UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

JEFFREY M. PENTZ

New Hampshire Public Utilities Commission

Docket No. DE 21-041

April 2, 2021

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LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jeffrey M. Pentz. My business address is 6 Liberty Lane West, Hampton, NH 03842.

Q. What is your relationship with Unitil Energy Systems, Inc.?

A. I am employed by Unitil Service Corp. ("USC") as a Senior Energy Analyst. USC provides management and administrative services to Unitil Energy Systems, Inc. ("UES") and Unitil Power Corp. ("UPC").

Q. Please briefly describe your educational and business experience.

A. I received my Bachelor of Arts degree in Economics from the University of Massachusetts. Before joining Unitil I worked as a Contracting and Transaction Analyst with Mint Energy, a retail electric supplier. My range of responsibilities included contract negotiation with brokers and customers, retail billing, and sales. Prior to Mint Energy, I worked as a data analyst for Energy Services Group. My responsibilities included supplier business transaction testing and integration with regulated utilities. I joined USC in February 2016 as an Energy Analyst with the Energy Contracts department. In January 2019 I was promoted to my current position as Senior Energy Analyst. I have primary responsibilities in the areas of load settlement, renewable energy credit procurement, renewable portfolio standard compliance, default service procurement, market research and operations, and monitoring renewable energy policy.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I have testified before the Commission in previous Default Service Solicitation proceedings.

II. PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony.

A. This testimony documents the solicitation process followed by UES in its acquisition of Default Service power supplies ("DS") for its G1 and Non-G1 customers as approved by the Commission in Order No. 25,397, dated July 31, 2012 (the "Order") granting UES's Petition for Approval of Revisions to its Default Service Solicitation Process for G1 and Non-G1 Customers.. With the current Request for Proposal ("RFP"), UES has contracted for a six-month default service power supply for 100% of its small customer group (Non-G1); 100% of its medium customer group (Non-G1); and 100% of its large customer group (G1) service requirements. Service begins on June 1, 2021.

Q. Please describe the documents provided with this filing.

Supporting documentation and additional detail of the solicitation process is provided in the Bid Evaluation Report ("Report"), attached as Schedule JMP-1. The structure, timing and requirements associated with the solicitation are fully described in the RFP issued on March 2, 2021 and is attached as Schedule JMP-2. An updated Customer Migration Report is attached as Schedule JMP-3. The Customer Migration Report shows monthly retail sales and customer counts supplied by competitive generation, total retail sales and customer counts (the sum of default service and competitive generation) and the percentage of sales and customers supplied by competitive generation. The report provides a rolling 13-month history which covers the period from February 2020 through February 2021. Renewable Portfolio Standard ("RPS") Compliance Cost Estimates are included as Schedule JMP-4. My testimony reviews UES's approach to compliance with the RPS which went into effect in January 2008. Schedule JMP-4 details projected obligations and price assumptions for the coming rate period. The price assumptions are based on recent market data information and alternative compliance payment prices. Lastly, Schedule JMP-5 provides historical price data by customer group that is no longer subject to confidential treatment. This schedule provides pricing histories associated with the most recent six-month rate periods for Non-G1 and G1 customers for which all pricing is currently subject to the Federal Energy Regulatory Commission's quarterly reporting requirements.

Q. Please summarize the approvals UES is requesting from the Commission.

A. UES requests that the Commission:

- Find that: UES has followed the solicitation process approved by the Commission; UES's analysis of the bids submitted was reasonable; and UES has supplied a reasonable rationale for its choice of the winning suppliers.

- Find that: the price estimates of renewable energy certificates ("RECs") proposed by UES, which are based on actual purchases or current market prices and information, are appropriate for inclusion in retail rates.
- On the basis of these findings, conclude that the power supply costs resulting from the solicitation are reasonable and that the amounts payable to the sellers under the supply agreements are approved for inclusion in retail rates.
- Issue an order granting the approvals requested herein on or before April 9, 2021, which is five (5) business days after the date of this filing.

