%	0.0626%
T-Mobile US	TMUS	167,504.00	0.44%	0.00%	8.50%	8.50%	0.0375%
Tapestry Inc.	TPR	12,431.70	0.03%	0.00%	10.00%	10.00%	0.0033%
Trimble Inc.	TRMB	18,759.80	0.05%	0.00%	12.50%	12.50%	0.0062%
Price (T. Rowe) Group	TROW	42,627.60	0.11%	2.30%	10.50%	12.92%	0.0145%
Travelers Cos.	TRV	39,626.80	0.10%	2.24%	9.00%	11.34%	0.0118%
Tractor Supply	TSCO	20,987.10	0.06%	1.15%	9.50%	10.70%	0.0059%
Tesla Inc.	TSLA	542,611.90	1.43%	0.00%	0.00%	0.00%	0.0000%
Tyson Foods 'A'	TSN	29,068.60	0.08%	2.23%	6.00%	8.30%	0.0063%
Trane Technologies plc	TT	42,648.30	0.11%	1.32%	0.00%	1.32%	0.0015%
Take-Two Interactive	TTWO	20,640.10	0.05%	0.00%	15.50%	15.50%	0.0084%
Twitter Inc.	TWTR	42,234.60	0.11%	0.00%	39.50%	39.50%	0.0439%
Texas Instruments	TXN	167,771.70	0.44%	2.24%	5.50%	7.80%	0.0344%
Textron Inc.	TXT	15,022.20	0.04%	0.12%	7.50%	7.62%	0.0030%
Tyler Technologies	TYL	19,052.20	0.05%	0.00%	8.00%	8.00%	0.0040%
Under Armour 'C'	UA	8,397.70	0.02%	0.00%	0.00%	0.00%	0.0000%
Under Armour 'A'	UAA	10,017.60	0.03%	0.00%	31.50%	31.50%	0.0083%
United Airlines Hldgs.	UAL	18,052.40	0.05%	0.00%	0.00%	0.00%	0.0000%
UDR Inc.	UDR	13,581.90	0.04%	3.21%	6.00%	9.31%	0.0033%
Universal Health `B'	UHS	13,348.80	0.04%	0.51%	10.00%	10.54%	0.0037%
Ulta Beauty	ULTA	17,965.50	0.05%	0.00%	12.50%	12.50%	0.0059%
UnitedHealth Group	UNH	386,568.00	1.02%	1.22%	12.00%	13.29%	0.1352%

Unum Group	UNM	6,184.00	0.02%	3.76%	3.00%	6.82%	0.0011%
Union Pacific	UNP	147,859.50	0.39%	1.92%	10.00%	12.02%	0.0467%
United Parcel Serv.	UPS	186,398.80	0.49%	1.90%	10.50%	12.50%	0.0613%
United Rentals	URI	23,257.00	0.06%	0.00%	7.50%	7.50%	0.0046%
U.S. Bancorp	USB	89,925.30	0.24%	2.80%	3.00%	5.84%	0.0138%
Visa Inc.	V	437,950.50	1.15%	0.60%	12.00%	12.64%	0.1456%
V.F. Corp.	VFC	33,116.50	0.09%	2.31%	5.50%	7.87%	0.0069%
ViacomCBS Inc.	VIAC	25,639.70	0.07%	2.42%	7.00%	9.50%	0.0064%
Valero Energy	VLO	31,589.10	0.08%	5.07%	13.00%	18.40%	0.0153%
Vulcan Materials	VMC	24,536.20	0.06%	0.80%	10.00%	10.84%	0.0070%
Vornado R'lty Trust	VNO	8,614.80	0.02%	4.71%	-18.50%	-14.23%	-0.0032%
Verisk Analytics	VRSK	28,118.20	0.07%	0.67%	7.50%	8.20%	0.0061%
VeriSign Inc.	VRSN	24,585.20	0.06%	0.00%	8.50%	8.50%	0.0055%
Vertex Pharmac.	VRTX	55,402.30	0.15%	0.00%	28.50%	28.50%	0.0415%
Ventas Inc.	VTR	20,277.60	0.05%	3.42%	4.50%	8.00%	0.0043%
Viatris Inc.	VTRS	0.00	0.00%	0.00%	19.58%	19.58%	0.0000%
Verizon Communic.	VZ	235,652.70	0.62%	4.46%	3.50%	8.04%	0.0498%
Wabtec Corp.	WAB	14,732.30	0.04%	0.62%	9.50%	10.15%	0.0039%
Waters Corp.	WAT	18,953.00	0.05%	0.00%	12.00%	12.00%	0.0060%
Walgreens Boots	WBA	47,377.40	0.12%	3.41%	7.50%	11.04%	0.0138%
Western Digital	WDC	21,805.60	0.06%	0.00%	5.00%	5.00%	0.0029%
WEC Energy Group	WEC	29,925.30	0.08%	2.91%	6.50%	9.50%	0.0075%
Welltower Inc.	WELL	30,395.10	0.08%	3.41%	0.00%	3.41%	0.0027%
Wells Fargo	WFC	191,195.50	0.50%	0.87%	-0.50%	0.37%	0.0019%
Whirlpool Corp.	WHR	15,052.60	0.04%	2.34%	7.00%	9.42%	0.0037%
Willis Towers Wat. plc	WLTW	33,773.10	0.09%	1.09%	7.50%	8.63%	0.0077%
Waste Management	WM	58,732.70	0.15%	1.65%	7.00%	8.71%	0.0135%
Williams Cos.	WMB	31,600.40	0.08%	6.30%	10.50%	17.13%	0.0142%
Walmart Inc.	WMT	401,775.60	1.06%	1.55%	6.00%	7.60%	0.0803%
Berkley (W.R.)	WRB	14,005.50	0.04%	0.61%	13.50%	14.15%	0.0052%
WestRock Co.	WRK	15,541.90	0.04%	1.64%	6.50%	8.19%	0.0034%
West Pharmac. Svcs.	WST	24,538.00	0.06%	0.21%	14.50%	14.73%	0.0095%
Western Union	WU	10,158.90	0.03%	3.79%	6.00%	9.90%	0.0026%
Weyerhaeuser Co.	WY	27,913.40	0.07%	1.82%	20.50%	22.51%	0.0165%
Wynn Resorts	WYNN	14,606.20	0.04%	0.00%	0.00%	0.00%	0.0000%
Xcel Energy Inc.	XEL	37,972.10	0.10%	2.64%	6.00%	8.72%	0.0087%
Xilinx Inc.	XLNX	29,610.50	0.08%	0.00%	7.50%	7.50%	0.0058%
Exxon Mobil Corp.	XOM	249,694.10	0.66%	5.95%	32.00%	38.90%	0.2555%
Dentsply Sirona	XRAY	14,756.90	0.04%	0.59%	5.50%	6.11%	0.0024%
Xylem Inc.	XYL	20,338.40	0.05%	0.99%	10.50%	11.54%	0.0062%
Yum! Brands	YUM	35,613.00	0.09%	1.68%	10.50%	12.27%	0.0115%
Zimmer Biomet Hldgs.	ZBH	34,544.40	0.09%	0.60%	8.50%	9.13%	0.0083%
Zebra Techn. 'A'	ZBRA	25,937.40	0.07%	0.00%	11.00%	11.00%	0.0075%
Zions Bancorp.	ZION	9,405.40	0.02%	2.37%	7.00%	9.45%	0.0023%
Zoetis Inc.	ZTS	81,353.40	0.21%	0.58%	10.00%	10.61%	0.0227%

[1] Sum of [7]
[2] Source: Value Line
[3] Weight based on market capitalization
[4] Source: Value Line
[5] Source: Value Line
[6] Equals [4] x (1 + (0.5 x [5])) + [5]
[7] Equals [3] x [6]

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Capital Asset Pricing Model

		[1]	[2]	[3]	[4]	[5]
		Risk Free Rate	**Proxy Group Average Beta**	**S&P 500 Estimated Required Market Return**	**Market Risk Premium**	**CAPM ROE**
	Current 30-Year Treasury (30-day Average)	2.30%	0.88	14.02%	11.72%	12.65%
	Current 30-Year Treasury (90-day Average)	2.21%	0.88	14.02%	11.81%	12.64%
	Current 30-Year Treasury (180-day Average)	1.91%	0.88	14.02%	12.11%	12.61%
[6]	Mean					12.64%

[1] Source: US Treasury Department
[2] Source: Attachment JC-6
[3] Source: Attachment JC-7
[4] Equals [3] - [1]
[5] Equals [1] + ([2] x [4])
[6] Equals Average of [5]

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Flotation Cost Adjustment

			[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
Company	**Ticker**	**Completion Date**	**Shares Issued (000)**	**Offering Price**	**Underwriting Discount**	**Offering Expense ($000)**	**Net Proceeds Per Share**	**Flotation Costs ($000)**	**Gross Equity Issue Before Costs ($000)**	**Net Proceeds ($000)**	**Flotation Cost Percentage**
Atmos Energy Corporation	ATO	12/3/2018	8,059	$92.75	$0.98	$1,000.00	$91.65	$8,873	$747,500	$738,627	1.19%
Atmos Energy Corporation	ATO	12/1/2017	4,558	$86.79	NA	NA	$86.65	$8,692	$403,692	$395,000	2.15%
Chesapeake Utilities Corporation	CPK	9/22/2016	960	$62.26	$2.33	$157.00	$59.77	$2,395	$59,800	$57,405	4.00%
Chesapeake Utilities Corporation	CPK	11/16/2006	690	$30.10	$1.13	$225.00	$28.65	$1,002	$20,779	$19,778	4.82%
New Jersey Resources Corporation	NJR	12/9/2020	6,545	$41.50	$1.24	$500.00	$40.19	$8,600	$271,636	$263,036	3.17%
NiSource Inc.	NI	9/8/2010	24,265	$16.50	$0.54	$400.00	$15.95	$13,411	$400,373	$386,962	3.35%
NiSource Inc.	NI	11/6/2002	41,400	$18.30	$0.55	$300.00	$17.74	$23,029	$757,620	$734,591	3.04%
Northwest Natural	NWN	6/7/2019	1,438	$67.00	$2.18	$400.00	$64.54	$3,530	$96,313	$92,782	3.67%
Northwest Natural	NWN	11/16/2016	1,012	$54.63	$2.05	$250.00	$52.33	$2,325	$55,286	$52,961	4.20%
South Jersey Industries	SJI	3/22/2021	11,788	$22.25	$0.78	$300.00	$21.45	$9,480	$262,272	$252,792	3.61%
South Jersey Industries	SJI	4/23/2018	12,669	$29.50	$1.03	$700.00	$28.41	$13,781	$373,750	$359,969	3.69%
Spire, Inc.	SR	5/10/2018	2,300	$68.75	$2.11	$325.00	$66.50	$5,177	$158,125	$152,948	3.27%
Spire, Inc.	SR	5/17/2016	2,185	$63.05	$2.05	$300.00	$60.86	$4,777	$137,764	$132,987	3.47%
Southwest Gas Corporation	SWX	11/30/2018	3,565	$75.50	$2.55	$600.00	$72.78	$9,684	$269,158	$259,474	3.60%
Unitil Corporation	UTL	12/14/2017	690	$48.30	$1.93	$400.00	$45.79	$1,733	$33,327	$31,594	5.20%
Unitil Corporation	UTL	5/16/2012	2,760	$25.24	$1.26	$544.46	$23.78	$4,029	$69,662	$65,633	5.78%
Mean								$7,532	$257,316		

Weighted Average Flotation Costs	2.927%

[1] Source: S&P Global
[2] Source: S&P Global; Company Prospectus Supplements
[3] Source: S&P Global; Company Prospectus Supplements
[4] Source: Company Prospectus Supplements
[5] Equals: ([1] x ([2] - [3]) - [4]) / [1]
[6] Equals ([1] x [3]) + [4]
[7] Equals [1] x [2]
[8] Equals [1] x [5]
[9] Equals [6] / [7]

Constant Growth Discounted Cash Flow Model
Earnings Growth
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	**Ticker**	**Indicated Annual Dividend**	**Weighted-Average Stock Price**	**Dividend Yield**	**Expected Dividend Yield**	**Adjusted for Flotation Costs**	**Zacks Earnings Growth**	**Yahoo Finance Earnings Growth**	**Value Line Earnings Growth**	**Average Earnings Growth**	**Mid ROE**	**Flotation-Adjusted ROE**
Atmos Energy	ATO	$2.65	$101.26	2.62%	2.71%	2.79%	7.30%	7.17%	7.00%	7.16%	9.87%	9.95%
Chesapeake Utilities	CPK	$1.96	$118.66	1.65%	1.71%	1.76%	NA	4.74%	8.50%	6.62%	8.33%	8.38%
NiSource Inc.	NI	$0.88	$25.69	3.43%	3.54%	3.64%	6.40%	3.52%	9.50%	6.47%	10.01%	10.12%
New Jersey Resources	NJR	$1.33	$42.46	3.13%	3.21%	3.31%	7.10%	6.00%	2.00%	5.03%	8.24%	8.34%
Northwest Natural	NWN	$1.92	$54.40	3.53%	3.61%	3.72%	3.90%	3.80%	5.50%	4.40%	8.01%	8.12%
ONE Gas Inc.	OGS	$2.40	$77.52	3.10%	3.18%	3.27%	5.00%	5.00%	6.00%	5.33%	8.51%	8.61%
South Jersey Inds.	SJI	$1.28	$25.06	5.11%	5.29%	5.45%	5.40%	4.90%	11.50%	7.27%	12.56%	12.72%
Spire Inc.	SR	$2.66	$75.24	3.54%	3.67%	3.78%	5.50%	7.31%	10.00%	7.60%	11.27%	11.38%
Southwest Gas	SWX	$2.42	$69.03	3.51%	3.61%	3.72%	5.50%	4.00%	9.00%	6.17%	9.78%	9.89%
Mean				3.29%	3.39%	3.49%	5.76%	5.16%	7.67%	6.23%	9.62%	9.72%
Median				3.43%	3.54%	3.64%	5.50%	4.90%	8.50%	6.47%	9.78%	9.89%

[1] Source: Value Line
[2] Source: Yahoo Finance, as of May 25, 2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [9])
[6] Source: Zacks
[7] Source: Yahoo Finance
[8] Source: Value Line
[9] Equals average ([6], [7], [8])
[10] Equals [4] + [9]
[11] Equals [5] + [9]
[12] Equals average of [11] - average of [10]

	Weighted Average Flotation Costs	2.93%
	Flotation-Adjusted ROE	9.72%
	Unadjusted ROE	9.62%
[12]	Flotation Cost Adjustment	0.10%

Small Size Premium

	Unitil - Northern Utilities	
[1]	Customers (000s)	35
[2]	Implied Equity ($ Millions)	$229.2
[3]	Implied Market Capitalization ($ Millions)	$414.9

Proxy Group

		[4]	[5]	[6]
Company Name	Ticker	Customers (000s)	Market Cap ($ Millions)	Market-to-Book Ratio
Atmos Energy	ATO	3,124	$12,819.7	1.82
Chesapeake Utilities	CPK	158	$2,033.5	2.88
NiSource Inc.	NI	3,482	$9,873.8	2.43
New Jersey Resources	NJR	539	$4,092.1	2.19
Northwest Natural	NWN	774	$1,648.3	1.81
ONE Gas Inc.	OGS	2,179	$3,888.5	1.76
South Jersey Inds.	SJI	391	$2,893.7	1.57
Spire Inc.	SR	1,693	$3,763.8	1.81
Southwest Gas	SWX	2,047	$3,856.2	1.42
Mean		1,599	$4,985.5	1.97
Median		1,693	$3,856.2	1.81

Duff & Phelps Size Premia [7]

	Market Capitalization ($ Millions)		
Decile	Lowest in Decile	Highest in Decile	Size Premium
1	$29,025.8	$1,966,078.9	-0.22%
2	$13,178.7	$28,808.1	0.49%
3	$6,743.4	$13,177.8	0.71%
4	$3,861.9	$6,710.7	0.75%
5	$2,445.7	$3,836.5	1.09%
6	$1,591.9	$2,444.7	1.37%
7	$911.6	$1,591.8	1.54%
8	$452.0	$911.1	1.46%
9	$190.0	$451.8	2.29%
10	$2.2	$189.8	5.01%

	Market Capitalization ($ Millions)		
Category	Lowest in Category	Highest in Category	Size Premium
Mid Cap	$2,445.7	$13,177.8	0.78%
Low Cap	$452.0	$2,444.7	1.43%
Micro Cap	$2.2	$451.8	3.21%

[1] Source: Company data.
[2] Source: Company data. Schedule RevReq-6, Column 4, Line 1.
[3] Equals [2] x Median of [6]
[4] Source: Company 10ks
[5] Source: Value Line, as of May 25, 2021
[6] Source: Value Line
[7] Source: Duff & Phelps Cost of Capital Navigator

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Proxy Group Capital Structure

Common Equity Ratio

Company Name	Ticker	2016	2017	2018	2019	2020	Average
Atmos Energy	ATO	61.30%	56.00%	65.70%	62.00%	60.00%	61.00%
Chesapeake Utilities	CPK	76.50%	71.10%	62.10%	56.10%	57.80%	64.72%
NiSource Inc.	NI	40.20%	36.50%	37.90%	36.90%	32.90%	36.88%
New Jersey Resources	NJR	52.30%	55.40%	54.60%	50.20%	44.90%	51.48%
Northwest Natural	NWN	55.60%	52.10%	51.90%	51.80%	50.80%	52.44%
ONE Gas, Inc.	OGS	61.30%	62.20%	61.40%	62.30%	58.50%	61.14%
South Jersey Industries	SJI	61.50%	51.50%	37.60%	40.80%	37.40%	45.76%
Spire, Inc.	SR	49.10%	50.00%	54.30%	55.00%	51.00%	51.88%
Southwest Gas	SWX	51.80%	50.20%	51.70%	52.10%	49.50%	51.06%
Average		**56.62%**	**53.89%**	**53.02%**	**51.91%**	**49.20%**	**52.93%**

Long-Term Debt Ratio

Company Name	Ticker	2016	2017	2018	2019	2020	Average
Atmos Energy	ATO	38.70%	44.00%	34.30%	38.00%	40.00%	39.00%
Chesapeake Utilities	CPK	23.50%	28.90%	37.90%	43.90%	42.20%	35.28%
NiSource Inc.	NI	59.80%	63.50%	55.30%	56.80%	61.20%	59.32%
New Jersey Resources	NJR	47.70%	44.60%	45.40%	49.80%	55.10%	48.52%
Northwest Natural	NWN	44.40%	47.90%	48.10%	48.20%	49.20%	47.56%
ONE Gas, Inc.	OGS	38.70%	37.80%	38.60%	37.70%	41.50%	38.86%
South Jersey Industries	SJI	38.50%	48.50%	62.40%	59.20%	62.60%	54.24%
Spire, Inc.	SR	50.90%	50.00%	45.70%	45.00%	49.00%	48.12%
Southwest Gas	SWX	48.20%	49.80%	48.30%	47.90%	50.50%	48.94%
Average		**43.38%**	**46.11%**	**46.22%**	**47.39%**	**50.14%**	**46.65%**

Source: Value Line

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NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

NED W. ALLIS

EXHIBIT NWA-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

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

A. My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

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

A. Yes, they were.

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 Northern Utilities, Inc. ("Northern" 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 Northern 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 gas 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
Distribution	3.17	$8,824,378	3.72	$10,329,813
General	7.16	521,206	4.08	297,232
Leak Prone Pipe		NA		707,897
General Reserve Adj.		NA		(147,312)
Total	3.27	9,345,584	3.91	11,187,630

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 net salvage estimates are more negative than the current estimates. While this is partially offset by service life estimates for some accounts that are longer than those used for the current depreciation rates, the overall result is a net increase 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. <u>DEPRECIATION STUDY</u>

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 Northern.

A. The study is a report entitled, "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2020." This report sets forth the results of my depreciation study for Northern. 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 gas 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 Northern. 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 Northern's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from Northern 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 gas 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 2011 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 2010 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 Northern'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 Northern'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 Northern?

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 of measuring and regulating station equipment 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 gas 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 12-year period for which data were available for Northern. 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 391.10, 394.10, 397.00 and 397.35. These accounts represent less than two percent of Northern'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 380.00, Services, 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 2011 through 2020 and statistically aged data were compiled from 1988 through 2010. The life tables for the 1988-2020 experience band and 2011-2020 experience bands are presented on pages VII-29 through VII-32 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-29 shows $30,687 retired during age interval 0.5-1.5 with $77,640,737 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0004 ($30,687/$77,640,737) and the survivor ratio is 0.9996 (1-0.0004). The percent surviving at age 0.5 of 99.98 percent is multiplied by the survivor ratio of 0.9996 to derive the percent surviving at age 1.5 of 99.94 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1988-2020. The resultant life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 45-R2.5 on page VII-8.

The experienced net salvage percentages are presented on page 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 2009 through 2020. The twelve-year period experienced negative $2,284,150 ($0 - $2,284,150) in net salvage for $2,521,234 plant retired. The result is net salvage of negative 91 percent ($2,284,150/$2,521,234). The most recent five-year average is negative 170 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 gas companies, the recommended net salvage for station equipment is negative 90 percent.

The calculation of the annual depreciation related to original cost of Account 380.00, Services as of December 31, 2020, is presented on pages IX-10 through IX-11 of Exhibit NWA-3. The calculation is based on the 45-R2.5 survivor curve, the negative net salvage of 90 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 Northern Depreciation Study is a decrease in annual depreciation expense at this date of $1,842,046.

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 results in a reduction in depreciation expense of $147,312 annually for Northern.

Additionally, I recommend a 5-year amortization to be established for leak prone pipe assets for which there are remaining unrecovered costs. The Company has replaced its bare steel or cast iron mains, although a portion of the costs of these assets were not fully recovered through depreciation at the time they were replaced. Because these assets have reached the end of their useful life, these costs should be recovered over as short a period as practical in order to most closely align the recovery of the costs of these assets with the generation of customers who received service from them. A 5-year amortization is recommended for the recovery of these costs and results in an annual depreciation expense of $707,897 for these assets.

IV. SUMMARY AND CONCLUSIONS

Q. Please now summarize your testimony.

A. The depreciation study provided as Exhibit NWA-3 was conducted based on widely accepted methods and results in reasonable depreciation rates to be used for the Company's assets. These rates appropriately reflect the rates at which the value of Northern's assets are being consumed over their useful lives. These rates are an appropriate basis for setting gas 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, it does.

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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

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
28.	2018	CA	A. 18-12-009	Pacific Gas & Electric Company	Depreciation
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
43.	2021	NH	DE 21-030	Unitil Energy Systems	Depreciation
44.	2021	FERC	ER21-1822-000	GridLiance High Plains	Depreciation

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NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

HAMPTON, NEW HAMPSHIRE

2020 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AS OF DECEMBER 31, 2020

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

NORTHERN UTILITIES, INC.

NEW HAMPSHIRE DIVISION

Hampton, New Hampshire

2020 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO GAS PLANT
AS OF DECEMBER 31, 2020

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Camp Hill, Pennsylvania

Docket No. DG 21-104
Exhibit NWA-3
Page 3 of 120

Excellence Delivered **As Promised**

July 22, 2021

Northern Utilities, 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 gas plant of the New Hampshire Division of Northern Utilities, 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

068731

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NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Northern Utilities, Inc.'s ("Northern" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the gas plant of its New Hampshire Division 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 an increase in depreciation expense. While somewhat offset by longer lives for some accounts, the overall increase in depreciation expense is primarily the result of more negative net salvage estimates for certain 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 2011 through 2020. In order to analyze data for a longer period of time, unaged data for the period of 1988 to 2010 was statistically aged and incorporated into the actuarial life analysis. Amortization accounting is also recommended for certain general plant accounts.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to gas plant in service as of December 31, 2020, as summarized in 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 $11.2 million for gas 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
GAS PLANT			
DISTRIBUTION PLANT	$277,936,056.89	3.72	10,329,813
GENERAL PLANT	7,282,182.57	4.08	297,232
LEAK PRONE PIPE	761,437.43		707,897
RESERVE ADJUSTMENT FOR AMORTIZATION			(147,312)
TOTAL DEPRECIABLE PLANT	**$285,979,676.89**	3.91	**11,187,630**

Docket No. DG 21-104

PART I. INTRODUCTION

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for the New Hampshire Division of Northern Utilities, Inc. ("Northern" or "Company") to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of gas 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 gas 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 gas industry, including knowledge of service lives and net salvage estimates used for other gas 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 gas 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 gas industry, and comparisons of the service life and net salvage estimates from our studies of other gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas 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,

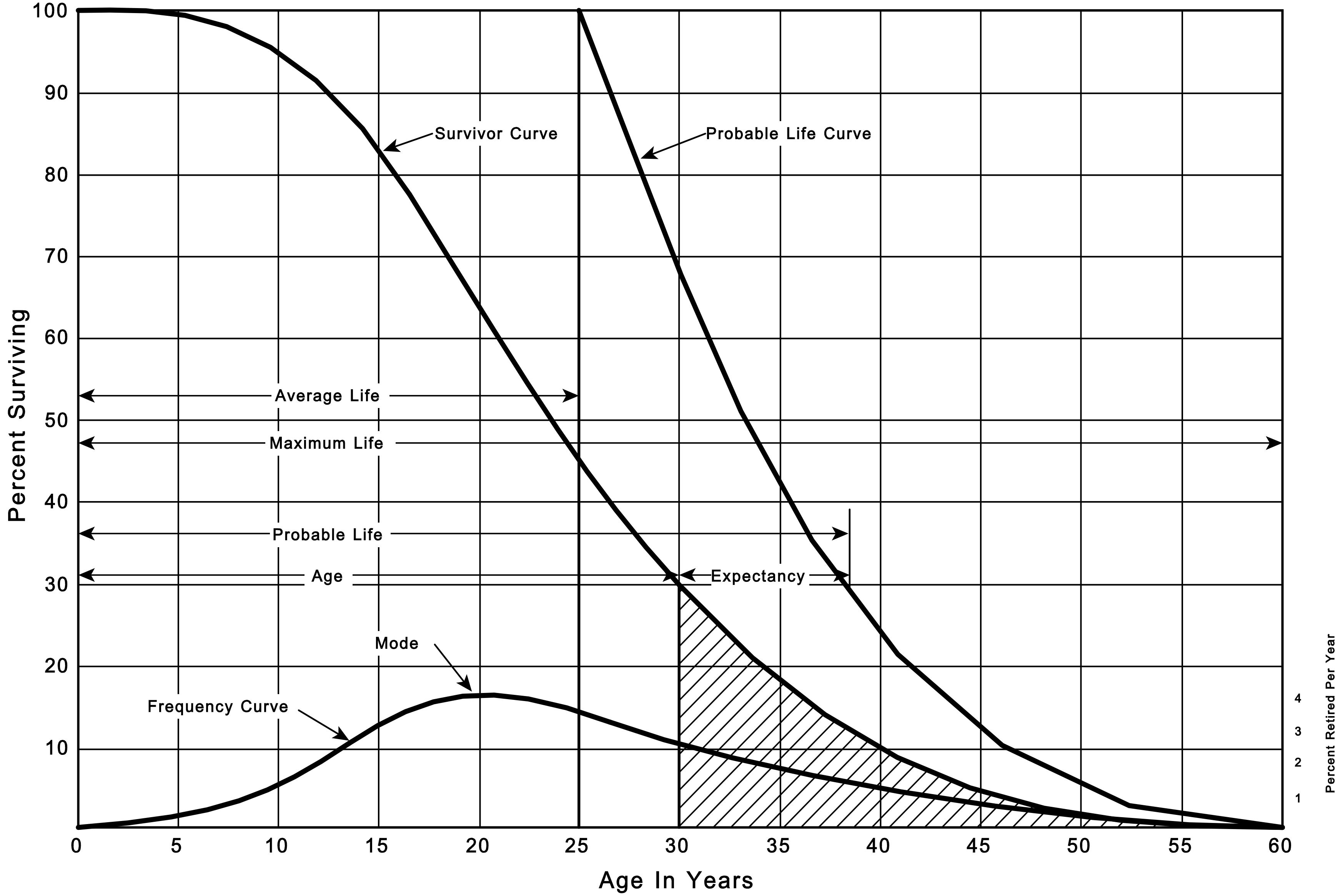

Figure 1. A Typical Survivor Curve and Derived Curves

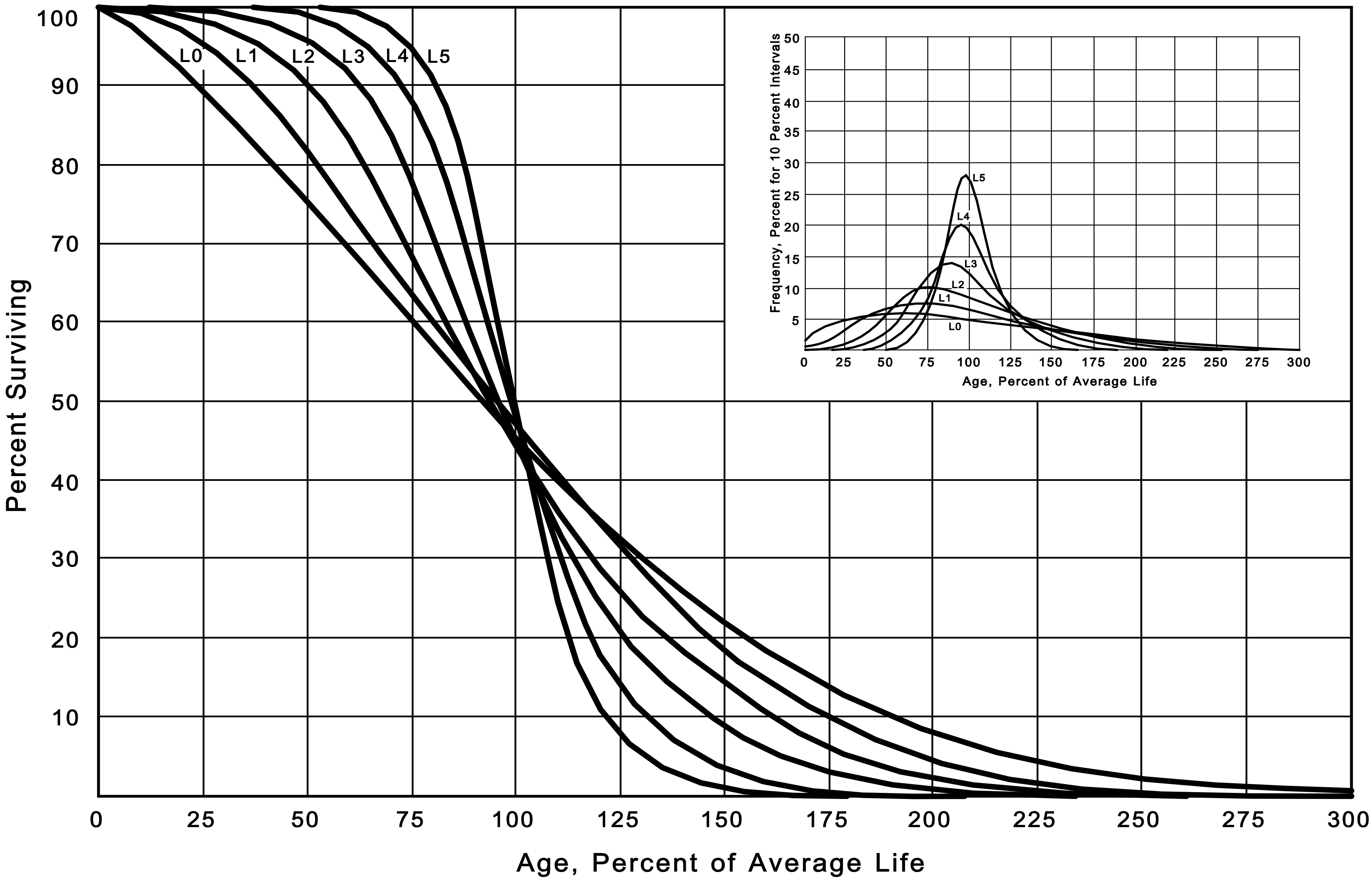

Figure 2. Left Modal or "L" Iowa Type Survivor Curves

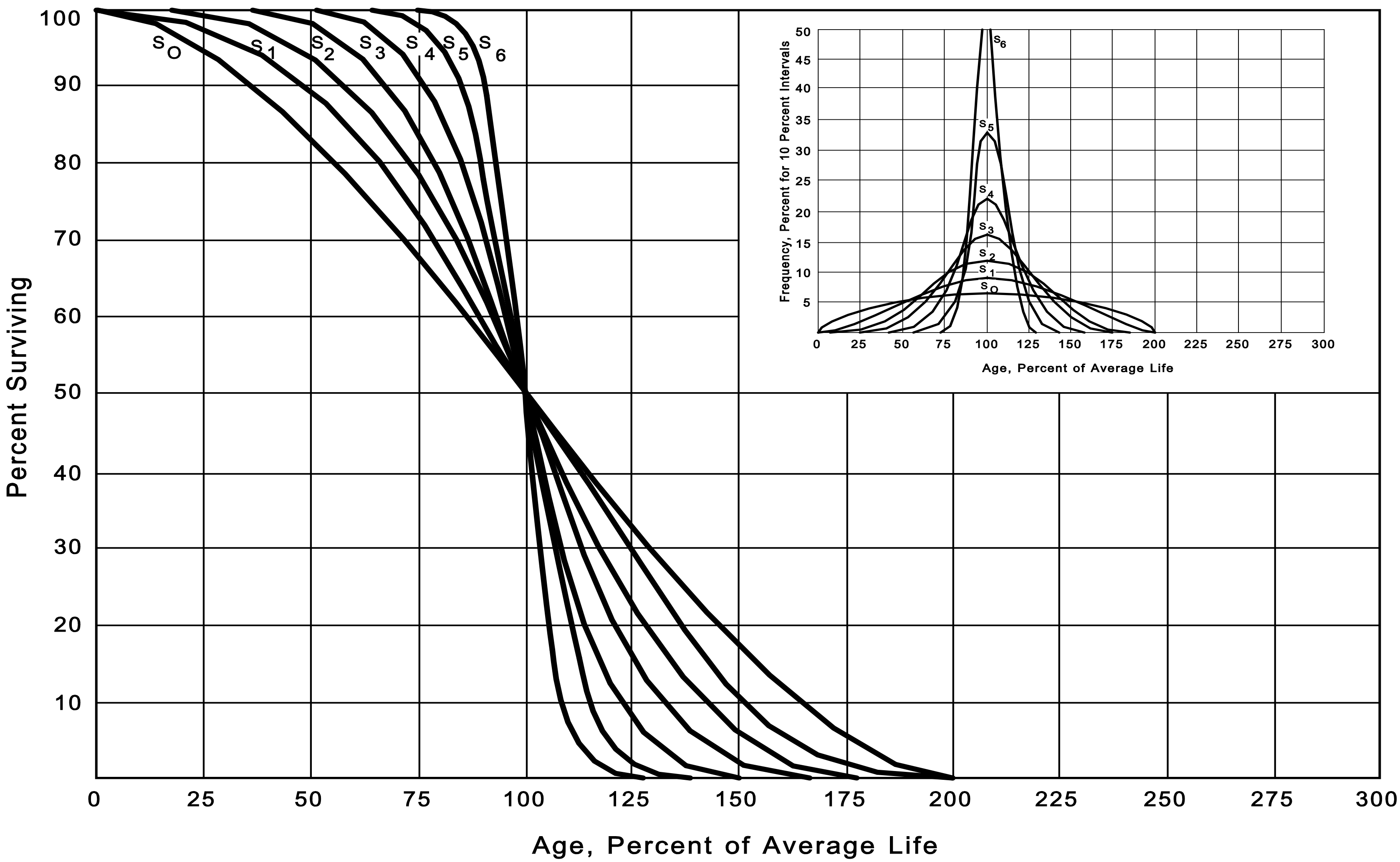

Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

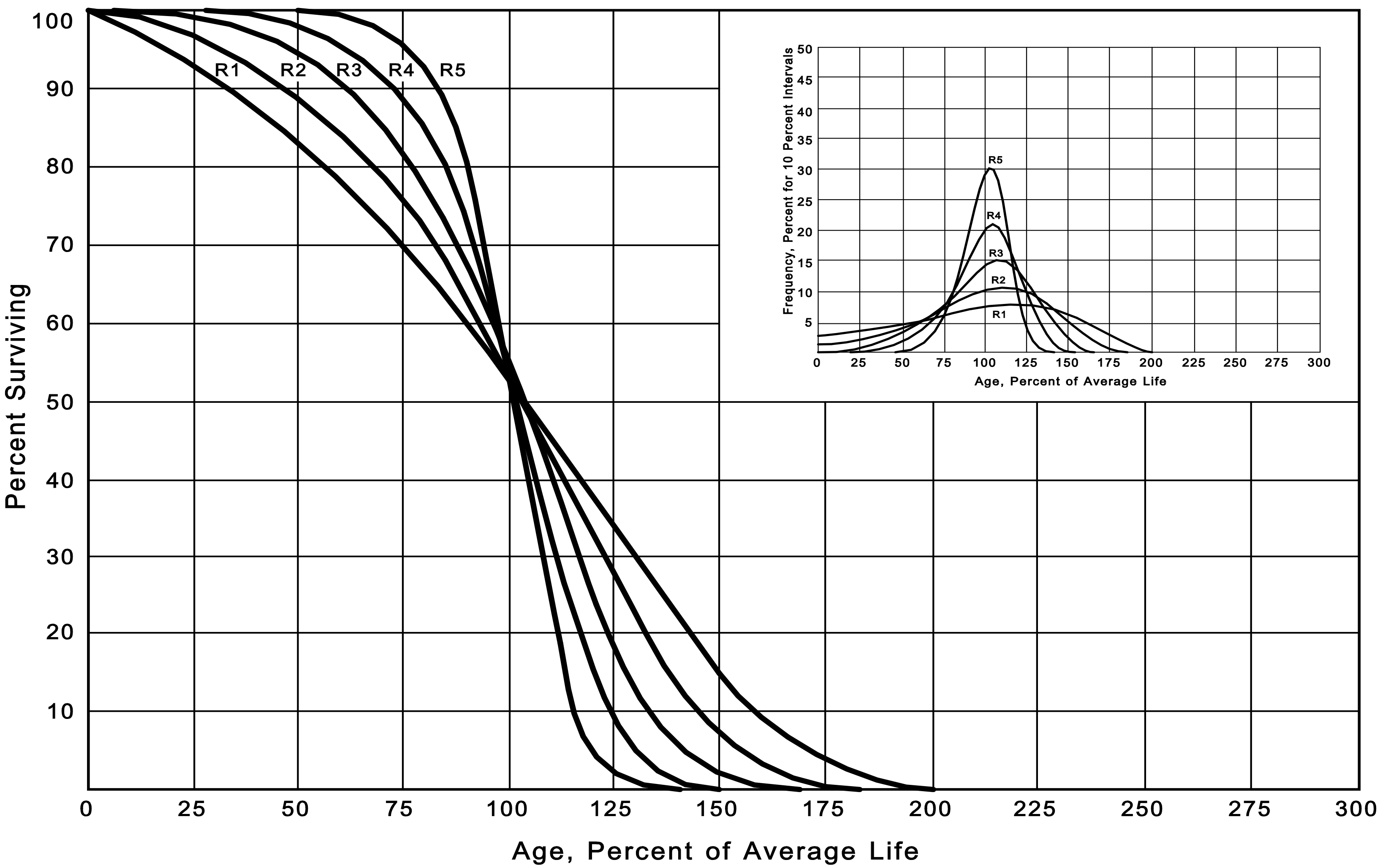

Figure 4. Right Modal or "R" Iowa Type Survivor Curves

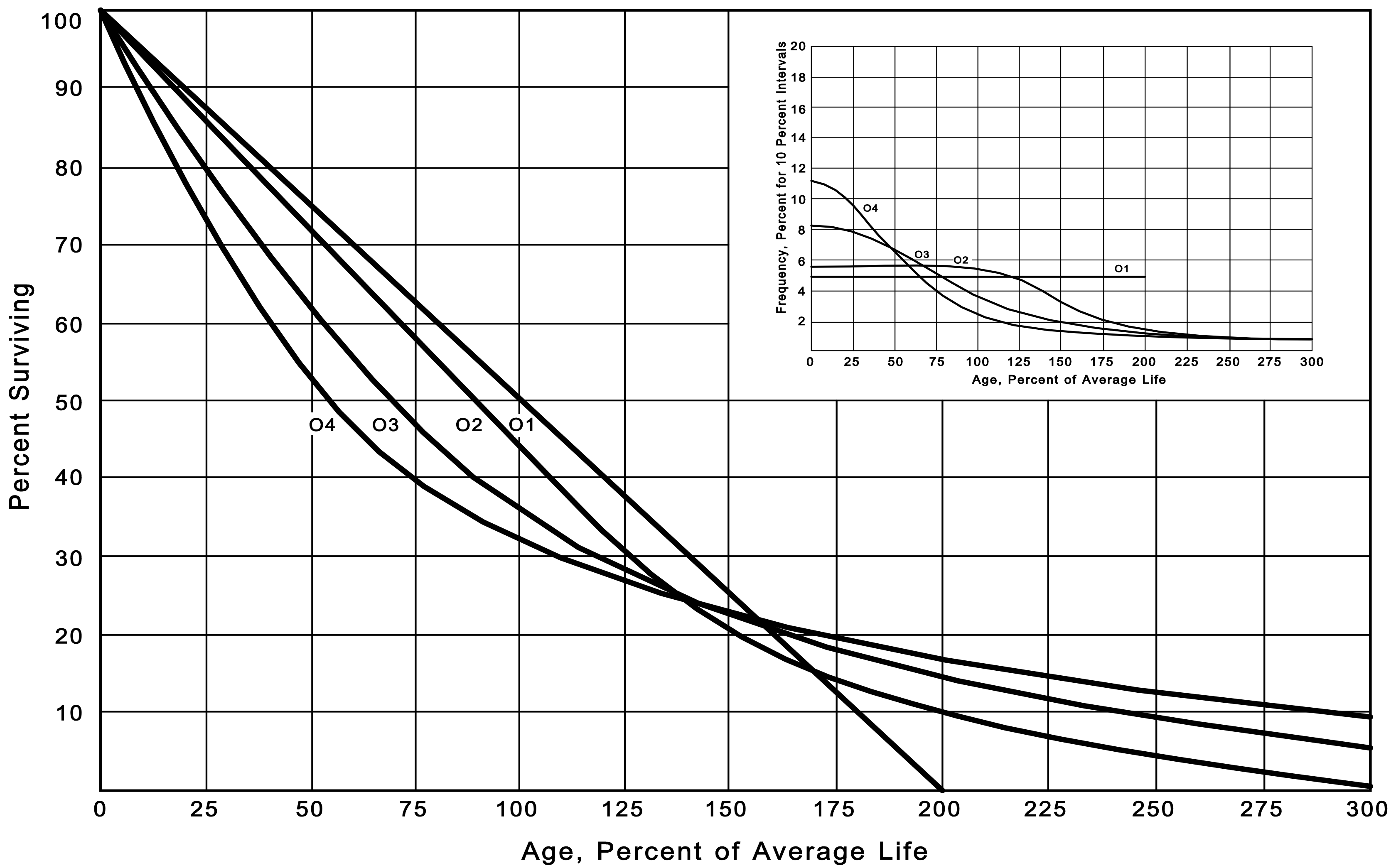

Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

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

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[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	Retirements, Thousands of Dollars During Year										Total During	Age
Placed	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
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.

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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 Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year: 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total at 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

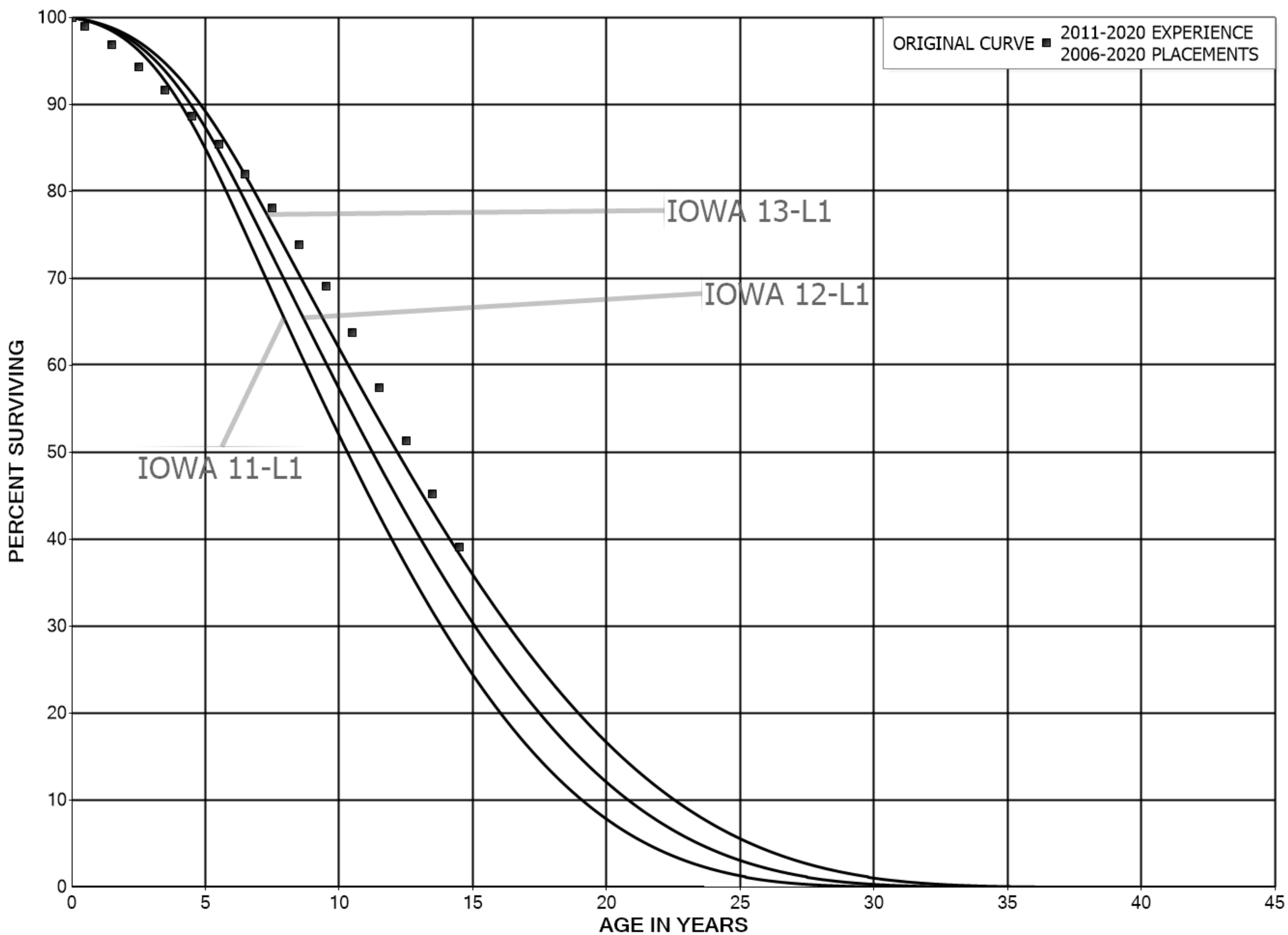


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

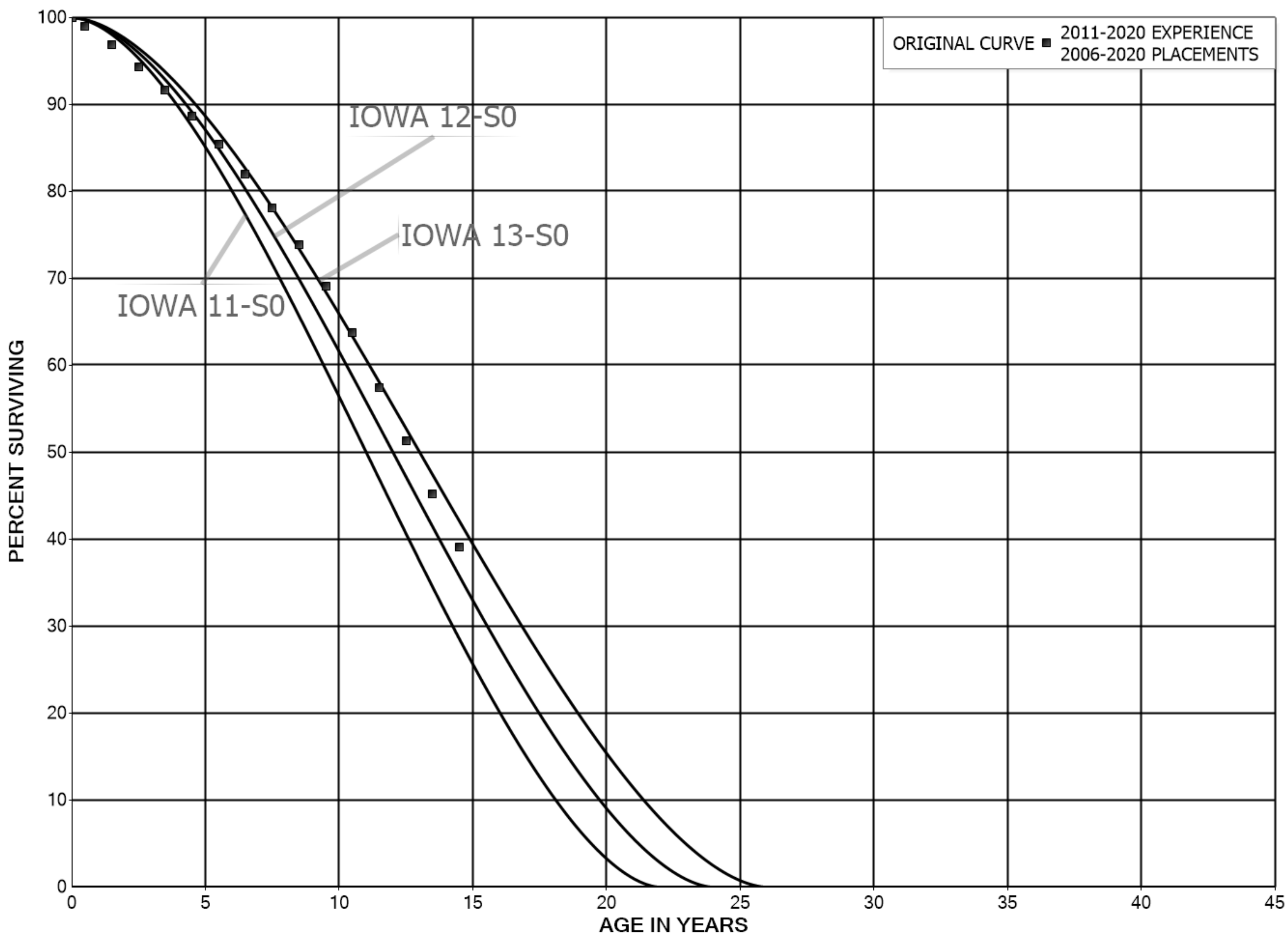


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

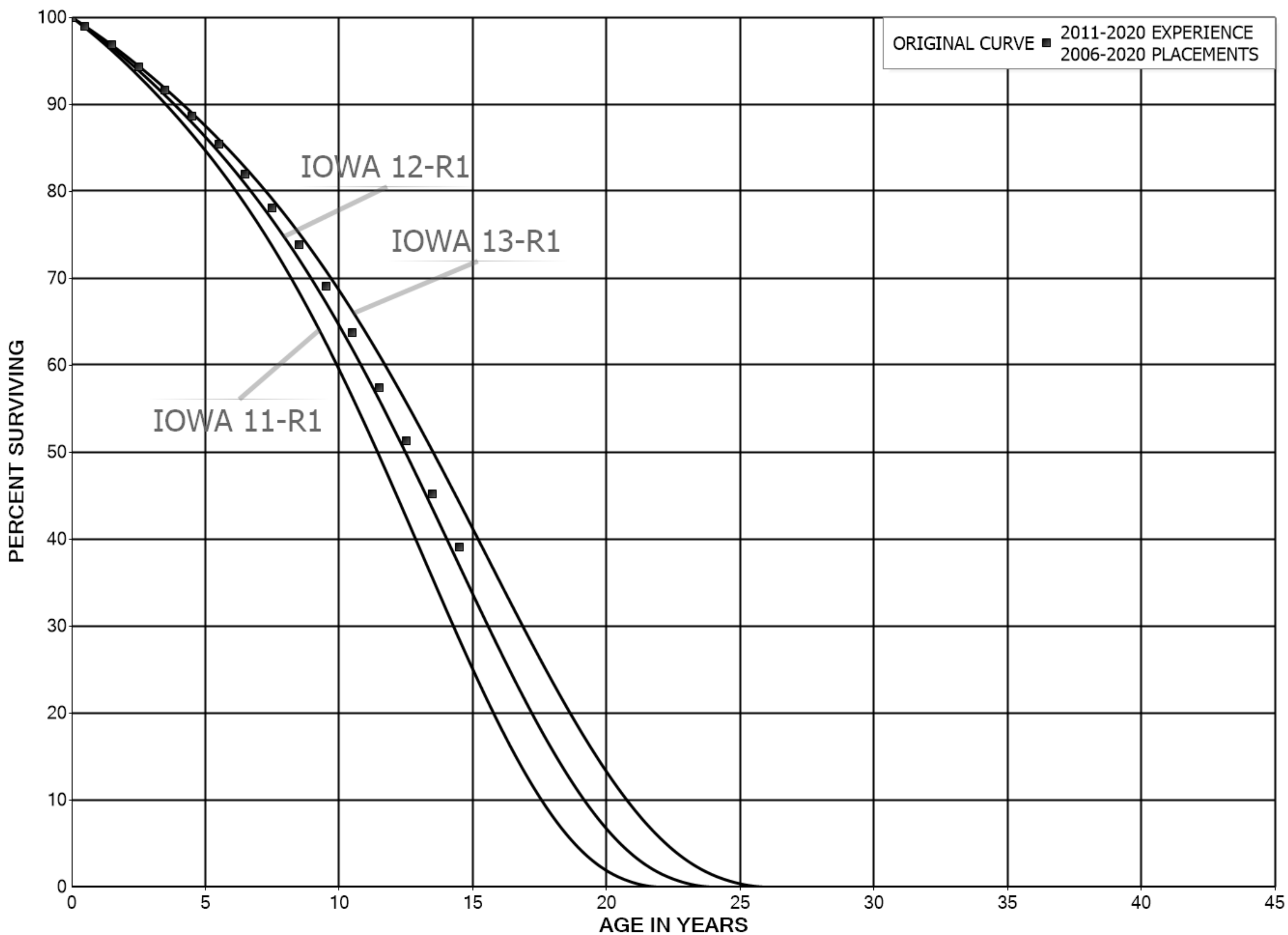
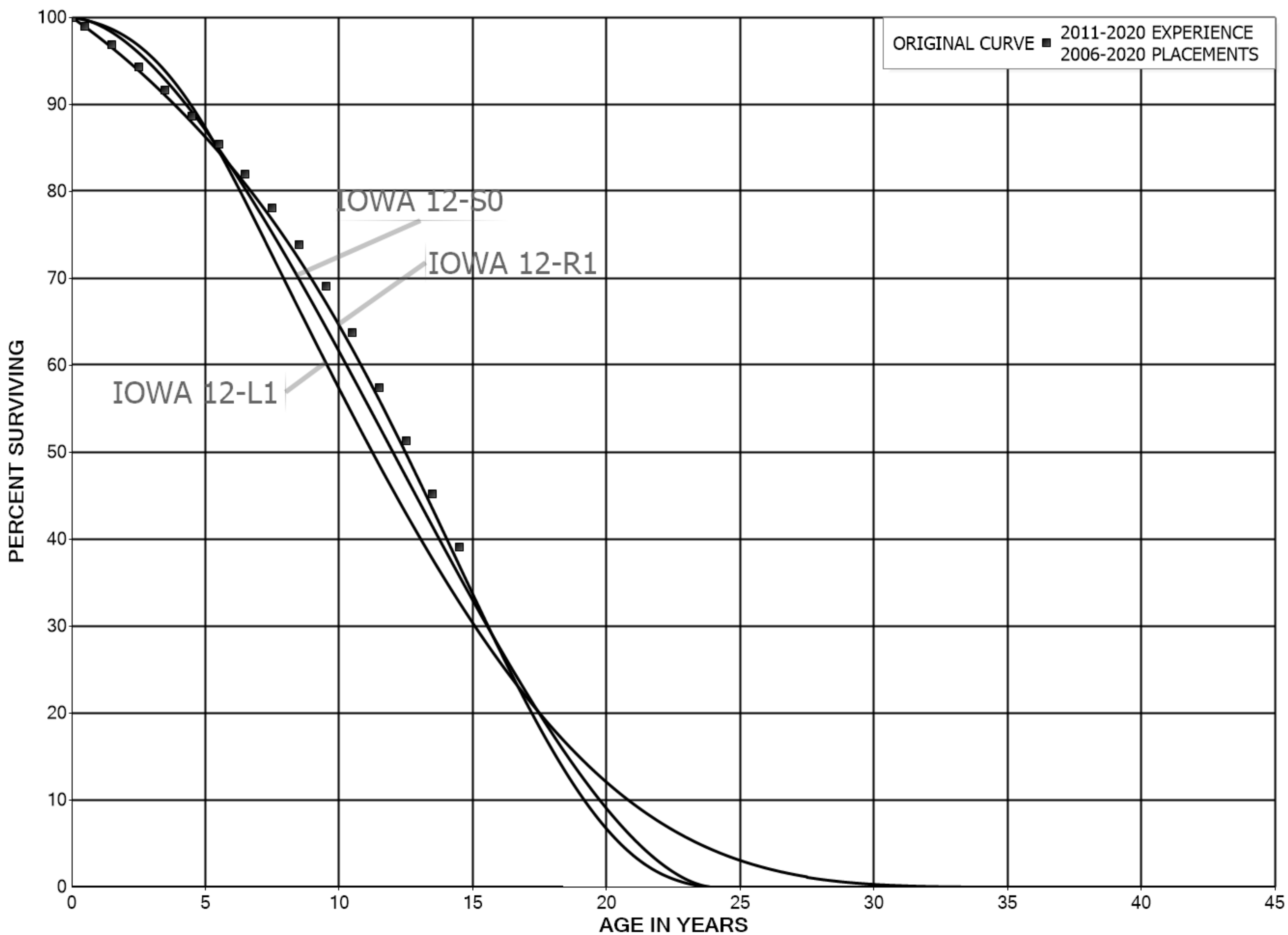


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



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:

June 9, 2021

Portsmouth Office
Forest Street Station

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 gas companies. For the statistical analysis, aged data were available from 2011 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 2011. The data for the years prior to 2011 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 1988 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 94 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

375	Structures and Improvements
376.2	Mains – Coated and Wrapped
376.4	Mains – Plastic
380	Services
381	Meters
382	Meter Installations
386	Other Property on Customers' Premises

Account 376.2, Mains – Coated and Wrapped, and Account 376.4, Mains - Plastic, which were studied together, comprise the largest depreciable group and are used to illustrate the manner in which the study was conducted for the groups using the retirement rate method. Aged retirement data were available from 2011 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 gas plant was placed in service. Statistically aged data was also available from 1988 through 2010. Both the full range of data from 1988 through 2020

and the aged data from 2011 through 2020 were analyzed using the retirement rate method. Additionally, because plastic and coated and wrapped steel mains are generally vintage 1966 or subsequent, in order to analyze a longer history of the experience of gas mains data for bare steel and cast iron mains were also considered.

The current survivor curve estimate for this account is the 47-R1.5. The retirement rate analysis indicates a longer service life than the current estimate. The original life tables depicted on the chart are presented on the pages that follow the chart. A chart depicting the estimated 55-R2.5 survivor curve and original life tables used as the basis for the estimate are presented on page VII-9 of the study. For the bands shown in the chart, those with placements prior to 1966 include the experience of bare steel and cast iron mains and those that only include placements from 1966 and subsequent effectively provide the experience for plastic and coated and wrapped steel mains. The recommended 55-R2.5 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 gas 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 2009 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.

Net Salvage Considerations

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 2009 through 2020 contributed significantly toward the net salvage estimates for seven plant accounts, representing approximately 96 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

375	Structures and Improvements
376.2	Mains – Coated and Wrapped
376.4	Mains – Plastic
376.6	Mains – Cathodic Protection
378.2	Measuring and Regulating Station Equipment
380	Services
381	Meters
382	Meter Installations

The net salvage analysis for Account 376 Mains is used to illustrate the methods for estimating net salvage. The analysis for this account includes the historical experience for all types of mains and cathodic protection. The current net salvage estimate for Account 376.2 is negative 50 percent and the current estimate for Accounts 376.4 and 376.6 is negative 35 percent. The historical data indicates a more negative estimate than the current estimate. The overall average net salvage is negative 213 percent. The most recent five-year average is negative 240 percent. Based on the historical data and the expectations provided by management for this account, a more negative net salvage estimate is recommended. The recommended negative 60 percent net salvage estimate, which is within the range of estimates used by other gas 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 gas 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 gas plant in service. The accounts and their amortization periods are as follows:

ACCT	TITLE	AMORTIZATION PERIOD, YEARS
391.10	Office Furniture and Equipment	15
394.10	Tools, Shop and Garage Equipment	25
397.00	Communication Equipment	15
397.35	Communication Equipment – ERTs	15

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 gas 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 gas 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.

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2020

	DEPRECIABLE GROUP	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)	(9)=(6)/(7)
	GAS PLANT								
	DISTRIBUTION PLANT								
375.00	STRUCTURES AND IMPROVEMENTS	55-R2.5	(10)	3,260,871.26	596,162	2,990,796	89,338	2.74	33.5
	MAINS								
376.20	COATED AND WRAPPED	55-R2.5	(60)	29,746,227.02	4,224,164	43,369,799	1,123,107	3.78	38.6
376.40	PLASTIC	55-R2.5	(60)	120,342,184.10	36,382,883	156,164,612	3,460,577	2.88	45.1
376.60	CATHODIC PROTECTION	30-S5	(60)	1,082,739.45	682,660	1,049,723	50,271	4.64	20.9
	TOTAL MAINS			151,171,150.57	41,289,708	200,584,134	4,633,955	3.07	
378.20	MEASURING AND REGULATING STATION EQUIPMENT	30-R2	(20)	7,328,248.14	672,808	8,121,090	356,985	4.87	22.7
380.00	SERVICES	45-R2.5	(90)	82,837,046.71	28,479,497	128,910,892	3,654,478	4.41	35.3
381.00	METERS	30-R2	(15)	4,624,610.24	1,226,613	4,091,689	247,087	5.34	16.6
382.00	METER INSTALLATIONS	30-R3	(10)	26,001,685.36	6,859,297	21,742,557	1,098,766	4.23	19.8
383.00	HOUSE REGULATORS	30-R3	0	733,549.58	212,401	521,148	24,378	3.32	21.4
386.00	OTHER PROPERTY ON CUSTOMERS' PREMISES	12-R2	0	1,978,895.03	959,565	1,019,330	224,826	11.36	4.5
	TOTAL DISTRIBUTION PLANT			**277,936,056.89**	**80,296,051**	**367,981,636**	**10,329,813**	**3.72**	
	GENERAL PLANT								
391.10	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	508,134.77	279,936	228,199	33,877	6.67	6.7
394.10	TOOLS, SHOP AND GARAGE EQUIPMENT								
	FULLY ACCRUED			115,969.89	115,970	0	0	-	-
	AMORTIZED	25-SQ	0	1,314,451.52	534,112	780,340	52,539	4.00	14.9
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT			1,430,421.41	650,082	780,340	52,539	3.67	
397.00	COMMUNICATION EQUIPMENT								
	FULLY ACCRUED			368,887.11	368,887	0	0	-	-
	AMORTIZED	15-SQ	0	1,504,593.10	798,757	705,836	100,381	6.67	7.0
	TOTAL COMMUNICATION EQUIPMENT			1,873,480.21	1,167,644	705,836	100,381	5.36	
397.35	COMMUNICATION EQUIPMENT - ERTs								
	FULLY ACCRUED			1,814,148.86	1,814,149	0	0	-	-
	AMORTIZED	15-SQ	0	1,655,997.32	772,348	883,649	110,435	6.67	8.0
	TOTAL COMMUNICATION EQUIPMENT - ERTs			3,470,146.18	2,586,497	883,649	110,435	3.18	
	TOTAL GENERAL PLANT			**7,282,182.57**	**4,684,159**	**2,598,024**	**297,232**	**4.08**	
	LEAK PRONE PIPE								
376.30	MAINS - BARE STEEL			190,836.93	(2,132,784)	2,323,621	464,724 *		
376.50	MAINS - JOINT SEALS			542,145.01	542,145	0	0 *		
376.80	MAINS - CAST IRON			28,455.49	(1,187,409)	1,215,864	243,173 *		
	TOTAL LEAK PRONE PIPE			**761,437.43**	**(2,778,047)**	**3,539,485**	**707,897**		

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

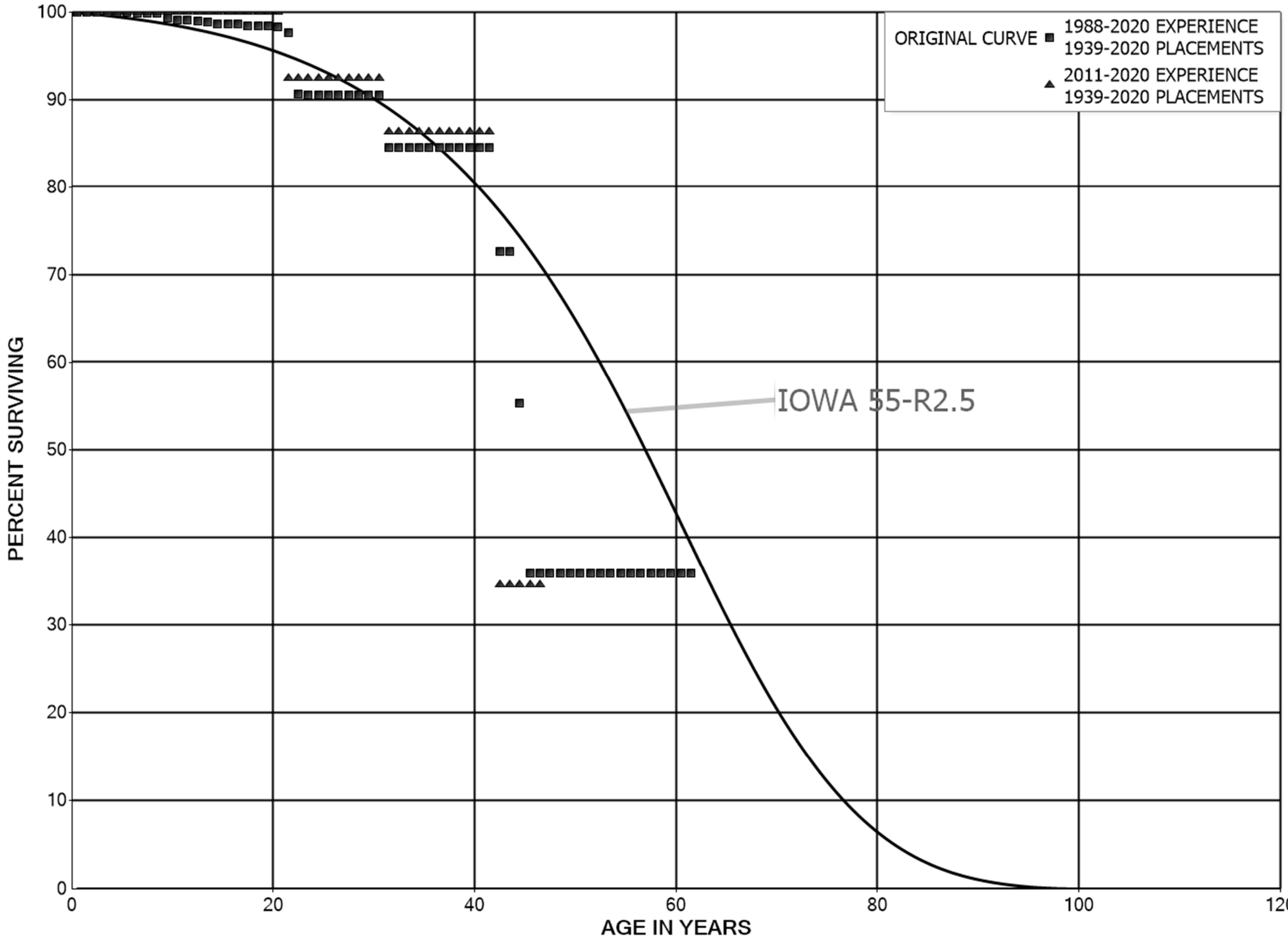
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2020

	DEPRECIABLE GROUP	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)	(9)=(6)/(7)
	UNRECOVERED RESERVE TO BE AMORTIZED								
391.10	OFFICE FURNITURE AND EQUIPMENT				18,142		(3,628) **		
394.10	TOOLS, SHOP AND GARAGE EQUIPMENT				135,659		(27,132) **		
397.00	COMMUNICATION EQUIPMENT				402,958		(80,592) **		
397.35	COMMUNICATION EQUIPMENT - ERTs				179,802		(35,960) **		
	TOTAL UNRECOVERED RESERVE TO BE AMORTIZED				**736,561**		**(147,312)**		
	TOTAL DEPRECIABLE PLANT			**285,979,676.89**	**82,938,723**	**374,119,145**	**11,187,630**	**3.91**	
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED								
303.02	INTANGIBLE SOFTWARE - 10 YEARS			2,064,603.93	643,542				
303.30	INTANGIBLE PLANT - MISCELLANEOUS SOFTWARE			5,176,113.26	3,802,861				
304.20	LAND RIGHTS			6,816.33					
374.40	LAND RIGHTS			89,111.32					
374.50	RIGHTS OF WAY			17,910.67					
389.10	LAND			232,946.85					
393.00	STORES EQUIPMENT			31,519.95	31,511				
396.00	POWER OPERATED EQUIPMENT			75,266.49	75,266				
397.25	COMMUNICATION EQUIPMENT - METSCAN			112,656.43	112,656				
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**7,806,945.23**	**4,665,837**				
	TOTAL GAS PLANT			**293,786,622.12**	**87,604,561**				

* FIVE-YEAR AMORTIZATION OF UNRECOVERED LEAK PRONE PIPE COSTS.
** FIVE-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING.

PART VII. SERVICE LIFE STATISTICS

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1988-2020

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	3,515,589	3,173	0.0009	0.9991	100.00
0.5	3,510,782	72	0.0000	1.0000	99.91
1.5	3,506,214	111	0.0000	1.0000	99.91
2.5	3,120,209	16	0.0000	1.0000	99.90
3.5	3,110,673	28	0.0000	1.0000	99.90
4.5	3,092,596	154	0.0000	1.0000	99.90
5.5	3,078,367	1,864	0.0006	0.9994	99.90
6.5	3,055,088	17	0.0000	1.0000	99.84
7.5	3,042,881	769	0.0003	0.9997	99.84
8.5	3,016,771	16,666	0.0055	0.9945	99.81
9.5	2,995,371	5,824	0.0019	0.9981	99.26
10.5	2,900,379	123	0.0000	1.0000	99.07
11.5	2,323,063	3,377	0.0015	0.9985	99.06
12.5	2,319,686	1,829	0.0008	0.9992	98.92
13.5	2,318,657	4,371	0.0019	0.9981	98.84
14.5	2,277,761	527	0.0002	0.9998	98.65
15.5	2,277,233	873	0.0004	0.9996	98.63
16.5	2,269,230	4,632	0.0020	0.9980	98.59
17.5	2,264,598	688	0.0003	0.9997	98.39
18.5	2,248,849	481	0.0002	0.9998	98.36
19.5	2,246,207	1,865	0.0008	0.9992	98.34
20.5	2,244,343	15,123	0.0067	0.9933	98.26
21.5	2,229,219	159,645	0.0716	0.9284	97.60
22.5	2,069,575	2,773	0.0013	0.9987	90.61
23.5	2,057,182		0.0000	1.0000	90.49
24.5	2,031,823		0.0000	1.0000	90.49
25.5	2,031,823		0.0000	1.0000	90.49
26.5	2,031,823	400	0.0002	0.9998	90.49
27.5	1,966,718		0.0000	1.0000	90.47
28.5	1,959,654		0.0000	1.0000	90.47
29.5	1,959,654		0.0000	1.0000	90.47
30.5	1,926,223	126,350	0.0656	0.9344	90.47
31.5	1,765,550		0.0000	1.0000	84.54
32.5	13,550		0.0000	1.0000	84.54
33.5	13,550		0.0000	1.0000	84.54
34.5	13,550		0.0000	1.0000	84.54
35.5	13,550		0.0000	1.0000	84.54
36.5	13,550		0.0000	1.0000	84.54
37.5	13,550		0.0000	1.0000	84.54
38.5	13,550		0.0000	1.0000	84.54

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1988-2020

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	13,550		0.0000	1.0000	84.54
40.5	13,550		0.0000	1.0000	84.54
41.5	13,550	1,906	0.1407	0.8593	84.54
42.5	10,777		0.0000	1.0000	72.64
43.5	10,777	2,579	0.2393	0.7607	72.64
44.5	8,198	2,887	0.3522	0.6478	55.26
45.5	5,311		0.0000	1.0000	35.80
46.5	4,911		0.0000	1.0000	35.80
47.5	4,911		0.0000	1.0000	35.80
48.5	6,203		0.0000	1.0000	35.80
49.5	6,203		0.0000	1.0000	35.80
50.5	6,203		0.0000	1.0000	35.80
51.5	6,203		0.0000	1.0000	35.80
52.5	6,203		0.0000	1.0000	35.80
53.5	6,203		0.0000	1.0000	35.80
54.5	6,203		0.0000	1.0000	35.80
55.5	6,203		0.0000	1.0000	35.80
56.5	6,203		0.0000	1.0000	35.80
57.5	6,203		0.0000	1.0000	35.80
58.5	6,203		0.0000	1.0000	35.80
59.5	6,203		0.0000	1.0000	35.80
60.5	6,203		0.0000	1.0000	35.80
61.5	6,203	646	0.1041	0.8959	35.80
62.5	5,557		0.0000	1.0000	32.07
63.5	2,978		0.0000	1.0000	32.07
64.5	646		0.0000	1.0000	32.07
65.5	646		0.0000	1.0000	32.07
66.5	646		0.0000	1.0000	32.07
67.5	646		0.0000	1.0000	32.07
68.5	646		0.0000	1.0000	32.07
69.5	646		0.0000	1.0000	32.07
70.5	646		0.0000	1.0000	32.07
71.5	646		0.0000	1.0000	32.07
72.5	646		0.0000	1.0000	32.07
73.5	646		0.0000	1.0000	32.07
74.5	646		0.0000	1.0000	32.07
75.5	646		0.0000	1.0000	32.07
76.5	646		0.0000	1.0000	32.07
77.5	646		0.0000	1.0000	32.07
78.5	646		0.0000	1.0000	32.07

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1988-2020

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	646		0.0000	1.0000	32.07
80.5	646		0.0000	1.0000	32.07
81.5					32.07

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2011-2020

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	502,896		0.0000	1.0000	100.00
0.5	590,429		0.0000	1.0000	100.00
1.5	1,163,127		0.0000	1.0000	100.00
2.5	777,232		0.0000	1.0000	100.00
3.5	767,712		0.0000	1.0000	100.00
4.5	786,189		0.0000	1.0000	100.00
5.5	772,114		0.0000	1.0000	100.00
6.5	757,829		0.0000	1.0000	100.00
7.5	745,639		0.0000	1.0000	100.00
8.5	735,358		0.0000	1.0000	100.00
9.5	727,239		0.0000	1.0000	100.00
10.5	638,071		0.0000	1.0000	100.00
11.5	60,878		0.0000	1.0000	100.00
12.5	60,878		0.0000	1.0000	100.00
13.5	82,423		0.0000	1.0000	100.00
14.5	71,257		0.0000	1.0000	100.00
15.5	71,257		0.0000	1.0000	100.00
16.5	64,127		0.0000	1.0000	100.00
17.5	128,831		0.0000	1.0000	100.00
18.5	120,834		0.0000	1.0000	100.00
19.5	118,673		0.0000	1.0000	100.00
20.5	157,262	11,925	0.0758	0.9242	100.00
21.5	184,878		0.0000	1.0000	92.42
22.5	2,063,228		0.0000	1.0000	92.42
23.5	2,053,609		0.0000	1.0000	92.42
24.5	2,028,249		0.0000	1.0000	92.42
25.5	2,028,249		0.0000	1.0000	92.42
26.5	2,028,249		0.0000	1.0000	92.42
27.5	1,963,545		0.0000	1.0000	92.42
28.5	1,956,481		0.0000	1.0000	92.42
29.5	1,956,481		0.0000	1.0000	92.42
30.5	1,917,892	126,350	0.0659	0.9341	92.42
31.5	1,752,001		0.0000	1.0000	86.33
32.5	2,773		0.0000	1.0000	86.33
33.5	2,773		0.0000	1.0000	86.33
34.5	2,773		0.0000	1.0000	86.33
35.5	2,773		0.0000	1.0000	86.33
36.5	3,173		0.0000	1.0000	86.33
37.5	3,173		0.0000	1.0000	86.33
38.5	3,173		0.0000	1.0000	86.33

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2011-2020

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	3,173		0.0000	1.0000	86.33
40.5	3,173		0.0000	1.0000	86.33
41.5	3,173	1,906	0.6006	0.3994	86.33
42.5	400		0.0000	1.0000	34.48
43.5	400		0.0000	1.0000	34.48
44.5	400		0.0000	1.0000	34.48
45.5	400		0.0000	1.0000	34.48
46.5					34.48
47.5					
48.5					
49.5					
50.5					
51.5					
52.5					
53.5	2,579		0.0000		
54.5	4,911		0.0000		
55.5	4,911		0.0000		
56.5	4,911		0.0000		
57.5	4,911		0.0000		
58.5	4,911		0.0000		
59.5	4,911		0.0000		
60.5	4,911		0.0000		
61.5	4,911		0.0000		
62.5	4,911		0.0000		
63.5	2,332		0.0000		
64.5					
65.5					
66.5					
67.5					
68.5					
69.5					
70.5					
71.5	646		0.0000		
72.5	646		0.0000		
73.5	646		0.0000		
74.5	646		0.0000		
75.5	646		0.0000		
76.5	646		0.0000		
77.5	646		0.0000		
78.5	646		0.0000		

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

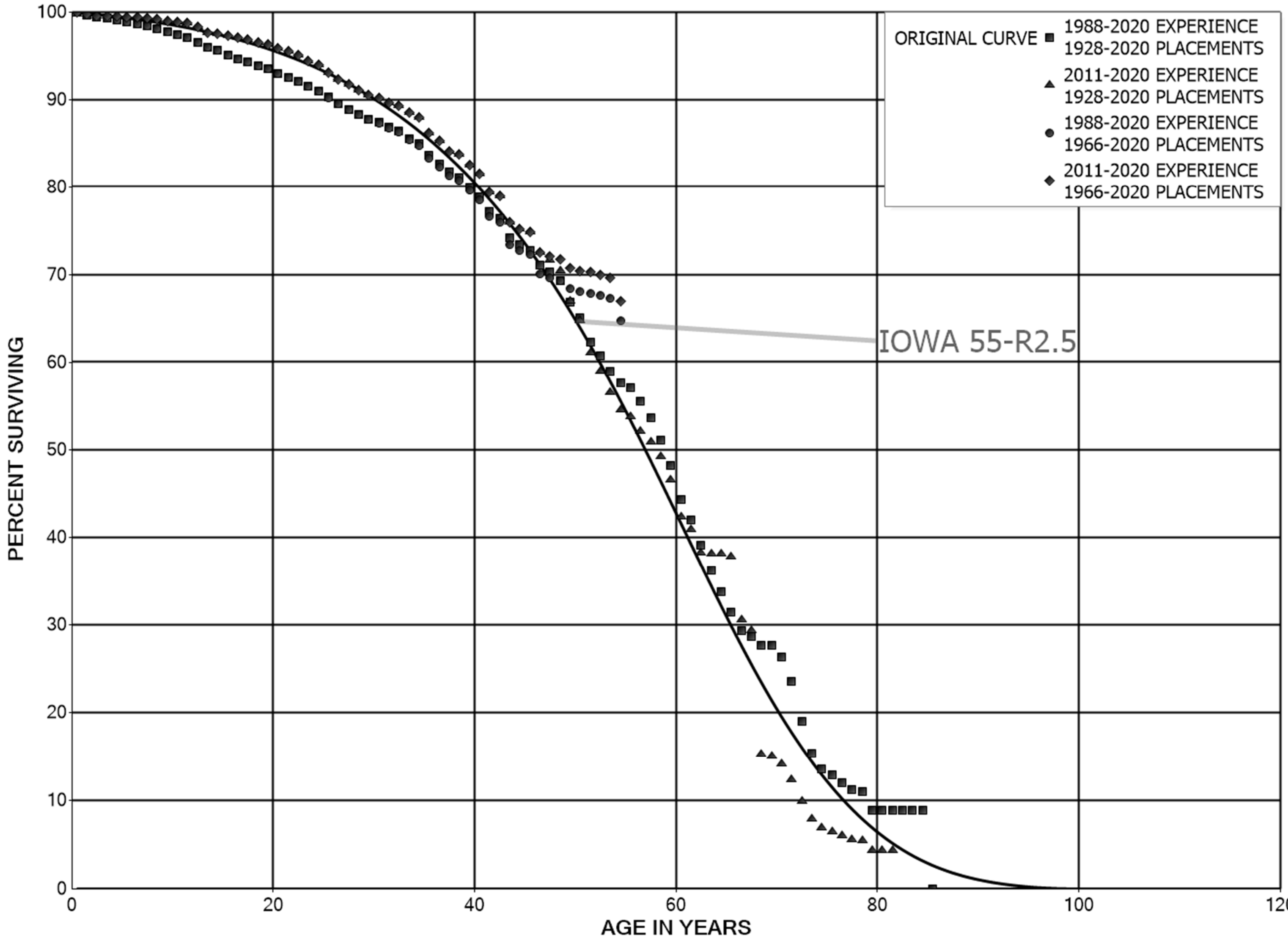
ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2011-2020

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	646		0.0000		
80.5	646		0.0000		
81.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 376.00 MAINS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 1988-2020

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	149,715,229	102,683	0.0007	0.9993	100.00
0.5	141,655,427	385,247	0.0027	0.9973	99.93
1.5	129,851,721	314,429	0.0024	0.9976	99.66
2.5	121,604,517	194,926	0.0016	0.9984	99.42
3.5	107,704,979	202,362	0.0019	0.9981	99.26
4.5	99,581,434	207,818	0.0021	0.9979	99.07
5.5	89,902,635	214,628	0.0024	0.9976	98.87
6.5	80,898,090	182,378	0.0023	0.9977	98.63
7.5	74,467,696	252,501	0.0034	0.9966	98.41
8.5	70,537,375	252,983	0.0036	0.9964	98.07
9.5	67,784,561	232,954	0.0034	0.9966	97.72
10.5	63,717,919	241,128	0.0038	0.9962	97.39
11.5	59,585,260	296,621	0.0050	0.9950	97.02
12.5	56,666,411	327,597	0.0058	0.9942	96.53
13.5	53,846,997	233,193	0.0043	0.9957	95.98
14.5	49,623,478	256,878	0.0052	0.9948	95.56
15.5	47,470,866	207,559	0.0044	0.9956	95.07
16.5	45,191,303	196,920	0.0044	0.9956	94.65
17.5	43,673,346	187,627	0.0043	0.9957	94.24
18.5	42,001,763	152,185	0.0036	0.9964	93.83
19.5	40,183,465	211,239	0.0053	0.9947	93.49
20.5	38,200,251	182,655	0.0048	0.9952	93.00
21.5	35,948,759	177,911	0.0049	0.9951	92.56
22.5	34,165,905	221,905	0.0065	0.9935	92.10
23.5	31,282,199	168,053	0.0054	0.9946	91.50
24.5	27,195,816	231,654	0.0085	0.9915	91.01
25.5	23,411,766	180,807	0.0077	0.9923	90.23
26.5	20,675,493	151,195	0.0073	0.9927	89.54
27.5	18,696,429	116,520	0.0062	0.9938	88.88
28.5	16,135,924	103,443	0.0064	0.9936	88.33
29.5	12,113,097	53,785	0.0044	0.9956	87.76
30.5	9,362,491	59,908	0.0064	0.9936	87.37
31.5	8,042,216	39,663	0.0049	0.9951	86.81
32.5	6,730,569	65,316	0.0097	0.9903	86.39
33.5	5,563,157	39,856	0.0072	0.9928	85.55
34.5	4,819,280	76,702	0.0159	0.9841	84.93
35.5	3,780,453	44,436	0.0118	0.9882	83.58
36.5	3,318,188	37,294	0.0112	0.9888	82.60
37.5	3,140,497	23,608	0.0075	0.9925	81.67
38.5	2,892,635	39,859	0.0138	0.9862	81.06

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 1988-2020

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	2,558,327	35,187	0.0138	0.9862	79.94
40.5	2,345,461	50,648	0.0216	0.9784	78.84
41.5	1,757,699	17,709	0.0101	0.9899	77.14
42.5	1,569,944	45,586	0.0290	0.9710	76.36
43.5	1,467,692	15,443	0.0105	0.9895	74.14
44.5	1,339,850	11,691	0.0087	0.9913	73.36
45.5	1,257,999	29,472	0.0234	0.9766	72.72
46.5	1,185,320	11,383	0.0096	0.9904	71.02
47.5	1,080,142	16,767	0.0155	0.9845	70.34
48.5	1,028,528	35,301	0.0343	0.9657	69.25
49.5	966,316	25,745	0.0266	0.9734	66.87
50.5	839,406	35,473	0.0423	0.9577	65.09
51.5	763,676	20,193	0.0264	0.9736	62.34
52.5	665,830	19,573	0.0294	0.9706	60.69
53.5	568,756	12,754	0.0224	0.9776	58.91
54.5	423,915	4,125	0.0097	0.9903	57.58
55.5	418,432	11,536	0.0276	0.9724	57.02
56.5	376,738	12,654	0.0336	0.9664	55.45
57.5	311,942	14,467	0.0464	0.9536	53.59
58.5	265,897	14,962	0.0563	0.9437	51.10
59.5	232,389	19,034	0.0819	0.9181	48.23
60.5	209,079	10,814	0.0517	0.9483	44.28
61.5	190,176	13,306	0.0700	0.9300	41.99
62.5	172,321	12,619	0.0732	0.9268	39.05
63.5	152,295	10,301	0.0676	0.9324	36.19
64.5	129,029	8,814	0.0683	0.9317	33.74
65.5	109,304	7,381	0.0675	0.9325	31.44
66.5	100,777	2,364	0.0235	0.9765	29.31
67.5	98,309	3,502	0.0356	0.9644	28.63
68.5	94,806	123	0.0013	0.9987	27.61
69.5	94,683	4,333	0.0458	0.9542	27.57
70.5	87,740	9,479	0.1080	0.8920	26.31
71.5	78,115	14,858	0.1902	0.8098	23.47
72.5	63,257	12,248	0.1936	0.8064	19.00
73.5	51,009	5,987	0.1174	0.8826	15.32
74.5	45,022	2,198	0.0488	0.9512	13.53
75.5	42,824	3,165	0.0739	0.9261	12.87
76.5	39,660	2,592	0.0654	0.9346	11.91
77.5	37,068	433	0.0117	0.9883	11.14
78.5	36,635	7,180	0.1960	0.8040	11.01

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 1988-2020

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	5,418		0.0000	1.0000	8.85
80.5	5,105		0.0000	1.0000	8.85
81.5	3,701		0.0000	1.0000	8.85
82.5	3,701		0.0000	1.0000	8.85
83.5	3,701		0.0000	1.0000	8.85
84.5	3,701	3,701	1.0000		8.85
85.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 2011-2020