III. SOLICITATION PROCESS

Q. Please discuss the Solicitation Process UES employed to secure the supply agreements for default service power supplies.

A. UES conducted an open solicitation in which it actively sought interest among potential suppliers to provide load-following power supply to its Default Service customers. UES provided bidders with appropriate information to enable them to assess the risks and obligations associated with providing supply services. UES did not discriminate in favor of or against any individual potential supplier who expressed interest in the solicitation. UES negotiated with all potential suppliers who submitted proposals to obtain the most favorable terms from each potential supplier. The structure, timing and requirements associated with the solicitation are fully described in the RFP issued on March 2, 2021. This is attached as Schedule JMP-2 and is summarized in the Bid Evaluation Report attached as Schedule JMP-1.

Q. How did UES ensure that the RFP was circulated to a large audience?

A. UES announced the electronic availability of the RFP to a list of power suppliers and brokers. The RFP was also distributed to all members of the NEPOOL Markets Committee and Participants Committee. As a result, the RFP had wide distribution throughout the New England supply marketplace, including distribution companies, consultants, and members of public agencies. UES followed up the E-mail solicitation with outreach to power suppliers to solicit their interest in bidding on any and all customer classes.

Q. What information was provided in the RFP to potential suppliers?

A. The RFP provides background information and historical data, details the service requirements and commercial terms, explains the process for selecting the winning bidders. To gain the greatest level of market interest in supplying the load, UES provided potential bidders with appropriate and accessible information. Data provided included historical hourly default service loads and daily capacity tags for each customer group; class average load shapes; historical monthly retail sales and customer counts by rate class and supply type; and the evaluation loads, which are the estimated monthly volumes that UES would use to weigh bids in terms of price. The retail sales report and the historical loads and capacity tag values were updated prior to final bidding to provide the latest information available.

Q. How did UES evaluate the bids received?

A. UES evaluated the bids on both quantitative and qualitative criteria, including price, market conditions, creditworthiness, willingness to extend adequate credit to UES to facilitate the transaction, capability of performing the terms of the RFP in a reliable manner and the willingness to enter into contractual terms acceptable to UES. UES compared the pricing strips proposed by the bidders by calculating weighted average prices for the supply requirement using the evaluation loads that were issued with the RFP.

Q. How did market conditions impact the prices for this next period?

A. Overall, pricing submitted for the Small and Medium classes (Non-G1) for the upcoming period from June 1, 2021 – November 30, 2021 is 9% higher than the same period a year ago and 26% lower than the previous 6-month period from December 1, 2020 to May 31, 2021. Pricing for the large customer class (G1) adder is 25% lower than the previous 6-month period and 2% lower than the same period a year ago. The decrease in pricing compared to the previous period can be attributed to seasonal decreases in forward natural gas prices, which have a direct effect on power futures. Lower capacity prices in the 2021-2022 capacity commitment period could also be a factor. The FCA clearing price for the 2020-2021 capacity period was $5.30/KW-month, while the clearing price for the 2021-2022 capacity period is $4.63/KW-month The increase in pricing compared to the same period last year can be attributed to higher forward natural gas prices, when compared to forward prices from one year ago. Considering these market conditions, the company determined that the pricing submitted was fair and competitive.

Q. Please summarize the winning bidders for each customer supply requirement.

A. UES selected NextEra Energy Marketing, LLC ("NextEra") as the winning bidder for the small customer (Non-G1) supply requirement (100% share) and the medium customer (Non-G1) supply requirement (100% share). UES Selected Exelon Generation Company, LLC ("Exelon") as the winner of the large customer (G1) supply requirement (100% share). All three transactions are for a period of six months. UES believes that NextEra and Exelon offer the best overall value in terms of both price and non-price considerations for the supply requirements sought.

Q. Please describe the contents of the Bid Evaluation Report.

A. Schedule JMP-1 contains the Bid Evaluation Report which further details the solicitation process, the evaluation of bids, and the selection of the winning bidders. The Report contains a narrative discussion of the solicitation process. Additional discussion regarding the selection of the winning bidders is provided along with several supporting exhibits that list the suppliers who participated, as well as the pricing they submitted and other information considered by UES in evaluating final proposals, including redlined versions of the final supply agreements.

On the basis of the information and analysis contained in the Bid Evaluation Report, UES submits that it has complied with the Commission's requirements, and that the resulting default service power supply costs are reasonable and that the amounts payable to the sellers under the supply agreements should be approved for inclusion in retail rates.

Q. Please elaborate on the supplier response to this solicitation.

A. UES followed up with a number of suppliers early in the process to solicit and gauge supplier interest. Bidder response for this solicitation deceased slightly when compared to the prior solicitation, due to one supplier temporarily halting participation in all default solicitations due to market conditions in Texas. The response from suppliers bidding an add-on charge for the G-1 large load continues to be limited, and participation levels remained the same when compared to the previous solicitation. Feedback from some bidders is the large load class is too small to serve. Additionally, large customer migration to a third party supplier is a concern for some bidders. The Company will continue to reach out to suppliers to encourage their participation.

Q. Please indicate the planned issuance date, filing date and expected approval date associated with UES's next default service solicitation.

A. Similar to the current solicitation, UES's next default service solicitation will be for one hundred percent (100%) of the small, medium and large customer supply requirements for a six-month period. Delivery of supplies will begin on December 1, 2021. UES plans to issue an RFP for these supplies on August 31, 2021, with a filing for approval of solicitation results planned for October 1, 2021 and approval anticipated by October 9, 2021.

IV. RENEWABLE PORTFOLIO STANDARD COMPLIANCE

Q. Please explain how UES is complying with the Renewable Portfolio Standard requirements.

A. In accordance with the settlement agreement dated July 16, 2009 (DE. 09-009) and as amended on December 6, 2011, UES will conduct two REC RFPs during each compliance year to obtain Existing RECs and/or Forward RECs to meet 100% of its projected REC obligations. In addition, UES may make REC purchases outside of the RFP process when it finds it advantageous to do so. To meet its 2020 and 2021 RPS compliance requirements, UES issued an RFP in October 2020 for approximately half of its 2020 and 2021 RPS requirements. UES plans on issuing a second RFP in October 2021 for the remainder of 2021 RPS requirements and half of its 2022 requirements. Tab A includes an exhibit summarizing UES's REC purchases for RPS compliance.

Q. Please describe UES's estimates of RPS compliance costs.

A. The current solicitation is for default service power supplies to be delivered beginning June 1, 2021. Schedule JMP-4 lists the percentage of sales and the resulting REC requirement for each class of RECs for RPS compliance along with UES's cost estimates for the period beginning June 1, 2021. UES's cost estimates are based on current market prices as communicated by brokers of renewable products, recent purchases of RECs, and alternative compliance payment rates ("ACP").

Q. Does UES's estimate of RPS costs incorporate the latest RPS requirements for 2021?

A. Yes. The following table provides a summary of the RPS requirements.

NH Renewable Portfolio Standards: 2021

Calendar Year	Class I *	Class I Thermal	Class II	Class III	Class IV
2021	11.40%	1.8%	0.7%	8.00%	1.5%

*Class I is the gross requirement which includes Class I Thermal. The net Class I requirement less the Class I Thermal Carve-Out requirement for 2020 is 8.9%, and 9.6% for 2021

Schedule JMP-4 RPS Compliance Costs Estimates incorporates the latest RPS requirements shown here.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

DE 21-041 – Unitil Energy Systems, Inc.