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	86,451,816	14,203	0.0002	0.9998	100.00
0.5	80,958,825	216,363	0.0027	0.9973	99.98
1.5	72,338,860	154,359	0.0021	0.9979	99.72
2.5	65,839,937	21,112	0.0003	0.9997	99.50
3.5	54,398,543	8,326	0.0002	0.9998	99.47
4.5	50,497,917	8,060	0.0002	0.9998	99.46
5.5	42,758,528	31,138	0.0007	0.9993	99.44
6.5	35,696,153	15,506	0.0004	0.9996	99.37
7.5	30,686,367	59,094	0.0019	0.9981	99.32
8.5	27,786,432	51,581	0.0019	0.9981	99.13
9.5	26,820,920	20,627	0.0008	0.9992	98.95
10.5	24,756,269	40,345	0.0016	0.9984	98.87
11.5	22,919,664	97,599	0.0043	0.9957	98.71
12.5	21,749,798	148,810	0.0068	0.9932	98.29
13.5	21,746,046	36,202	0.0017	0.9983	97.62
14.5	21,697,740	42,827	0.0020	0.9980	97.46
15.5	23,416,716	52,600	0.0022	0.9978	97.26
16.5	23,928,678	64,319	0.0027	0.9973	97.05
17.5	24,328,061	70,251	0.0029	0.9971	96.79
18.5	25,340,397	63,338	0.0025	0.9975	96.51
19.5	27,676,239	120,247	0.0043	0.9957	96.26
20.5	28,532,890	96,471	0.0034	0.9966	95.85
21.5	27,603,336	131,789	0.0048	0.9952	95.52
22.5	27,210,158	183,482	0.0067	0.9933	95.07
23.5	25,554,014	135,084	0.0053	0.9947	94.43
24.5	22,215,047	201,475	0.0091	0.9909	93.93
25.5	19,438,565	155,044	0.0080	0.9920	93.07
26.5	17,139,096	122,596	0.0072	0.9928	92.33
27.5	15,338,379	96,567	0.0063	0.9937	91.67
28.5	13,024,901	78,222	0.0060	0.9940	91.09
29.5	9,352,088	36,972	0.0040	0.9960	90.55
30.5	6,810,972	40,316	0.0059	0.9941	90.19
31.5	6,111,138	22,656	0.0037	0.9963	89.66
32.5	4,989,027	46,584	0.0093	0.9907	89.32
33.5	3,952,763	24,985	0.0063	0.9937	88.49
34.5	3,369,032	65,240	0.0194	0.9806	87.93
35.5	2,450,152	27,334	0.0112	0.9888	86.23
36.5	2,120,689	29,138	0.0137	0.9863	85.27
37.5	2,065,770	9,845	0.0048	0.9952	84.09
38.5	1,922,281	27,164	0.0141	0.9859	83.69

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 2011-2020

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	1,646,652	19,319	0.0117	0.9883	82.51
40.5	1,558,929	40,960	0.0263	0.9737	81.54
41.5	1,023,335	5,570	0.0054	0.9946	79.40
42.5	919,289	35,602	0.0387	0.9613	78.97
43.5	905,552	8,215	0.0091	0.9909	75.91
44.5	901,569	4,883	0.0054	0.9946	75.22
45.5	818,214	25,296	0.0309	0.9691	74.81
46.5	739,856	8,732	0.0118	0.9882	72.50
47.5	717,614	12,977	0.0181	0.9819	71.64
48.5	674,456	32,314	0.0479	0.9521	70.35
49.5	655,046	22,003	0.0336	0.9664	66.98
50.5	539,472	30,410	0.0564	0.9436	64.73
51.5	482,670	17,003	0.0352	0.9648	61.08
52.5	396,239	16,653	0.0420	0.9580	58.93
53.5	313,076	11,053	0.0353	0.9647	56.45
54.5	192,406	2,655	0.0138	0.9862	54.46
55.5	206,634	6,450	0.0312	0.9688	53.71
56.5	172,524	4,030	0.0234	0.9766	52.03
57.5	121,962	4,041	0.0331	0.9669	50.82
58.5	86,343	4,577	0.0530	0.9470	49.13
59.5	59,520	5,429	0.0912	0.9088	46.53
60.5	52,539	1,785	0.0340	0.9660	42.28
61.5	43,062	2,874	0.0668	0.9332	40.85
62.5	35,638	65	0.0018	0.9982	38.12
63.5	28,166	21	0.0008	0.9992	38.05
64.5	15,181	138	0.0091	0.9909	38.02
65.5	9,758	1,871	0.1917	0.8083	37.68
66.5	6,741	250	0.0372	0.9628	30.45
67.5	6,386	3,089	0.4838	0.5162	29.32
68.5	3,296	45	0.0137	0.9863	15.14
69.5	40,913	2,415	0.0590	0.9410	14.93
70.5	38,020	4,875	0.1282	0.8718	14.05
71.5	74,414	14,858	0.1997	0.8003	12.25
72.5	59,556	12,248	0.2057	0.7943	9.80
73.5	47,308	5,987	0.1265	0.8735	7.79
74.5	41,322	2,198	0.0532	0.9468	6.80
75.5	39,124	3,165	0.0809	0.9191	6.44
76.5	35,959	2,592	0.0721	0.9279	5.92
77.5	33,367	433	0.0130	0.9870	5.49
78.5	32,934	7,180	0.2180	0.7820	5.42

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2020 EXPERIENCE BAND 2011-2020

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	1,718		0.0000	1.0000	4.24
80.5	1,405		0.0000	1.0000	4.24
81.5					4.24
82.5	3,701		0.0000		
83.5	3,701		0.0000		
84.5	3,701	3,701	1.0000		
85.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2020 EXPERIENCE BAND 1988-2020

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	149,715,229	102,683	0.0007	0.9993	100.00
0.5	141,655,427	385,247	0.0027	0.9973	99.93
1.5	129,851,721	314,429	0.0024	0.9976	99.66
2.5	121,604,517	194,926	0.0016	0.9984	99.42
3.5	107,704,979	202,362	0.0019	0.9981	99.26
4.5	99,581,434	207,818	0.0021	0.9979	99.07
5.5	89,902,635	214,628	0.0024	0.9976	98.87
6.5	80,898,090	182,378	0.0023	0.9977	98.63
7.5	74,467,696	252,501	0.0034	0.9966	98.41
8.5	70,537,375	252,983	0.0036	0.9964	98.07
9.5	67,784,561	232,954	0.0034	0.9966	97.72
10.5	63,717,919	241,128	0.0038	0.9962	97.39
11.5	59,585,260	296,621	0.0050	0.9950	97.02
12.5	56,666,411	327,597	0.0058	0.9942	96.53
13.5	53,846,997	233,193	0.0043	0.9957	95.98
14.5	49,623,478	256,878	0.0052	0.9948	95.56
15.5	47,470,866	207,559	0.0044	0.9956	95.07
16.5	45,191,303	196,920	0.0044	0.9956	94.65
17.5	43,673,346	187,627	0.0043	0.9957	94.24
18.5	42,001,763	152,185	0.0036	0.9964	93.83
19.5	40,183,465	211,239	0.0053	0.9947	93.49
20.5	38,200,251	182,655	0.0048	0.9952	93.00
21.5	35,948,759	177,911	0.0049	0.9951	92.56
22.5	34,131,441	221,905	0.0065	0.9935	92.10
23.5	31,190,377	168,053	0.0054	0.9946	91.50
24.5	26,996,357	231,600	0.0086	0.9914	91.01
25.5	23,151,590	180,732	0.0078	0.9922	90.23
26.5	20,369,298	151,153	0.0074	0.9926	89.52
27.5	18,380,985	116,469	0.0063	0.9937	88.86
28.5	15,804,359	103,443	0.0065	0.9935	88.29
29.5	11,771,250	53,454	0.0045	0.9955	87.72
30.5	9,007,595	59,764	0.0066	0.9934	87.32
31.5	7,657,390	39,141	0.0051	0.9949	86.74
32.5	6,322,925	65,096	0.0103	0.9897	86.30
33.5	5,151,158	38,762	0.0075	0.9925	85.41
34.5	4,399,241	75,815	0.0172	0.9828	84.76
35.5	3,360,784	39,892	0.0119	0.9881	83.30
36.5	2,902,897	34,652	0.0119	0.9881	82.32
37.5	2,723,869	19,623	0.0072	0.9928	81.33
38.5	2,479,595	34,601	0.0140	0.9860	80.75

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2020 EXPERIENCE BAND 1988-2020

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	2,150,546	30,608	0.0142	0.9858	79.62
40.5	1,942,259	45,024	0.0232	0.9768	78.49
41.5	1,360,121	11,663	0.0086	0.9914	76.67
42.5	1,167,197	39,847	0.0341	0.9659	76.01
43.5	1,047,687	10,151	0.0097	0.9903	73.41
44.5	901,569	4,883	0.0054	0.9946	72.70
45.5	802,336	25,142	0.0313	0.9687	72.31
46.5	671,522	4,175	0.0062	0.9938	70.04
47.5	557,754	2,519	0.0045	0.9955	69.61
48.5	471,568	6,314	0.0134	0.9866	69.29
49.5	439,021	1,958	0.0045	0.9955	68.37
50.5	335,898	884	0.0026	0.9974	68.06
51.5	294,758	1,230	0.0042	0.9958	67.88
52.5	215,874	880	0.0041	0.9959	67.60
53.5	137,493	5,407	0.0393	0.9607	67.32
54.5					64.68

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2020 EXPERIENCE BAND 2011-2020

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	86,451,816	14,203	0.0002	0.9998	100.00
0.5	80,958,825	216,363	0.0027	0.9973	99.98
1.5	72,338,860	154,359	0.0021	0.9979	99.72
2.5	65,839,937	21,112	0.0003	0.9997	99.50
3.5	54,398,543	8,326	0.0002	0.9998	99.47
4.5	50,497,917	8,060	0.0002	0.9998	99.46
5.5	42,758,528	31,138	0.0007	0.9993	99.44
6.5	35,696,153	15,506	0.0004	0.9996	99.37
7.5	30,686,367	59,094	0.0019	0.9981	99.32
8.5	27,786,432	51,581	0.0019	0.9981	99.13
9.5	26,820,920	20,627	0.0008	0.9992	98.95
10.5	24,756,269	40,345	0.0016	0.9984	98.87
11.5	22,919,664	97,599	0.0043	0.9957	98.71
12.5	21,749,798	148,810	0.0068	0.9932	98.29
13.5	21,746,046	36,202	0.0017	0.9983	97.62
14.5	21,697,740	42,827	0.0020	0.9980	97.46
15.5	23,416,716	52,600	0.0022	0.9978	97.26
16.5	23,928,678	64,319	0.0027	0.9973	97.05
17.5	24,328,061	70,251	0.0029	0.9971	96.79
18.5	25,340,397	63,338	0.0025	0.9975	96.51
19.5	27,676,239	120,247	0.0043	0.9957	96.26
20.5	28,532,890	96,471	0.0034	0.9966	95.85
21.5	27,603,336	131,789	0.0048	0.9952	95.52
22.5	27,210,158	183,482	0.0067	0.9933	95.07
23.5	25,554,014	135,084	0.0053	0.9947	94.43
24.5	22,215,047	201,475	0.0091	0.9909	93.93
25.5	19,438,565	155,044	0.0080	0.9920	93.07
26.5	17,139,096	122,596	0.0072	0.9928	92.33
27.5	15,338,379	96,567	0.0063	0.9937	91.67
28.5	13,024,901	78,222	0.0060	0.9940	91.09
29.5	9,352,088	36,972	0.0040	0.9960	90.55
30.5	6,810,972	40,316	0.0059	0.9941	90.19
31.5	6,111,138	22,656	0.0037	0.9963	89.66
32.5	4,989,027	46,584	0.0093	0.9907	89.32
33.5	3,952,763	24,985	0.0063	0.9937	88.49
34.5	3,369,032	65,240	0.0194	0.9806	87.93
35.5	2,450,152	27,334	0.0112	0.9888	86.23
36.5	2,120,689	29,138	0.0137	0.9863	85.27
37.5	2,065,770	9,845	0.0048	0.9952	84.09
38.5	1,922,281	27,164	0.0141	0.9859	83.69

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

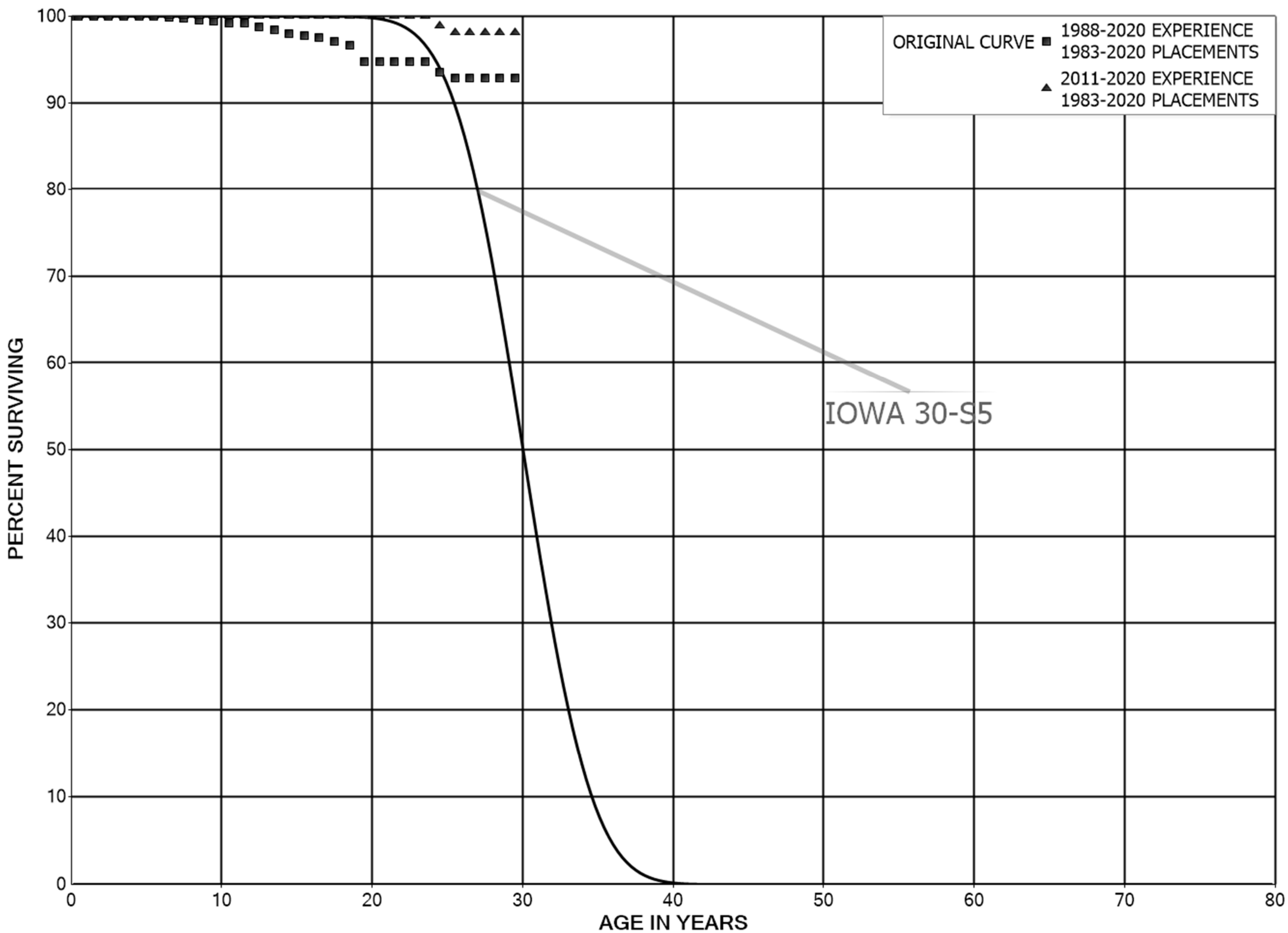
ACCOUNT 376.00 MAINS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2020 EXPERIENCE BAND 2011-2020

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	1,646,652	19,319	0.0117	0.9883	82.51
40.5	1,558,929	40,960	0.0263	0.9737	81.54
41.5	1,023,335	5,570	0.0054	0.9946	79.40
42.5	919,289	35,602	0.0387	0.9613	78.97
43.5	905,552	8,215	0.0091	0.9909	75.91
44.5	901,569	4,883	0.0054	0.9946	75.22
45.5	802,336	25,142	0.0313	0.9687	74.81
46.5	671,522	4,175	0.0062	0.9938	72.47
47.5	557,754	2,519	0.0045	0.9955	72.02
48.5	471,568	6,314	0.0134	0.9866	71.69
49.5	439,021	1,958	0.0045	0.9955	70.73
50.5	335,898	884	0.0026	0.9974	70.42
51.5	294,758	1,230	0.0042	0.9958	70.23
52.5	215,874	880	0.0041	0.9959	69.94
53.5	137,493	5,407	0.0393	0.9607	69.65
54.5					66.92

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 376.60 MAINS - CATHODIC PROTECTION
ORIGINAL AND SMOOTH SURVIVOR CURVES



Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.60 MAINS - CATHODIC PROTECTION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2020 EXPERIENCE BAND 1988-2020

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	1,076,745		0.0000	1.0000	100.00
0.5	1,065,855		0.0000	1.0000	100.00
1.5	942,686		0.0000	1.0000	100.00
2.5	836,411	0	0.0000	1.0000	100.00
3.5	808,306	231	0.0003	0.9997	100.00
4.5	692,772	512	0.0007	0.9993	99.97
5.5	608,126	569	0.0009	0.9991	99.90
6.5	552,247	470	0.0009	0.9991	99.80
7.5	551,776	1,230	0.0022	0.9978	99.72
8.5	548,873	656	0.0012	0.9988	99.50
9.5	533,004	873	0.0016	0.9984	99.38
10.5	524,429	451	0.0009	0.9991	99.21
11.5	494,578	2,163	0.0044	0.9956	99.13
12.5	449,768	1,470	0.0033	0.9967	98.70
13.5	362,798	1,755	0.0048	0.9952	98.37
14.5	320,292	503	0.0016	0.9984	97.90
15.5	273,751	532	0.0019	0.9981	97.74
16.5	249,942	1,232	0.0049	0.9951	97.55
17.5	218,227	969	0.0044	0.9956	97.07
18.5	206,627	4,206	0.0204	0.9796	96.64
19.5	199,838		0.0000	1.0000	94.67
20.5	194,455		0.0000	1.0000	94.67
21.5	164,967		0.0000	1.0000	94.67
22.5	98,063		0.0000	1.0000	94.67
23.5	86,284	1,033	0.0120	0.9880	94.67
24.5	74,999	533	0.0071	0.9929	93.54
25.5	50,475		0.0000	1.0000	92.88
26.5	34,248		0.0000	1.0000	92.88
27.5	17,636		0.0000	1.0000	92.88
28.5	1,070		0.0000	1.0000	92.88
29.5					92.88
30.5					
31.5	1,206		0.0000		
32.5	1,206		0.0000		
33.5	1,206		0.0000		
34.5	1,206		0.0000		
35.5	1,206		0.0000		
36.5	1,206		0.0000		
37.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

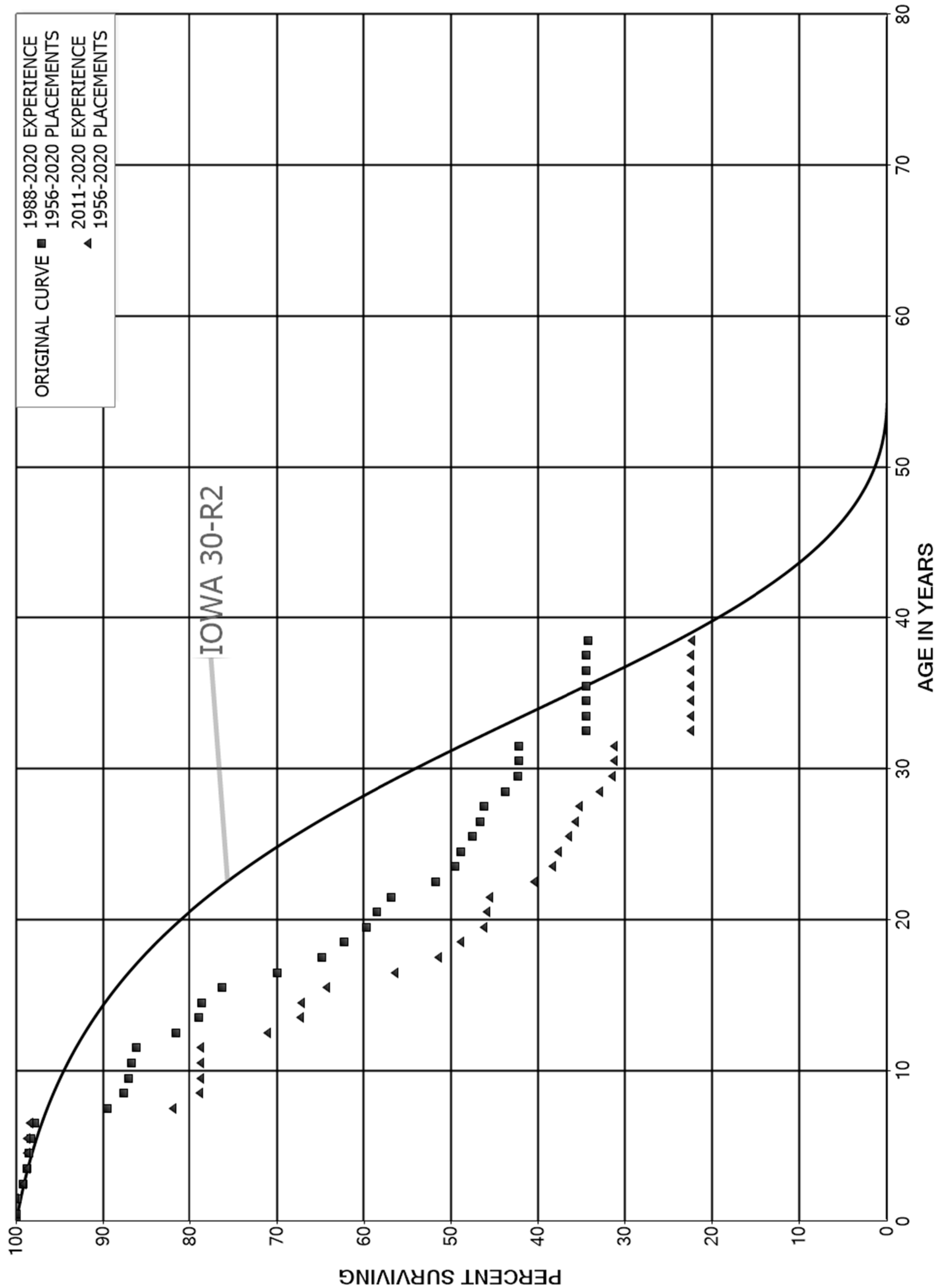
ACCOUNT 376.60 MAINS - CATHODIC PROTECTION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2020 EXPERIENCE BAND 2011-2020

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	555,784		0.0000	1.0000	100.00
0.5	538,090		0.0000	1.0000	100.00
1.5	444,321		0.0000	1.0000	100.00
2.5	380,693		0.0000	1.0000	100.00
3.5	438,087		0.0000	1.0000	100.00
4.5	362,330		0.0000	1.0000	100.00
5.5	324,233		0.0000	1.0000	100.00
6.5	300,668		0.0000	1.0000	100.00
7.5	331,150		0.0000	1.0000	100.00
8.5	340,108		0.0000	1.0000	100.00
9.5	327,477		0.0000	1.0000	100.00
10.5	325,159		0.0000	1.0000	100.00
11.5	325,247		0.0000	1.0000	100.00
12.5	341,036		0.0000	1.0000	100.00
13.5	267,316		0.0000	1.0000	100.00
14.5	236,818		0.0000	1.0000	100.00
15.5	214,771		0.0000	1.0000	100.00
16.5	207,721		0.0000	1.0000	100.00
17.5	194,383		0.0000	1.0000	100.00
18.5	201,351		0.0000	1.0000	100.00
19.5	199,838		0.0000	1.0000	100.00
20.5	194,455		0.0000	1.0000	100.00
21.5	164,967		0.0000	1.0000	100.00
22.5	98,063		0.0000	1.0000	100.00
23.5	86,284	1,033	0.0120	0.9880	100.00
24.5	74,999	533	0.0071	0.9929	98.80
25.5	50,475		0.0000	1.0000	98.10
26.5	34,248		0.0000	1.0000	98.10
27.5	17,636		0.0000	1.0000	98.10
28.5	1,070		0.0000	1.0000	98.10
29.5					98.10
30.5					
31.5	1,206		0.0000		
32.5	1,206		0.0000		
33.5	1,206		0.0000		
34.5	1,206		0.0000		
35.5	1,206		0.0000		
36.5	1,206		0.0000		
37.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2020 EXPERIENCE BAND 1988-2020

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	8,204,449	2,893	0.0004	0.9996	100.00
0.5	7,291,331	5,571	0.0008	0.9992	99.96
1.5	4,975,220	36,650	0.0074	0.9926	99.89
2.5	4,553,882	20,100	0.0044	0.9956	99.15
3.5	4,094,879	7,923	0.0019	0.9981	98.71
4.5	3,891,728	9,188	0.0024	0.9976	98.52
5.5	3,132,354	12,815	0.0041	0.9959	98.29
6.5	3,062,144	263,034	0.0859	0.9141	97.89
7.5	2,434,114	51,195	0.0210	0.9790	89.48
8.5	1,923,152	10,536	0.0055	0.9945	87.60
9.5	1,939,085	9,117	0.0047	0.9953	87.12
10.5	1,803,920	10,650	0.0059	0.9941	86.71
11.5	1,793,270	94,812	0.0529	0.9471	86.20
12.5	1,698,459	55,251	0.0325	0.9675	81.64
13.5	1,650,782	8,598	0.0052	0.9948	78.98
14.5	1,554,760	45,371	0.0292	0.9708	78.57
15.5	1,493,182	123,104	0.0824	0.9176	76.28
16.5	1,302,371	96,593	0.0742	0.9258	69.99
17.5	1,143,100	44,422	0.0389	0.9611	64.80
18.5	1,082,719	45,305	0.0418	0.9582	62.28
19.5	995,830	19,295	0.0194	0.9806	59.68
20.5	829,938	23,950	0.0289	0.9711	58.52
21.5	648,199	58,634	0.0905	0.9095	56.83
22.5	532,069	22,430	0.0422	0.9578	51.69
23.5	449,478	5,758	0.0128	0.9872	49.51
24.5	402,543	11,236	0.0279	0.9721	48.88
25.5	391,307	7,533	0.0193	0.9807	47.51
26.5	302,194	3,059	0.0101	0.9899	46.60
27.5	287,108	14,873	0.0518	0.9482	46.13
28.5	243,806	7,856	0.0322	0.9678	43.74
29.5	188,667	916	0.0049	0.9951	42.33
30.5	99,481		0.0000	1.0000	42.12
31.5	93,629	17,223	0.1839	0.8161	42.12
32.5	79,010		0.0000	1.0000	34.37
33.5	79,010		0.0000	1.0000	34.37
34.5	52,567		0.0000	1.0000	34.37
35.5	52,567		0.0000	1.0000	34.37
36.5	52,567		0.0000	1.0000	34.37
37.5	52,567	263	0.0050	0.9950	34.37
38.5	47,703		0.0000	1.0000	34.20

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2020 EXPERIENCE BAND 1988-2020

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	47,703		0.0000	1.0000	34.20
40.5	42,249	525	0.0124	0.9876	34.20
41.5	31,799		0.0000	1.0000	33.78
42.5	20,659		0.0000	1.0000	33.78
43.5	20,659		0.0000	1.0000	33.78
44.5	20,659		0.0000	1.0000	33.78
45.5	20,659		0.0000	1.0000	33.78
46.5	11,593		0.0000	1.0000	33.78
47.5	8,624		0.0000	1.0000	33.78
48.5	8,624		0.0000	1.0000	33.78
49.5	7,518		0.0000	1.0000	33.78
50.5	3,712		0.0000	1.0000	33.78
51.5	3,712		0.0000	1.0000	33.78
52.5	3,712		0.0000	1.0000	33.78
53.5	3,712		0.0000	1.0000	33.78
54.5	3,712	1,619	0.4361	0.5639	33.78
55.5	2,093		0.0000	1.0000	19.05
56.5	2,093		0.0000	1.0000	19.05
57.5	2,093		0.0000	1.0000	19.05
58.5	2,093		0.0000	1.0000	19.05
59.5	2,093		0.0000	1.0000	19.05
60.5	2,093		0.0000	1.0000	19.05
61.5	2,093		0.0000	1.0000	19.05
62.5	2,093		0.0000	1.0000	19.05
63.5	2,093		0.0000	1.0000	19.05
64.5					19.05

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2020 EXPERIENCE BAND 2011-2020

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	6,306,421		0.0000	1.0000	100.00
0.5	5,557,477		0.0000	1.0000	100.00
1.5	3,210,815	30,719	0.0096	0.9904	100.00
2.5	2,769,276	12,673	0.0046	0.9954	99.04
3.5	2,335,162		0.0000	1.0000	98.59
4.5	2,224,097		0.0000	1.0000	98.59
5.5	1,513,190	5,174	0.0034	0.9966	98.59
6.5	1,521,960	254,473	0.1672	0.8328	98.25
7.5	983,387	37,708	0.0383	0.9617	81.82
8.5	451,334	459	0.0010	0.9990	78.69
9.5	501,463		0.0000	1.0000	78.61
10.5	633,660		0.0000	1.0000	78.61
11.5	794,374	77,316	0.0973	0.9027	78.61
12.5	775,716	41,738	0.0538	0.9462	70.96
13.5	808,215	1,163	0.0014	0.9986	67.14
14.5	873,688	37,500	0.0429	0.9571	67.04
15.5	919,989	113,050	0.1229	0.8771	64.16
16.5	845,065	74,721	0.0884	0.9116	56.28
17.5	694,057	34,209	0.0493	0.9507	51.30
18.5	682,556	38,568	0.0565	0.9435	48.77
19.5	681,374	4,214	0.0062	0.9938	46.02
20.5	652,803	5,087	0.0078	0.9922	45.73
21.5	520,816	58,505	0.1123	0.8877	45.38
22.5	425,350	22,370	0.0526	0.9474	40.28
23.5	342,819	5,612	0.0164	0.9836	38.16
24.5	322,472	10,614	0.0329	0.9671	37.54
25.5	329,562	7,265	0.0220	0.9780	36.30
26.5	240,717	3,059	0.0127	0.9873	35.50
27.5	225,631	14,873	0.0659	0.9341	35.05
28.5	182,328	7,856	0.0431	0.9569	32.74
29.5	128,845	916	0.0071	0.9929	31.33
30.5	45,114		0.0000	1.0000	31.11
31.5	61,042	17,223	0.2821	0.7179	31.11
32.5	58,351		0.0000	1.0000	22.33
33.5	58,351		0.0000	1.0000	22.33
34.5	31,908		0.0000	1.0000	22.33
35.5	31,908		0.0000	1.0000	22.33
36.5	40,974		0.0000	1.0000	22.33
37.5	43,943	263	0.0060	0.9940	22.33
38.5	39,079		0.0000	1.0000	22.20

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

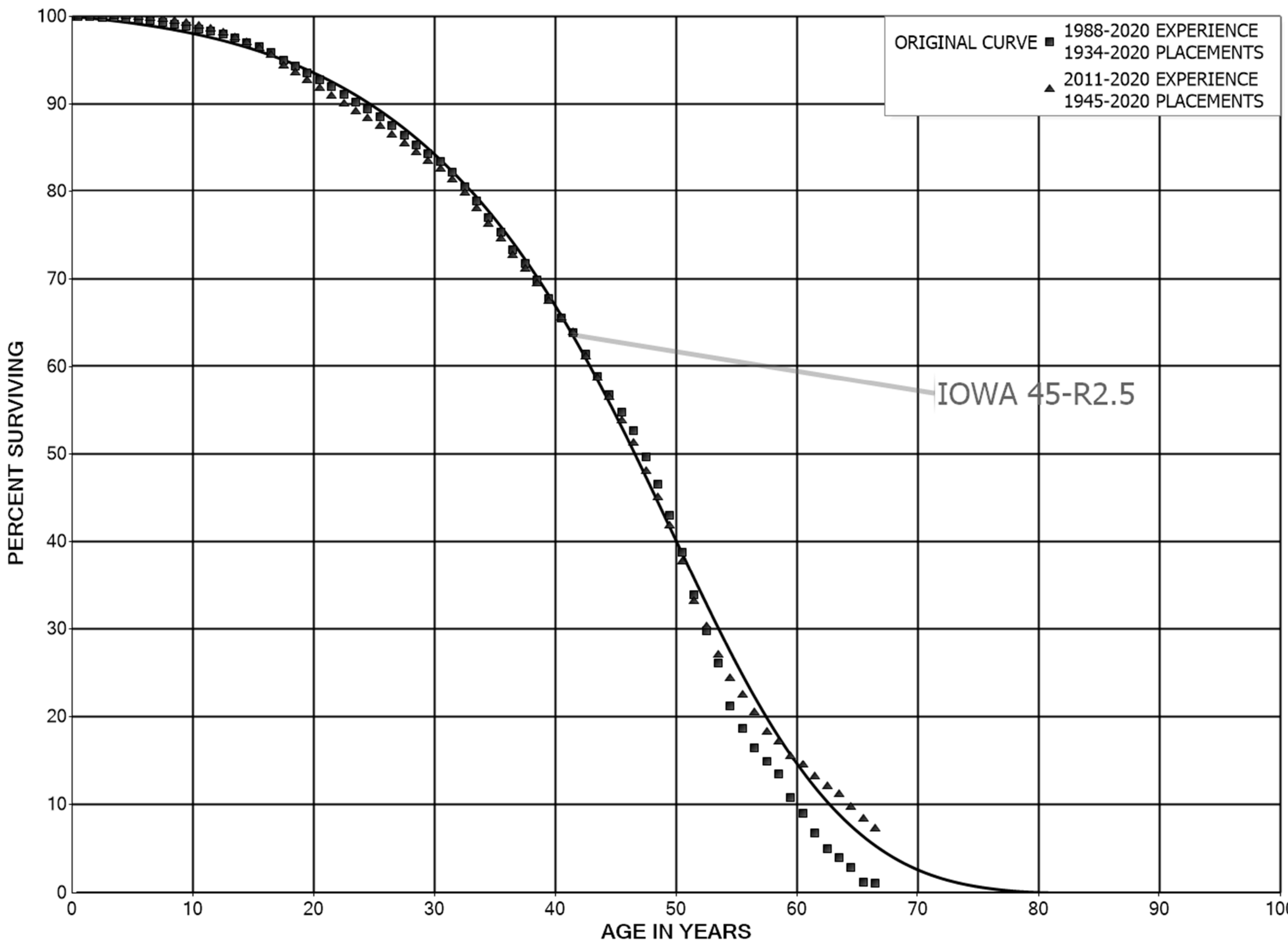
ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2020 EXPERIENCE BAND 2011-2020

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	40,186		0.0000	1.0000	22.20
40.5	38,537	525	0.0136	0.9864	22.20
41.5	28,087		0.0000	1.0000	21.89
42.5	16,947		0.0000	1.0000	21.89
43.5	16,947		0.0000	1.0000	21.89
44.5	16,947		0.0000	1.0000	21.89
45.5	16,947		0.0000	1.0000	21.89
46.5	7,882		0.0000	1.0000	21.89
47.5	4,913		0.0000	1.0000	21.89
48.5	4,913		0.0000	1.0000	21.89
49.5	3,806		0.0000	1.0000	21.89
50.5					21.89
51.5					
52.5					
53.5					
54.5	3,712	1,619	0.4361		
55.5	2,093		0.0000		
56.5	2,093		0.0000		
57.5	2,093		0.0000		
58.5	2,093		0.0000		
59.5	2,093		0.0000		
60.5	2,093		0.0000		
61.5	2,093		0.0000		
62.5	2,093		0.0000		
63.5	2,093		0.0000		
64.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 380.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1988-2020

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	82,700,546	16,997	0.0002	0.9998	100.00
0.5	77,640,737	30,687	0.0004	0.9996	99.98
1.5	73,895,770	37,698	0.0005	0.9995	99.94
2.5	68,099,721	49,616	0.0007	0.9993	99.89
3.5	61,126,399	52,119	0.0009	0.9991	99.82
4.5	55,578,404	51,576	0.0009	0.9991	99.73
5.5	48,983,091	80,387	0.0016	0.9984	99.64
6.5	43,868,106	64,372	0.0015	0.9985	99.47
7.5	37,592,978	84,331	0.0022	0.9978	99.33
8.5	33,027,925	86,820	0.0026	0.9974	99.11
9.5	30,372,454	89,469	0.0029	0.9971	98.85
10.5	27,703,342	76,371	0.0028	0.9972	98.55
11.5	25,856,486	97,810	0.0038	0.9962	98.28
12.5	24,323,194	109,002	0.0045	0.9955	97.91
13.5	23,294,097	111,480	0.0048	0.9952	97.47
14.5	21,648,975	112,205	0.0052	0.9948	97.01
15.5	20,792,241	139,807	0.0067	0.9933	96.50
16.5	19,727,563	181,421	0.0092	0.9908	95.85
17.5	18,743,180	141,057	0.0075	0.9925	94.97
18.5	17,537,176	137,296	0.0078	0.9922	94.26
19.5	16,752,719	144,333	0.0086	0.9914	93.52
20.5	15,774,016	135,180	0.0086	0.9914	92.71
21.5	14,794,767	144,068	0.0097	0.9903	91.92
22.5	13,682,753	120,705	0.0088	0.9912	91.02
23.5	12,551,233	109,470	0.0087	0.9913	90.22
24.5	11,478,570	117,432	0.0102	0.9898	89.43
25.5	10,553,464	115,923	0.0110	0.9890	88.52
26.5	8,958,591	115,404	0.0129	0.9871	87.55
27.5	8,130,497	103,705	0.0128	0.9872	86.42
28.5	7,121,240	84,354	0.0118	0.9882	85.32
29.5	5,850,519	66,026	0.0113	0.9887	84.31
30.5	4,622,637	66,531	0.0144	0.9856	83.36
31.5	3,846,766	75,050	0.0195	0.9805	82.16
32.5	3,142,565	68,561	0.0218	0.9782	80.55
33.5	2,552,273	60,040	0.0235	0.9765	78.80
34.5	2,136,397	47,502	0.0222	0.9778	76.94
35.5	1,801,977	46,390	0.0257	0.9743	75.23
36.5	1,599,820	35,419	0.0221	0.9779	73.29
37.5	1,445,973	36,438	0.0252	0.9748	71.67
38.5	1,272,404	39,644	0.0312	0.9688	69.87

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1988-2020

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	1,081,305	34,629	0.0320	0.9680	67.69
40.5	941,842	24,714	0.0262	0.9738	65.52
41.5	648,557	24,976	0.0385	0.9615	63.80
42.5	576,975	23,434	0.0406	0.9594	61.34
43.5	509,987	17,993	0.0353	0.9647	58.85
44.5	459,146	16,304	0.0355	0.9645	56.78
45.5	420,949	16,529	0.0393	0.9607	54.76
46.5	378,121	21,589	0.0571	0.9429	52.61
47.5	331,415	20,400	0.0616	0.9384	49.61
48.5	284,393	22,288	0.0784	0.9216	46.55
49.5	242,738	23,931	0.0986	0.9014	42.90
50.5	212,814	26,705	0.1255	0.8745	38.67
51.5	181,943	22,155	0.1218	0.8782	33.82
52.5	149,447	18,390	0.1231	0.8769	29.70
53.5	120,764	22,382	0.1853	0.8147	26.05
54.5	88,672	10,723	0.1209	0.8791	21.22
55.5	68,965	8,385	0.1216	0.8784	18.65
56.5	48,077	4,473	0.0930	0.9070	16.39
57.5	36,821	3,564	0.0968	0.9032	14.86
58.5	26,901	5,338	0.1984	0.8016	13.42
59.5	17,882	2,996	0.1675	0.8325	10.76
60.5	14,159	3,494	0.2468	0.7532	8.96
61.5	9,761	2,524	0.2586	0.7414	6.75
62.5	6,538	1,406	0.2150	0.7850	5.00
63.5	5,132	1,386	0.2700	0.7300	3.93
64.5	3,746	2,183	0.5828	0.4172	2.87
65.5	1,563	224	0.1432	0.8568	1.20
66.5	667	66	0.0988	0.9012	1.02
67.5	309	24	0.0784	0.9216	0.92
68.5	285	44	0.1546	0.8454	0.85
69.5	241	27	0.1131	0.8869	0.72
70.5	213	65	0.3027	0.6973	0.64
71.5	149	30	0.2033	0.7967	0.44
72.5	119	6	0.0527	0.9473	0.35
73.5	21		0.0000	1.0000	0.34
74.5					0.34

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2020 EXPERIENCE BAND 2011-2020

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	54,847,716		0.0000	1.0000	100.00
0.5	51,836,124	701	0.0000	1.0000	100.00
1.5	49,507,142	5,974	0.0001	0.9999	100.00
2.5	44,899,216	15,602	0.0003	0.9997	99.99
3.5	38,805,287	15,197	0.0004	0.9996	99.95
4.5	34,792,429	13,892	0.0004	0.9996	99.91
5.5	28,889,413	40,901	0.0014	0.9986	99.87
6.5	24,574,300	23,562	0.0010	0.9990	99.73
7.5	19,007,295	41,578	0.0022	0.9978	99.64
8.5	15,172,338	42,538	0.0028	0.9972	99.42
9.5	13,189,852	43,780	0.0033	0.9967	99.14
10.5	11,403,497	30,765	0.0027	0.9973	98.81
11.5	10,461,536	48,787	0.0047	0.9953	98.54
12.5	9,974,343	57,634	0.0058	0.9942	98.08
13.5	10,051,005	59,434	0.0059	0.9941	97.52
14.5	9,489,646	61,734	0.0065	0.9935	96.94
15.5	9,518,618	78,011	0.0082	0.9918	96.31
16.5	10,167,638	127,590	0.0125	0.9875	95.52
17.5	10,003,985	91,086	0.0091	0.9909	94.32
18.5	9,858,427	90,022	0.0091	0.9909	93.46
19.5	10,419,642	100,418	0.0096	0.9904	92.61
20.5	10,777,256	97,990	0.0091	0.9909	91.72
21.5	10,615,605	112,780	0.0106	0.9894	90.88
22.5	10,253,882	95,761	0.0093	0.9907	89.92
23.5	9,694,544	86,831	0.0090	0.9910	89.08
24.5	9,038,202	94,018	0.0104	0.9896	88.28
25.5	8,452,898	92,343	0.0109	0.9891	87.36
26.5	7,053,269	86,557	0.0123	0.9877	86.41
27.5	6,391,846	74,544	0.0117	0.9883	85.35
28.5	5,569,260	63,173	0.0113	0.9887	84.35
29.5	4,513,940	50,945	0.0113	0.9887	83.39
30.5	3,441,228	48,162	0.0140	0.9860	82.45
31.5	3,041,527	59,703	0.0196	0.9804	81.30
32.5	2,412,471	52,386	0.0217	0.9783	79.70
33.5	1,906,054	44,469	0.0233	0.9767	77.97
34.5	1,555,284	33,604	0.0216	0.9784	76.15
35.5	1,275,940	32,318	0.0253	0.9747	74.51
36.5	1,161,229	24,585	0.0212	0.9788	72.62
37.5	1,069,438	25,697	0.0240	0.9760	71.08
38.5	949,887	27,742	0.0292	0.9708	69.38

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

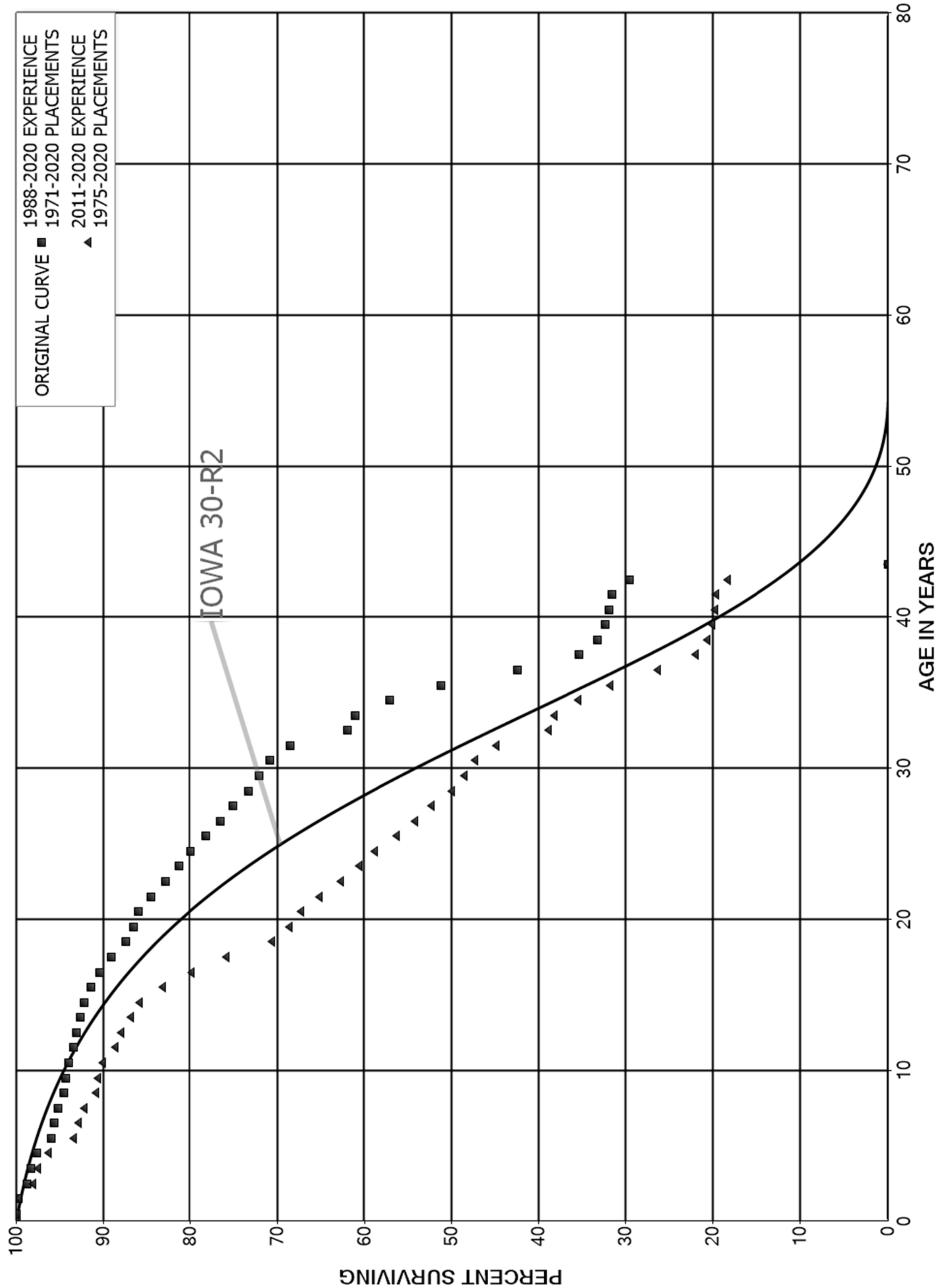
ACCOUNT 380.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2020 EXPERIENCE BAND 2011-2020

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	794,576	22,318	0.0281	0.9719	67.35
40.5	666,550	17,056	0.0256	0.9744	65.46
41.5	380,736	16,280	0.0428	0.9572	63.78
42.5	324,317	13,061	0.0403	0.9597	61.06
43.5	286,407	10,577	0.0369	0.9631	58.60
44.5	255,825	12,266	0.0479	0.9521	56.43
45.5	235,108	10,995	0.0468	0.9532	53.73
46.5	199,293	12,925	0.0649	0.9351	51.21
47.5	172,587	10,478	0.0607	0.9393	47.89
48.5	154,934	11,395	0.0735	0.9265	44.99
49.5	138,666	13,414	0.0967	0.9033	41.68
50.5	123,369	15,147	0.1228	0.8772	37.65
51.5	108,392	9,225	0.0851	0.9149	33.02
52.5	94,056	10,055	0.1069	0.8931	30.21
53.5	70,112	6,971	0.0994	0.9006	26.98
54.5	53,431	4,179	0.0782	0.9218	24.30
55.5	40,268	3,635	0.0903	0.9097	22.40
56.5	25,305	2,672	0.1056	0.8944	20.38
57.5	16,454	1,076	0.0654	0.9346	18.23
58.5	9,022	841	0.0932	0.9068	17.03
59.5	4,501	313	0.0696	0.9304	15.45
60.5	3,461	312	0.0902	0.9098	14.37
61.5	2,245	191	0.0851	0.9149	13.08
62.5	1,355	98	0.0720	0.9280	11.96
63.5	1,616	212	0.1310	0.8690	11.10
64.5	1,529	215	0.1403	0.8597	9.65
65.5	1,552	213	0.1374	0.8626	8.29
66.5	667	66	0.0988	0.9012	7.15
67.5	309	24	0.0784	0.9216	6.45
68.5	285	44	0.1546	0.8454	5.94
69.5	241	27	0.1131	0.8869	5.02
70.5	213	65	0.3027	0.6973	4.45
71.5	149	30	0.2033	0.7967	3.11
72.5	119	6	0.0527	0.9473	2.47
73.5	21		0.0000	1.0000	2.34
74.5					2.34

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 381.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2020 EXPERIENCE BAND 1988-2020

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	4,794,646	1,234	0.0003	0.9997	100.00
0.5	4,587,618	11,358	0.0025	0.9975	99.97
1.5	4,117,058	42,132	0.0102	0.9898	99.73
2.5	4,081,762	15,595	0.0038	0.9962	98.71
3.5	3,718,006	27,959	0.0075	0.9925	98.33
4.5	3,646,779	59,363	0.0163	0.9837	97.59
5.5	3,641,473	14,401	0.0040	0.9960	96.00
6.5	3,488,977	15,660	0.0045	0.9955	95.62
7.5	3,195,463	24,818	0.0078	0.9922	95.19
8.5	2,999,238	5,240	0.0017	0.9983	94.45
9.5	3,113,745	11,162	0.0036	0.9964	94.29
10.5	2,984,807	18,604	0.0062	0.9938	93.95
11.5	2,747,955	9,866	0.0036	0.9964	93.36
12.5	2,681,301	11,889	0.0044	0.9956	93.03
13.5	2,516,494	10,769	0.0043	0.9957	92.62
14.5	2,489,953	23,649	0.0095	0.9905	92.22
15.5	2,281,400	23,217	0.0102	0.9898	91.34
16.5	2,222,344	32,042	0.0144	0.9856	90.41
17.5	2,167,451	40,865	0.0189	0.9811	89.11
18.5	2,120,082	21,643	0.0102	0.9898	87.43
19.5	2,098,439	15,647	0.0075	0.9925	86.54
20.5	2,082,792	33,235	0.0160	0.9840	85.89
21.5	1,998,823	40,265	0.0201	0.9799	84.52
22.5	1,958,557	37,266	0.0190	0.9810	82.82
23.5	1,815,453	27,920	0.0154	0.9846	81.24
24.5	1,787,532	41,412	0.0232	0.9768	79.99
25.5	1,675,714	35,324	0.0211	0.9789	78.14
26.5	1,531,342	27,740	0.0181	0.9819	76.49
27.5	1,503,602	37,069	0.0247	0.9753	75.11
28.5	1,455,971	23,748	0.0163	0.9837	73.26
29.5	1,270,361	21,919	0.0173	0.9827	72.06
30.5	1,073,809	34,309	0.0320	0.9680	70.82
31.5	971,195	94,371	0.0972	0.9028	68.56
32.5	844,937	11,139	0.0132	0.9868	61.89
33.5	777,222	51,489	0.0662	0.9338	61.08
34.5	710,825	72,888	0.1025	0.8975	57.03
35.5	570,363	98,218	0.1722	0.8278	51.18
36.5	465,675	77,954	0.1674	0.8326	42.37
37.5	348,452	20,811	0.0597	0.9403	35.28
38.5	310,898	8,059	0.0259	0.9741	33.17

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-2020 EXPERIENCE BAND 1988-2020

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	163,594	2,417	0.0148	0.9852	32.31
40.5	161,177	1,761	0.0109	0.9891	31.83
41.5	68,875	4,363	0.0633	0.9367	31.49
42.5	779	779	1.0000		29.49
43.5					

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2020 EXPERIENCE BAND 2011-2020

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	2,520,127		0.0000	1.0000	100.00
0.5	2,457,503	8,858	0.0036	0.9964	100.00
1.5	2,259,299	39,325	0.0174	0.9826	99.64
2.5	2,206,253	12,581	0.0057	0.9943	97.91
3.5	1,997,352	25,084	0.0126	0.9874	97.35
4.5	1,896,590	56,414	0.0297	0.9703	96.12
5.5	2,045,335	11,201	0.0055	0.9945	93.27
6.5	1,668,374	12,178	0.0073	0.9927	92.75
7.5	1,421,690	21,519	0.0151	0.9849	92.08
8.5	1,104,124	1,541	0.0014	0.9986	90.68
9.5	1,137,120	7,261	0.0064	0.9936	90.56
10.5	925,250	14,654	0.0158	0.9842	89.98
11.5	700,313	5,324	0.0076	0.9924	88.55
12.5	630,246	8,326	0.0132	0.9868	87.88
13.5	602,885	7,127	0.0118	0.9882	86.72
14.5	623,361	19,098	0.0306	0.9694	85.69
15.5	502,296	20,122	0.0401	0.9599	83.07
16.5	569,050	28,534	0.0501	0.9499	79.74
17.5	548,398	37,924	0.0692	0.9308	75.74
18.5	523,207	15,065	0.0288	0.9712	70.50
19.5	701,946	12,976	0.0185	0.9815	68.47
20.5	903,925	28,191	0.0312	0.9688	67.21
21.5	919,748	35,838	0.0390	0.9610	65.11
22.5	932,694	30,938	0.0332	0.9668	62.58
23.5	872,582	25,379	0.0291	0.9709	60.50
24.5	871,809	37,590	0.0431	0.9569	58.74
25.5	860,312	32,458	0.0377	0.9623	56.21
26.5	731,850	25,459	0.0348	0.9652	54.09
27.5	756,979	35,125	0.0464	0.9536	52.21
28.5	762,578	21,599	0.0283	0.9717	49.78
29.5	846,293	20,962	0.0248	0.9752	48.37
30.5	652,198	33,788	0.0518	0.9482	47.17
31.5	696,140	93,882	0.1349	0.8651	44.73
32.5	682,201	10,353	0.0152	0.9848	38.70
33.5	706,041	51,408	0.0728	0.9272	38.11
34.5	691,276	72,798	0.1053	0.8947	35.34
35.5	570,280	98,191	0.1722	0.8278	31.61
36.5	465,620	77,944	0.1674	0.8326	26.17
37.5	348,406	20,795	0.0597	0.9403	21.79
38.5	310,868	8,029	0.0258	0.9742	20.49

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

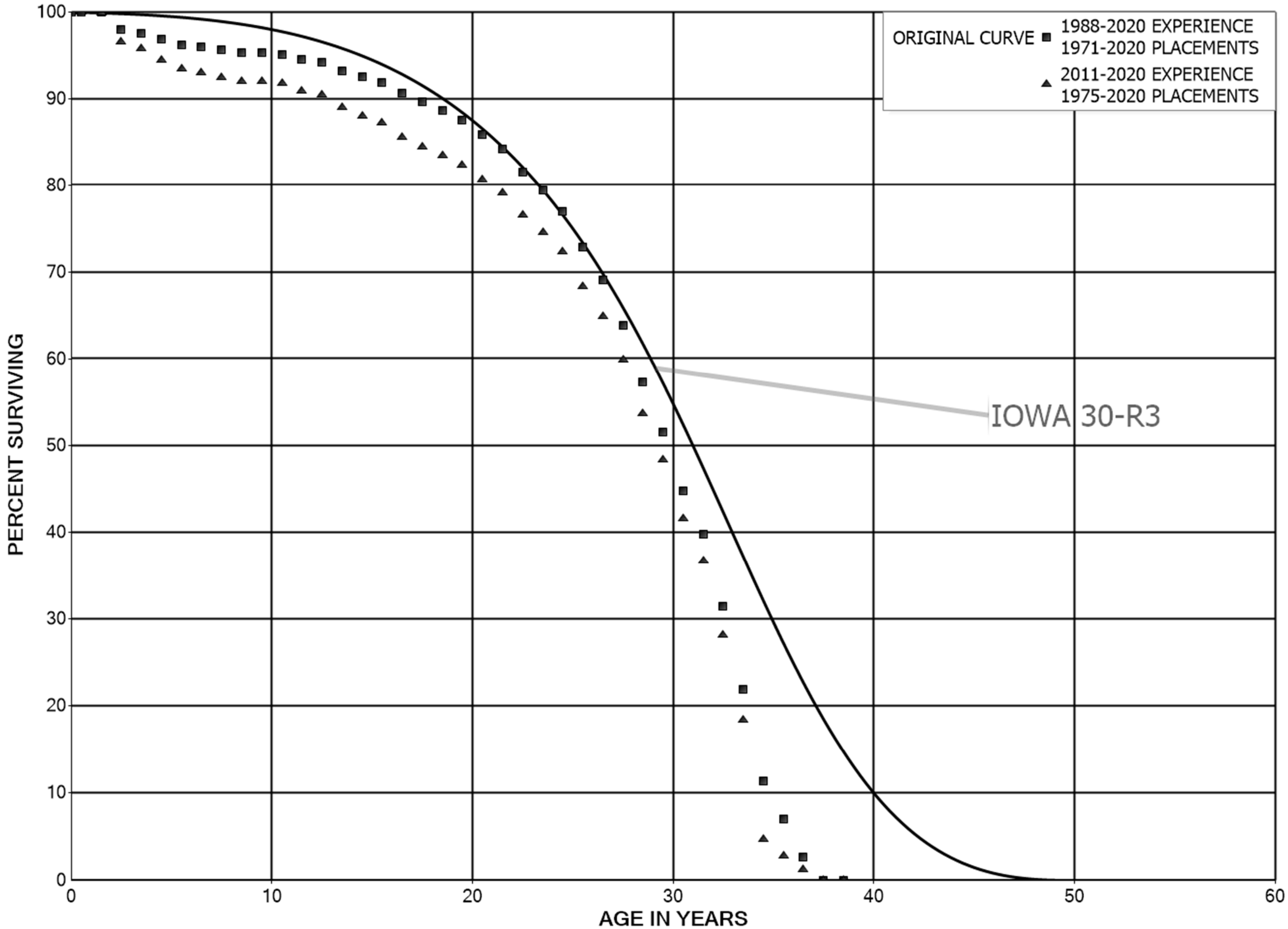
ACCOUNT 381.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1975-2020 EXPERIENCE BAND 2011-2020

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	163,594	2,417	0.0148	0.9852	19.96
40.5	161,177	1,761	0.0109	0.9891	19.67
41.5	68,875	4,363	0.0633	0.9367	19.45
42.5	779	779	1.0000		18.22
43.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 382.00 METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2020 EXPERIENCE BAND 1988-2020

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	28,537,902	117	0.0000	1.0000	100.00
0.5	26,720,358	19,128	0.0007	0.9993	100.00
1.5	24,809,192	480,440	0.0194	0.9806	99.93
2.5	22,865,309	101,832	0.0045	0.9955	97.99
3.5	20,862,443	165,972	0.0080	0.9920	97.56
4.5	19,336,737	117,131	0.0061	0.9939	96.78
5.5	17,838,390	50,077	0.0028	0.9972	96.19
6.5	16,163,807	56,921	0.0035	0.9965	95.92
7.5	14,474,357	45,595	0.0032	0.9968	95.59
8.5	12,291,386	4,688	0.0004	0.9996	95.29
9.5	12,314,176	18,484	0.0015	0.9985	95.25
10.5	11,903,014	70,132	0.0059	0.9941	95.11
11.5	11,007,340	42,634	0.0039	0.9961	94.55
12.5	9,960,103	104,019	0.0104	0.9896	94.18
13.5	9,341,672	69,655	0.0075	0.9925	93.20
14.5	8,445,808	58,159	0.0069	0.9931	92.50
15.5	7,931,827	110,023	0.0139	0.9861	91.86
16.5	7,376,797	79,661	0.0108	0.9892	90.59
17.5	6,794,743	72,999	0.0107	0.9893	89.61
18.5	6,163,837	80,619	0.0131	0.9869	88.65
19.5	5,655,667	103,515	0.0183	0.9817	87.49
20.5	5,127,077	105,411	0.0206	0.9794	85.89
21.5	4,420,786	137,026	0.0310	0.9690	84.12
22.5	3,879,861	101,054	0.0260	0.9740	81.51
23.5	3,392,348	102,321	0.0302	0.9698	79.39
24.5	2,965,289	160,596	0.0542	0.9458	77.00
25.5	2,494,768	127,853	0.0512	0.9488	72.83
26.5	2,014,386	154,645	0.0768	0.9232	69.09
27.5	1,527,645	156,294	0.1023	0.8977	63.79
28.5	1,061,540	106,392	0.1002	0.8998	57.26
29.5	706,569	93,024	0.1317	0.8683	51.52
30.5	513,692	58,023	0.1130	0.8870	44.74
31.5	304,711	63,623	0.2088	0.7912	39.69
32.5	148,388	45,362	0.3057	0.6943	31.40
33.5	63,580	30,741	0.4835	0.5165	21.80
34.5	32,839	12,649	0.3852	0.6148	11.26
35.5	20,190	12,483	0.6183	0.3817	6.92
36.5	7,708	7,692	0.9980	0.0020	2.64
37.5	16	16	1.0000		0.01
38.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

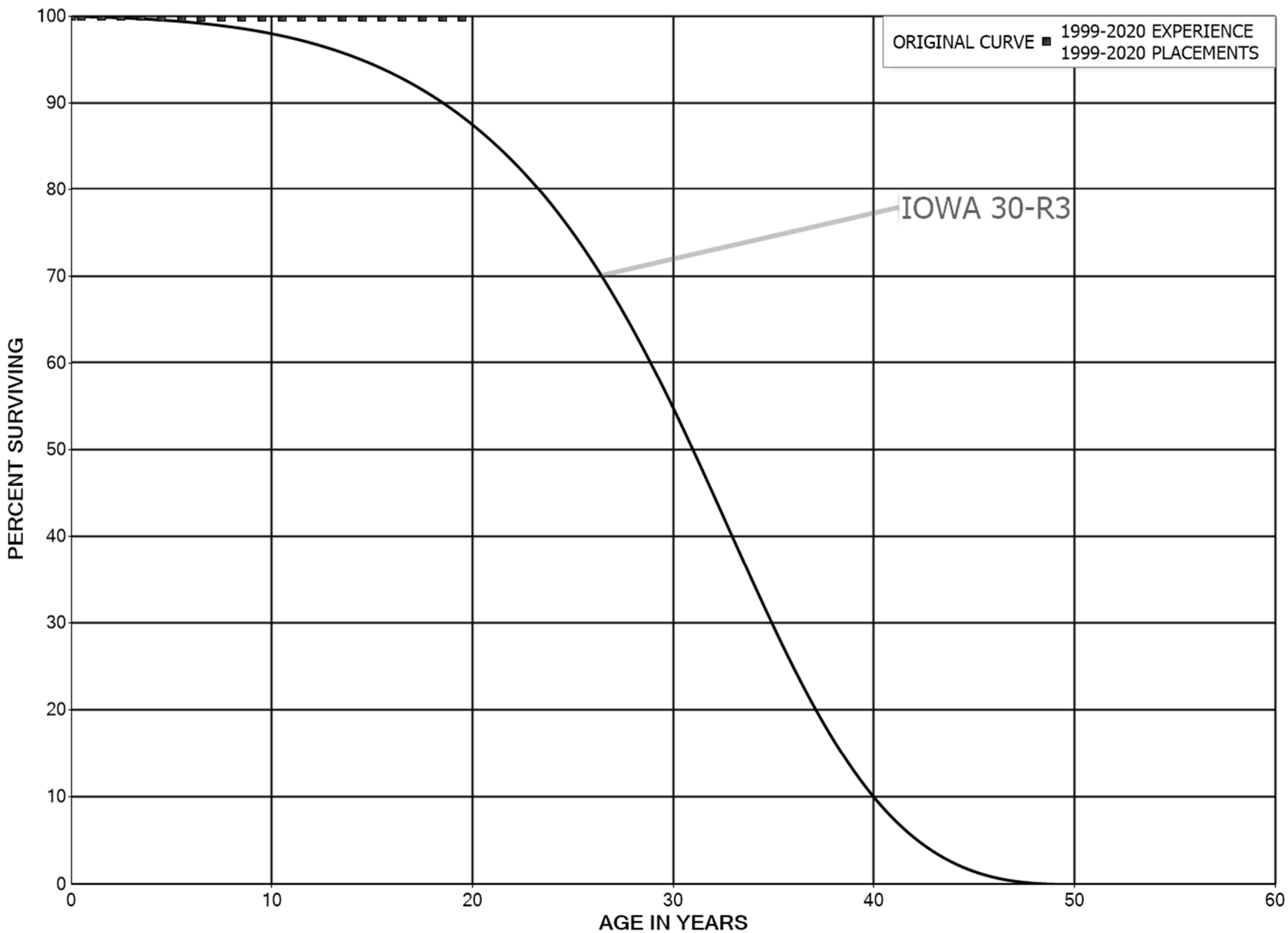
ACCOUNT 382.00 METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2020 EXPERIENCE BAND 2011-2020

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	16,761,346		0.0000	1.0000	100.00
0.5	15,243,465	18,815	0.0012	0.9988	100.00
1.5	14,148,890	479,951	0.0339	0.9661	99.88
2.5	13,180,187	101,132	0.0077	0.9923	96.49
3.5	11,769,517	165,030	0.0140	0.9860	95.75
4.5	11,107,129	115,829	0.0104	0.9896	94.41
5.5	10,095,832	48,203	0.0048	0.9952	93.42
6.5	8,895,298	54,376	0.0061	0.9939	92.98
7.5	7,724,887	42,479	0.0055	0.9945	92.41
8.5	6,104,155	331	0.0001	0.9999	91.90
9.5	6,575,324	12,620	0.0019	0.9981	91.89
10.5	6,607,791	63,259	0.0096	0.9904	91.72
11.5	6,384,162	34,835	0.0055	0.9945	90.84
12.5	5,826,381	93,648	0.0161	0.9839	90.34
13.5	5,633,435	56,578	0.0100	0.9900	88.89
14.5	5,109,518	44,771	0.0088	0.9912	88.00
15.5	4,937,944	95,160	0.0193	0.9807	87.23
16.5	4,792,215	61,512	0.0128	0.9872	85.55
17.5	4,615,015	54,929	0.0119	0.9881	84.45
18.5	4,371,540	61,300	0.0140	0.9860	83.44
19.5	4,223,270	82,609	0.0196	0.9804	82.27
20.5	4,043,193	82,516	0.0204	0.9796	80.66
21.5	3,601,692	116,088	0.0322	0.9678	79.02
22.5	3,238,894	83,431	0.0258	0.9742	76.47
23.5	2,882,564	86,275	0.0299	0.9701	74.50
24.5	2,537,763	140,272	0.0553	0.9447	72.27
25.5	2,137,357	106,546	0.0498	0.9502	68.28
26.5	1,710,681	131,545	0.0769	0.9231	64.87
27.5	1,281,479	134,606	0.1050	0.8950	59.88
28.5	877,835	87,191	0.0993	0.9007	53.59
29.5	566,456	79,256	0.1399	0.8601	48.27
30.5	404,816	47,446	0.1172	0.8828	41.52
31.5	234,498	54,602	0.2328	0.7672	36.65
32.5	99,271	34,900	0.3516	0.6484	28.12
33.5	32,884	24,580	0.7475	0.2525	18.23
34.5	19,328	7,822	0.4047	0.5953	4.60
35.5	16,451	9,347	0.5682	0.4318	2.74
36.5	7,104	7,089	0.9978	0.0022	1.18
37.5	16	16	1.0000		0.00
38.5					

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 383.00 HOUSE REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

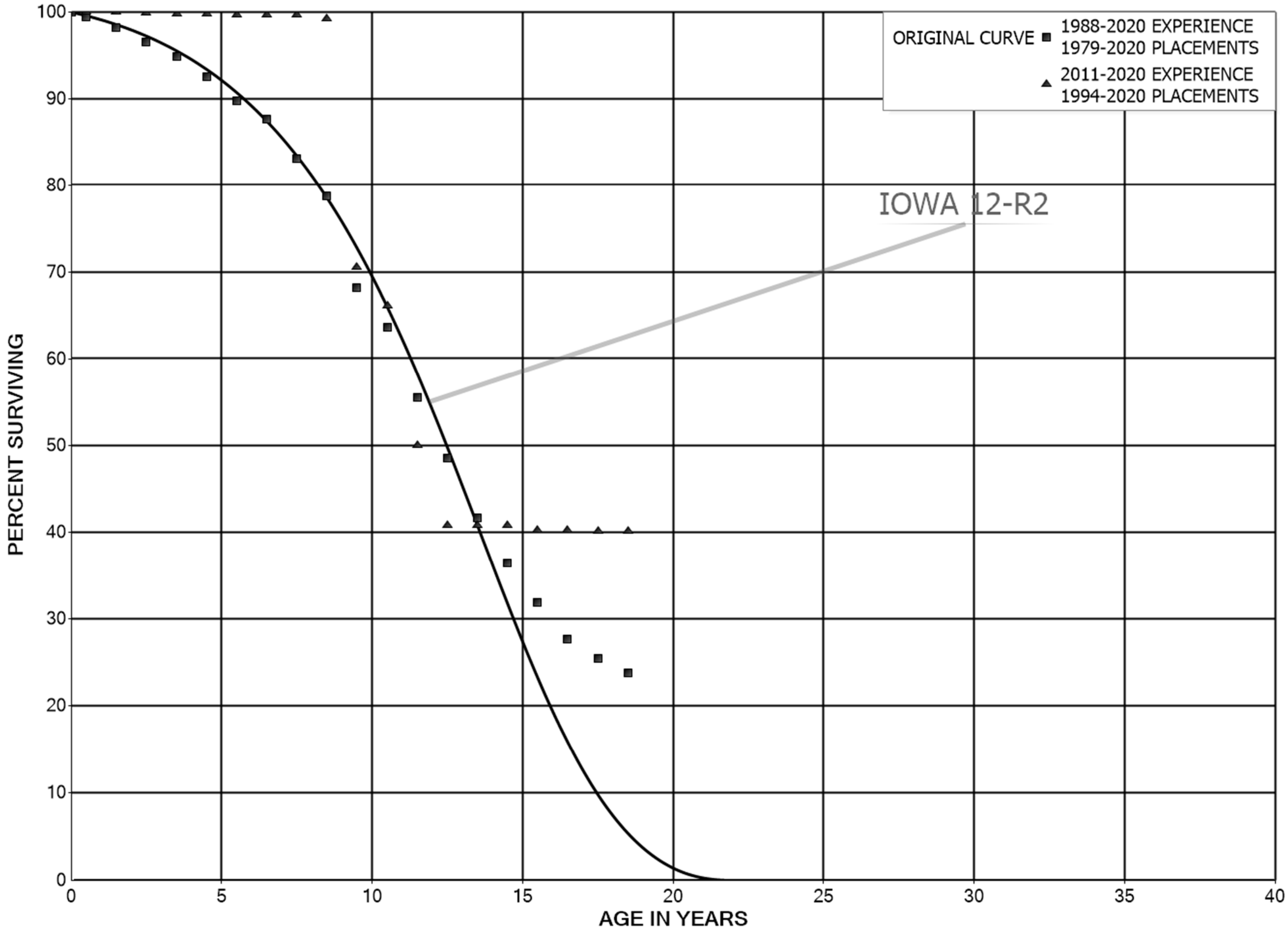
ACCOUNT 383.00 HOUSE REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1999-2020 EXPERIENCE BAND 1999-2020

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	734,380	114	0.0002	0.9998	100.00
0.5	723,305	197	0.0003	0.9997	99.98
1.5	652,271	259	0.0004	0.9996	99.96
2.5	581,394	146	0.0003	0.9997	99.92
3.5	533,756	75	0.0001	0.9999	99.89
4.5	494,226	21	0.0000	1.0000	99.88
5.5	448,714	17	0.0000	1.0000	99.87
6.5	402,339		0.0000	1.0000	99.87
7.5	389,444		0.0000	1.0000	99.87
8.5	325,257		0.0000	1.0000	99.87
9.5	315,791	2	0.0000	1.0000	99.87
10.5	222,729		0.0000	1.0000	99.87
11.5	185,193		0.0000	1.0000	99.87
12.5	185,193		0.0000	1.0000	99.87
13.5	185,193		0.0000	1.0000	99.87
14.5	185,193		0.0000	1.0000	99.87
15.5	185,193		0.0000	1.0000	99.87
16.5	145,657		0.0000	1.0000	99.87
17.5	145,114		0.0000	1.0000	99.87
18.5	144,764		0.0000	1.0000	99.87
19.5	10,520		0.0000	1.0000	99.87
20.5	6,776		0.0000	1.0000	99.87
21.5					99.87

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION
ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1979-2020 EXPERIENCE BAND 1988-2020

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	4,854,474	29,778	0.0061	0.9939	100.00
0.5	4,813,535	58,279	0.0121	0.9879	99.39
1.5	4,648,345	79,494	0.0171	0.9829	98.18
2.5	4,428,334	78,877	0.0178	0.9822	96.50
3.5	4,210,083	100,220	0.0238	0.9762	94.79
4.5	4,013,657	121,240	0.0302	0.9698	92.53
5.5	3,770,767	90,838	0.0241	0.9759	89.73
6.5	3,572,529	184,153	0.0515	0.9485	87.57
7.5	3,298,980	171,818	0.0521	0.9479	83.06
8.5	3,420,251	459,782	0.1344	0.8656	78.73
9.5	2,960,470	199,028	0.0672	0.9328	68.15
10.5	2,684,456	339,473	0.1265	0.8735	63.57
11.5	2,287,626	287,671	0.1258	0.8742	55.53
12.5	1,994,714	283,363	0.1421	0.8579	48.55
13.5	1,707,707	216,326	0.1267	0.8733	41.65
14.5	1,489,299	184,383	0.1238	0.8762	36.37
15.5	1,293,904	174,343	0.1347	0.8653	31.87
16.5	1,110,694	85,628	0.0771	0.9229	27.58
17.5	1,017,913	70,603	0.0694	0.9306	25.45
18.5	856,991	66,156	0.0772	0.9228	23.68
19.5	733,304	37,057	0.0505	0.9495	21.86
20.5	572,416	19,419	0.0339	0.9661	20.75
21.5	469,925	19,374	0.0412	0.9588	20.05
22.5	374,099	91,009	0.2433	0.7567	19.22
23.5	206,994	2,387	0.0115	0.9885	14.55
24.5	128,449	2,387	0.0186	0.9814	14.38
25.5	24,669	796	0.0323	0.9677	14.11
26.5					13.66

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1994-2020 EXPERIENCE BAND 2011-2020

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	1,097,829		0.0000	1.0000	100.00
0.5	1,090,704	885	0.0008	0.9992	100.00
1.5	1,028,612	989	0.0010	0.9990	99.92
2.5	955,501	868	0.0009	0.9991	99.82
3.5	864,313		0.0000	1.0000	99.73
4.5	838,813	686	0.0008	0.9992	99.73
5.5	782,863	549	0.0007	0.9993	99.65
6.5	751,001		0.0000	1.0000	99.58
7.5	710,345	2,824	0.0040	0.9960	99.58
8.5	654,454	189,504	0.2896	0.7104	99.18
9.5	557,198	35,084	0.0630	0.9370	70.46
10.5	602,370	146,552	0.2433	0.7567	66.03
11.5	481,533	88,781	0.1844	0.8156	49.96
12.5	463,961		0.0000	1.0000	40.75
13.5	536,415		0.0000	1.0000	40.75
14.5	619,990	9,499	0.0153	0.9847	40.75
15.5	700,872		0.0000	1.0000	40.13
16.5	735,772	796	0.0011	0.9989	40.13
17.5	727,823		0.0000	1.0000	40.08
18.5	637,504	1,592	0.0025	0.9975	40.08
19.5	578,382	2,387	0.0041	0.9959	39.98
20.5	452,163	2,387	0.0053	0.9947	39.82
21.5	366,704		0.0000	1.0000	39.61
22.5	290,253	7,162	0.0247	0.9753	39.61
23.5	206,994	2,387	0.0115	0.9885	38.63
24.5	128,449	2,387	0.0186	0.9814	38.19
25.5	24,669	796	0.0323	0.9677	37.48
26.5					36.27

PART VIII. NET SALVAGE STATISTICS

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 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
2010	187,432	13,323	7		0	13,323-	7-
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018	11,925	3,265	27		0	3,265-	27-
2019	126,350	45,486	36		0	45,486-	36-
2020	1,906	144,400			0	144,400-	
TOTAL	327,613	206,474	63		0	206,474-	63-
THREE-YEAR MOVING AVERAGES							
10-12	62,477	4,441	7		0	4,441-	7-
11-13							
12-14							
13-15							
14-16							
15-17							
16-18	3,975	1,088	27		0	1,088-	27-
17-19	46,092	16,250	35		0	16,250-	35-
18-20	46,727	64,384	138		0	64,384-	138-
FIVE-YEAR AVERAGE							
16-20	28,036	38,630	138		0	38,630-	138-

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.00 MAINS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009	8,862		0		0		0
2010	168,710	1,904	1		0	1,904-	1-
2011	436,388	331,675	76		0	331,675-	76-
2012	233,872	459,779	197	1,011	0	458,768-	196-
2013	195,118	711,056	364		0	711,056-	364-
2014	469,517	797,618	170	111	0	797,507-	170-
2015	173,621	820,632	473		0	820,632-	473-
2016	452,769	787,947	174		0	787,947-	174-
2017	94,402	570,072	604		0	570,072-	604-
2018	502,649	737,809	147		0	737,809-	147-
2019	20,196	1,786,133			0	1,786,133-	
2020	678,915	317,483	47		0	317,483-	47-
TOTAL	3,435,019	7,322,107	213	1,122	0	7,320,985-	213-
THREE-YEAR MOVING AVERAGES							
09-11	204,653	111,193	54		0	111,193-	54-
10-12	279,657	264,453	95	337	0	264,116-	94-
11-13	288,459	500,837	174	337	0	500,500-	174-
12-14	299,502	656,151	219	374	0	655,777-	219-
13-15	279,419	776,435	278	37	0	776,398-	278-
14-16	365,302	802,066	220	37	0	802,029-	220-
15-17	240,264	726,217	302		0	726,217-	302-
16-18	349,940	698,609	200		0	698,609-	200-
17-19	205,749	1,031,338	501		0	1,031,338-	501-
18-20	400,587	947,141	236		0	947,141-	236-
FIVE-YEAR AVERAGE							
16-20	349,786	839,889	240		0	839,889-	240-

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2011	115,652		0		0		0
2012	215,717	1,694	1		0	1,694-	1-
2013	259,722	18,985	7		0	18,985-	7-
2014		5,119				5,119-	
2015							
2016	263	1,203	457		0	1,203-	457-
2017	4,718	11,593	246		0	11,593-	246-
2018	24,499	7,756	32		0	7,756-	32-
2019	19,181	17,271	90		0	17,271-	90-
2020	279,719	272,577	97		0	272,577-	97-
TOTAL	919,470	336,198	37		0	336,198-	37-
THREE-YEAR MOVING AVERAGES							
11-13	197,030	6,893	3		0	6,893-	3-
12-14	158,480	8,599	5		0	8,599-	5-
13-15	86,574	8,035	9		0	8,035-	9-
14-16	88	2,107			0	2,107-	
15-17	1,660	4,265	257		0	4,265-	257-
16-18	9,826	6,851	70		0	6,851-	70-
17-19	16,132	12,207	76		0	12,207-	76-
18-20	107,800	99,202	92		0	99,202-	92-
FIVE-YEAR AVERAGE							
16-20	65,676	62,080	95		0	62,080-	95-

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009	2,921		0		0		0
2010	119,477	63,633	53		0	63,633-	53-
2011	392,584	116,573	30		0	116,573-	30-
2012	231,687	105,051	45		0	105,051-	45-
2013	178,958	139,735	78		0	139,735-	78-
2014	405,385	175,948	43		0	175,948-	43-
2015	316,598	195,246	62		0	195,246-	62-
2016	260,540	272,591	105		0	272,591-	105-
2017	181,892	224,274	123		0	224,274-	123-
2018	205,263	422,442	206		0	422,442-	206-
2019	138,125	340,691	247		0	340,691-	247-
2020	87,804	227,967	260		0	227,967-	260-
TOTAL	2,521,234	2,284,150	91		0	2,284,150-	91-
THREE-YEAR MOVING AVERAGES							
09-11	171,661	60,069	35		0	60,069-	35-
10-12	247,916	95,086	38		0	95,086-	38-
11-13	267,743	120,453	45		0	120,453-	45-
12-14	272,010	140,245	52		0	140,245-	52-
13-15	300,314	170,310	57		0	170,310-	57-
14-16	327,508	214,595	66		0	214,595-	66-
15-17	253,010	230,704	91		0	230,704-	91-
16-18	215,899	306,436	142		0	306,436-	142-
17-19	175,094	329,135	188		0	329,135-	188-
18-20	143,731	330,366	230		0	330,366-	230-
FIVE-YEAR AVERAGE							
16-20	174,725	297,593	170		0	297,593-	170-

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 381.00 METERS

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
2010	2,275		0		0		0
2011	6,376		0		0		0
2012	97,752	7,899	8		0	7,899-	8-
2013	190,297	4,721	2		0	4,721-	2-
2014	33,156	13,212	40		0	13,212-	40-
2015	137,414	5,657	4		0	5,657-	4-
2016	82,010	7,039	9		0	7,039-	9-
2017	31,148	44,327	142		0	44,327-	142-
2018	140,731	46,969	33		0	46,969-	33-
2019	175,177	66,850	38		0	66,850-	38-
2020	241,099	52,894	22		0	52,894-	22-
TOTAL	1,137,435	249,569	22		0	249,569-	22-
THREE-YEAR MOVING AVERAGES							
10-12	35,468	2,633	7		0	2,633-	7-
11-13	98,142	4,207	4		0	4,207-	4-
12-14	107,068	8,611	8		0	8,611-	8-
13-15	120,289	7,863	7		0	7,863-	7-
14-16	84,193	8,636	10		0	8,636-	10-
15-17	83,524	19,008	23		0	19,008-	23-
16-18	84,630	32,779	39		0	32,779-	39-
17-19	115,685	52,716	46		0	52,716-	46-
18-20	185,669	55,571	30		0	55,571-	30-
FIVE-YEAR AVERAGE							
16-20	134,033	43,616	33		0	43,616-	33-

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 382.00 METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2011		430				430-	
2012	127,025	22,286	18		0	22,286-	18-
2013	215,708	5,120	2		0	5,120-	2-
2014	56,912	22,679	40		0	22,679-	40-
2015	413,684	16,737	4		0	16,737-	4-
2016	261,495	26,215	10		0	26,215-	10-
2017	101,056	62,422	62		0	62,422-	62-
2018	274,007	52,452	19		0	52,452-	19-
2019	362,822	48,890	13		0	48,890-	13-
2020	1,108,186	94,033	8		0	94,033-	8-
TOTAL	2,920,895	351,263	12		0	351,263-	12-
THREE-YEAR MOVING AVERAGES							
11-13	114,244	9,279	8		0	9,279-	8-
12-14	133,215	16,695	13		0	16,695-	13-
13-15	228,768	14,845	6		0	14,845-	6-
14-16	244,030	21,877	9		0	21,877-	9-
15-17	258,745	35,125	14		0	35,125-	14-
16-18	212,186	47,030	22		0	47,030-	22-
17-19	245,962	54,588	22		0	54,588-	22-
18-20	581,672	65,125	11		0	65,125-	11-
FIVE-YEAR AVERAGE							
16-20	421,513	56,802	13		0	56,802-	13-

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2009	890		0	75	8	75	8
2010	97,275	1,665	2	2,010	2	345	0
2011	63,705		0	4,462	7	4,462	7
2012	63,105	220	0		0	220-	0
2013	61,468	6,514	11	887	1	5,627-	9-
2014	52,401	7,166	14	3,472	7	3,694-	7-
2015	54,265	5,662	10	4,026	7	1,636-	3-
2016		5,489		7,069		1,580	
2017	7,162	3,111	43	3,859	54	749	10
2018	78,400	5,337	7		0	5,337-	7-
2019	26,702	18,487	69	2,025	8	16,462-	62-
2020	88,909	13,917	16	11,358	13	2,559-	3-
TOTAL	594,281	67,567	11	39,244	7	28,323-	5-
THREE-YEAR MOVING AVERAGES							
09-11	53,957	555	1	2,182	4	1,627	3
10-12	74,695	628	1	2,157	3	1,529	2
11-13	62,759	2,245	4	1,783	3	462-	1-
12-14	58,991	4,633	8	1,453	2	3,180-	5-
13-15	56,045	6,447	12	2,795	5	3,652-	7-
14-16	35,555	6,106	17	4,856	14	1,250-	4-
15-17	20,476	4,754	23	4,985	24	231	1
16-18	28,521	4,646	16	3,643	13	1,003-	4-
17-19	37,421	8,978	24	1,962	5	7,017-	19-
18-20	64,670	12,580	19	4,461	7	8,119-	13-
FIVE-YEAR AVERAGE							
16-20	40,234	9,268	23	4,862	12	4,406-	11-

PART IX. DETAILED DEPRECIATION CALCULATIONS

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 375.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 55-R2.5
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)
1939	646.07	644	297	414	5.15	80
1956	2,331.59	2,123	980	1,585	9.47	167
1957	2,578.95	2,331	1,076	1,761	9.80	180
1974	400.00	299	138	302	17.60	17
1978	867.27	606	280	674	20.06	34
1988	1,752,000.57	981,119	452,977	1,474,224	27.00	54,601
1989	39,541.29	21,550	9,950	33,545	27.75	1,209
1990	38,588.71	20,452	9,443	33,005	28.50	1,158
1992	7,064.07	3,525	1,627	6,143	30.05	204
1993	64,704.70	31,278	14,441	56,734	30.83	1,840
1996	28,033.76	12,206	5,635	25,202	33.23	758
1997	10,179.76	4,265	1,969	9,229	34.05	271
1998	2,908.58	1,171	541	2,658	34.87	76
2001	2,160.50	761	351	2,026	37.38	54
2002	15,061.71	5,052	2,332	14,236	38.23	372
2004	7,130.00	2,145	990	6,853	39.96	171
2006	36,525.99	9,709	4,483	35,696	41.71	856
2007	80,891.87	20,078	9,270	79,711	42.59	1,872
2009	577,192.39	122,595	56,602	578,310	44.38	13,031
2010	89,167.96	17,335	8,003	90,082	45.28	1,989
2011	10,280.34	1,813	837	10,471	46.18	227
2012	25,341.82	4,009	1,851	26,025	47.09	553
2013	12,190.39	1,704	787	12,622	48.01	263
2014	21,414.74	2,600	1,200	22,356	48.93	457
2015	14,075.31	1,450	669	14,814	49.85	297
2016	18,049.54	1,523	703	19,151	50.78	377
2017	9,519.74	626	289	10,183	51.71	197
2018	385,894.39	18,138	8,375	416,109	52.65	7,903
2019	4,495.25	128	59	4,886	53.58	91
2020	1,634.00	15	7	1,790	54.53	33
	3,260,871.26	1,291,250	596,162	2,990,796		89,338

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.5 2.74

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.20 MAINS - COATED AND WRAPPED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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.. -60						
1966	132,086.54	159,964	57,811	153,527	13.37	11,483
1967	77,501.16	92,776	33,530	90,472	13.85	6,532
1968	77,653.61	91,851	33,195	91,051	14.34	6,349
1969	40,257.03	47,020	16,993	47,418	14.85	3,193
1970	101,164.72	116,631	42,151	119,713	15.37	7,789
1971	26,232.63	29,838	10,784	31,188	15.90	1,962
1972	83,667.64	93,805	33,901	99,967	16.46	6,073
1973	109,592.89	121,087	43,761	131,588	17.02	7,731
1974	103,748.29	112,878	40,794	125,203	17.60	7,114
1975	76,807.42	82,226	29,717	93,175	18.20	5,120
1976	109,214.74	115,013	41,566	133,178	18.80	7,084
1977	37,152.34	38,455	13,898	45,546	19.42	2,345
1978	160,548.94	163,187	58,976	197,902	20.06	9,866
1979	409,275.74	408,385	147,592	507,249	20.70	24,505
1980	43,068.59	42,148	15,232	53,678	21.36	2,513
1981	80,380.79	77,095	27,862	100,747	22.03	4,573
1982	151,252.52	142,078	51,347	190,657	22.71	8,395
1983	51,857.84	47,672	17,229	65,744	23.40	2,810
1984	242,047.42	217,579	78,634	308,642	24.10	12,807
1985	486,633.21	427,389	154,460	624,153	24.81	25,157
1986	250,066.60	214,385	77,479	322,628	25.53	12,637
1987	132,202.41	110,532	39,947	171,577	26.26	6,534
1988	180,829.00	147,293	53,232	236,094	27.00	8,744
1989	335,583.03	266,023	96,142	440,791	27.75	15,884
1990	861,440.61	664,095	240,006	1,138,299	28.50	39,940
1991	1,040,463.64	778,800	281,461	1,383,281	29.27	47,259
1992	194,698.61	141,317	51,072	260,446	30.05	8,667
1993	95,253.88	66,975	24,205	128,201	30.83	4,158
1994	78,711.86	53,535	19,348	106,591	31.62	3,371
1995	1,956,738.22	1,285,342	464,527	2,666,254	32.42	82,241
1996	2,743,363.66	1,737,405	627,903	3,761,479	33.23	113,195
1997	1,122,566.68	684,155	247,256	1,548,851	34.05	45,488
1998	237,851.01	139,286	50,338	330,224	34.87	9,470
1999	269,017.19	151,041	54,587	375,841	35.70	10,528
2000	426,366.89	228,969	82,750	599,437	36.54	16,405
2001	216,541.16	110,994	40,114	306,352	37.38	8,196
2002	795,988.45	388,328	140,343	1,133,239	38.23	29,643
2003	180,173.75	83,390	30,137	258,141	39.09	6,604
2004	126,576.67	55,380	20,015	182,508	39.96	4,567
2005	64,723.58	26,681	9,643	93,915	40.83	2,300
2006	610,096.03	235,878	85,247	890,907	41.71	21,360

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.20 MAINS - COATED AND WRAPPED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 55-R2.5
NET SALVAGE PERCENT.. -60

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2007	282,906.41	102,136	36,912	415,738	42.59	9,761
2008	840,635.19	281,714	101,812	1,243,204	43.48	28,593
2009	140,254.84	43,331	15,660	208,748	44.38	4,704
2010	6,923.14	1,958	708	10,369	45.28	229
2011	138,416.44	35,514	12,835	208,631	46.18	4,518
2012	157,802.55	36,312	13,123	239,361	47.09	5,083
2013	308,648.66	62,762	22,682	471,156	48.01	9,814
2014	911,382.58	160,928	58,160	1,400,052	48.93	28,613
2015	291,358.68	43,653	15,776	450,398	49.85	9,035
2016	12,588.06	1,545	558	19,583	50.78	386
2017	1,248,891.66	119,534	43,200	1,955,027	51.71	37,808
2018	5,888,360.91	402,575	145,492	9,275,885	52.65	176,180
2019	4,741,285.11	195,872	70,789	7,515,267	53.58	140,263
2020	257,375.80	3,521	1,272	410,529	54.53	7,528
	29,746,227.02	11,688,236	4,224,164	43,369,799		1,123,107

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.6 3.78

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.40 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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.. -60						
1974	1,923.80	2,093	2,180	898	17.60	51
1975	17,542.19	18,780	19,557	8,511	18.20	468
1976	26,751.89	28,172	29,337	13,466	18.80	716
1977	42,510.76	44,001	45,821	22,196	19.42	1,143
1978	20,711.52	21,052	21,923	11,215	20.06	559
1979	127,838.75	127,561	132,837	71,705	20.70	3,464
1980	134,610.93	131,733	137,181	78,196	21.36	3,661
1981	214,067.70	205,317	213,809	128,699	22.03	5,842
1982	73,398.62	68,947	71,799	45,639	22.71	2,010
1983	92,518.10	85,050	88,568	59,461	23.40	2,541
1984	175,948.18	158,162	164,703	116,814	24.10	4,847
1985	476,009.18	418,058	435,349	326,266	24.81	13,151
1986	463,087.86	397,011	413,431	327,510	25.53	12,828
1987	974,479.27	814,743	848,440	710,727	26.26	27,065
1988	1,114,495.11	907,805	945,351	837,841	27.00	31,031
1989	954,857.85	756,935	788,241	739,532	27.75	26,650
1990	1,848,760.33	1,425,232	1,484,178	1,473,839	28.50	51,714
1991	2,880,906.15	2,156,393	2,245,580	2,363,870	29.27	80,761
1992	2,265,458.28	1,644,324	1,712,332	1,912,401	30.05	63,641
1993	1,664,427.28	1,170,292	1,218,694	1,444,390	30.83	46,850
1994	2,470,065.71	1,680,000	1,749,483	2,202,622	31.62	69,659
1995	1,618,511.66	1,063,168	1,107,140	1,482,479	32.42	45,727
1996	1,218,190.16	771,494	803,402	1,145,702	33.23	34,478
1997	1,508,570.63	919,407	957,433	1,456,280	34.05	42,769
1998	1,367,302.44	800,692	833,808	1,353,876	34.87	38,826
1999	1,944,059.53	1,091,504	1,136,648	1,973,847	35.70	55,290
2000	1,456,590.21	782,224	814,576	1,515,968	36.54	41,488
2001	1,542,582.52	790,691	823,393	1,644,739	37.38	44,001
2002	733,853.60	358,015	372,822	801,344	38.23	20,961
2003	1,263,749.01	584,903	609,094	1,412,904	39.09	36,145
2004	1,963,975.90	859,279	894,818	2,247,543	39.96	56,245
2005	1,908,213.42	786,611	819,145	2,233,996	40.83	54,715
2006	3,504,074.28	1,354,759	1,410,791	4,195,728	41.71	100,593
2007	2,346,871.25	847,277	882,320	2,872,674	42.59	67,449
2008	1,894,351.61	634,835	661,091	2,369,872	43.48	54,505
2009	3,938,400.56	1,216,745	1,267,069	5,034,372	44.38	113,438
2010	3,969,937.28	1,122,571	1,169,000	5,182,900	45.28	114,463
2011	2,592,770.40	665,243	692,757	3,455,676	46.18	74,831
2012	4,256,983.95	979,583	1,020,098	5,791,076	47.09	122,979
2013	6,206,518.21	1,262,058	1,314,256	8,616,173	48.01	179,466
2014	8,278,802.88	1,461,838	1,522,298	11,723,787	48.93	239,603

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.40 MAINS - PLASTIC

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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.. -60						
2015	9,464,162.94	1,417,959	1,476,605	13,666,056	49.85	274,144
2016	8,101,261.09	994,576	1,035,711	11,926,307	50.78	234,862
2017	12,985,516.38	1,242,870	1,294,274	19,482,552	51.71	376,766
2018	3,232,484.22	220,998	230,138	4,941,837	52.65	93,862
2019	7,755,557.09	320,398	333,649	12,075,242	53.58	225,368
2020	9,248,523.42	126,520	131,753	14,665,884	54.53	268,951
	120,342,184.10	34,937,879	36,382,883	156,164,612		3,460,577

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 2.88

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 376.60 MAINS - CATHODIC PROTECTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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 30-S5						
NET SALVAGE PERCENT.. -60						
1983	1,205.82	1,854	1,929			
1991	1,069.53	1,538	1,711			
1992	16,566.40	23,440	26,133	373	3.47	107
1993	16,611.90	23,062	25,711	868	3.97	219
1994	16,227.44	22,026	24,556	1,408	4.55	309
1995	23,991.12	31,719	35,363	3,023	5.21	580
1996	10,252.03	13,150	14,661	1,742	5.95	293
1997	11,779.22	14,594	16,271	2,576	6.77	381
1998	66,903.24	79,784	88,950	18,095	7.64	2,368
1999	29,488.21	33,703	37,575	9,606	8.57	1,121
2000	5,383.56	5,877	6,552	2,062	9.53	216
2001	2,582.15	2,684	2,992	1,139	10.51	108
2002	10,631.12	10,489	11,694	5,316	11.50	462
2003	30,482.95	28,451	31,720	17,053	12.50	1,364
2004	31,744.74	27,935	31,144	19,648	13.50	1,455
2005	46,037.88	38,058	42,430	31,231	14.50	2,154
2006	40,750.36	31,513	35,134	30,067	15.50	1,940
2007	85,499.21	61,559	68,631	68,168	16.50	4,131
2008	42,647.16	28,432	31,699	36,536	17.50	2,088
2009	29,399.79	18,032	20,104	26,936	18.50	1,456
2010	7,701.89	4,313	4,809	7,514	19.50	385
2011	15,213.21	7,708	8,594	15,747	20.50	768
2012	1,673.26	759	846	1,831	21.50	85
2014	55,310.10	19,174	21,377	67,119	23.50	2,856
2015	84,134.66	24,679	27,514	107,101	24.50	4,371
2016	116,508.17	27,962	31,174	155,239	25.50	6,088
2017	28,105.13	5,246	5,849	39,119	26.50	1,476
2018	106,274.68	14,169	15,797	154,242	27.50	5,609
2019	123,169.30	9,854	10,985	186,086	28.50	6,529
2020	25,395.22	677	755	39,877	29.50	1,352
	1,082,739.45	612,441	682,660	1,049,723		50,271

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.9 4.64

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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 30-R2						
NET SALVAGE PERCENT.. -20						
1956	2,092.93	2,512	2,512			
1970	3,806.03	4,359	1,896	2,671	1.37	1,950
1971	1,106.53	1,254	546	782	1.66	471
1973	2,969.09	3,298	1,435	2,128	2.23	954
1974	9,065.61	9,965	4,335	6,544	2.52	2,597
1978	11,140.22	11,728	5,102	8,266	3.68	2,246
1979	9,924.70	10,330	4,494	7,416	3.98	1,863
1980	5,454.31	5,609	2,440	4,105	4.29	957
1982	4,601.48	4,616	2,008	3,514	4.92	714
1986	26,442.33	25,004	10,878	20,853	6.36	3,279
1988	1,997.49	1,824	794	1,603	7.17	224
1989	9,563.82	8,565	3,726	7,751	7.61	1,019
1990	88,269.71	77,465	33,700	72,224	8.06	8,961
1991	47,282.57	40,587	17,657	39,082	8.54	4,576
1992	28,429.95	23,847	10,374	23,742	9.03	2,629
1993	12,026.64	9,838	4,280	10,152	9.55	1,063
1994	81,580.09	64,971	28,264	69,632	10.09	6,901
1996	41,176.92	30,948	13,463	35,949	11.21	3,207
1997	60,161.57	43,773	19,043	53,151	11.81	4,501
1998	57,495.52	40,431	17,589	51,406	12.42	4,139
1999	157,788.96	106,981	46,540	142,807	13.05	10,943
2000	146,597.27	95,641	41,607	134,310	13.69	9,811
2001	41,583.39	26,014	11,317	38,583	14.36	2,687
2002	15,958.64	9,550	4,155	14,995	15.04	997
2003	90,272.94	51,528	22,416	85,912	15.73	5,462
2004	74,106.34	40,195	17,486	71,442	16.44	4,346
2005	20,252.89	10,394	4,522	19,781	17.17	1,152
2006	99,500.37	48,118	20,933	98,467	17.91	5,498
2007	24,735.98	11,220	4,881	24,802	18.66	1,329
2010	125,530.07	45,191	19,660	130,976	21.00	6,237
2012	510,303.63	150,440	65,446	546,918	22.63	24,168
2013	375,408.77	98,207	42,723	407,768	23.46	17,381
2014	60,163.02	13,717	5,967	66,229	24.30	2,725
2015	752,225.70	145,935	63,487	839,184	25.15	33,367
2016	210,046.65	33,523	14,584	237,472	26.01	9,130
2017	446,176.51	55,683	24,224	511,188	26.88	19,017

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 378.20 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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 30-R2						
NET SALVAGE PERCENT.. -20						
2018	411,279.24	36,852	16,032	477,503	27.76	17,201
2019	2,346,661.58	126,720	55,127	2,760,867	28.65	96,365
2020	915,068.68	16,471	7,165	1,090,917	29.55	36,918
	7,328,248.14	1,543,304	672,808	8,121,090		356,985

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.7   4.87

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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-R2.5						
NET SALVAGE PERCENT.. -90						
1946	20.90	38	33	7	2.40	3
1947	91.42	163	143	31	2.67	12
1953	292.26	506	444	111	4.03	28
1954	671.82	1,156	1,014	262	4.25	62
1958	699.02	1,176	1,031	297	5.16	58
1959	903.62	1,511	1,325	392	5.39	73
1960	726.94	1,208	1,059	322	5.63	57
1961	3,680.94	6,080	5,332	1,662	5.88	283
1962	6,355.74	10,431	9,148	2,928	6.13	478
1963	6,783.16	11,058	9,698	3,190	6.39	499
1964	12,503.13	20,240	17,751	6,005	6.66	902
1965	8,983.81	14,441	12,665	4,404	6.93	635
1966	9,709.91	15,489	13,584	4,865	7.22	674
1967	13,889.13	21,979	19,276	7,113	7.52	946
1968	10,340.61	16,224	14,229	5,418	7.84	691
1969	4,166.81	6,480	5,683	2,234	8.17	273
1970	5,992.62	9,230	8,095	3,291	8.52	386
1971	19,367.11	29,536	25,903	10,895	8.88	1,227
1972	30,227.00	45,613	40,003	17,428	9.26	1,882
1973	31,166.50	46,491	40,773	18,443	9.67	1,907
1974	53,623.05	79,039	69,318	32,566	10.09	3,228
1975	30,966.35	45,068	39,525	19,311	10.53	1,834
1976	40,208.07	57,755	50,652	25,743	10.98	2,345
1977	52,330.67	74,107	64,993	34,435	11.46	3,005
1978	55,881.43	77,956	68,368	37,807	11.96	3,161
1979	275,526.95	378,319	331,791	191,710	12.48	15,361
1980	113,580.32	153,412	134,544	81,259	13.01	6,246
1981	157,336.43	208,791	183,112	115,827	13.57	8,536
1982	141,597.39	184,499	161,808	107,227	14.14	7,583
1983	118,428.13	151,360	132,745	92,268	14.73	6,264
1984	157,305.16	197,060	172,824	126,056	15.33	8,223
1985	289,551.20	355,153	311,474	238,673	15.95	14,964
1986	362,892.18	435,299	381,763	307,732	16.59	18,549
1987	527,771.01	618,596	542,517	460,248	17.24	26,697
1988	642,330.27	734,966	644,575	575,853	17.90	32,171
1989	722,229.72	805,654	706,569	665,667	18.58	35,827
1990	1,174,749.88	1,276,227	1,119,268	1,112,757	19.27	57,746
1991	1,200,969.31	1,269,206	1,113,110	1,168,732	19.97	58,524
1992	919,697.30	943,994	827,895	919,530	20.69	44,443
1993	716,799.89	713,646	625,877	736,043	21.42	34,362
1994	1,505,265.27	1,451,624	1,273,093	1,586,911	22.16	71,612

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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-R2.5						
NET SALVAGE PERCENT.. -90						
1995	818,903.31	763,784	669,849	886,067	22.91	38,676
1996	992,732.01	894,054	784,097	1,102,094	23.67	46,561
1997	1,059,598.24	919,828	806,701	1,206,536	24.44	49,367
1998	990,461.53	827,198	725,464	1,156,413	25.22	45,853
1999	876,104.74	702,095	615,747	1,048,852	26.02	40,309
2000	878,108.74	674,036	591,138	1,077,269	26.82	40,167
2001	674,162.26	494,431	433,622	847,286	27.63	30,665
2002	1,078,684.12	753,765	661,062	1,388,438	28.45	48,803
2003	819,174.43	543,708	476,839	1,079,592	29.28	36,871
2004	973,643.34	611,714	536,481	1,313,441	30.12	43,607
2005	812,057.28	481,048	421,885	1,121,024	30.97	36,197
2006	1,606,379.42	893,264	783,404	2,268,717	31.83	71,276
2007	1,020,947.03	530,652	465,389	1,474,410	32.69	45,103
2008	1,493,382.34	720,706	632,069	2,205,357	33.57	65,694
2009	1,843,043.82	820,958	719,991	2,781,792	34.45	80,749
2010	2,671,965.32	1,090,939	956,768	4,119,966	35.33	116,614
2011	2,659,771.39	984,889	863,761	4,189,805	36.23	115,645
2012	4,923,906.11	1,636,170	1,434,943	7,920,479	37.13	213,318
2013	6,392,849.94	1,881,358	1,649,975	10,496,440	38.03	276,004
2014	5,276,911.46	1,347,913	1,182,137	8,843,995	38.95	227,060
2015	6,740,284.28	1,462,763	1,282,862	11,523,678	39.86	289,104
2016	5,656,703.12	1,005,558	881,888	9,865,848	40.79	241,869
2017	7,132,601.96	990,783	868,930	12,683,014	41.71	304,076
2018	6,134,925.45	608,695	533,833	11,122,525	42.65	260,786
2019	4,185,709.11	249,163	218,520	7,734,327	43.59	177,434
2020	5,698,423.53	113,034	99,132	10,727,873	44.53	240,913
	82,837,046.71	32,473,287	28,479,497	128,910,892		3,654,478

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.3 4.41

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Exhibit NWA-3
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NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 30-R2
NET SALVAGE PERCENT.. -15

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1978	63,732.62	64,302	42,480	30,813	3.68	8,373
1979	90,540.78	90,308	59,660	44,462	3.98	11,171
1981	139,244.85	135,579	89,568	70,564	4.60	15,340
1982	16,742.55	16,096	10,634	8,620	4.92	1,752
1983	39,269.77	37,242	24,603	20,557	5.26	3,908
1984	6,469.46	6,049	3,996	3,444	5.61	614
1985	67,574.85	62,247	41,122	36,589	5.97	6,129
1986	14,907.32	13,509	8,924	8,219	6.36	1,292
1987	56,576.00	50,423	33,311	31,751	6.75	4,704
1988	31,887.54	27,906	18,436	18,235	7.17	2,543
1989	68,305.23	58,625	38,730	39,821	7.61	5,233
1990	174,633.10	146,872	97,029	103,799	8.06	12,878
1991	161,862.22	133,153	87,965	98,177	8.54	11,496
1992	10,562.06	8,490	5,609	6,537	9.03	724
1994	109,047.73	83,227	54,982	70,423	10.09	6,979
1995	70,406.64	52,251	34,519	46,449	10.64	4,366
1997	105,838.72	73,799	48,754	72,961	11.81	6,178
1999	50,734.28	32,965	21,778	36,566	13.05	2,802
2002	6,504.34	3,730	2,464	5,016	15.04	334
2003	22,851.10	12,500	8,258	18,021	15.73	1,146
2004	39,553.68	20,560	13,583	31,904	16.44	1,941
2005	186,736.65	91,841	60,673	154,074	17.17	8,973
2006	16,812.96	7,792	5,148	14,187	17.91	792
2007	155,845.21	67,746	44,755	134,467	18.66	7,206
2008	78,337.17	31,741	20,969	69,119	19.43	3,557
2009	274,298.32	102,939	68,005	247,438	20.21	12,243
2010	215,511.82	74,352	49,119	198,720	21.00	9,463
2012	327,050.70	92,399	61,042	315,066	22.63	13,922
2013	279,446.75	70,057	46,282	275,082	23.46	11,726
2014	420,634.17	91,909	60,718	423,011	24.30	17,408
2016	96,428.24	14,749	9,744	101,148	26.01	3,889
2017	361,829.90	43,275	28,589	387,515	26.88	14,416
2018	94,028.64	8,074	5,334	102,799	27.76	3,703
2019	484,857.36	25,091	16,576	541,010	28.65	18,883
2020	285,547.51	4,926	3,254	325,126	29.55	11,003
	4,624,610.24	1,856,724	1,226,613	4,091,689		247,087

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.6 5.34

Docket No. DG 21-104

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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 30-R3						
NET SALVAGE PERCENT.. -10						
1987	39,445.49	36,737	28,931	14,459	4.60	3,143
1988	92,699.87	85,043	66,973	34,997	4.98	7,028
1989	150,957.68	136,275	107,320	58,733	5.38	10,917
1990	99,852.77	88,529	69,719	40,119	5.82	6,893
1991	248,579.65	216,106	170,188	103,250	6.29	16,415
1992	309,810.37	263,660	207,638	133,153	6.79	19,610
1993	332,096.45	276,051	217,397	147,909	7.33	20,179
1994	352,528.89	285,795	225,070	162,712	7.89	20,623
1995	309,924.92	244,550	192,589	148,328	8.48	17,492
1996	324,737.91	248,859	195,982	161,230	9.10	17,718
1997	386,459.60	286,946	225,977	199,129	9.75	20,423
1998	403,899.23	289,823	228,242	216,047	10.43	20,714
1999	600,879.74	415,967	327,584	333,384	11.12	29,981
2000	425,074.52	283,041	222,901	244,681	11.84	20,666
2001	427,551.14	273,093	215,067	255,239	12.58	20,289
2002	557,906.97	340,805	268,392	345,306	13.34	25,885
2003	502,392.92	292,525	230,370	322,262	14.12	22,823
2004	476,074.53	263,412	207,443	316,239	14.91	21,210
2005	485,986.37	254,286	200,256	334,329	15.73	21,254
2006	861,596.42	424,907	334,624	613,132	16.55	37,047
2007	552,222.21	255,127	200,919	406,525	17.40	23,364
2008	1,030,117.67	443,428	349,210	783,919	18.26	42,931
2009	852,840.11	339,601	267,444	670,680	19.14	35,041
2010	421,722.10	154,166	121,409	342,485	20.03	17,099
2012	2,196,535.86	656,406	516,935	1,899,254	21.85	86,922
2013	1,669,722.44	442,037	348,115	1,488,580	22.78	65,346
2014	1,667,799.91	384,656	302,926	1,531,654	23.71	64,599
2015	1,435,971.17	281,163	221,422	1,358,146	24.66	55,075
2016	1,403,893.92	225,465	177,559	1,366,724	25.62	53,346
2017	1,940,997.90	243,401	191,684	1,943,414	26.58	73,116
2018	1,522,528.07	136,779	107,717	1,567,064	27.55	56,881
2019	1,973,648.00	106,380	83,776	2,087,237	28.53	73,159
2020	1,945,230.56	34,942	27,518	2,112,236	29.51	71,577
	26,001,685.36	8,709,961	6,859,297	21,742,557		1,098,766

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.8 4.23

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 30-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)
1999	6,775.57	4,264	4,289	2,487	11.12	224
2000	3,744.90	2,267	2,280	1,465	11.84	124
2001	134,243.25	77,951	78,403	55,840	12.58	4,439
2002	350.30	195	196	154	13.34	12
2003	542.83	287	289	254	14.12	18
2004	39,535.89	19,887	20,002	19,534	14.91	1,310
2009	37,535.84	13,588	13,667	23,869	19.14	1,247
2010	93,060.08	30,927	31,106	61,954	20.03	3,093
2011	9,465.59	2,862	2,879	6,587	20.93	315
2012	64,187.72	17,438	17,539	46,649	21.85	2,135
2013	12,894.30	3,103	3,121	9,773	22.78	429
2014	46,358.20	9,720	9,776	36,582	23.71	1,543
2015	45,490.64	8,097	8,144	37,347	24.66	1,514
2016	39,455.52	5,761	5,794	33,662	25.62	1,314
2017	47,491.48	5,414	5,445	42,046	26.58	1,582
2018	70,618.38	5,767	5,800	64,818	27.55	2,353
2019	70,836.85	3,471	3,491	67,346	28.53	2,361
2020	10,962.24	179	180	10,782	29.51	365
	733,549.58	211,178	212,401	521,148		24,378

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.4   3.32

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 386.00 OTHER PROPERTY ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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 12-R2						
NET SALVAGE PERCENT.. 0						
1994	23,873.55	23,874	23,874			
1995	101,392.20	101,392	101,392			
1996	76,158.18	76,158	76,158			
1997	76,096.54	76,097	76,097			
1998	76,451.16	76,451	76,451			
1999	83,071.82	81,687	62,109	20,963	0.20	20,963
2000	123,831.03	118,981	90,464	33,367	0.47	33,367
2001	57,530.70	53,935	41,008	16,523	0.75	16,523
2002	90,319.47	82,491	62,720	27,599	1.04	26,538
2003	7,153.19	6,360	4,836	2,317	1.33	1,742
2004	8,867.40	7,670	5,832	3,035	1.62	1,873
2005	11,011.24	9,231	7,019	3,992	1.94	2,058
2006	2,082.08	1,686	1,282	800	2.28	351
2007	3,643.31	2,836	2,156	1,487	2.66	559
2008	5,241.14	3,892	2,959	2,282	3.09	739
2009	57,357.02	40,341	30,672	26,685	3.56	7,496
2010	76,985.59	50,747	38,584	38,402	4.09	9,389
2012	143,385.65	80,296	61,051	82,335	5.28	15,594
2013	89,395.84	45,071	34,269	55,127	5.95	9,265
2014	107,399.88	47,882	36,406	70,994	6.65	10,676
2015	121,649.76	46,734	35,533	86,117	7.39	11,653
2016	96,206.38	30,786	23,407	72,799	8.16	8,921
2017	139,373.50	35,192	26,757	112,616	8.97	12,555
2018	171,146.73	31,376	23,856	147,291	9.80	15,030
2019	144,276.16	16,111	12,250	132,026	10.66	12,385
2020	84,995.51	3,187	2,423	82,573	11.55	7,149
	1,978,895.03	1,150,464	959,565	1,019,330		224,826

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 11.36

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	224,447.63	172,077	172,073	52,375	3.50	14,964
2010	18,803.58	13,163	13,163	5,641	4.50	1,254
2011	1,820.07	1,153	1,153	667	5.50	121
2012	26,428.04	14,976	14,976	11,452	6.50	1,762
2013	133,660.63	66,830	66,827	66,834	7.50	8,911
2014	6,042.09	2,618	2,618	3,424	8.50	403
2015	3,651.85	1,339	1,339	2,313	9.50	243
2016	6,673.54	2,002	2,002	4,672	10.50	445
2017	4,364.84	1,018	1,018	3,347	11.50	291
2018	5,941.70	990	990	4,952	12.50	396
2019	18,505.11	1,851	1,851	16,654	13.50	1,234
2020	57,795.69	1,926	1,926	55,870	14.50	3,853
	508,134.77	279,943	279,936	228,199		33,877

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7 6.67

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 394.10 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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						
1992	27,385.41	27,385	27,385			
1993	12,409.22	12,409	12,409			
1994	20,052.13	20,052	20,052			
1995	56,123.13	56,123	56,123			
	115,969.89	115,969	115,970			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	30,741.37	30,127	29,958	783	0.50	783
1997	22,755.60	21,390	21,270	1,485	1.50	990
1998	33,774.01	30,397	30,227	3,547	2.50	1,419
1999	50,066.79	43,057	42,816	7,251	3.50	2,072
2000	10,212.93	8,375	8,328	1,885	4.50	419
2001	18,174.14	14,176	14,097	4,078	5.50	741
2002	8,399.98	6,216	6,181	2,219	6.50	341
2003	15,486.21	10,840	10,779	4,707	7.50	628
2004	38,224.04	25,228	25,087	13,137	8.50	1,546
2005	7,715.09	4,783	4,756	2,959	9.50	311
2006	30,667.12	17,787	17,687	12,980	10.50	1,236
2008	48,815.30	24,408	24,271	24,544	12.50	1,964
2009	248,756.76	114,428	113,787	134,970	13.50	9,998
2010	197,936.06	83,133	82,667	115,269	14.50	7,950
2011	25,087.59	9,533	9,480	15,608	15.50	1,007
2012	24,296.89	8,261	8,215	16,082	16.50	975
2013	145,321.22	43,596	43,352	101,969	17.50	5,827
2014	27,446.67	7,136	7,096	20,351	18.50	1,100
2015	30,833.38	6,783	6,745	24,088	19.50	1,235
2016	47,306.04	8,515	8,467	38,839	20.50	1,895
2017	39,782.10	5,569	5,538	34,244	21.50	1,593
2018	76,355.10	7,636	7,593	68,762	22.50	3,056
2019	75,529.94	4,532	4,507	71,023	23.50	3,022
2020	60,767.19	1,215	1,208	59,559	24.50	2,431
	1,314,451.52	537,121	534,112	780,340		52,539
	1,430,421.41	653,090	650,082	780,340		52,539

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.9 3.67

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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						
1991	20,776.59	20,777	20,777			
1992	65,780.69	65,781	65,781			
1993	33,432.84	33,433	33,433			
1994	11,586.00	11,586	11,586			
1995	48,773.69	48,774	48,774			
1996	35,392.71	35,393	35,393			
1998	52,121.15	52,121	52,121			
1999	45,663.49	45,663	45,663			
2001	8,875.30	8,875	8,875			
2005	46,484.65	46,485	46,485			
	368,887.11	368,888	368,887			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	32,656.80	31,568	31,424	1,233	0.50	1,233
2008	425,712.04	354,759	353,139	72,573	2.50	29,029
2009	185,879.43	142,508	141,857	44,022	3.50	12,578
2010	83,755.25	58,629	58,361	25,394	4.50	5,643
2011	8,608.03	5,452	5,427	3,181	5.50	578
2012	211,531.15	119,868	119,321	92,211	6.50	14,186
2013	10,039.05	5,020	4,997	5,042	7.50	672
2014	2,564.26	1,111	1,106	1,458	8.50	172
2015	82,503.03	30,251	30,113	52,390	9.50	5,515
2016	5,660.46	1,698	1,690	3,970	10.50	378
2017	109,158.37	25,470	25,354	83,805	11.50	7,287
2018	42,502.63	7,084	7,052	35,451	12.50	2,836
2019	133,059.36	13,306	13,245	119,814	13.50	8,875
2020	170,963.24	5,698	5,672	165,291	14.50	11,399
	1,504,593.10	802,422	798,757	705,836		100,381
	1,873,480.21	1,171,310	1,167,644	705,836		100,381

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0   5.36

NORTHERN UTILITIES, INC.
NEW HAMPSHIRE DIVISION

ACCOUNT 397.35 COMMUNICATION EQUIPMENT - ERTs

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF 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						
2003	1,635,028.25	1,635,028	1,635,028			
2004	73,637.00	73,637	73,637			
2005	105,483.61	105,484	105,484			
	1,814,148.86	1,814,149	1,814,149			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	8,323.98	8,047	8,038	286	0.50	286
2007	269,434.27	242,491	242,211	27,223	1.50	18,149
2008	113,656.57	94,713	94,604	19,053	2.50	7,621
2009	65,996.83	50,598	50,540	15,457	3.50	4,416
2010	72,888.13	51,022	50,963	21,925	4.50	4,872
2012	131,079.51	74,279	74,193	56,886	6.50	8,752
2013	172,937.38	86,469	86,369	86,568	7.50	11,542
2014	169,053.77	73,256	73,171	95,882	8.50	11,280
2015	23,991.36	8,797	8,787	15,205	9.50	1,601
2016	40,712.03	12,214	12,200	28,512	10.50	2,715
2017	74,662.09	17,421	17,401	57,261	11.50	4,979
2018	170,013.85	28,336	28,303	141,711	12.50	11,337
2019	212,363.28	21,236	21,211	191,152	13.50	14,159
2020	130,884.27	4,362	4,357	126,527	14.50	8,726
	1,655,997.32	773,241	772,348	883,649		110,435
	3,470,146.18	2,587,390	2,586,497	883,649		110,435

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 3.18

UNITIL CORPORATION
NORTHERN UTILITIES, INC.

COMPARISON OF CURRENT ANNUAL DEPRECIATION EXPENSE VS. PROPOSED ANNUAL DEPRECIATION EXPENSE AS OF DECEMBER 31, 202(

				CURRENT				PROPOSED				
	DEPRECIABLE GROUP	ORIGINAL COST AS OF DECEMBER 31, 2020	BOOK DEPRECIATION RESERVE	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)=(7)x(2)	(7)	(8)	(9)	(10)	(11)	(12)=(10)-(6)
	DISTRIBUTION PLANT											
375.00	STRUCTURES AND IMPROVEMENTS	3,260,871.26	596,162	70-L0	0	46,630	1.43	55-R2.5	(10)	89,338	2.74	42,708
	MAINS											
376.20	COATED AND WRAPPED	29,746,227.02	4,224,164	47-R1.5	(25)	791,250	2.66	55-R2.5	(60)	1,123,107	3.78	331,857
376.40	PLASTIC	120,342,184.10	36,382,883	47-R1.5	(35)	3,453,821	2.87	55-R2.5	(60)	3,460,577	2.88	6,756
376.60	CATHODIC PROTECTION	1,082,739.45	682,660	30-S5	(25)	45,150	4.17	30-S5	(60)	50,271	4.64	5,121
	TOTAL MAINS	151,171,150.57	41,289,708			4,290,221	2.84			4,633,955	3.75	343,734
378.20	MEASURING AND REGULATING STATION EQUIPMENT	7,328,248.14	672,808	30-R2	(5)	256,489	3.50	30-R2	(20)	356,985	4.87	100,496
380.00	SERVICES	82,837,046.71	28,479,497	45-R2.5	(65)	3,040,120	3.67	45-R2.5	(90)	3,654,478	4.41	614,358
381.00	METERS	4,624,610.24	1,226,613	30-R2	0	154,000	3.33	30-R2	(15)	247,087	5.34	93,087
382.00	METER INSTALLATIONS	26,001,685.36	6,859,297	33-R4	(10)	865,856	3.33	30-R3	(10)	1,098,766	4.23	232,910
383.00	HOUSE REGULATORS	733,549.58	212,401	30-R3	0	24,427	3.33	30-R3	0	24,378	3.32	(49)
386.00	OTHER PROPERTY ON CUSTOMERS' PREMISES	1,978,895.03	959,565	13.5-R1.5	0	146,636	7.41	12-R2	0	224,826	11.36	78,190
	TOTAL DISTRIBUTION PLANT	**277,936,056.89**	**80,296,051**			**8,824,378**	**3.17**			**10,329,813**	**3.72**	**1,505,435**
	GENERAL PLANT											
391.10	OFFICE FURNITURE AND EQUIPMENT	508,134.77	279,936	11.5-S3	0	44,208	8.70	15-SQ	0	33,877	6.67	(10,331)
394.10	TOOLS, SHOP AND GARAGE EQUIPMENT											
	FULLY ACCRUED	115,969.89	115,970	19-R3	0	6,100	5.26			0	-	(6,100)
	AMORTIZED	1,314,451.52	534,112	19-R3	0	69,140	5.26	25-SQ	0	52,539	4.00	(16,601)
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT	1,430,421.41	650,082			75,240	5.26			52,539	3.67	(22,701)
397.00	COMMUNICATION EQUIPMENT											
	FULLY ACCRUED	368,887.11	368,887	11-R5	0	33,532	9.09			0	-	(33,532)
	AMORTIZED	1,504,593.10	798,757	11-R5	0	136,768	9.09	15-SQ	0	100,381	6.67	(36,387)
	TOTAL COMMUNICATION EQUIPMENT	1,873,480.21	1,167,644			170,299	9.09			100,381	5.36	(69,918)
397.35	COMMUNICATION EQUIPMENT - ERTs											
	FULLY ACCRUED	1,814,148.86	1,814,149	15-SQ	0	121,004	6.67			0	-	(121,004)
	AMORTIZED	1,655,997.32	772,348	15-SQ	0	110,455	6.67	15-SQ	0	110,435	6.67	(20)
	TOTAL COMMUNICATION EQUIPMENT - ERTs	3,470,146.18	2,586,497			231,459	6.67			110,435	3.18	(121,024)
	TOTAL GENERAL PLANT	**7,282,182.57**	**4,684,159**			**521,206**	**7.16**			**297,232**	**4.08**	**(223,974)**
	LEAK PRONE PIPE											
376.30	MAINS - BARE STEEL	190,836.93	(2,132,784)	NONDEPRECIABLE		0				464,724		464,724
376.50	MAINS - JOINT SEALS	542,145.01	542,145	NONDEPRECIABLE		0				0		0
376.80	MAINS - CAST IRON	28,455.49	(1,187,409)	NONDEPRECIABLE		0				243,173		243,173
	TOTAL LEAK PRONE PIPE	**761,437.43**	**(2,778,047)**			**0**				**707,897**		**707,897**
	UNRECOVERED RESERVE TO BE AMORTIZED											
391.10	OFFICE FURNITURE AND EQUIPMENT		18,142							(3,628) *		(3,628)
394.10	TOOLS, SHOP AND GARAGE EQUIPMENT		135,659							(27,132) *		(27,132)
397.00	COMMUNICATION EQUIPMENT		402,958							(80,592) *		(80,592)
397.35	COMMUNICATION EQUIPMENT - ERTs		179,802							(35,960) *		(35,960)
	TOTAL UNRECOVERED RESERVE TO BE AMORTIZED		**736,561**							**(147,312)**		**(147,312)**
	TOTAL DEPRECIABLE PLANT	**285,979,676.89**	**82,938,723**			**9,345,584**	**3.27**			**11,187,630**	**3.91**	**1,842,046**

* 5-YEAR AMORTIZATION OF UNRECOVERED RESERVE RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING

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NORTHERN UTILITIES, INC.

Supplementary Filing Requirements

In accordance with New Hampshire Code of Administrative Rules Part Puc 1604, Full Rate Case Filing Requirements, 1604.01 (a), Northern Utilities, Inc. ("Company" or "NU") has prepared responses to the following requests as provided herein:

<u>**(Request) (Page #)**</u>

(1) (000004) 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;

(2) (000008) Annual reports to stockholders and statistical supplements, if any, for the most recent 2 years;

(3) (000009) Federal income tax reconciliation for the test year;

(4) (000010) 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;

(5) (000012) A detailed list of charitable contributions charged in the test year above the line showing donee, the 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 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;

(6) (000013) 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;

(7) (000015) The utility's most recent cost of service study if not previously filed in an adjudicative proceeding;

(8) (000016) The utility's most recent construction budget;

(9) (000026) 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;

(10) (000049) The utility's Securities and Exchange Commission 10K forms and 10Q forms or hyperlinks thereto, for the most recent 2 years;

(11) (000050) 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) (000052) The utility's most recent depreciation study if not previously filed in an adjudicative proceeding;

(13) (000053) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding;

(14) (000219) 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) (000222) Copies of all officer and executive incentive plans;

(16) (000242) 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) (000243) 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) (000245) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

(19) (000246) Balance sheets and income statements for the previous 2 years if not previously filed with the commission;

(20) (000247) Quarterly income statements for the previous 2 years if not previously filed with the commission;

(21) (000249) Quarterly sales volumes for the previous 2 years, itemized for residential and other classifications of service, if not previously filed with the commission;

(22) (000251) A description of the utility's projected need for external capital for the 2 year period immediately following the test year;

(23) (000252) 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) (000254) The amount of outstanding short term debt, on a monthly basis during the test year, for each short-term indebtedness;

(25) (000256) 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) (000258) Support for figures appearing on written testimony and in accompanying exhibits.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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) – 1 Attachment 1 for the internal financial reports (balance sheets and income statements) for the above requested periods.

Northern Utilities, Inc.
Inc Stmt - NH - Rate Case
G_NU_NH_IS_Rate Case

	YTD December 2019	MTD January 2020	MTD December 2020	YTD December 2020
OPERATING REVENUES				
Sales:				
Residential (480)	$34,517,227.13	$4,656,524.61	$4,164,087.50	$30,041,334.70
General Service (481)	28,306,834.03	3,465,342.14	3,205,756.33	22,321,899.94
Firm Transport Revenues (484, 489)	9,829,867.28	1,151,861.26	1,110,030.35	9,739,813.60
Sales for Resale (483)	2,870,978.98	60,384.67	42,386.44	1,107,459.45
Other Sales (495)	(3,515,439.00)	(441,271.74)	228,202.01	2,244,617.36
Total Sales	72,009,468.42	8,892,840.94	8,750,462.63	65,455,125.05
Other Operating Revenues:				
Late Charge (487)	76,773.15	14,195.89	0.00	36,760.56
Misc. Service Revenues (488)	875,754.96	69,575.00	74,500.23	852,303.57
Rent from Property (493 & 457)	200,952.00	18,219.00	18,219.00	218,628.00
Other Revenues	(311,587.39)	0.00	15,064.66	120,656.07
Total Other Operating Revenues	841,892.72	101,989.89	107,783.89	1,228,348.20
TOTAL OPERATING REVENUES	72,851,361.14	8,994,830.83	8,858,246.52	66,683,473.25
OPERATING EXPENSES				
Operation & Maint. Expenses:				
Production (710-813)	28,226,731.36	3,861,752.11	3,166,760.33	23,544,859.85
Transmission (850-857)	72,713.01	6,252.13	6,916.57	63,828.91
Distribution (870-894) (586)	3,509,448.39	310,762.01	365,844.50	3,733,377.07
Cust. Accounting (901-905)	2,768,757.96	260,924.09	267,909.80	2,608,188.94
Cust. Service & Info (906-910)	2,319,375.02	86,327.89	376,726.67	2,341,705.53
Sales Expenses (911-916)	64,467.20	3,709.06	5,985.25	69,177.75
Admin. & General (920-935)	7,679,291.15	640,946.18	591,960.68	6,740,776.50
Total O & M Expenses	44,640,784.09	5,170,673.47	4,782,103.80	39,101,914.55
Other Operating Expenses:				
Deprtn. & Amort. (403-407)	9,004,943.38	799,210.38	857,982.18	9,693,558.76
Taxes-Other Than Inc. (408)	4,306,297.50	426,424.76	130,288.38	4,867,773.94
Federal Income Tax (409)	52,380.19	362,704.17	379,787.35	(30,211.07)
State Franchise Tax (409)	(309,547.45)	114,154.90	626,862.95	(384,643.78)
Def. Income Taxes (410,411)	2,975,683.09	108,881.92	(296,802.74)	2,600,178.96
Total Other Operating Expenses	16,029,756.71	1,811,376.13	1,698,118.12	16,746,656.81
TOTAL OPERATING EXPENSES	60,670,540.80	6,982,049.60	6,480,221.92	55,848,571.36
NET UTILITY OPERATING INCOME	12,180,820.34	2,012,781.23	2,378,024.60	10,834,901.89
OTHER INCOME & DEDUCTIONS				
Other Income:				
Other (415- 421)	242,786.84	23,135.80	33,106.65	206,338.79
Other Income Deduc. (425, 426)	232,635.71	17,383.46	24,218.34	151,744.19
Taxes Other than Income Taxes:				
Income Tax, Other Inc & Ded	2,751.63	1,557.91	2,407.22	14,785.85
Net Other Income (Deductions)	7,399.50		6,481.09	39,808.75
GROSS INCOME	12,188,219.84	2,016,975.66	2,384,505.69	10,874,710.64
Interest Charges (427 - 432)	4,673,981.74	427,512.64	423,039.89	4,778,440.54
NET INCOME	7,514,238.10	1,589,463.02	1,961,465.80	6,096,270.10

Northern Utilities, Inc.
Combined Balance Sheet (NH & ME)
G_NU_BS_Rate Case

	December 2019	January 2020	December 2020
ASSETS			
UTILITY PLANT			
Gas (101-106, 114)	$622,701,812.89	$625,112,029.80	$689,321,122.58
Const. Work in Progress (107)	12,576,741.64	11,920,075.90	13,301,948.50
Total Utility Plant	635,278,554.53	637,032,105.70	702,623,071.08
Less: Accum. Depr. & Amort (108-111, 115)	(143,066,941.59)	(144,786,798.03)	(175,354,389.54)
Net Utility Plant	492,211,612.94	492,245,307.67	527,268,681.54
OTHER PROPERTY & INVESTMENTS			
Nonutility Property (121)	2,943,712.34	2,943,712.34	3,058,116.38
Less: Accum.Prov. for Depr. and Amort. (122)	(2,913,893.26)	(2,940,561.89)	(2,971,261.24)
Total Other Prop. & Invest.	29,819.08	3,150.45	86,855.14
CURRENT ASSETS			
Cash (131)	$337,596.85	($348,097.04)	$370,260.09
Other Special Deposits (134, 136)	2,500.00	2,500.00	0.00
Working Funds (135)	1,750.00	1,750.00	1,750.00
Accounts Receivable (142)	21,416,442.65	22,582,115.81	23,594,967.02
Other Accounts Receivable (143)	154,773.31	142,176.13	199,463.96
(Less) Accum. Prov. for Uncoll. Acct (144)	(441,587.83)	(413,241.54)	(1,158,007.43)
Accts Receivable-Assoc. Cos. (146)	5,559,766.01	2,176,462.67	8,913,185.12
Plant Material & Operating Supplies (154)	4,162,205.58	4,358,770.56	4,464,730.02
Stores Expense Undistributed (163)	655,825.52	707,156.07	708,099.81
Gas Stored Underground - Current	401,480.61	262,870.41	267,731.25
Liquified Natural Gas Stored and Held for Processing	46,623.05	37,671.07	40,347.69
Prepayments (165)	4,450,028.61	4,611,054.63	2,161,366.78
Accrued Revenues (173)	9,587,863.54	7,438,527.71	8,534,883.10
Miscellaneous Current and Accrued Assets (174)	5,666,175.53	4,155,487.28	4,624,272.16
Total Current Assets	52,001,443.43	45,715,203.76	52,723,049.57
DEFERRED DEBITS			
Unamortized Debt Expense (181)	1,208,586.32	1,227,818.76	1,359,851.23
Regulatory Assets (182)	23,818,108.99	14,802,640.03	27,935,356.03
Preliminary Survey Chgs (183)	663,266.65	678,848.15	861,958.45
Clearing Accounts (184)	173,313.84	1,388,507.40	203,053.82
Misc. Deferred Debits (186)	1,250,862.64	1,273,884.26	864,679.14
Unrecovered Purchase Gas Costs (191)	2,803,584.01	2,891,528.92	6,818,463.80
Total Deferred Debits	29,917,722.45	22,263,227.52	38,043,362.47
TOTAL ASSETS	$574,160,597.90	$560,226,889.40	$618,121,948.72

Northern Utilities, Inc.
Combined Balance Sheet (NH & ME)
G_NU_BS_Rate Case

	December 2019	January 2020	December 2020
LIABILITIES AND CAPITAL			
PROPRIETARY CAPITAL			
Common Stock Equity			
Common Stock of Subs, Par Value (201)	1,000.00	1,000.00	1,000.00
Other Paid-In Capital (208, 211)	200,699,000.00	200,699,000.00	207,074,000.00
Retained earnings (216)	24,380,042.44	24,013,784.57	24,453,103.55
Total Proprietary Capital	225,080,042.44	224,713,784.57	231,528,103.55
LONG TERM DEBT			
Other Long-Term Debt (224)	198,200,000.00	198,200,000.00	230,000,000.00
Total Long Term Debt	198,200,000.00	198,200,000.00	230,000,000.00
Capital Leases-Noncurrent	706,610.32	1,172,759.07	1,092,628.92
CURRENT LIABILITIES			
Accounts Payable (232)	8,651,894.04	6,297,393.62	7,178,825.54
Notes Payable (233)	28,494,680.03	28,666,839.96	26,747,021.72
Accts. Payable-Assoc. Co's (234)	6,497,178.34	6,120,881.60	7,400,408.89
Customer Deposits (235)	640,562.43	626,328.64	592,301.78
Taxes Accrued (236)	292,533.71	1,286,273.02	63,034.19
Interest Accrued (237)	1,824,919.44	2,659,886.51	2,094,466.69
Dividends Declared (238)	3,304,600.00	3,666,585.00	3,666,585.00
Tax Collections Payable (241)	94,758.52	68,278.26	174,522.35
Misc. Current Liabilities (242)	11,636,693.25	9,812,680.73	9,024,630.21
Capital Leases - Current (243)	431,168.75	535,246.32	519,504.85
Total Current Liabilities	61,868,988.51	59,740,393.66	57,461,301.22
DEFERRED CREDITS			
Other Deferred Credits (253)	35,921,433.54	19,221,777.00	40,177,075.27
Other Regulatory Liabilities (254)	21,739,717.95	21,722,427.95	21,336,059.65
Accum. Deferred Inc. Taxes - Other Prop. (282, 283)	46,747,167.58	47,241,125.14	53,374,153.90
Accum. Def. Income Taxes (282, 283)	(16,103,362.44)	(11,785,377.99)	(16,847,373.79)
Total Deferred Credits	88,304,956.63	76,399,952.10	98,039,915.03
TOTAL LIABILITIES AND CAPITAL	$574,160,597.90	$560,226,889.40	$618,121,948.72

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(2) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

Response:

Northern Utilities, Inc. does not make an annual report to stockholders.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(3) Federal income tax reconciliation for the test year.

Response:

Please refer to Schedule RevReq-3-22, Page 3 of 4 for the federal and state income tax reconciliation for the test year.

Northern Utilities, Inc.
DG 21-104

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.

NORTHERN UTILITIES, 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

Northern Utilities, Inc.
DG 21-104

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 above the line showing donee, the 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 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 charged above the line during the test year.

Northern Utilities, Inc.
DG 21-104

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:

a. Please see PUC 1604.01(a) – 06 Attachment 1 for a list of advertising charged above the line greater than $50.

b. N/A.

Northern Utilities, Inc.
List of Advertising by Media and Subject Matter
2020

PUC 1604.01(a) - 06
Attachment 1
Page 1 of 1

Advertising above the line in excess of $50

Media	Subject Matter	Account Number	Amount
Radio	Gas Connectors	30-40-24-00-909-52-00	$ 1,674
Radio	Gas Leak Response	30-40-24-00-909-52-00	1,810
Radio	Home Safety	30-40-24-00-909-52-00	1,810
Radio	Carbon Monoxide	30-40-24-00-909-52-00	1,810
Radio	Presidents Message	30-40-24-00-913-53-00	1,659
Radio	Dig Safe	30-40-24-00-909-52-00	1,810
Radio	Gas Leak Recognition	30-40-24-00-909-52-00	1,810
Radio	Pipeline Safety	30-40-24-00-909-52-00	1,810
	Subtotal - Radio Advertising		$ 14,193
Social Media	Carbon Monoxide	30-40-24-00-909-52-00	$ 59
Social Media	Home Safety Hazardss	30-40-24-00-909-01-00	140
Social Media	January Mythbuster	30-40-24-00-909-01-00	80
Social Media	Gas Connectors	30-40-24-00-909-52-00	240
Social Media	Natural Gas Appliances	30-40-24-00-909-01-00	70
Social Media	Dig Safe	30-40-24-00-909-52-00	142
Social Media	MyUnitil Energy Tools	30-40-24-00-909-01-00	60
Social Media	EE Tips - Ceiling Fans & Energy	30-40-24-00-909-01-00	50
Social Media	Gas Leak Recognition	30-40-24-00-909-52-00	180
Social Media	Gas Leak Response	30-40-24-00-909-52-00	256
Social Media	Pipeline Safety	30-40-24-00-909-52-00	240
Social Media	Home Safety	30-40-24-00-909-52-00	240
Social Media	Corrugated Stainless Steel Tubing (CSST)	30-40-24-00-909-52-00	194
Social Media	Clear meters of Snow and Ice	30-40-24-00-909-52-00	103
	Subtotal - Social Media Advertising		$ 2,054
	Grand Total		$ 16,247

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(8) The utility's most recent construction budget.

Response:

See PUC 1604.01(a) – 8 Attachments 1 for the utility’s most recent construction budget.

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Capital Budget 2021 Northern NH

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
Electric Totals:	0	0	0	0	0	0	0	0
Blankets:Gas	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631	0	0
Communications:Gas	25,010	34,572	0	34,572	0	34,572	100	0
Distribution:Gas	13,778,675	19,046,590	265,003	18,781,587	0	18,781,587	0	0
Tools, Shop, Garage:Gas	215,547	215,547	0	215,547	0	215,547	0	0
Office:Gas	14,000	14,000	0	14,000	0	14,000	0	250
Transportation:Gas	4	4	0	4	0	4	0	0
Gas Totals:	20,148,002	27,763,299	343,958	27,419,340	0	27,419,340	100	250
Blankets:Water Heater	222,320	222,320	0	222,320	0	222,320	0	0
Hotwater Totals:	222,320	222,320	0	222,320	0	222,320	0	0
Structures:General	1,118,000	1,118,000	0	1,118,000	0	1,118,000	0	0
General/Common Totals:	1,118,000	1,118,000	0	1,118,000	0	1,118,000	0	0
Totals:	**21,488,322**	**29,103,619**	**343,958**	**28,759,660**	**0**	**28,759,660**	**100**	**250**

Capital Budget System • Report • Budget Item Requests

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Blankets:Gas**	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	MAB21	Distribution System Improvements (Under $40,000)	414,364	572,785	0	572,785	0	572,785
A	1	MAC21	Distribution System Improvements (Under $40,000) Carryover	12,692	17,544	0	17,544	0	17,544
A	1	MBB21	New Gas Services	1,903,924	2,631,839	78,955	2,552,884	0	2,552,884
A	1	MBC21	New Gas Services Carryover	22,455	31,040	0	31,040	0	31,040
A	2	MCB21	Corrosion Control	109,514	151,384	0	151,384	0	151,384
A	1	MDB21	Abandon Gas Services	154,381	213,404	0	213,404	0	213,404
A	1	MDC21	Abandoned Gas Service Carryover	6,947	9,603	0	9,603	0	9,603
A	2	MEB21	Gas Service Upgrades (Renewals)	1,319,316	1,823,722	0	1,823,722	0	1,823,722
A	2	MEC21	Gas Service Upgrades Carryover	8,514	11,769	0	11,769	0	11,769
A	2	MFB21	Gas Meter Installation Company Driven	591,407	817,516	0	817,516	0	817,516
A	2	MFC21	Gas Meter Installation Company Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MGB21	Gas Meter Installation : Customer Driven	648,284	896,139	0	896,139	0	896,139
A	1	MGC21	Gas Meter Installation : Customer Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MHB21	Meter Purchases - Company	325,579	450,056	0	450,056	0	450,056
A	1	MIB21	Meter Purchases - Customer	384,583	531,618	0	531,618	0	531,618
A	2	MMB21	Gas Distribution System Improvements - Systems Operations	175,640	242,791	0	242,791	0	242,791
A	2	MMC21	Gas Disribution System Improvements - Systems Operations-Carryover	26,250	36,286	0	36,286	0	36,286
			Totals:	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Communications:Gas**	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	ECG01	Replace and Upgrade Gas SCADA Master	16,556	22,886	0	22,886	0	22,886
A	2	ECG02	Provide New Gas SCADA Communications - various locations	8,453	11,685	0	11,685	0	11,685
			Totals:	25,010	34,572	0	34,572	0	34,572

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Distribution:Gas**	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	JAB00	Gas Main Extensions over $40,000	1,917,085	2,650,032	265,003	2,385,028	0	2,385,028
A	1	JAC00	Gas Main Extensions carryover	45,945	63,511	0	63,511	0	63,511
A	2	JHB00	Gas Highway Projects City State	2,102,792	2,906,740	0	2,906,740	0	2,906,740
A	2	JHC00	Gas Highway Projects Carryover	7,511	10,382	0	10,382	0	10,382
A	2	JPB01	Asphalt Restoration 2020 Projects	551,350	762,144	0	762,144	0	762,144
A	3	JPB03	Distribution Gas Main Upgrades	310,419	429,100	0	429,100	0	429,100
A	2	JPB04	Farm Tap Replacement	362,196	500,672	0	500,672	0	500,672
A	2	JPB05	Regulator Station OPP/Redundancy	172,469	238,408	0	238,408	0	238,408
A	3	JPB21	Heater Replacement - Newfields Station	777,819	1,075,197	0	1,075,197	0	1,075,197
A	2	JPB22	Henry Law Ave Dover Replacement	141,665	195,827	0	195,827	0	195,827
A	2	JPB23	Plaistow System Improvement Phase 2	360,450	498,258	0	498,258	0	498,258
A	3	JPB24	Bartlett Avenue/High Street Stations Rebuild-PHASE 1	389,818	538,855	0	538,855	0	538,855
A	3	JPB25	Monroe Street Station Upgrade	271,408	375,174	0	375,174	0	375,174
A	1	JPB26	Stard Road Mini-DR Station Install	282,908	391,071	0	391,071	0	391,071
A	3	JPB27	Rutland Street Station Rebuild	338,408	467,790	0	467,790	0	467,790
A	2	JPB28	Ashbrook Rd., Exeter	154,182	213,130	0	213,130	0	213,130
A	2	JPB29	Partridge Green Replacement Rochester	633,242	875,346	0	875,346	0	875,346
A	2	JPB30	GIS Data Development - Services & Station Utilities	104,000	143,762	0	143,762	0	143,762
A	2	JPB31	AC Interference Mitigation (NH)	48,068	66,445	0	66,445	0	66,445
A	2	JPB32	Railroad Ave. Rochester	874,095	1,208,283	0	1,208,283	0	1,208,283
A	2	JPB33	Borthwick Ave. Footbridge Crossing	199,988	276,448	0	276,448	0	276,448
A	2	JPB34	Middle Road System Improvement	456,051	630,410	0	630,410	0	630,410
A	2	JPB35	Atkinson System Improvement Phase 3	995,339	1,375,881	0	1,375,881	0	1,375,881
A	1	JPC01	Rochester Reinforcement - 99 PSIG Station-Carryover	419,661	580,107	0	580,107	0	580,107
A	1	JPC02	Rochester Reinforcement Phase 3 - 99 psig Main Carryover	1,696,334	2,344,883	0	2,344,883	0	2,344,883
A	1	JPC03	Atkinson System Improvement Phase 2 Carryover	165,471	228,735	0	228,735	0	228,735
			Totals:	13,778,675	19,046,590	265,003	18,781,587	0	18,781,587

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Tools, Shop, Garage:Gas**	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	EAG01	Tools: Normal Additions and Replacements	33,497	33,497	0	33,497	0	33,497
A	2	EAG02	Tools: Normal Additions and Replacements - Systems Operations	17,000	17,000	0	17,000	0	17,000
A	3	EAG03	Normal add & replace- tools & equipment - Metering and FS	5,050	5,050	0	5,050	0	5,050
A	2	EAG04	Mueller Equipment	110,000	110,000	0	110,000	0	110,000
A	2	EAG05	Emergency Response Trailer	30,000	30,000	0	30,000	0	30,000
A	2	EAG06	TTQM Tools for OQ Training	20,000	20,000	0	20,000	0	20,000
			Totals:	215,547	215,547	0	215,547	0	215,547

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Office:Gas**	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	EDG01	Office Furniture & Equipment- Normal Additions & Replacements	5,000	5,000	0	5,000	0	5,000
A	3	EDG02	Chair Replacement - Year 3 of 3 Year Replacement Program	9,000	9,000	0	9,000	0	9,000
			Totals:	14,000	14,000	0	14,000	0	14,000

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Transportation:Gas**	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	FGB01	#44- Metering- Van	1	1	0	1	0	1
A	2	FGB02	#58- Manager Gas Operations- SUV	1	1	0	1	0	1
A	2	FGB03	#13- Service- Weld Truck	1	1	0	1	0	1
A	2	FGB04	#47- Distribution- Backhoe	1	1	0	1	0	1
			Totals:	4	4	0	4	0	4

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Capital Budget 2021 Northern NH

Status	Priority	Budget Number	Description **Blankets:Gas**	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	MAB21	Distribution System Improvements (Under $40,000)	414,364	572,785	0	572,785	0	572,785
A	1	MAC21	Distribution System Improvements (Under $40,000) Carryover	12,692	17,544	0	17,544	0	17,544
A	1	MBB21	New Gas Services	1,903,924	2,631,839	78,955	2,552,884	0	2,552,884
A	1	MBC21	New Gas Services Carryover	22,455	31,040	0	31,040	0	31,040
A	2	MCB21	Corrosion Control	109,514	151,384	0	151,384	0	151,384
A	1	MDB21	Abandon Gas Services	154,381	213,404	0	213,404	0	213,404
A	1	MDC21	Abandoned Gas Service Carryover	6,947	9,603	0	9,603	0	9,603
A	2	MEB21	Gas Service Upgrades (Renewals)	1,319,316	1,823,722	0	1,823,722	0	1,823,722
A	2	MEC21	Gas Service Upgrades Carryover	8,514	11,769	0	11,769	0	11,769
A	2	MFB21	Gas Meter Installation Company Driven	591,407	817,516	0	817,516	0	817,516
A	2	MFC21	Gas Meter Installation Company Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MGB21	Gas Meter Installation : Customer Driven	648,284	896,139	0	896,139	0	896,139
A	1	MGC21	Gas Meter Installation : Customer Driven Carryover	5,458	7,545	0	7,545	0	7,545
A	1	MHB21	Meter Purchases - Company	325,579	450,056	0	450,056	0	450,056
A	1	MIB21	Meter Purchases - Customer	384,583	531,618	0	531,618	0	531,618
A	2	MMB21	Gas Distribution System Improvements - Systems Operations	175,640	242,791	0	242,791	0	242,791
A	2	MMC21	Gas Disribution System Improvements - Systems Operations-Carryover	26,250	36,286	0	36,286	0	36,286
			Totals:	6,114,766	8,452,586	78,955	8,373,631	0	8,373,631

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Capital Budget 2021 Northern NH

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	GPB01	Normal Improvements to Portsmouth Facility	18,000	18,000	0	18,000	0	18,000
A	3	GPB02	HVAC Upgrades	800,000	800,000	0	800,000	0	800,000
A	3	GPB04	Facilities Improvements - Portsmouth	300,000	300,000	0	300,000	0	300,000
			Totals:	1,118,000	1,118,000	0	1,118,000	0	1,118,000

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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:

Please see PUC 1604.01(a) - 9 Attachment 1 for the chart of accounts.

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-00-00-101-00-00	NH GAS PLANT IN SERVICE	Assets
30-40-00-00-101-02-00	RIGHT OF USE ASSETS	Assets
30-40-00-00-101-02-01	CONTRA RIGHT OF USE ASSETS	Assets
30-40-00-00-101-03-00	GAS PLANT IN SERVICE - NH - CIS	Assets
30-40-00-00-101-90-00	NH GAS PLANT IN SERVICE (GA CONTRA)	Assets
30-40-00-00-106-00-00	GS CMPL CNST NT CLSS - NH	Assets
30-40-00-00-107-00-00	GAS CONST IN PROGRESS - NH	Assets
30-40-00-00-107-01-02	RWIP GAS SALVAGE	Assets
30-40-00-00-107-01-03	RWIP GAS COST OF REMOVAL	Assets
30-40-00-00-107-90-00	CONST WORK IN PROGRESS-CONST (GA) - NH	Assets
30-40-00-00-108-01-00	ACCUM DEPR GENERAL PLANT - NH	Assets
30-40-00-00-108-01-05	ACCUM DEPREC RESERVE - NH	Assets
30-40-00-00-108-04-00	ACCUMULATED DEPRECIATION - COR - NH	Assets
30-40-00-00-108-90-00	ACCUM DEPR - GENL PLANT - NH (GA CONTRA)	Assets
30-40-00-00-111-05-00	ACCUM AMORT COMPUTER SW - NH	Assets
30-40-00-00-111-05-01	COMPUTER SW RETIREMENT - NH	Assets
30-40-00-00-111-07-00	ACCUM AMORT - NH - CIS	Assets
30-40-00-00-114-00-00	GROSS PLANT ACQUISITION ADJ - NH	Assets
30-40-00-00-114-01-00	GROSS PAA - UNREGULATED - NH	Assets
30-40-00-00-131-00-01	CASH - SUSPENSE - NH	Assets
30-40-00-00-131-00-02	CASH - SUPPLY - NH	Assets
30-40-00-00-135-00-00	CASH - PETTY CASH - NH	Assets
30-40-00-00-136-00-00	MARGIN DEPOSIT	Assets
30-40-00-00-142-00-00	A/R - OTHER - NH	Assets
30-40-00-00-142-01-00	A/R- SALES - NH	Assets
30-40-00-00-142-01-01	A/R SALES SUSPENSE - NH	Assets
30-40-00-00-142-01-02	A/R- SALES - COG - NH	Assets
30-40-00-00-142-02-00	A/R MANUAL ENTRIES - NH	Assets
30-40-00-00-142-03-00	A/R SUNDRY - NH	Assets
30-40-00-00-142-03-02	A/R MISC ACCRUALS - NH	Assets
30-40-00-00-142-04-04	A/R REIMBURSABLE PROJECTS - NH	Assets
30-40-00-00-143-00-00	A/R - OTHER - NH	Assets
30-40-00-00-143-03-03	A/R DRUG SUBSIDY - NH	Assets
30-40-00-00-143-25-00	A/R CUST PURCH- WATER HEATERS - NH	Assets
30-40-00-00-144-00-00	AFDA - (BEG BAL) - DISTRIBUTION - NH	Assets
30-40-00-00-144-00-27	AFDA - NON-DISTRIBUTION - NH	Assets
30-40-00-00-144-01-00	ALLOW FOR DOUBTFUL ACCTS - NH - DISTR	Assets
30-40-00-00-144-04-00	AFDA - BEG BAL - NON DIST - NH	Assets
30-40-00-00-144-13-00	AFDA - UNBILLED REVENUE RECEIVABLE - NH	Assets
30-40-00-00-154-01-00	MATERIALS & SUPPLIES - NH	Assets
30-40-00-00-154-02-00	MATERIALS & SUPPLIES NU TRANSFER - NH	Assets
30-40-00-00-154-03-00	MATERIALS & SUPPLIES FGE TRANSFER	Assets
30-40-00-00-163-00-00	STORES EXP UNDISTRIBUTED - NH	Assets
30-40-00-00-163-01-00	STOREROOM OPERATING EXPENSE - NH	Assets
30-40-00-00-163-02-00	STOCK OVER & SHORT - NH	Assets
30-40-00-00-163-03-00	OBSOLETE STOCK - NH	Assets
30-40-00-00-163-05-00	STOREROOM - SHIPPING COSTS - NH	Assets
30-40-00-00-164-16-00	INVENTORY - NAT GAS SSNE (TENN GAS/TGP) - NH	Assets
30-40-00-00-165-01-00	PREPAID PROPERTY INSURANCE - NH	Assets
30-40-00-00-165-01-01	PREPAID INJURIES & DAMAGES INS - NH	Assets
30-40-00-00-165-02-00	PREPAID NH PUC ASSESSMENT - NH	Assets
30-40-00-00-165-04-01	FASB 87 - PREPAID PENSION - NH	Assets
30-40-00-00-165-11-00	PREPAID PROPERTY TAX - NH	Assets
30-40-00-00-165-12-00	PREPAID POSTAGE - NH	Assets
30-40-00-00-165-16-00	PREPAID HEALTH CLAIMS	Assets
30-40-00-00-165-19-00	OTHER MISC PREPAYMENT - NH	Assets
30-40-00-00-165-20-00	PREPAID GAS IRP PROGRAM - NH	Assets
30-40-00-00-173-01-00	ACCRUED REVENUE MISC	Assets
30-40-00-00-173-22-00	UNBILLED REVENUE - BASE - NH	Assets
30-40-00-00-173-28-00	ACCRUED REVENUE - RATE RELIEF - NH	Assets
30-40-00-00-173-30-00	PRICE RISK - CURRENT - NH	Assets
30-40-00-00-173-31-00	ERC SITE COSTS - CURRENT - NH	Assets
30-40-00-00-173-32-00	ACCRUED REV - WORK CAP - PEAK - NH	Assets
30-40-00-00-173-34-00	ACCRUED REV - BAD DEBT - PEAK - NH	Assets

Account Code	Account Description	Type
30-40-00-00-173-36-00	ACCRUED REV - WORK CAP - OFF PEAK - NH	Assets
30-40-00-00-173-37-00	ACCRUED REV - BAD DEBT- OFF PEAK - NH	Assets
30-40-00-00-173-38-00	ACCRUED REV - RLIAP- NH	Assets
30-40-00-00-173-41-02	ACCRUED REVENUE EE - R - NH	Assets
30-40-00-00-173-41-06	ACCRUED REVENUE EE - CI - NH	Assets
30-40-00-00-173-77-00	ACCRUED REVENUE - RLIARA - NH	Assets
30-40-00-00-173-78-00	ACCRUED REVENUE - RATE CASE EXP - NH	Assets
30-40-00-00-173-80-00	ACCRUED REVENUE-EEBB RES - NH	Assets
30-40-00-00-173-81-00	ACCRUED REVENUE LRR - NH	Assets
30-40-00-00-173-82-00	ACCRUED REVENUE - OBF - NH - RESIDENTIAL	Assets
30-40-00-00-173-82-01	ACCRUED REVENUE - OBF - NH - C&I	Assets
30-40-00-00-173-90-00	ACCRUED REVENUE - CREDIT BALANCE RECLASS - NH	Assets
30-40-00-00-173-90-01	ACCRUED REVENUE - YEAREND FT AP ACCRUAL	Assets
30-40-00-00-174-05-00	VACATION ACCRUAL	Assets
30-40-00-00-174-25-00	INVENTORY - EXCHANGE GAS - W10	Assets
30-40-00-00-174-26-00	Inventory - Exchange Gas - Union	Assets
30-40-00-00-175-01-00	PRICE RISK ASSET - CURRENT - NH	Assets
30-40-00-00-175-02-00	PRICE RISK ASSET - NON CURRENT -NH	Assets
30-40-00-00-182-00-27	REG ASSET - NON-DIST BAD DEBT - NH	Assets
30-40-00-00-182-03-28	REG ASSET - RATE CASE - 2013 - NH	Assets
30-40-00-00-182-03-40	REG ASSET - RATE CASE - 2017 - NH	Assets
30-40-00-00-182-04-09	REGULATORY ASSET - PBOP FAS 158	Assets
30-40-00-00-182-04-10	REGULATORY ASSET - PENSION FAS 158	Assets
30-40-00-00-182-04-11	REGULATORY ASSET - SERP - NH	Assets
30-40-00-00-182-04-19	REGULATORY ASSET - OTHER PBOP	Assets
30-40-00-00-182-04-20	REGULATORY ASSET - OTHER PENSION	Assets
30-40-00-00-182-04-21	REGULATORY ASSET - OTHER SERP	Assets
30-40-00-00-182-14-00	REG ASSET - DEFERRED PANDEMIC COSTS - NH	Assets
30-40-00-00-182-15-00	REG ASSET - DEFERRED PROPERTY TAXES - NH	Assets
30-40-00-00-182-21-00	REG ASSET - WORK CAP - OFF PEAK COMM - NH	Assets
30-40-00-00-182-22-00	REG ASSET - OFF PEAK BAD DEBT - NH	Assets
30-40-00-00-182-29-00	REG ASSET - ERC COSTS - NH - VOUCHERS	Assets
30-40-00-00-182-36-00	REG ASSET - ERC - PRIOR YEAR LAYERS - NH	Assets
30-40-00-00-182-42-00	REG ASSET - ERC COSTS - NH	Assets
30-40-00-00-182-44-00	REG ASSET - PRICE RISK - NC - NH	Assets
30-40-00-00-182-50-00	REGULATORY ASSET - SFAS109 - NH	Assets
30-40-00-00-182-81-00	REG ASSET - PNGTS RATE CASE - CURRENT NH	Assets
30-40-00-00-182-82-00	REG ASSET - GRANITE RATE CASE- NH	Assets
30-40-00-00-182-99-01	REG ASSET - OCA CONSULTING COSTS	Assets
30-40-00-00-183-00-00	PREL SURVEY & INVESTIGATION - NH	Assets
30-40-00-00-184-00-00	ENG & OPER OVERHEADS - NH	Assets
30-40-00-00-184-00-02	GENERAL OVERHEADS - NH	Assets
30-40-00-00-184-02-00	TRANS EXP LIGHT VEHICLES - NH	Assets
30-40-00-00-184-03-00	HEAVY TRUCKS - NH	Assets
30-40-00-00-184-04-00	GAS EXEMPT STOCK - NH	Assets
30-40-00-00-184-06-00	SMALL TOOLS - NH	Assets
30-40-00-00-184-08-00	CASH DISCOUNTS TAKEN - NH	Assets
30-40-00-00-184-12-01	LT MAINT & PARTS - NH	Assets
30-40-00-00-184-12-02	LT LEASING - NH	Assets
30-40-00-00-184-12-03	LT FUEL - NH	Assets
30-40-00-00-184-12-04	LT TAXES, REG, INS, TOLLS - NH	Assets
30-40-00-00-184-12-05	LT OTHER - NH	Assets
30-40-00-00-184-13-01	HT MAINT & PARTS - NH	Assets
30-40-00-00-184-13-02	HT LEASING - NH	Assets
30-40-00-00-184-13-03	HT FUEL - NH	Assets
30-40-00-00-184-13-04	HT TAXES, REG, INS, TOLLS - NH	Assets
30-40-00-00-184-13-05	HT OTHER - NH	Assets
30-40-00-00-185-01-00	NONPROD - GAS OPERATIONS - NH	Assets
30-40-00-00-186-10-00	PROPERTY TAX ABATEMENT REC - LT - NH	Assets
30-40-00-00-186-20-00	LT PORTION - IRP	Assets
30-40-00-00-186-27-02	CIS REPLACEMENT - NH	Assets
30-40-00-00-186-30-00	TRANSITION COSTS - NH	Assets
30-40-00-00-186-30-01	TRANSACTION COSTS - NH	Assets
30-40-00-00-186-50-00	PLANT AND M&S ACCRUALS - NH	Assets

Account Code	Account Description	Type
30-40-00-00-186-80-00	GAS SUPPLIER REFUND A/R - NH	Assets
30-40-00-00-190-01-99	DEF FIT - DEBIT BALANCE RECLASS	Assets
30-40-00-00-190-02-99	DEF SIT - DEBIT BALANCE RECLASS	Assets
30-40-00-00-191-10-00	UNRECOVERED GAS COSTS - OFF PEAK COMM - NH	Assets
30-40-00-00-191-20-00	UNRECOVERED GAS COSTS - PEAK COMM - NH	Assets
30-40-00-00-191-40-00	DEFERRED HEDGING COSTS - NH	Assets
30-40-00-00-227-01-00	OPER LEASE OBLIG - NONCURRENT	Liabilities
30-40-00-00-232-03-23	RETIREE HEALTH INS CONTRIBUTIONS	Liabilities
30-40-00-00-232-05-02	A/P - CUSTOMER CREDIT BALANCES-NH	Liabilities
30-40-00-00-232-15-00	ACCTS PAYABLE OTHER	Liabilities
30-40-00-00-232-21-00	CUSTOMER REFUNDS - NH	Liabilities
30-40-00-00-232-21-01	A/P - CUSTOMER DEPOSIT REFUND - NH	Liabilities
30-40-00-00-232-80-00	A/P - CDFA FOR EEBB PROGRAM	Liabilities
30-40-00-00-232-80-01	A/P - CDFA FOR EEBB PROGRAM - 2015	Liabilities
30-40-00-00-235-01-00	CUSTOMER DEPOSITS ACTIVE - NH	Liabilities
30-40-00-00-235-03-00	CUSTOMER BILLED DEPOSITS - NH	Liabilities
30-40-00-00-235-09-01	A/P-UNCLAIMED CREDIT BALANCE REFUNDS	Liabilities
30-40-00-00-236-01-30	FED INC TAX CURRENT - NH	Liabilities
30-40-00-00-236-01-31	FED INC TAX PRIOR - NH	Liabilities
30-40-00-00-236-02-30	NH INC TAX - CURRENT	Liabilities
30-40-00-00-236-02-31	NH INC TAX - PRIOR	Liabilities
30-40-00-00-236-02-40	STATE BET-CURRENT	Liabilities
30-40-00-00-236-02-41	STATE BET- NH - PRIOR	Liabilities
30-40-00-00-236-03-10	TAXES FICA-NU NH	Liabilities
30-40-00-00-236-04-10	TAXES FEDERAL UNEMPLOYMNT-NU NH	Liabilities
30-40-00-00-236-06-11	TAXES UNEMPLOYMENT-NH	Liabilities
30-40-00-00-236-76-00	ACCRUED PROPERTY TAXES - NH	Liabilities
30-40-00-00-241-19-03	SALES TAX PAYABLE -CA-GST HST	Liabilities
30-40-00-00-242-00-00	MISC ACCRUED LIABILITIES - NH	Liabilities
30-40-00-00-242-03-20	ACCRUED HEALTH INSURANCE - NH	Liabilities
30-40-00-00-242-03-25	ACCRUED DENTAL INSURANCE - NH	Liabilities
30-40-00-00-242-04-01	ACCRUED LEGAL-LOCAL-NH	Liabilities
30-40-00-00-242-04-02	ACCRUED LEGAL-CORP-NH	Liabilities
30-40-00-00-242-04-03	ACCRUED LEGAL-POWER SUPPLY-NH	Liabilities
30-40-00-00-242-04-04	ACCRUED LEGAL-REGULATORY-NH	Liabilities
30-40-00-00-242-04-08	ACCRUED LEGAL-CLAIMS AND LITIGATION	Liabilities
30-40-00-00-242-05-05	ACCRUED PUC ASSESSMENT- NH	Liabilities
30-40-00-00-242-06-00	FAS 158 ADJ-SERP CURRENT - NH	Liabilities
30-40-00-00-242-26-00	ACCRUED INCENTIVE COMPENSATION - NH	Liabilities
30-40-00-00-242-30-00	ACCRUED VACATION-NH	Liabilities
30-40-00-00-242-31-10	INSURANCE CLAIMS RESERVE - NH	Liabilities
30-40-00-00-242-33-00	UNEARNED REVENUE - UNH CONTRACT - NH	Liabilities
30-40-00-00-242-37-00	CURRENT ERC LIABILITIES - NH	Liabilities
30-40-00-00-242-90-00	REGULATORY LIABILITIES CURRENT - NH	Liabilities
30-40-00-00-242-90-01	UNDISTRIB COMMODITY SUPPLIER REFUNDS - NH	Liabilities
30-40-00-00-242-90-02	MISC REG LIABILITY - NH	Liabilities
30-40-00-00-242-90-11	ATV RECONCILIATION ACCRUAL - NH-PEAK	Liabilities
30-40-00-00-242-90-25	REG LIAB - GAS SUPPLIER REFUNDS-NH	Liabilities
30-40-00-00-242-90-43	PRICE RISK LIABILITY SHORT TERM- NH	Liabilities
30-40-00-00-243-01-00	OPER LEASE OBLIG - CURRENT	Liabilities
30-40-00-00-244-00-00	PRICE RISK LIABILITY - NH	Liabilities
30-40-00-00-244-01-00	PRICE RISK LIABILITY - NC - NH	Liabilities
30-40-00-00-252-01-00	LT REIMB CONTRIBUTIONS - NH	Liabilities
30-40-00-00-253-03-01	LT ERC COSTS - NH	Liabilities
30-40-00-00-253-04-01	FASB 87 - ACCRUED PENSION	Liabilities
30-40-00-00-253-04-03	ACCRUED SFAS 106 LIABILITY - NH	Liabilities
30-40-00-00-253-04-11	FAS 158 ADJ - PENSION - NH	Liabilities
30-40-00-00-253-04-13	FAS 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-253-04-14	FAS 158 ADJ - SERP - NH	Liabilities
30-40-00-00-254-01-00	REG LIAB - PRICE RISK - NC - NH	Liabilities
30-40-00-00-254-04-00	REGULATORY LIABILITY-COST OF REMOVAL-NH	Liabilities
30-40-00-00-254-05-00	REG LIAB - FAS109 COSTS - NH	Liabilities
30-40-00-00-254-05-01	REGULATORY LIABILITY - ASC 740 - NH	Liabilities
30-40-00-00-254-05-03	REGULATORY LIABILITY-ASC 740 REV REQ	Liabilities

Account Code	Account Description	Type
30-40-00-00-254-90-25	REG LIAB - GAS SUPPLIER REFUND	Liabilities
30-40-00-00-282-01-66	DEF FIT- R & D	Liabilities
30-40-00-00-282-02-66	DEF SIT- R & D	Liabilities
30-40-00-00-283-00-23	ACC DEF FIT-NONCURRENT 27811	Liabilities
30-40-00-00-283-00-43	ACC DEF SIT-NONCURRENT 27810	Liabilities
30-40-00-00-283-01-31	DEF FIT - ACCEL DEPR - NH	Liabilities
30-40-00-00-283-01-34	DEF FIT - SFAS 106 OPEB - NH	Liabilities
30-40-00-00-283-01-35	DEF FIT - PENSION FAS 87 - NH	Liabilities
30-40-00-00-283-01-42	DEF FIT - DEF RATE CASE COSTS - NH	Liabilities
30-40-00-00-283-01-43	DEF FIT - REMEDIATION - NH	Liabilities
30-40-00-00-283-01-51	DEF FIT - TRANSITION COSTS - NH	Liabilities
30-40-00-00-283-01-52	DEF FIT - TRANSACTION COSTS - NH	Liabilities
30-40-00-00-283-01-55	DEF FIT - OTHER - NH	Liabilities
30-40-00-00-283-01-59	DEF FIT - FASB 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-283-01-60	DEF FIT- PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-01-63	DEF FIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-01-64	DEF FIT - INSURANCE CLAIM RESERVE - NH	Liabilities
30-40-00-00-283-01-99	DEF FIT - DEBIT BALANCE RECLASS	Liabilities
30-40-00-00-283-02-31	DEF SIT- ACCEL DEPR - NH	Liabilities
30-40-00-00-283-02-34	DEF SIT- SFAS 106 OPEB - NH	Liabilities
30-40-00-00-283-02-35	DEF SIT- PENSION FAS 87 - NH	Liabilities
30-40-00-00-283-02-42	DEF SIT- DEF RATE CASE COSTS - NH	Liabilities
30-40-00-00-283-02-43	DEF SIT- REMEDIATION - NH	Liabilities
30-40-00-00-283-02-51	DEF SIT - TRANSITION COSTS - NH	Liabilities
30-40-00-00-283-02-52	DEF SIT - TRANSACTION COSTS - NH	Liabilities
30-40-00-00-283-02-59	DEF SIT- FASB 158 ADJ - PBOP - NH	Liabilities
30-40-00-00-283-02-60	DEF SIT- PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-02-63	DEF SIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-02-64	DEF SIT - INSURANCE CLAIM RESERVE- NH	Liabilities
30-40-00-00-283-02-99	DEF SIT - DEBIT BALANCE RECLASS	Liabilities
30-40-00-00-283-03-03	TCJA REV REQ GROSS-UP	Liabilities
30-40-00-00-283-05-01	ACCUM DEF (ASC 740) GROSS-UP	Liabilities
30-40-00-00-283-11-38	DEF FIT - BAD DEBT- NH	Liabilities
30-40-00-00-283-11-39	DEF FIT - ACCRUED REVENUE - NH	Liabilities
30-40-00-00-283-11-41	DEF FIT- PREPAID PROPERTY TAX - NH	Liabilities
30-40-00-00-283-12-38	DEF SIT- BAD DEBT - NH	Liabilities
30-40-00-00-283-12-39	DEF SIT- ACCRUED REVENUE - NH	Liabilities
30-40-00-00-283-12-41	DEF SIT- PREPAID PROPERTY TAX - NH	Liabilities
30-40-00-00-283-91-59	DEF FIT - SFAS 158 PBOP - NH	Liabilities
30-40-00-00-283-91-60	DEF FIT - PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-91-63	DEF FIT - SFAS 158 SERP - NH	Liabilities
30-40-00-00-283-92-59	DEF SIT - SFAS 158 PBOP - NH	Liabilities
30-40-00-00-283-92-60	DEF SIT - PENSION FAS 158 - NH	Liabilities
30-40-00-00-283-92-63	DEF SIT - SFAS 158 SERP - NH	Liabilities
30-40-01-00-431-00-99	INVENTORY FINANCE CHARGES - PEAK - NH	Expenses
30-40-01-00-921-03-00	DUES & SUBSCRIPTIONS	Expenses
30-40-01-00-923-00-02	OS LEGAL - MISC	Expenses
30-40-01-00-928-01-00	REG COMM ASSESSMENT/FEES-NH	Expenses
30-40-01-00-928-02-00	REG COMM EXP - MISC-NH	Expenses
30-40-01-00-928-03-00	REG COMM EXP - LEGAL-NH	Expenses
30-40-01-10-419-00-00	INTEREST INCOME-DMD-COM-P-NH	Revenues
30-40-01-10-431-00-00	INTEREST EXPENSE-DMD-COM-P-NH	Expenses
30-40-01-13-419-00-00	INTEREST INCOME-WC-P-NH	Revenues
30-40-01-13-431-00-00	INTEREST EXPENSE-WC-P-NH	Expenses
30-40-01-14-419-00-00	INTEREST INCOME-BAD DEBT-P-NH	Revenues
30-40-01-14-431-00-00	INTEREST EXPENSE-BAD DEBT-P-NH	Expenses
30-40-01-40-419-00-00	INTEREST INCOME-DMD-COM-OP-NH	Revenues
30-40-01-40-431-00-00	INTEREST EXPENSE-DMD-COM-OP-NH	Expenses
30-40-01-43-419-00-00	INTEREST INCOME-WC-OP-NH	Revenues
30-40-01-43-431-00-00	INTEREST EXPENSE-WC-OP-NH	Expenses
30-40-01-44-419-00-00	INTEREST INCOME-BAD DEBT-OP-NH	Revenues
30-40-01-44-431-00-00	INTEREST EXPENSE-BAD DEBT-OP-NH	Expenses
30-40-01-70-419-00-00	INT INC-SUP REF-DEMAND-NH	Revenues
30-40-01-70-431-00-00	INT EXP-SUP REF-DEMAND-NH	Expenses

Account Code	Account Description	Type
30-40-01-71-419-00-00	INT INC-SUP REF - COMMODITY - NH	Revenues
30-40-01-71-431-00-00	INT EXP-SUP REF - COMMODITY - NH	Expenses
30-40-01-72-419-10-05	INTEREST INCOME- LDAC EEC-NH	Revenues
30-40-01-72-431-10-05	INTEREST EXPENSE- LDAC EEC	Expenses
30-40-01-72-495-00-99	LDAC-EEC LOST BASE REVENUE	Revenues
30-40-01-77-419-00-00	INTEREST INCOME-RLIARA-NH	Revenues
30-40-01-77-431-00-00	INTEREST EXPENSE-RLIARA-NH	Expenses
30-40-01-78-419-00-00	INTEREST INCOME - RATE CASE EXP - NH	Revenues
30-40-01-78-431-00-00	INTEREST EXPENSE - RATE CASE EXP - NH	Expenses
30-40-01-81-419-00-00	INTEREST INCOME - LRA - NH	Revenues
30-40-01-81-431-00-00	INTEREST EXPENSE - LRA - NH	Expenses
30-40-02-00-923-30-00	MKT DEV - GENERAL -NH	Expenses
30-40-02-00-930-24-00	MISC GENERAL EXPENSES - NH	Expenses
30-40-02-50-184-07-00	WATER HEATER OVERHEADS - NH	Assets
30-40-02-50-923-06-00	USC - WATER HEATER PROGRAM (GAS)-NH	Expenses
30-40-03-00-408-03-10	TAXES FICA - NH	Expenses
30-40-03-00-408-04-10	TAXES FEDERAL UNEMPLOYMENT - NH	Expenses
30-40-03-00-408-06-11	TAXES UNEMPLOYMENT - NH	Expenses
30-40-03-00-408-08-10	TAXES STATE HEALTH - NH	Expenses
30-40-03-00-426-01-00	PENALTIES-NH	Expenses
30-40-03-00-426-10-00	DONATIONS - NH	Expenses
30-40-03-00-920-05-00	INCENTIVE COMPENSATION - NH	Expenses
30-40-03-00-926-00-00	EMPL PENSION-PAYROLL	Expenses
30-40-03-00-926-01-00	EMPL PENSION-401K	Expenses
30-40-03-00-926-02-01	FASB 87- PENSION - SERVICE	Expenses
30-40-03-00-926-02-20	FASB 87- PENSION - OTHER	Expenses
30-40-03-00-926-03-00	HEALTH INSUR MEDICAL ONLY	Expenses
30-40-03-00-926-03-01	HEALTH INS - EMP CONTR - MEDICAL ONLY	Expenses
30-40-03-00-926-03-03	HEALTH INS - DRUG SUBSIDY	Expenses
30-40-03-00-926-04-00	EMPL BENEFIT-LIFE INSURANCE	Expenses
30-40-03-00-926-06-00	EMPL BENEFITS OTHER-USC	Expenses
30-40-03-00-926-06-01	EMP BENEFITS OTHER - SHARED - NH	Expenses
30-40-03-00-926-09-00	SFAS 106- PBOP - SERVICE	Expenses
30-40-03-00-926-09-19	SFAS 106- PBOP - OTHER	Expenses
30-40-03-00-926-10-00	EMPL PENSION FUND SERVICES	Expenses
30-40-03-00-926-11-00	MISC GENERAL EXPENSE	Expenses
30-40-03-00-926-12-00	DENTAL INSURANCE	Expenses
30-40-03-00-926-12-01	DENTAL INSURANCE - EMP CONTRIBUTION	Expenses
30-40-03-00-926-13-00	AD&D INSURANCE	Expenses
30-40-03-00-926-14-00	LTD INSURANCE	Expenses
30-40-03-00-926-24-00	VISION INSURANCE	Expenses
30-40-03-00-926-24-01	VISION - EE CONTR	Expenses
30-40-08-00-419-00-00	INTEREST INCOME-MISC-NH	Revenues
30-40-08-00-419-01-00	INTEREST INCOME - HEDGING - NH	Revenues
30-40-08-00-419-09-00	INT INC-OTHER - NH	Revenues
30-40-08-00-419-09-01	INT INC - CASH POOL - NH	Revenues
30-40-08-00-421-00-00	MISC NON OPER INCOME - NH	Revenues
30-40-08-00-426-10-00	DONATIONS - NH	Expenses
30-40-08-00-427-00-00	INTEREST ON LT DEBT - NH	Expenses
30-40-08-00-428-00-00	AMORT OF DEBT EXPENSE - NH	Expenses
30-40-08-00-430-00-00	INTEREST EXPENSE - ASSOC. CO. - NH	Expenses
30-40-08-00-431-00-00	OTHER INTEREST EXPENSE - NH	Expenses
30-40-08-00-431-01-00	INTEREST EXPENSE - HEDGING - NH	Expenses
30-40-08-00-431-32-00	INT EXP-NON COMPETE LIABILITY	Expenses
30-40-08-00-457-00-01	RENTAL INCOME - GRANITE	Revenues
30-40-08-00-457-00-02	RENTAL INCOME - USOURCE	Revenues
30-40-08-00-457-00-03	RENTAL INCOME - USC	Revenues
30-40-08-00-480-00-99	CONVERTED REVENUE RESIDENTIAL NON EXT	Revenues
30-40-08-00-481-00-99	CONVERTED REVENUE COMMERCIAL NON EXT	Revenues
30-40-08-00-481-02-99	CONVERTED REVENUE INDUSTRIAL NON EXT	Revenues
30-40-08-00-481-10-01	SIMPLEX NU CONVERTED REVENUE	Revenues
30-40-08-00-481-11-01	NAT GYPSUM NU CONVERTED REVENUE	Revenues
30-40-08-00-481-12-01	FOSS NU CONVERTED REVENUE	Revenues
30-40-08-00-485-00-00	UNBILLED SALE	Revenues

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-08-00-487-00-01	LATE PAYMENT FEE - RES - NH	Revenues
30-40-08-00-487-00-02	LATE PAYMENT FEE - COMM - NH	Revenues
30-40-08-00-487-00-03	LATE PAYMENT FEE - ANCILLARY SERVICES	Revenues
30-40-08-00-488-00-03	RECONNECT FEE - NH	Revenues
30-40-08-00-488-00-04	UNAUTHORIZED USE OF GAS - NH	Revenues
30-40-08-00-488-00-05	POOL ADMINISTRATION	Revenues
30-40-08-00-488-00-06	3RD PARTY BILLING	Revenues
30-40-08-00-488-00-07	CUSTOMER TELEMETERING	Revenues
30-40-08-00-488-00-08	METER TEST REVENUE	Revenues
30-40-08-00-488-00-09	CUSTOMER RE-ENTRY FEE	Revenues
30-40-08-00-489-01-01	R-6 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-02	R-11 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-03	R-5 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-04	R-10 NU CONVERTED REVENUE	Revenues
30-40-08-00-489-01-99	CONVERTED REVENUE RESIDENTIAL EXT	Revenues
30-40-08-00-489-02-99	CONVERTED REVENUE COMMERCIAL EXT	Revenues
30-40-08-00-489-03-99	CONVERTED REVENUE INDUSTRIAL EXT	Revenues
30-40-08-00-489-11-01	NAT GYPSUM NU CONVERTED REVENUE	Revenues
30-40-08-00-489-12-00	FOSS NU CONVERTED REVENUE	Revenues
30-40-08-00-489-12-01	Foss W-EXT-Excess (3)	Revenues
30-40-08-00-493-00-02	RENTAL INCOME -USOURCE	Revenues
30-40-08-00-495-10-01	UNBILLED REVENUE - SEASONALITY - NH	Revenues
30-40-08-00-495-50-00	RATE RELIEF - NU NH	Revenues
30-40-08-00-921-01-08	BANK FEES & COMMITMENT FEES - NH	Expenses
30-40-08-00-921-01-11	CREDIT RATING FEES	Expenses
30-40-08-00-923-00-00	OS- LEGAL CLAIMS AND LITIGATIONS	Expenses
30-40-08-00-923-00-01	OS LEGAL - CORP-NH	Expenses
30-40-08-00-924-00-00	PROPERTY INSURANCE	Expenses
30-40-08-00-925-00-00	D & O AND FIDUCIARY	Expenses
30-40-08-00-925-02-00	GENERAL LIABILITY	Expenses
30-40-08-00-925-02-02	GENERAL LIABILITY CLAIMS	Expenses
30-40-08-00-925-04-00	WORKERS COMPENSATION EXP	Expenses
30-40-08-00-930-02-00	TRUSTEE/REGISTRAR EXPENSE - NH	Expenses
30-40-08-01-480-01-01	R-6 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-01-02	R-11 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-02-01	R-5 W-NEXT-Customer Charge	Revenues
30-40-08-01-480-02-02	R-10 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-01-01	G-40 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-01-02	G-50 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-02-01	G-41 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-02-02	G-51 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-03-01	G-42 W-NEXT-Customer Charge	Revenues
30-40-08-01-481-03-02	G-52 W-NEXT-Customer Charge	Revenues
30-40-08-01-489-01-01	R-6 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-02	R-11 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-03	R-5 W-EXT-Customer Charge	Revenues
30-40-08-01-489-01-04	R-10 W-EXT-Customer Charge	Revenues
30-40-08-01-489-02-01	G-40 W-EXT-Customer Charge	Revenues
30-40-08-01-489-02-02	G-50 W-EXT-Customer Charge	Revenues
30-40-08-01-489-03-01	G-41 W-EXT-Customer Charge	Revenues
30-40-08-01-489-03-02	G-51 W-EXT-Customer Charge	Revenues
30-40-08-01-489-04-01	G-42 W-EXT-Customer Charge	Revenues
30-40-08-01-489-04-02	G-52 W-EXT-Customer Charge	Revenues
30-40-08-01-489-11-01	Nat Gypsum W-EXT-Customer Charge	Revenues
30-40-08-01-489-12-01	Foss W-EXT-Customer Charge	Revenues
30-40-08-02-480-01-01	R-6 W-NEXT-First Step	Revenues
30-40-08-02-480-01-02	R-11 W-NEXT-First Step	Revenues
30-40-08-02-480-02-01	R-5 W-NEXT-First Step	Revenues
30-40-08-02-480-02-02	R-10 W-NEXT-First Step	Revenues
30-40-08-02-481-01-01	G-40 W-NEXT-First Step	Revenues
30-40-08-02-481-01-02	G-50 W-NEXT-First Step	Revenues
30-40-08-02-481-02-01	G-41 W-NEXT-First Step	Revenues
30-40-08-02-481-02-02	G-51 W-NEXT-First Step	Revenues
30-40-08-02-481-03-01	G-42 W-NEXT-First Step	Revenues

Account Code	Account Description	Type
30-40-08-02-481-03-02	G-52 W-NEXT-First Step	Revenues
30-40-08-02-489-01-01	R-6 W-EXT-First Step	Revenues
30-40-08-02-489-01-02	R-11 W-EXT-First Step	Revenues
30-40-08-02-489-01-04	R-10 W-EXT-First Step	Revenues
30-40-08-02-489-02-01	G-40 W-EXT-First Step	Revenues
30-40-08-02-489-02-02	G-50 W-EXT-First Step	Revenues
30-40-08-02-489-03-01	G-41 W-EXT-First Step	Revenues
30-40-08-02-489-03-02	G-51 W-EXT-First Step	Revenues
30-40-08-02-489-04-01	G-42 W-EXT-First Step	Revenues
30-40-08-02-489-04-02	G-52 W-EXT-First Step	Revenues
30-40-08-02-489-11-01	Nat Gypsum W-EXT-First Step	Revenues
30-40-08-02-489-12-01	Foss W-EXT-First Step	Revenues
30-40-08-03-480-01-01	R-6 W-NEXT-Excess	Revenues
30-40-08-03-480-01-02	R-11 W-NEXT-Excess	Revenues
30-40-08-03-480-02-01	R-5 W-NEXT-Excess	Revenues
30-40-08-03-480-02-02	R-10 W-NEXT-Excess	Revenues
30-40-08-03-481-01-01	G-40 W-NEXT-Excess	Revenues
30-40-08-03-481-01-02	G-50 W-NEXT-Excess	Revenues
30-40-08-03-481-02-02	G-51 W-NEXT-Excess	Revenues
30-40-08-03-481-12-01	Foss W-NEXT-Excess	Revenues
30-40-08-03-489-01-01	R-6 W-EXT-Excess	Revenues
30-40-08-03-489-01-02	R-11 W-EXT-Excess	Revenues
30-40-08-03-489-01-04	R-10 W-EXT-Excess	Revenues
30-40-08-03-489-02-01	G-40 W-EXT-Excess	Revenues
30-40-08-03-489-02-02	G-50 W-EXT-Excess	Revenues
30-40-08-03-489-03-02	G-51 W-EXT-Excess	Revenues
30-40-08-03-489-12-01	Foss W-EXT-Excess	Revenues
30-40-08-04-481-12-01	Foss W-NEXT-Excess (2)	Revenues
30-40-08-04-489-12-01	Foss W-EXT-Excess (2)	Revenues
30-40-08-05-481-12-01	Foss S-NEXT-Excess (3)	Revenues
30-40-08-05-489-12-01	Foss S-EXT-Excess (3)	Revenues
30-40-08-06-480-01-01	R-6 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-01-02	R-11 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-02-01	R-5 S-NEXT-Customer Charge	Revenues
30-40-08-06-480-02-02	R-10 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-01-01	G-40 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-01-02	G-50 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-02-01	G-41 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-02-02	G-51 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-03-01	G-42 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-03-02	G-52 S-NEXT-Customer Charge	Revenues
30-40-08-06-481-10-01	Simplex S-NEXT-Customer Charge	Revenues
30-40-08-06-481-12-01	Foss S-NEXT-Customer Charge	Revenues
30-40-08-06-489-01-01	R-6 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-02	R-11 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-03	R-5 S-EXT-Customer Charge	Revenues
30-40-08-06-489-01-04	R-10 S-EXT-Customer Charge	Revenues
30-40-08-06-489-02-01	G-40 S-EXT-Customer Charge	Revenues
30-40-08-06-489-02-02	G-50 S-EXT-Customer Charge	Revenues
30-40-08-06-489-03-01	G-41 S-EXT-Customer Charge	Revenues
30-40-08-06-489-03-02	G-51 S-EXT-Customer Charge	Revenues
30-40-08-06-489-04-01	G-42 S-EXT-Customer Charge	Revenues
30-40-08-06-489-04-02	G-52 S-EXT-Customer Charge	Revenues
30-40-08-06-489-11-01	Nat Gypsum S-EXT-Customer Charge	Revenues
30-40-08-06-489-12-01	Foss S-EXT-Customer Charge	Revenues
30-40-08-07-480-01-01	R-6 S-NEXT-First Step	Revenues
30-40-08-07-480-01-02	R-11 S-NEXT-First Step	Revenues
30-40-08-07-480-02-01	R-5 S-NEXT-First Step	Revenues
30-40-08-07-480-02-02	R-10 S-NEXT-First Step	Revenues
30-40-08-07-481-01-01	G-40 S-NEXT-First Step	Revenues
30-40-08-07-481-01-02	G-50 S-NEXT-First Step	Revenues
30-40-08-07-481-02-01	G-41 S-NEXT-First Step	Revenues
30-40-08-07-481-02-02	G-51 S-NEXT-First Step	Revenues
30-40-08-07-481-03-01	G-42 S-NEXT-First Step	Revenues

Account Code	Account Description	Type
30-40-08-07-481-03-02	G-52 S-NEXT-First Step	Revenues
30-40-08-07-481-10-01	Simplex S-NEXT-First Step	Revenues
30-40-08-07-481-11-01	Nat Gypsum S-NEXT-First Step	Revenues
30-40-08-07-481-12-01	Foss S-NEXT-First Step	Revenues
30-40-08-07-489-01-01	R-6 S-EXT-First Step	Revenues
30-40-08-07-489-01-02	R-11 S-EXT-First Step	Revenues
30-40-08-07-489-01-04	R-10 S-EXT-First Step	Revenues
30-40-08-07-489-02-01	G-40 S-EXT-First Step	Revenues
30-40-08-07-489-02-02	G-50 S-EXT-First Step	Revenues
30-40-08-07-489-03-01	G-41 S-EXT-First Step	Revenues
30-40-08-07-489-03-02	G-51 S-EXT-First Step	Revenues
30-40-08-07-489-04-01	G-42 S-EXT-First Step	Revenues
30-40-08-07-489-04-02	G-52 S-EXT-First Step	Revenues
30-40-08-07-489-11-01	Nat Gypsum S-EXT-First Step	Revenues
30-40-08-07-489-12-01	Foss S-EXT-First Step	Revenues
30-40-08-08-480-01-01	R-6 S-NEXT-Excess	Revenues
30-40-08-08-480-01-02	R-11 S-NEXT-Excess	Revenues
30-40-08-08-480-02-01	R-5 S-NEXT-Excess	Revenues
30-40-08-08-480-02-02	R-10 S-NEXT-Excess	Revenues
30-40-08-08-481-01-01	G-40 S-NEXT-Excess	Revenues
30-40-08-08-481-01-02	G-50 S-NEXT-Excess	Revenues
30-40-08-08-481-02-02	G-51 S-NEXT-Excess	Revenues
30-40-08-08-481-12-01	Foss S-NEXT-Excess	Revenues
30-40-08-08-489-01-01	R-6 S-EXT-Excess	Revenues
30-40-08-08-489-01-02	R-11 S-EXT-Excess	Revenues
30-40-08-08-489-01-04	R-10 S-EXT-Excess	Revenues
30-40-08-08-489-02-01	G-40 S-EXT-Excess	Revenues
30-40-08-08-489-02-02	G-50 S-EXT-Excess	Revenues
30-40-08-08-489-03-02	G-51 S-EXT-Excess	Revenues
30-40-08-08-489-12-01	Foss S-EXT-Excess	Revenues
30-40-08-09-481-12-01	Foss S-NEXT-Excess (2)	Revenues
30-40-08-09-489-12-01	Foss S-EXT-Excess (2)	Revenues
30-40-09-00-875-00-01	INTERVAL DATA NU NH	Expenses
30-40-09-00-902-00-00	CUST ACCTS METER READ EXP NH	Expenses
30-40-09-00-921-17-00	TELEPHONE SERVICE - SERVICE CENTER - NH	Expenses
30-40-10-00-403-00-00	DEPRECIATION GAS - NH	Expenses
30-40-10-00-403-24-00	DEPRECIATION GAS - NH	Expenses
30-40-10-00-404-03-00	AMORTIZATION OF COMP SOFTWARE	Expenses
30-40-10-00-404-04-00	AMORT INTANGIBLE SOFTWARE - NH	Expenses
30-40-10-00-406-00-00	AMORT-INVESTMNT TAX CREDIT - NH	Expenses
30-40-10-00-407-01-00	AMORTIZATION - EXCESS ADIT - BASE REV	Expenses
30-40-10-00-407-04-19	AMORTIZATION OF OTHER PBOP COST	Expenses
30-40-10-00-407-04-20	AMORTIZATION OF OTHER PENSION COST	Expenses
30-40-10-00-407-04-21	AMORT OF OTHER SERP COST	Expenses
30-40-10-00-407-09-01	AMORT EXP-FAS 109 REG LIABILITY - GAS - NH	Expenses
30-40-10-00-407-11-00	AMORT - NON DIST BAD DEBT REG ASSET - ME	Expenses
30-40-10-00-408-00-00	OTHER TAXES	Expenses
30-40-10-00-408-02-10	NH SURPLUS TAX	Expenses
30-40-10-00-408-02-18	NH BET TAX EXPENSE	Expenses
30-40-10-00-408-10-00	PAYROLL TAXES CAPTIALIZED - NH	Expenses
30-40-10-00-408-12-00	LOCAL OPER. PROPERTY TAX - NH	Expenses
30-40-10-00-408-12-01	LOCAL OPER PROPERTY TAX ABATEMENTS - NH	Expenses
30-40-10-00-409-01-30	FED INCOME TAX CURRENT - GAS - NH	Expenses
30-40-10-00-409-01-31	FED INCOME TAX - PRIOR - GAS - NH	Expenses
30-40-10-00-409-01-32	FED INCOME TAX - NON OPER - GAS - NH	Expenses
30-40-10-00-409-02-30	STATE INCOME TAX EXP - CURRENT - NH	Expenses
30-40-10-00-409-02-31	STATE INCOME TAX EXP - PRIOR - NH	Expenses
30-40-10-00-409-02-32	STATE INC TAX-NON OPER-CURRENT-NH	Expenses
30-40-10-00-410-01-00	DEF FIT EXP - NH	Expenses
30-40-10-00-410-01-30	DEF FIT EXP-ACCEL DEPRECIATION - NH	Expenses
30-40-10-00-410-01-34	DEF FIT EXP-SFAS 106 OPEB - NH	Expenses
30-40-10-00-410-01-35	DEF FIT EXP-PENSION FAS 87 - NH	Expenses
30-40-10-00-410-01-37	DEF FIT EXP-STOCK COMP - NH	Expenses
30-40-10-00-410-01-38	DEF FIT EXP-BAD DEBT - NH	Expenses

Account Code	Account Description	Type
30-40-10-00-410-01-39	DEF FIT EXP-ACCRUED REVENUE - NH	Expenses
30-40-10-00-410-01-41	DEF FIT EXP-PREPAID PROP TAX - NH	Expenses
30-40-10-00-410-01-42	DEF FIT EXP-RATE CASE COSTS - NH	Expenses
30-40-10-00-410-01-45	DEF FIT EXP-REMEDIATION - NH	Expenses
30-40-10-00-410-01-51	DEF FIT-TRANSITION COSTS - NH	Expenses
30-40-10-00-410-01-52	DEF FIT-TRANSACTION COSTS - NH	Expenses
30-40-10-00-410-01-64	DEF FIT-MISC - NH	Expenses
30-40-10-00-410-01-66	DEF FIT EXP- R&D	Expenses
30-40-10-00-410-02-00	DEF SIT EXP- NH	Expenses
30-40-10-00-410-02-30	DEF SIT EXP-ACCEL DEPRECIATION-NH	Expenses
30-40-10-00-410-02-34	DEF SIT EXP-SFAS 106 OPEB - NH	Expenses
30-40-10-00-410-02-35	DEF SIT EXP-PENSION FAS 87 - NH	Expenses
30-40-10-00-410-02-37	DEF SIT EXP-STOCK COMP - NH	Expenses
30-40-10-00-410-02-38	DEF SIT EXP-BAD DEBT - NH	Expenses
30-40-10-00-410-02-39	DEF SIT EXP-ACCRUED REVENUE - NH	Expenses
30-40-10-00-410-02-41	DEF SIT EXP-PREPAID PROP TAX - NH	Expenses
30-40-10-00-410-02-42	DEF SIT EXP-RATE CASE COSTS - NH	Expenses
30-40-10-00-410-02-45	DEF SIT EXP-REMEDIATION - NH	Expenses
30-40-10-00-410-02-51	DEF SIT-TRANSITION COSTS - NH	Expenses
30-40-10-00-410-02-52	DEF SIT-TRANSACTION COSTS - NH	Expenses
30-40-10-00-410-02-64	DEF SIT-MISC - NH	Expenses
30-40-10-00-410-02-66	DEF SIT EXP- R&D	Expenses
30-40-10-00-410-03-03	DEF TAX - TCJA REV REQ GROSS-UP	Expenses
30-40-10-00-411-01-00	AMORTIZATION - EXCESS ADIT - BASE REV - NH	Expenses
30-40-10-00-411-01-10	DEF TAX - DISCRETE TAX PROVISION	Expenses
30-40-10-00-421-00-01	USC BELOW THE LINE RECLASS	Expenses
30-40-10-00-426-01-01	USC BELOW THE LINE RECLASS	Expenses
30-40-10-00-426-01-02	USC PENALTIES RECLASS	Expenses
30-40-10-00-426-05-00	OTHER INCOME DEDUCTIONS - NH	Expenses
30-40-10-00-426-20-00	NIPSCO AMORTIZATION	Expenses
30-40-10-00-426-21-00	SQI METER TO CASH	Expenses
30-40-10-00-432-00-00	AFUDC-BORROWED FUNDS - NH	Expenses
30-40-10-00-485-21-00	COMMERCIAL TRANS NORMALIZATION	Revenues
30-40-10-00-485-52-00	INDUSTRIAL TRANS NORMALIZATION	Revenues
30-40-10-00-493-00-00	INTERCOMPANY RENT	Revenues
30-40-10-00-493-00-01	RENTAL INCOME - GSG	Revenues
30-40-10-00-493-00-03	RENTAL INCOME - USC	Revenues
30-40-10-00-495-00-27	ACCRUED REVENUE - NON DIST BAD DEBT	Revenues
30-40-10-00-495-10-00	UNBILLED GAS REVENUE - NH	Revenues
30-40-10-00-495-10-01	ACCRUED REVENUE - TCJA 2018	Revenues
30-40-10-00-495-10-02	UNBILLED REVENUE - SEASONALITY - NH	Revenues
30-40-10-00-495-30-00	ACCRUED REVENUE - OTHER	Revenues
30-40-10-00-813-01-00	USC-GAS PRODUCTION OTHER - NH	Expenses
30-40-10-00-851-02-00	USC- DISPATCH	Expenses
30-40-10-00-851-02-01	USC- DISPATCH - CAP	Expenses
30-40-10-00-880-02-00	USC-GAS DISTRIBUTION - NH	Expenses
30-40-10-00-880-02-01	USC-GAS DISTRIBUTION - NH-CAP	Expenses
30-40-10-00-885-06-00	UNPROD TIME/CAPITALIZED - NH	Expenses
30-40-10-00-903-06-00	USC - CUSTOMER ACCOUNTING	Expenses
30-40-10-00-904-00-00	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expenses
30-40-10-00-904-00-27	PROVISION FOR DOUBTFUL ACCTS - NON-DIST - NH	Expenses
30-40-10-00-920-05-00	INCENTIVE COMPENSATION CAPITALIZED	Expenses
30-40-10-00-920-09-00	PAYROLL ACCRUAL	Expenses
30-40-10-00-921-15-00	SVC CENTER CAPITALIZED- SHARED NH	Expenses
30-40-10-00-921-19-00	TELEPHONE SVS CAPITALIZED- SHARED NH	Expenses
30-40-10-00-923-02-00	OUTSIDE SERVICES-AUDIT-NH	Expenses
30-40-10-00-923-03-00	OS UNITIL SERVICE CORP-NH	Expenses
30-40-10-00-923-03-01	OS UNITIL SERVICE CORP-NH-CAP	Expenses
30-40-10-00-923-03-05	USC OUTSIDE SERVICES-DIRECT CHGS-NH	Expenses
30-40-10-00-923-03-07	DIRECT CHARGES CAPITALIZED	Expenses
30-40-10-00-923-03-08	USC ALLOCATED PBOP EXPENSE	Expenses
30-40-10-00-923-03-09	USC ALLOCATED SERP EXPENSE	Expenses
30-40-10-00-923-03-10	USC ALLOCATED PENSION EXPENSE	Expenses
30-40-10-00-923-04-00	OS OTHER	Expenses

Northern Utilities, Inc.
Chart of Accounts
NH Division

Account Code	Account Description	Type
30-40-10-00-923-09-00	OUTSIDE SERVICES-NH	Expenses
30-40-10-00-924-00-01	PROPERTY INS CAPITALIZED	Expenses
30-40-10-00-925-02-01	GEN LIAB CAPITALIZED	Expenses
30-40-10-00-925-04-01	WORKERS COMP CAPITALIZED	Expenses
30-40-10-00-926-01-01	401K CAPITALIZED	Expenses
30-40-10-00-926-02-10	PENSION - USC ALLOC - SVC	Expenses
30-40-10-00-926-02-30	PENSION - USC ALLOC - OTHER	Expenses
30-40-10-00-926-02-99	FASB 87 - YEAR END ACCRUAL ADJ	Expenses
30-40-10-00-926-03-02	EMPLOYEE BENEFIT ACCRUAL ADJ	Expenses
30-40-10-00-926-05-00	BENEFIT COST CAPITALIZED	Expenses
30-40-10-00-926-08-00	PENSION - SVC CAPITALIZED	Expenses
30-40-10-00-926-08-12	PENSION - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-08-20	PENSION - OTHER - CAPITALIZED	Expenses
30-40-10-00-926-08-30	PENSION - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-926-09-10	PBOP - USC ALLOC - SVC	Expenses
30-40-10-00-926-09-29	PBOP - USC ALLOC - OTHER	Expenses
30-40-10-00-926-11-10	SERP - USC ALLOC - SVC	Expenses
30-40-10-00-926-11-31	SERP - USC ALLOC - OTHER	Expenses
30-40-10-00-926-17-00	PBOP - SVC CAPITALIZED	Expenses
30-40-10-00-926-17-12	PBOP - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-17-19	PBOP - OTHER - CAPITALIZED	Expenses
30-40-10-00-926-17-29	PBOP - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-926-18-12	SERP - USC ALLOC - SVC CAPITALIZED	Expenses
30-40-10-00-926-18-31	SERP - USC ALLOC - OTHER DEFERRED	Expenses
30-40-10-00-930-10-00	MISC EXP - PANDEMIC COSTS - NH	Expenses
30-40-10-00-930-20-00	MISC EXPENSE	Expenses
30-40-10-00-931-00-00	RENT- GARAGE SPACE - NH	Expenses
30-40-10-00-935-11-00	SVC CENTER CAPITALIZED - NH	Expenses
30-40-10-11-723-01-02	LPG EXPENSE MISC - ELECTRIC PEAK - NH	Expenses
30-40-10-13-419-00-99	WORKING CAPITAL - PEAK - NH	Revenues
30-40-10-43-419-00-99	WORKING CAPITAL - OFF PEAK - NH	Revenues
30-40-12-00-923-04-00	OS - ENGINEERING - NH	Expenses
30-40-13-00-921-03-00	DUES & SUBSCRIPTIONS - NH	Expenses
30-40-13-00-921-38-00	PC SOFTWARE & SUPPLY - NH	Expenses
30-40-13-00-923-00-02	OS LEGAL - MISC	Expenses
30-40-13-00-923-06-00	OS IRP EXPENSE-NH	Expenses
30-40-13-00-923-07-00	OS EXPENSE OTHER - NH	Expenses
30-40-13-00-928-03-00	POWER SUPPLY - LEGAL-NH	Expenses
30-40-15-00-923-00-00	OS- LEGAL CLAIMS AND LITIGATIONS	Expenses
30-40-15-00-930-20-00	MISC GENERAL EXP - STATUTORY REP FEES	Expenses
30-40-21-00-415-05-00	JOBBING	Revenues
30-40-21-00-426-05-01	OTHER INC DED - CUSTOMER RELATIONS	Expenses
30-40-21-00-431-04-00	INTEREST ON CUSTOMER DEPOSITS - NH	Expenses
30-40-21-00-903-02-00	BILLG/ACCT FORMS/SUPPLIES - NH	Expenses
30-40-21-00-903-04-00	POSTAGE - NH	Expenses
30-40-21-00-903-05-01	MISC COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-02	COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-03	SUNDRY COST OF COLLECTIONS - NH	Expenses
30-40-21-00-903-05-04	O/S VENDOR SERVICES - MAILROOM - NH	Expenses
30-40-21-00-903-08-00	MISC CUSTOMER RELATIONS - NH	Expenses
30-40-21-00-903-10-00	O/S REMITTANCE LOCK BOX	Expenses
30-40-21-00-904-00-00	PROVISION FOR DOUBTFUL ACCTS - DISTR - NH	Expenses
30-40-21-00-904-01-00	PROVISION FOR DOUBTFUL ACCTS - SUNDRY - NH	Expenses
30-40-21-00-904-99-99	BD EXP CIS CNVRTED WO	Expenses
30-40-21-00-909-01-00	NEIGHBOR HELPING NEIGHBOR	Expenses
30-40-21-00-921-01-09	CREDIT CARD FEES	Expenses
30-40-21-00-923-02-00	MISC COSTS - AFCC-NH	Expenses
30-40-21-00-923-08-00	MISC COSTS - AFCC-NH	Expenses
30-40-21-14-904-00-05	BD EXP CIS R5-W -DIST	Expenses
30-40-21-14-904-00-06	BD EXP CIS R6-W-DIST	Expenses
30-40-21-14-904-00-10	BD EXP CIS R10-W-DIST	Expenses
30-40-21-14-904-00-11	BD EXP CIS R11-W-DIST	Expenses
30-40-21-14-904-00-40	BD EXP CIS G40-W-DIST	Expenses
30-40-21-14-904-00-41	BD EXP CIS G41-W-DIST	Expenses

Account Code	Account Description	Type
30-40-21-14-904-00-42	BD EXP CIS G42-W-DIST	Expenses
30-40-21-14-904-00-50	BD EXP CIS G50-W-DIST	Expenses
30-40-21-14-904-00-51	BD EXP CIS G51-W-DIST	Expenses
30-40-21-14-904-00-52	BD EXP CIS G52-W-DIST	Expenses
30-40-21-14-904-00-65	BD EXP CIS SP CT-W-DIST	Expenses
30-40-21-14-904-99-99	BD EXP CIS CNVRTED WO	Expenses
30-40-21-44-904-00-05	BD EXP CIS R5-S-DIST	Expenses
30-40-21-44-904-00-06	AFDA R6 - RES NONHEAT - SUMMER - DIST	Expenses
30-40-21-44-904-00-10	BD EXP CIS R1-S-DIST	Expenses
30-40-21-44-904-00-11	BD EXP CIS R11-S-DIST	Expenses
30-40-21-44-904-00-40	BD EXP CIS G40-S-DIST	Expenses
30-40-21-44-904-00-41	BD EXP CIS G41-S-DIST	Expenses
30-40-21-44-904-00-42	BD EXP CIS G42-S-DIST	Expenses
30-40-21-44-904-00-50	BD EXP CIS G50-S-DIST	Expenses
30-40-21-44-904-00-51	BD EXP CIS G51-S-DIST	Expenses
30-40-21-44-904-00-52	BD EXP CIS G52-S-DIST	Expenses
30-40-21-44-904-00-65	BD EXP CIS SP CT-S-DIST	Expenses
30-40-21-44-904-04-40	AFDA G-40 - LOW ANNUAL_HIGH - SUMMER - DIST	Expenses
30-40-22-00-913-31-02	ADVERTISING-SHARED SERVICES/SAFETY	Expenses
30-40-22-00-921-24-00	SAFETY - SHARED SERVICES	Expenses
30-40-22-00-923-15-00	OS - Emergency Mgmt & Compliance	Expenses
30-40-22-00-932-01-00	MGP MAINTENANCE COSTS - NH-SHARED SEVICES/MGP	Expenses
30-40-24-00-426-02-00	SOCIAL ADVERTISING -BELOW LINE - NH	Expenses
30-40-24-00-426-04-00	CIVIC ACTIVITIES-STATE	Expenses
30-40-24-00-426-04-01	CIVIC ACTIVITIES-FEDERAL-NH	Expenses
30-40-24-00-426-10-00	COMMUNITY DONATIONS - NH	Expenses
30-40-24-00-426-16-00	COMMUNITY SPONSORSHIPS - NH	Expenses
30-40-24-00-426-17-00	OUTREACH AND EDUCATION - NH	Expenses
30-40-24-00-909-01-00	SOCIAL ADVERTISING - NH	Expenses
30-40-24-00-909-52-00	OUTREACH AND EDUCATION	Expenses
30-40-24-00-913-53-00	CUSTOMER COMMUNICATION	Expenses
30-40-24-00-923-09-00	OUTSIDE SERVICES - NH	Expenses
30-40-24-00-930-51-00	COMMUNITY SPONSORSHIPS-NH	Expenses
30-40-24-00-930-54-00	MEDIA SERVICES-NH	Expenses
30-40-24-00-930-60-00	EMERGENCY COMMUNICATIONS-NU-NH	Expenses
30-40-27-00-852-00-00	COMMUNICATION SYSTEM EXP NU NH	Expenses
30-40-27-00-935-06-01	MAINTENANCE SOFTWARE DISPATCH	Expenses
30-40-28-00-902-00-00	CUST ACCT METER READ EXP - NH	Expenses
30-40-70-00-920-00-00	A&G SALARIES - NH	Expenses
30-40-80-00-415-00-00	JOBBING REVENUE - NH	Revenues
30-40-80-00-415-06-00	MDSE ADMIN-WH	Revenues
30-40-80-00-415-08-00	INST HW (CORRECT O&M)	Revenues
30-40-80-00-415-11-00	INST FURNACE LABOR	Revenues
30-40-80-00-415-13-00	MDSE GEN OPER(correct O&M)	Revenues
30-40-80-00-415-15-00	MDSE INST B/F LB/PT	Revenues
30-40-80-00-415-70-00	JOBBING PARTS REVENUE - NH	Revenues
30-40-80-00-415-71-00	JOBBING LABOR REVENUE - NH	Revenues
30-40-80-00-415-73-00	UNH REVENUE	Revenues
30-40-80-00-416-00-00	JOBBING EXPENSE - NH	Expenses
30-40-80-00-416-73-00	UNH EXPENSE	Expenses
30-40-80-00-416-73-01	UNH EXPENSE - DIG SAFE	Expenses
30-40-80-00-416-73-02	UNH EXPENSE - HIGH RISK DIG SAFE	Expenses
30-40-80-00-416-73-03	UNH EXPENSE - SERVICE SURVEY	Expenses
30-40-80-00-416-73-04	UNH EXPENSE - MAIN SURVEY	Expenses
30-40-80-00-416-73-05	UNH EXPENSE - QUARTERLY SURVEY	Expenses
30-40-80-00-416-73-06	UNH EXPENSE - PUBLIC BUILDING SURVEY	Expenses
30-40-80-00-416-73-07	UNH EXPENSE - STAND BY FEE	Expenses
30-40-80-00-416-73-08	UNH EXPENSE OTHER-MAIN/SERVICE RELOCATES DAMAGES	Expenses
30-40-80-00-416-80-00	JOBBING PARTS EXPENSE - NH	Expenses
30-40-80-00-416-81-00	JOBBING LABOR EXPENSE - NH	Expenses
30-40-80-00-416-82-00	MDSE COST OF APPL - WH	Expenses
30-40-80-00-416-84-00	JOBBING - UNH EXPENSE	Expenses
30-40-80-00-416-85-00	EQUIPMENT TRAINING FEE FOR SERVICE	Expenses
30-40-80-00-426-00-00	PENALTIES - NH	Expenses

Account Code	Account Description	Type
30-40-80-00-426-10-00	DONATIONS - NH	Expenses
30-40-80-00-717-00-00	PROD OPER LABOR LPG - NH	Expenses
30-40-80-00-717-01-00	PROD OPER LABOR LNG - NH	Expenses
30-40-80-00-717-02-00	PROD OPER LABOR OTHER - NH	Expenses
30-40-80-00-718-00-00	DISPATCHING PRODUCTION - NH	Expenses
30-40-80-00-735-01-00	PROD OPER MISC EXPENSE - NH	Expenses
30-40-80-00-735-03-00	PROD INSPECTIONS & ALARMS LPGA - NH	Expenses
30-40-80-00-735-04-00	PROD UNPRODUCTIVE - NH	Expenses
30-40-80-00-735-05-00	PROD INSPECTIONS & ALARMS LNG - NH	Expenses
30-40-80-00-741-01-00	PROD MAINT STRUCT & IMP LNG - NH	Expenses
30-40-80-00-742-01-00	PROD MAINT E - EQUIPMENT - LNG - NH	Expenses
30-40-80-00-743-00-00	GAS SYS PRODUCTION TRAINING - NH	Expenses
30-40-80-00-769-00-00	MAINT OF SCADA - PRODUCTION - NH	Expenses
30-40-80-00-857-00-00	T&D OPER MEAS & REGULATG STN - NH	Expenses
30-40-80-00-857-96-00	MEAS+REG.STA-STORERM EXP	Expenses
30-40-80-00-870-00-00	DISTRIBUTION OPERATION SUPERVISION - NH	Expenses
30-40-80-00-874-00-00	MISC EXP MAINS AND SERVICES - NH	Expenses
30-40-80-00-874-01-00	GAS SYSTEM TRAINING - NH	Expenses
30-40-80-00-874-02-00	DISTRIBUTION VALVE MAINTENANCE-NH	Expenses
30-40-80-00-874-02-01	DISTRIBUTION INTEGRITY MANAGEMENT - NH	Expenses
30-40-80-00-874-02-02	DISTRIBUTION MANUAL UPDATES - NH	Expenses
30-40-80-00-874-03-00	UNION GAS ON CALL PAY	Expenses
30-40-80-00-874-04-00	DIG SAFE EXPENSE - NH	Expenses
30-40-80-00-874-04-01	DIG SAFE EXPENSE - HIGH RISK- NH	Expenses
30-40-80-00-874-05-00	SERVICE LINE SURVEY - NH	Expenses
30-40-80-00-874-06-00	PUBLIC BUILDING SURVEY - NH	Expenses
30-40-80-00-874-07-00	GAS MAIN SURVEY - NH	Expenses
30-40-80-00-874-08-00	HIGH RISK BRIDGE SURVEY	Expenses
30-40-80-00-874-09-00	OUTSIDE LEAK INVESIGATION	Expenses
30-40-80-00-874-10-00	CRITICAL VALVE INSPECTIONS	Expenses
30-40-80-00-874-24-00	MAINS+SERV-TRANSP	Expenses
30-40-80-00-875-00-00	REG STATION EXPENSE (GEN) - NH	Expenses
30-40-80-00-875-01-00	SYSTEM OPS STANDBY	Expenses
30-40-80-00-875-02-00	SYSTEM OPS UPRODUCTIVE	Expenses
30-40-80-00-875-03-00	SYSTEM OPS TRAINING	Expenses
30-40-80-00-875-04-00	REGULATION SUPERVISION	Expenses
30-40-80-00-875-05-00	ODORANT TESTING - NH	Expenses
30-40-80-00-875-06-00	REG STATN STANDBY/DAMAGE PREV - NH	Expenses
30-40-80-00-875-08-00	MTR & HSE REG - INVESTIGATE METER READING	Expenses
30-40-80-00-875-09-00	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expenses
30-40-80-00-875-10-00	SYSTEM CRITICAL VALVE INSPECTION	Expenses
30-40-80-00-878-00-00	METER ORDERS - GENERAL	Expenses
30-40-80-00-878-01-00	METERTURN ON & OFFS - NH	Expenses
30-40-80-00-878-02-00	METERS-REMOVES & INSTALLS - NH	Expenses
30-40-80-00-878-03-00	REPAIR FIT LEAKS - NH	Expenses
30-40-80-00-878-04-00	SERVICING GAS METER BRACKETS	Expenses
30-40-80-00-878-04-01	METER & SERVICE TRANSPORTATION EXP	Expenses
30-40-80-00-878-05-00	M&S UNPRODUCTIVE TIME	Expenses
30-40-80-00-878-05-01	M&S UNPRODUCTIVE TIME - SICK	Expenses
30-40-80-00-878-05-02	M&S UNPRODUCTIVE TIME - HOLIDAY	Expenses
30-40-80-00-878-05-03	M&S UNPRODUCTIVE TIME - VACATION	Expenses
30-40-80-00-878-05-04	M&S UNPRODUCTIVE TIME - OTHER	Expenses
30-40-80-00-878-05-05	M&S UNPRODUCTIVE TIME TRAINING	Expenses
30-40-80-00-878-06-00	METER & SERVICE SUPERVISION	Expenses
30-40-80-00-878-07-00	MTR & HSE REG - READ IN/OUTS - NH	Expenses
30-40-80-00-878-08-00	MTR & HSE REG - FIELD INVESTIGATE	Expenses
30-40-80-00-878-09-00	MTR & HSE REG - INVESTIGATE DEVICE/ERT	Expenses
30-40-80-00-878-10-00	MTR & HSE REG - CHG MTR ERT - NH	Expenses
30-40-80-00-878-13-00	MTR & HSE REG - TRAINING - EM&C NH	Expenses
30-40-80-00-878-14-00	MTR & HSE REG - MISC - EM&C NH	Expenses
30-40-80-00-878-28-00	MTR & HSE REG - TOOLS & EQUP - NH	Expenses
30-40-80-00-878-30-00	MTR & HSE REG - MTR INSTRUM - NH	Expenses
30-40-80-00-878-33-00	MTR & HSE REG - FLEET - NH	Expenses
30-40-80-00-878-80-00	MTR & HSE REG - CHG MTR ERT - NH	Expenses

Account Code	Account Description	Type
30-40-80-00-878-86-00	MTR & HSE REG - MTR INSTRUM MAINT - ME BY NH	Expenses
30-40-80-00-879-00-00	CUSTOMER LEAK INVESTIGATION - NH	Expenses
30-40-80-00-879-01-00	EASY CARE SVC PLAN BASIC NO CHARGE NH	Expenses
30-40-80-00-880-00-00	T&D OPER SYSTEM EXP - NH	Expenses
30-40-80-00-880-03-00	OTHER EXPENSES-MISC - NH	Expenses
30-40-80-00-880-04-00	METERING SYS - GAS TRAINING	Expenses
30-40-80-00-880-99-00	COMPANY USE - NH	Expenses
30-40-80-00-885-00-00	MAINTENANCE GEN SUPERVISION - NH	Expenses
30-40-80-00-885-01-00	UNPROD TIME/SICKNESS - NH	Expenses
30-40-80-00-885-02-00	UNPROD TIME/WEATHER - NH	Expenses
30-40-80-00-885-03-00	UNPROD TIME/HOLIDAYS - NH	Expenses
30-40-80-00-885-04-00	UNPROD TIME/VACATION - NH	Expenses
30-40-80-00-885-05-00	UNPROD TIME/OTHER - NH	Expenses
30-40-80-00-885-05-01	UNPROD TIME TRAINING	Expenses
30-40-80-00-886-00-00	T&D MAINT STRUCTURES & IMPROV - NH	Expenses
30-40-80-00-887-00-00	MAINT OF MAINS - NH	Expenses
30-40-80-00-887-01-00	MAINT OF MAINS LEAK REPAIR - CORROSION - NH	Expenses
30-40-80-00-887-01-01	MAINT OF MAINS TRANSPORTATION EXP- NH	Expenses
30-40-80-00-887-03-00	CORROSION MAINS - NH	Expenses
30-40-80-00-887-04-00	CORROSION BRIDGES - NH	Expenses
30-40-80-00-887-07-00	T&D MAINT OF MAINS - BRIDGE - COMMON	Expenses
30-40-80-00-889-00-00	MAINT OF REG EQUIP (DISTRICT)- NH	Expenses
30-40-80-00-890-00-00	MAINT OF REG EQUIP (INDUST) - NH	Expenses
30-40-80-00-891-00-00	MAINT OF REG EQUIP (GATE STATION) - NH	Expenses
30-40-80-00-891-01-00	MAIN DISTRI SCADA -DISTRIBUTION- NH	Expenses
30-40-80-00-892-00-00	MAINT OF SERVICES - NH	Expenses
30-40-80-00-892-01-00	CORROSION SERVICES- NH	Expenses
30-40-80-00-892-14-00	MAINT SERV- TRANSPORTATION EXP - NH	Expenses
30-40-80-00-892-15-00	MAINT SERV- 3RD PARTY BILLING- NH	Expenses
30-40-80-00-893-00-00	MAINT OF MTRS & HOUSE REGULTRS - NH	Expenses
30-40-80-00-893-04-00	MAINT METER - STOREROOM - NH	Expenses
30-40-80-00-894-00-00	T&D MAINT SYSTEM EQUIPMENT - NH	Expenses
30-40-80-00-894-01-00	MAINT OF SYSTEM OPS EQUIPMENT - NH	Expenses
30-40-80-00-902-00-00	CUST ACCTS METER READ EXP- NH	Expenses
30-40-80-00-903-00-00	CREDIT DISCONNECTION - NH	Expenses
30-40-80-00-903-03-00	CREDIT & COLLECTIONS/PYRL - NH	Expenses
30-40-80-00-903-04-01	POSTAGE - LOCAL - SHARED NH	Expenses
30-40-80-00-903-05-00	MISC CREDIT EXPENSES - NH	Expenses
30-40-80-00-907-00-00	CUSTMR SERVICE & INFO SUPRVN - NH	Expenses
30-40-80-00-908-01-00	CUSTOMER SERVICE/PAYRL - NH	Expenses
30-40-80-00-908-02-00	CUSTOMER SERVICE/MISC - NH	Expenses
30-40-80-00-911-00-00	SUPERVISION - NH	Expenses
30-40-80-00-912-00-00	SELLING EXPENSE - NH	Expenses
30-40-80-00-920-00-00	A&G SALARIES-NH	Expenses
30-40-80-00-920-05-00	OPER SUPP - ADMIN TRAINING - GAS - NH	Expenses
30-40-80-00-921-01-00	GEN OFFICE SUPPLIES & EXP - SHARED NH	Expenses
30-40-80-00-921-01-20	UNALLOWABLE MEALS EXP - NH	Expenses
30-40-80-00-921-02-00	TRAVEL & MEALS EXP - NH	Expenses
30-40-80-00-921-16-00	SERVICE CENTER EXPENSED - SHARED NH	Expenses
30-40-80-00-921-17-00	TELEPHONE SERVICE - SERVICE CENTER - NH	Expenses
30-40-80-00-921-18-00	Telephone Services - NH	Expenses
30-40-80-00-922-00-00	ADMINISTRATIVE EXPENSES TRANSFERRED - NH	Expenses
30-40-80-00-923-00-00	OS LEGAL - LOCAL-NH-DOC-ONLY	Expenses
30-40-80-00-923-18-00	O/S WORK STOPPAGE	Expenses
30-40-80-00-925-01-00	INJURIES & DAMAGES SAFETY	Expenses
30-40-80-00-926-06-00	Employee Benefits Other - NUNH	Expenses
30-40-80-00-930-01-00	GENERAL ADVERTISING-NH	Expenses
30-40-80-00-930-03-00	DUES TO ORGANIZATIONS - NH	Expenses
30-40-80-00-930-11-00	SVC CENTER CAPITALIZED - NH	Expenses
30-40-80-00-932-04-00	MAINT OF GENL PLANT - EQUIP - SHARED NH	Expenses
30-40-80-00-935-01-00	MAINT - GEN STRUC - SHARED PORTSMOUTH	Expenses
30-40-80-00-935-01-20	MAINT - GEN STRUC - SHARED PLAISTOW	Expenses
30-40-80-00-935-02-00	MAINT - OFFICE EQUIPMENT - SHARED NH	Expenses
30-40-80-11-723-01-02	LPG EXPENSE MISC - ELECTRIC- PEAK-NH	Expenses

Account Code	Account Description	Type
30-40-80-54-415-71-00	EXCESS SERVICE LABOR - NH	Revenues
30-45-00-00-142-01-00	EXT SUPPLIER 1 - A/R - NH	Assets
30-45-00-00-142-02-00	EXT SUPPLIER GLOBAL - A/R - NH	Assets
30-45-00-00-142-03-00	EXT SUPPLIER METROMEDIA - A/R - NH	Assets
30-45-00-00-142-04-00	EXT SUPPLIER SHELL - A/R - NH	Assets
30-45-00-00-142-05-00	EXT SUPPLIER SPRAGUE - A/R - NH	Assets
30-45-00-00-142-06-00	EXT SUPPLIER SANTA BUCKLEY - A/R - NH	Assets
30-45-00-00-142-08-00	EXT SUPPLIER A/R - SOUTH JERSEY - NH	Assets
30-45-00-00-142-09-00	EXT SUPPLIER A/R - GLACIAL - NH	Assets
30-45-00-00-142-10-00	EXT SUPPLIER - UGI ENERGY SVCS - A/R - NH	Assets
30-45-00-00-142-10-02	EXT SUPPLIER - REVENUE - UGI ENERGY SVCS - NH	Assets
30-45-00-00-142-25-00	EXT SUPPLIER AR - PEOPLES POWER - NH	Assets
30-45-00-00-232-01-02	EXT SUPPLY 1-REVENUE-NH	Liabilities
30-45-00-00-232-02-02	EXT SUPPLIER GLOBAL-REVENUE-NH	Liabilities
30-45-00-00-232-03-02	EXT SUPPLIER METROMEDIA-REVENUE-NH	Liabilities
30-45-00-00-232-04-02	EXT SUPPLIER SHELL-REVENUE-NH	Liabilities
30-45-00-00-232-05-02	EXT SUPPLIER - REVENUE - SPRAGUE - NH	Liabilities
30-45-00-00-232-06-02	EXT SUPPLY REVENUE-SANTA BUCKLEY-NH	Liabilities
30-45-00-00-232-08-02	EXT SUPPLY REVENUE-SOUTH JERSEY-NH	Liabilities
30-45-00-00-232-09-02	EXT SUPPLY REVENUE-GLACIAL-NH	Liabilities
30-45-00-00-232-10-02	EXT SUPPLIER- REVENUE - UGI ENERGY SVCS - NH	Liabilities
30-45-00-00-232-25-02	EXT SUPPLIER - REVENUE PEOPLES POWER-NH	Liabilities
30-47-29-50-418-05-00	WATER HEATER RENTAL BAD DEBT	Revenues
30-47-29-50-488-01-00	WATER HEATER RENTAL-REVENUE	Revenues
30-47-29-50-488-05-00	RENTAL WH BAD DEBT - NH	Revenues
30-47-29-50-894-01-00	WATER HEATER MAINTENANCE - GAS - NH	Expenses
30-47-29-50-904-05-00	BD EXP CIS WH WO	Expenses
30-47-29-50-923-06-00	USC EXPS - WATER HTR PROG - NH	Expenses
30-47-29-51-415-01-00	ANNUAL INSPECTION REVENUE - NH	Revenues
30-47-29-51-418-05-00	CLEAN & CHECK REVENUE - BAD DEBT	Revenues
30-47-29-51-488-01-00	CLEAN & CHECK REVENUE	Revenues
30-47-29-51-894-01-00	NH ANNUAL INSPECTIONS- PARTS & LABOR	Expenses
30-47-29-52-418-05-00	CONVERSION BURNER RNTL BAD DEBT	Revenues
30-47-29-52-488-01-00	CONVERSION BURNER RENTAL-REVENUE	Revenues
30-47-29-52-488-05-00	CONV BURN BAD DEBT - NH	Revenues
30-47-29-52-894-01-00	CONVERSION BURNER MAINTENANCE - NH	Expenses
30-47-29-52-904-05-00	BD EXP CIS CB WO-DIST	Expenses
30-47-29-53-418-05-00	EQUIP PROTECTION PLAN BAD DEBT	Revenues
30-47-29-53-488-01-00	EQUIP PROTECTION PLAN REV COMM	Revenues
30-47-29-53-488-02-00	EQUIP PROTECTION PLAN REV COMM	Revenues
30-47-29-53-894-01-00	EASY CARE SVC PLAN PTS & LBR	Expenses
30-47-29-53-894-02-00	NH EQUIP PROTECTION PLAN PTS & LBR	Expenses
30-47-29-53-904-05-00	BD EXP CIS EZ WO-DIST	Expenses
30-47-29-53-923-06-00	USC EXPS - EASY CARE - NH	Expenses
30-47-29-54-418-05-00	INTERIOR GAS LINE BAD DEBT	Revenues
30-47-29-54-488-01-00	INTERIOR GAS LINES REV- RESIDENTIAL	Revenues
30-47-29-54-904-05-00	BD EXP CIS GAS LINE WO	Expenses
30-47-29-55-488-01-00	ANNUAL INSPECTION REVENUE - NH	Revenues
30-47-29-56-418-01-00	NH EQUIP SALES - REVENUE	Revenues
30-47-29-56-418-01-10	NH EQUIP SALES - PARTS & LABOR	Revenues
30-47-29-60-488-00-00	EQUIP PROTECTION PLAN REVENUE - COMMERCIAL	Revenues
30-48-02-00-426-15-00	VISIBILITY - NH	Expenses
30-48-29-00-426-13-00	ADVERTISING - NH	Expenses
30-48-29-00-426-14-00	MARKET DEVELOPMENT - GENERAL - NH	Expenses
30-48-29-00-426-15-00	VISIBILITY - NH	Expenses
30-48-29-00-913-31-02	ADVERTISING	Expenses
30-48-29-00-923-00-03	MKT DEV/PROJ MGMT - NH	Expenses
30-48-29-00-923-30-00	MKT DEV - GENERAL - NH	Expenses
30-48-29-00-923-30-01	MARKETING - NH	Expenses
30-48-29-00-923-32-03	FIELD OPERATIONS/ACCOUNT MGMT-NH	Expenses
30-48-29-00-930-31-02	ADVERTISING	Expenses
30-49-01-10-480-01-01	R-6 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-480-01-02	R-11 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-480-02-01	R-5 W-NEXT-Demand Cost of Gas	Revenues

Account Code	Account Description	Type
30-49-01-10-480-02-02	R-10 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-01-01	G-40 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-01-02	G-50 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-02-01	G-41 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-02-02	G-51 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-03-01	G-42 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-03-02	G-52 W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-10-01	Simplex W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-11-01	Nat Gypsum W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-481-12-01	Foss W-NEXT-Demand Cost of Gas	Revenues
30-49-01-10-495-00-00	ACCRUED REV-PEAK-DEMAND-NH	Revenues
30-49-01-10-710-04-88	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expenses
30-49-01-10-710-04-99	PRODUCTION & STORAGE ALLOW -DEMAND - PEAK - NH	Expenses
30-49-01-10-930-00-88	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expenses
30-49-01-10-930-00-99	MISC OVERHEAD ALLOWANCE - DEMAND - PEAK - NH	Expenses
30-49-01-11-431-00-99	INVENTORY FINANCE CHARGES - PEAK - NH	Expenses
30-49-01-11-480-01-01	R-6 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-01-02	R-11 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-02-01	R-5 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-480-02-02	R-10 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-01-01	G-40 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-01-02	G-50 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-02-01	G-41 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-02-02	G-51 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-03-01	G-42 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-03-02	G-52 W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-10-01	Simplex W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-11-01	Nat Gypsum W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-11-481-12-01	Foss W-NEXT-Commodity Cost of Gas	Revenues
30-49-01-12-480-01-01	R-6 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-01-02	R-11 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-02-01	R-5 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-480-02-02	R-10 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-01-01	G-40 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-01-02	G-50 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-02-01	G-41 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-02-02	G-51 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-03-01	G-42 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-03-02	G-52 W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-10-01	Simplex W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-11-01	Nat Gypsum W-NEXT-Reconciliation Costs	Revenues
30-49-01-12-481-12-01	Foss W-NEXT-Reconciliation Costs	Revenues
30-49-01-13-480-01-01	R-6 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-01-02	R-11 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-02-01	R-5 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-480-02-02	R-10 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-01-01	G-40 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-01-02	G-50 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-02-01	G-41 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-02-02	G-51 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-03-01	G-42 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-03-02	G-52 W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-10-01	Simplex W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-11-01	Nat Gypsum W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-481-12-01	Foss W-NEXT-Working Capital Allowance	Revenues
30-49-01-13-495-00-00	ACCRUED REV-WORK CAPITAL-PEAK-NH	Revenues
30-49-01-14-480-01-01	R-6 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-01-02	R-11 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-02-01	R-5 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-480-02-02	R-10 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-01-01	G-40 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-01-02	G-50 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-02-01	G-41 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-02-02	G-51 W-NEXT-Bad Debt Allowance	Revenues

Account Code	Account Description	Type
30-49-01-14-481-03-01	G-42 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-03-02	G-52 W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-10-01	Simplex W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-11-01	Nat Gypsum W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-481-12-01	Foss W-NEXT-Bad Debt Allowance	Revenues
30-49-01-14-495-00-00	ACCRUED REV-BAD DEBT-PEAK-NH	Revenues
30-49-01-15-480-01-01	R-6 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-01-02	R-11 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-02-01	R-5 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-480-02-02	R-10 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-01-01	G-40 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-01-02	G-50 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-02-01	G-41 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-02-02	G-51 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-03-01	G-42 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-03-02	G-52 W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-10-01	Simplex W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-11-01	Nat Gypsum W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-15-481-12-01	Foss W-NEXT-Miscellaneous Overhead	Revenues
30-49-01-16-480-01-01	R-6 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-01-02	R-11 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-02-01	R-5 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-480-02-02	R-10 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-01-01	G-40 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-01-02	G-50 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-02-01	G-41 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-02-02	G-51 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-03-01	G-42 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-03-02	G-52 W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-10-01	Simplex W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-11-01	Nat Gypsum W-NEXT-Production & Storage Capacity	Revenues
30-49-01-16-481-12-01	Foss W-NEXT-Production & Storage Capacity	Revenues
30-49-01-17-480-01-01	R-6 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-01-02	R-11 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-02-01	R-5 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-480-02-02	R-10 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-01-01	G-40 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-01-02	G-50 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-02-01	G-41 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-02-02	G-51 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-03-01	G-42 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-03-02	G-52 W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-10-01	Simplex W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-11-01	Nat Gypsum W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-17-481-12-01	Foss W-NEXT-Deferral of Jurisdictional Demand Costs	Revenues
30-49-01-42-480-01-01	R-6 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-01-02	R-11 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-02-01	R-5 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-480-02-02	R-10 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-01-01	G-40 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-01-02	G-50 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-02-01	G-41 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-02-02	G-51 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-03-01	G-42 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-03-02	G-52 S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-10-01	Simplex S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-11-01	Nat Gypsum S-NEXT-Reconciliation Costs	Revenues
30-49-01-42-481-12-01	Foss S-NEXT-Reconciliation Costs	Revenues
30-49-01-44-480-01-01	R-6 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-01-02	R-11 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-02-01	R-5 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-480-02-02	R-10 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-01-01	G-40 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-01-02	G-50 S-NEXT-Bad Debt Allowance	Revenues

Account Code	Account Description	Type
30-49-01-44-481-02-01	G-41 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-02-02	G-51 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-03-01	G-42 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-03-02	G-52 S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-10-01	Simplex S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-11-01	Nat Gypsum S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-481-12-01	Foss S-NEXT-Bad Debt Allowance	Revenues
30-49-01-44-495-00-00	ACCRUED REV-BAD DEBT-OFF PEAK-NH	Revenues
30-49-01-45-480-01-01	R-6 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-01-02	R-11 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-02-01	R-5 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-480-02-02	R-10 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-01-01	G-40 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-01-02	G-50 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-02-01	G-41 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-02-02	G-51 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-03-01	G-42 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-03-02	G-52 S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-10-01	Simplex S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-11-01	Nat Gypsum S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-45-481-12-01	Foss S-NEXT-Miscellaneous Overhead	Revenues
30-49-01-47-480-01-01	R-6 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-01-02	R-11 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-02-01	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-480-02-02	R-10 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-01-01	G-40 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-01-02	G-50 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-02-02	G-51 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-03-01	G-42 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-03-02	G-52 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-10-01	SIMPLEX S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-11-01	NAT GYPSUM S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-47-481-12-01	FOSS S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-48-480-02-01	R-5 S-NEXT-DEFERRAL OF JURISDICTIONAL DEMAND COSTS	Revenues
30-49-01-72-480-01-01	R-6 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-01-02	R-11 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-02-01	R-5 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-480-02-02	R-10 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-01-01	G-40 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-01-02	G-50 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-02-01	G-41 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-02-02	G-51 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-03-01	G-42 NEXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-481-03-02	G-52 S-NEXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-01-01	R-6 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-01-02	R-11 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-01-04	R-10 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-02-01	G-40 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-02-02	G-50 EXT-DSM (DEMAND SIDE MANAGEMENT)	Revenues
30-49-01-72-489-03-01	G-41 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-03-02	G-51 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-04-01	G-42 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-489-04-02	G-52 S-EXT-DSM (Demand Side Management)	Revenues
30-49-01-72-495-00-99	LDAC-EEC LOST BASE REVENUE	Revenues
30-49-01-72-495-01-01	ACCRUED REVENUE-LDAC-EEC-LOW INCOME	Revenues
30-49-01-72-495-01-02	ACCRUED REVENUE-LDAC-EEC-RESIDENTIAL	Revenues
30-49-01-72-495-01-06	ACCRUED REVENUE-LDAC-EEC-SMALL C&I	Revenues
30-49-01-73-480-00-00	ERC - RECLASS FROM RCE- RPC	Revenues
30-49-01-73-480-01-01	R-6 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-01-02	R-11 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-02-01	R-5 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-480-02-02	R-10 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-01-01	G-40 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-01-02	G-50 S-NEXT-ERC (Environmental Recovery Costs)	Revenues

Account Code	Account Description	Type
30-49-01-73-481-02-01	G-41 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-02-02	G-51 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-03-01	G-42 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-481-03-02	G-52 S-NEXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-01	R-6 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-02	R-11 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-01-04	R-10 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-02-01	G-40 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-02-02	G-50 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-03-01	G-41 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-03-02	G-51 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-04-01	G-42 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-489-04-02	G-52 S-EXT-ERC (Environmental Recovery Costs)	Revenues
30-49-01-73-735-01-00	ERC AMORTIZATION - NH	Expenses
30-49-01-75-480-01-01	R-6 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-01-02	R-11 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-02-01	R-5 S-NEXT-Wells LNG	Revenues
30-49-01-75-480-02-02	R-10 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-01-01	G-40 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-01-02	G-50 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-02-01	G-41 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-02-02	G-51 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-03-01	G-42 S-NEXT-Wells LNG	Revenues
30-49-01-75-481-03-02	G-52 S-NEXT-Wells LNG	Revenues
30-49-01-75-489-01-01	R-6 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-02	R-11 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-03	R-5 S-EXT-Wells LNG	Revenues
30-49-01-75-489-01-04	R-10 S-EXT-Wells LNG	Revenues
30-49-01-75-489-02-01	G-40 S-EXT-Wells LNG	Revenues
30-49-01-75-489-02-02	G-50 S-EXT-Wells LNG	Revenues
30-49-01-75-489-03-01	G-41 S-EXT-Wells LNG	Revenues
30-49-01-75-489-03-02	G-51 S-EXT-Wells LNG	Revenues
30-49-01-75-489-04-01	G-42 S-EXT-Wells LNG	Revenues
30-49-01-75-489-04-02	G-52 S-EXT-Wells LNG	Revenues
30-49-01-76-481-01-01	G-40 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-01-02	G-50 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-02-01	G-41 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-02-02	G-51 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-03-01	G-42 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-481-03-02	G-52 S-NEXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-02-01	G-40 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-02-02	G-50 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-03-01	G-41 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-03-02	G-51 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-04-01	G-42 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-76-489-04-02	G-52 S-EXT-CCE (Customer Choice Expense)	Revenues
30-49-01-77-480-01-01	R-6 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-01-02	R-11 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-02-01	R-5 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-02-02	R-10 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-480-10-01	LI DISCOUNT - R10 - DISTRIBUTION	Revenues
30-49-01-77-480-10-02	LI DISCOUNT - R10 - SUPPLY	Revenues
30-49-01-77-481-01-01	G-40 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-01-02	G-50 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-02-01	G-41 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-02-02	G-51 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-03-01	G-42 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-481-03-02	G-52 S-NEXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-01	R-6 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-02	R-11 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-01-04	R-10 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-02-01	G-40 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-02-02	G-50 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-03-01	G-41 S-EXT-RLIARA (Residential Low Income)	Revenues

Account Code	Account Description	Type
30-49-01-77-489-03-02	G-51 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-04-01	G-42 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-489-04-02	G-52 S-EXT-RLIARA (Residential Low Income)	Revenues
30-49-01-77-495-00-00	ACCRUED REVENUE - RLIARA- NH	Revenues
30-49-01-77-928-03-00	REG COMM EXP - ASSESSMENTS - RLIARA	Expenses
30-49-01-78-407-01-00	AMORTIZATION OF RATE CASE COSTS - NH	Expenses
30-49-01-78-480-00-00	RCE - RECLASS TO ERC	Revenues
30-49-01-78-480-01-01	R-6 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-01-02	R-11 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-02-01	R-5 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-480-02-02	R-10 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-01-01	G-40 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-01-02	G-50 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-02-01	G-41 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-02-02	G-51 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-03-01	G-42 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-481-03-02	G-52 S-NEXT-RCE (Rate Case Expense)	Revenues
30-49-01-78-489-01-01	R-6 EXT-RCE	Revenues
30-49-01-78-489-01-02	R-11 EXT-RCE	Revenues
30-49-01-78-489-01-03	R-5 EXT-RCE	Revenues
30-49-01-78-489-01-04	R-10 EXT-RCE	Revenues
30-49-01-78-489-02-01	G-40 EXT-RCE	Revenues
30-49-01-78-489-02-02	G-50 EXT-RCE	Revenues
30-49-01-78-489-03-01	G-41 EXT-RCE	Revenues
30-49-01-78-489-03-02	G-51 EXT-RCE	Revenues
30-49-01-78-489-04-01	G-42 EXT-RCE	Revenues
30-49-01-78-489-04-02	G-52 EXT-RCE	Revenues
30-49-01-78-489-10-01	Simplex EXT-RCE	Revenues
30-49-01-78-489-11-01	Nat Gypsum EXT-RCE	Revenues
30-49-01-78-489-12-01	Foss EXT-RCE	Revenues
30-49-01-79-480-00-00	RECLASS TO ERC	Revenues
30-49-01-79-480-01-01	R-6 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-01-02	R-11 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-02-01	R-5 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-480-02-02	R-10 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-01-01	G-40 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-01-02	G-50 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-02-01	G-41 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-02-02	G-51 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-03-01	G-42 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-481-03-02	G-52 S-NEXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-01	R-6 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-02	R-11 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-03	R-5 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-01-04	R-10 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-02-01	G-40 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-02-02	G-50 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-03-01	G-41 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-03-02	G-51 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-04-01	G-42 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-489-04-02	G-52 S-EXT-RPC (Recon of Perm Changes)	Revenues
30-49-01-79-495-00-00	ACCD REVENUE-RATE RELIEF - NH	Revenues
30-49-01-80-495-00-00	ACC REV ON EEBB RESIDENTIAL	Revenues
30-49-01-81-480-01-01	R-6 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-01-02	R-11 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-02-01	R-5 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-480-02-02	R-10 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-01-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-01-02	G-50 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-02-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-02-02	G-51 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-03-01	G-42 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-481-03-02	G-52 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-02-01	G-40 NEXT-LOST REVENUE ADJ	Revenues

Account Code	Account Description	Type
30-49-01-81-489-02-02	G-50 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-03-01	G-41 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-03-02	G-51 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-04-01	G-42 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-489-04-02	G-52 NEXT-LOST REVENUE ADJ	Revenues
30-49-01-81-495-00-00	ACCRUED REV-LRA-NH	Revenues
30-49-01-82-495-00-00	ACCRUED REVEUNE - OBF - NH - RESIDENTIAL	Revenues
30-49-01-82-495-01-00	ACCRUED REVEUNE - OBF - NH - C&I	Revenues
30-49-02-50-908-29-10	Res HVAC/Appl ImplSvcs/STAT - Int	Expenses
30-49-02-50-908-29-13	Res HVAC/Appl Plan/Admin - Int	Expenses
30-49-02-50-908-29-14	Res HVAC/Appl Plan/Admin - Ext	Expenses
30-49-02-50-908-29-20	Res HVAC/Appl Marketing - Int	Expenses
30-49-02-50-908-29-21	Res HVAC/Appl Marketing - Ext	Expenses
30-49-02-50-908-29-30	Res HVAC/Appl Evaluation - Int	Expenses
30-49-02-50-908-29-31	Res HVAC/Appl Evaluation - Ext	Expenses
30-49-02-50-908-29-40	Res HVAC/Appl Rebates	Expenses
30-49-02-50-908-29-41	Res HVAC/Appl ImplSvcs/STAT - Ext	Expenses
30-49-02-50-908-29-42	Res HVAC/Appl Loans/Financing	Expenses
30-49-02-50-908-32-15	RES BEHAVIOR IMPLSVCS/STAT - INT	Expenses
30-49-02-50-908-32-16	RES BEHAVIOR PLAN/ADMIN - INT	Expenses
30-49-02-50-908-32-17	RES BEHAVIOR PLAN/ADMIN - EXT	Expenses
30-49-02-50-908-32-22	RES BEHAVIOR MARKETING - INT	Expenses
30-49-02-50-908-32-23	RES BEHAVIOR MARKETING - EXT	Expenses
30-49-02-50-908-32-32	RES BEHAVIOR EVALUATION - INT	Expenses
30-49-02-50-908-32-33	RES BEHAVIOR EVALUATION - EXT	Expenses
30-49-02-50-908-32-42	RES BEHAVIOR REBATES	Expenses
30-49-02-50-908-32-43	RES BEHAVIOR IMPLSVCS/STAT - EXT	Expenses
30-49-02-50-908-34-10	RES HPWES IMPLSVCS/STAT - INT	Expenses
30-49-02-50-908-34-13	RES HPWES PLAN/ADMIN - INT	Expenses
30-49-02-50-908-34-14	RES HPWES PLAN/ADMIN - EXT	Expenses
30-49-02-50-908-34-20	RES HPWES MARKETING - INT	Expenses
30-49-02-50-908-34-21	RES HPWES MARKETING - EXT	Expenses
30-49-02-50-908-34-30	RES HPWES EVALUATION - INT	Expenses
30-49-02-50-908-34-31	RES HPWES EVALUATION - EXT	Expenses
30-49-02-50-908-34-40	RES HPWES REBATES	Expenses
30-49-02-50-908-34-41	RES HPWES IMPLSVCS/STAT - EXT	Expenses
30-49-02-50-908-43-35	RES FINANCING - BUYDOWN/REBATES	Expenses
30-49-02-50-908-47-10	Res NewHomes/Reno ImplSvcs/STAT - Int	Expenses
30-49-02-50-908-47-13	Res NewHomes/Reno Plan/Admin - Int	Expenses
30-49-02-50-908-47-14	Res NewHomes/Reno Plan/Admin - Ext	Expenses
30-49-02-50-908-47-20	Res NewHomes/Reno Marketing - Int	Expenses
30-49-02-50-908-47-21	Res NewHomes/Reno Marketing - Ext	Expenses
30-49-02-50-908-47-30	Res NewHomes/Reno Evaluation - Int	Expenses
30-49-02-50-908-47-31	Res NewHomes/Reno Evaluation - Ext	Expenses
30-49-02-50-908-47-40	Res NewHomes/Reno Rebates	Expenses
30-49-02-50-908-47-41	Res NewHomes/Reno ImplSvcs/STAT - Ext	Expenses
30-49-02-50-908-48-14	Res Statewide Marketing - Int	Expenses
30-49-02-50-908-48-22	Res Statewide Marketing - Ext	Expenses
30-49-02-51-908-01-10	LI SINGLEFAM IMPLSVCS/STAT - INT	Expenses
30-49-02-51-908-01-13	LI SINGLEFAM PLAN/ADMIN - INT	Expenses
30-49-02-51-908-01-14	LI SINGLEFAM PLAN/ADMIN - EXT	Expenses
30-49-02-51-908-01-20	LI SINGLEFAM MARKETING - INT	Expenses
30-49-02-51-908-01-21	LI SINGLEFAM MARKETING - EXT	Expenses
30-49-02-51-908-01-30	LI SINGLEFAM EVALUATION - INT	Expenses
30-49-02-51-908-01-31	LI SINGLEFAM EVALUATION - EXT	Expenses
30-49-02-51-908-01-40	LI SINGLEFAM REBATES	Expenses
30-49-02-51-908-01-41	LI SINGLEFAM IMPLSVCS/STAT - EXT	Expenses
30-49-02-51-908-48-15	LI Statewide Marketing - Int	Expenses
30-49-02-51-908-48-23	LI Statewide Marketing - Ext	Expenses
30-49-02-52-908-21-01	C&I Edu ImplSvc/STAT - Int	Expenses
30-49-02-52-908-21-02	C&I Edu ImplSvc/STAT - Ext	Expenses
30-49-02-52-908-21-03	C&I Edu Mrkting - Ext	Expenses
30-49-02-52-908-21-04	C&I Edu Eval - Ext	Expenses
30-49-02-52-908-22-01	Res Edu ImplSvc/STAT - Int	Expenses

Account Code	Account Description	Type
30-49-02-52-908-22-02	Res Edu ImplSvc/STAT - Ext	Expenses
30-49-02-52-908-22-03	Res Edu Mrkting - Ext	Expenses
30-49-02-52-908-22-04	Res Edu Eval - Ext	Expenses
30-49-02-52-908-48-16	C&I Statewide Marketing - Int	Expenses
30-49-02-52-908-48-24	C&I Statewide Marketing - Ext	Expenses
30-49-02-52-908-51-10	C&I SM BUS SVCS IMPLSVC/STAT - INT	Expenses
30-49-02-52-908-51-13	C&I SM BUS SVCS PLAN/ADMIN - INT	Expenses
30-49-02-52-908-51-14	C&I SM BUS SVCS PLAN/ADMIN - EXT	Expenses
30-49-02-52-908-51-20	C&I SM BUS SVCS MARKETING - INT	Expenses
30-49-02-52-908-51-21	C&I SM BUS SVCS MARKETING - EXT	Expenses
30-49-02-52-908-51-30	C&I SM BUS SVCS EVALUATION - INT	Expenses
30-49-02-52-908-51-31	C&I SM BUS SVCS EVALUATION - EXT	Expenses
30-49-02-52-908-51-40	C&I Sm Bus Rebates	Expenses
30-49-02-52-908-51-41	C&I SM BUS SVCS IMPLSVC/STAT - EXT	Expenses
30-49-02-52-908-52-10	C&I LG BUS SVCS IMPLSVCS/STAT - INT	Expenses
30-49-02-52-908-52-13	C&I LG BUS SVCS PLAN/ADMIN - INT	Expenses
30-49-02-52-908-52-14	C&I LG BUS SVCS PLAN/ADMIN - EXT	Expenses
30-49-02-52-908-52-20	C&I LG BUS SVCS MARKETING - INT	Expenses
30-49-02-52-908-52-21	C&I LG BUS SVCS MARKETING - EXT	Expenses
30-49-02-52-908-52-30	C&I LG BUS SVCS EVALUATION - INT	Expenses
30-49-02-52-908-52-31	C&I LG BUS SVCS EVALUATION - EXT	Expenses
30-49-02-52-908-52-40	C&I Lg Bus Rebates	Expenses
30-49-02-52-908-52-41	C&I LG BUS SVCS IMPLSVCS/STAT - EXT	Expenses
30-49-02-72-908-00-50	GAS GENERAL PLAN/ADMIN - ALL INT	Expenses
30-49-02-72-908-00-61	GAS GENERAL IMPLSVC/STAT - ALL INT	Expenses
30-49-02-72-908-00-70	GAS GENERAL EVALUATION - ALL INT	Expenses
30-49-02-72-908-00-71	GAS GENERAL EVALUATION - ALL EXT	Expenses
30-49-02-72-908-00-80	GAS GENERAL MARKETING - ALL INT	Expenses
30-49-02-72-908-00-90	GAS GENERAL MARKETING - ALL EXT	Expenses
30-49-02-72-908-00-95	GAS GENERAL PLANNING&ADMIN/LEGAL - ALL EXT	Expenses
30-49-02-72-908-00-96	GAS GENERAL PLAN/ADMIN - RES INT	Expenses
30-49-02-72-908-00-97	GAS GENERAL PLAN/ADMIN - C&I INT	Expenses
30-49-02-80-495-00-01	LOAN PAYBACK-EEBB-RES	Revenues
30-49-02-80-495-00-02	LOAN WRITEOFF-EEBB-RES	Revenues
30-49-02-80-495-00-03	LOAN WRITEOFF RECOVERY-EEBB-RES	Revenues
30-49-02-80-495-20-00	EEBB - GRANT FUNDING_REIMBURSEMENT - CDFA	Revenues
30-49-02-82-495-00-01	OBF LOAN PAYBACK - RESIDENTIAL	Revenues
30-49-02-82-495-00-02	OBF LOAN PAYBACK - C&I	Revenues
30-49-02-82-495-00-03	OBF Loan Write Off - Residential	Revenues
30-49-02-82-495-00-04	OBF Loan Write Off - C&I	Revenues
30-49-02-82-495-00-05	OBF Loan Write Off - Recovery - Residential	Revenues
30-49-02-82-495-00-06	OBF Loan Write Off- Recovery - C&I	Revenues
30-49-02-82-908-00-01	OBF LOANS - RESIDENTIAL	Expenses
30-49-02-82-908-00-02	OBF LOANS - C&I	Expenses
30-49-10-10-483-02-00	SUPPLIER REFUND - RETAIL MARKETERS	Revenues
30-49-10-10-488-00-00	SUPPLIER REFUND DEMAND CREDITS	Revenues
30-49-10-10-798-06-05	ASSET MGT CR - PNGTS CASE COSTS - NH	Expenses
30-49-10-10-804-03-02	PEAK DEMAND CHARGES DEFERRED - NH	Expenses
30-49-10-10-804-90-10	SUPPLIER REFUND - DEMAND - PEAK DEMAND	Expenses
30-49-10-11-495-00-90	ACCRD REV-DEM-COMM- UNBILLED-PEAK-NH	Revenues
30-49-10-13-419-00-99	WORKING CAPITAL - PEAK - NH	Revenues
30-49-10-13-495-00-90	ACCRD REV-WORK CAP-UNBILLED- PEAK-NH	Revenues
30-49-10-14-495-00-90	ACCRD REV-BAD DEBT- UNBILLED- PEAK-NH	Revenues
30-49-10-14-904-00-99	BAD DEBT ALLOWANCE - PEAK - NH	Expenses
30-49-10-44-495-00-90	ACCRD REV-BAD DEBT- UNBILLED- OFF PEAK - NH	Revenues
30-49-10-44-904-00-99	BAD DEBT ALLOWANCE - OFF PEAK - NH	Expenses
30-49-13-10-483-00-00	SALES FOR RESALE - DEMAND - PEAK - NH	Revenues
30-49-13-10-483-02-00	COMPANY MANAGED DEMAND - PEAK - NH	Revenues
30-49-13-10-483-20-90	COMPANY MANAGED DEMAND - PEAK - NH EST	Revenues
30-49-13-10-798-06-00	CAPACITY RELEASE- PEAK - NH	Expenses
30-49-13-10-798-06-02	PIPELINE CAPACITY RELEASE - CAP ASSIGN - PEAK - NH	Expenses
30-49-13-10-798-06-08	CUSTOMER REENTRY FEE - NH	Expenses
30-49-13-10-798-60-90	CAPACITY RELEASE- PEAK - NH - EST	Expenses
30-49-13-10-799-01-02	CAPACITY MITIGATION - PEAK - NH	Expenses

Account Code	Account Description	Type
30-49-13-10-799-12-90	CAPACITY MITIGATION - PEAK - NH - EST	Expenses
30-49-13-10-804-01-01	TRANSPORTATION - DEMAND - PEAK - NH	Expenses
30-49-13-10-804-02-01	SUPPLY PURCHASES - DEMAND - PEAK - NH	Expenses
30-49-13-10-804-11-90	TRANSP - DEMAND - PEAK EST - NH	Expenses
30-49-13-10-804-21-90	SUPPLY PURCHASES -DEMAND- PEAK EST - NH	Expenses
30-49-13-10-807-05-00	MISC PURCHASED GAS COSTS - NH	Expenses
30-49-13-10-807-05-10	FUEL TAX RECOVERY - NH	Expenses
30-49-13-10-808-02-00	STORAGE COSTS -DEMAND - PEAK - NH	Expenses
30-49-13-10-808-20-90	STORAGE COSTS -DEMAND - PEAK EST - NH	Expenses
30-49-13-10-813-00-00	OTHER GAS SUPPLY EXPENSES - PEAK	Expenses
30-49-13-11-483-00-01	SALES FOR RESALE - COMMODITY - PEAK - NH	Revenues
30-49-13-11-483-02-00	COMPANY MANAGED COMMODITY- PEAK - NH	Revenues
30-49-13-11-483-10-90	SALES FOR RESALE COMMODITY - PEAK - NH - EST	Revenues
30-49-13-11-483-20-90	COMPANY MANAGED COMMODITY- PEAK - NH EST	Revenues
30-49-13-11-484-00-00	TRANSPORTATION CHARGES - COMMODITY - PEAK - NH	Revenues
30-49-13-11-804-01-02	TRANSPORTATION COMMODITY - PEAK - NH	Expenses
30-49-13-11-804-02-02	SUPPLY PURCHASES COMMODITY- PEAK - NH	Expenses
30-49-13-11-804-04-01	ATV RECON CHARGES - PEAK - NH	Expenses
30-49-13-11-804-04-02	ATV IMBALANCE PENALTIES-PEAK-NH	Expenses
30-49-13-11-804-12-90	TRANSPORTATION VARIABLE - PEAK EST - NH	Expenses
30-49-13-11-804-22-90	SUPPLY PURCHASES COMMODITY- PEAK EST - NH	Expenses
30-49-13-11-806-01-00	GRANITE OBA - NH - PEAK	Expenses
30-49-13-11-807-00-00	HEDGING - COMMODITY - NH - PEAK	Expenses
30-49-13-11-808-01-01	LNG VAPORIZED FOR SENDOUT-BOILOFF - PEAK - NH	Expenses
30-49-13-11-808-02-00	NAT GAS STORAGE WITHDRAWALS - NH-PEAK	Expenses
30-49-13-11-808-02-01	STORAGE COSTS - COMMODITY - PEAK - NH	Expenses
30-49-13-11-808-21-90	STORAGE WITHDRAWLS - PEAK EST - NH	Expenses
30-49-13-11-812-00-00	COMPANY USE - PEAK - NH	Expenses
30-49-21-14-904-00-01	PROVISION FOR DOUBTFUL ACCTS - CGA	Expenses
30-49-21-14-904-00-05	BD EXP CIS R5-W-NON-DIST	Expenses
30-49-21-14-904-00-06	BD EXP CIS R6-W-NON-DIST	Expenses
30-49-21-14-904-00-10	BD EXP CIS R10-W-NON-DIST	Expenses
30-49-21-14-904-00-11	BD EXP CIS R11-W-NON-DIST	Expenses
30-49-21-14-904-00-40	BD EXP CIS G40-W-NON-DIST	Expenses
30-49-21-14-904-00-41	BD EXP CIS G41-W-NON-DIST	Expenses
30-49-21-14-904-00-42	BD EXP CIS G42-W-NON-DIST	Expenses
30-49-21-14-904-00-50	BD EXP CIS G50-W-NON-DIST	Expenses
30-49-21-14-904-00-51	BD EXP CIS G51-W-NON-DIST	Expenses
30-49-21-14-904-00-52	BD EXP CIS G52-W-NON-DIST	Expenses
30-49-21-14-904-01-00	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - PEAK	Expenses
30-49-21-44-904-00-02	PROVISION FOR DOUBTFUL ACCTS - CGA	Expenses
30-49-21-44-904-00-05	BD EXP CIS R5-S-NON-DIST	Expenses
30-49-21-44-904-00-06	BD EXP CIS R6-S-NON-DIST	Expenses
30-49-21-44-904-00-10	BD EXP CIS R10-S-NON-DIST	Expenses
30-49-21-44-904-00-11	BD EXP CIS R11-S-NON-DIST	Expenses
30-49-21-44-904-00-40	BD EXP CIS G40-S-NON-DIST	Expenses
30-49-21-44-904-00-41	BD EXP CIS G41-S-NON-DIST	Expenses
30-49-21-44-904-00-42	BD EXP CIS G42-S-NON-DIST	Expenses
30-49-21-44-904-00-50	BD EXP CIS G50-S-NON-DIST	Expenses
30-49-21-44-904-00-51	BD EXP CIS G51-S-NON-DIST	Expenses
30-49-21-44-904-00-52	BD EXP CIS G52-S-NON-DIST	Expenses
30-49-21-44-904-01-00	PROVISION FOR DOUBTFUL ACCTS - CGA - NH - OFF PEAK	Expenses
30-49-21-44-904-05-52	BD EXP CIS G52-S-NON-DIST	Expenses

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(10) The utility's Securities and Exchange Commission 10K forms and 10Q forms or hyperlinks thereto, for the most recent 2 years.

Response:

Northern Utilities, Inc. does not make Form 10-K or Form 10-Q filings.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(11) 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.

Response:

Please see PUC 1604.01(a) - 11 Attachment 1 for a list of amounts charged above the line in 2020.

Northern Utilities, Inc.
NH Division

Organization	Amount	Account Charged	Purpose
American Gas Association	$ 28,609	30-40-13-00-921-03-00	Membership Dues
Northeast Gas Association	6,000	30-40-80-00-930-03-00	Membership Dues
Total	$ 34,609		

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(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 Allis of Gannett Fleming.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(13) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding.

Response:

Please see PUC 1604.01(a) – 13 Attachment 1 which is Northern Utilities Inc.'s Annual Report to Noteholders for the year ended December 31, 2020.

On October 17, 2018, the Maine Public Utilities Commission issued an Order in Maine PUC Docket 2015-00155 indicating an intent to "initiate periodic audits" of all Maine Local Distribution Companies ("LDCs") "to allow for a comprehensive, structured and in-depth examination of LDC gas supply procurement and management decisions and activities." The Commission expressly noted that its decision to conduct audits was not based on any finding or indication of LDC imprudence or poor management and "[would] not be conducted as a management audit pursuant to Title 35-A, section 113" of Maine's statutes. 2015-00155, *Inquiry into Regulatory and Rate-Setting Approaches for Natural Gas Supply Costs*, Inquiry Findings and Conclusions at 3 (October 17, 2018). The Commission first conducted an audit of Northern Utilities, Inc.'s Maine Division ("Northern Utilities Maine"). 2018-00300, *Northern Utilities Inc. Review of Gas Supply Procurement and Management Activities*, Notice of Summary Investigation (October 18, 2018). The Maine Commission's third-party consultant, Liberty Consulting Group, issued its Final Report on December 19, 2019. Though the investigation was not a "Management Audit" as that term is defined in 35-A M.R.S. § 113, the Company is providing a copy of the Final Report as Puc 1604.01(a) – 13 Attachment 2.

In Northern Utilities Maine's last rate case, 2019-00092, the Maine Commission ordered that a management audit under 35-A M.R.S. § 113 be initiated for the purpose of examining the Company's implementation of its new customer information system ("CIS"). The Maine Commission's third-party consultant, Liberty Consulting Group, issued a Final Report of its audit on February 26, 2021. The Company provides a copy of the Final Report as Puc 1604.01(a) – 13 Attachment 3. Unitil disputes the findings of the audit, and Northern Utilities Maine recently submitted extensive testimony rebutting Liberty Consulting Group's conclusions regarding, among other things, vendor selection, project and cost management, CIS implementation, and

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:
ratepayer impact. Northern Utilities Maine's June 30, 2021 rebuttal filing can be found at:

https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=111071&CaseNumber=2021-00022

Northern Utilities continues to participate actively in the audit proceeding to demonstrate that the full amount of the CIS project costs are reasonable and justifiable, and will pursue full recovery in rates of these costs.

NORTHERN UTILITIES, 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 additionally certify that the accompanying calculation worksheets, pursuant to Sections 10.1 and 10.5 of the Northern Utilities Inc. Note Purchase 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 Northern Utilities, Inc. Note 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 Default or 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

Northern Utilities, Inc.

(a) Ratio of Funded Indebtedness to Total Capitalization

The information below is being provided in accordance with Section 10.1 (a) of the Note Purchase Agreements for Northern Utilities, Inc.'s 5.29% Senior Notes, due March 2, 2020 ,3.52% Senior Notes, due November 1, 2027, 7.72% Senior Notes, due December 3, 2038, 4.42% Senior Notes, due October 15, 2044, 4.32% Senior Notes, due November 1, 2047, 4.04% Senior Notes due September 12, 2049 and 3.78% Senior Notes, due September 15, 2040.

	(Millions) As of December 31, 2020	
Funded Indebtedness [1]	$	228.6
Total Capitalization	$	460.2
Funded Indebtedness / Total Capitalization [2]		49.7%

[1] **Funded Indebtedness is Total Capitalization less Common Stock Equity as of the balance sheet date.**

[2] **Per Section 10.1(a) of the Note Purchase Agreements, Funded Indebtedness cannot exceed 65% of Total Capitalization.**

Northern Utilities, Inc.

(a) Restrictions on Dividends

The information below is being provided in accordance with Section 10.1 (a) of the Note Purchase Agreements for Northern Utilities, Inc.'s 5.29% Senior Notes, due March 2, 2020 ,3.52% Senior Notes, due November 1, 2027, 7.72% Senior Notes, due December 3, 2038, 4.42% Senior Notes, due October 15, 2044, 4.32% Senior Notes, due November 1, 2047, 4.04% Senior Notes due September 12, 2049 and 3.78% Senior Notes, due September 15, 2040. As Section 11 (f) of the Note 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	$ 168.0
Add: Equity Contributions - 2020	6.4
Add: Net Income - 2020	14.7
Subtotal	**$ 189.1**
Less: Dividends Declared / Paid - 2020	14.6
Available for Dividends [1]	**$ 174.5**

[1] Per Section 10.5 (a) of the Note 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.

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INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Northern Utilities, Inc.
Hampton, NH

We have audited the accompanying financial statements of Northern Utilities, 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 Northern Utilities, 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

NORTHERN UTILITIES, INC.
For the Period Ended December 31, 2020

NORTHERN UTILITIES, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31,		
	2020	2019	2018
Operating Revenues	**$ 155.5**	$ 166.6	$ 179.1
Operating Expenses:			
Cost of Gas Sales	**63.2**	73.3	90.7
Operation and Maintenance	**28.6**	30.6	29.5
Depreciation and Amortization	**21.6**	20.1	16.9
Taxes Other Than Income Taxes	**10.4**	9.4	8.8
Total Operating Expenses	**123.8**	133.4	145.9
Operating Income	**31.7**	33.2	33.2
Interest Expense	**10.8**	10.6	10.4
Other Expense (Income), Net	**0.6**	0.2	1.0
Income Before Income Taxes	**20.3**	22.4	21.8
Income Taxes	**5.6**	6.2	6.0
Net Income	**$ 14.7**	$ 16.2	$ 15.8

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions)

	December 31,	
	2020	2019
ASSETS:		
Current Assets:		
Cash and Cash Equivalents	$ 0.4	$ 0.3
Accounts Receivable – (Net of Allowance for Doubtful Accounts of $1.2 and $0.4)	22.8	21.1
Due from Affiliates	1.5	---
Accrued Revenue	15.2	12.4
Exchange Gas Receivable	4.4	5.5
Gas Inventory	0.3	0.4
Materials and Supplies	5.2	4.9
Prepayments and Other	2.0	1.9
Total Current Assets	51.8	46.5
Utility Plant:		
Gas	687.7	621.6
Construction Work in Progress	13.3	12.5
Utility Plant	701.0	634.1
Less: Accumulated Depreciation	145.5	112.7
Net Utility Plant	555.5	521.4
Other Noncurrent Assets:		
Regulatory Assets	27.9	23.8
Operating Lease – Right of Use Assets	1.6	1.1
Other Assets	2.1	2.1
Total Other Noncurrent Assets	31.6	27.0
TOTAL ASSETS	$ 638.9	$ 594.9

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
BALANCE SHEETS
($ in Millions, except par value and shares data)

	December 31, 2020	December 31, 2019
LIABILITIES AND CAPITALIZATION:		
Current Liabilities:		
Accounts Payable	$ 10.0	$ 11.7
Short-Term Debt	26.7	28.5
Long-Term Debt, Current Portion	---	8.1
Energy Supply Contract Obligations	4.4	5.5
Dividends Payable	3.7	3.3
Due to Affiliates	---	0.9
Environmental Obligations	0.2	0.6
Regulatory Liabilities	0.4	1.0
Other Current Liabilities	4.6	4.8
Total Current Liabilities	50.0	64.4
Noncurrent Liabilities:		
Deferred Income Taxes	42.4	36.5
Cost of Removal Obligations	29.8	30.3
Retirement Benefit Obligations	38.1	31.0
Regulatory Liabilities	15.5	15.8
Environmental Obligations	1.8	2.1
Operating Leases – Less Current Portion	1.1	0.7
Other Noncurrent Liabilities	---	0.1
Total Noncurrent Liabilities	128.7	116.5
Capitalization:		
Long-term Debt, Less Current Portion	228.6	188.9
Shareholder's Equity:		
Common Stock, $10 Par Value		
Authorized - 200 shares		
Issued and Outstanding - 100 shares	207.1	200.7
Retained Earnings	24.5	24.4
Total Shareholder's Equity	231.6	225.1
Total Capitalization	460.2	414.0
Commitments and Contingencies (Note 5)		
TOTAL LIABILITIES AND CAPITALIZATION	$ 638.9	$ 594.9

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CASH FLOWS
($ in Millions)

	Year Ended December 31,		
	2020	2019	2018
Operating Activities:			
Net Income	**$ 14.7**	$ 16.2	$ 15.8
Adjustments to Reconcile Net Income to Cash Provided by (Used in) Operating Activities:			
Depreciation and Amortization	**21.6**	20.1	16.9
Deferred Tax Provision	**5.6**	6.2	6.0
Changes in Working Capital Items:			
Accounts Receivable	**(1.7)**	6.6	(1.9)
Accrued Revenue	**(2.8)**	8.2	(2.0)
Exchange Gas Receivable	**1.1**	2.0	(2.1)
Due to/from Affiliates	**(2.4)**	0.9	2.8
Accounts Payable	**(1.7)**	(4.2)	(0.8)
Regulatory Liabilities	**(0.6)**	0.6	(2.1)
Other Changes in Working Capital Items	**(1.0)**	(0.3)	1.1
Deferred Regulatory and Other Charges	**(0.8)**	0.3	1.4
Other, net	**2.7**	(0.8)	(8.6)
Cash Provided by Operating Activities	**34.7**	55.8	26.5
Investing Activities:			
Property, Plant, and Equipment Additions	**(55.4)**	(69.6)	(53.3)
Cash Used in Investing Activities	**(55.4)**	(69.6)	(53.3)
Financing Activities:			
(Repayment of) Proceeds from Short-Term Debt, net	**(1.8)**	(29.7)	55.2
Issuance of Long-Term Debt	**40.0**	40.0	---
Repayment of Long-Term Debt	**(8.2)**	(8.4)	(18.3)
Long-Term Debt Issuance Costs	**(0.2)**	(0.2)	---
Net (Decrease) Increase in Exchange Gas Financing	**(1.1)**	(2.0)	2.1
Dividends Paid	**(14.3)**	(11.8)	(11.9)
Equity Contribution	**6.4**	25.5	---
Cash Provided by Financing Activities	**20.8**	13.4	27.1
Net Increase (Decrease) in Cash and Cash Equivalents	**0.1**	(0.4)	0.3
Cash and Cash Equivalents at Beginning of Year	**0.3**	0.7	0.4
Cash and Cash Equivalents at End of Year	**$ 0.4**	$ 0.3	$ 0.7
Supplemental Cash Flow Information:			
Interest Paid	**$ 9.8**	$ 9.4	$ 10.0
Income Taxes Paid (Refunded)	**$ ---**	$ ---	$ 0.6
Non-cash Investing Activity:			
Capital Expenditures Included in Accounts Payable	**$ 0.5**	$ 0.1	$ 0.1
Right of Use Assets Obtained in Exchange for Lease Obligations	**$ 0.5**	$ 1.1	$ ---

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
($ in Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2018	$ 175.2	$ 16.1	**$ 191.3**
Net Income		15.8	**15.8**
Dividends Declared ($99,881 Per Common Share)		(9.9)	**(9.9)**
Balance at December 31, 2018	$ 175.2	$ 22.0	**$ 197.2**
Net Income		16.2	**16.2**
Dividends Declared ($138,510 Per Common Share)		(13.8)	**(13.8)**
Equity Contribution	25.5		**25.5**
Balance at December 31, 2019	$ 200.7	$ 24.4	**$ 225.1**
Net Income		14.7	**14.7**
Dividends Declared ($146,663 Per Common Share)		(14.6)	**(14.6)**
Equity Contribution	6.4		**6.4**
Balance at December 31, 2020	$ 207.1	$ 24.5	**$ 231.6**

(The accompanying Notes are an integral part of these financial statements.)

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 1: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations - Northern Utilities, Inc. (Northern Utilities or Company), a wholly-owned subsidiary of Unitil Corporation (Unitil), provides natural gas service in southeastern New Hampshire and portions of southern and central Maine, including the city of Portland and the Lewiston-Auburn area and is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC) and the Maine Public Utilities Commission (MPUC). Northern Utilities' 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 Northern Utilities' employees and contractors ability to provide ongoing services to Northern Utilities, (ii) by reducing customer demand for electricity or gas, or (iii) by reducing the supply of electricity or gas, each of 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 Northern Utilities, Unitil has interests in two other distribution utility companies, one doing business in New Hampshire and one doing business in Massachusetts, an interstate natural gas transmission pipeline company (Granite State), a service company (Unitil Service Corp.), a realty company, a power company, and a non-regulated company.

Transactions among Northern Utilities and other affiliated companies include professional and management services rendered by Unitil Service Corp. of approximately $24.8 million, $26.1 million and $23.9 million in the years ended December 31, 2020, 2019 and 2018, respectively. The Company's transactions with affiliated companies are subject to review by the NHPUC, MPUC and the Federal Energy Regulatory Commission (FERC).

In 2019 and 2020, Northern Utilities received capital contributions of $25.5 million and $6.4 million, respectively, from Unitil.

Approximately 7%, 6% and 5% of the Company's natural gas purchases for the years ended December 31, 2020, 2019 and 2018, respectively, were from Granite State.

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.

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 - Gas 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 MPUC and NHPUC which determine 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 MPUC and 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 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.

NORTHERN UTILITIES, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

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,		
Gas Operating Revenues ($ millions):	**2020**	**2019**	**2018**
Billed and Unbilled Revenue:			
Residential	$ 54.5	$ 61.9	$ 61.5
C&I	91.7	106.4	105.7
Other	4.9	7.8	6.9
Total Billed and Unbilled Revenue	151.1	176.1	174.1
Rate Adjustment Mechanism Revenue	4.4	(9.5)	5.0
Total Gas Operating Revenues	**$ 155.5**	**$ 166.6**	**$ 179.1**

Retirement Benefit Costs - The Company co-sponsors the Pension Plan, which is a defined benefit pension plan. The Pension Plan was closed to new non-union employees effective January 1, 2010. The Pension Plan was closed to United Steelworkers of America Local 12012-6 employees hired subsequent to December 31, 2010 and to Utility Workers Union of America Local 341 employees hired subsequent to April 1, 2012. The Company also co-sponsors a non-qualified retirement plan, the SERP, covering certain executives of the Company, and an employee 401(k) savings plan. Additionally, the Company co-sponsors the PBOP Plan, primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets as an asset or liability the overfunded or underfunded status of its retirement benefit obligations (RBO) based on the projected benefit obligations. The Company has recognized a corresponding Regulatory Asset, reflecting ultimate recovery from customers through rates. The regulatory asset (or regulatory liability) is amortized as the actuarial gains and losses and prior service cost are amortized to net periodic benefit cost for the Pension and PBOP plans. All amounts are remeasured annually. See Note 7 (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

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to an annual composite rate of 3.01%, 3.04% and 2.96% in 2020, 2019 and 2018, respectively, based on the average depreciable property balances at the beginning and end of the year. Depreciation expense for Northern Utilities was $19.4 million, $17.9 million and $16.2 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Sales Taxes - The Company bills its customers sales tax in Maine. This tax is remitted to the Maine Revenue Service and is excluded from revenues on the Company's Statements of Earnings. There is no sales tax in New Hampshire.

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 Northern Utilities, 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.

Allowance for Uncollectible Accounts - The Company recognizes a provision for doubtful accounts that reflects the Company's estimate of expected credit losses for electric and gas 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 MPUC and 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

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has been that the assumptions used in evaluating the adequacy of the allowance for doubtful accounts have proven to be reasonably accurate.

Accounts Receivable, Net includes $1.1 million and $0.4 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	$ **8.4**	$ 5.0
Unbilled Revenues	**6.8**	7.4
Total Accrued Revenue	$ **15.2**	$ 12.4

Exchange Gas Receivable - The Company has a gas exchange and storage agreement whereby natural gas purchases during the months of April through October are delivered to a third party. The third party delivers natural gas back to the Company during the months of November through March. The exchange and storage gas volumes are recorded at weighted average cost. Exchange Gas Receivable was $4.4 million and $5.5 million at December 31, 2020 and 2019, respectively. Although the asset management agreement associated with the exchange gas receivable may qualify as an embedded derivative because its terms contain notional amounts, the Company does not classify the agreement as a derivative because it meets the criteria for exception as a contract for normal purchases and normal sales, as such instruments are defined per the FASB Codification.

Gas Inventory - The Company uses the weighted average cost methodology to value natural gas inventory. Natural gas inventory was $0.3 million and $0.4 million at December 31, 2020 and 2019, respectively.

	December 31,	
Gas Inventory ($ millions)	**2020**	2019
Natural Gas	$ **0.3**	$ 0.4
Liquefied Natural Gas	**---**	---
Total Gas Inventory	$ **0.3**	$ 0.4

Materials and Supplies - Materials and Supplies consist of distribution construction and 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 $5.2 million and $4.9 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

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an allowance for funds used during construction (AFUDC). The average annualized interest rate applied to AFUDC was 2.88%, 4.32% and 2.64% 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, depreciation 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 $29.8 million and $30.3 million, respectively.

Regulatory Accounting - Northern Utilities' principal business is the distribution of natural gas and it is regulated by the MPUC and NHPUC. 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.

	December 31,	
Regulatory Assets consist of the following ($ millions)	**2020**	2019
Retirement Benefit Obligations	**$ 21.4**	$ 16.6
Rate Adjustment Mechanisms	**7.1**	3.8
Environmental Obligations	**4.5**	5.9
Income Taxes	**0.9**	1.2
Other	**2.4**	1.3
Total Regulatory Assets	**$ 36.3**	$ 28.8
Less: Current Portion of Regulatory Assets [1]	**8.4**	5.0
Regulatory Assets - noncurrent	**$ 27.9**	$ 23.8

(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	**$ 0.4**	$ 1.0
Income Taxes	**15.2**	15.4
Other	**0.3**	0.4
Total Regulatory Liabilities	**15.9**	16.8
Less: Current Portion of Regulatory Liabilities	**0.4**	1.0
Regulatory Liabilities - noncurrent	**$ 15.5**	$ 15.8

Generally, the Company receives a return on investment on its Regulatory Assets for which a cash outflow has been made. Included in Regulatory Assets as of December 31, 2020 are $4.3 million of environmental costs, rate case costs and other expenditures to be recovered over the next seven years. Regulators have authorized recovery of these expenditures, but without a return. The Company expects that it will recover all its investments in long-lived assets through its utility rates, including those amounts recognized as Regulatory Assets.

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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 Consolidated 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).

Derivatives - The Company enters into energy supply contracts to serve its customers. The Company follows a procedure for determining whether each contract qualifies as a derivative instrument under the guidance provided by the FASB Codification on Derivatives and Hedging. For each contract, the Company reviews and documents the key terms of the contract. Based on those terms and any additional relevant components of the contract, the Company determines and documents whether the contract qualifies as a derivative instrument as defined in the FASB Codification. The Company has determined that its energy supply contracts either do not qualify as a derivative instrument under the guidance set forth in the FASB Codification, have been elected as a normal purchase, or have contingencies that have not yet been met in order to establish a notional amount.

The Company previously operated a regulatory approved hedging program designed to fix or cap a portion of its gas supply costs for the coming years of service, which included use of derivative instruments. The hedging program was terminated in 2018.

Under the hedging program previously operated by the Company, any gains or losses resulting from the change in the fair value of these derivatives were passed through to ratepayers directly through the Company's Cost of Gas Clause. The fair value of these derivatives was determined using Level 2 inputs (valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly), specifically based on the NYMEX closing prices for outstanding contracts as of the balance sheet date. As a result of the ratemaking process, the Company recorded gains and losses resulting from the change in fair value of the derivatives as regulatory liabilities or assets, then reclassified these gains or losses into Cost of Gas Sales when the gains and losses were passed through to customers through the Cost of Gas Clause.

The Company had no derivative assets or liabilities recorded on its Consolidated Balance Sheets as of December 31, 2020 and December 31, 2019. There were no losses / (gains) recognized in Regulatory Assets / Liabilities for the years ended December 31, 2020 and 2019. There were no losses / (gains) reclassified into the Consolidated Statements of Earnings for the years ended December 31, 2020 and 2019.

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Energy Supply Obligations - The Company enters into asset management agreements under which it releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. The gas volumes related to these agreements are recorded in Exchange Gas Receivable on the Company's Balance Sheets while the corresponding obligations are recorded in Energy Supply Obligations.

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 5 (Commitments and Contingencies).

Environmental Matters - The Company's past and present operations include activities that are generally subject to extensive federal and state environmental laws and regulations. The Company has or will recover substantially all of the costs of the environmental remediation work performed to date from customers or from its insurance carriers. The Company believes it is in compliance with all applicable environmental and safety laws and regulations, and the Company believes that as of December 31, 2020, there are no material losses that would require additional liability reserves to be recorded other than those disclosed in Note 5, Commitments and Contingencies below. Changes in future environmental compliance regulations or in future cost estimates of environmental remediation costs could have a material effect on the Company's financial position if those amounts are not recoverable in regulatory rate mechanisms.

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.

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.

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NOTE 2: DEBT AND FINANCING ARRANGEMENTS

Long-Term Debt and Interest Expense

All the Company's long-term debt is issued under unsecured promissory notes with negative pledge provisions, which, among other things, limit the incursion of additional long-term debt. Accordingly, in order for the Company to issue new long-term debt, covenants of the existing long-term agreements must be satisfied, including that the Company has total funded indebtedness less than 65% of total capitalization. The Company's unsecured promissory note agreements require that if it defaults on any long-term debt agreement, it would constitute a default under all its long-term debt agreements. The default provisions are not triggered by the actions or defaults of other companies owned by Unitil. The Company's long-term debt agreements also contain covenants restricting its ability to incur liens and to enter into sale and leaseback transactions, and restricting its ability 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, Northern Utilities issued $40 million of Notes due 2040 at 3.78% and 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.

On September 12, 2019, Northern Utilities issued $40 million of Notes due 2049 at 4.04%. Northern Utilities 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 these issuances have been netted against Long-Term Debt for presentation purposes on the Company's Balance Sheets.

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
Senior Notes:		
5.29% Senior Notes, Due March 2, 2020	---	8.2
3.52% Senior Notes, Due November 1, 2027	**20.0**	20.0
7.72% Senior Notes, Due December 3, 2038	**50.0**	50.0
3.78% Senior Notes, Due September 15, 2040	**40.0**	---
4.42% Senior Notes, Due October 15, 2044	**50.0**	50.0
4.32% Senior Notes, Due November 1, 2047	**30.0**	30.0
4.04% Senior Notes, Due September 12, 2049	**40.0**	40.0
Total Long-Term Debt	**230.0**	198.2
Less: Unamortized Debt Issuance Costs	**1.4**	1.2
Total Long-Term Debt, net of Unamortized Debt Issuance Costs	**228.6**	197.0
Less: Current Portion	---	8.1
Total Long-Term Debt, Less Current Portion	**$ 228.6**	$ 188.9

The aggregate amount of Note repayment requirements is zero in each of 2021 – 2025 and $230.0 million thereafter.

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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 $286.5 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

Northern Utilities' short-term borrowings are presently provided under a cash pooling and loan agreement between Unitil 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 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. The Company had short-term debt outstanding through bank borrowings of approximately $26.7 million and $28.5 million at December 31, 2020 and 2019, respectively.

Northern Utilities enters into asset management agreements under which Northern Utilities releases certain natural gas pipeline and storage assets, resells the natural gas storage inventory to an asset manager and subsequently repurchases the inventory over the course of the natural gas heating season at the same price at which it sold the natural gas inventory to the asset manager. There was $5.4 million and $6.5 million of natural gas storage inventory at December 31, 2020 and 2019, respectively, related to these asset management agreements. The amount of natural gas inventory released in December 2020, which was payable in January 2021, was $1.0 million and recorded in Accounts Payable at December 31, 2020. The amount of natural gas inventory released in December 2019, which was payable in January 2020, was $1.0 million and recorded in Accounts Payable at December 31, 2019.

Leases

The Company leases some of its vehicles 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 $0.7 million, $0.5 million and $0.8 million respectively.

The balance sheet classification of the Company's lease obligations is presented in the following table:

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	December 31,	
Lease Obligations (millions)	**2020**	**2019**
Operating Lease Obligations:		
Other Current Liabilities (current portion)	**$ 0.5**	$ 0.4
Operating Leases, Less Current Portion (noncurrent portion)	**1.1**	0.7
Total Lease Obligations	**$ 1.6**	$ 1.1

Cash paid for amounts included in the measurement of operating lease obligations for the twelve months ended December 31, 2020 and 2019 was $0.7 million and $0.5 million, respectively, and was 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 $1.1 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	$ 584
2022	448
2023	382
2024	289
2025	50
2026-2030	---
Total Payments	**1,753**
Less: Interest	141
Amount of Lease Obligations Recorded on Balance Sheets	**$ 1,612**

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 3.5 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.7%. As of December 31, 2019, the weighted average remaining lease term is 3.2 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.9%.

NOTE 3: RESTRICTION ON DIVIDENDS

Under the terms of the Note Purchase Agreements relating to Northern Utilities' Senior Notes, $174.5 million was available for dividends and similar distributions at December 31, 2020. Common dividends declared by Northern Utilities are paid exclusively to Unitil Corporation.

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NOTE 4: ENERGY SUPPLY

Natural Gas Supply:

Northern Utilities' C&I customers are entitled to purchase their natural gas supply from third-party gas suppliers. Many of Northern Utilities' large, and some of its medium, C&I customers purchase their gas supply from third-party suppliers. Most small C&I customers, and all residential customers, purchase their gas supply from Northern Utilities under regulated rates and tariffs. As of December 2020, 80% of the Company's largest New Hampshire gas customers, representing 39% of the Company's New Hampshire gas therm sales, and 67% of the Company's largest Maine customers, representing 25% of the Company's Maine gas therm sales, purchased their gas supply from a third-party supplier.

The approved costs associated with the acquisition of such wholesale natural gas supplies for customers who do not contract with third-party suppliers are recovered on a pass-through basis through periodically-adjusted rates and are included in Cost of Gas Sales in the Statements of Earnings.

Regulated Natural Gas Supply:

Northern Utilities purchases the majority of its natural gas from U.S. domestic and Canadian suppliers largely under contracts of one year or less, and on occasion from producers and marketers on the spot market. Northern Utilities arranges for gas transportation and delivery to its system through its own long-term contracts with various interstate pipeline and storage facilities, through peaking supply contracts delivered to its system, or in the case of liquefied natural gas (LNG), via trucking of supplies to storage facilities within Northern Utilities' service territory.

Northern Utilities has available under firm contract 122,000 million British Thermal Units (MMbtu) per day of year-round and seasonal transportation capacity to its distribution facilities, and 4.3 billion cubic feet (BCF) of underground storage. As a supplement to pipeline natural gas, Northern Utilities owns an LNG storage and vaporization facility. This plant is used principally during peak load periods to augment the supply of pipeline natural gas.

NOTE 5: COMMITMENTS AND CONTINGENCIES

Regulatory Matters

Overview - Northern Utilities is a New Hampshire corporation and a public utility under both New Hampshire and Maine law. Northern Utilities provides natural gas distribution services to approximately 69,400 customers in 47 New Hampshire and southern Maine communities at rates established under traditional cost of service regulation. Under this regulatory structure, the Company recovers the cost of providing distribution service to its customers based on a representative test year, in addition to earning a return on their capital investment in utility assets. The Company's business customers are entitled to purchase their natural gas supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through the Company as the provider of basic service energy supply. The Company purchases natural gas for basic 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.

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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. Each state public utility commission, with jurisdiction over the areas that are served by Northern Utilities, issued orders directing how the tax law changes were to be reflected in rates. Northern Utilities has complied with these orders and has made the required changes to its rates as directed by the commissions.

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 - Maine - On March 26, 2020, the MPUC approved an increase to base revenue of $3.6 million, a 3.6% increase over the Company's test year operating revenues, effective April 1, 2020. The order approved a return on equity of 9.48%, and a hypothetical capital structure of 50% equity and 50% debt. As part of the order and increase in base revenue, the MPUC provided for recovery of some but not all of the Company's implementation costs associated with its customer information system pending the completion of an investigation. On March 9, 2021, the MPUC opened a new docket and issued the notice of investigation to determine the amount of customer information system costs that will be allowed in rates. The Company believes that the customer information system costs were prudently incurred and that the investigation will not have a material impact on its financial position, operating results or cash flows.

Targeted Infrastructure Replacement Adjustment - Maine - The settlement in Northern Utilities' Maine division's 2013 rate case authorized the Company to implement a TIRA rate mechanism to adjust base distribution rates annually to recover the revenue requirements associated with targeted investments in gas distribution system infrastructure replacement and upgrade projects, including the Company's Cast Iron Replacement Program (CIRP). In its Final Order issued on February 28, 2018 for Northern Utilities' 2017 base rate case, the MPUC approved an extension of the TIRA mechanism for an additional eight-year period, which will allow for annual rate adjustments through the end of the CIRP program. The Company's most recent request under the TIRA mechanism, to increase annual base rates by $1.4 million for 2019 eligible facilities, was approved by the MPUC on April 29, 2020, effective May 1, 2020.

Base Rates - New Hampshire - On May 2, 2018, the NHPUC approved a settlement agreement providing for a net annual revenue increase of $3.2 million, incorporating the effect of the TCJA, and an initial step increase to recover post-test year capital investments. The Company's second annual revenue step increase of approximately $1.4 million to recover eligible capital investments in 2018 was approved by the NHPUC effective May 1, 2019. According to the terms of the settlement agreement, Northern Utilities' next distribution base rate case shall be based on a historical test year no earlier than the twelve months ending December 31, 2020.

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

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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. Northern Utilities is an active participant in this proceeding, and is in full compliance with all regulatory orders governing service shut-off moratoriums and other customer service protection measures. These matters remain pending.

Northern Utilities / Granite State - Firm Capacity Contract - Northern Utilities relies on the transport of gas supply over its affiliate Granite State pipeline to serve its customers in the Maine and New Hampshire service territories. Granite State facilitates critical upstream interconnections with interstate pipelines and third party suppliers essential to Northern Utilities' service to its customers. Northern Utilities reserves firm capacity through a contract with Granite State, which is renewed annually. Pursuant to statutory requirements in Maine and orders of the MPUC, Northern Utilities submits an annual informational report requesting approval of a one-year extension of its 12-month contract for firm pipeline capacity reservation, with an evergreen provision and three-month termination notification requirement. On May 13, 2020, the MPUC approved Northern Utilities' request to extend its contract for firm transmission service on its affiliate Granite State pipeline for another year, extending the current contract for the period of November 1, 2020 through October 31, 2021.

Reconciliation Filings - Northern Utilities has a number of regulatory reconciling accounts which require annual or semi-annual filings with the MPUC and NHPUC, respectively, to reconcile costs and revenues and seek approval of any rate changes. These filings include: costs associated with energy efficiency programs in New Hampshire as directed by the NHPUC; and the actual wholesale energy costs for natural gas incurred by Northern Utilities. Northern Utilities 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.

Contractual Obligations

The table below lists the Company's known specified gas supply contractual obligations as of December 31, 2020.

	Payments Due by Period						
Gas Supply Contractual Obligations as of December 31, 2020 (millions)	**Total**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026 & Beyond**
Gas Supply Contracts	**$ 542.7**	**$ 52.7**	**$ 47.0**	**$ 44.2**	**$ 35.3**	**$ 34.9**	**$ 328.6**

Environmental Matters

The Company's past and present operations include activities that are generally subject to extensive and complex federal and state environmental laws and regulations. The Company is in material compliance with applicable environmental and safety laws and regulations and, as of December 31, 2020, has not identified any material losses reasonably likely to be incurred in excess of recorded amounts. However, we cannot assure that significant costs and liabilities will not be incurred in the future. It is possible that other developments, such as increasingly stringent federal, state or local environmental laws and regulations could result in increased environmental compliance costs. Based on the Company's current assessment of its environmental responsibilities, existing legal requirements and regulatory policies, the Company does not believe that these environmental costs will have a material adverse effect on the Company's consolidated financial position or results of operations.

Manufactured Gas Plant (MGP) Sites - Northern Utilities has an extensive program to identify, investigate and remediate former manufactured gas plant (MGP) sites, which were operated from the

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mid-1800s through the mid-1900s. In New Hampshire, MGP sites were identified in Dover, Exeter, Portsmouth, Rochester and Somersworth. In Maine, Northern Utilities has documented the presence of MGP sites in Lewiston and Portland, and a former MGP disposal site in Scarborough.

Northern Utilities has worked with the Maine Department of Environmental Protection and New Hampshire Department of Environmental Services (NH DES) to address environmental concerns with these sites. Northern Utilities or others have completed remediation activities at all sites; however, on site monitoring continues at several sites which may result in future remedial actions as directed by the applicable regulatory agency. In July 2019, the NH DES requested that Northern Utilities review modeled expectations for groundwater contaminants against observed data at the Rochester site. In June 2020, the NH DES coupled the submittal of the review to a proposed extension of the gas distribution system by Northern Utilities; both the review and extension are expected to be completed by the end of the second quarter of 2021. While any recommendation is subject to approval by the NH DES, the Company has accrued $0.8 million for estimated costs to complete the remediation at the Rochester site, which is included in the Environmental Obligations table below.

The NHPUC and MPUC have approved regulatory mechanisms for the recovery of MGP environmental costs. For Northern Utilities' New Hampshire division, the NHPUC has approved the recovery of MGP environmental costs over succeeding seven-year periods. For Northern Utilities' Maine division, the MPUC has authorized the recovery of environmental remediation costs over succeeding five-year periods.

The Environmental Obligations table below shows the amounts accrued for Northern Utilities related to estimated future cleanup costs associated with Northern Utilities' environmental remediation obligations for former MGP sites. Corresponding Regulatory Assets were recorded to reflect that the future recovery of these environmental remediation costs is expected based on regulatory precedent and established practices.

Environmental Obligations

	(millions)	
	2020	**2019**
Total Balance at Beginning of Period	**$ 2.7**	$ 2.0
Additions	**0.1**	0.9
Less: Payments / Reductions	**0.8**	0.2
Total Balance at End of Period	**$ 2.0**	$ 2.7
Less: Current Portion	**0.2**	0.6
Noncurrent Balance at End of Period	**$ 1.8**	$ 2.1

Litigation - The Company is also involved in other 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

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collection of fuel and gas costs in rates. Consequently, there is limited commodity price risk after consideration of the related rate-making.

NOTE 6: 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 Provision			
Federal	**3,925**	4,314	4,289
State	**1,704**	1,875	1,744
Total Deferred Income Taxes	**5,629**	6,189	6,033
Total Income Tax Expense	**$ 5,629**	$ 6,189	$ 6,033

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	**7**	**6**	**6**
Utility Plant Differences	—	—	—
Other , net	—	**1**	—
Effective Income Tax Rate	**28%**	**28%**	**27%**

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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	**$ 10,317**	$ 8,383
Net Operating Loss Carryforwards	**12,768**	14,985
Other, net	**183**	—
Total Deferred Tax Assets	**$ 23,268**	$ 23,368
Deferred Tax Liabilities		
Utility Plant Differences	**$ 64,195**	$ 59,785
Regulatory Assets & Liabilities	**753**	(556)
Other, net	**693**	685
Total Deferred Tax Liabilities	**65,641**	59,914
Net Deferred Tax Liabilities	**$ 42,373**	$ 36,546

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 take as a credit on employment tax form 941. In the third quarter of 2020, the Company recorded an ERC of $0.2M 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, 2019 and December 31, 2020 the Company had recorded a net Regulatory Liability in the amount of $15.4 million and $15.3 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 noted above 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

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temporary timing differences. The Company estimates the ARAM flow back period to be approximately fifteen years, for protected and unprotected excess ADIT. The Company estimates the ARAM flow back period to be approximately fifteen years, for protected and unprotected excess ADIT. As of December 31, 2020, the Company flowed back $0.1 million to customers in its Maine jurisdictions. New Hampshire liabilities will begin to flow back once rate proceedings have finalized in that jurisdiction.

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, Maine, 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 and the Maine Revenue Service.

NOTE 7: 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 was closed to new non-union employees effective January 1, 2010. The Pension Plan was closed to United Steelworkers of America Local 12012-6 employees hired subsequent to December 31, 2010 and to Utility Workers Union of America Local 341 employees hired subsequent to April 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

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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	**$ 1,317**	$ 1,219	$ 1,302	**$ 1,129**	$ 992	$ 1,228	**$ 120**	$ 103	$ 200
Interest Cost	**1,672**	1,786	1,601	**1,024**	1,111	1,095	**232**	235	166
Expected Return on Plan Assets	**(2,612)**	(2,338)	(2,124)	**(1,072)**	(850)	(840)	**---**	---	---
Prior Service Cost Amortization	**306**	306	306	**194**	196	278	**24**	23	78
Actuarial Loss Amortization	**1,610**	959	1,209	**191**	69	437	**438**	261	199
Sub-total	**2,293**	1,932	2,294	**1,466**	1,518	2,198	**814**	622	643
Amounts Capitalized and Deferred	**(919)**	(773)	(899)	**(620)**	(636)	(925)	**(264)**	(200)	(207)
NPBC Recognized	**$ 1,374**	$ 1,159	$ 1,395	**$ 846**	$ 882	$ 1,273	**$ 550**	$ 422	$ 436

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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	**$ 26,871**	$ 20,444	**$ 11,293**	$ 8,353	**$ ---**	$ ---
Actual Return on Plan Assets	**4,632**	5,858	**1,943**	1,934	**---**	---
Employer Contributions	**1,712**	2,561	**1,227**	1,269	**276**	253
Participant Contributions	**---**	---	**90**	51	**---**	---
Benefits Paid	**(1,764)**	(1,992)	**(584)**	(314)	**(276)**	(253)
Plan Assets at End of Year	**$ 31,451**	$ 26,871	**$ 13,969**	$ 11,293	**$ ---**	$ ---
Change in PBO:						
PBO at Beginning of Year	**$ 38,918**	$ 29,620	**$ 25,628**	$ 20,808	**$ 4,772**	$ 3,175
Service Cost	**1,317**	1,219	**1,129**	992	**120**	103
Interest Cost	**1,672**	1,786	**1,024**	1,111	**232**	235
Plan Amendments	**732**	---	**---**	---	**---**	94
Participant Contributions	**---**	---	**90**	51	**---**	---
Benefits Paid	**(1,764)**	(1,992)	**(584)**	(314)	**(276)**	(253)
Actuarial (Gain) or Loss	**6,297**	8,285	**3,318**	2,980	**1,098**	1,418
PBO at End of Year	**$ 47,172**	$ 38,918	**$ 30,605**	$ 25,628	**$ 5,946**	$ 4,772
Funded Status: Assets vs PBO	**$ (15,721)**	$ (12,047)	**$ (16,636)**	$ (14,335)	**$ (5,946)**	$ (4,772)

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 as a liability the underfunded status of its retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets, net of tax, of $21.4 million and $16.6 million at December 31, 2020 and 2019, respectively, to recognize the future collection of these plan obligations in gas 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 $43.7 million and $35.9 million as of December 31, 2020 and 2019, respectively. The ABO for the SERP was $4.9 million and $3.7 million as of December 31, 2020 and 2019, respectively. For the PBOP Plan, the ABO and PBO are the same.

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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.

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	**$ 1,712**	$ 2,561	$ 5,670	**$ 1,227**	$ 1,269	$ 1,353	**$ 276**	$ 253	$ 165
Participant Contributions	**$ ---**	$ ---	$ ---	**$ 90**	$ 51	$ 64	**$ ---**	$ ---	$ ---
Benefit Payments	**$ 1,764**	$ 1,992	$ 1,339	**$ 584**	$ 314	$ 389	**$ 276**	$ 253	$ 165

The following table represents estimated future benefit payments ($000's).

Estimated Future Benefit Payments			
	Pension	PBOP	SERP
2021	$ 2,164	$ 708	$ 269
2022	1,912	769	269
2023	2,444	791	268
2024	2,867	872	268
2025	2,625	999	500
2026 - 2030	$ 17,095	$ 6,746	$ 2,645

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 December 31, 2018 pending payment of benefits.

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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%

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 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.

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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):

Description	Balance as of December 31,	Fair Value Measurements at Reporting Date Using: 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	$ 18,253	$ 18,253	$ ---	$ ---
Fixed Income Funds	11,573	11,573	---	---
Total Mutual Funds	29,826	29,826	---	---
Cash Equivalents	292	292	---	---
Total Assets in the Fair Value Hierarchy	$ 30,118	$ 30,118	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	1,333			
Total Assets	$ 31,451			
2019				
Pension Plan Assets:				
Equity Funds	$ 14,711	$ 14,711	$ ---	$ ---
Fixed Income Funds	9,611	9,611	---	---
Total Mutual Funds	24,322	24,322	---	---
Cash Equivalents	160	160	---	---
Total Assets in the Fair Value Hierarchy	$ 24,482	$ 24,482	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	2,389			
Total Assets	$ 26,871			

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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	$ 6,258	$ 6,258	$ ---	$ ---
Equity Funds	7,711	7,711	---	---
Total Assets	$ 13,969	$ 13,969	$ ---	$ ---
2019				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 4,921	$ 4,921	$ ---	$ ---
Equity Funds	6,372	6,372	---	---
Total Assets	$ 11,293	$ 11,293	$ ---	$ ---

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 $1,259,300, $1,188,000 and $1,082,000 for the years ended December 31, 2020, 2019 and 2018, respectively.

Examination of Natural Gas Supply Resource Procurement and Management by Northern Utilities Inc. d/b/a Until

<u>Final Report – Public Version</u>
<u>Confidential Material Redacted</u>

Presented to:
State of Maine
Public Utilities Commission

Presented by:
The
Liberty Consulting Group

December 10, 2019

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Executive Summary

The Maine Public Utilities Commission (MPUC, or the Commission) selected The Liberty Consulting Group (Liberty) to conduct an examination of the natural gas supply procurement and management protocols and practices of Northern Utilities, Inc. d/b/a Unitil (NUI, or the Company). This summary presents our principal findings, conclusions and recommendations. This following chapters of this report presents the detailed results of our examination.

We have categorized the results of our review into six overall subject areas, which, combined, encompass a broad review of the matters affecting gas supply procurement and management:

1. Organization, Staffing and Controls
2. Gas Supply Planning and Forecasting
3. Gas Supply Procurement
4. Gas Supply Management
5. Measurement and Balancing
6. Price Risk Management.

We issued 101 data requests, and conducted two rounds of interviews with Company management. We issued a draft report to the Company, whose management responded with comments and requests for the redaction of confidential information. We made changes to the report to the extent consistent with the exercise of our independent judgment.

I. Organization, Staffing and Controls

NUI provides gas distribution and supply services in New Hampshire and Maine. Unitil, NUI's parent, also owns electric distribution companies in Concord and Hampton, New Hampshire, a combination electric and gas distribution utility in Massachusetts, and an interstate gas pipeline operating in New Hampshire and Maine.

Unitil acquired NUI and the interstate pipeline from Bay State Gas Company (now d/b/a Columbia Gas of Massachusetts) in 2008. That transaction left one important gas-supply process interrelationship with the former parent -- an exchange arrangement providing access to interstate pipeline capacity under contract to NUI, but to which NUI has no physical connection.

In 1984, Unitil formed a service company to provide joint management and administrative services to its subsidiaries. Essentially all management employees work for the service company. An Energy Contracts unit within the Financial Services Division of the service company conducts the gas-supply function. Gas Operations reports to a different Vice President of the service company. It has responsibility for supply-related functions such as gas control and measurement. The interstate pipeline operates as a separate entity, but most of its employees also work for the service company.

All three jurisdictions in which Unitil's gas distribution utilities operate permit varying degrees of customer choice for electricity and natural gas supply. NUI's Energy Contracts unit works with personnel in both Gas Operations and Electric Operations to ensure delivery of third-party supplies. Energy Contracts has a more comprehensive set of planning responsibilities for the gas business. Its role includes administration associated with deliveries of third-party supplies, supply planning for customers who buy their supplies from the Company, and supply-capacity planning for both sales-service and distribution-service customers.

Qualified and experienced personnel staff Energy Contracts and Gas Operations. Performance measurement meets prevailing industry practice. However, we found a lack of written policies and procedures addressing gas-supply functions and activities (discussed below under Gas Supply Management). The lack of documented policies and procedures creates exposure to loss of continuity in understanding and executing them, particularly in a smaller organization. ***We recommended that management update personnel descriptions.***

We also found some controls weaknesses in the following areas:

- Documentation of gas supply decisions
- Limits on authority to approve transactions
- Separation of transaction-related functions
- Internal Audit examinations
- Employee acknowledgement of the Company's Code of Conduct.

We recommended that management: (a) add gas-price information, including estimated prices, to the record of daily gas-supply selections, and (b) re-examine its supply processes from a controls perspective. The process re-examination should conclude within six months of the issuance of this report, which will give management sufficient time to address the identified controls issues.

II. Gas Supply Planning and Forecasting

NUI's Integrated Resource Plan, filed in July of this year, comprehensively and clearly presented management's forecasting and supply-planning methods. We examined methods with reference to prevailing industry practices, and how and how well decisions about supply resources incorporate the results of applying those methods.

Management considered 30 years of history (the gas years of 1988/89 through 2017/18) to populate its normal- and design-weather data. The data capture effective degree-days (EDDs) by adjusting temperature data for wind speed. Separate calculations apply those parameters for the Maine and New Hampshire Divisions. Regression analysis of billing data supported the development of econometric models for forecasting numbers of customers and use per customer for each customer segment. Management made reductions to the resulting customer-segment forecasts to reflect energy-efficiency savings.

Management calculated Design Day requirements using regression analysis of actual daily throughput data, separately for each Division. Management also updated both the Residential Heating Use Per Customer model and the Peak-Day forecasting model between the 2015 IRP and the current one.

Unitil developed a comprehensive marketing program soon after it acquired NUI. That program identified customers on main but not connected, and low-use customers as targets with the highest potential. Management had also slated facilities in Maine for a Cast Iron Replacement program. Management continues special promotions and special incentives offers to prospective customers for connection in the areas affected by that program.

Energy Contracts remains informed about other company activities that might affect requirements for gas supply. Personnel gather at Seasonal Readiness Meetings to discuss new initiatives, such as a targeted area build-out. Other initiatives undergo discussion in the course of normal internal coordination.

Management inputs requirements forecasts into an optimization model. The model designs a portfolio of supply resources that provides the best fit for the input forecast. NUI uses SENDOUT, widely used for such purposes in the gas distribution business to solve for the least-cost mix of options for meeting demand, subject to user-defined constraints.

NUI has found that three pipeline options compare favorably with the alternative of relying on delivered supplies. For its seasonal and peaking requirements, management issues requests for proposals (RFPs) annually. It seeks seasonal supplies first, along with asset-management services for its legacy pipeline and storage assets. A second RFP for peaking supplies follows in mid-summer. Management has continued to discuss additional pipeline supply projects with potential offerors, and it has recently re-started work on on-system supply options.

We concluded that load-forecasting methods conformed to prevailing industry practice, but that weather-analysis methods warranted improvement. ***We recommended that NUI test the use of Monte Carlo-based weather distributions.*** Monte Carlo simulations are finding increasingly broad use in utility supply planning. ***We also recommended that management expand its analysis of additional gas-supply resources to include increased utilization of existing and newly-acquired pipeline capacity.***

III. Gas Supply Procurement

NUI's gas-supply capacity portfolio accesses the U. S. Gulf Coast, Central and Eastern Pennsylvania, Eastern Canada, and Dawn, Ontario supply sources. NUI had most of its current capacity when Unitil acquired it. Management has since renewed, converted or terminated essentially all pipeline and storage contracts then in place. The terminations sought cost reduction, or movement of receipt points closer to the NUI distribution system. NUI has also relocated its largest underground storage to Dawn, and increased capacity and maximum daily withdrawal capability.

NUI also accesses markets to supply its LNG storage and regasification facility in Lewiston, Maine. LNG enters the region at the Canaport receiving terminal in New Brunswick and at the Distrigas facility in Everett, Massachusetts. The NUI system also connects to the Maritimes & Northeast Pipeline system (M&NP); revaporized LNG from the Canaport terminal can reach NUI and other U. S. markets via M&NP pipeline facilities.

Management organizes these capacity resources into "paths" connecting each supply point to NUI's affiliated pipeline, which then delivers to the distribution system. At Lewiston, Maine, the only NUI distribution-system receipt point not served by that pipeline, NUI connects directly to M&NP, and buys supply delivered there. NUI shares all its pipeline capacity with the retail marketers who serve customers on its distribution system.

Management has sought to reduce the portion of supply bought on a delivered basis, pursuing alternatives taking the forms of pipeline connections and increases in underground storage. These resources have provided access to upstream supply points more liquid than those of New England. Capacity from such projects permits year-round use, but NUI's requirements are seasonal. Management's analysis, presented in the new IRP and in its applications for approval of participation in the new projects, holds that lower prices and greater price stability associated with access to the more-liquid supply points favor these projects over delivered supply.

NUI purchases gas supplies annually through two requests for proposals (RFPs). The first covers supplies provided as part of agreements to manage certain of NUI's capacity assets, winter-season supplies delivered through NUI's pipeline affiliate, and summer-season supplies delivered to storage-area pooling points or to injection points for storage. The second RFP covers peaking supplies delivered to the pipeline affiliate's receipt points or to NUI's receipt point on M&NP.

Management solicits offers to manage its path-based packages under asset-management agreements (AMAs) having one-year terms. Management requires asset managers to provide supply at a relevant index price, plus variable transportation and fuel charges. For each path, NUI provides the third-party managers an estimate of the amount of capacity that must be assigned to retail marketers. The third parties selected benefit in these arrangements by selling gas to NUI at agreed prices and by using any remaining capacity on the path (after meeting NUI and retail marketers' requirements) to serve other customers. NUI generally awards management of each path to the third party offering the largest asset-management fee. Over the last six years (2014-2015 through 2019-2020), asset-management revenue has covered an average of 23 percent of asset demand costs (between 11 and 36 percent in any given year).

NUI has required winter supplies significantly beyond the capacity of the capacity portfolio and pending supply projects. Management has addressed these winter needs recently with contracts for: (a) base-load supplies delivered in equal daily amounts, and (b) peaking supplies up to maximum daily quantities elected by NUI. Base-load supply contracts generally call for one delivery quantity for November through March and another for December through February. Peak-supply contracts address the five winter months.

New England gas market price volatility and constrained pipeline capacity create substantial risk for suppliers. While competition to provide commodity supply to NUI has been reasonably robust, some competitors have disappeared.

Management issues the RFP for delivered peaking service in late June or early July, with the service to begin November 1. Offerors provide the service from November 1 through the following March 31.

Management requires that prospective sellers of gas or asset-management services enter into a NAESB (North American Energy Standards Board) Base Contract for Sale and Purchase of Natural Gas with it in order to do business. Management evaluates the financial stability of those who seek to bid, but requests collateral rather than rejecting a possible supplier if it is concerned about the supplier's finances. NUI bought gas from 13 suppliers in 2018, an increase of two over the number in 2017. The top four suppliers accounted for 81.7 percent of volumes purchased.

We found NUI's management of supply procurement a notable strength. Management employed effective contracting practices, and entered contracts appropriate in meeting supply needs. ***We did, however, recommend that NUI initiate an intensive effort to reduce dependence on delivered peaking service.*** The effort should include both demand-side and supply-side options.

IV. Gas Supply Management

The challenges that NUI faces managing its gas supply include: (a) use of *multiple pipelines* to supply a *large number of delivery points*, (b) a *fragmented service territory* imposing locational requirements on deliveries, (c) a large penetration by *retail marketers*, (d) large swings in gas requirements due to high *weather variability*, and (e) NUI's *downstream location* on almost all pipelines serving, which produces narrow nominated-versus-delivered amount tolerances during the winter. We found planning, complex under these circumstances, attentive, comprehensive, and supported by appropriate systems and processes.

Operations planning begins with a general forecast to construct seasonal supply plans. The Energy Contracts staff assigns supply resources to particular delivery points. The staff then generates monthly plans that further detail and align sources and deliveries. A Daily Forecast file applies a seven-day weather forecast to generate a corresponding daily forecast of supply requirements at the pipeline delivery locations that serve NUI. Management then nominates from among the available supply resources the quantities that they want delivered to each receipt location. Management updates the Daily Forecast file every day with new weather data.

NUI's service territories, do not have robust connections among themselves. Five points of receipt bring gas into the pipeline connecting all but one of them; 38 points provide for deliveries from that pipeline. An NUI lateral connects Lewiston to the other portions of the service territory, but Lewiston depends also on winter access to an M&NP delivery point and NUI's liquefied natural gas (LNG) storage and regasification facility. Limits on the pipeline's flow capacity prohibit unlimited movement of gas from different receipt points to all the NUI points of delivery, necessitating consideration of location-specific requirements.

Management allocates shares of each NUI supply-capacity path to retail marketers in proportion to the design daily demands of each marketer's load. The marketers receive most resources directly, but NUI operates two of them -- the Lewiston LNG facility and a small storage contract and the pipeline capacity for delivering the stored gas. The marketers can trade their assigned "slices" of the NUI supply-capacity portfolio among themselves to optimize their capacity holdings, but must deliver their required amounts to specified pipeline receipt points.

NUI's primary reliance on asset-management agreements (AMAs) makes two primary activities the focus of supply-management: (a) nominating quantities for delivery to the relevant pipeline, including withdrawals from storage, under each AMA, and (b) calling on the small quantities of supply NUI manages directly as needed by marketers or NUI's system-supply customers. Management must address locational requirements first. After addressing that constraint, it can select among available resources on the basis of cost. Gas Control uses Energy Contracts' regression models relating weather conditions and sendout requirements to generate forecasts of requirements for the coming seven days, based on expected weather conditions.

NUI's lack of sizeable upstream pipeline capacity limits its occasions for secondary-market activities. Management places most available capacity into the path-based asset-management agreements, whose underlying RFPs estimate pipeline capacity required to serve NUI and retail marketer loads. Those bidding to supply asset management factor their ability to make economic use of any unused capacity into pricing their bids.

We found NUI's gas-supply management a strength, but a lack of written procedures risks operational continuity should NUI experience a loss of key skills. ***We recommended that management prepare written procedures to guide the nominations and dispatch functions.*** We also found that some short-term forecasting tools might be improved with an industry best practice known as "deep neural networks." ***We therefore recommended that management explore the application of neural network methods to short-term requirements forecasting.***

V. Measurement and Balancing

NUI's overall measurement scheme uses upstream-pipeline measurement of deliveries into NUI's pipeline affiliate (or NUI's distribution system for M&NP deliveries for Lewiston). The affiliate measures its deliveries into NUI's system; NUI, in turn, measures its deliveries to its customers. At year-end 2018, NUI's Maine Division had 34,119 active meters. NUI filed descriptions of how each of its meter types operates, and of the circumstances in which each is deployed, with its initial response in Docket No. 2018-00331, *Inquiry into Meter Testing and Standards of Local Distribution Companies*.

The interstate pipelines calibrate their meters at least annually. NUI's pipeline affiliate inspects its turbine and rotary meters monthly to verify their operation, and it calibrates its flow computers annually. NUI tests meters before installation and calibrates its largest ones quarterly. Field audits conducted each year sample the non-instrumented rotary and diaphragm meters. The audits seek to validate proper operation of the reading indexes and the automated meter reading (AMR) devices. The practice is to examine two percent of small-diaphragm meters and 25 percent of large diaphragm ones each year.

NUI's billing system identifies anomalies in billings, such as measurements showing no usage at customer locations known to be active. Upon detecting anomalies, technicians visit the meter to examine the circumstances. NUI also tests meters on customer request. NUI has identified certain meter types with known problems, replacing them as practical. Management also has a practice of retiring certain meter types to reduce the number of types in inventory. Otherwise, NUI retires meters that are more than 20 years old.

NUI takes a number of measures to reduce lost and unaccounted for (LAUF) gas. Management measures company use for office facilities and for vaporization and heaters at its LNG facility and district regulator stations. Management also installs correctors that compensate for variances in pressure and temperature for commercial and industrial customers. Another measure employed calls for checks of customer service regulators and adjustment of them on installation and routine meter changes. NUI also conducts an aggressive leak-repair program.

Management reports that most leaks occur along the cast-iron portions of its distribution system. It plots leaks on maps, to serve as a factor in planning the cast-iron replacement program. NUI has completed that replacement program in New Hampshire, now finding no leaks there. As do most gas distribution companies, NUI calculates (separately for Maine, New Hampshire, and Fitchburg) annual LAUF percentage by summing monthly calculations from July of the previous year through June of the reporting year.

Balancing consists of getting deliveries into the distribution system to match deliveries out of it. Balancing poses special challenges for NUI, because of its weather changes, penetration by retail marketers, and the company's location at downstream ends of the gas pipelines that serve it. Service interruptions on its four upstream pipelines affect it. NUI's Delivery Service Terms and Conditions provide for passing through to the marketers any flow restrictions, such as upstream imbalance warnings or operational flow orders (OFOs). Any penalties caused by marketer imbalances are passed along to the offender.

Management generally manages intra-day balancing needs by adjusting storage withdrawals for the first half of the winter, then with off-system sales in the second half. Its contracts for peaking supply and its on-system LNG facility are additional resources for addressing imbalances if necessary.

We found that NUI's metering and testing programs generally conform to prevailing industry practice. Management employed metering strategies are effective in isolating usage by customers and the Company. In particular, we found managements systems, practices and processes for balancing a strength. We had no measurement and balancing improvement recommendations

VI. Price Risk Management

NUI operated a financial hedging program when Unitil acquired it. NUI refocused the program and operated it subject to periodic review by the Commission. In early 2017, NUI petitioned the Commission to allow it to suspend the program for one year, followed by determining the best course going forward. Management also noted that it was replacing one of its gas storage contracts with a larger one that would result in an increase in the volume of gas with physically hedged pricing for the 2018-2019 Winter Period.

The next year, NUI requested that the Commission allow it to terminate the financial hedging program. The Commission approved the request, stating "the current hedging program benefits do not appear to warrant the ongoing cost …." The Commission proposed that NUI describe its price risk management objectives and actions taken to reduce customer exposure to gas price volatility in its IRP filing. Our report provides a brief history of NUI financial hedging, and reviewed the approach to inventory strategy as it relates to providing a physical hedge.

We concluded that NUI's hedging objectives have changed under Until ownership, but the Company has always stated the objective of protecting customers from natural gas price volatility. Volatility in the benchmark price for the natural gas futures contract (a monthly price at a Gulf Coast location) comprised the focus late 2008 and early 2009. Since that time, volatility in that price benchmark has generally reduced, while volatility in daily New England prices has increased.

NUI has substituted increased physical hedging and particular contracting strategies for financial hedging, but the objective is clear: to "insulate customers from the volatility of *daily* index prices".

We also found that NUI's focus on storage and contracting strategies to reduce exposure to gas-price volatility reflects its core strengths. Management has no other particular use for expertise in financial derivatives, and has chosen not to acquire it for the sole purpose of gas-price hedging.

NUI has established controls, policies and procedures that reflected the limited scope of its hedging activity. Its move to increased physical hedging and supply contracting make its processes sufficient, albeit informal. ***We recommended that additional structure be added to those functions.***

We also found that management has reviewed program results regularly, and recommended changes as market trends and program results have developed. Supply-contracting evaluations and decisions have been driven primarily by considerations of supply security and reduced operational risk, but the role of those decisions in protecting the Company's customers from price volatility has increasingly entered those deliberations as the potential benefits to price stability have been realized.

Examination of Natural Gas Supply Resource Procurement and Management by Northern Utilities Inc. d/b/a Until

Final Report – Public Version
Confidential Material Redacted

Presented to:
State of Maine
Public Utilities Commission

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I. Organization, Staffing, and Controls

A. Background

Organization sets the basic framework for conducting and managing gas supply activities. Those activities require a trained and capable staff with particular skills and knowledge of the gas markets in which they operate. Operational policies and procedures provide definition and control to the conduct of the supply function.

We employed the following evaluation criteria:

1. Ability of the organization structure for the gas-supply function to allow effective and prompt decision-making subject to appropriate controls
2. Quality of coordination and communication of gas-supply functions and resources with related functions and groups.
3. Sufficiency of skills and experience of key managers and contributors
4. Performance assessment transparency and connection to material performance drivers
5. Sufficiency, clarity, and efficiency of policies and procedures governing supply processes
6. Comprehensiveness and sufficiency of approval processes and authority levels to enable and control needed supply commitments and expenditures
7. Adequacy of documentation to support regulatory oversight and review.

B. Findings

Unitil, the parent of Northern Utilities, Inc. (NUI), also owns electric distribution utilities in Concord and Hampton, New Hampshire, Fitchburg Gas and Electric Light Company (FG&E, a combination electric and gas distribution utility in Massachusetts), and Granite State Gas Transmission, Inc. (GSGT), an interstate gas pipeline operating in New Hampshire and Maine. NUI provides gas distribution and supply services in New Hampshire and Maine. The two smaller electric distribution companies, Concord Electric Company and Exeter & Hampton Electric Company, merged in 2002 to form Unitil Energy Systems. The Company's home office is in Hampton, New Hampshire.

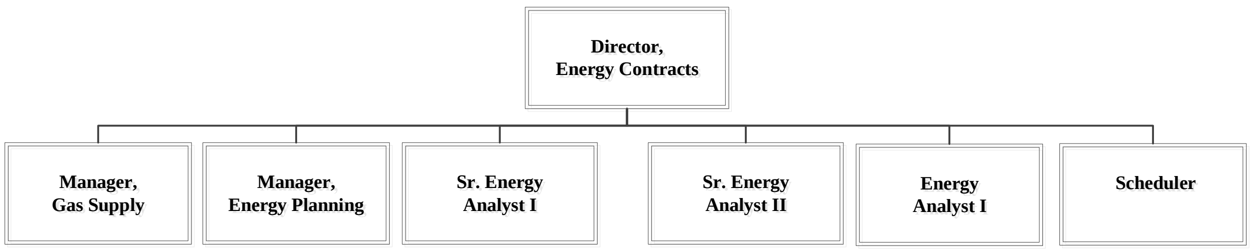
The parent owns no electricity-generating assets. Unitil sold an unregulated energy brokering and advisory business in early 2019, after which all of the operations it owns operate as fully rate-regulated businesses. Gas-supply assets include a small liquefied natural gas (LNG) storage and regasification plant in Lewiston, Maine, owned by Northern, and a small LNG plant and a propane-air peaking plant, owned by FG&E.

Unitil acquired NUI and GSGT in 2008 from Bay State Gas Company (now doing business as Columbia Gas of Massachusetts). That transaction left one important gas-supply process interrelationship with the former parent, an exchange arrangement which provides access to interstate pipeline capacity under contract to NUI, but to which NUI has no physical connection.

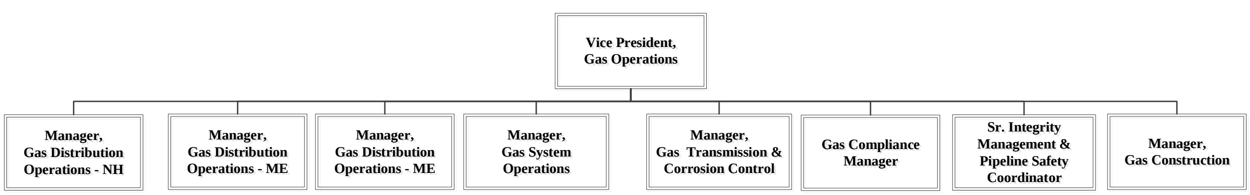
1. Organization

Unitil formed Unitil Service Corp. (USC) in 1984 to provide joint management and administrative services to its subsidiaries. Essentially all management employees work for USC. This service-company approach finds common application in holding companies operating in multiple jurisdictions or through multiple operating entities. USC provides those services at cost, which it allocates among the utilities served, pursuant to settled cost-allocation policies. The operating companies make available to each of their regulators those costs for examination and approval, if not otherwise, then at least in general rate proceedings. Each utility also has employees dedicated to its individual management and operations. Their costs get charged directly to the utility involved. Gas supply operates as one of the centrally-provided services, subject, like the others, to cost allocation.

Two key organizations under USC work together in performing the principal activities required to manage supply for NUI and for the other Unitil utilities. First, the Energy Contracts unit within USC's Financial Services Division manages the gas supply function. The diagram below shows the components of that unit. The Director, Energy Contracts reports to the Financial Services Division's Senior Vice President, Chief Financial Officer & Treasurer.



The second major organization, Gas Operations, has responsibility for gas distribution system operations, reporting under a different USC Vice President. Gas Operations is responsible for supply-related functions such as gas control and measurement. The components of that organization are shown in the diagram below. As we explain below, Energy Contracts' principal interaction with the Gas Operations organization involves Gas System Operations.



USC's Financial Services Division operates from Hampton, New Hampshire. The Gas Control personnel of the Gas Operations Division operate from the Operations Center in Portsmouth, New Hampshire. GSGT operates on a co-located basis with Unitil's Operations Center in Portsmouth, New Hampshire, but as a separate entity. Most GSGT personnel are employees of USC. The U. S. Federal Energy Regulatory Commission's Order 717, regarding standards of conduct for transmission providers, applies at the employee level, and prohibits the flow of information from transportation-function employees to market-function employees.

All three jurisdictions in which Unitil's gas distribution utilities operate permit varying degrees of customer-choice for electricity and natural gas supplies. The Unitil utilities therefore must provide various third-party administrative services, referred to as Supplier Services, and manage their systems to deliver supplies from multiple suppliers who provide electricity or gas to end users. As typical in restructured jurisdictions, Unitil retains the obligation to provide "default service," which includes the acquisition of supplies for those of its gas-system customers who do not choose competitive suppliers.

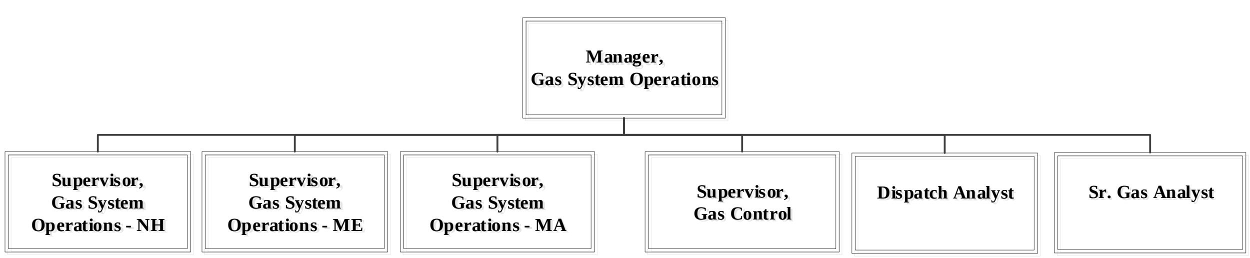
The Energy Contracts unit works with personnel in both Gas Operations and Electric Operations to ensure delivery of third-party supplies. The Manager, Energy Planning spends nearly all of his time on gas work. The electric work of Energy Contracts includes supply contract administration; the New England Independent System Operator (ISO-NE) has responsibility for power-supply planning. Thus, Energy Contracts has a more administrative role in electricity-related planning, but also responding as needed to occasional needs, such as response to regulatory initiatives (*e.g.*, renewable power supplies). Energy Contracts also buys supplies of both gas and electricity to provide default service. Two Energy Contracts personnel, the Manager, Gas Supply and the Senior Scheduler, spend 100 percent of their time dedicated to gas work. The unit dedicates two Senior Energy Analysts I to activities undertaken for electric customers. The Senior Energy Analyst II and an Energy Analyst spend about half of their time on gas work, including the Supplier Services activity.

Energy Contracts has a more comprehensive set of planning responsibilities for the gas business. Its role includes not only all of the administration associated with deliveries of third-party supplies, but also supply planning for customers who buy their supplies from the Company, and supply-capacity planning for both sales-service and distribution-service customers. The Manager, Gas Supply, and the Manager, Energy Planning, have primary responsibility for gas-supply procurement and capacity planning; the Manager, Energy Planning, and Senior Scheduler collaborate on the allocation of capacity to third-party suppliers; the Manager, Gas Supply, and the Senior Scheduler have major responsibilities for daily deliveries of system supply.

NUI serves a substantial number of "capacity-exempt" customers, for whom it does not acquire supply capacity. These customers accounted for 22 percent of distribution-system throughput for the Maine Division in 2018, and almost 29 percent of throughput for the New Hampshire Division. Distribution-system planning must account for these customers, but supply planning does not.

Energy Contracts' Manager, Gas Supply, works regularly with the Supervisor, Gas Control, to identify each day's pipeline supplies in the appropriate amounts to the Company's major delivery points into GSGT for those supplies. The Senior Scheduler must get the supplies nominated from the Company's upstream receipt points to the proper GSGT receipt points and subsequent delivery into NUI's distribution system.

The diagram below shows the organization of the Gas System Operations unit.



2. *Staffing*

a. Personnel

The Director, Energy Contracts has 25 years of utility experience, including negotiation of supply agreements, resource planning, portfolio management, and participation in regulatory proceedings. He joined the Company in 1994 and has held positions in finance and energy contracts groups. He has responsibility for supply planning and procurement for Unitil's electric distribution companies and gas distribution companies, as well as the structure and operation of the retail choice programs operated by each of the distribution companies. He also serves as a logistics section chief in the Company's emergency response organization.

The Manager of Gas Supply has spent her 20-year career at the downstream end of the gas industry in New Hampshire and Maine. She has held customer sales and service, accounting and administration, and scheduling and trading positions for a variety of participants in those markets, including pipelines and marketers, before beginning with NUI in 2010. She has held her current position since the beginning of 2013.

The Manager of Energy Planning has worked for the Company since graduating from college in 1995. He worked on supply planning, worked for Unitil's brokering business, and worked on energy supply for both the electric and gas sides of the business prior to Unitil's acquisition of NUI in late 2008. Since that time, his primary responsibilities have encompassed gas-supply planning and acquisition, including designing the capacity assignment provisions of the retail choice programs operated by each of the distribution companies. He performs yearly analyses of supplier performance, which the Company uses to assess and make changes in its gas-supply arrangements. He plays a major role in cost-of-gas proceedings before the Maine and New Hampshire Public Utility Commissions, and in other regulatory proceedings before state and federal agencies.

The Senior Scheduler has held gas scheduling positions with the Company since 2012. He has responsibility for nominating and scheduling gas on the interstate pipelines and storage facilities within the asset portfolios of NUI and FG&E. He also has a key role in implementing the capacity assignment provisions of the retail choice programs that each of the distribution companies operates and is now largely responsible for their day-to-day operations.

The Senior Energy Analyst II has worked for the Company since graduating from college in 2008. He has responsibility for natural gas demand forecasting, including long-term demand forecasts and daily operational forecasts, as well as day-to-day operations of gas and electric Supplier Services, including monthly cash-outs of third-party gas suppliers under the retail choice programs.

Outside of Energy Contracts, the Supervisor of Gas Control has important gas-supply responsibilities. She works in the Gas Operations organization and has worked in Gas Control for NUI since 1984, spanning changes in NUI ownership by different parents. During periods of cold weather, she coordinates closely with the Manager, Gas Supply in daily operation of the Company's gas-supply assets. She also provides direct supervision, coordination, and training for other Gas Control personnel.

b. Performance Measurement

Each employee receives a minimum of one written performance appraisal each year. Supervisors, managers, and Department Heads are encouraged to do written quarterly updates. Compensation adjustments tie to successful performance for specific accountabilities stated in each person's position description.

Part of the annual performance appraisal process is Goals for Next Year, which can be used to build performance and document achievement. Training is prescribed for individuals as appropriate as part of their annual performance reviews. All supervisors, managers, and Department heads receive formal training in performance management to ensure that Unitil does the best possible job of recognizing and documenting performance.

c. Position Descriptions

Unitil uses position descriptions for the jobs within each unit to provide sufficient detail about what the unit does and who has responsibility for the roles needed to accomplish unit work activities. Position descriptions describe each of the incumbent's principal accountabilities, with an estimate of what portion of time will be spent on each one. Each position description also describes the incumbent's principal challenges, decision-making authority, and required competencies. We found some of the job descriptions outdated when compared with current position responsibilities. Management agrees that an updating process is warranted.

3. *Policies and Procedures*

We found a lack of written policies and procedures addressing the gas-supply functions and activities. Incumbents are well experienced and familiar with their responsibilities. However, upon departures of key personnel, the lack of documented policies and procedures creates exposure to loss of continuity in understanding and executing them, particularly in a smaller organization. The Company's responses to our data requests in this examination provide a sound starting point for documentation. Management has agreed to develop it.

4. *Controls*

a. Documentation of Gas Supply Decisions

NUI's documentation of its gas-supply decisions takes several forms. First, for its capacity-commitment decisions (such as the decision to participate in the proposed Westbrook Xpress Project), Energy Contracts preserves its quantitative evaluations in its files. Qualitative factors generally enter final decisions, but they are not separately recorded. Rather, the Company presents all of its analysis, quantitative and qualitative, in its filings with its regulatory agencies for approval of its commitments.

Management uses the same process to document other evaluations, such as integrated resource plans, energy-efficiency programs, etc. There may be some internal analysis prior to filing, but the Company presents all evaluations, quantitative and qualitative, in its filings with its regulators, and considers those filings to be its documentation of any decisions taken as a result of those evaluations.

Management documents its commodity-purchase decisions in several ways. Annual request-for-proposals processes (RFPs) produce asset-management agreements (AMAs), winter and summer base-load purchase contracts, and contracts for delivered peaking services. Retained documentation includes all of the offers received, the Company's analysis of the offers, and the signed contracts for the offers selected. The signed contracts generally take the form of confirmations, issued under previously-executed standard contracts, such as the North American Energy Standards Board (NAESB) contract.

All of the term-purchase contracts – AMAs, base-load contracts, and contracts for delivered peaking service – use externally-determined pricing: either published index prices or the last-day-settlement price of the New York Mercantile Exchange (NYMEX) gas futures contract. Almost all use monthly prices; only a few sources, such as daily swing quantities under one AMA, use daily prices. Those daily prices are also externally-determined; they are generally also published index prices, but daily ones, rather than monthly.

Gas in storage also has an externally-determined price. NUI requires its storage asset manager to fill the storage ratably (at a uniform rate) over the storage-injection period with gas priced at a monthly index. Thus, when withdrawn, the storage gas comes to NUI at the weighted average price determined by the specified fill rate times the specified price, adjusted for any storage injection and withdrawal charges.

With this contract structure, almost all of NUI's day-to-day decisions are quantity nominations from sources with established prices. Management documents those decisions by retaining the spreadsheets containing each day's nomination information. Those spreadsheets are designed for input into the reports that the Company files with its Cost of Gas filings. Thus, its Cost of Gas filings reflects its records of sources of gas used each day. Filings with the Commissions add gas price information.

We selected at random a fall day and a spring day for identifying the nature and types of transaction records available to document supply choices available and the selections made. Conducting the supply function in the winter requires utilization of all sources, permitting fewer choices. Summer supply mostly uses base-load resources, which involve few choices that change day to day. Energy Contracts staff produced the records for the days we selected, and we confirmed that the choices made were appropriate. We also examined with Company personnel decisions made on a peak day in January 2019. Full records of the weather conditions had been saved, along with records of the decisions made. We judged those decisions to have been reasonable in the circumstances.

We had one issue with the documentation. For each of the days that we requested, a decision was made using estimated pricing. Those prices were not recorded. In comments on the draft of this report, the Company pointed out that, for the fall day, the selection was driven by locational considerations. Given the physical limits of GSGT and the Company's distribution system, not all sources can be delivered to every service area. Where the supply is needed dictates some choices.) Thus, while price might have played a role, it was not the determining factor in the choice.

On the fall day, Energy Contracts staff elected to take some daily swing gas available under two of the AMAs. One agreement provided for the gas to be priced at a daily index. Those indexes are not published until the day after transaction execution. Thus, transactions like that one must be entered on the basis of an estimated price.

Indicative prices are available each day. The Intercontinental Exchange (ICE) provides an on-line platform that shows offers and some transactions on a real-time basis. When deciding whether to enter a particular daily transaction, Energy Contracts staff generally consults ICE to view similar offers. It is likely that they did so on the day that the daily swing supply was taken, but there is no record of such action and what prices they might have observed.

In comments on the draft of this report, the Company pointed out that, due to illiquidity on their supplying pipelines, indicative pricing may or may not be available each day. Moreover, the time when Northern must make decisions can further affect the availability of indicative pricing. For example, Northern's next-day nominations to asset managers are due before 9 a.m., before active trading on ICE begins. Thus, the best pricing reference (for next day) is current-day published Gas Daily indices for nearby pipelines, such as Algonquin Gas Transmission and Tennessee Gas Pipeline. Northern also makes late-day sales between 7 and 8 a.m., when there is no activity on ICE. Spot-market purchases, which are very rare, would likely occur during business hours and ICE would be consulted if any nearby pipeline activity is posted.

The spring day presented the same documentation issue. Energy Contracts staff had decided by that time that the Company was "long" on supply at that point in the winter. Thus, on the day we selected, the staff was looking for a one-day sale to an off-system customer. Such a customer made an offer, at a price that it specified. As in the case of the fall transaction, the staff would likely have consulted ICE to see whether to accept the offer or to look for another. Whether they did, and what price information they found, was not recorded.

b. Dollar Limits on Authority to Approve Transactions

We did not initially find clear, documented definition of expenditure authority levels, which form an important measure for controlling commitments. Management advised that the Company has embedded those levels into its accounting system and specified responsibility for setting levels in its Security Administration policy. That system prevents Company personnel from approving payments in an amount that exceeds an individual's authority.

That system does not, however, address employees' ability to commit the Company to an expenditure. We learned that the authority to commit relies primarily on term:

- The Manager, Gas Supply can commit to transactions shorter than one month
- The Director, Energy Contracts can commit to any term for gas supply
- The CFO commits for any incremental supply capacity.

Company personnel are generally aware of who has what level of authority. Furthermore, we did not find any examples of employees exceeding their authority levels. We did not, however, find that those levels could be communicated explicitly to a party outside of the Company seeking some kind of commitment.

c. Separation of Transaction-Related Functions

For purposes of financial controls, companies with energy-trading operations separate transactions functions among transaction execution (front office), confirmation (middle office), and invoice verification (back office). Such separation ensures that transactions take place under controls that promote accuracy, measurement, and integrity.

NUI does not employ such a clear separation. Members of the Energy Contracts staff perform these functions together. When we raised the separation issue, management responded that Internal Audit is now reviewing needs and methods for strengthening such controls.

d. Examinations of Gas Supply by Internal Audit

As with most gas distribution utilities, supply operations and transactions bring large costs and impose risk. It is common to see periodic reviews by the internal audit function of gas supply costs and operations. We did not find that practice at NUI. Management has agreed that internal audit's 2019 activities plan will include gas supply, and that it will expand its Sarbanes-Oxley testing of financial controls to include gas supply.

e. Code of Conduct

We find use of a comprehensive code stressing the importance of ethical, objective conduct a material element in creating an effective controls environment for gas supply. Such codes should clearly specify values, expected conduct, prohibitions, and consequences. Regular acknowledgement of receipt, understanding, and acceptance of the behavioral standards and the limits such codes play an important role in ensuring that conduct regarding gas supply transactions has the objectivity and integrity necessary to optimize costs for customers.

Unitil has such a code. We found it appropriate in stressing the importance of ethical conduct, communicating appropriate values, describing promoted and prohibited behaviors, and specifying the consequences of failure to conform to expectations and requirements. Company officers acknowledge it and agree to be bound by it annually. New employees are given the code and asked to acknowledge it when they join the Company.

We did not find a requirement for annual acknowledgement by Energy Contracts staff. Management agreed that this should be done and undertook to initiate it going forward.

f. Gas Supply Risk Management

The gas-supply function presents considerable risks to Unitil as an enterprise. We examined the Company's approach to identifying and addressing these risks. We found this function to be addressed satisfactorily.

C. Conclusions

1. Organization of the gas-supply function is compact, efficient, and effective.

The Company plans for and manages a rather complicated supply system with relatively few people. Individuals' roles in supply processes are well defined, and coordination with essential functions in other organizations is well established and smooth.

The same individuals shift from an intense focus on operations in the winter to analysis, planning, and re-contracting in the spring and summer. Because the same individuals do both, operating experience is brought directly to bear on evaluation and planning going forward. As the Manager, Energy Planning is also the Company's principal witness in its gas-cost recovery proceedings, the Commission and the Company's customers have access to as much detail as they want regarding what the Company has done and what it plans to do.

Seasonal readiness meetings support higher-level coordination with other Company operations. Distribution-system planning holds these meetings in the fall and spring and other business functions attend, as well as Energy Contracts. Energy Contracts also occasionally asks distribution-system planning for analysis of particular supply problems.

2. The training and experience of gas-supply personnel is commensurate with system needs and with what we have observed at other similarly-sized entities.

The Company is fortunate to have extremely capable and highly experienced individuals in the gas-supply function. The staff is very small for the amount of work they do.

3. Performance assessment is consistent with prevailing industry practice.

Annual performance reviews with quarterly updates is the standard among most industries. Relating compensation adjustments to performance in identified accountabilities is best practice. Unitil's practice of providing formal training in performance management is a strong one.

4. Some position descriptions are out of date. *(Recommendation #1)*

The Company uses position descriptions in several ways, including comprehensive statements of an individual's role in his or her organization, and careful statements of accountabilities that can be used in performance assessment.

The Company's policy is that position descriptions are to be updated annually. Some have not been but should be. Management has agreed to do so.

5. Documentation of supply decisions is not quite adequate. *(Recommendation #2)*

The results of NUI's gas-supply evaluations are presented in various filings with the Maine and New Hampshire Public Utility Commissions: primarily Integrated Resource Plans, requests for Commission approval of long-term supply contracts, and periodic Cost of Gas filings. With the assistance of Energy Contracts staff, we examined daily records for four different days within the past gas year (November through October). Records were generally adequate to support review of the decisions made. However, we found no documentation of the estimated prices of supply options considered on the day that the choice was made.

NUI pays indexed prices for almost all its daily gas-supply transactions, with spot-market purchases (only occasionally) and off-system sales the exceptions. The gas-supply contracts, typically part of asset-management agreements, specify the indexes that apply. While the value of any of those indexes for any given day can be retrieved currently or after the fact, they are generally not settled until the day after a transaction is agreed to. Thus, agreement must occur with respect to an estimated price. Management does not retain those estimates, but should. Similarly, for the occasional off-system sale, prices at the time of the transaction can only be estimated. Those estimates are not retained, but they should be.

6. Controls are insufficiently formal. *(Recommendation #3)*

NUI employs less formal controls than we have seen elsewhere, an approach it considers generally appropriate to its small size. For example, although individuals who conduct supply processes show familiarity with procedures, they are not documented. Expenditure-authority levels exist for payments, but are not clear in limiting authority to make commitments including matters like signing gas-purchase contracts. Also, widely employed controls, such as who compares supplier confirmations to Company nominations or purchases, and who approves invoices for payment, are not applied in a structured way.

controls need to become more comprehensive and formal. Management should place less reliance on the integrity of individual staff members. When we brought our concerns in this area to the Company's attention in a Roundtable discussion., the Company provided some additional information and undertook to correct deficiencies in others.

D. Recommendations

1. Update position descriptions. *(Conclusion #4)*

Management has agreed to do this.

2. Add gas-price information, including estimated prices, to the record of daily gas-supply selections. *(Conclusion #5)*

Our review of supply-selection records for individual days did not reveal records of gas-price information, including estimated prices used to decide on daily-priced transactions, for that day in those records. We believe that information should be recorded in order to complete the transaction records.

We think the correction for this deficiency is to add another tab containing all price information to the spreadsheet that serves as the record for decisions made each day. This fix should be made immediately.

3. Re-review supply processes from a controls perspective. *(Conclusion #6)*

NUI's supply processes function smoothly and competently. We had some concerns that we shared with the Company about the controls environment for those processes, and the Company undertook to address them. We recommend that the intended solutions be reviewed after the Company has had time to implement them, which we estimate to be in about six months from the time that this report is issued.

Particular areas to be reviewed include the following:

1. The Energy Contracts unit, which conducts the gas-supply function, does not have Mission and Function statements; it uses detailed job descriptions instead. The job descriptions must

be updated, but they must also assign clear responsibilities in areas of control: the person who evaluates supply-related decisions cannot be the same person who made the decision.

2. Regarding policies and procedures, the responsibilities, accountabilities, activities, and interactions with others involved in conducting the gas-supply function are not recorded in a way that allows someone to perform the function if an incumbent is absent for some reason, or to evaluate the results. The Company's accountants and auditors can now verify that the costs produced by those processes are accurate; the question is whether they are appropriate; *i.e.*, free of mistakes and free of any possible malfeasance.
3. The processes of transaction execution, confirmation and invoice verification should be separated to ensure accuracy and integrity.
4. At the time of our review, Unitil's Internal Audit unit was due to perform a comprehensive evaluation of the gas-supply function soon. Conduct of gas-supply operations was to be examined, and strengthening controls had been identified as a key objective of that review.

II. Gas Supply Planning and Forecasting

A. Background

Ensuring sufficient supply to fill requirements at optimum prices requires sound supply planning. We applied the following criteria in examining supply planning at Northern Utilities (NUI):

1. Conformity of weather data handling and analysis methods with industry norms and unique service territory circumstances
2. Consistency of assumptions, variables and probabilities in capacity planning should comport with observable supply obligations
3. Existence of efforts appropriate to identifying and establishing alternate sources of supply.
4. Regularity and comprehensiveness of evaluations of peak-period performance
5. Strength of the correlation between the capacity portfolio and the load duration curve
6. Gas plans should be consistent with related corporate planning elements.

This chapter explores the supply-planning processes, how they produce the identification of supply requirements, and how management plans for supplying those requirements. We also generally address the relationship of supply planning to other areas of system planning, especially marketing plans.

B. Findings

The newly-filed Integrated Resource Plan comprehensively and clearly presents management's forecasting and supply-planning methods. Section V.B describes weather analysis; Section V.C. addresses Planning Standards and Design Weather; Section V.D. covers forecasts of numbers of customers, use per customer and peak-day analysis. We examined Company methods with reference to prevailing industry practices, and how and how well decisions about supply resources incorporate the results of applying those methods.

1. Weather Analysis

The Company uses 30 years of history (the gas years of 1988/89 through 2017/18) to populate its normal and design weather data. The data capture effective degree-days (EDDs) by adjusting temperature data for wind speed. Data for the Maine Division came from the Portland, Maine weather station at the Portland International Airport, and for the New Hampshire Division from the weather station at Pease International Tradeport.

Management calculated normal-year EDDs separately for its Maine and New Hampshire Divisions, by summing for each their 30-year average billing-cycle EDDs for each month. Management used a 1-year-in-30 return period to determine winter period (November through March) design-year EDDs It used normal (average) weather for summer month (April through October) determination of design EDDs. The Company calculated design-winter EDD by summing the billing-cycle EDD for each winter in the data set (1988/89 through 2017/18), then using the 30-year average and standard deviation to select the winter EDD with a once-in-30-years probability of occurrence. It then distributed the winter design EDDs among the individual winter months by multiplying the normal EDD for each winter month by an adjustment factor equal to the design-winter EDD divided by the normal-winter EDD.

2. *Requirements Forecasting*

The new IRP presents the methods for requirements forecasting and the results of applying them. The Company combined its rate classes into customer segments: residential, commercial and low-load-factor industrial, and high-load-factor commercial and industrial (C&I), driven by characteristics of their consumption. Regression analysis of billing data supported the development of econometric models for forecasting numbers of customers and use per customer for each segment. Separate equations drove the results for the Maine and New Hampshire Divisions.

Management made reductions to the resulting customer-segment forecasts to reflect energy-efficiency savings, applying separate adjustments for each segment and for each of the two Divisions. Those adjustments yielded Net Demand by segment for each Division. Adjustments to total Company-wide Net Demands for Company Use and for lost and unaccounted for gas (LAUF) yielded forecasts of Normal Year Throughput for each Division.

Planning Load comprises another important planning parameter. This parameter measures Normal Year Throughput adjusted to design weather conditions, less the projected loads of Capacity Exempt customers. The Company developed Planning Load forecasts for Design Year and Design Day conditions for both Maine and New Hampshire Divisions.

Management uses estimated Design Day requirements to calculate its need for peak-day supply capacity. It calculates Design Day requirements using regression analysis of actual daily throughput data, separately for each Division.

On January 21, 2019, the Company experienced a new system record peak-day throughput. To test its Design Day forecasting model, the Company put that day's weather conditions into it. The model ended up under-forecasting actual throughput on that day for both Divisions - - by 3.0 percent combined, by 3.8 percent for Maine, and by 2.1 percent for New Hampshire. The Company concluded that the Design Day model is "reasonably accurate, and does not show a bias towards over-predicting Design Day demand."

a. Analysis of Forecast Performance

In preparing the new IRP, management compared the forecasts of its prior IRP with actual performance. That comparison led to two modifications. First, it removed from the Residential Heating Use Per Customer model a price variable. The re-specified model more accurately predicted actual use per customer for the period between the previous IRP (2015) and the current one. Second, management updated the peak-day forecasting model to improve its performance.

The 2015 IRP comprised the most recent version as we began our field work. In reviewing it before the new one became available, we observed that actual throughput on January 2, 2014 was well below what the Company's peak-day forecasting model would have predicted. Management explained that it reviews daily forecast performance regularly, given the importance of forecasts for day-to-day operations. The Company noticed the discrepancy for that date immediately, and investigated it promptly. It found several explanatory circumstances:

- An extreme snow/blizzard event closed schools and businesses
- A large change in temperature occurred extremely quickly
- With New Year's Day the day before, resumption of normal work-day activities on January 2nd may have ramped up more slowly than usual.

b. Interaction Between Gas Supply and Marketing

The Company developed a comprehensive marketing program soon after it acquired NUI. That program identified customers on main but not connected, and low-use customers as targets with the highest potential. The Maine service territory had lower saturation than New Hampshire, thus presenting the better opportunities. Management had also slated facilities in Maine for a Cast Iron Replacement program. The Company continues special promotions and special incentives offers to prospective customers for connection in the areas affected by that program.

Management annually updates details of its marketing programs; *e.g.*, locations of special focus. The Energy Contracts unit, which is responsible for gas supply, uses these details to anticipate where additional supply might be needed.

Energy Contracts is informed when other Company activities might affect requirements for gas supply. Company personnel gather at Seasonal Readiness Meeting to discuss new initiatives, such as a targeted area build-out. Other initiatives are discussed in the course of normal internal coordination.

3. *Portfolio Analysis*

Gas distribution companies like NUI use three types of supply assets to meet customer demand:

- Year-round asses, primarily pipeline capacity
- Seasonal assets, typically storage facilities that are filled in summer, then re-deliver in winter
- Peaking assets, most often liquefied natural gas (LNG) storage and revaporization facilities or propane-air plants, that provide high deliverability for short periods in response to peak weather events.

Prior to Unitil's acquisition of NUI, the Company was assigned some still-operating "legacy" pipeline and storage capacity as part of the wholesale gas market restructuring required by FERC Order No. 636. This group of assets included capacity on the Iroquois Gas Transmission System (IGTS), the Tennessee Gas Pipeline system (TGP), and the Algonquin Gas Transmission Company system (AGT). Most of these assets are relatively old, considerably depreciated, and therefore, attractively priced. They comprise the foundation of NUI's supply portfolio.

Also prior to Unitil's acquisition of NUI, the Company contracted for resources known as "the Wells Replacement Contracts." Those contracts served seasonal and peaking requirements, but with supplies delivered to NUI's principal receipt points. NUI entered into them as part of a settlement regarding an LNG manufacturing and storage facility planned for installation in Wells, Maine. NUI did not actually construct the facility, choosing instead to enter three replacement contracts involving: (a) delivered pipeline supply from Duke Energy, (b) a combination liquid/vapor LNG service from Distrigas, and (c) liquid-only LNG supply from Distrigas. Distrigas owned an LNG receiving terminal located in Everett, MA. Distrigas sold the facility to ENGIE North America, Inc., which recently re-sold it to Exelon Generation Company, LLC. Constellation LNG, LLC, a subsidiary of Exelon, operates the facility.

The last of the Wells Replacements Contracts expired in late 2011. Their expiration, plus growth in NUI's load since that time, have created a significant requirement for additional supplies in both seasonal and peaking roles.

Weather is the primary driver of supply requirements for companies like NUI. Current forecasting techniques provide forecasts of daily supply requirements for most any weather, with normal-year and design-year weather used most often.

Management inputs requirements forecasts into an optimization model. The model designs a portfolio of supply resources that provides the best fit for the input forecast. NUI uses SENDOUT, widely used for such purposes in the gas distribution business. SENDOUT considers demand forecasts, available supply and delivery options, and the costs associated with them, to produce projections of costs for meeting demand with various combinations of supply options. It solves for the least-cost mix of options for meeting demand, subject to user-defined constraints. The model incorporates the legacy assets, enabling it to solve for the least-cost mix of *additional* supply options.

As the IRP notes (See, *e.g.*, Section III), NUI has limited supply options, both in number and in type. Several options for expanding U. S. pipelines to New England have been abandoned. Suppliers of regasified LNG mostly offer supply on a delivered basis.

For its seasonal and peaking requirements, NUI issues requests for proposals (RFPs) annually. It seeks seasonal supplies first, along with asset-management services for its legacy pipeline and storage assets. A second RFP for peaking supplies follows in mid-summer.

The offers that NUI receives in response to the RFPs essentially all provide supply on a delivered basis. Delivered supplies mean that the provider bears the burden of getting the gas to NUI's principal receipt points. The resulting contracts are mostly on a year-to-year basis. [redacted]

NUI has found that three pipeline options compare favorably with the alternative of relying on delivered supplies. Accordingly, the Company has entered contracts for three increments to its pipeline-capacity resources:

- 9,965 MMBtu/day on Phase III of the Portland XPress Project, scheduled to enter service in November 2020
- 7,500 MMBtu/day on the Atlantic Bridge Project, also anticipated to enter service in November 2020
- 9,965 MMBtu/day on Phase III of the Westbrook XPress Project, anticipated to enter service in November 2022.

The Company's applications for approval of its participations in the Portland XPress and Atlantic Bridge Projects have been approved by the Commission. Its application for the Westbrook XPress Project recently secured approval.

Each of these three projects would replace a portion of what NUI would otherwise require in the way of delivered supplies. The Company's analysis indicates that primary benefits these projects would bring lies in access to reliable supply points having lower and more stable pricing than is available with delivered supplies. These features make them preferable to management.

The new IRP shows changes from the Company's current winter-period mix of pipeline, storage and delivered supplies after these new projects enter service. Figure IX-1, reproduced below, shows the Company's assessment that it would require delivered supplies (seasonal and peaking) for almost 100 days under design-winter conditions, before any of the three projects goes into service. It would meet almost half of peak-day requirements with delivered supplies. Figure IX-2, also reproduced below, shows the Company's view of requirements for delivered supplies after the three new projects go into service. Those requirements drop to about 40 days, and accounts for significantly less (about one-third) of the design day. Comparison of the two figures shows that the three new projects push the Union Dawn Storage resource up in the dispatch stack, reducing considerably the requirement for delivered supplies. (As a seasonal resource, the Union Dawn Storage should be above year-round capacity, old and new, in the dispatch stack.)

Figure IX-1: Load Duration Curve, Design Winter 2019/20

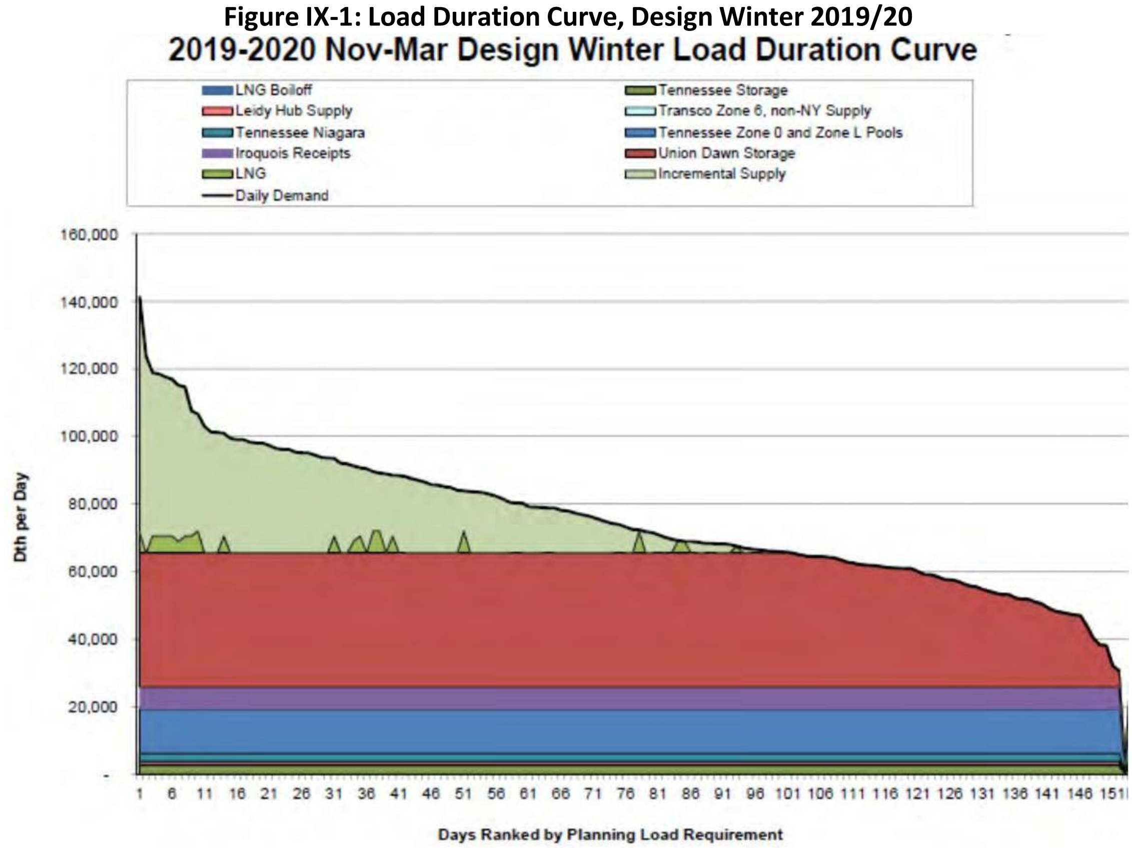
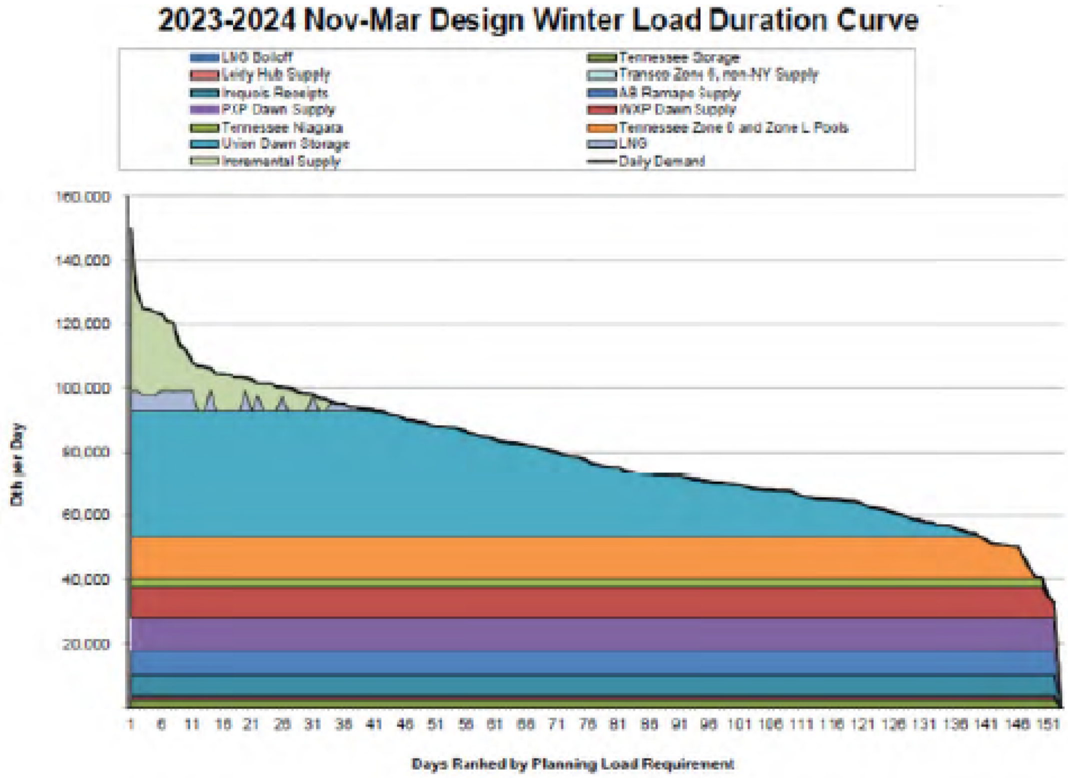


Figure IX-2: Load Duration Curve, Design Winter 2023/24



4. *Development of Supply Options*

Management believes that its continued dependence on delivered supplies, even after adding the three increments of pipeline capacity, entails risk. Particular concerns include constrained delivery capacity on peak days, and the limited number of offerors for delivered supplies. The Company continues to discuss additional pipeline supply projects with potential offerors, and it has recently re-started work on on-system supply options.

C. Conclusions

1. The Company's weather analysis could be improved. *(Recommendation #1)*

Management's use of averages and standard deviation in its weather analysis implies normally-distributed weather. Normal distributions have most values clustered around the mean (average), which falls in the middle of the range of values. Other values taper off symmetrically in both higher and lower directions. Standard deviation measures the dispersion of a distribution. For a normal distribution, 68 percent of values lie within one standard deviation of the mean, and 95 percent within two standard deviations.

With 2.5 percent of observations higher than two standard deviations above the mean, and 2.5 percent lower, there exists a 2.5 percent probability that a value will fall above the mean-plus-two-standard-deviations, and a 2.5 percent probability that a value will fall below mean-minus-two-standard-deviations. Analysis of design weather should focus on concern about EDD values higher than the mean plus two standard deviations. A normal distribution indicates a 2.5 percent probability of such an occurrence. That probability corresponds to a 1-in-40 chance of occurrence. If weather observations such as EDD values fit a normal distribution, the 1-in-30 standard would correspond to a probability of occurrence of 3.33 percent.

Careful studies of weather data usually show it not normally distributed; *i.e.*, values do not cluster around averages as much as they would be if normally distributed. They vary more than a normal distribution would suggest. Extreme values may occur more often than standard-deviation analysis would suggest.

Some of the analysis in the new IRP implicitly provides evidence that weather data for both Divisions does not fit a normal distribution. Recorded Peak Day EDD and Cold Snap EDD for both Divisions exceed the values calculated with the 1-in-30 standard. This demonstrates that weather more severe than would be predicted by the 1-in-30 standard has occurred in both Divisions within the past 30 years.

Industry best practice now calls for use of Monte Carlo simulation to develop distributions representing the actual occurrence of weather variables in particular locations, such as the weather stations that NUI uses for its analysis. Using such a distribution would enable management to choose for each variable values having the probability of occurrence desired for planning. Normal- and Design-Year requirements could be calculated for the weather that has actually occurred, rather than for weather that fits a normal distribution. Simulation of actual weather may also enable NUI to estimate more precisely the requirements of customers served by retail marketers. More precise estimates could enable NUI to release more of its contracted capacity to asset managers, thereby increasing the amounts they would be willing to pay for the rights to manage the assets.

2. Load forecasting methods conform to prevailing industry practice and they adequately serve the Company's needs.

Numbers of customers times use per customer for forecasting supply requirements reflects currently prevailing industry practice. Regression analysis for developing forecasting models for both parameters also finds commonly utility-industry use.

3. Management routinely evaluates the performance of its forecasting methods.

Management compares forecasts with actuals in the course of preparing succeeding IRPs. It conducts examinations of daily forecast models soon after any discrepancy occurs, given that daily operations rely on these models. This reflects an appropriate level of attention to accuracy.

4. Management adequately coordinates gas supply planning with other areas of corporate planning.

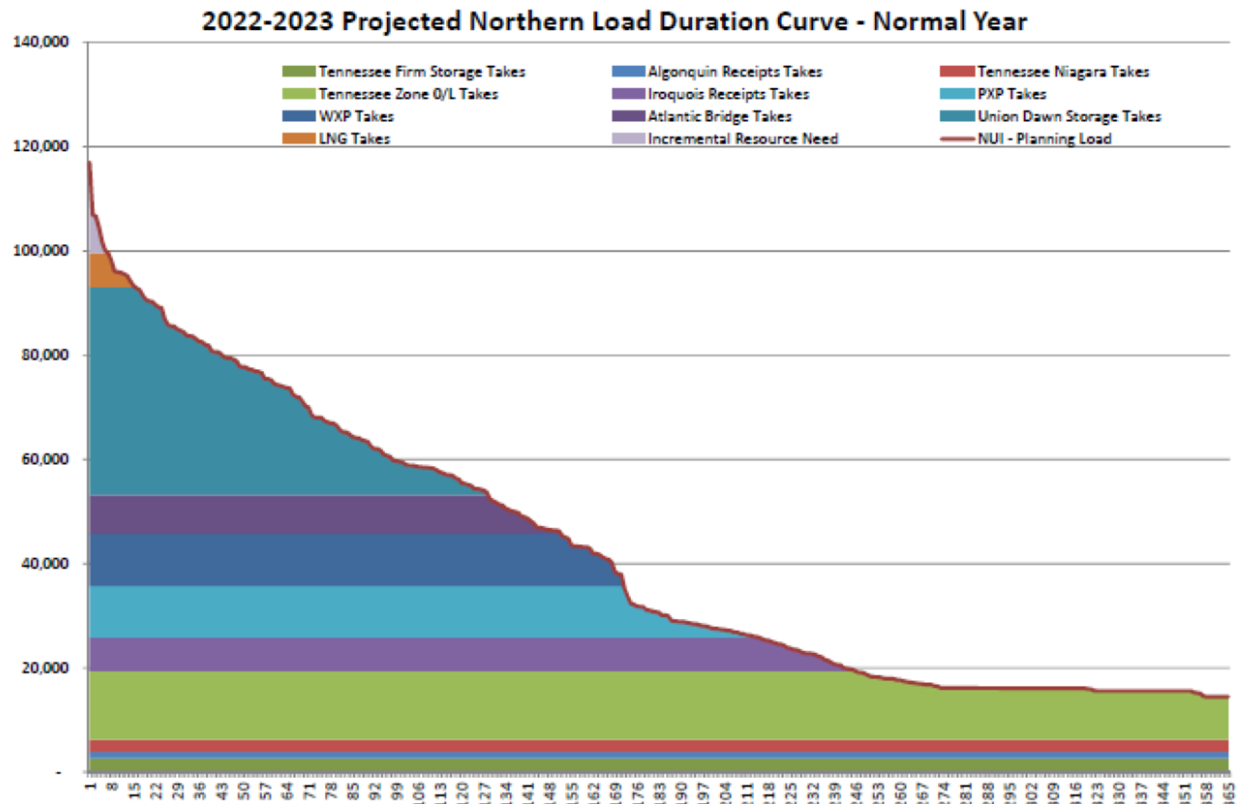
Much of this coordination takes place informally, in the course of preparation for various initiatives. The Company has two "readiness" meetings each year that inform department heads about plans that might affect them. Those gatherings engender deeper inquiry by Energy Contracts personnel into plans that might affect the gas-supply function.

5. Management should expand the scope of its resource analysis. *(Recommendation #2)*

We found the discussion in the Resource Balance (Section VII) and Incremental Resources Options (Section VIII) sections of the IRP oriented toward the peaking portion of the resource stack. We want to ensure that other parts of the Company's supply portfolio also receive attention.

We reproduce below a 365-day load duration curve (as contrasted with the 151-day durations shown in the IRP and reproduced above) that management prepared to respond to our request.

Company comments on a draft of this report noted that it does consider 365-day utilization in its supply planning, and that it provided summer-period load duration curves in the IRP. It presented winter and summer load curves were presented separately because the dispatch order changes from winter to summer. Company comments also noted that, even at 151 days of utilization, daily variability in weather can cause some non-use in winter months (warm days in November, March) and more use in shoulder summer months (cold days in April, October). Inter-seasonal variability offers another reason why Company presents seasonal load duration curves.



This more complete curve suggests the capacity of the new pipeline projects will see limited service outside of the winter season. That pipeline capacity provides 365-days-per-year capacity, but:

- PXP capacity shows use on about 215 days per year
- WXP capacity shows use on about 170 days
- Atlantic Bridge capacity shows use on about 160 days.

Local gas distribution companies outside of New England use pipeline capacity in non-winter months to fill storage. New England circumstances overall differ, because of the limited availability of in-market storage. Pipeline capacity connecting New England with other areas is not useful for filling storage in those other areas because no supplies are available to move from New England to those other areas. Imported LNG is available in New England, but regasifying it to move it to storage in other areas would add too much to its costs.

LNG facilities effectively comprise New England's in-market storage sources. Individual local gas distribution companies own all but the LNG import terminals, making them part of each owner's state-jurisdictional assets. Some LDCs "rent" space in others' LNG facilities, but we have not found such arrangements typical.

Our concern with NUI's stated approach to its resource analysis is its focus on the peaking portion of its resource requirements. How to use the available pipeline capacity when its new projects go into service should also form a focus of its supply-planning work.

The need to address both peak requirements and pipeline capacity use require joint consideration and analysis. Capacity available in the non-winter months offer a resource that can contribute to the economic viability of an LNG facility (for example, by bringing gas from a supply point with low and stable off-peak prices to a storage facility). New England's differences between summer prices and the value of gas in winter can be significant. Substituting gas bought in the summer for gas that would have been bought in the winter would likely provide considerable economic benefit. That benefit should be considered in any analysis of a new LNG facility.

D. Recommendations

1. **Test the use of Monte Carlo distributions in the Company's weather analysis.** *(Conclusion #1)*

The Company should test the use of Monte Carlo-based weather distributions in its supply planning. Formerly complex and expensive to use, Monte Carlo software has improved considerably, and is finding increasingly broad use in utility-company supply planning.

The test of whether the Monte Carlo analysis is worth what it costs to implement and operate depends on whether it makes a difference in calculated requirements for supply for system-supply customers. This population includes transportation customers for whom the Company must provide supply capacity. It can be used to calculate normal-weather requirements and design-weather requirements. It could also be used to estimate the capacity requirements of the retail marketers to whom NUI is assigning capacity. Without testing, however, it is not possible to say how this method might affect those parameters.

The Company should look into application of Monte Carlo methods soon. It should report on its plan for testing these methods in the proceeding to consider the findings of this audit (Docket No. 2018-00300) and present its results with its summer cost-of-gas filing.

2. **Expand the scope of the Company's resource analysis.** *(Conclusion #5)*

The IRP reports that the Company has engaged a consultant to

> *… help identify Non-Pipeline Supply Resources. Possible projects include adding storage to Northern's existing LNG facility in Lewiston, exploring options to construct a new LNG facility and looking for opportunities to purchase renewable natural gas (RNG).*

The scope of that work should expand to include utilization of the available capacity on the Company's newly-added pipeline capacity.

Combining the available pipeline capacity with capacity in an LNG manufacturing and storage facility is a natural choice. Using the capacity with the Lewiston facility would require installing liquefaction; any new facility would likely include liquefaction.

Scale is an important aspect of the economics of an LNG facility, suggesting that partnering with other potential users to explore a larger facility warrants consideration. An asset manager might explore combining NUI's available pipeline capacity with someone else's LNG facility. Thus, partnering with an asset manager should also be explored.

Adequate study of possibilities such as these will likely take some time. The Company should report on its results periodically, to assure its customers and the Commission that it is taking the effort seriously. Annual reports, with one of its cost-of-gas filings, should be sufficient.

III. Gas Supply Procurement

A. Background

Effective gas supply procurement requires a structured, well-controlled, rigorously executed, and transparent set of processes, critical in ensuring supply to customers at the lowest prices consistent with reliability requirements. Key elements include clear delineation of supply requirements, establishment of risk tolerances and means for ensuring satisfaction of them, a sound and objectively executed procurement processes, promoting a robust number of offerors competing for the opportunity to supply, assessment of the reliability of offers received, and competitiveness of the delivered prices of alternatives.

Gas supply planning identifies requirements for supply, and the duration of requirements (from a few peak days per year to seasonal or year-round). Planning and executing effective procurement of supply requires a sound process for identifying accessible options that can fill each requirement. Considerations include:

- Sourcing from a sufficiently broad array of supply points to provide enough diversity to assure competitive prices and protection from disruptions
- Options configured to fit the requirement
- A sufficient number of competitors to assure competitively-determined prices.

The preceding chapter of this report examined how the Company identifies its requirements for supply, and how well it addresses its concern about its limited number of supply options. This chapter turns to the processes for selecting among available capacity options, and for securing an appropriate assembly of supply sources from among them. We applied the following criteria in evaluating gas supply procurement:

1. Clarity of objectives for purchasing and price-risk-management activities, their comprehensiveness and support for meeting customer needs reliably, yet cost effectively
2. Sufficiency of focus on liquid, transparent markets in gas procurement and price risk management
3. Robustness of the range and numbers of suppliers identified and pre-qualified to meet likely needs, including short-term and emergency conditions
4. Adequacy of information maintained for identified and pre-qualified vendors
5. Analytical rigor and objective execution of offer evaluations, including application of specific criteria, weightings, responsiveness, and supplier performance history
6. Consistency of capacity contracts consistent with appropriate quality and reliability objectives
7. Promotion of the identification and use of sufficient numbers and types of vendors to ensure a sufficient range of competitive options for meeting supply needs.

B. Findings

1. *Supply Portfolio Summary*

The Company's supply capacity portfolio accesses several important supply regions:

- The U. S. Gulf Coast, via long-haul capacity on the Tennessee Gas Pipeline system (TGP)

- Central and Eastern Pennsylvania, via Texas Eastern Transmission Corporation (TXE) and the Algonquin Gas Transmission system (AGT), and via short-haul capacity on TGP, and using Company storage capacity in this region
- Pipeline supplies from eastern Canada, via TGP from the Niagara import point, and via the Iroquois Gas Transmission System (IGTS) from an import point at Waddington, NY
- The Dawn, Ontario supply point, via Enbridge, the TransCanada PipeLines system (TCPL), the Trans Quebec & Maritimes system (TQM) and the Portland Natural Gas Transportation System (PNGTS).

The Company had access to most of its still-existing capacity when Unitil acquired NUI in December 2008. Since that acquisition, NUI has renewed, converted or terminated essentially all of the pipeline and storage contracts then in place. The terminations it made sought cost reduction, moving receipt points closer to the Company's distribution system, or both. The table below, modified from one included in the Company's 2015 IRP, shows the disposition of each of the contracts from that original portfolio.

Table VI-2: Pipeline Transportation and Underground Storage Contracts by Capacity Path					**Updates by Contract Path**
Capacity Path	**Vendor**	**Contract ID**	**Receipt Zone**	**Delivery Zone**	**Contract Disposition**
Chicago Path	Vector	FT-1-NUI-0122	Alliance	Dawn	Terminated
Chicago Path	Vector	FT-1-NUI-C0122	St. Clair (Canada)	Dawn	Terminated
Chicago Path	Union	M12205	Dawn	Parkway	Converted
Chicago Path	TransCanada	41235	Union Parkway Belt	Iroquois	Converted
Chicago Path	Iroquois	R181001	Waddington	Wright	Renewed
Chicago Path	Tennessee	95196	TGP Zone 5	TGP Zone 6	Renewed
Chicago Path	Tennessee	41099	TGP Zone 5	TGP Zone 6	Renewed
Chicago Path	Algonquin	93002F	Mendon, MA	Brockton, MA	Renewed
PNGTS Year-Round	PNGTS	1997-003	Pittsburgh	Granite	Converted
Tennessee Niagara	Tennessee	5292	TGP Zone 5	TGP Zone 6	Renewed
Tennessee Niagara	Tennessee	39735	TGP Zone 5	TGP Zone 6	Renewed
Tennessee Long-haul	Tennessee	5083	TGP Zone 0	TGP Zone 6	Renewed
Tennessee Long-haul	Tennessee	5083	TGP Zone L	TGP Zone 6	Renewed
Algonquin Long-haul	Algonquin	93201A1C	Lambertville, NJ	Taunton, MA	Renewed
Tennessee Firm Storage	Tennessee	5195	TGP TGP Zone 4	TGP TGP Zone 4	Renewed
Tennessee Firm Storage	Tennessee	5265	TGP Zone 4	TGP Zone 6	Renewed
Washington 10 Path	Washington 10	01052	W10 Withdrl Meter	Vector	Terminated
Washington 10 Path	Vector Vector	CRL-NUI-1096	Alliance	Dawn	Terminated
Washington 10 Path	TransCanada	CRL-NUI-1097	Washington 10	Dawn	Terminated
Washington 10 Path	PNGTS	33322	Union Dawn	East Hereford	Renewed
Washington 10 Path		1997-004	Pittsburgh	Granite	Converted
All Capacity Paths	Granite	14-001-FT-NN	NA	Northern	Renewed

Reviews of the original capacity portfolio as those contracts expired resulted in some modifications. In particular, the Company converted the "Chicago" path in the original portfolio to today's "Dawn Storage" path. It also relocated its largest underground storage from Washington 10 to Dawn, increased it from 3.4 Bcf to 4.0 Bcf, and increased the maximum daily withdrawal capability from 34,000 Dth to 40,000 Dth. The region around Dawn, including adjacent parts of Michigan in the U. S., includes a number of gas storage facilities. Dawn operates as well as a highly active trading point, reflecting its convergence (as the new IRP depicts) for supplies from important gas-producing regions, including the Western Canadian Sedimentary Basin and the Marcellus/Utica region in Ohio, New York, Pennsylvania and West Virginia.

NUI also accesses the markets for liquefied natural gas (LNG) to supply its LNG storage and regasification facility in Lewiston, Maine. LNG enters the region at the Canaport LNG receiving terminal in New Brunswick and at the Distrigas facility in Everett, Massachusetts. (Exelon Generation Company, LLC now owns the Distrigas facility (see Chapter II)). The NUI system also connects to the Maritimes & Northeast Pipeline system (M&NP). The offshore Nova Scotia gas-producing areas have become depleted, but revaporized LNG from the large Canaport terminal in New Brunswick can reach NUI and other U. S. markets via M&NP pipeline facilities.

The following table lists the components of the Company's supply capacity portfolio, including the pending Portland Xpress and Atlantic Bridge and the proposed Westbrook Xpress Project. The table shows that all of the Company's sources involve multiple receipts and deliveries between their sources and their arrival at NUI's distribution system.

Pipeline Transportation and Underground Storage Contracts by Capacity Path

Capacity Path	Vendor	Contract ID	Contract End Date	Receipt Zone	Delivery Zone
Iroquois Receipts	Iroquois	181003	10/31/2024	Waddington	Wright
Iroquois Receipts	Tennessee	95196	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Tennessee	41099	10/31/2022	TGP Zone 5	TGP Zone 6
Iroquois Receipts	Algonquin	93002F	10/31/2020	Mendon, MA	Brockton, MA
TGP Niagara	Tennessee	5292	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Niagara	Tennessee	39735	3/31/2025	TGP Zone 5	TGP Zone 6
TGP Long-haul	Tennessee	5083	10/31/2023	TGP Zone 0, L	TGP Zone 6
Algonquin Receipts	Texas Eastern	800384	10/31/2024	Leidy Storage	Lambertville, NJ
Algonquin Receipts	Algonquin	93201A1C	10/31/2020	Lambertville, NJ	Taunton, MA
TGP Firm Storage	Tennessee	5195	3/31/2025	TGP Zone 4	TGP Zone 4
TGP Firm Storage	Tennessee	5265	3/31/2025	TGP Zone 4	TGP Zone 6
Dawn Storage	Enbridge	LST086	3/31/2023	Dawn Hub	Dawn Hub
Dawn Storage	Enbridge	M12256	10/31/2033	Dawn Hub	Parkway
Dawn Storage	TransCanada	57901	3/31/2033	Parkway	East Hereford
Dawn Storage	TransCanada	57055	10/31/2032	Parkway	East Hereford
Dawn Storage	PNGTS	FTN-NUI-0001	10/31/2033	Pittsburg, NH	Newington, NH
Portland Xpress	Enbridge	TBD	10/31/2040	Dawn Hub	Parkway
Portland Xpress	TransCanada	TBD	10/31/2040	Parkway	East Hereford
Portland Xpress	PNGTS	TBD	10/31/2040	Pittsburg, NH	Newington, NH
Westbrook Xpress	Enbridge	TBD	10/31/2037	Dawn Hub	Parkway
Westbrook Xpress	TransCanada	TBD	10/31/2037	Parkway	East Hereford
Westbrook Xpress	PNGTS	TBD	10/31/2037	Pittsburg, NH	Newington, NH
All Capacity Paths	Granite	16-100-FT-NN	10/31/2020	NA	Northern

The Company organizes these capacity resources into "paths." The paths connect each supply point to NUI's affiliate Granite State Gas Transmission, Inc. (GSGT). GSGT then delivers to the Company's distribution system. The table below lists the paths and their maximum daily quantities.

NUI shares all its pipeline capacity with retail marketers who serve customers on its distribution system. The table indicates the method by which NUI shares each path with the marketers:

- Capacity Release: allows the marketer to directly manage the asset
- Company-Managed: the Company manages the asset, fulfilling requests of marketers for their share of that resource.

Long-Term Resources by Capacity Path

Capacity Path	Resource Type	Max Daily Quantity	Method of Assignment	Status
Iroquois Receipts Path	Pipeline	6,434	Company-managed	Existing
Tennessee Niagara Capacity	Pipeline	2,327	Capacity Release	Existing
Tennessee Long-haul Capacity	Pipeline	13,109	Capacity Release	Existing
Algonquin Receipts Path	Pipeline	1,251	Company-managed	Existing
Tennessee Firm Storage Capacity	Storage	2,644	Capacity Release	Existing
Dawn Storage Path	Storage	39,863	Capacity Release	Existing
Lewiston On-System LNG Plant	Peaking	6,500	Company-managed	Existing
Existing Long-Term Capacity		**72,128**		**Existing**
Portland XPress Project (11/2020)	Pipeline	9,965	Capacity Release	Pending
Atlantic Bridge Capacity (11/2020)	Pipeline	7,500	Capacity Release	Pending
Pending Long-Term Capacity		**89,593**		**Pending**
Westbrook XPress Project (11/2022)	Pipeline	9,965	Capacity Release	Proposed
Proposed Long-Term Capacity		**99,558**		**Proposed**

NUI has only one receipt point on its distribution system that is not served by GSGT. That one is Lewiston, Maine, where NUI connects directly to M&NP. There is currently no upstream capacity for that point; NUI buys supply delivered there. The pending Atlantic Bridge capacity will deliver to that point, allowing NUI to look for upstream resources to serve it.

2. *Capacity Contracting*

Capacity contracting decisions since the Company's acquisition by Unitil have involved renewing or converting almost all capacity resources. Management viewed the portion consisting of supplies bought on a delivered basis as too large. Management has therefore sought to pursue alternatives in the period since the acquisition. Available alternatives have come in the form of pipeline connections, plus some increase in underground storage. These resources have reduced the portion of supply acquired on a delivered basis, because they have provided access to upstream supply points which are more liquid than the ones in New England. These resources include:

- The Dawn Storage Path, which went into service in April 2018, involved re-contracting of existing pipeline capacity combined with some added capacity
- The Atlantic Bridge project, which involves added capacity on the AGT system, accessing supply points in New Jersey
- The Portland Xpress project's addition to PNGTS capacity, with upstream capacity on TCPL and Enbridge, which will provide additional access to the Dawn supply point
- The Westbrook Xpress project's addition of further capacity on PNGTS and upstream pipelines TCPL and Enbridge to access Dawn.

Acquiring capacity from such projects permits year-round use, but the Company's requirements are seasonal. Nevertheless, the new IRP suggests that the lower prices and greater price stability associated with access to the more-liquid supply points favor these projects over delivered supply.

It shows expected utilization of these resources and the legacy ones under both Normal-Year and Design-Year conditions. The Company presented detailed analysis of the benefits of the Atlantic Bridge and Portland Xpress projects in proceedings to consider whether to approve them. Recently, the Commission approved a similarly detailed analysis of the Westbrook Xpress project.

Management continues to review its remaining capacity portfolio as additional contracts expire, and as particular supply problems or opportunities present themselves. Analysis includes careful quantitative comparisons of alternatives, plus application of qualitative considerations unique to each potential opportunity presented. The IRP presents a detailed discussion of the Company's resource evaluation methods.

The Energy Contracts group is responsible for assessing opportunities. It does not prepare formal decision documents, but does preserve quantitative assessments of the alternatives it considers. When decisions lead to change, the Company presents the results of all assessments, quantitative and qualitative, in its next gas-cost-adjustment filing.

3. Commodity Purchasing

NUI purchases gas supplies annually through two requests for proposals (RFPs). The first, typically issued in mid-February, seeks proposals for particular supplies and supply services, including

- Supplies provided as part of agreements to manage certain of NUI's capacity assets
- Winter-season supplies, delivered to GSGT receipt points for re-delivery to NUI
- Summer-season supplies delivered to storage-area pooling points or to injection points for storage held by NUI.

The second RFP focuses on peaking supplies. Typically issued in June, the RFP requests supplies delivered to GSGT interconnects with PNGTS or the Company's receipt point on M&NP. These supplies are to address "demand swings and peak winter days".

a. Asset Management Agreements

Operating the many capacity paths to which the Company has access would require managing relatively small amounts of capacity on multiple pipelines every day. Management therefore simplifies its daily operating challenges by aggregating each path's components into a package. It then offers the resulting path-based packages for bid under asset-management agreements (AMAs). Management selects from among the third parties offering for each package one to operate each package. This leaves to NUI the role of ensuring accurate nominations to each package's third-party asset manager for delivery of supply using that path to NUI for meeting system-supply customer needs.

Management solicits offers to manage these path-based packages under AMAs having one-year terms. The Company requires asset managers to provide supply at a relevant index price, plus variable transportation and fuel charges associated with deliveries to the specified delivery point. For paths that go through Canada, asset managers must administer all import/export filings, and pay all duties, GST taxes and any other miscellaneous charges. For each path, NUI provides the third-party managers an estimate of the amount of capacity that must be assigned to retail marketers.

The Company requires asset managers that win the right to manage the Dawn storage asset to buy the gas that remains in storage when the manager assumes responsibility for managing its operation. The manager must then fill the storage at a cost developed as though the storage capacity had been filled ratably (uniformly) at an indexed price specified by NUI. The specified prices typically use a local index, with additions for variable injection and fuel charges. Withdrawals occur when NUI nominates them, with billing for them at inventory cost when withdrawn. At the end of the storage withdrawal season NUI repurchases any remaining inventory at the final weighted average cost.

Third parties find benefit in these arrangements by: (a) selling gas to NUI at the prices their winning offerings require, and by (b) using any remaining capacity on the path (after meeting NUI and retail marketers' requirements) to serve other customers the manager may find. Thus, for example, an asset manager who finds opportunity for storage arbitrages can do so for its own account, presumably allowing it to offer NUI better compensation for use of the asset. Management generally awards management of each "path" to the third-party offering NUI the largest asset-management "fee." NUI's view of offeror capabilities and commitment to reliable service comprise factors that can cause an award not to follow raw pricing. Over the last six years (2014-2015 through 2019-2020), asset-management revenue has covered an average of 23 percent of asset demand costs (between 11 and 36 percent in any given year).

b. Delivered Supplies

Chapter II addressed expiration of the Wells Supply Contracts, whose expiration, combined with load growth since 2008, has left a considerable requirement for supplies beyond the capabilities of the legacy capacity portfolio. The pending and proposed supply projects will address a significant part of that requirement, but the Company needs additional supplies delivered to its city gate or receipt points on GSGT in the winter months.

In recent years, this requirement has been addressed in two parts:

- Contracts for delivered "base-load" supplies; *i.e.*, those delivered in the same amounts on every day of a specified period
- Contracts for delivered "peaking" supplies; *i.e.*, committing suppliers to deliver up to a maximum daily quantity of supply as the Company calls for it.

Base-load supplies are generally seasonal. Winter-period ones provide for one quantity delivered every day for the months of November through March, and a second quantity delivered every day for the months of December through February. Summer-period ones call for constant quantities every day of the specified summer months.

i. Delivered Base-Load Supplies

The Company secures delivered base-load supplies under its annual RFP, which specifies the required delivery points and the pricing structures considered acceptable by NUI. The 2019 RFP, for example, specified the last-day settlement price of the NYMEX gas contract for each month of the delivery period – November through March or December through February – plus or minus a basis differential. Bidders specified the basis differential they were willing to accept in their offers. NUI picked the supplier with the smallest basis differential.

Also in the annual RFP are small quantities of summer-period supplies. Those supplies are to be delivered to storage-area pooling points, and a storage-injection point under contract to NUI. The 2019 RFP requested:

- 1,800 Dth/day for the months of April through December, delivered to TGP's Station 313 Pool)
- 900 Dth/day for the months of April through October, delivered to NUI's storage injection meter on the 300 Leg of TGP Zone 4.

The RFP-requested pricing for both was the last-day settlement price of the NYMEX gas contract for each month of the delivery period, plus or minus a basis differential. The RFP instructed bidders to specify the basis differential they were willing to accept.

ii. Delivered Peaking Supplies

The second RFP seeks delivered peaking supplies. For the winter of 2018-2019, the Company requested as much as 40,000 Dth/day, subject to an annual maximum of 800,000 Dth. The Company sought to reserve the power to nominate up to 40,000 Dth/day, delivered to specified delivery points. Offerors specified the maximum they would commit to providing to each of the specified delivery points. Offerors had the option of proposing either fixed pricing or a stated daily index price (such as the Algonquin City Gates price), plus a fixed demand charge that would be paid in each of the months covered by the service. For indexed pricing, qualified offerors effectively competed on the basis of the demand charge. Fixed pricing required consideration of both demand and commodity components for all offers.

In late 2018, the Company issued a special RFP for a three-, four- or five-year term, rather than the one-year term of previous contracts. Termination of gas production offshore Nova Scotia has given the Company concern about the availability of supply when NUI needs it. Management sought to consider whether entering a longer-term commitment might increase supply reliability.

The special RFP used delivery and pricing specifications similar to those of prior RFPs for this type of supply:

- Sellers specified maximum daily quantity and annual contract quantity at each of six listed delivery points
- Pricing could be at the monthly Bidweek Algonquin City Gates spot-price index, or at NYMEX last-day settle for the month in which the deliveries occurred, plus a fixed demand charge covering the entire period to be covered by the supplier's offer.

[redacted]

4. Supplier Competition

The New England market has seen multiple competitors propose additions to delivery capacity, but most projects have stalled or been abandoned. NUI has looked at each, and is participating in the pipeline projects that have survived, to meet its objective of reducing dependence on delivered supplies.

Competition to provide commodity supply has been reasonably robust, but some competitors have disappeared as market risks intensify. The New England market presents comparatively high risks for suppliers because of price volatility and constrained pipeline capacity. Those with supply available at an upstream point, but who cannot get it to a customer because of a pipeline issue, may need to secure additional supply in the market where delivery must occur, potentially facing potentially ruinous price or default risk.

a. The Annual RFP

Providing asset-management service or delivered supply to NUI requires financial resources and management skills. The following table shows how many firms competed to supply each of those services in response to NUI's last five annual RFPs. Not every competitor bid on every path. The table shows by path the lowest and highest bidder numbers. Similarly, for delivered supply not every supplier bid on delivering to every point; the table shows the range of competitors for any point.

Annual AMA and Base-Load Supply Bidder Numbers

	4/1/2015-3/31/2016	**4/1/2016-3/31/2017**	**4/1/2017-3/31/2018**	**4/1/2018-3/31/2019**	**4/1/2019-3/31/2020**
Asset Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Delivered Base-Load Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

One of the AMA opportunities involves NUI's long-haul capacity on the TGP system. That capacity accesses supply points in the U. S. Gulf Coast, near the upstream end of the TGP system, and delivers to the southern end of GSGT's pipeline system, and to GSGT at a NUI city gate in New Hampshire, both near TGP's downstream end. That AMA routinely draws the [redacted] The AMA for NUI's TGP capacity from the Niagara import point to its receipt points routinely draws the [redacted] The AMA for the Dawn Storage path (previously the Washington 10 Storage path) draws by far the largest asset-management fees, as it offers many optimization opportunities.

The competition for winter base-load supply routinely draws [redacted] Competition varies for the other delivered-supply opportunities offered in the annual RFP.

b. The Peaking RFP

The competition for delivered peaking supplies is conducted separately. The annual RFP is issued in mid-February, with contracts awarded in March. The RFP for delivered peaking service is issued in late June or early July, with the service to begin November 1. The service is provided from November 1 through the following March 31.

The peaking-service RFP traditionally provided for day-ahead nominations for the service, with a must-take provision for the nominated quantity. Beginning with the 2016 RFP (for the service period November 1, 2016 through March 31, 2017), NUI requested offers requiring day-ahead nominations, and offers allowing intra-day nominations. The following table shows the number of offers that the Company received for each type of service.

Numbers of Offers Received for Delivered Peaking Supply

	11/1/2015-3/31/2016	**11/1/2016-3/31/2017**	**11/1/2017-3/31/2018**	**11/1/2018-3/31/2019**
Day-Ahead Nominations	[redacted]	[redacted]	[redacted]	[redacted]
Intra-Day Nominations	[redacted]	[redacted]	[redacted]	[redacted]

As noted earlier, the Company in late 2018 issued an RFP for a multi-year delivered peaking service. [redacted]

c. Supplier Qualification

The Company requires that prospective sellers of gas or asset-management services enter into a NAESB (North American Energy Standards Board) Base Contract for Sale and Purchase of Natural Gas with it in order to do business. The Company evaluates the financial stability of any firm that wants to bid, but requests collateral rather than rejecting a possible supplier if it is concerned about the supplier's finances. For suppliers, NUI considers the physical assets that would be used to fulfill a contract. For asset managers, NUI considers a proposer's operational experience and technical capabilities. The Company says that it is willing to discuss a relationship with interested suppliers; its focus in any such discussion is to ensure that a prospective supplier understands and accepts the obligations that would come with a supply relationship with NUI. New suppliers are given relatively small opportunities to perform as tests of their suitability for a supply relationship with NUI.

As indicated in the table below, three new suppliers have been added in the last three years.

5. *Supply Contracts*

All of the Company's U.S. pipeline and storage capacity is on (or in) facilities regulated by the U.S. Federal Energy Regulatory Commission (FERC) Those facilities offer their services under FERC-approved tariffs, and NUI's contracts for its share of those facilities are service agreements issued pursuant to those tariffs. The only exception is the Company's LNG storage and regasification facility, which it owns. The Canadian Energy Regulator (formerly the National Energy Board) or the Ontario Energy Board regulate pipeline and storage capacity in Canada. Rates for pipeline transportation service are regulated, but rates for storage are market-based.

As noted, the Company uses the NAESB Base Contract for Sale and Purchase of Natural Gas as the basis for its relationships with all suppliers of asset-management services and natural gas. The Company uses its RFPs, and the confirmations issued when it accepts an offer for services or supply, to add specific details to govern the relationship. Those added specifics are often quite detailed as they include detailed operating provisions.

Company personnel review each year's performance under all contracts. RFPs and transaction confirmations for the succeeding year are modified to improve performance if possible. The principal objective of each year's modifications is to reduce operational risks to the Company and its customers.

6. *Suppliers*

The table below lists the Company's suppliers for 2016, 2017 and 2018. The list is in order of most supply to least for 2018.

Suppliers of Natural Gas to NUI (Dth)

Supplier	2016	2017	2018
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

7. *Documentation*

For decisions about capacity commitments, internal evaluations, which primarily take the form of spreadsheets comparing cost provisions of available alternatives, are annotated and saved. Details of both quantitative and qualitative evaluations are presented to the Maine and New Hampshire Public Utility Commissions in requests for approval of contractual commitments.

For decisions about commodity, the Company saves all of its RFPs, all of the responses that it receives, and all of its bid evaluations as documentation for its selections of asset managers and providers of delivered supply. Day to day, spreadsheets detailing nominations under in-force contracts are saved. Any purchases or sales outside of the AMAs and delivered-supply agreements are entered into GTRAC, which is the Company's transaction-tracking system. The spreadsheets and GTRAC are structured to support the Company's twice-yearly cost-of-gas adjustment filings.

C. Conclusions

1. We found management of supply procurement a notable NUI strength.

1 [redacted]

NUI has the benefit of a capable and experienced staff in the supply procurement function. Key personnel have deep experience in the unique circumstances of the Company's service territory, a commitment to careful analysis, and a continuing interest in evaluating performance in order to improve. Capacity options are limited, and the number of suppliers is limited for the services the Company requires, but performance in those circumstances is exceptional.

In the complex and high-risk nature of the supply environment in which the Company operates, the Company has developed supply processes well suited to that environment. Rather than try to operate a system with many small moving parts, NUI has organized its capacity portfolio into paths that connect liquid, transparent supply points to NUI's receipt points, and hires asset managers to operate each one.

For requirements that must be met with delivered supplies, the Company encourages bidders to participate by offering as much delivery-point flexibility as it can. We also believe that putting a large and diverse number of supply opportunities into one annual RFP encourages more suppliers to participate, as they can see relatively accessible opportunities to establish a relationship with NUI. We note with interest that the Company has recently attracted additional suppliers in spite of the highly-constrained and high-risk nature of the New England markets.

2. Contracting practices are effective and resulting contracts appropriate in meeting supply needs.

Analysis of the Company's results suggests that its contracting practices are highly effective. There is typically a significant spread between the highest and lowest bids. This spread indicates that the competition is extracting as much value as possible from each path.

Each year's performance is evaluated as part of preparing for the succeeding year's competitions. Any ideas for improving that performance are incorporated into the contracts for the succeeding year.

3. The Company has clear objectives for its procurement activities.

For adding to or upgrading its capacity portfolio, the Company looks for access to deep, liquid markets. It operates its existing resources to emphasize transparency and liquidity, as well.

Service competitions are structured to support price stability. RFPs specify commodity pricing related to an available index that exhibits stability, or to the last-day-settlement price of the NYMEX contract.

4. Bid evaluations are rigorous and objective.

RFPs are carefully constructed to provide unambiguous offers. Those offers are evaluated primarily on price, with a review of supply reliability and pipeline scheduling capabilities as threshold tests for an award.

5. Maintaining a sufficient number of suppliers is increasingly difficult. *(Recommendation #1)*

NUI can find abundant competitors for the right to operate its resources that access highly-liquid supply points. On the other hand, it is difficult for suppliers to compete in the highly-constrained New England gas market. With the termination of gas production offshore Nova Scotia, some suppliers for whom that was a major source may no longer participate. Other suppliers may limit their participation in order to avoid the risks of participation.

[redacted]

D. Recommendations

1. Initiate an intensive effort to reduce dependence on [redacted] delivered peaking service. *(Conclusion #5)*

NUI's multi-year contract for delivered peaking supplies make a useful time window available to pursue alternatives. That effort should begin immediately, and should have high priority.

The effort should start on the demand side. NUI currently has no curtailment plan, and it has limited information on its customers' alternate-fuel capabilities. Regarding dual-fuel capability, the Company reports "Dual fuel capability is not incorporated into the Delivery Service Terms and Conditions or the Company's planning activities in any manner."

The delivered peaking service is costly. Because its pricing under the current and recent contracts involves large demand charges assessed over all five of the winter months, all customers are paying a high price to maintain service for customers who might be willing to get off when supply costs are high. This situation begs for a thoughtful demand-response program.

There may also be other supply-side options. The new owner of the Distrigas terminal should be approached regarding supply options. It has some pipeline capacity, and provides delivered-supply services to some customers. That terminal also delivers into both the TGP and AGT pipeline systems, however, as well as into the local distribution company (National Grid). Distrigas and its LDC customer might both be possibilities for peaking-supply options.

Other LDCs have LNG facilities that have provided storage services for customers other than the owner. Among those, Southern Connecticut Gas Company, now a subsidiary of Avangrid, once offered contract peaking services through an affiliate formed to offer such services into the interstate gas markets. The large LNG facility in Providence, RI has in times past offered LNG storage services to customers other than its owner. As NUI's requirement is relatively small, and could be divided into multiple small pieces, any number of LDCs might be able to offer a portion of its requirements.

Remote peak-period supply services in the highly constrained New England gas market will present risks. NUI has several advantages in pursuing such options:

- Its connection to multiple interstate pipeline systems through affiliate GSGT
- Its ability to displace supplies entering GSGT's system to different parts of its service territory

- A highly-skilled staff who has considerable knowledge of delivery systems and issues in the New England market, and considerable experience in operating complex delivery processes.

The Company's apparent plan [redacted] is to engage a consultant to pursue on-system LNG facilities, both expansion of the current plant in Lewiston, and a new plant in another locations. While expansion of the current plant might be competitive in cost, a new facility is likely to be very costly. The Company's analysis will not be complete until it has pursued these other demand-side and supply-side options as aggressively as it is pursuing additions to its on-system plant.

IV. Gas Supply Management

A. Background

Effective gas supply management requires operation of the supply portfolio in a manner that achieves reliable deliveries to customers at the lowest overall cost. Placing delivery capacity controlled by the company, but temporarily not required for serving the company's on-system customers into secondary markets comprises a central element of effective supply management.

We applied the following criteria in evaluating supply management:

1. Scope and focus of policies and procedures for operating the gas-supply portfolio on the cost and reliability interests of on-system customers
2. Sufficiency of the operational planning structure and execution to ensure no disadvantage to customers through operating errors or omissions or supplier or pipeline penalties
3. Control of personnel with Maine-service-area-only responsibilities over actions and decisions that could disadvantage Maine customers
4. Consistency of commodity transportation costs charged to Maine customers with operations that optimize overall costs for them
5. Comprehensive, regular, accurate verification of pipeline transportation costs and consistency with services received
6. Aggressiveness of marketing of unutilized assets in line with appropriate transaction limits, controls, and risk management.

B. Findings

NUI manages its supply on an integrated basis; *i.e.*, it uses all supply assets to serve customers in both Maine and New Hampshire.NUI faces particular challenges in managing its gas supply for a number of material reasons. First, *multiple pipelines* transport Company supply to a large number of delivery points:

- A gate station near Lewiston, Maine, on the Maritimes & Northeast Pipeline (M&NP) system
- Four receipt points on affiliate Granite State Gas Transmission, Inc.'s (GSGT's) system in Maine and New Hampshire, and one in Massachusetts
- A gate station at affiliate Fitchburg Gas and Electric Light Company (FG&E) in Massachusetts
- Several gate stations at former parent Bay State Gas Company in Massachusetts.

Deliveries to Bay State return to NUI through an exchange agreement under which Bay State delivers supply to NUI via GSGT at connections on the Portland Natural Gas Transportation System (PNGTS).

Second, the Company's *fragmented service territory* imposes locational requirements on deliveries from particular sources of supply. Third, *retail marketers* deliver large amounts of gas to the Company's system - - roughly 40 percent in Maine and 50 percent in New Hampshire - - to serve their customers through NUI's distribution system. These volumes coming for multiple marketers complicate management and measurement accuracy. Fourth, comparatively high *weather variability* creates large swings in gas requirements, exacerbated by frequent, large daily differences between forecasted and actual weather. Fifth, the *downstream location* of the service territory on almost all of pipelines serving the Company means that, during the winter, when prompt delivery of requested gas volumes is most essential, the pipelines narrow their delivery tolerances. (Delivery tolerances refer to how close the actual quantity taken from the pipeline at the delivery point matches the quantity nominated to that point.) This means that both NUI and the retail marketers that serve customers on NUI's distribution system must take extra precautions to ensure that the supplies that they deliver to the pipelines match their customers' usage.

We found Company planning, complex under these circumstances, attentive, comprehensive, and supported by appropriate systems and processes, as we discuss below.

1. Operations Planning

The Company organizes its supply capacity portfolio by "path"- - each consisting of grouped capacity assets that move supply from where NUI buys or stores it to key delivery points:

- The M&NP gate station at Lewiston that delivers to NUI
- A gate station in Westbrook, Maine that serves both M&NP and PNGTS, and delivers to GSGT
- PNGTS gate stations at Eliot, Maine and Newington, New Hampshire that deliver to GSGT
- Tennessee Gas Pipeline (TGP) gate stations in Haverhill, Massachusetts, and Salem, New Hampshire that deliver to GSGT
- TGP gate stations that serve affiliate FG&E.

Other paths delivering to receipt points on GSGT support the exchange agreement with Bay State. Management must allocate the assets in each path, including those delivering to Bay State, between:

- Itself to serve its system-supply customers
- Marketers, for serving their end users.

Operations planning begins by using a general forecast to construct seasonal supply plans. The Energy Contracts staff assigns supply resources to particular delivery points, based on a rough estimate of loads expected at each point. This process produces baseline estimates of capacity amounts on each path required for its system-supply customers and marketers' customers.

The staff then reduces these seasonal plans to monthly plans, which further detail and align sources and deliveries. At the beginning of each month, the Company asks that each marketer validate its list of customers. Any changes from the prior month undergo examination for adjustment in the capacity management systems that support allocation of capacity resources.

The pipelines, including GSGT, use electronic bulletin boards (EBBs) to manage their systems. Users nominate the quantities that they want to pipeline to transport, the locations where they want to put gas in – receipt points – and the locations where they want to take gas out – delivery points. All users input this information every day, and may adjust it within each day. With this information, the pipelines can assess whether their systems are physically capable of accomplishing all the requested movements. When they get close to their physical limits, they will impose flow restrictions, such as narrowing delivery tolerances. Because NUI is near the downstream ends of the major pipelines that serve it, pipeline capacity is quite limited. As a consequence, the pipelines that serve NUI operate under operational flow orders (OFOs) for most of every winter. Those orders narrow delivery tolerances to half or less of the normal levels.

2. *Day-to-Day Operations*

A Daily Forecast file embeds the monthly plans. This file applies a seven-day weather forecast to generate a corresponding daily forecast of supply requirements at the pipeline delivery locations that serve NUI. NUI personnel then nominate from among the available supply resources the quantities that they want delivered to each receipt location. Volumes under the exchange agreement with Bay State generally comprise a base-loaded volume, which means that they don't change every day. They change seasonally, but not every day.

Management updates the Daily Forecast file every day with new weather data. An accompanying Imbalance File shows whether actual deliveries have matched requirements, and provides up-to-date assessments of surplus or shortage in deliveries.

Affiliate pipeline GSGT provides the "backbone" of the Company's distribution system. Except for FG&E in Massachusetts, the Company's service territories almost all connect to and receive deliveries by GSGT. The service territories, however, do not have robust connections among themselves.

The five points (identified earlier in this chapter) of delivery into GSGT take more than seven times more (38) delivery points to get gas from GSGT into the various segments of NUI's service territory. The Westbrook Gate Station into GSGT lies very near the pipeline's northernmost delivery point, which serves an NUI lateral connecting to the Lewiston service territory. The lateral effectively serves as an extension of GSGT, connecting Lewiston to the other portions of the service territory. That lateral does not have sufficient capacity to meet Lewiston's demand during the winter. An M&NP delivery point and NUI's liquefied natural gas (LNG) storage and regasification facility also serve the Lewiston area.

GSGT and the lateral to Lewiston connect the Maine and New Hampshire service territories to each other. That interconnection allows operation of the system on an integrated basis; *i.e.*, the Maine and New Hampshire territories operate as one system. Limits on GSGT flow capacity, however, prohibit unlimited movement of gas from different GSGT receipt points to all its points of delivery to NUI. Accordingly, location-specific requirements must be addressed before supply can flow among receipt and delivery points.

a. Coordination with Retail Choice Program

The Company allocates shares of each of its supply-capacity paths to retail marketers in proportion to the design daily demands of each marketer's load. Allocations take place on a "slice-of-the-system" basis. Thus, each marketer gets a proportionate share of every resource. The marketers receive most resources through direct assignment, but the Company operates two:

- The Company's LNG storage and regasification facility in Lewiston, Maine
- A small TGP storage contract and the pipeline capacity for delivering the stored gas to GSGT.

These resources do not form part of the paths operated under contract with NUI by third-party asset managers. The Company manages these two asset groups in-house and provides supply from them in response to marketers' nominations. In practice, Northern can provide any supply in response to nominations by marketers for the Company-managed resources. That is, if a marketer requests Company-managed supply, Northern can fulfill the requirement with pipeline-delivered gas, rather than gas from the two Company-managed assets.

The marketers serving end users can trade their assigned "slices" among themselves, to optimize their capacity holdings as they see fit. They must, however, deliver their required amounts to specified GSGT receipt points, thus allowing the correct amount of supply to reach each of the marketers' customers. The marketers nominate their own capacity on GSGT's system. However, GSGT's meters for delivery into NUI's distribution system do not measure volumes continuously. Thus, marketers must also report their deliveries into GSGT on NUI's Centralized Supplier Interface (CSI). All marketer nominations for their Maine supply pools go to Westbrook, and nominations for New Hampshire pools go to Newington or to Haverhill. Management can verify correct volumes to be sent to the proper NUI receipt points when marketers nominate their supplies on NUI's system.

Marketers have responsibility for ensuring deliveries for their requirements, regardless of how weather and conditions may cause them to vary from nominations. NUI's Delivery Service Terms and Conditions, part of its tariff, make clear marketer responsibilities and penalties for failure to fulfill them.

b. Nominations and Dispatch

The Company's contracts for supply resources address procedures for daily resource nominations. NUI's extensive use of asset-management agreements (AMAs) make the following the primary focuses of its supply-management activities:

- Nominating quantities for delivery to GSGT, including withdrawals from storage, under each AMA
- Calling on the small quantities of supply it manages directly, when needed by the retail marketers or the Company's system-supply customers

Management must address locational requirements first. Recall that GSGT capacity limits prevent supplies received by GSGT from being delivered to any point on GSGT's system unless locational requirements are met. After addressing that constraint, the Company can select among available resources on the basis of cost.

Gas Control prepares the Daily Forecast File. Gas Control's files contain the daily forecast parameters determined in the regression models that Energy Contracts developed and maintain. These models use historical sendout information to develop relationships between EDD (weather) and sendout. Each day, Gas Control uses those models and the weather forecast for the next seven days to forecast gas requirements over that period. Weather forecast updates occur five times per day. Cold-weather nominations for supply can change up to five times per day, in accord with industry nominations cycles: timely, evening, and three intra-day cycles.

Energy Contracts carefully coordinates its nominations work with the activities of Gas Control, which performs complementary activities that include:

- Providing daily requirements estimates to the retail suppliers for the non-daily-metered customer pools (monthly-metered customers), using an automated process based on customer-specific regression analyses conducted annually by Energy Contracts, as part of the Annual TCQ Update process required by the Delivery Service Terms and Conditions
- Operating NUI's LNG facility, and ordering additional supplies during the facility's use.

3. *Management of Available Capacity*

The Company uses contracts for supplies delivered to GSGT or its city gates and delivered peaking supplies as a substantial part of its supply resources. Therefore, NUI does not have the sizeable amount of upstream pipeline capacity that some other gas distributors have available for secondary-market activities. It places most of its available capacity into the path-based asset-management agreements discussed earlier. Company RFPs for asset-management services provide estimates of the amounts of its pipeline capacity required to serve its load and of the amounts required to be assigned to retail marketers. Prospective asset managers consider their ability to make economic use of any unused capacity that they estimate will be available to them when pricing their bids in competing for the right to manage a particular asset.

NUI tends to over-nominate in winter, to ensure that its customers get enough supply, and to avoid pipeline imbalance penalties. When deliveries appear to exceed requirements, the Company adjusts by reducing storage withdrawals in the first half of the winter, and engages in off-system sales in the second half.

In the past, the Company released during the summer season some pipeline capacity under its management. More recently, it has placed that capacity into one of its asset-management agreements, in an effort to recover more of the costs of the capacity through increased asset-management fees and to increase reliability.

4. *Procedures and Documentation*

Gas supply operations operate smoothly and confidently. All participants know their roles and responsibilities well, but no written procedures exist. The Energy Contracts staff has developed a series of spreadsheets that record various aspects of the supply-management process. The staff updates these spreadsheets daily, and retains each day's sheets for documentation purposes. The spreadsheets are structured to capture all information required for cost-of-gas filings with the Commission.

C. Conclusions

1. We found NUI gas supply management a notable strength.

Company personnel have developed systems and processes to deal with the complexities of the Company's gas-supply resources and service territories. Close coordination between Energy Contracts and Gas Control during cold-weather days results in highly-effective performance in a difficult operating environment.

The nature of the Company's service territories and the physical aspects of gas supply rule out effective operation of the Maine and New Hampshire Divisions on a segregated basis. We found it clear that the interests of on-system customers serve as the predominant drivers for supply operations in all of its service territories. Management routinely addresses the allocation of administrative costs among them to its three state jurisdictions -- Maine, Massachusetts and New Hampshire. FG&E has its own supply portfolio, but NUI allocates its gas costs between Maine and New Hampshire. Those Commissions and the Company's customers have ample opportunities to satisfy themselves regarding the rules that produce those allocations, and the results that they produce.

Physical aspects of the service territories and gas delivery systems limit choices in dispatch. After satisfying locational requirements, the Company employs economic dispatch. These processes result in the lowest possible costs to each group of customers.

The Company effectively employs its path-based, asset-management agreements to place capacity sometimes not needed. Offering the asset-management opportunity to multiple bidders encourages the extraction of maximum value for on-system customers. Those marketers who can find the most effective off-system use for capacity they manage presumably reflect the margins they gain when competing for asset-management roles.

2. **Preferable short-term forecasting tools may exist; they warrant examination.** *(Recommendation #1)*

The Company uses regression models developed in-house for short-term load forecasting (embedded in the Daily Forecast File). This approach improves on traditional methods for performing this function. Nevertheless, industry best practice for this application supplements these models with a tool known as "deep neural networks". NUI may be able to enhance its short-term forecasts, and thus improve its dispatch, by using this technique. A description of the technique and its application to short-term natural gas forecasting, is presented in a recent journal article in *Energies* by Gregory D. Merkel, Richard J. Povinelli and Ronald H. Brown. (Published: 2 August 2018).

3. **The lack of written procedures risks operational continuity, should NUI experience a loss of key skills which, while now sufficient, do not exist in reasonably large number.** *(Recommendation #2)*

The Energy Contracts and Gas Control staffs have developed efficient and effective processes for gas-supply management. That detailed knowledge of those processes is concentrated in a small group of individuals, however, presents a risk of discontinuity.

Written procedures would reduce that risk by capturing a significant share of their expertise. The potential loss of highly experienced incumbents, due to retirement, accidents or illness, or departure from the Company, should be addressed.

The solution to these concerns is to develop written procedures for daily nominations and dispatch. Much of the substance of such procedures has been developed in responding to data requests in the course of this audit. The task that remains is to complete them, and then re-format them into steps that can be followed by other persons, and by auditors.

D. Recommendations

1. **Explore the application of neural network methods to the Company's short-term requirements forecasting.** *(Conclusion #2)*

As noted above, these methods now comprise industry best practice for this function. The Company should explore their application to its Daily Load Forecast. Improved forecasts should improve dispatch, hopefully lowering the requirement for same-day and intra-day adjustments.

Evaluation of such applications can take place in short time order. We recommend that the Company report on its progress in the proceeding to consider the findings of this audit (Docket No. 2018-00300).

2. **Prepare written procedures to guide the nominations and dispatch functions.** *(Conclusion #3)*

Much of the substance of required and appropriate procedures has been developed in responding to data requests in the course of this examination. What remains is to complete them and revise them into a procedures format. We regard this recommendation as a priority. The Company should initiate this effort with dispatch, and report on its progress in the proceeding to consider the findings of this audit (Docket No. 2018-00300).

V. Measurement and Balancing

A. Background

Sound measurement methods and practices support accurate determination of total gas costs. Effective balancing minimizes penalties from delivering pipelines, and supports the appropriate distribution of gas costs among customers. We evaluated measurement and balancing under the following criteria:

1. Application of metering and testing programs conforming to industry standards and to the Company's unique circumstances
2. Design and execution of metering strategies to isolate deliveries to various customer classes and Company uses
3. Design and execution of a balancing strategy and practices appropriate for each customer class.

B. Findings

1. Management Strategies and Processes

NUI receives almost all of its gas supplies via pipeline. Affiliate Granite State Gas Transmission, Inc. (GSGT) receives most of the field purchases and storage and delivered supplies, redelivering them to NUI. The Lewiston, Maine areas comprises the principal exception; NUI receives gas there from the Maritimes & Northeast Pipeline (M&NP) directly into its distribution system. The Company also operates a small liquefied natural gas (LNG) facility in Lewiston, which receives its supplies by truck, and then delivers the regasified product into the distribution system. As discussed in Chapter IV, the Company can also supply the Lewiston, Maine area through a lateral on NUI's system, but this lateral does not have sufficient capacity to meet locational demands during the winter.

NUI delivers some of the gas that it buys for transport on its capacity on the Tennessee Gas Pipeline system (TGP) and Iroquois Gas Transmission System (IGTS) and all of the gas that it buys for delivery on its Algonquin Gas Transmission system (AGT) capacity to Bay State Gas Company receipt points in Lawrence, Agawam and Taunton in Massachusetts. Bay State, in return, delivers gas on capacity that it holds on the Portland Natural Gas Transmission System (PNGTS) to GSGT receipt points at Westbrook and Eliot, Maine, and Newington, New Hampshire, for redelivery to NUI. Bay State contracts for capacity on GSGT, which it uses to deliver to NUI. An exchange agreement negotiated as part of the sale of NUI to Unitil covers these deliveries. This exchange agreement provides access for NUI to supplies sourced on TGP and on AGT, to which NUI has no physical connection.

The overall measurement scheme uses pipeline measurement of their own deliveries into GSGT, or into NUI's distribution system in the case of M&NP delivering into Lewiston. GSGT measures its deliveries into NUI's system. NUI, in turn, measures its deliveries to its customers.

At year-end 2018, the Company's Maine Division had 34,119 active meters. Most of those (almost 33,000) consisted of diaphragm-type meters, which the Company uses for residential and small commercial and industrial (C&I) customers. The Company employs rotary meters for larger C&I customers, and turbine meters for the largest C&Is. NUI had only six turbine meters in operation at the end of 2018. The Company filed descriptions of how each meter type operates, and of the circumstances in which each is deployed, with its initial response in Docket No. 2018-00331, *Inquiry into Meter Testing and Standards of Local Distribution Companies*.

The interstate pipelines calibrate their meters at least annually. GSGT inspects its turbine and rotary meters monthly to verify their operation, and it calibrates its flow computers annually. NUI tests meters before installation, and calibrates its largest ones quarterly. Field audits conducted each year sample the non-instrumented rotary and diaphragm meters. The audits seek to validate proper operation of the reading indexes and the automated meter reading (AMR) devices. The practice is to examine two percent of small-diaphragm meters and 25 percent of large diaphragm ones each year.

NUI's billing system identifies anomalies in billings, such as measurements showing no usage at customer locations known to be active. Upon detecting anomalies, technicians visit the meter to examine the circumstances. NUI also tests meters on customer request.

NUI has identified certain meter types with known problems, replacing them as practical. Management also has a practice of retiring certain meter types to reduce the number of types in inventory. Otherwise, NUI retires meters more than 20 years old.

NUI requires its meter manufacturers to provide test data for new meters purchased. The Company sends meters removed for testing to a testing facility in Pennsylvania. Testing applies a protocol established by Unitil. In the 10 years that Unitil has owned the Company, the Maine Division has received test results for 13,358 purchased meters, and for 1,910 meters removed for testing.

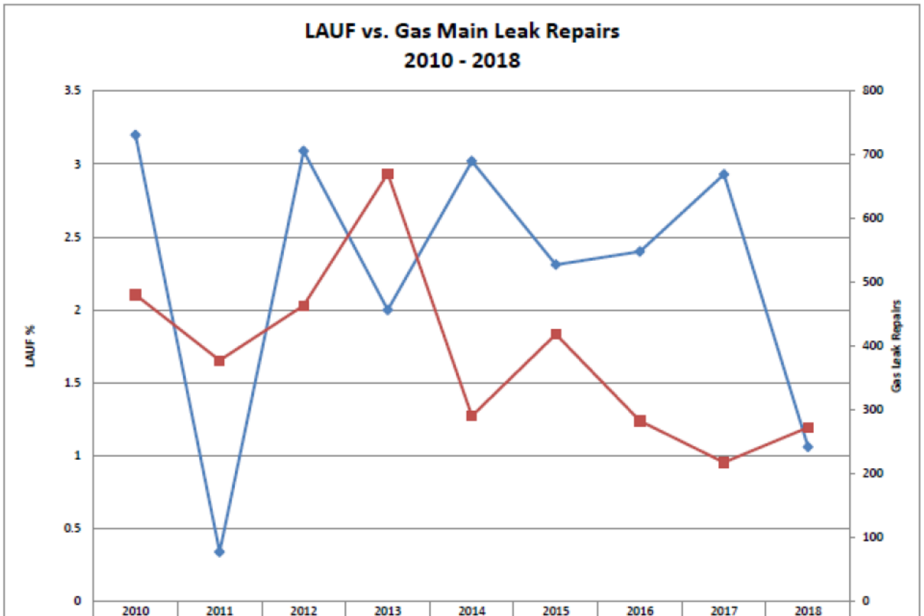
The Company generally follows manuals published by the American Gas Association (AGA) to guide meter accuracy and testing standards and protocols. Management observed that the three jurisdictions in which it operates have different requirements regarding metering standards.

2. *Lost and Unaccounted for Gas*

A variety of factors produce Lost and Unaccounted for Gas (LAUF); *e.g.*, meter accuracy, timing differences between billing measurements at upstream points and individual customer meters, company usage, measurement accuracy of LNG inventory, boil-off gas, theft, pipe leaks, and accounting differences. NUI's measures to reduce LAUF include:

- It measures Company use for domestic heat and hot water at various facilities and for vaporization and heaters at its LNG facility and district regulator stations, and deducts the measured quantities from LAUF calculations
- It installs correctors that compensate for variances in pressure and temperature for commercial and industrial customers
- It checks customer service regulators and adjusts them upon installation and routine meter changes, to ensure accurate delivery pressures, and, in turn, measurement
- It conducts an aggressive leak repair program.

The Company reports that most leaks occur along the cast-iron portions of its distribution system. Management plots leaks on maps, to serve as a factor in planning the cast-iron replacement program. NUI has completed that replacement program in New Hampshire, now finding no leaks there. While logic suggests that repairing leaks would reduce LAUF, management has found no clear correlation between leak repairs and LAUF (see the graph below), which reflects the fact that a factors beyond leaks materially influence LAUF.



	2010	2011	2012	2013	2014	2015	2016	2017	2018
LAUF	3.2	0.34	3.09	2	3.02	2.31	2.4	2.93	1.06
Leaks	481	378	464	671	291	419	283	218	273

NUI has organized its cast-iron replacement program by geographic areas. During work in an active area, the Company usually replaces meters as well, and upgrades service lines as necessary or appropriate.

As do most gas distribution companies, NUI calculates its annual LAUF percentage by summing monthly calculations from July of the previous year through June of the reporting year. The Company calculates LAUF separately for its Maine and New Hampshire Divisions, and for subsidiary Fitchburg Gas and Electric Light Company (FG&E) in Massachusetts.

The next table, taken from the Company's PHMSA F7100.1-1 Annual Report for the Maine Division, shows the Company's LAUF calculation for the years 2014 through 2018. NUI often appears to receive more gas than it delivers (positive LAUF) in winter, but then appears to deliver more than it receives in the spring (negative LAUF). Cycle billing produces this pattern, characteristic of most gas LDCs. For this reason, reported LAUF usually employs a 12-month calculation period.

Northern Utilities, Inc.
Maine Division
Lost and Unaccounted For, Company use, and Therm Factor Data

12 Months Ending June	Month	Total - ME City-Gate (MCF)	Therm Factor	Total - ME City-Gate (Dth)	Total System Billed Sales (Dth)	Company Use (Dth)	Lost and Unaccounted For (Dth)	Lost and Unaccounted For (%)
2014	Jul-13	360,798	1.0170	366,931	361,116	37	5,778	1.60%
2014	Aug-13	373,504	1.0126	378,210	366,661	8	11,541	3.15%
2014	Sep-13	399,136	1.0281	410,352	378,996	14	31,342	8.27%
2014	Oct-13	575,408	1.0386	597,619	485,235	34	112,350	23.15%
2014	Nov-13	1,004,257	1.0272	1,031,573	843,493	173	187,907	22.28%
2014	Dec-13	1,454,069	1.0317	1,500,163	1,286,509	337	213,317	16.58%
2014	Jan-14	1,581,927	1.0386	1,642,989	1,587,741	2,465	52,783	3.32%
2014	Feb-14	1,354,980	1.0356	1,403,217	1,450,516	1,170	(48,469)	-3.34%
2014	Mar-14	1,373,442	1.0300	1,414,645	1,408,731	1,306	4,608	0.33%
2014	Apr-14	821,018	1.0312	846,634	1,008,764	933	(163,063)	-16.16%
2014	May-14	500,294	1.0371	518,855	619,888	373	(101,406)	-16.36%
2014	Jun-14	373,847	1.0438	390,221	427,439	86	(37,304)	-8.73%
2015	Jul-14	355,102	1.0396	369,164	370,442	33	(1,311)	-0.35%
2015	Aug-14	359,916	1.0408	374,600	353,033	26	21,541	6.10%
2015	Sep-14	411,741	1.0179	419,111	385,511	26	33,574	8.71%
2015	Oct-14	582,481	1.0170	592,383	514,552	112	77,719	15.10%
2015	Nov-14	1,025,629	1.0272	1,053,526	827,326	448	225,752	27.29%
2015	Dec-14	1,256,340	1.0356	1,301,066	1,222,092	976	77,998	6.38%
2015	Jan-15	1,634,539	1.0403	1,700,410	1,525,468	1,237	173,705	11.39%
2015	Feb-15	1,634,909	1.0406	1,701,286	1,710,367	2,860	(11,941)	-0.70%
2015	Mar-15	1,379,495	1.0347	1,427,364	1,499,295	2,179	(74,109)	-4.94%
2015	Apr-15	854,091	1.0266	876,810	1,052,591	1,059	(176,840)	-16.80%
2015	May-15	498,638	1.0251	511,154	590,016	245	(79,108)	-13.41%
2015	Jun-15	438,073	1.0224	447,886	462,683	80	(14,877)	-3.22%

12 Months Ending June	Month	Total - ME City-Gate (MCF)	Therm Factor	Total - ME City-Gate (Dth)	Total System Billed Sales (Dth)	Company Use (Dth)	Lost and Unaccounted For (Dth)	Lost and Unaccounted For (%)
2016	Jul-15	392,545	1.0228	401,495	398,252	28	3,216	0.81%
2016	Aug-15	387,281	1.0208	395,336	382,252	14	13,070	3.42%
2016	Sep-15	395,272	1.0212	403,652	387,311	37	16,304	4.21%
2016	Oct-15	679,374	1.0308	700,299	557,542	89	142,668	25.59%
2016	Nov-15	902,671	1.0280	927,946	778,166	381	149,398	19.20%
2016	Dec-15	1,080,621	1.0313	1,114,444	1,061,183	1,103	52,158	4.92%
2016	Jan-16	1,444,975	1.0395	1,502,052	1,363,726	1,435	136,891	10.04%
2016	Feb-16	1,280,645	1.0417	1,334,048	1,397,147	1,836	(64,935)	-4.65%
2016	Mar-16	1,104,015	1.0322	1,139,565	1,226,006	1,558	(87,999)	-7.18%
2016	Apr-16	880,207	1.0289	905,645	954,764	1,270	(50,389)	-5.28%
2016	May-16	586,114	1.0234	599,830	666,178	574	(66,921)	-10.05%
2016	Jun-16	423,131	1.0260	434,132	464,054	71	(29,993)	-6.46%
2017	Jul-16	383,017	1.0192	390,371	375,734	28	14,610	3.89%
2017	Aug-16	393,016	1.0195	400,680	404,659	26	(4,005)	-0.99%
2017	Sep-16	413,879	1.0176	421,163	393,396	29	27,739	7.05%
2017	Oct-16	658,449	1.0199	671,552	547,913	198	123,441	22.53%
2017	Nov-16	934,347	1.0215	954,435	846,936	718	106,780	12.61%
2017	Dec-16	1,435,585	1.0311	1,480,231	1,214,257	1,192	264,782	21.81%
2017	Jan-17	1,402,244	1.0337	1,449,500	1,438,474	1,601	9,426	0.66%
2017	Feb-17	1,251,854	1.0442	1,307,186	1,361,604	1,580	(55,998)	-4.11%
2017	Mar-17	1,401,927	1.0344	1,450,153	1,347,498	1,528	101,127	7.50%
2017	Apr-17	812,508	1.0258	833,470	1,034,142	1,212	(201,884)	-19.52%
2017	May-17	614,371	1.0245	629,423	702,918	640	(74,135)	-10.55%
2017	Jun-17	426,811	1.0253	437,609	444,976	380	(7,747)	-1.74%
2018	Jul-17	393,491	1.0220	402,147	445,002	27	(42,882)	-9.64%
2018	Aug-17	400,454	1.0227	409,545	397,745	27	11,774	2.96%
2018	Sep-17	403,092	1.0223	412,081	401,100	39	10,942	2.73%
2018	Oct-17	502,147	1.0249	514,651	489,750	141	24,760	5.06%
2018	Nov-17	1,046,849	1.0337	1,082,128	814,852	657	266,620	32.72%
2018	Dec-17	1,592,327	1.0360	1,649,651	1,378,493	1,182	269,975	19.58%
2018	Jan-18	1,677,857	1.0410	1,746,649	1,797,898	2,559	(53,808)	-2.99%
2018	Feb-18	1,228,124	1.0356	1,271,845	1,407,008	1,974	(137,137)	-9.75%
2018	Mar-18	1,265,450	1.0363	1,311,386	1,295,226	1,677	14,483	1.12%
2018	Apr-18	974,101	1.0346	1,007,805	1,101,347	1,234	(94,776)	-8.61%
2018	May-18	514,209	1.0266	527,887	659,106	752	(131,971)	-20.02%
2018	Jun-18	429,087	1.0326	443,076	466,445	118	(23,487)	-5.04%
2014		10,172,678	1.0323	10,501,409	10,225,089	6,937	269,384	**2.57%**
2015		10,430,953	1.0330	10,774,760	10,513,377	9,280	252,104	**2.34%**
2016		9,556,852	1.0316	9,858,444	9,636,580	8,396	213,468	**2.17%**
2017		10,128,007	1.0294	10,425,773	10,112,507	9,131	304,135	**2.92%**
2018		10,427,188	1.0337	10,778,851	10,653,973	10,386	114,492	**1.06%**

3. *Balancing*

Balancing consists of getting deliveries into the distribution system to match deliveries out of it. Effective balancing promotes: (a) getting the correct gas costs to each customer or class of customers, and (b) avoiding imbalance penalties. Balancing poses special challenges for NUI, because: (a) its service territory experiences large changes in weather, which, in turn, results in large changes in gas requirements, and (b) retail marketers supply a large portion of NUI's load. The marketers bring supplies for their customers to NUI which must then deliver those supplies to marketer customers. The next table shows, for a sample winter month (January 2018), the influence of both factors. It shows the magnitude of the load supplied by marketers, as much as one-third on some days, and it shows the impact of weather changes. Notice Column 6, which shows for that month a forecast variance range of minus 24 percent to plus 29 percent.

Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 15	Col 16
			Col 4- Col 3	(Col 4 / Col 3) - 1			Col 8 - Col 7	(Col 8 / Col7) -1		
Gas Day	Forecast Average ME/NH EDD	Actual Average ME/NH EDD	Forecast EDD Variance (EDD)	Forecast EDD Variance (Percentage)	Forecasted Northern System Sendout (Dth)	Actual Northern System Sendout (Dth)	Forecast Sendout Variance (Dth)	Forecast Sendout Variance (Percentage)	Total System Supply	Imbalance (Dth)
1/1/2018	68.0	70.3	2.3	3%	143,319	137,700	-5,619	-4%	141,034	3,334
1/2/2018	58.0	58.7	0.7	1%	124,097	131,944	7,847	6%	128,527	-3,417
1/3/2018	50.0	49.7	-0.3	-1%	109,124	112,367	3,243	3%	110,380	-1,987
1/4/2018	51.5	51.4	-0.1	0%	110,822	105,102	-5,720	-5%	115,428	10,326
1/5/2018	72.0	71.5	-0.5	-1%	144,456	138,437	-6,019	-4%	145,472	7,035
1/6/2018	75.5	75.0	-0.5	-1%	146,632	143,516	-3,116	-2%	149,039	5,523
1/7/2018	57.5	56.2	-1.4	-2%	120,565	120,460	-105	0%	132,258	11,798
1/8/2018	41.0	39.7	-1.4	-3%	96,749	100,426	3,678	4%	104,717	4,291
1/9/2018	44.5	39.8	-4.8	-11%	96,602	90,918	-5,684	-6%	92,993	2,075
1/10/2018	37.5	34.7	-2.8	-7%	89,094	85,159	-3,935	-4%	77,398	-7,761
1/11/2018	24.5	22.0	-2.6	-10%	71,332	65,508	-5,824	-8%	64,983	-525
1/12/2018	20.5	15.6	-4.9	-24%	59,691	50,784	-8,906	-15%	56,321	5,537
1/13/2018	50.5	48.4	-2.2	-4%	90,542	91,172	630	1%	91,917	745
1/14/2018	57.5	56.8	-0.7	-1%	114,825	116,497	1,672	1%	120,118	3,621
1/15/2018	53.5	52.8	-0.7	-1%	115,179	119,964	4,786	4%	119,654	-310
1/16/2018	40.0	38.8	-1.3	-3%	93,172	94,830	1,658	2%	93,500	-1,330
1/17/2018	42.0	41.7	-0.3	-1%	93,964	94,994	1,030	1%	98,057	3,063
1/18/2018	44.5	44.9	0.3	1%	99,262	95,161	-4,101	-4%	92,782	-2,379
1/19/2018	38.5	37.0	-1.6	-4%	88,611	84,789	-3,822	-4%	84,510	-279
1/20/2018	30.0	28.8	-1.3	-4%	67,172	71,443	4,271	6%	68,287	-3,156
1/21/2018	32.5	31.1	-1.5	-4%	73,485	71,656	-1,829	-2%	79,185	7,529
1/22/2018	33.0	42.7	9.7	29%	80,509	95,592	15,083	19%	83,898	-11,694
1/23/2018	27.0	33.8	6.8	25%	71,362	84,713	13,351	19%	67,275	-17,438
1/24/2018	46.5	46.2	-0.3	-1%	97,494	100,221	2,727	3%	101,875	1,654
1/25/2018	55.0	52.5	-2.6	-5%	116,912	112,865	-4,047	-3%	108,780	-4,085
1/26/2018	44.0	42.8	-1.2	-3%	98,311	98,791	480	0%	84,235	-14,556
1/27/2018	26.5	22.3	-4.3	-16%	63,862	63,186	-676	-1%	67,641	4,455
1/28/2018	32.5	28.1	-4.5	-14%	72,875	72,224	-651	-1%	72,566	342
1/29/2018	44.5	44.0	-0.5	-1%	95,659	95,525	-134	0%	94,640	-885
1/30/2018	48.0	49.5	1.5	3%	102,212	110,823	8,611	8%	107,877	-2,946
1/31/2018	41.0	40.3	-0.7	-2%	94,744	93,817	-926	-1%	99,101	5,284

NUI's location at or near the downstream ends of the gas pipelines that serve it compounds the problem. As a consequence of NUI's location, service interruptions almost anywhere on any of the four upstream pipelines that serve NUI adversely affect it. All four operate under flow restrictions for much of every winter. The four are TGP, M&NP, PNGTS and AGT, the latter through the exchange agreement with Bay State. "Upstream" refers primarily to upstream of GSGT, which delivers to NUI; however, the Union Gas system, TransCanada PipeLines (TCPL) and Trans Quebec & Maritimes (TQM) are upstream of PNGTS, and deliveries to PNGTS can be affected by interruptions on those systems. TCPL and IGTS are upstream of some of the Company's TGP capacity.

NUI's service territory consists of several areas in Maine and New Hampshire - - areas minimally or not at all connected to each other. GSGT serves as the link among them, except for the area around Lewiston, which M&NP facilities serve directly. This configuration imposes some locational needs on which sources can go to which portions of the territory, but NUI manages balancing by considering the system as an integrated whole.

Balancing starts with annual resource acquisition, which results in asset-management agreements and commodity-supply contracts tailored to the Company's load forecast. Monthly plans assign portions of the Company's pipeline capacity to retail marketers and asset managers, then Energy Contracts develops detailed plans for the Company's own load. Energy Contracts and Gas Control then manage supply resources for the Company-supplied load day-to-day. That process begins with an Imbalance file that shows daily and cumulative balances for the current month. If the Company is short at a point, it orders extra supplies for the next day.

Retail marketers have responsibility for their own load forecasts for Daily Metered customer pools; Northern estimates daily demand for marketers' Non-Daily Metered customer pools. Northern communicates its estimates to the marketers daily. Retail marketers have responsibility to get enough supply to NUI's city gates to meet their customers' requirements. The marketers nominate into GTRAC, NUI's system for matching marketer deliveries from GSGT to the Company's system, to their customers' consumption. NUI's Delivery Service Terms and Conditions provide that any flow restrictions, such as upstream imbalance warnings or operational flow orders (OFOs), are passed along to the marketers. Any penalties caused by marketer imbalances are passed along to the offender.

The Company generally manages intra-day balancing, which might occur due to changes in the weather or supply problems from a particular source, with adjustments to storage withdrawals for the first half of the winter, then with off-system sales in the second half. The Company's contracts for peaking supply and its on-system LNG facility are additional resources for addressing imbalances if necessary.

C. Conclusions

1. Metering and testing programs generally conform to prevailing industry practice.

In interviews and in response to our data requests, the Company emphasizes that its metering and measurement practices conform to the regulations of the three states in which it operates (Maine, Massachusetts and New Hampshire). We found its practices generally conforming to prevailing industry practice.

We understand that the metering and testing programs of all of the gas LDCs operating in Maine, and the relationship of those programs to industry practice, are being explored in Docket No. 2018-

00331. NUI is participating actively in this proceeding, and anticipates additional protocols to ensure meter accuracy.

2. The Company's metering strategies are effective in isolating usage by customers and the Company.

NUI's distribution system consists of multiple groups of customers that are not connected to each other, but are connected to GSGT. GSGT has a relatively large number (38) of delivery points into NUI's system, each of which is metered. That large number of metering points, most of which are serving defined groups of customers, provides a lot of disaggregated data on customer usage.

The Company is also careful to measure its own usage. Taken together, this large amount of measurement data relative to the number of users provides confidence that usage information is accurate.

3. NUI's systems, practices and processes for balancing are a strength.

NUI's location, system configuration and supply resources present significant challenges for balancing. NUI has made significant investments of time and talent to address these challenges. The Company's objective in making this investment has been to facilitate balancing by all, rather than collecting penalties.

D. Recommendations

Liberty has no recommendations in this area.

VI. Price Risk Management

A. Background

Price-risk management programs, including physical and financial hedging, can comprise an important element in effective gas-supply procurement and management. We evaluated this subject using the following criteria:

1. Focus and clarity of objectives
2. Correlation between hedging instruments selected and attainment of program objectives
3. Sufficiency of policies and procedures in reflecting knowledgeable assessment of program risks, and careful design of elements to control risks
4. Completeness and effectiveness of administration of controls
5. Frequency and scope of program results review and modifications made to improve results.

NUI operated a financial hedging program when Unitil acquired the Company in 2008. NUI refocused the program, and operated it subject to periodic review by the Commission until 2017. Early in that year, the Company petitioned the Commission to allow it to suspend the program for one year, allowing option contracts held at that time to expire, followed by determining the best course going forward. The Company also noted that it was replacing one of its gas storage contracts with a larger one that would result in an increase in the volume of gas with physically hedged pricing for the 2018-2019 Winter Period.

The next year, the Company requested that the Commission allow it to terminate the financial hedging program. The Commission approved the Company's request, stating "the current hedging program benefits do not appear to warrant the ongoing cost …." The Commission went on to say

> *The Commission would propose that Northern include in its integrated resource planning filing an in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposure to gas price volatility from year to year, including whether or not use of financial instruments may be warranted.*

In this chapter, we provide a brief history of the Company's financial-hedging program, and then review the Company's approach to inventory strategy as it relates to providing a physical hedge.

B. Findings

1. The Initial Hedging Program

At the time that Unitil acquired the Company, NUI was operating a hedging program that was initially approved in 2003. That program's portfolio approach employed both physical and financial hedging to fix the prices of 70 percent of its winter supply requirements and 40 percent of its needs for May and October. The financial portion of the program used futures contracts.

When Unitil assumed control of the program, it added more structure to the financial-hedging component. Forty percent of futures contracts purchased to hedge NUI's non-storage pipeline supplies were bought pursuant to a time-based strategy: equal amounts were purchased in each of the 12 months of the year prior to the year being hedged. Up to another 30 percent of non-storage supplies could be bought with "price-triggered" hedges: purchases structured to acquire an additional 10 percent of non-pipeline supplies when certain price targets were reached. Taken together, the time-based and price-triggered hedges could result in 70 percent of non-storage supplies being hedged.

a. 2010 Program Changes

The price-based part of the program produced repeated losses, due to generally falling NYMEX prices. In its order approving NUI's 2007-2008 Winter Period CGF rates, the Commission required NUI to file a detailed evaluation of the effectiveness of the hedging program since its inception. That proceeding began with testimony from witnesses for NiSource, which owned the Company before Unitil acquired it.

The evaluation was filed after Unitil acquired the Company. In its April 2009 Annual Report on Financial Hedging Activity for November 2008 through April 2009, NUI reported that the program had not provided as much price stability as originally expected. In August, NUI filed a proposed program redesign, with three primary changes:

1. The introduction of a price ceiling above which purchases of futures contracts would be deferred until prices fell below the ceiling
2. The complete elimination of the price-based component of the existing program
3. A process that provided for sales of futures contracts that appreciated above a specified percentage.

NUI updated its program redesign in February 2010. To the three changes listed above, it added

> *… adoption of a portfolio approach to hedging whereby Northern would combine its physically hedged supplies with its financial hedges to begin each peak season with approximately 70 percent of the supply requirements available under a fixed-price. The remaining supply (approximately 30%) would be purchased at market prices throughout the peak period*

The Company also proposed to modify the hedging plan schedule. Rather than buy hedges over the 12 months prior to the start of each six-month cost-of-gas period, the Company proposed to submit a hedging plan once a year, providing a 12-month purchasing schedule with an 18-month window to implement the plan. Each plan filing would outline a three-year schedule of projected hedging activity that would include a three-year projection of sendout requirements, the peak-season resources expected to provide fixed pricing (storage and fixed-price contracts), and the financial hedging volumes required to meet the fixed-price supply quantity target. Hedging activity would continue into the delivery season if necessary to: (a) make purchases postponed due to limits imposed by the price ceiling, and (b) sell appreciated contracts under the appreciation rule.

The Commission approved NUI's proposals.

b. 2013 Program Changes

Two years later, in the spring of 2012, the Commission noted the price stability and low prices in the markets for natural gas, and directed NUI to propose changes to the hedging program. The Company worked with a brokerage firm to develop a new approach to hedging, which involved protecting against price "spikes", rather than trying to reduce price volatility.

Protection against price spikes could be achieved by purchasing options, particularly "call" options, which give the holder the right to buy at a specified price, irrespective of what was happening to market prices. In this way, the Company could effectively "cap" the prices that it would pay for gas, while preserving the opportunity for lower prices if market prices went down. This approach also had the advantage of requiring much smaller cash outlays than buying futures contracts.

NUI's proposals retained the 70-percent target, which it had inherited from NiSource. That target would apply to winter-season commodity requirements, rather than all 12 months, and it would be attained using both physical and financial hedges. By that time, physical storage provided approximately 50 percent of winter-season requirements, leaving only 20 percent to be hedged financially. Northern picked a type of option that suited its use in the financial segment of the Company's hedging program. The financial hedges would be "out-of-the-money" call options, *i.e.*, options providing the right to purchase at a specified price (the "strike" price) that was above the current price.

NUI proposed to continue to submit annual hedging plans with its off-peak cost-of-gas (CGF) filings. The plans would include calculations to determine the number of call options to be purchased for the current hedging period and the two succeeding ones, which would provide a three-year projection of expected hedging activity.

The Commission approved the revised program.

c. 2016 Program Changes

In the hedging plan for the 2017/2018 period (submitted in February 2016), NUI proposed an increased hedging budget in order to set the strike prices for the call options closer to futures contract prices. The options purchased in previous hedging plans had been too far "out of the money", and thus had expired without any benefit to the Company's gas costs. The Company had analyzed recent experience and current market conditions, and recommended paying more for options in order that the strike prices might be set closer to levels suggested by current futures contracts.

The Commission approved the Company's proposal for one year, but required the Company to file an evaluation of actual results of this program compared with what would have happened if the budget had not been increased.

d. Program Suspension and Termination

The following year, NUI reported that the options contracts under the old budget had indeed expired worthless, but it appeared that the ones with strike prices closer to futures prices were also going to expire worthless, due to the general stability of prices. NUI recommended that the program be suspended for a year, and then decide how to proceed.

NUI also reported that it had replaced an expiring storage contract with a larger contract, thereby increasing the proportion of its supplies covered by a physical hedge (buying gas at summer prices to be consumed the following winter).

The Commission approved suspension of the program, but directed further discussions to consider whether changes to the program should be made. By the next year (2018), all parties were largely agreed that, in the current period of stable gas prices, the benefits of the financial hedging program were not worth its costs. The Commission approved NUI's proposal to terminate the financial hedging program, but ordered

> *The Commission would propose that Northern include in its integrated resource planning filing an in depth discussion of its price risk management objectives and a description of actions it has taken, or will take, to reduce customers' exposure to gas price volatility from year to year, including whether or not use of financial instruments may be warranted.*

2. *Alternative Methods of Price Risk Management*

The Company has been sensitive to the high level of price volatility in the Northeast gas markets, and interested parties' and the Commission's interest in protecting its customers from the effects of that volatility. The Company's preferred approach to addressing that volatility has been by way of its physical procurement strategies, however. In particular,

- The Company's most-recent replacement of an expiring storage contract increased the storage quantity by 15 percent
- The Company structures its delivered supply and LNG contracts to be priced with respect to a monthly index, rather than daily ones
- Longer term, it is adding pipeline capacity that will connect its service territory with supply points that are more liquid and have more stable – and lower – pricing.

On the latter point, pipeline-capacity additions include participation in the Portland Express Project, the Atlantic Bridge Project and Phase III of the Westbrook Xpress Project. If the first two successfully enter service, the Company's proposed addition of capacity through the Westbrook Xpress Phase III Project will reduce its purchases of delivered supply to only about one percent of its total annual supplies.

3. *Program Management*

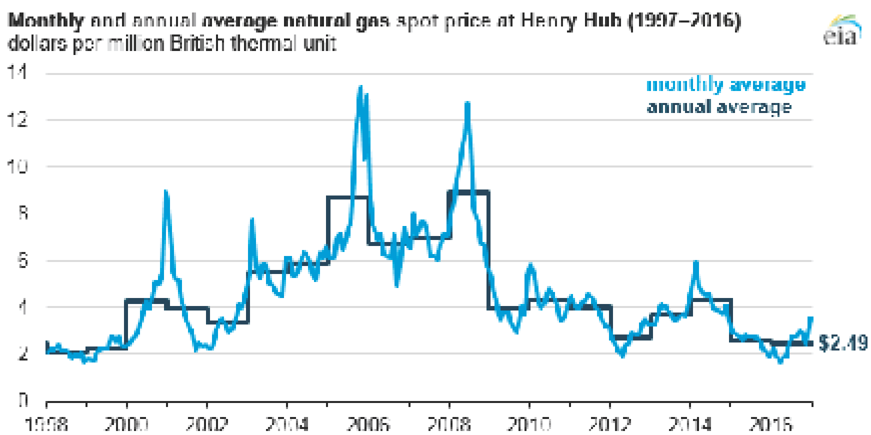
NUI had formal procedures governing operation of its financial hedging program, but the program's small size allowed it to be conducted and managed without a separate structure. The Company's Chief Financial Officer first, and then the Director of Energy Contracts, sent written instructions to execute trades to a broker who had worked with NiSource initially, and then continued working with NUI after Unitil acquired the Company. Both the Energy Contracts group and the Company's Treasury Department received daily and monthly statements of the Company's positions. Prior to converting to options contracts, Energy Contracts calculated margin-call exposure associated with futures contracts daily, and then submitted it to the Finance Department daily. Energy Contracts coordinated payment requests for margin account funding with the Director of Finance. A Senior Treasury Analyst contacted the broker for any requests to withdraw excess margin funds. The Company filed a Summary Transaction Report with the two PUCs each month.

C. Conclusions

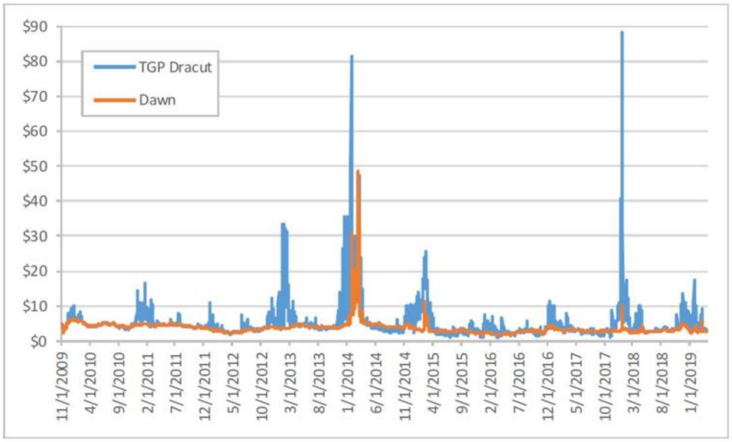
1. The objectives of NUI's hedging program have changed over the period that Unitil has owned the Company.

The stated objective of the hedging program has always been to protect NUI's customers from the consequences of natural gas price volatility. In late 2008 and early 2009, when Unitil took the program over from NiSource, the focus was volatility in the Henry Hub price. The hedging program that Unitil took over used gas futures contracts to reduce the consequences of that volatility. Gas futures contracts provide the right to buy a stated quantity at a stated price for a selected month at the Henry Hub location.

Unitil's principal change to the program, substituting call options on futures contracts for the contracts, was an effort to address the same objective – volatility in the Henry Hub price – at less cost, and with less requirement for credit support. While the level of Henry Hub prices has fluctuated somewhat since 2008, the general trend has been toward less volatility. The following chart, taken from a recent report by the U. S. Department of Energy's Energy Information Administration (EIA), illustrates this trend.



Over the same period, volatility in daily prices in the New England region has increased. The reasons for this increased volatility are well known -- increased demand for gas without corresponding increases in gas-supply capacity. The chart below, taken from NUI's recently-filed Integrated Resource Plan, illustrates this trend, using the daily spot price at TGP's Dracut location.



NUI has substituted increased physical hedging and particular contracting strategies for financial hedging, but the objective is clear: to "insulate customers from the volatility of *daily* index prices". (Emphasis added). As the Company has also stated.

> *As feasible Northern structures its Delivered Supply and LNG contracts to be indexed to monthly rather than daily prices, in order to insulate customers from daily index pricing, which can become extreme particularly on very cold days when delivered peaking supplies are needed.*

2. NUI's selection of hedging "instruments" reflects core strengths of its operations.

We noted earlier NUI's strengths in: (a) knowledge of the gas-supply infrastructure in its region, (b) knowledge of the operational risks of that infrastructure, (c) structuring its supply contracts and asset-management agreements to reduce risk, and (d) effective operation of its gas-supply resources. The Company's focus on storage and contracting strategies for reducing its customers' exposure to gas-price volatility reflects those strengths. The Company has no other particular use for expertise in financial derivatives, and chooses not to acquire it for the sole purpose of gas-price hedging.

3. Controls, policies and procedures have reflected the Company's approach to hedging.

During the period of financial hedging, the Company established controls, policies and procedures that reflected the limited scope of the hedging activity. The activity was conducted by the Director of Energy Contracts, in cooperation and coordination with Treasury and Finance. With the move to increased physical hedging and supply contracting, Energy Contracts' normal processes of analysis and approval are considered sufficient. As noted in the chapter on Organization, Staffing and Controls, those processes have been in place, if somewhat informal. Liberty has recommended that additional structure be added to those functions.

4. Company personnel have reviewed program results regularly, and have recommended changes as market trends and program results have developed.

NUI began examining the results of the financial-hedging program as soon as it took the program over from NiSource, and made several recommendations for program improvements before recommending that it be terminated. The Commission remarked favorably on NUI's program evaluations and recommendations for improvement multiple times over the period that the financial-hedging program operated.[2]

NUI's supply-contracting evaluations and decisions over the period have been driven primarily by considerations of supply security and reduced operational risk. The role of those decisions in protecting the Company's customers from price volatility has increasingly entered those deliberations, however, as the potential benefits to price stability have been realized. Price risk management has now been recognized as a feature of the Company's physical procurement strategies.[3]

D. Recommendations

Liberty has no recommendations in this area.

[2] See, *e.g.*, Order, dated April 28, 2017, in Docket No. 2017-00028, *NORTHERN UTILITIES, INC. d/b/a UNITIL, Proposed Cost of Gas Factor for May 2017 - October 2017*, at page 7, and Order, issued in Docket No. 2016-00025, *NORTHERN UTILITIES, INC. d/b/a UNITIL, Proposed Cost of Gas Factor for May 2016 – October 2016*, on April 29, 2016, at page 6.
[3] See, *e.g.*, *2019 Integrated Resource Plan*, at page VI-115.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Philip L. Bartlett, II
CHAIRMAN

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Randall D. Davis
COMMISSIONERS

Harry Lanphear
ADMINISTRATIVE DIRECTOR

March 9, 2021

Harry Lanphear
Administrative Director
Maine Public Utilities Commission
18 State House Station
Augusta, ME 04330

Re: Public Utilities Commission, Investigation of Inclusion of CIS Implementation Costs in Rates of Northern Utilities, Inc. d/b/a Unitil (35-A M.R.S. § 1303(2)), Docket No. 2021-00022

Dear Harry:

Please find enclosed The Liberty Consulting Group's report of its audit of the implementation of Northern Utilities, Inc. d/b/a Unitil's customer information system.

Sincerely,

Katie M. Gray
Deputy General Counsel

Final Report
Management Audit of Implementation of Northern Utilities, Inc. d/b/a Unitil's Customer Information System

Presented to:

State of Maine
Public Utilities Commission

Presented by:

The
Liberty Consulting Group

February 26, 2021

1451 Quentin Rd Suite 400, #343
Lebanon, Pennsylvania 17042

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I. Objectives and Scope

A. Work Scope and Objectives

The Maine Public Utilities Commission (Commission) retained The Liberty Consulting Group (Liberty) to conduct a management audit examining Unitil's implementation of a Customer Information System (CIS) and a Meter Data Management System (MDMS) for its operating utilities, which include Northern Utilities' natural gas operations in Maine. The audit focused on evaluating the:

- Reasonableness of service company (Unitil Service Corporation) decisions and process underlying and producing the implementation
- Selection of external vendors and consultants employed to plan, execute, and oversee implementation
- Effectiveness and efficiency of management of CIS/MDMS planning and implementation
- Assessment of project scope, schedule, and cost reasonableness.

B. Background to the Audit

Unitil began in early 2012 a process to replace its CIS and billing system (termed "SunGard" or "HTE") used for operations across its New England service territory at each of its utility operations:

- Northern Utilities: natural gas service to 67,862 customers in Maine and New Hampshire
- Unitil Energy: electricity service to 76,564 customers in New Hampshire
- Fitchburg Gas and Electric Light Company: provider of electric and natural gas service to customers in New Hampshire (29,565 electric, 16,049 natural gas).

As of 2012, Unitil had used HTE for more than 14 years. Its vendor announced at the time plans to end support for continued use of the system. Unitil began exploration of how to implement a new, system-wide CIS consisting of the following components:

- Base CIS capabilities
- A new MDMS
- A new customer portal
- 34 sub-systems to facilitate usage of the overall package of software and systems.

The first plans for implementation of what Unitil termed its "COSMOS" project called for initial work to design and describe full needs and requirements and to prepare a Request for Proposals which Unitil Service Corporation would issue to vendors - - to begin in March of 2012. The initial COSMOS schedule called for the new systems to begin operation ("Go-Live") in April 2015. Delays extended this date by 27 months - - to July 2017. Changes in outside resources and significant cost increases accompanied the delayed implementation - - the initially expected cost of $11.5 million eventually grew by more than three times, to $36.8 million by the July 2017 Go-Live date. The first management-approved budget of $12.7 million came in February 2013.

Commission Docket No. 2019-00092, which addressed a Northern Utilities rate filing, first reviewed recovery of Maine customers' 22 percent share of new system costs. Parties in that docket expressed concerns that information provided by Unitil did not sufficiently explain and justify the substantial cost increases associated with the implementation. The Commission Order in that docket initiated a management audit to "examine all aspects of Unitil's CIS implementation" and "provide a basis upon which the Commission may decide the prudence" of amounts expended on the new system in excess of its originally-proposed $12.7 million cost.

C. Audit Methods and Work Activities

CISs comprise a key component of modern utility operations, supporting a wide variety of customer service functions. These functions including billing, collections, customer call center operations, customer communications, and field operations, among others. Well-managed utilities recognize that close attention to the proper scope, approach, governance, and staffing (by vendors and employees) of CIS projects comprise central element in completing implementation of these systems successfully. MDMSs also play a critical role, importing, validating, scrubbing, and processing meter data for use in billing customers and management analysis.

CIS implementations present complex and difficult projects. Typical issues utilities have faced with them include ambitious or insufficiently detailed scope, optimistic timelines, underestimation of governance needs, incomplete or inconsistent project reporting, late identification of resource needs, ineffective vendor management, slow recognition and response to emerging problems and lags in making progress timely and efficiently, and incomplete or overlapping testing of capabilities and functionality before Go-Live.

We created an engagement work structure designed to provide a comprehensive foundation for forming conclusions in the three key areas set forth in the RFP:

1. The reasonableness of overall management of implementation and of decision-making methods, protocols, processes, timeliness, and effectiveness
2. Management's hiring and use of vendors and consultants
3. Management's decisions and their impacts on project scope, schedule, and costs.

Our work plans provided for an examination extending across the entire COSMOS implementation life cycle - - from Business Case development through post Go-Live operation. We examined the reasonableness of project scope, schedule, and cost. We organized our evaluation according to the following areas:

- *One: CIS Business Case*
- *Two: Selection of Software and Service*
- *Three: Governance and Project Management*
- *Four: Resource Management*
- *Five: Vendor Management*
- *Six: Scope/Change Order Management*
- *Seven: Schedule/Timeline Management*
- *Eight: Cost Management*
- *Nine: Risk Management*
- *Ten: Test Plan Management*
- *Eleven: Go-Live*
- *Twelve Post Go-Live Management*

We examined how activities in each area affected performance effectiveness, efficiency, and timeliness across all phases of CIS planning, development, and execution. We evaluated overall management of the project including the decision-making protocols and processes, to determine whether the project scope, schedule, and costs were reasonable.

This report presents the results of our examination, major work elements of which comprised:

- An initial project kick-off meeting supported by a detailed presentation by company and external personnel most familiar with the CIS implementation

- 19 interviews with management and vendors, conducted in successive rounds, as we gained knowledge from other field work underway
- 189 data requests, also conducted in successive rounds, as we learned more about the major components of the CIS implementation
- A review of critical project scoping and definition materials
- Review of project cost and schedule tracking materials as well as change orders used to justify changes in scope, schedule, and costs.

D. COSMOS Project Summary

In early 2012, Unitil began the process of developing a replacement for its legacy customer information and billing system, known as SunGard or HTE, for all of Unitil's operating utilities. The system's vendor, SunGard, declared in 2010 that HTE had reached its "end of life," meaning that SunGard would soon cease providing support for the system. This system had been in place since the mid-1990s; Unitil deemed it functionally obsolete.

Unitil brought in an individual consultant employed by a firm it described as familiar with utility-industry CIS implementations, to assist with identifying the scope of the project, and its key objectives. Management formed a working group, which reported to a Steering Committee. Supported by the outside consultant, this group solicited proposals from a range of firms offering to provide CIS development and implementation services. Unitil ultimately selected Systems & Software (S&S), a subsidiary of an entity commonly known as Harris (N. Harris Computer Corporation, governed by Toronto Exchange listed Constellation Software, Inc.). The Unitil CIS would employ a Systems & Software product known as enQuesta. Management believed that Systems & Software's New England base would make it "a nimble, responsive and dedicated partner." Unitil signed a contract with Systems & Software in May 2013. For the COSMOS project's companion, MDMS element, Unitil selected Harris division SmartWorks, employing a product known as MeterSense.

Management revised the original project cost estimate of $11.5 million to $12.7 million in February 2013 and lengthened the original schedule by six months. The 29-month project schedule then applicable included the following:

- 2 months of planning and a project kick-off
- 2 months of discovery
- 8-month design phase
- 5-month development phase
- 7 months of testing
- 3 months of preparation, data conversion, and transition to meet a Go-Live Date of March 30, 2015
- 2 months of post Go-Live support.

Major schedule slippage began in the project's first stages. With progress lagging, management engaged Grant Thornton, self-billed as an "independent audit, tax and advisory firm," in July 2014 to assist with certain testing, data conversion, and internal control design issues. By October 2014, the COSMOS project was 8 months behind schedule (some 20 months into the work). With project schedule continuing to lag, in January 2015 Unitil extended the planned Go-Live Date, but by only 6 months - - to October 2015.

In April 2015, just six months before the expected Go-Live Date, Grant Thornton offered what Unitil termed a "mid-cycle" project review, assessing project status and risks. Grant Thornton recommendations coming before the Unitil Board of Directors in July 2015 stated that "Unitil must manage the work plan actively and aggressively every day," requiring it to:

- Take control of the work plan
- Update, expand and validate the work and test plans
- Strengthen project management and streamline reporting structure.

During the same presentation, Unitil project leadership told the Board that it had taken ownership of the plan, was reorganizing and adding resources, and was obtaining commitment from the software vendor to add resources and improve quality control. Shortly thereafter, Unitil asked Grant Thornton to undertake project functions originally within the Systems & Software Statement of Work. Shortly thereafter, in October 2015 (the then-scheduled Go-Live date) actual expenditures of $13.6 million already surpassed the project budget of $12.7 million. Management responded by extending the schedule again, pushing the Go-Live Date out by 16 months - - to April 30, 2017. Actual Go-Live did not happen until July 5, 2017.

In summary, initially planned as a 29-month, $11.5 million implementation, including post-implementation activities, the COSMOS project stretched to 58 months in duration and $36.8 million in costs. The next table compares planned and actual project activity durations.

Comparison of Planned versus Actual Schedule Duration

Project Activity	**Duration** (months)	
	Original	**Actual**
Planning & Kick-Off	2	2
Discovery	2	2
Business Process Analysis & Design	8	16
Development	5	10
Testing	7	21
Pre-Go-Live Preparation	1	1
Go-Live	2	3
Post Implementation Activities	2	3
Total	**29**	**58**

II. Conclusions

A. Overall Summary

The COSMOS project exceeded schedule and budget by large margins for reasons substantially affected by Unitil's lack of experience in implementing systems of this type, a weak vendor selection process, undue optimism in the selected vendor's ability to complete implementation for the very low levels of work planned, delays in vendor performance, and material gaps in providing for project governance and management. It should have completed implementation sooner and for substantially lower costs, through avoidance of delays, avoidance of work duplication by vendors, and inefficiencies involved with a mid-stream vendor change.

Management did, however, notably succeed in avoiding the cutover and early operations problems that have plagued a number of other CIS implementations in the industry. Added efforts to ensure a smooth cutover and effective initial operation took time and effort, but provided for effective, albeit delayed implementation. The introduction of Unitil's enQuesta CIS and SmartWorks MDMS produced minimal impact to the customer experience or to customer service operational performance. We credit those results to comprehensive and effective training, a well-planned transition, and adequate post go-live support.

Project reporting comprised an area of performance that we found particularly lacking and incomplete. The resulting gaps make it difficult to track costs by cause and to measure the amount by which avoidable project costs resulted from decisions or performance not in accord with good utility practice. Nevertheless, it is possible to assess the costs resulting from ineffective decisions and management possible at a global level. The most fundamental driver of cost increases came from the decision to select Systems & Software on a fixed-price basis, for a cost of $4.4 million, which eventually became $7.1 million.

This decision did not recognize the implications of the extremely low number of hours underlying the Systems & Software bid. With consultation from an outside individual lacking significant experience in CIS implementation, Unitil failed to recognize that Systems & Software could not conceivably perform the full scope of development work and provide for effective testing and project management for a small fraction of the hours (and thus the costs) proposed by leading firms. However, at project completion, the total dollars paid to Systems & Software did end up amounting to about the same as the costs proposed by two first-tier CIS bidders (one offering the CIS platform and the other serving as implementer) in 2012.

We did find that Systems & Software experienced problems, charged for change orders ordinarily considered as part of base work, and failed to manage the project effectively. However, even more effective performance would not have produced total development, testing, and project management costs less than those charged by Systems & Software, were there no other implementation costs to consider. However, Unitil found itself required to retain another firm (Grant Thornton) mid-course to move the project adequately to completion. Unitil committed initially to another $3.3 million for this consultant - - an amount that increased dramatically to $8.1 million. Back at the time of Systems & Software's selection, sounder recognition than Unitil had of the work needed to implement the system would have led to costs in the range of those offered by the other two, top-tier combinations (either by retaining one of them or working with Systems & Software to create a more appropriate work scope and costs). In the second place, Unitil hired Grant Thornton without competition. To this day, the experience of the personnel Grant Thornton provided to the project remain unclear. Moreover, Grant Thornton provided little detail explaining the many hours its consultants charged, and project cost reporting does little to close that gap. Competition for the services provided by Grant Thornton would also likely have produced a more CIS-experienced team. Unitil should also have managed Grant Thornton's costs better.

Two central project cost assessment observations result from Unitil's vendor selection and utilization. First, it unexpectedly took Systems & Software and Grant Thornton together to perform the services needed to complete the COSMOS project. Second, they accomplished this result with:

- Material gaps in Systems & Software performance
- Inherent inefficiencies from "changing horses mid-stream" to strengthen project management and testing performance and planning
- Repetition and duplication of effort by Grant Thornton of work performed by Systems & Software
- Weak management of performance and charges by Grant Thornton, who came to the project without a strong CIS implementation background.

Unitil should not have paid twice for the overlap in scope between Systems & Software and Grant Thornton or the other inefficiencies involved. We compared the combined charges of Systems & Software and Grant Thornton ($15.2 million in total) against the amounts of the other two first-tier bidding combinations. The higher of their two bids was $8.1 million - - $7.1 million less than the $15.2 million.

Failing the ability to use project documentation to assess cost growth by root cause, we consider it reasonable to begin by targeting the excess of Systems & Software plus Grant Thornton costs over the higher bid of the two other, first-tier combinations as the base measure of costs that Unitil could have avoided had it either selected one of them, or begun COSMOS after working with Systems & Software to develop a suitable project scope, cost, and schedule baseline. The gap in Systems & Software's 2012-proposed resource commitments was so clear, Unitil should have undertaken such efforts. We consider the selection of one of those firms clearly more appropriate, but cannot conclude that selecting Systems & Software after successful efforts to adjust scope and price would have been demonstrably imprudent.

Moving from our base calculation, we considered the fact that scope changes could well have affected the costs of the others as well, but not so substantially, given the allowances made in their bids and in their extensive levels of experience in implementing energy utility CISs. A 25 percent contingency added to the $8.1 million offer we used as a baseline produces an amount of about $2.0 million. We consider this an appropriate amount to add for cost risk and for addressing Unitil's focus on ensuring that pre-Go-Live activities like testing would smooth the transition to the new CIS. Note that allowing 25 percent exceeds the 20 percent contingency factor we have seen used in other CIS implementation projects. That $2.0 million reduces our base calculation of excess costs to $5 million.

Our review of other vendor contracts did not show any of them having individual cost growth that caused concern in terms of overall cost growth. Internal employee costs comprised the remaining major cost source. However, Unitil did not commit a large internal project management team, thus mitigating the impact on strictly time-based internal employee activities. Moreover, their costs for training and testing certainly contributed strongly to the smooth transition to the new CIS and MDMS. We therefore did not ultimately question the internal costs that reflect the many hours spent by employees in these activities.

In summary, reducing the excess of combined Systems & Software plus Grant Thornton costs over 125 percent of the larger of the two bids by first-tier vendor combinations leaves $5 million as the expected value by which sound performance by Unitil would have reduced implementation costs.

We do believe that the better decision would have been not to choose Systems & Software, but we cannot find selecting this vendor imprudent per se. What did fail to meet good practice, however, was for an inexperienced owner, using a CIS-inexperienced consultant to begin and continue on the project without recognizing how unrealistic Systems & Software's resource commitments were, to continue on that course for so long with problems continuing, to manage the work so loosely, and then to make a sole-source selection of a firm (also without demonstrated experience) to assist late in the project and to do so with so little detail to justify the large cost increases for its services.

Unitil may not have proven successful had it worked with Systems & Software at the outset to set a more defined and appropriate scope. It may not even have wanted to had it believed that vendor's costs likely to match or exceed those of the first tier bids. Whatever the outcome, we believe the proper comparative measure is an actual 2012 bid from a first-tier bidder, adjusted to reflect uncertainty. Finally, using the Systems & Software charges alone (without the addition of costs from Grant Thornton) is equally invalid - - there was no prospect for securing the systems ultimately delivered for the bid costs of Systems & Software.

B. Specific Conclusions

1. Unitil structured and initiated the CIS project with an insufficiently developed understanding of expected work scope and resultingly unrealistic budget expectations.

Limited definition of project scope before Systems & Software contract signing eventually produced an essentially doubling of the design, development, and testing effort, substantially delaying the project schedule to accommodate the Grant Thornton transition, additional custom coding, configuration, testing, and resolution of testing issues and code defects required for successful completion prior to Go-Live Date. It was unrealistic to expect reasonably complete design, development, testing and project management for the effective numbers of hours underlying Systems & Software's fixed-fee offer. Bids by two other combinations that Unitil evaluated as finalists made proposals essentially tripling the number of hours required. Both, unlike Systems & Software, operated as major CIS implementers in the investor-owned electric and gas utility industry. Systems & Software, by contrast, provided CIS-related services primarily in the water industry at that time.

2. Unitil's use of a consultant without substantial CIS-definition, scoping, and vendor selection experience contributed to the selection of Systems & Software without first establishing an effective scope, schedule, and budget foundation.

Unitil clearly lacked a solid understanding of project scope and work requirements as it began a search for vendors to employ. It reached out to a firm to assist it in scoping and vendor selection, but did not end up with a firm possessing reasonably broad CIS implementation experience. More significantly, the consultant that the firm provided to Unitil to help guide identification of project requirements prior to CIS and MDMS vendor selection had not done a CIS vendor selection - - as he acknowledged to Unitil before his formal engagement.

Development of the work scope for the vendor RFP confirmed a lack of understanding of the full scope of CIS implementation requirements. As a result, Unitil lacked a detailed CIS requirements baseline for use in defining and assessing the reasonableness of project schedules and budgets eventually received from RFP responders. The RFP listed some 700 functional requirements - - less than a third of the typical 2,400 provided by established CIS selection vendors. Unitil thus began the project with inadequately defined requirements, which contributed both to ill-defined and under-scoped project requirements and an unsound basis for assessing bidder responses.

Moreover, we did not find the documentation evaluating, comparing, and making a recommendation from among the responding vendors either clear or convincing. Nor do the memories of those remaining at Unitil provide useful clarity. The documentation we did see appeared to be partial, and, to the extent it pointed in any direction, it showed the selected vendor at or below average in all non-cost categories except for functional requirements. Unitil could not provide clear documentation of the vendor cost evaluation. We did not find documentation or recollection of a clear, defensible vendor evaluation supporting Systems & Software selection over offerors with much more experience in the relevant utility market.

The information that remains available demonstrates a peculiar and what should have to Unitil proved a disconcerting Systems & Software combination of high hourly rates and a low number of total hours (see the following table). The net effect was an extraordinarily low comparative cost - - notably so in comparison with offerors having far more experience in working with investor-owned electric and gas utilities in CIS development and implementation.

Implementation Services Cost Comparison

Cost Item	Systems & Software	Oracle/Deloitte	SAP/Deloitte
Total cost	$3,910,080	$8,112,568	$7,293,474
Total hours	24,438	67,668	66,988
Blended Cost per hour	$160.00	$118.89	$108.88

The Systems & Software bid proved so large an outlier from those of the other qualified offerors that it should have raised questions and resulted in a deeper analysis before selecting Systems & Software. Specifically, detailed questioning and clear justification should have been required to validate the vendor's ability to accomplish this complicated project with only a third of the effort of the two other bidders. Unitil should have considered the mismatch, as Deloitte, a very highly experienced CIS project management and system implementer, bid two comparatively scoped first tier utility industry CIS solutions. We found no documentation addressing the evaluation of this significant variance in estimated effort. Moreover, it is clear that such inquiries could not have produced a soundly based comfort in the executability of the Systems & Software offering, but rather, at most, agreement on a much clearer, more detailed and comprehensive scope, and pricing at least generally in line with those of the top-tier offerors.

We do not argue in the abstract the ability of Systems & Software to perform capably, but its claimed ability to do so for 1/3 the hours of far more experienced offerors should either have led Unitil to select one of the other two finalists, or to work carefully with Systems & Software to give the firm a more realistic grasp of needs that the other two firms, probably well better then Unitil, had from their past experience.

In any event, Unitil engaged Systems & Software on a fixed-price basis for the sum of $4.4 million for the software and project management services. It eventually paid Systems & Software a total amount of $7.1 million - - interestingly an amount in the range of the bids of the other two, first-tier bidders in the business. A more curious owner and a more experienced CIS selection consultant would clearly have undertaken significantly more work to produce a sound working basis with Systems & Software - - thus avoiding many of the gaps, barriers, and problems that Unitil had to address throughout the first years of the project. A “tight” and more comprehensive Statement of Work (SOW) with Systems & Software would have minimized the need for change orders during the course of development. To show their magnitude, Unitil approved 139 Systems & Software change orders totaling more than $2.4 million.

3. Unitil began the project and continued under it for several years without clear, consistent, or independent project governance.

Unitil did not have a governance plan setting forth defined roles and responsibilities. Such a plan is essential for large and experienced owners - - it has all the more importance for ones like Unitil. The lack of development and execution of such a plan comprised a significant management failing, and one all the more surprising to have resulted following advice from an outside consultant during the project’s first, definitional stages. Failing a more clearly established governance role and body, the Unitil Board of Directors appears to have provided the top-level oversight (independent of project leadership) that existed. According to project documentation, however, the Board reviewed and discussed the project infrequently, suggesting inconsistent independent oversight, given the lack of a high-level oversight role from below that level. The project developed clear progress delays and cost issues in its early stages. The lack of rigorous, continual outside oversight encourages such problems to persist and to grow, as they in fact did.

We did not find clear definition of Steering Committee and Stakeholder Committee responsibilities, nor does the available documentation show attentive execution of consistent roles. Incomplete documentation of their activities corroborates the lack of clarity in roles and responsibilities and suggests a weak influence on the course of project events. Moreover, participants changed with exceptional frequency and it appears that the Steering Committee stopped meeting altogether in mid-2015, at which point the Stakeholder Committee commenced meetings. Even the Stakeholder Committee meetings stopped in the fall of 2016 - - well before project go-live in July 2017.

4. No formal approach to documentation or close management of project schedule appears to have occurred for an extended time.

From pre-start justification and definition to project end, tracking and documentation failed to conform to a reasonable standard of regularity, completeness, or action-orientation. The nature of data and narrative reported, combined with duplication in status reports, led to a lack of clear and concise project status documentation. As late as October 2016, Stakeholder Committee minutes documented, "Concerns around the status report providing the level of detail to understand what is happening during the project."

The Systems & Software project manager created the CIS plan using MS Project in June 2013, with the expectation that weekly updates would follow regularly. The "final" version of the Systems & Software MS Project plan was last updated in April 2015, according to documentation management provided. Status reports indicate the first plan Grant Thornton developed was ready to be baselined (with schedule mapped out using clearly defined due dates and a final deadline) in November 2015. Management could not provide the requested MS Project copy of this plan. Interviews with project team members and Grant Thornton consultants indicated that weekly project status spreadsheets guided the management of the project. However, the weekly project status spreadsheets that Unitil provided did not display an integrated project schedule. Their use of stand-alone spreadsheet tabs for each of the primary project schedule categories did not provide an effective alternative.

Others have used schedule tools like MS Project to highlight delays and project slippage. Relying instead on high-level reporting in Excel format here sacrificed key information and analysis for identifying, measuring, and addressing gaps in resources and impact to the schedule's critical-path activities. The lack of critical path analysis that applied here obscured understanding of true schedule status, the causes of delays, the locations and magnitudes of overloads on resources, and where effective recovery action could be brought to bear. Unitil did not insist on regular communication and use of a tool, such as MS Project, to provide early warnings about schedule slippage. Even highly experienced owners and implementers use such methods to manage effectively, even though they begin projects like the one at issue here with much greater experience. The resulting failure to set clear expectations and monitor delivery of them inevitably tends to aggravate schedule loss and expand cost growth unnecessarily on projects like COSMOS.

5. Retaining and outside consultant mid-course made sense, but the sole-source selection was not a strong one, nor did it correct project gaps with efficiency.

Grant Thornton, whose project management services Unitil did not initially anticipate needing at all, began providing project management services under a contract with a value of $3.3 million. Unitil eventually paid Grant Thornton $8.1 million, as the project schedule extended 29 months following the firm's mid-2015 review. As did the Systems & Software contract, the Grant Thornton arrangement also produced a large increase over initial amounts:

- Grant Thornton by $4.8 million - - from $3.3 million to $8.1 million.
- Systems & Software by $2.7 million - - from $4.4 million to $7.1 million.

The combined payments to the two firms ($15.2 million) represent $7.1 million more than the higher of the other two finalists for similar services. It is reasonable to conclude that Unitil could not have finished the project for less than the general magnitude of bids by two other very highly experienced combinations, who represented leaders in the most relevant market. It is equally clear however, that choosing one of them, even with a reasonably significant level of cost increases to address unknowns and changes would have produced far less than the $15.2 million in combined payments to Systems & Software and Grant Thornton. Even allowing a 25 percent adder for changes and unknowns to the higher of those two other bids leaves $5 million in unexplained Systems & Software plus Grant Thornton costs.

It is that difference that we attribute to the need for disruptive, mid-course correction and the use of less experienced outside firms (both Systems & Software and to Grant Thornton) for the type of work involved.

Before retaining Grant Thornton, Unitil did not seek proposals from multiple vendors for the services involved. The selection appears to have resulted primarily from a relationship created in providing Unitil with accounting and tax services to the Unitil financial organization, headed by the Senior Vice President – Chief Financial Officer. This sole source selection came despite a lack of substantial Grant Thornton direct experience in the CIS implementation context. Unitil had, but did not even return to review the project management services bids it received under the 2012 vendor selection RFP. The Controller and Chief Accounting Officer, who assumed more leadership for the project at the time Grant Thornton was brought in, indicated a lack of knowledge that such bids even existed. The Oracle/Deloitte bid (ranked second in in the CIS Selection process) included a separate project management services bid. Deloitte had substantial experience in CIS implementation and providing large-scale project management services across many industries. Deloitte's project management services bid was half that of Grant Thornton's bid, as seen in the table below, compared with other project management services bids from the 2012 CIS RFP selection process:

Project Management Offering Price Comparison

Company	Bid/SOW Cost
2015 Sole Sourcing	
Grant Thornton	$3.3 Million
2012 Vendor RFP	
Deloitte/Oracle	$1.6 Million
CIBER/SAP	$264,000
Deloitte/SAP	$818,400

Grant Thornton's initial compensation level exceeded other bids for project management services received during the CIS selection process many times over. That gap, very large at the outset, expanded greatly over the remainder of the project. By the end of the project, Grant Thornton billed $8.1 million, $4.8 million over its initial fee basis.

6. Training was comprehensive and effective.

Unitil prepared and delivered complete and comprehensive training to end users ahead of enQuesta go-live. The training plan was co-written by Unitil staff and Grant Thornton consultants. Training benefited from an extended schedule following the decision to delay go-live until July 5th. This 3-

month period was used to finish preparing training manuals, job aids, and system and user documentation.

7. Post Go-Live support was well-planned and delivered.

Unitil prepared and delivered complete and comprehensive training to end users ahead of enQuesta go-live. Unitil's post go-live planning and management of defect resolution and staff to manage these defects kept backlog within manageable levels. Unitil went live with few defects requiring later resolution. Defects discovered internally after go-live and in response to customer inquiries and complaints were managed through Unitil's established defect resolution process. Unitil was able to correct defects without noticeable impact on customer billing or customer satisfaction.

8. Customer Experience and performance was not impacted by the deployment.

Liberty's review of Unitil's customer service performance prior to, during, and following the enQuesta go-live shows a high level of service with no apparent service degradation. While call volumes increased slightly in 2017, regulatory complaints remained low, call handling service levels exceeded goal, most bills were issued on time, and very few bills were estimated.

III. Findings

A. Summary

We present below the key findings supporting our conclusions about COSMOS project decisions, organization structures, resource planning (internal and vendor), scheduling, design, development, testing, training, conversion, and go-live. These findings address how project management organizations, resources, and activities served to:

- Define project scope, cost, quality, and schedule objectives
- Manage resource application
- Ensure effective and efficient vendor performance
- Monitor and influence schedule progress
- Control scope and change orders
- Manage costs, risks, and quality.

We offer our findings in the following categories, which comprehensively address the key aspects of COSMOS planning, development, and implementation through and in the initial phases immediately following Go-Live:

- CIS Business Case
- CIS Selection
- Grant Thornton Selection
- Governance
- Project Management
- Resource Management
- Vendor Management
- Cost Management
- Scope Control
- Change Order Management
- Schedule Management
- Risk Management
- Test Management
- Go-Live Management
- Post-Go-Live Management

Well-managed CIS implementations center around a customer-service delivery vision that includes clearly defined objectives and a full understanding of how the CIS solution will support that vision. The initial phase includes the application of a well-structured and defined set of methods for selecting the vendor or vendors who will provide the software solution and the professional and project management services associated with doing so. The development vendor's work should operate under a scope defined sufficiently to allow for a reasonably fixed price for a set of well-defined services, milestones, and deliverables.

Working with the vendor, the owner must establish a firm and final solution design that includes clear and comprehensive descriptions of business processes, pre- and post-implementation roles and organizations, and identification of associated business changes. These factors provide a baseline that first supports development of the definition and design of the system's technical components and functionality. The foundation established thereafter supports careful, complete conversion of data from legacy to new systems, for designing and executing a testing program that will validate new system functionality, and for designing and delivering the training needed to permit effective use of the new system.

Implementing and testing solution design includes:

- Business process assessment and re-engineering
- Data conversion to allow data existing in legacy systems to undergo successful processing in the new system

- Hardware and software configurations
- Go-Live acceptance criteria
- Pre-Go-Live testing to ensure satisfaction of those criteria
- Training of system users, and
- Post go-live transition plans.

Late-stage preparation for Go-Live includes assessment of the system and its user organizations and resources, user acceptance testing, a "Go/No-Go" decision to go live, migration to production, and end user training. Post-Go-Live activities focus on monitoring and resolving known issues deferred until after Go-Live and promptly detecting and responding to any further issues identified post Go-Live, in order to transition into ongoing support mode.

Effective CIS implementation depends on quantitative objectives to track performance in meeting goals for schedule, cost and quality. Additionally, management should monitor performance and progress on achieving the goals and assess whether the project has the required resources necessary to achieve the goals.

B. Management's Business Case for New CIS

A sound justification process should precede all major projects and programs. For those like Unitil's COSMOS project, the prevailing utility industry approach employs the business case analysis to justify proceeding. This approach evaluates costs, benefits, and risks of options, and offers the rationale for the solution adopted, comparing it with potential alternatives. Obsolescence drove Unitil's decision, but did not obviate the need for:

- Identifying and evaluating those options that did remain
- Carefully choosing from among them
- Documenting project
  - *Approach*
  - *Direction*
  - *Structure*
  - *Scope*
  - *Objectives*
  - *Deliverables*
  - *Budget*
  - *Schedule*
  - *Execution Risks*
  - *Organization*
  - *Needed Skills*
  - *Contributors*
  - *Resource Numbers*
  - *Systems & Tools*

Whether called a business case or something else, and whether for an optional or compelled project, documentation of effective justification, scope, and requirements provides a primary means for securing executive support and funding and for setting the parameters that will guide continuous monitoring and evaluating execution success and threats, and influencing project activities to maximize quality, cost, and schedule success.

Specific purposes that a business case serves include:

- Validating through analysis of needs, potential solutions, and their comparative costs, benefits, and risks
- Ensuring team and corporate alignment on the business problem, its solution, and the needs and challenges for executing it
- Identifying project team structure, roles, and those of the resulting system's business owner
- Formalizing budget approval requirements and methods

- Providing a baseline for assessing potential changes to scope, capabilities, cost, and schedule changes allocation if later questioned
- Providing a source, for keeping project efforts aligned with expectations and intentions, while supporting a properly controlled means for changing them.

Unitil management did not create a business case or something of similar purpose and scope before embarking on the COSMOS project. Management cited functional obsolescence of the HTE and vendor issuance of an end-of-life notice as reasons. Therefore, management developed items normally part a formal business case (*e.g.*, cost estimates, timelines, and staffing) only after project commencement. We found that more evolutionary approach problematic, as compared with the benefits that a "from the start" approach offers. The lack of documentation and the inability of those still at Unitil to fill in the gaps even partially from memory, combined with the course of the project through its first years, indicate well less than the required early definition, structure, and attention.

Our inquiries disclosed no detailed information about the development of the initial project budget. Interviews disclosed that the then-vice president of IT developed it, but we could not determine what that budget included or the structure, methods, and details of its creation.

Well-expressed and comprehensive statements of project goals provide a tangible statement of what a project like COSMOS can and should achieve. These statements comprise an important component of a business case, setting project expectations and intentions. A June 2012 senior management meeting presentation these desired outcomes:

- Future proofing
    - M&A, regulatory
- Agility: Configuration over customization
- Enhance customer experience
- Optimize operations
    - Customer Self-Service
    - Mailing costs
    - Call times & call volumes
    - Debt collections
    - General process efficiencies.

The same 2012 presentation also offered these "Keys for Success:"

- *Collaboration*
- *Capture permanent improvement*
- *Creativity*
- *Understanding other department/function impacts*
- *Building for the future/crafting the future vision*
- *Cost*
- *Participation*
- *Team contributions*
- *Meeting deadline*
- *Flexibility/willingness to change*
- *Seamless to the customer*
- *Simplicity and consistency across sites*

A subsequent, July 2013 Project Charter presented project goals and objectives in the following words:

Unitil is seeking a replacement system, or more importantly a comprehensive solution that addresses the concerns of the current CIS environment and yields significant improvements by providing a Modern Rate and Billing engine efficiently supporting:

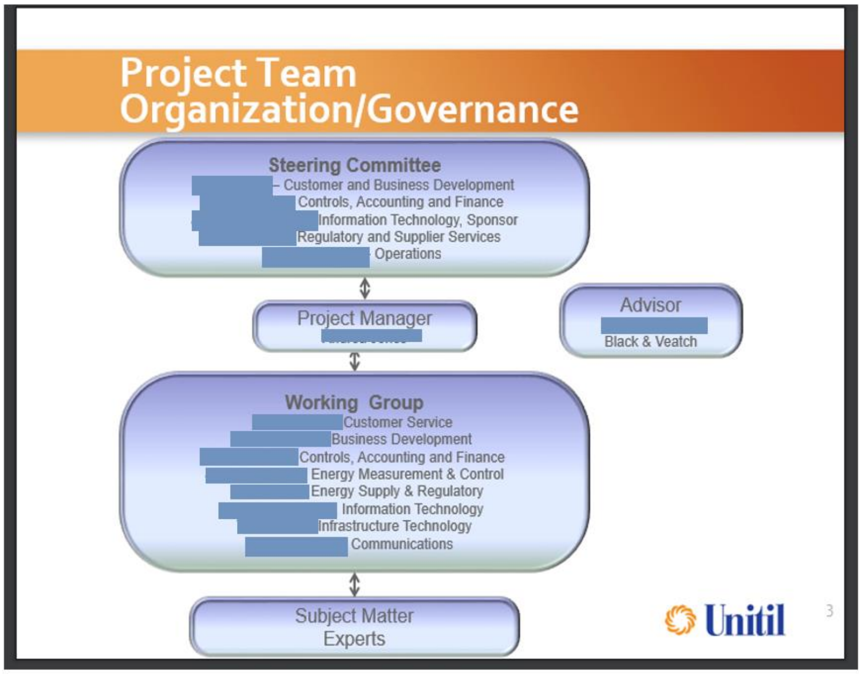
- *Deregulated markets*
- *Multi-customer aggregations (entire towns in some cases)*
- *Retail choice*
- *Purchase of Receivables legislation*
- *Customer specific contracts*
- *Various customer switching policies*
- *Net Metering*
- *Multiple jurisdictions*
    - Gas (MA, NH, ME)
    - Electric (MA, NH)
- *Decoupling*
- *Alternative Rate Structures (e.g. Time of Use)*
- *Improving controls and auditability of the entire meter to cash cycle*
- *Bringing full-range functionality commensurate with expected capabilities in contemporary systems to replace the limited functionality now in place for*
    - meter data management
    - meter asset management
    - integrated service order management initiation, tracking and closeout
- *Offering new capabilities in customer care, relationship management, business development, and advanced alternative rate offerings*
- *Providing new and requisite functionality to support the development and cultural engagement around utility best practices*
- *Providing streamlined data flows among all applications and modules*
- *Supporting customer interactions with a rich and full array of immediately available information and self-service functionality relevant to the customer to enhance their experience with Unitil*
- *Providing a modern, configurable user interface with the ability to perform self-directed ad-hoc reporting.*

The Project Charter statement of goals and objectives, developed after Implementation Kickoff, focused on functional requirements while the senior management presentation expressed desired outcomes for future proofing, agility, enhancing customer experience, and optimizing operations. Later in the implementation, project goals emphasized achieving accuracy (“balance to the penny”) and minimizing complaints to regulators (zero complaints).

C. CIS Selection

A Project Team brought together in 2011 evaluated CIS and MDMS software and services vendors. The following chart depicts this organization.

CIS Selection Project Team Organization Chart



The working group researched best practices for successful CIS projects. Some team members attended CSWeek, an annual international conference to advance utility customer service through the delivery of educational opportunities, forums for networking and sharing of innovative best practices. Guiding principles reportedly referenced included:

- Customizing versus configuration with zero modifications
- Employing third-party implementers and consultants who know CIS products
- Effecting strong governance and project management
- Regularly updating the project plan
- Strongly vetting requirements to produce a clear statement of work accompanied by a fixed-fee contract.

1. CIS Evaluation and Selection Consultant

The project team sought to secure outside expertise to assist in defining project requirements and in retaining a vendor to implement a CIS solution for Unitil. These vendor-retention services included Request for Proposal (RFP) development, bidder evaluation, and selection advice. Such CIS selection consultants provide a framework and often templates for the selection process, assist in development and completion of evaluation worksheets, conduct reference checking, and perform site visits, among other activities.

We consider the following a reasonably typical and useful expression of a qualifications statement for a CIS Selection Consultant (this one involving a gas utility), describing the required skills and experience as follows:

> *Proposers must have a proven track record with CIS selection projects within the gas utility marketplace. Specifically, Proposers must have (i) at least 10 years of experience in pre-RFP requirements gap analysis and requirements gathering, (ii) the assembly and issuance*

of RFPs, (iii) the evaluation of commercially available CIS solutions and system integrators, and (iv) the negotiation and approval of final contract(s) associated with a project with this scope in the utility industry.

Unitil's IT department was arranging in September 2011 with an information and technology firm predominantly serving government to provide assistance in COSMOS vendor selection. The firm did not appear to have direct CIS development experience but had experience with Smart Grid and smart meter work, including its integration with CISs (which is, for example, a function of an MDMS). The consultant offered by the outside firm moved to another firm (also one without extensive CIS development experience).

Unitil has stated that the firm to which this individual moved had familiarity with CIS implementations in the utility industry, making the consultant it used capable of assisting to determine project scope and key details, and to develop the vendor RFP and assist in evaluating responses to it and selecting the winner. We do not consider the firm to which he went, and from which he presumably derived support and assistance, at that time to have considerable CIS implementation or CIS vendor selection experience. Nor did the individual himself. He directly acknowledged not having performed a CIS vendor selection process. The consultant actually first delivered (in November 2011) a sample Request for Proposals and Project Plan not for the CIS, but for the MDMS, asserting relevance of MDMS functional requirements to CIS.

Unitil did not seek proposals from other vendors to provide the services at issue. Moreover, while there was a request for additional detail about the individual consultant's experience, no responsive documentation or verbal recollection about closure of that request appears to exist. We did not find the individual selected by Unitil either a specialist in CIS solution implementation or experienced in CIS vendor selection. Even more telling than the corporate and individual backgrounds came with the list of functional requirements eventually underlying the RFP that Unitil issued. It contained less than a third of the entries one might normally expect, perhaps adding color to the first offering of MDMS materials as relevant to the COSMOS CIS aspects.

The next table compares aspects of experience and content in providing CIS vendor-selection services.

Utility Industry CIS Evaluation and Selection Vendors

Criterion	Top 3 Vendors	Unitil's Consultant
Experience		
CIS software and services selection	More than 30 years	No prior CIS selection service
Comprehensive industry specific software and systems requirements	More than 30 years	No resume available
In depth CIS application experience	More than 30 years	No resume available
Clarity of Approach, Methods, Tools (to assist in CIS vendor selection)		
Templates	Templates for business case evaluation and vendor selection	Provided some templates; evaluation workbook not completed; did not include all evaluation factors

References	Structured, categorized reference checking, site visits, budgeting, and due diligence	Reference calls free form in nature
Site Visits	Structured, categorized results	Site visits free form in nature
Bid Scoping/Modification	Clear focus, analysis, documents	None documented
Bid Price Evaluation	Transparent, analytical, documented	No documentation of evaluation
Comprehensive list of functional requirements	Over 2,600 functional requirements	RFP and evaluation included approximately 700 functional requirements
Established databases for estimating CIS budget and timeline	Yes	No
Review of CIS SOW	Details include pricing by modification, interface, for example.	Limited pricing of modifications and interfaces. Functional requirements noted as “included in fixed price “or “needs further definition.”
CIS Evaluation Agreement		
Price of Engagement	$248,500	$204,793
Consultant Deliverables	28	6

2. *Evaluation and Selection of the CIS Implementer*

Unitil worked with the selection consultant to prepare an RFP soliciting proposals for implementing a new CIS solution. Gartner, whose work Unitil referenced, has for many years ranked providers of a range of applications (including utility CISs). It uses what it terms a “magic quadrant” to assess ability to deliver versus completeness of vision, as the accompanying diagram depicts.

Gartner Magic Quadrant

The RFP went to fifteen CIS and two MDMS vendors in late May 2012. Unitil received nine written proposals, providing a sound mix of two of Gartner’s CIS leaders (SAP and Oracle), Harris solutions, the parent of the vendor ultimately chosen (not rated by Gartner) and lesser-known solutions. Two firms made offerings using one of the lead platforms (Oracle) and three did so using another lead platform (SAP).

Unitil disqualified one vendor for failing to meet minimum requirements. Unitil, working with its selection consultant, narrowed the field to three candidates (Oracle/Deloitte, SAP/Deloitte, and Systems & Software). After preliminary evaluations, Unitil and its selection consultant then participated in site demonstrations, follow up meetings, conference calls, and reference checking with and involving the remaining vendor candidates.

Unitil management did not complete an evaluation sheet accounting for all the factors deemed relevant. Its consultant, however, evaluated the eight remaining proposals in tabular form, with Systems & Software scoring third, including consideration of comparative costs. Like Systems & Software, the top finisher was a non-top-tier firm (Cayenta) that offered comparatively very low costs. A top-tier bidder (SAP/Deloitte) also finished ahead of Systems & Software despite having very much higher costs.

Weighting of comparative costs generally results from a transparent arithmetic calculation of some sort. We could not derive that calculation here, nor could Unitil explain it. In any event, it is clear that the evaluation ranked Systems & Software even lower than third when considering all non-cost factors together. The next table shows where its offering ranked in those categories - - average or below in all other categories, except Functional Requirements. It is curious to find so high a comparative ranking in this last category, given its lack of investor-owned electric/gas utility experience compared with the first-tier offerings and the project-long challenges Systems & Software had in satisfying Unitil's functional requirements.

Comparative Systems & Software Offering Rankings

Criterion	Rank	vs. Best	vs. Average	vs. Median
Functional Requirements	2	99.2%	104.4%	102.7%
Technical Requirements	4	90.9%	100.0%	100.0%
Quality of Proposal	4	60.0%	82.8%	100.0%
Bidder Quals & Experience	6	67.6%	87.2%	83.6%
Project Management	4	67.4%	88.3%	100.0%
Roadmap	6	86.7%	95.9%	89.7%

Its unexceptional ratings in other areas contrasted with a very low offered cost as compared with the top-tier offerings. Systems & Software bid a peculiar combination of high hourly rates and a low number of total hours. The net effect was an extraordinarily low comparative cost - - providing clear indication of the lack of a common understanding of the expected services and deliverables. The next table summarizes these cost-affecting parameters. We created it using a blended rate per hour calculated by applying the hours and implementation service costs of the bidders shown.

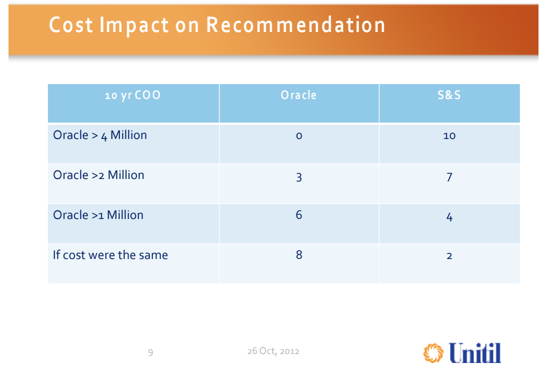
Implementation Services Cost Comparison

	Systems & Software	Oracle/Deloitte	SAP/Deloitte
Total cost	$3,910,080	$8,112,568	$7,293,474
Total hours	24,438	67,668	66,988
Blended Cost per hour	$160.00	$118.89	$108.88

An effective selection process requires sound evaluation of the full scope of services and deliverables offered, with a plan and risk analysis for addressing services not included in particular offerings. Here, the Systems & Software bid proved so large an outlier as to raise substantial questions that required deeper analysis of the very low hours proposed by Systems & Software.

We found the top-tier offerings in line, with the second-place finalist (Oracle/Deloitte) proposing nearly three times the hours of Systems & Software. Unitil should have considered the mismatch, coming from first-tier, very highly experienced providers in the investor-owned utility business, material enough to warrant further investigation before proceeding with the Systems & Software offering as made.

A Steering Committee meeting in November 2012 considered the recommendation to select the offering of Systems & Software. The evaluation considered the SAP offering the least attractive, given perceived complexity of the product. With Oracle/Deloitte and Systems & Software thus remaining, the recommendation documentation did not provide a final evaluation sheet. Unitil's selection consultant presented the accompanying chart. It appears to recommend Systems & Software based on the variation in cost of the Systems & Software bid as compared to the Oracle bid. However, we could not determine its calculation basis, nor could anyone remaining at Unitil explain its formulation or intended contribution.


Cost Impact on Recommendation

10 yr COO	Oracle	S&S
Oracle > 4 Million	0	10
Oracle >2 Million	3	7
Oracle >1 Million	6	4
If cost were the same	8	2

9 26 Oct, 2012 Unitil

The next table shows Unitil's reported decision criteria forming the basis for the recommendation and summary comparisons between Oracle/Deloitte and Systems & Software.

Recommendation Decision Criteria

Criteria	Oracle	S&S
Rates	Best rate module for administering difficult and complex rates	Demonstrated can develop what is needed
Third Party	More mature/Large deregulation market experience	• Gas only 3rd party experience • Demonstrated can develop what is needed
CSR Interface	Not as intuitive	• CSR preference – user friendly • Best customer experience
Customer Self Service (Web & Mobile)	• Requires future version(s) • Lagging in customer facing functionality	• Advanced customer facing functions • CSS capability includes chat and SMS
Culture	• Difficult communication through sales process • Poor Listeners, want to "manage"	• Very responsive through sales process • Better Listeners, engaged • More comfortable cultural fit
Reporting	Better business analytics	Cognos – Good, but more complex
Roadmap	• Industry leader in rates • Enhance customer interaction functionality	• Social Media, Rich Customer Functionality • Enhanced scalability
Enhancements & Upgrades Model	• Unitil developed (internal resources) • Core changes on Oracle's upgrade schedule, not Unitil's	• Vendor (external resources) • Smaller more nimble - responding to Unitil changes

The recommendation noted the ability to use Systems & Software for ***customization***, rather than the industry trend of ***configuration*** without core code development. The customization approach relies on writing new code (*e.g.*, programs, class files, scripts) in the software to meet user-specific requirements. Configuration instead uses application-embedded tools to tailor capabilities to specific requirements without the need for writing code. Customization requires greater effort and more risk, given the need for programmers to work outside the application. Custom code has a greater tendency to lose functionality following application upgrades. Configuration has become favored in large part because it works from within the application. It therefore requires less effort and produces less risk by providing in-application tools to make changes in the manner expressly intended by application design.

The evaluation team recognized that Systems & Software served in the public sector and primarily at water utilities. The team learned that SEMCO, an investor-owned natural gas distribution utility serving 430,000 customers in Michigan and Alaska, had used the Systems & Software solution to implement a new CIS. A site visit to SEMCO produced the observations shown in the table below.

SEMCO Site Visit Notes	
Pros	Cons
• Very responsive to regulatory changes - - will respond to "showstopper" immediately • "80% spot on" identifying requirements in first round • Collections experienced most improvements - - ultimately reduced staff by 5 or 6 • On-screen icon alerts that customer registered account online • Payment by phone or web will generate e-mail confirmation number to customer • Representative with company old and new system took six months to get comfortable with system. • Billing edit criteria screens very flexible - - many options to pull exceptions for daily work • Edit exceptions went way down after a modification including using the degree day for consumption parameter calculations	• Can only process payments with future if made via the web • No CSR date/time stamp unless work order issued to create activity • Missing three core criteria areas (Rate engine, 3rd Party Billing and Net metering); will need development of modification; will require CIS team to drive development and testing; this approach creates risks • "Recreating the wheel" - - "Is this where we want to spend our time and resources?" • May end up with something that looks and functions like existing system, with some improvements. If so, better to work with H T E to improve the SunGard system? • "We don't know what we don't know." Design may neglect critical process or future requirements - - could be costly mistakes. • Can system keep pace with "ever increasing regulations?" Is S&S keeping up with the industry changes or relying on Unitil to drive the future regulatory requirements and system improvements?

The cons appear to us to outweigh the pros materially. Moreover, they raise fundamental questions about the application of the Systems & Software offering to the needs of Unitil as an electric and gas utility. The CIS Replacement Recommendation to Senior Management contained recommendations to mitigate risk. The next table identifies Systems & Software risks, mitigation, and provides our observations about management's application of them.

Systems & Software Risk Mitigation Strategy

Risk	Mitigation	Liberty Observations
Vendor development more extensive than estimated, affecting implementation schedule	Perform Technical Review – (Completed) and define financial penalties for missed delivery dates	Financial penalties were initially established but later waived.
Premature end-of-life for enQuesta product	Create financial obligations from vendor for an extended period	Contract included an escrow section
Regulatory changes requiring product enhancements	Negotiate cost ceiling or sharing or other protections	Protections not negotiated; S&S received $160 firm rates for change orders.
Overall project break-down despite assurances of success	Milestone-based, performance payment plan with recovery options for major failures to perform	Milestone payment plan included in SOW, but later changed to flat payment per month - - not tied to performance

3. Statement of Work

The process of estimating project costs by the leading CIS implementation providers has become increasingly accurate within the industry, therefore eliminating much of the need for change orders to produce the functionality sought by Unitil. A sound, comprehensive, detailed, and clear SOW forms a key to that elimination. After closing in on a preferred vendor, selection consultants typically guide the due diligence needed to examine the details of the vendor solution, confirm solution scope adequacy, and tailor the SOW accordingly. Typically, this multi-day detailed review of the vendor product takes place in workshops with the vendor, using the utility's detailed requirements, scripts and other information as guides.

This review often results in the identification of required product modifications, interfaces, conversion items, configuration items, business process work arounds, and related additions, deletion, alterations, and clarifications. The vendor then uses a hopefully detailed list of agreed upon changes to update its pricing. The company then reviews the updated pricing document, with pricing agreement using a clearly changed SOW.

We requested all Systems & Software cost sheets; Unitil provided only the bid costs, despite the fact that the final contract reflects an increase of approximately $63,000. Unitil's scope confirmation process did not materially change project scope from that requested in the RFP. Only two modifications and one system interface were added to the Systems & Software SOW.

The Systems & Software SOW defines modifications and interfaces as follows:

> *"Modification" shall be defined as custom code that is inserted into the standard system or code that is extended from the standard system in the form of interfaces, API's, etc. All modifications developed for Unitil will be rolled into the base system at the next major release. "Interface" is the passing of data between two separate and distinct systems; can be accomplished via real time or in batch mode.*

The City of Anaheim employed Systems & Software in a similar capacity in roughly the same time frame. Unitil's project team considered the City a comparable client for use in comparing lessons learned in addressing Systems & Software work changes and go-live circumstances and needs, using the City's experience in making recommendations to the Steering Committee. The next table compares the City's and Unitil's SOW.

Comparison of S&S SOW for Unitil vs. City of Anaheim

SOW Additional Costs	Unitil	City
Modification number	2	25
Modification cost	$61,400	$144, 642
Effective $/Modification	$30,700	$5,786
Interface number	1	17
Interface costs	$6,400	$126, 900
Effective $/Interface	$6,400	$7,465
Cost Standard reports & Cognos BI	$12,800	Included

The City established a fixed price SOW with Systems & Software for a broader range of modifications and interfaces than did Unitil. The City SOW's larger number of modifications and interfaces produced a more realistic cost for services and fewer change orders. In contrast, Unitil's SOW fees included minimal numbers of modifications and interfaces, which ultimately contributed significantly to the $2.4 million in change order costs. Unitil's and its CIS selection consultant's lack of experience resulted in a project SOW that was under-scoped and under-budgeted.

A clear example shows in the vendor evaluation documents. Numerous evaluation notes indicated Systems & Software could not accommodate the complexity required to accommodate utility-rates requirements. Despite that fact, we did not find documentation addressing how the Systems & Software undertaking conformed to the need to develop custom modifications that would support Unitil's customer rate and billing requirements, calculations, and support.

D. Grant Thornton Selection

In mid-2015, Unitil decided that the needs of the COSMOS project exceeded the capability of the resources it was bringing to bear. Up until that point, Systems & Software was managing the project working with a Unitil project manager. Unitil retained Grant Thornton to expand the project's capabilities, explained as follows at the August 2015 Steering Committee meetings:

> *Based on the information available to management at that time, the Company decided that additional support was necessary to match the complexity of the project and enable the current resources (internal and external to Unitil) to focus their efforts on specific areas of the project within their respective areas of expertise.*

Grant Thornton provided both project management and testing-related services. Utilities implementing large projects, such as a CIS, but without sufficient internal project management resources contract with an outside firm to provide such services. In this instance, as detailed in the Grant Thornton SOW, project management services were defined as assisting Unitil with certain activities including CIS and MDMS implementation, project management, program management support, work stream support, quality review, oversight and management of testing.

Management justified retaining Grant Thornton on a sole-source selection using the following criteria:

Grant Thornton Engagement Criteria

Criterion	Liberty Observations
Familiarity with Unitil resulting in a "low" learning curve and the ability to contribute without significant project delay	Grant Thornton had provided Unitil tax services, tax audits, and consulting services related to risk and internal control; no documentation evidenced Grant Thornton work with CIS or IT projects
Ability to provide the resources who had extensive CIS and/or systems implementation experience	No documentation supports CIS or other systems implementation experience No resumes were reviewed to determine experience of personnel providing project management and testing services
Management's knowledge that Grant Thornton's fees for professional services were reasonable as compared to other professional services firms	Unitil used bids for integrated audit services, not CIS work, from 2014

The Systems & Software contract (see *Section C.3* above) included project management services. Management stated a desire to permit Systems & Software to focus on the software implementation, instead of managing the project, even though it made no adjustment to Systems & Software compensation for reducing its project management undertaking.

Customary practice would call for more than management's sole-source retention by a senior Unitil executive, particularly of a firm without substantial experience in project management services in the CIS implementation context. We found no documentation justifying the decision or explaining the lack of a more competitive procurement process.

The 2012 RFP under which Unitil selected Systems & Software produced some discrete project management services quotations. The senior executive who selected Grant Thornton said he did not know of them. Oracle/Deloitte, who finished second in the CIS Selection process had presented a separate project management services bid. Deloitte has substantial CIS implementation experience and is experienced in providing large-scale project management services across many industries. The next table compares other project management services quotations under the 2012 RFP process.

Comparison of Management Services Cost Quotations

Entity	Bid/SOW Cost
Grant Thornton	$3.3 Million
Deloitte/Oracle	$1.6 Million
CIBER/SAP	$264,000
Deloitte/SAP	$818,400

By the end of the project, Grant Thornton billed $4.8 million over its initial compensation amount, producing a total of $8.1 million in payments from Unitil.

E. Governance

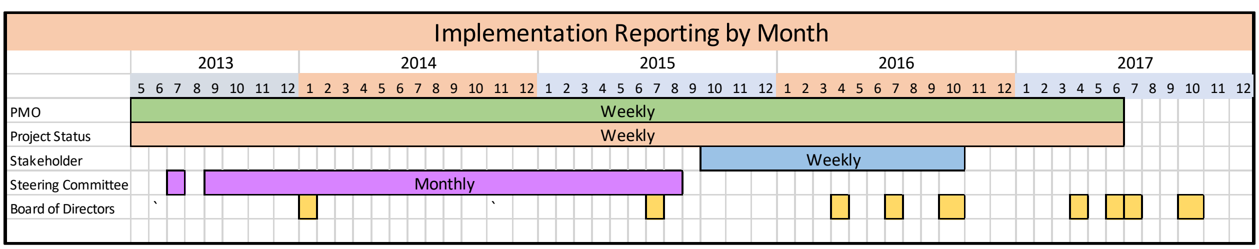
Project governance comprises a project's strategic management and governance functions and the decision-making layers responsible for providing project oversight and managing project direction, risks, budget, schedule and approach. A suitably layered project governance structure and resources provide a timely and comprehensive basis for securing senior level guidance and support. Governance involves organizations and measures that include oversight committees, steering committees, technical committees, project status reports, and required approvals. The oversight layers should consist of senior executives not directly responsible for or assigned to the project, thus bringing an arms-length, objective perspective to the project and seasoned executive input, advice and guidance to support the project sponsors. The decision-making layers should be responsible for providing day-to-day project oversight and managing project direction, risks, budget, schedule and approach.

Unitil did not have a governance plan with defined roles and responsibilities.

1. *Project Oversight*

Projects of this type generally employ an executive champion who serves as a sponsor and mentor for the project team. This executive role has particular value when, as often occurs, support from a particular department or manager has become problematic. The Vice President – Information Technology served as the initial Project Sponsor, as documented in the Communication Plan, Project Kick-Off, Project Charter, and status reports. The same individual was listed as having a project leadership role (Project Director). This position also showed as part of the Steering Committee, producing a less than an arm's-length separation from the project. Unitil's Controller later took this role, but we found no mention of the change or its reasons in status reports or presentations. Interviews confirmed that the Project Sponsor had asked the Controller to step into a leadership role on the project at the 2015 mid-project review.

The Board of Directors appears to have been the source of high-level oversight. According to project documentation, the Board reviewed and discussed the project infrequently, as seen in the chart below, suggesting intermittent, inconsistent independent oversight of the project.



It is also not evident that the Steering Committee and Stakeholder Committee roles had clear definition or consistent execution. We found documentation of their activities incomplete. Participants changed with exceptional frequency, and it appears that the Steering Committee stopped meeting in mid-2015, at which point the Stakeholder Committee commenced its meetings. However, the Stakeholder Committee stopped meeting in the fall of 2016, well before project Go-Live in July 2017.

2. *Project Quality Assurance*

Utilities implementing projects of this type, size, complexity, and risk typically create an independent quality assurance function to provide regularly unbiased evaluations of progress, problems, and risks. This outside function provides a direct, independent line of communication with senior leadership not beholden to project management. Such a quality assurance function does not displace the observations and insights of those within the project organization, but rather supplements them, to ensure that problems, gaps, delays, and barriers are identified and mitigated as quickly and effectively as possible.

The Stakeholder minutes indicated a non-project Business Owner was not satisfied that the level of project communication provided sufficient information about the project. The Controller indicated she should meet with the Grant Thornton lead for the workstream involved. Stakeholder oversight depends on information comprehensively, commonly, and transparently provided to all members on a common basis.

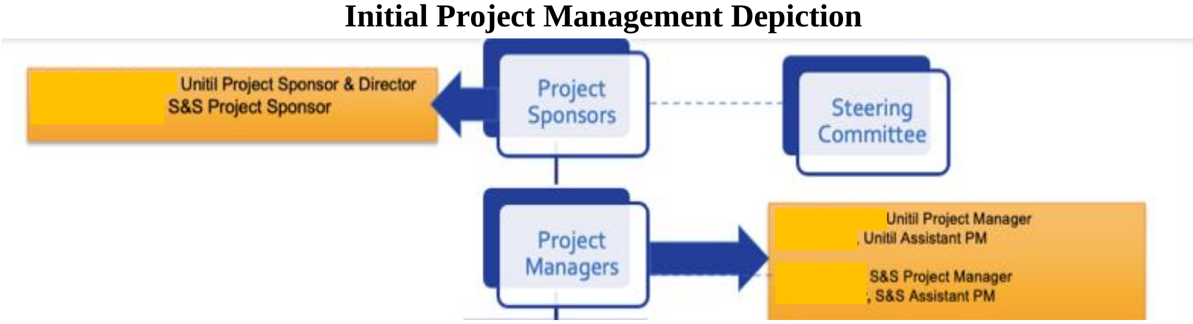
Grant Thornton's scope included the provision of quality management services. However, our review did not identify documentation of Grant Thornton quality assurance reviews. Management statements at interviews indicated that Grant Thornton did so, but we found the documentation presented limited to a few pages in Steering Committee reports at mid project review and at Go-Live. We did not find evidence that it carried out this role in a regular, comprehensive, structured, and appropriately documented manner. Moreover, with a PMO and testing role, Grant Thornton did not have a status that ensured a perspective independent of project management.

3. *Project Management*

The principle of "unity of command" comprises a best practice for project management. It means that each individual resource (employee, vendor, or contractor) should receive direction from one manager and remain answerable to that manager. A lack of unity that leads to multiple sources of assigning tasks and responsibilities inevitably tends to produce confusion and conflicts affecting cost, schedule, and quality. A project can operate under the direction of more than one "project manager." This approach requires clear roles and responsibilities that do not overlap, and it also requires a resource above them sufficiently engaged in project details to resolve potential confusion or conflict, and to ensure a vision that recognizes the need to harmonize their efforts.

The COSMOS project initially had two project managers, one from Systems & Software and one from Unitil. The next chart shows a simplification of the organization approach to project management presented at the Project Kickoff.

Initial Project Management Depiction



The Systems & Software SOW defines the following project management roles.

Description of Project Roles

Title	Role Description
Project Sponsor	• Secures spending authority and resources for the project. • Acts as a vocal and visible champion, legitimizes the project's goals and objectives. • Keeps abreast of major project activities. • Provides support for the Project Director and Project Manager.
Project Director *(note: this individual was also the Project Sponsor)*	• Provides a single point of accountability to deliver the project in accordance with the project commitments. • Has full project authority, within the limits of the established budget and company operating policies, to manage and direct assigned project resources and make decisions regarding the project direction. • Establishes the project resource assignments and ensures that the project is properly managed and staffed. • Chairs and participates in Steering Committee meetings and decisions. • As needed, participate in project planning (high level) and the development of the Project Plan. • Provides as needed support for the Project Manager. • As needed, assists with major issues, problems, and policy conflicts; removes obstacles. • Approves scope changes; signs off on major deliverables; and signs off on approvals to proceed to each succeeding project phase.
Unitil Project Manager	• Day-to-day management of the project and project teams. • Day-to-day management of the vendor(s). • Lead risk assessments and manage the identification and tracking processes. • Oversight/update of the project risk/issue/defect logs and make recommendations as needed. • Manage the project contracts to ensure vendor compliance. • Oversee, track, inspect, and manage the vendor project deliverables. • Development of a weekly report that outlines the status of the project. • Present reports to the Steering Committee on a bi-monthly basis. • Provide project improvement recommendations on a monthly basis. • From time to time support the Unitil with issues that may be escalated between the Vendor and the Unitil. Offer opinion regarding the issues root cause and the responsible party to correct the issue. • Day-to-day management of the detailed project schedule.
S&S Project Manager	• The Project Manager will be responsible for managing the implementation of enQuesta. The Project Manager will work closely with Unitil's Project Manager to ensure that the project is completed on time.

Other Systems & Software SOW content further defines project roles and responsibilities. Systems & Software had responsibility for managing the project on behalf of Unitil. Systems & Software had responsibility for maintaining the schedule using MS Project as the tool. Each of the two project managers had responsibility for weekly and monthly status reports, weekly team meetings, and the monthly Steering Committee presentations. Each project manager had various responsibilities (some overlapping), regarding risk, project schedule, deliverable acceptance, and direction of team members.

The Systems & Software SOW required both Unitil and Systems & Software to have a dedicated Project Manager. However, status reports indicate both Unitil and Systems & Software project managers also had substantial other responsibilities that prevented deep engagement in project details on a real-time basis.

The project referenced setting up a PMO in the Project Charter, responsible for managing and tracking the progress of the project as reported through weekly PMO status reports. However, the PMO structure itself was not defined as such in any of the organization charts provided as project documentation until mid-2015, when Grant Thornton was contracted to provide project management and other services for COSMOS.

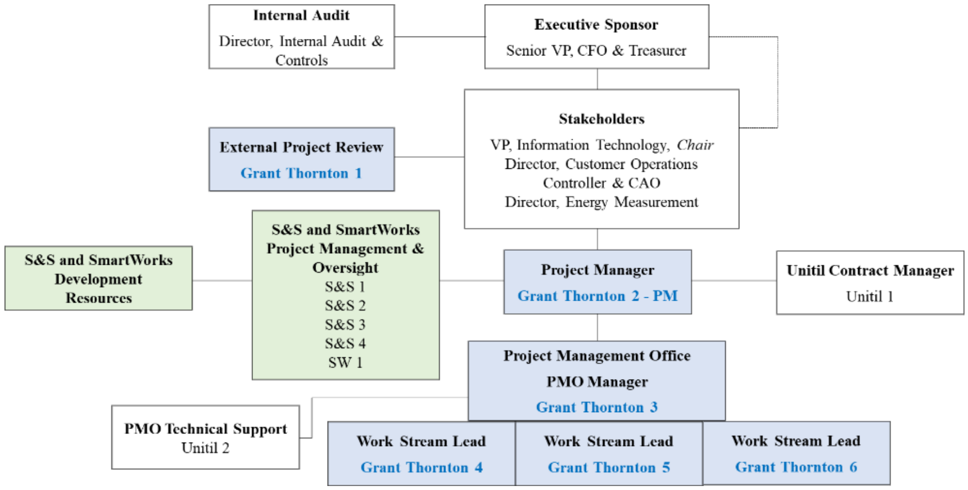
Use of a structured PMO in the utility industry elevates the importance and contribution of project management. It recognizes the value in creating a staff specializing in project management processes, techniques, and thinking. These offices standardize processes and tools and assemble forms of expertise focusing on the management of project activities. They typically bring a strengthened form of project management to a wide range of project types and sizes. Not all utilities formalize them to the same extent or use them across the same breadth of activities. Moreover, even the largest utilities contract out project management services on complex or “one-off” projects.

For COSMOS, per the Grant Thornton SOW, its services were defined as assisting Unitil with certain activities including CIS and MDMS implementation, project management, program management support, work stream support, quality review, oversight and management of testing.

The number of project managers expanded with the addition of Grant Thornton personnel to the project managers for Systems & Software and Unitil. That addition was not accompanied by a documented project description of the Grant Thornton project management role or about any changes in the project management roles of Systems & Software and Unitil. The Systems & Software SOW remained the most current documentation. However, an organization chart came following the Grant Thornton mid project review. This chart also identified a changed project sponsor, again without documentation to support that change. The chart shows a Grant Thornton individual designated “Project Manager” with persons designated as project managers explicitly for Systems & Software and Unitil reporting to him and a Project Management Office (PMO), headed by a four Grant Thornton individuals (a PMO Manager and three workstream managers reporting to him) reported to the Grant Thornton Project Manager.

This change following Grant Thornton’s 2015 arrival appears to have unified project management responsibility in a way that did not exist at project inception. There was no individual between the Grant Thornton Project Manager and the Stakeholders, as compared with a box showing joint (Systems & Software and Unitil) project managers and joint project sponsors above them.

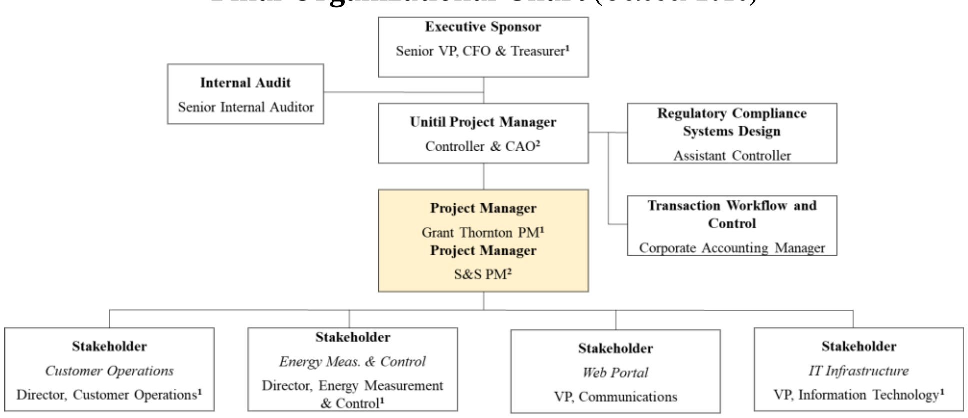
Organizational Chart After Mid-Project Review



External resources are shown in the two shaded boxes (green for Systems & Software, blue for Grant Thornton).

However, in October 2016, the final organization chart reinserts the VP Controller as a Unitil Project Manager to whom reported Grant Thornton and Systems & Software project managers shown in a single box. The placement of the Unitil project manager above the other two does nominally indicate unity of command but begs the question of removal from Grant Thornton in that role and moving the Systems & Software project manager to an apparently lateral level of authority rather than subservience to the Grant Thornton project manager. We could not confirm the reason for the change. Moreover, our review of project reporting and interviews support a conclusion that Unitil did not maintain consistently through the project a single source of project management responsibility and accountability at the day-to-day, dedicated level.

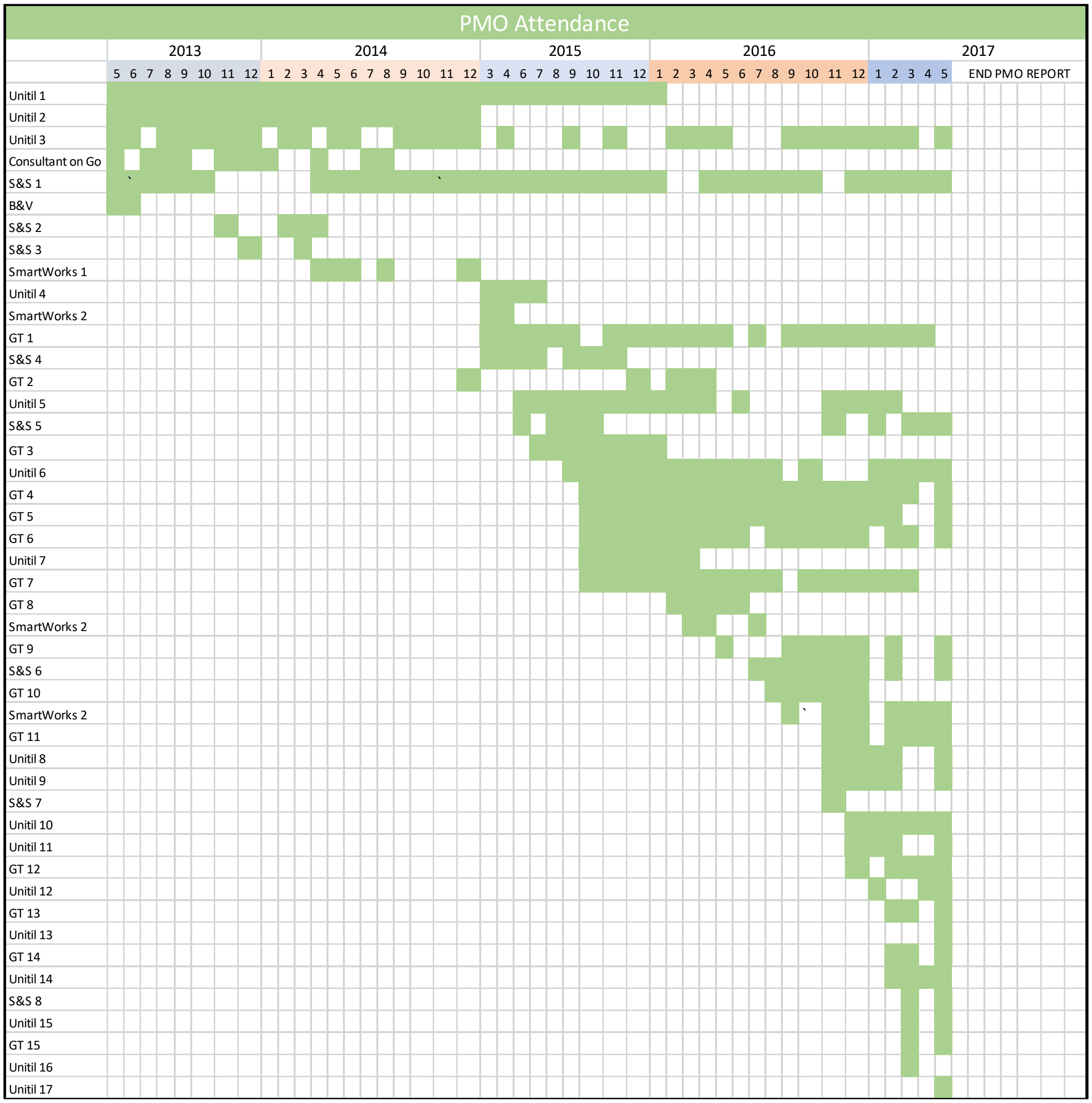
Final Organizational Chart (October 2016)



Note 1 designates personnel from the previous chart who maintained the same role, while note 2 designates personnel who are shown in the previous chart and had a change in role. External resources are shown in the yellow shaded box.

The PMO held weekly meetings and each week produced a PMO report. Using these reports, in months they were available, Liberty compiled the chart below to indicate turnover and lack of continuity at these meetings. Only two PMO members attended from beginning to end. The amount of knowledge transfer provided with each change was not documented. A large number of Grant Thornton personnel cycled in and out of the PMO during its tenure on the project.

PMO Meeting Summary



We did not find documentation addressing the performance of the Grant Thornton PMO. Unitil personnel we interviewed stated that Grant Thornton provided feedback orally. Following Go-Live, the COSMOS project organization completed formal hand-off to the Business Process Managers responsible for using the systems on October 6, 2017. Grant Thornton continued to bill the project through the end of 2017. We could not find documentation addressing the PMO roles and responsibilities from July 2017 to year-end 2017.

4. *Status Reporting*

High quality and consistent project reporting plays a central role in effectively managing large, complex projects - - in two particularly critical ways. First, it permits project management to track and evaluate progress and compare it to the current plan, expectations, and metrics. Significant projects tend to evolve over time as they face changing external circumstances and internally driven challenges. Current, high-quality, comprehensive, and issue-focused reporting allows project management to track progress using objective dimensions, assess changes, identify risks, and create and monitor the effectiveness of mitigation measures. In so doing, such reporting also provides a record of key decisions made, the course of cost, schedule, and quality progress, actions taken, and their level of success. Well-run utilities understand their need to demonstrate the prudence of large investments that customer rates will recover, along with the importance of such documentation in making decisions and actions transparent and understandable.

Second, good reporting informs top leadership and other key stakeholders of project progress and serves to keep them actively involved in the project. The information provided should contain the details necessary to allow stakeholders, given their role and level of management, to provide timely input and observations, make well-informed decisions about any needed changes, and in general have comfort that they know what they need to maintain adequate overall project oversight.

As we found with governance, the level, quality, and consistency of reporting varied over the course of the project, at times and in ways not conforming to expected practice. The Business Process Analysis phase defined and communicated a detailed project plan and charter. However, we did not find initial status reporting comprehensive, clear, concise, and (most importantly) actionable. It appears the same audience received multiple status reports. Not all reports were shared across all the parties represented in project management, resulting in a diminution of transparency. The Systems & Software SOW presented a variety of templates for status reporting, but we did not find them routinely used.

Grant Thornton’s assumption of PMO responsibility brought significant improvement in reporting quality. However, we still did not observe the use of Key Performance Indicators (KPIs) which the industry typically uses to track progress. Moreover, we did not observe regular or consistent evaluations of progress against the new project plan delivered in December 2016. Robust reporting of risks or mitigation strategies also varied in the status reports, lacking continuity from one report to the next.

An October 2016 Stakeholder Meeting discussed concern about whether status reporting was providing the level of detail needed to understand project status, issues, and actions. Grant Thornton had already been onboard for a year or so in project management, giving the stakeholders time to identify such concerns and for Grant Thornton to address them. It would be natural to expect that Grant Thornton would have placed a high priority on learning about and responding early to the concerns of those exercising off-project oversight roles.

Overall, we found from pre-project business case components to the end of the project a lack of reasonably expected consistency, breadth and depth, clarity, and actionability of documented project tracking, analysis, and corrective action planning, execution, and effectiveness monitoring.

Our concern lies not so much in volume, but more in clarity and conciseness in timely identification and analysis of project status information and corrective action needs.

5. Resource Management

Managing staffing effectively on a project like COSMOS requires ensuring that the right people in the right numbers with the right skills and tools perform the right tasks at the right time, ably, and efficiently. Successful outcomes require effective staff management. Unitil displayed material gaps in efforts to staff the project appropriately.

Projects like COSMOS require significant numbers of experienced resources. One common way of assessing the quality of vendor and consultant experience is to question the extent to which key staff members that have worked on projects of similar size and complexity and then to ensure their actual engagement as outlined. Systems & Software offered resumes in their proposal but did not assign many of them to the Unitil project. We had difficulty in assessing the background and experience of the Grant Thornton resources as well. Seeking to validate management's statements that Grant Thornton team members had CIS experience, our data request for resumes produced this response:

> *Third-party professional services firms were expected to assign qualified individuals to the project. The experience of third-party personnel was discussed; however, Unitil does not have the resumes for third-party personnel (e.g., Systems and Software, Grant Thornton) who held roles as Project Managers and/or Project Leads.*

The best we can make of this response is that Grant Thornton's resources were experienced enough because they were expected to be. The lack of availability of those resumes now calls into question the degree to which Unitil ever examined closely the backgrounds they "expected" to get.

During the CIS implementation, Systems & Software was expected to staff the project with team members who had skills that aligned with their role on the project. With resume documentation not available, it is not known if some of the delays by Systems & Software were the result of a lack of skills for the role they were asked to do. Systems & Software also had a major leadership organizational change at a time when Unitil was pressing it to find a solution to continuous delays. Unitil reported that initially the leadership changes were positive. However, within a few months delays in deliverables returned.

Unitil's internal project managers and leads also did not have experience with a project of this type, size, or complexity. Taken alone, that fact might not have been of singular importance, but it emphasized the need for due diligence regarding the experience levels and skills of Systems & Software and Grant Thornton. Unitil reassigned its original project manager after Grant Thornton arrived. No documentation supports that change and interview responses seeking such support did not produce clear responses.

Typical CIS projects involve an auditing-type activity that reviews mock conversions and ensures that financial and non-financial controls and targets are met. Many CIS projects use a project accountant to provide financial reporting independent of the project team. Unitil instead staffed the project teams and governance largely with employees from its accounting and finance departments or by Grant Thornton personnel. The CIS process owner, VP External Affairs and

Customer Relations, engaged early in the project and not again until right before Go-Live. This executive's lack of regular engagement between these two points caused a knowledge and experience gap that Customer Service staff who work with CIS processes daily could have provided the project team. Post-project feedback and lessons learned documentation supports the existence of this gap.

Comments from some status reports indicate the existence of resource constraints.

> *There is a resourcing constraint across all Functional Areas as we will be creating integration test scripts as we continue to work through Functional Testing. In most cases, the same resources are also responsible for testing Letters/Notices, Reports and Interfaces as well as core enQuesta functionality and Regression testing. Based upon the development/delivery schedule for Reports & Interfaces, and the completion of Regression testing, the timing of integration test script creation overlaps with testing.*

However, we could not conclude that lingering unavailability of project resources drove extension of the schedule. In Stakeholder meeting minutes identifying resource constraints, we saw references to Grant Thornton's assignment of one of its consultants to fill the position. Thus, the impact of internal resource limitations came in the form of the incremental costs of using outside consulting resources.

F. Vendor Management

Effective contract management begins with creating a sound definition of the professional services to be acquired, including clearly defined deliverables, accountabilities and quality standards, and proceeds to incorporate effective processes for measuring and reporting performance to support efforts to ensure the cost, time, and quality effectiveness of those services.

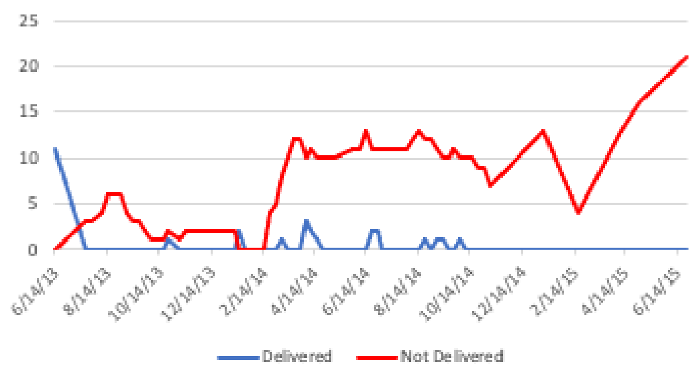
The initial Systems & Software SOW included a tight payment-by-deliverable fixed fee contract. That approach was nominally functional, but soon undercut because the Statement of Work failed to address sufficiently the full scope of requirements for the project. Consequently, major additional work requirements contributed to transforming the Systems & Software payment schedule. The change replaced payment after completion of key deliverables to monthly payments not tied to deliverables. A change order was created at the time of the extension and $595,000 was added to S&S fees, with the money remaining in the contract spread equally across the project's estimated remaining months.

Our inquiries did not produce regular reports or logs detailing deliverable acceptance issues or, as a result, status, quality, and consequences for the Systems & Software contract. Management stated that project status reports comprised the only source of tracking deliverable status. The Milestone (a group of deliverables) Acceptance forms were provided, and any detail was stored in SharePoint. See section *J. Risk Management* for information about SharePoint access.

Effective project management requires managing vendors and contractors to schedule, like other resources - - identifying problems, and developing, executing, and tracking mitigation plans to address any delays. Management has stated that Unitil actively monitored and tracked all aspects of the CIS implementation project. However, we did not find documentation indicating efforts to subject Systems & Software's performance as the project implementer to formal written analysis or evaluation by Unitil. To the extent that management did develop concerns with Systems & Software's performance, they are described minimally in Stakeholder status reporting (see Stakeholder Meeting Summary below). Clearly, those concerns did arise, as evidenced by the 2015 retention of Grant Thornton to assess the project and then to assume responsibility for project management.

PMO status reports show Systems & Software missing deliverable dates as early as September 2013. We did not find nominal documentation of missed deliverables in the PMO report accompanied by analysis of materiality, root causes, threats created, or mitigation plans or actions intended. The June 2015 report, the last status of its kind produced, listed 21 late Systems & Software deliverables. The next graph shows the fall in deliverables made and the increase in those late through June 2015.

Scheduled and Actual Deliverables (through June 2015)



Stakeholder meeting minutes do note Systems & Software's performance and contract issues in the months after the mid-2015 period reflected in the preceding graph. A September 2016 letter from Unitil's president to Systems & Software's president provides some specific documentation about these issues. It came well after the issues with Systems & Software were first identified and documented by the Stakeholder Meeting minutes.

Stakeholder Meeting Summary

Meeting	Notes
10-13-15	First Stakeholder meeting and S&S discussion. Discuss Harris contract strategy. S&S wanted move to time and materials pricing, Unitil VP - IT denies. Contacting attorney for negotiations
10-20-15	S&S not comfortable committing to schedule, given insufficient information/involvement with schedule conversations. Change orders submitted for past work to be discussed with larger contract change in November
12-9-15	Change orders requiring extra cost after approval discussed. VP -IT to follow up
12-16-15	Deliverables broken out to those completed and payable in 2015 ($350,000) and those separated for future payment after testing ($128,000). New proposal from S&S received previous Friday; call with Unitil counsel
1-27-16	Meeting with S&S to review new organizational structure
2-9-16	Leadership reorganization S&S
3-23-16	Expect update on progress diagnosing incidents and delivery dates for fixes released for retest by Unitil
4-13-16	Improvement in code and performance by S&S
8-3-16	Grant Thornton going to S&S to review development processes and identify improvements
9-14-16	S&S meeting produces commitment to additional resources; outstanding code not to be delivered until Jan. 2017, surprising Unitil; discussed lack of transparency and urgency. Stressed ensuring status report color coding accurately reflects progress against schedule
9-21-16	Unitil explores phased implementation approach. Concern that apparent progress after S&S meetings followed by performance regression
9-28-16	S&S meeting commits to all code delivered by Jan 2017; weekly schedule to be developed, discussed with S&S to address timing and delivery.

These notes confirm a continuing inability of Systems & Software to meet schedule dates. We observed that Systems & Software continues to miss deadlines through the present, as it works on the CIS enhancement projects that Unitil has continued to undertake since Go-Live.

We did not find evidence regarding acceptance of any of Grant Thornton's expected deliverables. We expected to find them as a measure of Unitil's diligence in managing the provision of services with such a large dollar value. The information to which management referred our inquiry about them consisted of more than 300 status reports and presentations, but did not identify any that specifically addressed Grant Thornton deliverables acceptance.

G. Scope/Change Management

The scope management process needed for a project like COSMOS should monitor and limit scope creep. It requires documenting, tracking, and approving/disapproving requested project changes. Levels of authority for authorizing changes typically depend on the degree of change involved.

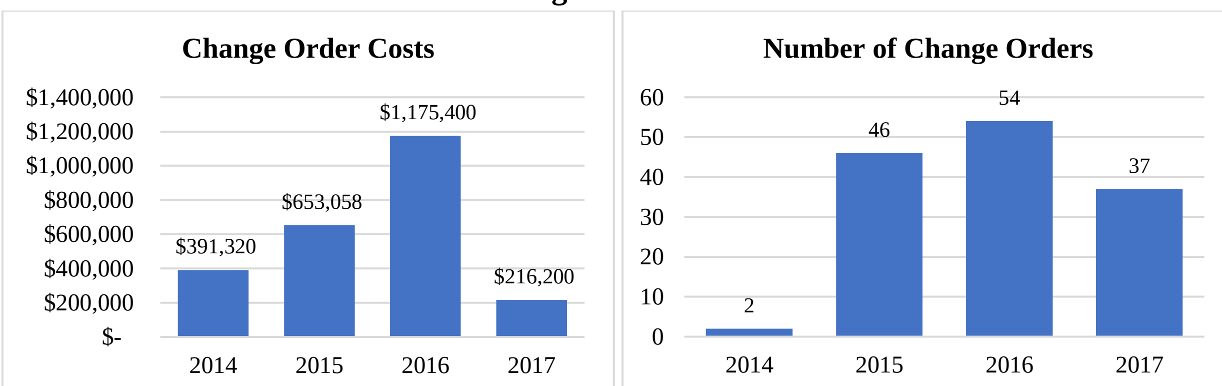
The Systems & Software SOW and the Project Charter detailed the means for processing and managing change orders. The change control process required that requests affecting project scope, schedule or cost must receive the approval of the Project Sponsor. A review of the approved change requests does not show evidence of approval by the Project Sponsor continuously through the project. Beginning in October 2016, the Assistant Controller began approving change orders, ultimately in violation of the expressed policy in the Project Charter.

Stakeholder meetings addressed the change order process, change order approvals, issues of and change order approval matters (*e.g.*, Systems & Software work starting or completing before change order approval). The September 14, 2016 Stakeholder Meeting reviewed the change order process, noting "All CO's need to be complete and signed off before the work is started by Systems & Software."

Unitil approved 139 Systems & Software (CIS) and MeterSense (MDMS) change orders during the project totaling $2.4 million in additional fees. Systems & Software change order fees totaled more than half of the original $4.4 million fixed fee contract.

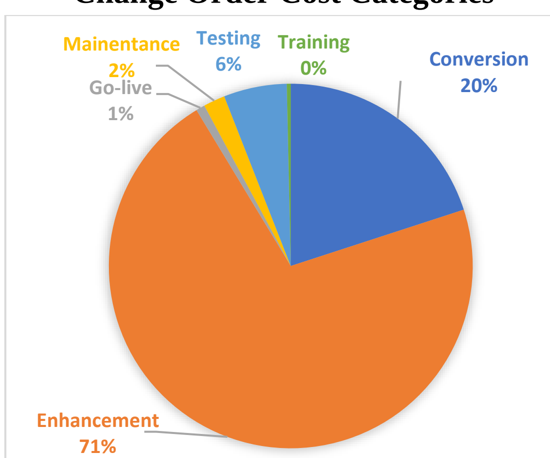
Change order volume and cost increased significantly from 2014 to 2016, as seen in the charts below. In 2017, Unitil approved $75,480 in 18 change orders leading up to go-live. Another 19 change orders totaling $140,720 were approved post go-live from July through November.

Change Order Details



The majority of change order costs represent enhancements to the software. However, 20 percent of change order costs were incurred to support additional conversion activities.

Change Order Cost Categories



Data conversion's primary objective seeks to convert required master and transactional data from legacy systems to the new solution, in this case from the legacy HTE system to new enQuesta.

Best practice in CIS implementations does not limit the number of data conversions, but instead calls for completing as many conversions as necessary and agreed to by both vendor and client.

A review of the Systems & Software SOW confirms that change orders were not needed for conversion. The detailed conversion deliverable, as listed in the Systems & Software's Information System Agreement Cost Sheet does not specify a set number of conversions, but rather lists conversion, priced at $450,000, as included in the fixed price implementation cost. The detailed deliverable description says:

> *Completion of Data Conversion Design Specifications/Detailed Data Mapping (Target System) and testing. Successful completion of all data conversion execution and cleanup and delivery of all data conversion deliverables.*

The SOW obligates Unitil to assist Systems & Software in completing a Data Conversion Plan to "establish the number of pre-install conversions and dates to ensure conversion success."

Systems & Software originally developed the Conversion Plan with review by Grant Thornton and Unitil. This plan covered four data conversions as in scope and two more for mock Go-Live and Go-Live. The Conversion Plan, like the other plans created after the SOW is signed, is not a contract. Unitil approved $487,200 in change orders for conversion-related activities that were marked as "included" in the SOW.

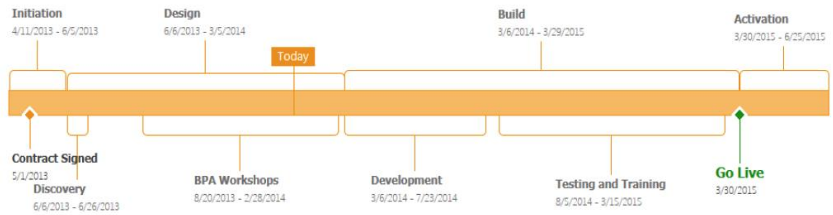
The Systems & Software SOW did not sufficiently define project scope. This lack of definition was a primary driver of Systems & Software's issuing 139 change orders totaling $2.4 million over the life of the project, including scope changes leading up to and following the Go-Live date. Project documentation does not demonstrate change order approval in the manner prescribed by the project charter. Moreover, examination of the Systems & Software SOW and its detailed deliverables for data conversion indicate Unitil should not have paid for conversion change orders, as the fixed-price contract included them.

H. Schedule/Time Management

A project like COSMOS should operate under a detailed project plan updated weekly. Good practice calls for the creation of a master, detailed schedule at initiation, supported by an appropriate schedule tool (for example, MS Project). Gantt or PERT charts should exist and undergo continual updating to support effective tracking, monitoring, and reporting of progress. Identification and assessment of critical path activities is important in analyzing downstream impacts of current sources of delay and in making adjustments to address slippage.

The Systems & Software project manager created the CIS plan using MS Project in June 2013. In October 2013, a high-level schedule timeline (see the following chart) came before the Steering Committee without detail about activities and completion. This same high-level timeline was presented to the Board in January 2014.

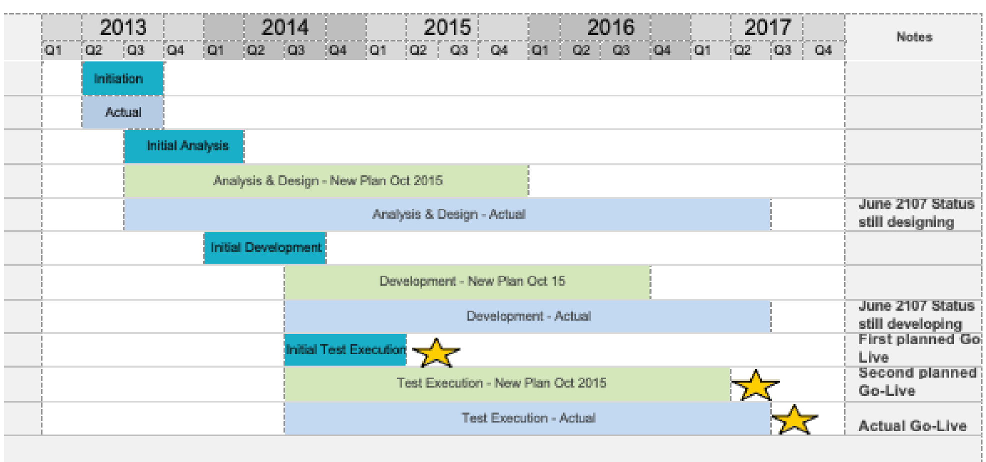
2013 Project Schedule



The expectation was that Systems & Software would update this plan weekly. The final version of the Systems & Software MS Project plan underwent its last update in April 2015. Status reports indicate the first plan developed by Grant Thornton was ready to be baselined in November 2015. We requested, but did not receive, the Grant Thornton integrated MS Project plan; management instead provided a PDF snapshot of the project at one point in time, and no documentation confirming that the MS Project plan was updated weekly, as expected. Interviews with project team members and Grant Thornton consultants indicated that project management used weekly project status spreadsheets to manage the project. However, the weekly project status spreadsheets did not contain an integrated project schedule - - instead presenting stand-alone spreadsheet tabs for each of the primary schedule categories.

Use of a tool like many others have employed (*e.g.*, MS Project) would have helped project management more timely and effectively address delays and project slippage. The initial Systems & Software timeline (teal), the Grant Thornton October 2015 plan (green), and actual schedule (light blue) and Go-Live dates (stars) for the four major tasks (initiation, analysis, development, test execution) are presented and contrasted in the following diagram.

Overall Project Timeline

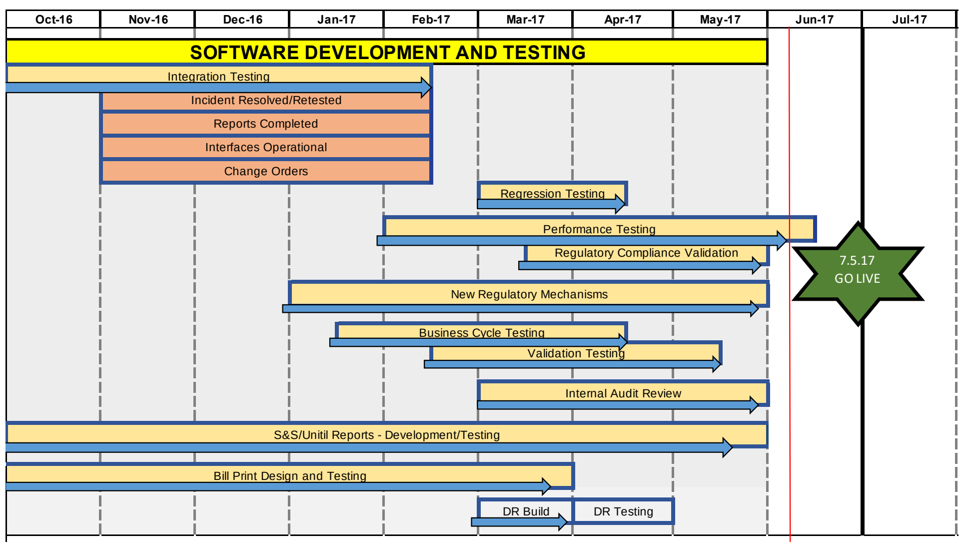


Reliance on high-level reporting in Excel format sacrificed key information and analysis useful in identifying gaps in resources and impacts to critical path. Status reports showed the timeline at a very high level and in Excel format. The lack of critical path analysis obscures understanding of true schedule status, what is driving delays and resource overload, and where action can be taken to recover. Unitil did not insist on the daily use of a tool, such as MS Project, that provides early warnings about schedule slippage.

Meeting minutes of a September 2016 Stakeholder meeting noted a desire to "…enforce more monitoring of the schedule and be able to raise concerns immediately when project is in trouble." Notes of that meeting also observed, very late in the project, that, "Currently the schedule is static, but a new schedule will be created once a decision is made about the implementation approach." We requested all project schedules but did not receive this one in response.

Minutes from the last, October 2016 Stakeholder meeting noted that progress would be shown on a Gantt chart that can be reviewed weekly. The next diagram shows the Gantt chart.

Project Timeline - - October 2016 to July 2017



This schedule shows software development and testing completion at the end of May 2017, well after code development was previously reported as complete. The June 6, 2017 status report showed five open interface development and testing issues with the last interface deployment scheduled for June 28, 2017. The June 2017 status report also documented regression testing as 95 percent complete, while the chart above shows completion in mid-April.

No integrated project plan existed; instead, management employed individual spreadsheets detailing task progress on a stand-alone basis. Therefore, presentation of the Gantt chart weekly offered only a static picture requiring manual updates that made it difficult to synchronize with project status reports and other project documentation. The examples cited in the previous paragraph show the mismatches that resulted. The use of an integrated project schedule, updated daily via a project management tool, would have substantially enhanced project management.

I. Cost Management

COSMOS experienced an extraordinary budget and cost history. At project inception, Unitil planned an \$11.5 million project, with a scheduled Go-Live date in October 2015. Management extended that date into 2017 following the July 2015 project review. By that time, to-date expenditures of over $11 million had already consumed essentially all of the original $11.5 million expected cost. In fact, actual expenditures had already reached (given actual project status) an unrealistically high 90 percent of the modest 2013 increase (about 10 percent) to the approved budget. The next 2 ½ years would see expenditures of $26.8 million, more than twice the amounts spent in the first two years. At the end of 2017, project cost totaled over $36 million - - more than three times the initial budget.

The next table summarizes this project's budget and cost history.

Project Budget/Cost History

Category	Yearly Spends							Total	
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**$**	**%**
Internal Labor	583,512	998,775	1,611,856	2,027,418	2,347,617	2,950,744	84,273	*10,604,195*	29%
Contractors	241,258	713,966	1,340,211	4,343,340	7,593,614	6,920,740	74,108	*21,227,237*	59%
Purchases	43,080	1,801,200	497,773	854,100	235,185	892,706	31,055	*4,355,099*	12%
Year Total	*867,850*	*3,513,941*	*3,449,840*	*7,224,858*	*10,176,416*	*10,764,190*	*189,436*	36,186,531	100%
To-Date Total	*867,850*	*4,381,791*	*7,831,631*	*15,056,489*	*25,232,905*	*35,997,095*	*36,186,531*	*36,186,531*	100%
	Budgets							**Change**	
Approved	11,500,000	12,670,000	12,670,000	18,300,000	22,000,000	29,800,000	29,800,000	159%	
Remaining	10,632,150	8,288,209	4,838,369	3,243,511	(3,232,905)	(6,197,095)	(6,386,531)		

Unitil has continued to authorize and average of about $1.4 million in yearly expenditures to enhance the enQuesta system following its actual Go-Live date of July 2017.

The data show a continuing struggle by management in securing a sound view of expected project costs. Total costs grew by a factor of three over five years and budgets could not even keep up with costs already incurred, yet alone those to go. The project began with an expected cost (in 2012) of $11.5 million and grew through its last, 2017 iteration to $29.8 million, an increase of 159 percent. As late as 2015, several years into the project, the budget stood at half of final costs. The preceding table shows a continuing inability to produce a realistic view of eventual costs. Less than 20 percent of the then-current budget remained in 2015. Even more significantly, 2016 produced a budget increase of 20 percent (to $22 million), but to-date expenditures by year end had already exceeded that increased budget by 15 percent. An even larger increase in 2017 (by 35 percent to $29.8 million) proved no more meaningful - - to-date costs for the year exceeded the budget by 21 percent. These numbers underscore what appears an abandonment of the use of budgets to manage costs, as opposed to management of costs against a realistic budget (even one incorporating a reasonable degree of "stretch").

Effective cost management requires that project management establish detailed budgets, track costs regularly, assess cost progress against clear deliverables, milestones, and expectations, assess the causes of variances, and respond to adverse cost trends and circumstances. It takes regular, comprehensive, and cause-based reporting to manage costs effectively. Regular reporting also needs to make costs, trends, causes, and concerns transparent to those outside the project as well - - typically an oversight committee for projects like this one.

These elements of effective cost control apply on all projects; they become all the more critical for a project facing such rapid and large increases and operating steadily and under transparently unrealistic budgets. The circumstances should have produced close and continuing scrutiny at the highest levels. We did not find reporting of project costs a formal part of Steering Committee or Board of Director reporting. Several years into the project, the October 2015 Stakeholder meeting minutes note that:

> *The Team Lead-Energy Management and Control brought up the idea of discussing the budget. He thought that would be one of the items discussed at this weekly meeting, as it plays that into the decision-making process. VP-Controller commented that the expenditures are discussed monthly and are available monthly for groups to see what they are spending. He will additionally email out relevant information to the group.*

The lack of clarity and focus on budget and cost reporting reoccurred the next month, with the November 2015 Stakeholder meeting having "[d]iscussed budget relative to the stakeholder's group role. Decision made to have Mark clarify role of members as it relates to budget."

Costs for outside contractors ($21.2 million) comprised about 60 percent of total project costs, roughly double the costs of internal labor. Payments to the two largest contractors accounted for close to three quarters of contractor costs:

- Grant Thornton: $8.1 million
- Systems & Software: $7.2 million.

The original Systems & Software contract amount was $4,445,160 plus expenses. Systems & Software was paid an additional $2,720,309 (change order fees) for a total of $7,165,469. Unitil management's comments about the Systems & Software team and costs are below.

> *During the project, S&S augmented its original project team with additional onsite and offsite staff. The Company was not billed for additional services provided by S&S, and as such does not have an estimate of the value of such services. The additional resources were provided by S&S to Unitil at no additional cost.*

The nature of a fixed fee contract like that with Systems & Software (not unusual for such work) makes the vendor responsible for any added resources needed to perform the agreed scope of work. Systems & Software was compensated for any out-of-scope items and an extension of the schedule. At go-live, Unitil's "build" of enQuesta became Systems & Software's newest release of enQuesta software. In effect, a smaller utility secured not an "off-the-shelf solution" that would have eased its engagement and management needs greatly, but rather a highly customized solution. Unitil essentially drove design of the vendor's product, investing in Systems & Software's development of a solution not only tailored to Unitil's needs, but producing a new release for Systems & Software. We explain later the commendable success experienced in supporting the customer experience at a comparatively high level upon and after Go-Live. Our fundamental concern about the project lies not in "gold plating," but rather in:

- The unrealistic expectation that a non-top-tier firm could bring off that result for the extraordinarily low costs it proposed
- The inefficiency suffered when Unitil found it necessary mid-course to bring in another outside firm to supply what Systems & Software was responsible for but not supplying as planned
- The use of an outside firm without substantial experience in managing even on target CIS projects, let alone ones experiencing large cost and schedule troubles

- The failure to hold that second outside firm, whose costs grew substantially, to effective cost management.

As initially projected, Grant Thornton's fees for its SOW were $3,250,000 plus expenses and plus a 3.5 percent administrative fee. We have not seen the use of administrative fee adders for work of this type. The agreement with Grant Thornton (from September 2015) states that, "*If it appears that the estimated fee will be exceeded, we will consult with you so that you will have a better understanding of our fees before we continue.*" An interview with the senior Unitil executive responsible for retaining and managing Grant Thornton's work stated that this consultation occurred at meeting discussions not reduced to any memorialization. Such an informal approach does not conform to good utility practice when increases prove material.

Grant Thornton received an additional $4,848,573, producing a total of $8,108,574 (153 percent above the base fee). Management has not produced any documentation to support the increased fees. Moreover, Unitil could not rely on the Grant Thornton invoices to explain or justify the fees charged with a helpful level of consistency. About 44 percent of the contractor's invoices as contained in the company files presented hours by staff, without any statement of activities performed, or project responsibilities. The next table shows what comprised the more "detailed" Grant Thornton invoices. Management says that it regularly received detail like that shown below, but its files do not contain it.

Sample of "Detailed" Grant Thornton Invoicing

January 2017 Project and Testing Management Fee Detail

	1/2	1/9	1/16	1/23	1/30	Hours	Rates	Fees
Chris Lilley		6	1	1		8	$ 285	$ 2,280.00
Bob Hersh	2	3				5	$ 285	$ 1,425.00
Boyd Graham	36	52	43	16	3	150	$ 230	$ 34,500.00
Tom Friedman	6	29	27	5		67	$ 230	$ 15,410.00
Paul Goldenberg	32	40	40	40	16	168	$ 205	$ 34,440.00
Larry Swanson	7	32	34	32	16	121	$ 205	$ 24,805.00
Nick Morteo	34	18	44	42	16	154	$ 205	$ 31,570.00
Brian Fellman	32	40	42	40	18	172	$ 205	$ 35,260.00
Maura MacDonald	36	42	46	46	19	189	$ 170	$ 32,130.00
Laura Kenney	40	16	41	43		140	$ 140	$ 19,600.00
April Gammal	36	48	40	44	16	184	$ 140	$ 25,760.00
Ash Rao					16	16	$ 140	$ 2,240.00
Nick Pate	34	40	40	40	18	172	$ 140	$ 24,080.00
Cory Whited	43	46	45	46	18	198	$ 115	$ 22,770.00
Total						1744		$ 306,270.00

The remaining 56 percent of Grant Thornton provided even less detail (see the example below).

Undetailed Grant Thornton Invoice Example

GrantThornton

Grant Thornton LLP
75 State St # 13
Boston, MA 02109-1827

T 617.723.7900
F 617.723.3640
www.GrantThornton.com

This address should be used for correspondence only
For all payments, kindly use remittance instructions below

Req # 171832
6/5/17 DKF

To: Unitil Service Corp.
Attn: Larry Brock
6 Liberty Lane West
Hampton, NH 03842-1704

Date: May 19, 2017

Bill Number: 953181537 **Client-Assignment Code:** 1289093-35252

Professional services rendered in connection with CIS implementation PMO.	$ 283,235.00
Expenses, including an administrative expense charge of 3.5%	63,985.91
Total Amount of Bill:	**$ 347,220.91**

Terms: As agreed upon
Federal ID No. 36-6055558

Finally, no invoices were provided that supported five other payments to Grant Thornton that totaled $32,173.

J. Risk Management

Effective project management requires careful and continuous risk identification, description, quantification, and planned mitigation, and documentation of the results of mitigation activities performed. The project charter documented a risk management process for identifying and documenting risks. We found the Initial Risk Register well developed, identifying risks and assigning them priorities, owners, mitigation, and dates. Management moved this initial risk register to an online SharePoint site. Grant Thornton in assuming PMO management, added a "risk/issue" section to the weekly Status Report, replacing the risk register. These risks could change from week to week; *i.e.*, we did not find consistency or tracking of risk opening, status, mitigation, or closing.

K. Test Plan and Management

CIS implementation projects rely heavily on pre-operation testing to ensure delivery of expected CIS solution capabilities and functionality. Defects and gaps will certainly result during development; extensive testing to identify them and subsequent efforts to resolve and retest them prove essential to successful CIS implementation.

1. Test Plan Strategy

Systems & Software developed the initial test plan. Management has stated that the original plan remained unchanged throughout project duration. We observed, however, that a "Grant Thornton Testing Strategy After the Project Reset" presented in October 2015 added new testing principles, which included:

- Adding Systems & Software test quality assurance staff to permit pre-testing of changes more effectively before deployment into the testing environment
- Strengthening and simplifying test-phase entrance and exit criteria, ensuring that functional testing would meet exit criteria before entering integration testing
- Finance and accounting testing and internal audit validation separate from the overall test plan
- Fully testing the new COSMOS environment (enQuesta, MeterSense and its integrated components) at the conclusion of Integration Testing
- Performing dry run "Go Live" testing after completion of Integration Testing with subsequent lockdown (code freezing and configuration control) of the final, approved production system.

Status reports and presentations we reviewed indicated a high level of software defects or errors. For example, the report of the July 13, 2016 Stakeholder meeting noted that, "*Testing progress slowed due to number of blocked test cases resulting from a high number of open incidents*."

In summary, the Systems & Software scope included responsibility for executing testing activities. With development and testing activities not proceeding well, Unitil turned to Grant Thornton and its testing strategy. Unitil received no price relief from Systems & Software for the insertion of Grant Thornton and its resulting charges to Unitil. We acknowledge value added by Grant Thornton, but it clearly came at the cost of repeating Systems & Software planning and testing work and with the inefficiency inherent in making major mid-course adjustments. Thus, Unitil bore avoidable added costs, again as a result of its unreasonable expectations about the ability of Systems & Software to perform all that Unitil expected for the price that Systems & Software had offered.

2. Test Methods

Unitil has credited its information-systems testing methods as a key attribute of its CIS implementation:

> *Unitil'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 Unitil's business process requirements. While the new software is under development in the test environment, Unitil begins extensive functional, integration, regression, performance and business cycle testing of the system.*

Creation of a separate testing environment comprises standard procedure, not a novel approach, for implementing software of the type relevant here. Moreover, testing while new software remains under development presents a high-risk approach. While reported as beneficial for the schedule, Systems & Software did not meet the testing objectives and testing exit criteria. The project schedule included a mandatory code freeze, but project management did not enforce it. We observed the release of multiple code changes right up to the system launch, without testing to assess the impact of the fixes on previous testing.

Management has also reported that:

> *The information system testing methodology used at Unitil is proprietary and owned by Unitil to achieve its unique audit, financial and regulatory compliance business objectives… It is written into Unitil's Information Technology Application Change Management policy.*

Unitil's 2016 Application Management and Change Control Policy expresses the following testing directives: (a) testing for completeness and accuracy, (b) documentation of test plans and results prior to deployment, and (c) Internal Audit review and validation of test results before the system goes into production. While sound, we do not find such elements unique to Unitil; typical CIS methods include these expectations.

A senior member of Unitil's management team and Project Lead in the COSMOS project said in an interview that, "Unitil wants things perfect, we balance to the penny, wanted it absolutely perfect." Financial controls typically comprise an element of CIS implementation, in balance with nonfinancial controls. The next table shows a matrix that we consider reasonably typical. It summarizes financial and non-financial controls and targets from the 2012 CSWeek Best CIS Implementation winner.

CIS Implementation Controls Sample

Control Type	Control	Criticality	Target	Actual
Non Financial	Person	Critical	99%	100.0
	Premise	Critical	99%	99.4
	Account	Critical	99%	100.0
	Item	Critical	99%	100.0
	Meter	Critical	99%	100.0
	Register	Critical	99%	100.0
	Service Point	Critical	99%	99.9
	Service Agreement	Critical	99%	99.9
	Landlord	Non-Critical	95%	100.0
	Customer Contacts	Non-Critical	95%	100.0
Financial	Meter Read	Critical	99%	100.0
	Register Read	Critical	99%	100.0
	Bill (Count & Amount)	Critical	99%	100.0
	Payment (Count & Amount)	Critical	99%	100.0
	Adjustment (Count & Amount)	Critical	99%	99.5
	Financial Transactions	Critical	99%	100.0
	Deposits	Critical	99%	100.0
	Balance	Critical	99%	100.0
	Collection Agency Referral	Non-Critical	95%	100.0

Unitil has also observed that its CIS implementation included 20 data conversions. This conversion work followed a Systems & Software change order that produced additional fees for the vendor. We find full conversions typically preformed regularly throughout a project, according to a schedule mutually agreed upon by the client and implementer. For more information about conversion costs see Section *G. Scope/Schedule Management*.

The Systems & Software test plan methods included Systems & Software testing of its code. However, no plan existed for Unitil to perform unit testing, a material part of the process for accepting deliverables from Systems & Software. The Systems & Software SOW said,

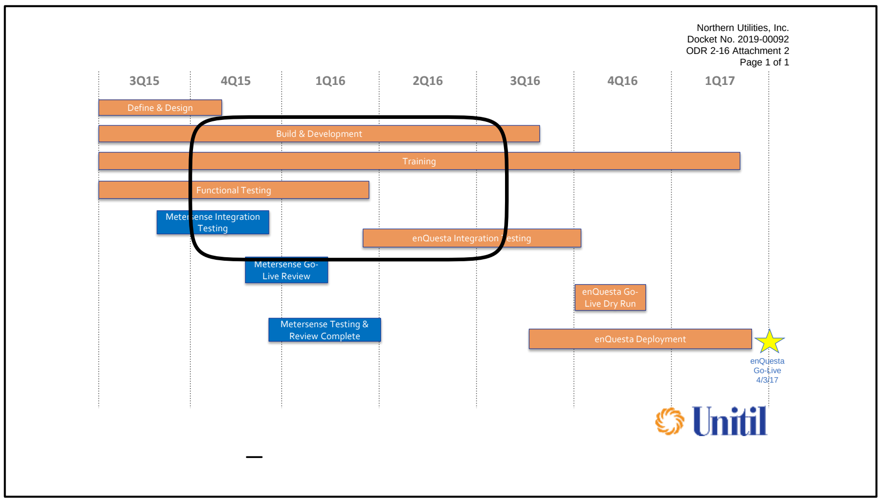
> *All components defined in the Functional Specifications are delivered to Unitil. Each modification must have been successfully tested by Unitil to ensure compliance with the Functional Specifications.*

We found no documentation about when Unitil unit-tested the code, which occurs typically at deliverable acceptance. The Deliverable Acceptance forms provided did not include detail supporting the unit-testing of the code.

3. *Test Phase Overlap*

Both the original Systems & Software and the later Grant Thornton test plans intended to do functional and integration testing before development completion. The next diagram shows the plan Grant Thornton first provided; it indicates planned overlap in testing phases.

Grant Thornton Initial Test Plan



The diagram shows considerable overlap of the various testing work streams involved, with identified defects undergoing remediation through code changes, and with subsequent test phases underway executed. This approach creates the risk of failing to examine interconnected features and functionality properly. Testing in separate test environments should be limited to features and functionality that are truly independent of each other.

Overlapping testing in different environments inevitably produces the identification of "bugs" introduced to the other environments, which can create additional correction work. Sound testing runs the unit testing, functional testing, integrated testing, and user acceptance testing one after another - - not in parallel. Otherwise, such bugs may not be appropriately tested if not tested in all other environments.

To avoid parallel testing, "Build & Development" completion and unit and functional testing should occur prior to integration testing. In the diagram above, Systems & Software continues code development until near the end of 3Q16 at which point Functional Testing has been completed and Integration testing is nearly complete. Our review of project status reports indicated instances of uncompleted unit tests that affected the scope of integrated testing. The status reports documented code that was not received and tested prior to the start of these integrated testing cycles. The reports show lack of adherence to the good practice of completing unit and functional testing prior to beginning integrated testing cycles.

Unitil considers the four and one-half year duration of COSMOS appropriate, in significant part because it "demanded perfection," tasking Grant Thornton to execute a more rigorous test plan and an enhanced PMO. We did not find in the RFP to which Systems & Software responded or in the SOW governing its work language indicating unique or unusually high client expectations compared to what we normally have seen. Management has stated that testing beyond the normal and its quest for perfection had material schedule extension and cost increase consequences. We conducted our examination of project documentation and our interviews with this asserted higher standard in mind. Here, we found testing in line with a typical CIS project with the exception of user acceptance testing. We did not find reason to believe that unusually high standards imposed by Unitil had material cost or schedule consequences.

We reviewed the Grant Thornton Principles of Testing (Section 11.a), which re-expressed testing expectations. We did not find provisions outside those typical of CIS implementation. Moreover, there was a failure to achieve some principles fully, for example:

- Code development and testing continued up until one month prior to Go-Live
- Functional testing exit criteria were not met
- Integration testing exit criteria were not met
- Readiness Testing, which included participation by the business owners, was not documented in status reports
- Situational testing approved by Change Request 67 was never included in test plans or in status reports.

Management reported completion of functional, integration, regression, and interfaces testing to the Board of Directors in April 2017. Changes to software code were reported to be "locked down" with no changes anticipated. Subsequent Status Reports in April through June tell a different story. The final PMO meeting on May 2, 2017 produced the statement that, "[Name excluded] *stressed the action plans are down to a matter of days. The mindset should change to closing out the work efforts. The next couple of weeks will determine if things will fall off go live and become work arounds.*" The final project status report of June 6, 2017 documented the existence of continuing development, testing, and integration tasks.

L. Go-Live Preparation & Project Readiness

Preparation of system users and the Customer Service organization prior to Go-Live comprises an essential element in effectively transitioning to a new CIS. End-user training and support comprise central elements of that preparation. Training should address technical (application) requirements and changes in business processes. Training materials, post Go-Live support details, and system usage documentation require regular updating and communication to all end-users before Go-Live. Following Go-Live, management should monitor support processes and action plans created to address any issues encountered. Appropriate support covers trouble-shooting, live assistance, defect tracking and resolution, and communication of workaround options. System work arounds pending permanent solution require documentation, communication to all users, and monitoring.

1. *Organization Change Management*

In March 2013, Unitil contracted with Consultants On The Go LLC to provide Organizational Change Management services, specifically bid for COSMOS. The Organization Change Management Statement of Work assumed a 24-month project and a fixed-price contract to provide:

- Organizational Change Management Leadership
- Executive Leadership Interviews and Change Assessments
- Organization Change Management Strategy (including Communication Strategy)
- Monthly Communication Plan
- Sponsor Roadmap
- Change Management Training for executives, core team/SME's, managers, and supervisors.

Over the course of six to eight months, the OCM consultant delivered the services listed above, as documented in Steering Committee meeting minutes and presentations. The OCM Strategy and Communications Plan and Sponsor Roadmap were presented and approved by September 2013. OCM training for managers and supervisors took place in mid-October. In December, Change Management for Change Agent training was delivered to Project Team members and Steering Committee members received Managing Change for Leaders training.

Following the training, the OCM consultant worked with Unitil on a monthly basis to create Project COSMOS related articles and communications in the Unitil employee newsletter. A bi-monthly manager and supervisor "Change Forum" was also created to encourage continuing dialog among the management team.

Consultant On The Go provided organizational change management services for the first 24 months of the project, working under a fixed-price contract. When the Project COSMOS schedule was extended as a result of the mid-project review, Consultant On The Go's contract was not extended.

After the Grant Thornton project restructuring in mid-2015, Grant Thornton consultants assumed responsibility for Organizational Change Management. In February 2016, another Change Management Plan was created and employees, managers, and stakeholder committee members were asked to complete change assessment surveys and participate in workshops and recurring change management meetings. Communications were planned and the SharePoint project site was updated.

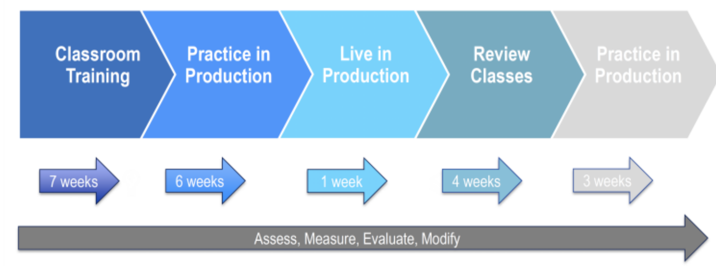
While Grant Thornton did assume responsibility for organizational change management, the Grant Thornton Change Management Plan did not build on the prior consultant's change management strategy or deliverables; rather, Grant Thornton developed from scratch another plan with similar activities, duplicating prior work.

2. *Training*

To prepare and train users on use of the new system, Unitil developed a comprehensive training strategy combining instructor-led training, self-training, and applied learning. Customer Service representatives, as deeply engaged system users, received more intensive training, which incorporated two training simulation exercises called "Practice in Production" and "Live in

Production." During Practice in Production sessions, employees listened to pre-recorded customer calls and practiced responding to the recorded customer inquiries by navigating and interacting with the new system. Live in Production was a parallel training exercise in which one employee served the customer using the existing customer system (HTE) while the other listened to the same call and practiced serving the same customer using the new enQuesta system. To make this possible, Unitil conducted a data conversion (from HTE to enQuesta) immediately prior to the training so employees could train with the most current version of system data. Both of these simulation exercises allowed employees to practice using the new system and apply their learning by listening to actual customer inquiries. Parallel training also provided an opportunity to test the system in a production-like simulation prior to Go-Live. The following diagram summarizes Unitil's training strategy.

Training Strategy Summary



Training for enQuesta users commenced on April 25, 2017 with a class of Customer Service representatives. Unitil had previously conducted training class dry-runs to prepare and train project team members and project coordinators. Management provided training at several locations to accommodate all users with minimum travel. Classroom training extended over a seven-week period followed by six weeks of Practice in Production and a week of Live in Production. Customer Service representatives then went back into classes to review and refresh. Another three weeks of Practice in Production strengthened knowledge and familiarity with the system.

At the end of training, employees evaluated the training received and provided feedback regarding readiness. Nearly all (98 percent) completing surveys indicated they felt prepared for Go-Live launch.

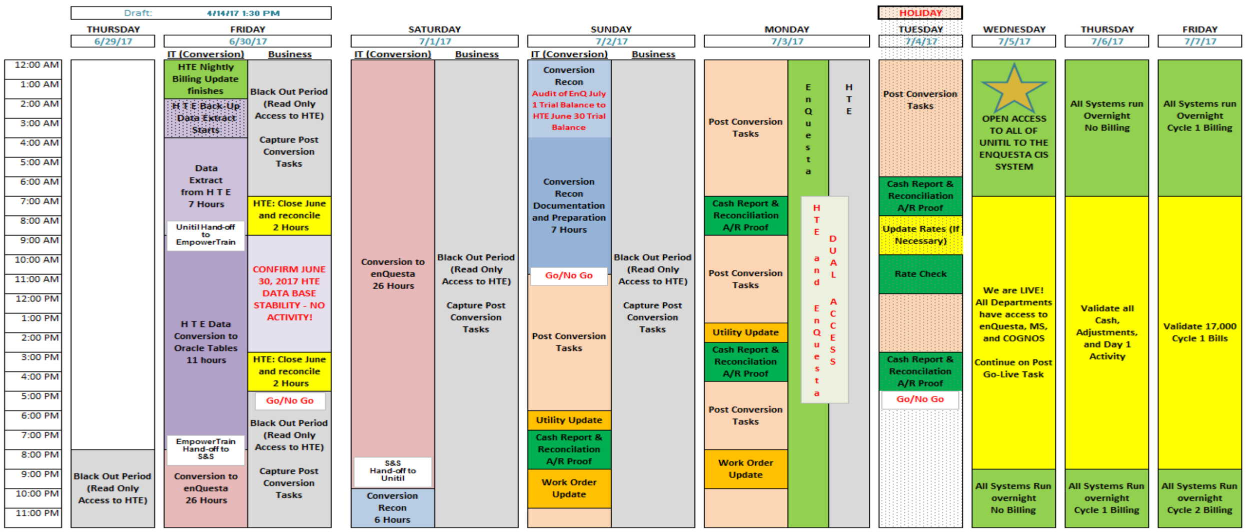
3. *Go-Live Planning*

Planning assumed a July 5, 2017 cutover. A "cutover plan" documented project tasks remaining to complete testing, documentation, training, planning, and communication. The cutover plan included detailed Go-Live preparation steps, Go-Live tasks, and the first 100 days of post-go live activities.

The project team conducted a dry-run of Go-Live in April 2017, letting participants practice tasks and develop a better understanding of required time to perform Go-Live tasks. Unitil continued to operate its HTE System as a back-up, permitting it to serve as a backup should a decision to postpone Go-Live occur.

Unitil develop a Go-Live plan and 5-day launch sequence to guide project launch. The plan sequenced Go-Live implementation of enQuesta over the Fourth of July weekend, beginning with monthly close-out in HTE on Friday June 30, 2017. Management planned conversion activities for early Saturday morning, followed by post-conversion tasks on Sunday, Monday, and Tuesday. Unitil planned to go live with enQuesta on Wednesday, July 5, 2017.

Go-Live Launch Sequence



4. Project Readiness

Before transitioning a new system into production, practice calls for satisfaction of an objective set of criteria to determine system and organizational readiness and to verify completion of all that needs to be in place. The go/no-go decision point stands as one of the most important decisions in the project lifecycle. The wrong decision can produce significant negative business impact if there remain material unresolved defects, poorly designed applications, insufficient training, inadequate systems security, or poorly-communicating interfaces, to cite some examples.

Ideally, an independent resource, well versed in CIS implementations, should conduct an assessment of Go-Live readiness - - project managers, systems integrators, software vendors, and company personnel bring a risk of bias or influence from the pressure to implement on time.

Project readiness (or Go-Live) acceptance criteria, should undergo thorough review as part of the readiness assessment, with all information shared with the project steering committee and project sponsor responsible for the go/no-go decision, and with complete identification and communication of known risks and mitigation methods or work arounds. At a minimum, a readiness assessment should confirm the following:

- Complete and successful testing
- Staff in place and trained
- Conversion and cutover plans practiced and perfected
- Post Go-Live support planned and ready to go

The Systems & Software Statement of Work defined both the "Go Live Criteria" and "Post Implementation Criteria" for the project. Grant Thornton also outlined testing acceptance and readiness criteria. MeterSense, the MDMS application used separately defined readiness criteria. Unitil deployed MeterSense ahead of the CIS application (enQuesta). The next table summarizes the Go-Live criteria for the COSMOS project, with our observations about their satisfaction.

COSMOS Go-Live Criteria

S&S	Grant Thornton	Liberty Observations
Successful completion of all functional tests, all integration tests, all performance tests and signed off all user acceptance tests.	All test cases and business scenarios are tested	User Acceptance documentation was incomplete.
All requirements in the Functional requirements delivered, with any exceptions agreed to by both S&S and Unitil via the Change Order process.	All critical reports are created	Change Orders document many exceptions to the Functional requirements.
Successful simulation dress rehearsal and integration tests.	System interfaces are developed, tested, and working effectively.	Late development and testing of interfaces with no documentation of completion.
The data conversion has been balanced / adequately explained to Unitil's satisfaction.	The data conversion from HTE to enQuesta is sufficiently tested and can be reliably repeated	Conversion was balanced for financial and nonfinancial items.
CIS testing that parallels a production sample of all customer types, meter reads will be compared to the legacy calculations and the new system calculations. The results are expected to be exact or explained to Unitil's satisfaction.	Business Cycle testing is complete	Weekly status reports are discontinued before Business Cycle Testing is documented as complete.
No Priority 0 or Priority 1 defects unless Unitil and S&S mutually agree to proceed.	All 0 and 1 priority incidents that are required for go live are closed or a manual work-around is developed to meet the business requirement	59 Open Priority 0 and 1 incidents (June 6, 2017 project status). Grant Thornton memo indicates Unitil business leaders have signed off on necessary work arounds for go-live.
Mutually agreed upon Priority 2 defects.		
Post-implementation support plan in place with a staffing plan.	A sufficient plan and organization is in place to support enQuesta and other new applications after go live either through in-house resources or 3rd party vendors such as S&S	100 day-plans with staffing plans On-site support by S&S and Grant Thornton and other vendors at go-live.
	User security is in place and tested	Security testing appears to have been completed prior to go-live.
	End user training is delivered, and users can effectively operate enQuesta	Comprehensive User Training was delivered.
	A Cutover Plan is in place that outlines the detailed steps necessary for: • Pre-launch • Launch sequence at go live • Post launch (first 100 days)	Detailed launch sequence and cutover plan.
	Organizational Readiness • Staffing plans are sufficient and new employees are on-boarded • 100 days plans from each department are in place and are reasonable	Post go-live 100-day plans for key business areas include staffing plans.

	Unitil has the necessary technology infrastructure in place to effectively operate all new applications	Performance testing was completed prior to Go-Live.
	Internal Audit review is complete and without significant issue	Internal Audit documented its review in the 6/20/17 Memo.

Unitil executive management conducted a Readiness Assessment meeting on June 26, 2017 to discuss project status, review Internal Audit and Grant Thornton Readiness Assessment results, and outline the senior management and Board Communication Plan to set expectations for Go-Live. This review included a synopsis of the Incident Resolution Plan, which defined post Go-Live support and problem escalation processes. The team also identified post Go-Live activities to be conducted to validate customer invoices.

Ultimately, Senior Management made the decision to go live, informing the Audit Committee of the Unitil Board of Directors on June 26, 2017. The decision was based on COSMOS project readiness, as assessed by:

- Unitil Internal Audit
- Grant Thornton
- Systems & Software
- Deloitte

Internal Audit conducted audits of data conversion, internal controls, and monthly business process testing. Business Process Testing consisted of a series of activities testing rates, account reconciliation, cash receipt processing and reconciliation, transaction processing, and month-end activities and reconciliation. Internal Audit validated Go-Live readiness through its validation of the busines process testing. A June 20, 2017 Audit memo stated:

> *Internal Audit supports management's assertion that the design of their business process testing was adequate to validate the Company's readiness to Go-Live with enQuesta.*

Grant Thornton and Systems & Software also completed system readiness reviews. Grant Thornton's readiness memo documents its criteria for system assessment, primarily consisting of project milestone completions, cutover, launch and post launch plans development, and organizational readiness as defined by sufficient staffing and support plans in place.

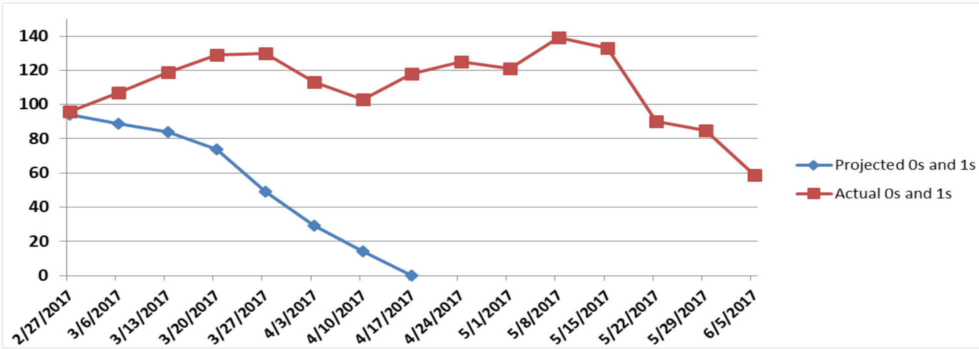
Unitil's financial auditor, Deloitte, also conducted a review of the enQuesta deployment's financial compliance with reconciliation and reporting requirements.

Grant Thornton's readiness criteria included completion of Regression Testing; *i.e.*, completion of all test cases and business scenarios and closure of all 0 and 1 priority incidents required for Go-Live (or a satisfactory manual work-around in place to the underlying business requirement. Grant Thornton evaluated Regression Testing readiness as "meeting expectations" and noted that:

> *Several incidents remain that will either be completed before Go Live or deferred to the Post Go Live phase. Unitil business leaders have signed off on necessary workarounds for Go Live.*

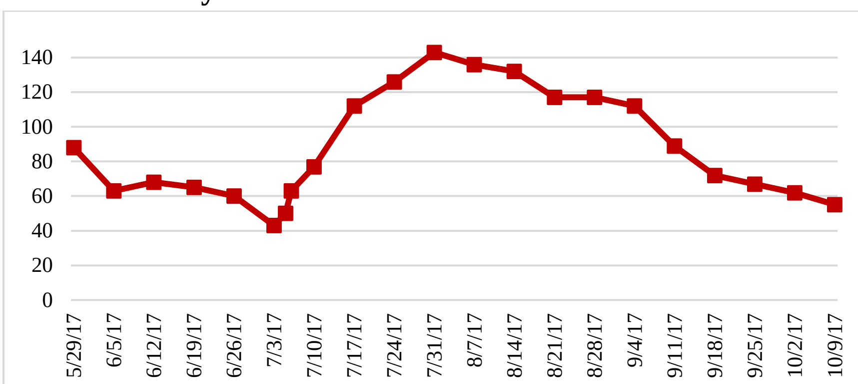
Project documentation shows a number of open priority 0 and 1 incidents at Go-Live. The last project status report documents project progress as of June 6, 2017. Of note, 95 percent of 2,500 planned test cases showed as complete, leaving 114 open test cases and 59 priority 0 and 1 incidents for completion prior to the July 5th launch. The next graph shows the unresolved priority 0 and 1 incidents as of June 16, 2017.

Priority 0 and 1 Incident Closure Up to Go-Live



Our examination of the analysis of the project incident log from the end of May through early September 2017 shows priority 0 and 1 incidents unclosed at Go-Live.

Priority 0 and 1 Incident Closure After Go-Live



Additional priority 0 and 1 incidents were logged following Go-Live, peaking at the end of July 2017. At the end of post Go-Live (100 days), Unitil reported 55 unresolved priority 0 and 1 incidents, back in line with the number of incidents reported in the June 6 status report, before Go-Live. The following table defines incident priority categorization.

Incident Priorities

#	Priority	Description	Response Time
0	Showstopper	Customer down or cannot run critical Billing or C&C process	15 Minutes
1	High	Business critical, but not preventing all users from getting work done (*e.g.*, a particular update that cannot be run needs to be run before the next business day.)	1 Hour
2	Medium	Issue has a work around usable until issue resolution. (*e.g.*, particular work order cannot be updated)	4 Hours
3	Low	Cosmetic issue or requested functionality to be considered for a future version. (*e.g.*, columns displayed on a particular screen)	24 Hours

Management built three go/no-go decision points into the launch sequence for Go-Live:

- Day 1, following HTE data conversion to Oracle
- Day 3 following conversion of HTE data to enQuesta
- Day 5 following post-conversion tasks.

However, the detailed cutover plan did not include them, nor did other project documentation confirm them, making it unclear whether these decision points were discussed or considered during launch.

Conversion ended on Saturday July 1 at 7:00pm, taking a total of 45 hours to complete. Post-conversion activities continued through Monday July 3. The "My Unitil" website went live on Tuesday July 4 at 7:00 pm. Conversion validation activities were conducted on July 5 and 6. Cycle 1 bills were run on the evening of July 6 and validated over the weekend. Unitil validated successive billing cycles through July 21.

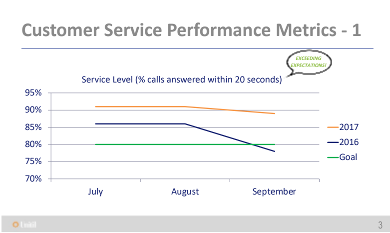
M. Post Go-Live Management

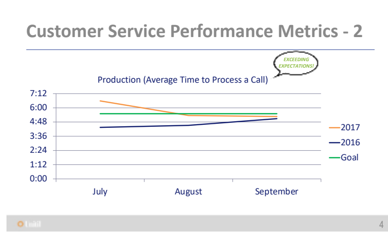
Following Go-Live, post Go-Live support processes require monitoring, with action plans created and executed to address any issues encountered. System work arounds require careful documentation and communication to all users, followed by monitoring pending completion of a permanent solution.

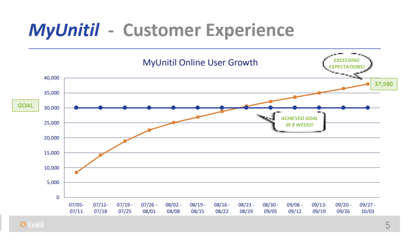
Project performance metrics, referred to commonly as Key Performance Indicators (KPIs), help to ensure a transition that minimizes billing problems, delays in handling customer inquiries, and customer complaints. Monitoring performance through the use of KPIs includes setting targets (the desired level of performance) and tracking performance and progress against targets. Unitil tracked post-go live performance through the following KPIs:

- Complaints to Regulators
- Call Center Service Level
- Average Call Time
- MyUnitil Online User Growth
- Customer Satisfaction.

Unitil's performance following Go-Live, as measured by these KPIs, proved generally positive, as the following graphs demonstrate.







1. *Post Go-Live Support*

At Go-Live, Unitil's "build" of enQuesta became Systems & Software's newest release of enQuesta software. Unitil's HTE-to-enQuesta conversion Go-Live Incident Resolution Plan detailed accountability for addressing the incidents during and after business hours through the first 100 days, and post 100 days. Unitil contracted with Systems & Software and Grant Thornton to provide on-site support in July and August, with a commitment from Systems & Software to continue incident resolution until zero incidents.

A Command Center and Incident Analysis Team, manned with Grant Thornton individuals, had responsibility for classifying and routing incidents.

After the post Go-Live period (100 days), Unitil made problem resolution part of the everyday workload, with incident support moving to Unitil's Trouble Ticketing System (TESS). Unitil released temporary staffing and project management transitioned to business process managers.

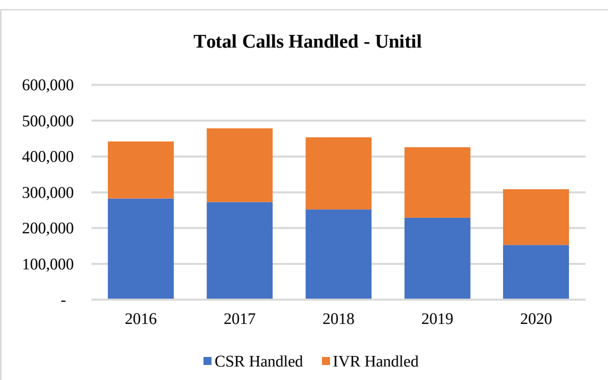
As part of project wrap-up, Unitil solicited feedback about the project from various business groups in August, following Go-Live. A review of this feedback reveals the following themes:

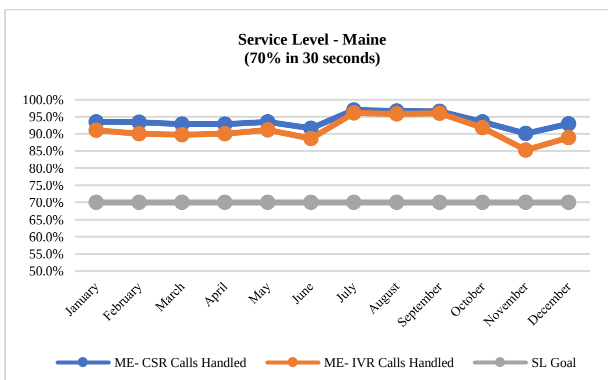
- Business Owners and operations were not involved early enough in the project
- Early project lacked Executive Sponsorship and underestimated effort
- Go-live issues
- Testing gaps/completeness.

Capturing lessons learned is an important step in project management. Unitil captured its lessons learned as part of the post-project review process. A best practices approach is to capture lessons learned throughout the project lifecycle, not just at completion. It is important to capture both successes and failures on projects and to leverage these lessons in future projects so any failed lessons can be avoided.

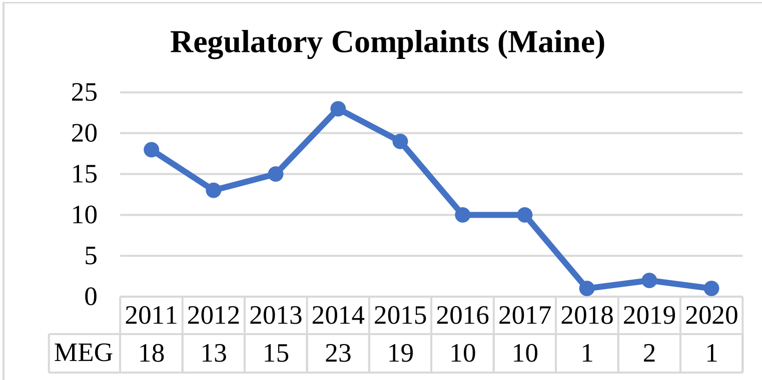
2. *Post Go-Live Customer Service Performance*

A review of total customer calls handled prior to, during, and following the enQuesta go-live shows slightly increased call volumes during 2017, with IVR calls hitting a 5-year peak in 2017 (note that IVR calls include the October 2017 storm). In Maine, service level remained well above goal during 2017 for CSR and IVR handled calls.





A review of Unitil's Maine Regulatory Complaints shows a steady decline since 2014 with minimal complaints registered in 2017 and very few in years 2018, 2019, and 2020 (October).



Unitil Maine issues more than 400,000 bills each year to customers. Since enQuesta's deployment, Unitil Maine experienced very few estimated bills or re-bills as seen in the following table.

Post-Implementation Rebills and Estimated Bills

Year	Rebills	Estimated Bills
2017 July to Dec	211	132
2018	1,653	263
2019	640	347
2020 (Jan to July)	348	405

Since enQuesta go-live, Unitil has issued most bills to customers within a day of obtaining the meter reading. The following table shows the number of bills issued by day following the meter reading.

Post-Implementation Billing Dates

	2017	2017%	2018	2018%	2019	2019%	2020	2020%
1 Day--->	172,388	87.6%	359,703	89.3%	392,432	95.6%	242,251	99.4%
2 Days--->	21,533	10.9%	31,731	7.9%	17,325	4.2%	1,019	0.4%
3 Days--->	1,928	1.0%	7,998	2.0%	244	0.1%	233	0.1%
4 Days--->	155	0.1%	410	0.1%	98	0.0%	135	0.1%
5 Days--->	211	0.1%	83	0.0%	70	0.0%	56	0.0%
6 Days--->	32	0.0%	442	0.1%	30	0.0%	31	0.0%
7 Days--->	19	0.0%	910	0.2%	23	0.0%	20	0.0%
8 to 14 Days--->	55	0.0%	1,318	0.3%	70	0.0%	69	0.0%
Over 14 Days--->	393	0.2%	8	0.0%	9	0.0%	2	0.0%
Total	**196,714**	**100.0%**	**402,603**	**100.0%**	**410,301**	**100.0%**	**243,816**	**100.0%**

Liberty's review of Unitil's customer service performance prior to, during, and following the enQuesta go-live shows a high level of service with no apparent service degradation. While call volumes increased slightly in 2017, regulatory complaints remained low, call handling service levels exceeded goal, most bills were issued on time, and very few bills were estimated.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

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 **CONFIDENTIAL** lists the officers of Northern Utilities, Inc. (“Northern”). These officers receive no direct compensation from Northern for their services. Rather, each officer of Northern is an employee of Unitil Service Corp. (“Unitil Service”), and their entire compensation for all job responsibilities is paid 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 19.85% of the total compensation was allocated to Northern - NH in 2019, and approximately 20.18% was allocated to Northern - NH in 2020.

The compensation listed for officers Meissner, Black, Brock, Collin, Hevert, LeBlanc 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, Hurstak, 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 Northern’s Petition.

Attachment 2 lists the directors of Northern and the total annual compensation for each person in 2019 and 2020. As is the case with Northern’s officers, Northern’s Board of Directors receives no direct compensation from Northern. All Directors’ compensation in 2019 and 2020 was allocated to Unitil Corporation’s subsidiaries through the Unitil Service billing system, with amounts allocated to Northern – NH using the same percentages as indicated above for the allocation of compensation for Northern’s officers.

PUC 1604.01(a) - 14 Att 1

REDACTED

Northern Utilities, 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]
LeBlanc	VP	$ 211,550.00	$ 88,153.00	$ 60,156.55	$ 224,125.00	$ 90,120.00	$ 74,338.39
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]
OFFICERS' TOTAL CALENDAR YEAR 2019 / OFFICERS' TOTAL CALENDAR YEAR 2020		**$ 2,523,963.00**	**$ 1,307,762.00**	**$ 1,976,128.43**	**$ 3,010,829.00**	**$ 1,424,509.00**	**$ 1,673,255.90**

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

Northern Utilities, 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.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(15) Copies of all officer and executive incentive plans.

Response:

Incentive plans in which officers and executives participate include the following:

Management Incentive Plan – Attachment 1
Unitil Corporation Second Amended and Restated 2003 Stock Plan – Attachment 2

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).

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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 Northern Utilities, Inc. ("Northern"), the voting stock consists solely of common stock. All shares of common stock of Northern are owned by Unitil Corporation. Further, no director or officer, or spouse or minor child owns or controls any of the outstanding shares of common stock individually, directly or indirectly.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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. Quarterly income statements for the previous 2 years if not previously filed with the commission.

Response:

a. N/A
b. Please see PUC 1604.01(a) - 17 Attachment 1 for a list of all payment for contractual services over $50,000.00.
c. N/A
d. Please see PUC 1604.01(a) - 17 Attachment 1 for the total number of items compromising the expenditure.

Northern Utilities, Inc.

PUC 1604.01 (a) - 17
Attachment 1
Page 1 of 1

Company	Total Expenditure	Total Items for Expenditure	Description
AECOM	230,010.18	24	Professional Services
ANDERSON WELDING LLC	313,178.94	11	Construction
APPLUS RTD	66,147.50	38	Professional Services
ATLANTIC HEATING COMPANY INC	87,481.00	119	Professional Services
CENTRAL MAINE POWER	77,212.82	416	Utility
CHASCO INC	425,013.00	35	Professional Services
COASTAL ROAD REPAIR	108,936.75	44	Paving
COLLINS PIPE	641,023.10	231	Materials
CONCENTRIC ENERGY ADVISORS	59,331.75	2	Professional Services
CONSOLIDATED COMMUNICATIONS	98,612.97	71	Utility
CONSOLIDATED COMMUNICATIONS	45,587.03	35	Utility
CONSOLIDATED PIPE & SUPPLY CO INC	216,631.30	5	Materials
CONTINENTAL INDUSTRIES	96,394.06	12	Materials
ELSTER AMERICAN METER	811,587.73	26	Materials
ELSTER PERFECTION CORPORATION	193,326.71	14	Materials
ENERGY FEDERATION INC	316,145.91	64	Incentives
ENERGY SOLUTIONS	134,287.76	21	Professional Services
F W WEBB COMPANY	66,870.09	105	Materials
GDS ASSOCIATES INC	61,609.66	19	Incentives
GORHAM SAND & GRAVEL INC	95,086.50	4	Materials
GRANITE GROUP	119,982.50	137	Rental Program
HART PLUMBING & HEATING INC	70,649.89	107	Plumbing
HEWITT & HEWITT LLC	86,550.00	10	Professional Services
INDEPENDENT PIPE & SUPPLY CO	70,134.47	57	Materials
ISCO INDUSTRIES	56,792.58	5	Materials
ITRON INC	151,450.11	6	Materials
JDH ENERGY SOLUTIONS LLC	325,289.90	108	Construction
K C AUTO REPAIR	214,252.22	173	Vehicle maintenance
KNOWLES INDUSTRIAL SERVICES	62,735.79	4	Professional Services
KUBRA DATA TRANSFER LTD	316,541.29	28	Communications
LIBERTY CONSULTING GROUP	111,228.75	4	Professional Services
MATTER COMUNICATIONS	56,000.00	12	Professional Services
MCDONALD MFG CO	58,115.04	6	Materials
MERCHANTS AUTOMOTIVE GROUP	1,204,580.63	133	Vehicle maintenance
MRC GLOBAL	401,111.02	48	Materials
MUELLER CO.	132,190.92	31	Materials
NEUCO	24,062,706.35	1916	Construction
NEW ENGLAND CONTROLS	66,866.30	16	Materials
NEW ENGLAND TRAFFIC CONTROL	109,670.02	51	Construction
NEWELL & CRATHERN LLC	59,317.84	11	Incentives
NG ADVANTAGE LLC	120,467.32	1	Construction
OMARK CONSULTANTS INC	146,293.88	68	Construction
PATRIOT MECHANCIAL LLC	1,001,537.13	341	Construction
PAVEMENT TREATMENTS, INC.	132,375.61	16	Paving
PIERCE ATWOOD LLP	142,360.39	47	Professional Services
PIONEER INSPECTION LLC	239,041.22	12	Professional Services
PORTSMOUTH CAR CLINIC	91,450.19	252	Vehicle maintenance
POWELL CONTROLS	717,264.97	79	Materials
PPI GAS DISTRIBUTION INC	263,273.70	72	Materials
PROCESS PIPELINE SERVICES	600,894.99	86	Construction
QUANTITATIVE BUSINESS ANALYTICS LLC	90,000.00	2	Professional Services
QUARTER TURN RESOURCES	169,788.07	5	Materials
R W LYALL & COMPANY	530,092.37	33	Materials
SANFORD POLICE DEPT	56,022.75	21	Construction
SCADA NETWORK SERVICES INC	81,340.60	13	Professional Services
SCOTTMADDEN INC	99,115.00	7	Professional Services
SHAW BROTHERS CONSTRUCTION	385,873.00	1	Construction
SOUTHERN NH SERVICES	75,882.01	7	Rebate
STRAFFORD COUNTRY COMMUNITY ACTION	251,221.85	13	Rebate
TITAN MECHANICAL INC	13,332.72	10	Construction
TMD SERVICE	14,915.00	9	Construction
TRI MONT ENGINEERING CO	1,225,889.71	35	Professional Services
UPSCO INC	163,703.24	23	Materials
UTILITIES & INDUSTRIES	147,207.39	11	Materials
WILLIAM WELLS	128,669.15	12	Professional Services
WOOD ENVIRONMENTAL	66,935.49	15	Professional Services

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(18) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations.

Response:

Per past rate-making treatment in New Hampshire, water heaters and conversion burners are included in the cost of service.

	Amount – 12/31/20
Utility Plant in Service	$ 1,893,900
Completed Construction Not Classified	84,995
Utility Plant in Service	1,978,895
Reserve for Depreciation	959,565
Net Utility Plant in Service	$ 1,019,330

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
Inc Stmt - NH - Rate Case
G_NU_NH_ISQ_Rate Case

Schedule 4 NH
5/5/2021
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								
Sales:								
Residential (480)	$17,297,900.33	$6,893,753.73	$2,763,678.97	$7,561,894.10	$13,498,306.05	$6,274,846.81	$2,757,279.77	$7,510,902.07
General Service (481)	14,339,998.13	5,583,142.74	2,469,239.92	5,914,453.24	9,908,747.36	4,304,388.35	2,227,408.36	5,881,355.87
Firm Transport Revenues (484, 489)	3,385,106.39	2,203,157.39	1,636,242.38	2,605,361.12	3,385,617.77	2,082,894.55	1,616,713.87	2,654,587.41
Sales for Resale (483)	2,480,636.94	192,625.69	36,327.05	161,389.30	725,085.32	130,520.47	74,843.45	177,010.21
Other Sales (495)	(5,720,375.24)	(3,555,748.19)	1,390,872.75	4,369,811.68	(2,948,222.62)	(1,294,125.26)	2,719,598.64	3,767,366.60
Total Sales	31,783,266.55	11,316,931.36	8,296,361.07	20,612,909.44	24,569,533.88	11,498,524.92	9,395,844.09	19,991,222.16
Other Operating Revenues:								
Late Charge (487)	16,690.38	35,805.55	14,405.35	9,871.87	36,802.72	(41.37)	(0.79)	0.00
Misc. Service Revenues (488)	189,543.15	203,559.87	230,178.89	252,473.05	195,522.26	184,147.70	227,097.71	245,535.90
Rent from Property (493 & 457)	50,238.00	50,238.00	50,238.00	50,238.00	54,657.00	54,657.00	54,657.00	54,657.00
Other Revenues	(295,304.18)	(46,606.52)	6,655.70	23,667.61	(43,223.23)	(1,192.72)	130,297.58	34,774.44
Total Other Operating Revenues	(38,832.65)	242,996.90	301,477.94	336,250.53	243,758.75	237,570.61	412,051.50	334,967.34
TOTAL OPERATING REVENUES	31,744,433.90	11,559,928.26	8,597,839.01	20,949,159.97	24,813,292.63	11,736,095.53	9,807,895.59	20,326,189.50
OPERATING EXPENSES								
Operation & Maint. Expenses:								
Production (710-813)	15,897,984.69	2,992,646.32	1,803,296.09	7,532,804.26	9,679,399.66	3,734,187.69	3,281,204.15	6,850,068.35
Transmission (850-857)	14,925.74	18,508.91	20,591.29	18,687.07	16,482.16	15,657.39	12,962.87	18,726.49
Distribution (870-894) (586)	825,902.76	829,704.98	973,980.45	879,860.20	914,785.18	837,253.58	974,637.13	1,006,701.18
Cust. Accounting (901-905)	796,921.15	614,299.84	740,995.02	616,541.95	717,133.94	502,507.61	597,049.97	791,497.42
Cust. Service & Info (906-910)	475,075.64	493,122.36	458,269.04	892,907.98	584,640.54	384,754.36	425,587.90	946,722.73
Sales Expenses (911-916)	18,673.75	17,084.36	12,737.55	15,971.54	17,779.26	15,158.77	16,924.44	19,315.28
Admin. & General (920-935)	2,001,034.98	1,953,404.11	2,060,366.26	1,664,485.80	1,934,001.93	1,504,409.67	1,518,700.11	1,783,664.79
Total O & M Expenses	20,030,518.71	6,918,770.88	6,070,235.70	11,621,258.80	13,864,222.67	6,993,929.07	6,827,066.57	11,416,696.24
Other Operating Expenses:								
Deprtn. & Amort. (403-407)	2,441,576.01	2,082,009.70	2,212,111.30	2,269,246.37	2,402,289.30	2,406,501.08	2,408,757.41	2,476,010.97
Taxes-Other Than Inc. (408)	1,218,120.73	925,510.62	996,155.03	1,166,511.12	1,251,898.27	1,273,193.69	1,245,615.57	1,097,066.41
Federal Income Tax (409)	(339.69)	(1,030,359.41)	50,284.72	1,032,794.57	(9,122.89)	4,342.47	(14,832.03)	(10,598.62)
State Franchise Tax (409)	(138.75)	(420,859.28)	(310,425.43)	421,876.01	(3,624.12)	1,725.07	(397,389.42)	14,644.69
Def. Income Taxes (410,411)	1,841,423.87	1,564,761.43	(237,311.03)	(193,191.18)	1,641,046.53	(41,173.10)	(87,341.26)	1,087,646.79
Total Other Operating Expenses	5,500,642.17	3,121,063.06	2,710,814.59	4,697,236.89	5,282,487.09	3,644,589.21	3,154,810.27	4,664,770.24
TOTAL OPERATING EXPENSES	25,531,160.88	10,039,833.94	8,781,050.29	16,318,495.69	19,146,709.76	10,638,518.28	9,981,876.84	16,081,466.48
NET UTILITY OPERATING INCOME	6,213,273.02	1,520,094.32	(183,211.28)	4,630,664.28	5,666,582.87	1,097,577.25	(173,981.25)	4,244,723.02
OTHER INCOME & DEDUCTIONS								
Other Income:								
Other (415- 421)	53,130.56	59,976.42	87,780.59	41,899.27	81,066.45	30,889.15	100,617.63	(6,234.44)
Other Income Deduc. (425, 426)	51,374.24	57,835.74	66,764.18	56,661.55	34,000.01	53,292.65	24,096.80	40,354.73
Taxes Other than Income Taxes:								
Income Tax, Other Inc & Ded	478.44	583.14	5,725.08	(4,035.03)	12,747.01	(6,067.54)	20,724.13	(12,617.75)
Net Other Income (Deductions)	1,277.88	1,557.54	15,291.33	(10,727.25)	34,319.43	(16,335.96)	55,796.70	(33,971.42)
GROSS INCOME	6,214,550.90	1,521,651.86	(167,919.95)	4,619,937.03	5,700,902.30	1,081,241.29	(118,184.55)	4,210,751.60
Interest Charges (427 - 432)	1,237,862.07	1,157,776.47	1,124,118.49	1,154,224.71	1,256,222.14	1,164,752.88	1,115,083.71	1,242,381.81
NET INCOME	4,976,688.83	363,875.39	(1,292,038.44)	3,465,712.32	4,444,680.16	(83,511.59)	(1,233,268.26)	2,968,369.79

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
Quarterly Sales Volumes (Therms)
New Hampshire

	Therms Qtr 1 2020	Therms Qtr 2 2020	Therms Qtr 3 2020	Therms Qtr 4 2020	Therms YTD 2020
Residential:					
R-6	83,528	54,674	37,913	55,501	231,616
R-5	8,588,415	3,617,817	1,035,892	4,046,430	17,288,554
R-10	236,594	113,221	23,181	92,303	465,299
Total Residential	8,908,537	3,785,712	1,096,986	4,194,234	17,985,469
Commercial:					
G-40	5,033,279	1,747,006	371,936	2,292,641	9,444,862
G-50	483,244	291,376	342,735	356,407	1,473,762
G-41	6,953,852	2,664,815	728,090	3,402,189	13,748,946
G-51	1,674,092	845,097	839,538	1,110,773	4,469,500
Total Commercial	14,144,467	5,548,294	2,282,299	7,162,010	29,137,070
Industrial					
G-42	2,435,807	1,089,754	620,034	1,677,926	5,823,521
G-52	4,078,851	3,896,872	3,876,176	4,332,317	16,184,216
Special Contract	3,124,848	2,366,008	2,773,498	2,944,269	11,208,623
Total Industrial	9,639,506	7,352,634	7,269,708	8,954,512	33,216,360
Grand Total	32,692,510	16,686,640	10,648,993	20,310,756	80,338,899

	Therms Qtr 1 2019	Therms Qtr 2 2019	Therms Qtr 3 2019	Therms Qtr 4 2019	Therms YTD 2019
Residential:					
R-6	90,111	52,221	36,815	57,534	236,681
R-5	9,528,223	3,651,169	1,004,461	4,573,834	18,757,687
R-10	292,547	119,970	21,470	107,924	541,911
Total Residential	9,910,881	3,823,360	1,062,746	4,739,292	19,536,279
Commercial:					
G-40	6,090,014	2,087,331	463,355	2,536,199	11,176,899
G-50	748,603	426,450	349,002	390,468	1,914,523
G-41	7,135,433	2,712,160	780,334	3,735,745	14,363,672
G-51	1,723,072	1,253,455	1,010,527	1,356,065	5,343,119
Total Commercial	15,697,122	6,479,396	2,603,218	8,018,477	32,798,213
Industrial					
G-42	2,376,724	1,064,178	601,528	1,973,973	6,016,403
G-52	4,569,441	4,447,329	4,079,452	4,158,318	17,254,540
Special Contract	3,225,478	3,245,717	3,122,855	3,110,317	12,704,367
Total Industrial	10,171,643	8,757,224	7,803,835	9,242,608	35,975,310
Grand Total	35,779,646	19,059,980	11,469,799	22,000,377	88,309,802

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(22) A description of the utility's projected need for external capital for the 2 year period immediately following the test year.

Response:

Northern Utilities, Inc. ("Northern") regularly reviews and analyzes its financing requirements. Over the next two years, Northern does not have definitive permanent financing plans. Northern will continue to monitor its need to raise long-term capital and request approval from the Commission if necessary.

For short-term debt financing, Northern 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 subject to annual adjustment.

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
New Hampshire & Maine Divisions
Sources and Uses of Funds for Years 2021 and 2022
Including the Projected Construction Budgets
($000's)

	2021 Forecast	2022 Forecast
Sources:		
Net Income	$ 17,742	$ 20,296
D&A	24,179	26,190
Change in DIT	7,777	4,672
Net Borrowings and Other	28,574	24,729
Total Uses	$ 78,272	$ 75,886
Uses:		
Capex	$ 64,388	$ 63,107
Dividends	13,884	12,779
Debt Retirements	-	-
Total Uses	$ 78,272	$ 75,886

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Northern Utilities, Inc.
Short-Term Debt Outstanding
12 Months Ended December 31, 2020

Line No.	Month	Month-End Amount Outstanding	Average Daily Borrowings
1	January 2020	$ 28,666,840	$ 25,109,148
2	February 2020	24,794,114	23,351,619
3	March 2020	28,316,841	27,127,612
4	April 2020	27,939,753	25,053,060
5	May 2020	26,822,898	25,283,108
6	June 2020	25,298,270	24,327,028
7	July 2020	33,152,219	29,181,116
8	August 2020	37,754,315	34,429,766
9	September 2020	4,906,721	20,504,100
10	October 2020	18,132,923	9,559,681
11	November 2020	22,751,664	19,566,665
12	December 2020	26,747,022	24,606,907

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.

Unitil
NH GAS OPERATIONS

Northern Utilities, Inc.

Pursuant to the New Hampshire Code of Administrative Rules, Part 1604.01(a)(25), Northern Utilities, Inc., hereby certifies the following:

No expense for the parent company (Unitil Corporation) is included in the cost of service for Northern Utilities, Inc., as filed in this rate case.

Daniel J. Hurstak
Controller
Northern Utilities, Inc.

State of New Hampshire
County of Rockingham, ss.

Signed and sworn this

18th day of May, 2021

Notary Public

Sandra L. Whitney
NOTARY PUBLIC
State of New Hampshire
My Commission Expires January 22, 2025

Northern Utilities, Inc.
DG 21-104

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(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.