Default Service RFP
Bid Evaluation Report

Small Customers (100%): June 1, 2021 – November 30, 2021
Medium Customers (100%): June 1, 2021 – November 30, 2021
Large Customers (100%): June 1, 2021 – November 30, 2021

RFP Issue Date: March 2, 2021

Filing Date: April 2, 2021

Unitil Energy Systems, Inc. (“UES”)
Default Service RFP
Bid Evaluation Report

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Unitil Energy Systems, Inc.
Bid Evaluation Report

Introduction

On Tuesday, March 2, 2021, UES announced that its Request for Proposals ("RFP") for Default Service ("DS") supplies for the period beginning June 1, 2021 was available. In accordance with UES's DS supply proposal as approved by the Commission in Order No. 25,397 ("the Order"), UES issued this RFP to obtain fixed monthly price offers to supply one-hundred percent (100%) of the small and medium customer groups for the six-month period beginning June 1, 2021. In addition, UES also sought variable monthly prices to supply one-hundred percent (100%) of the G1, or large customer default service group, for a six-month period beginning June 1, 2021. The RFP sought monthly adders (which would be fixed for the month, but could vary by month) that would be added to the real-time locational marginal price to determine the wholesale cost.

The RFP issued on March 2, 2021, was consistent in form and substance to the prior RFP issued by UES on August 25, 2020. On March 17, 2021, UES filed with the Commission a redlined version of the current RFP, marked to show changes from the RFP issued on August 25, 2020. A copy of the RFP documents issued to the market on March 2, 2021, including the Proposal Submission Form, the proposed Power Supply Agreement ("PSA"), the proposed PSA Amendment, and Non-Disclosure Agreement are attached to the petition as Schedule JMP-2.

UES received bids from qualified suppliers who competed to serve the load requirements. The winner of the six-month small customer (Non-G1) default service requirement and the medium customer (Non-G1) default service requirement was Nextera Energy Marketing, LLC ("Nextera"). The winner of the six-month large customer (G1) default service requirement was Exelon Generation Company, LLC ("Exelon"). These suppliers offer the best overall value for the service requirements. The default service power supply prices obtained by UES are the result of a competitive solicitation and are reflective of current market conditions. This Bid Evaluation Report ("Report") describes UES's solicitation process and its selection of the winning bidders.

UES's comparison of bids, which is confidential and for which UES seeks protective treatment as described in the cover letter and motion for protective treatment accompanying this filing, is included in Tab A to this Report. Details of the market response, including bid prices, and certain non-price considerations and selection rationale, are also included in the Tab A materials.

Solicitation Process

UES issued its request for proposals on Tuesday, March 2, 2021 to 25 suppliers and brokers. The RFP was also distributed to all members of the NEPOOL Markets Committee and the Participants Committee. As a result, the RFP had wide distribution throughout the New England supply marketplace.

The RFP documents and accompanying data files were provided to interested parties via the Company's RFP website. The RFP described the specifics of UES's DS, the related customer-switching rules, the form of power service sought, and the evaluation criteria. The RFP documents included a Proposal Submission Form, a proposed Power Supply Agreement ("PSA"), proposed PSA Amendment for use by suppliers who are currently serving load or have previously served load, a Non-Disclosure Agreement, and various data files.

To gain the greatest level of market interest in supplying the loads, UES provided potential bidders with appropriate information, including along with the RFP, UES provided historical hourly loads and daily capacity tag values for UES's DS customers for the period from January 1, 2015 through February 28, 2021. UES also provided an Excel spreadsheet containing historic retail monthly sales and customers reports from January 1, 2015 through February 28, 2021. The monthly reports detail by customer rate class the monthly retail billed kWh sales and the number of customers receiving DS and competitive generation supply. Also provided to potential suppliers was class average load shape (8760 hours) data and distribution loss factors associated with each rate class.

Lastly, UES provided Bid Sheets with estimated monthly volumes expected to be purchased under default service for the term during which service was sought. As described in the RFP, UES used these estimated monthly loads to evaluate and weigh competing bids in terms of price. In the RFP, UES refers to these estimated loads as the "evaluation loads." The RFP makes clear that the supplier's obligation is for actual loads and is not in any way limited by the RFP's use of the evaluation loads.

Throughout the solicitation, UES contacted potential bidders, responded to bidder questions, researched bidder qualifications and actively participated in maintaining bidder interest through regular telephone and electronic communications. UES did not discriminate in favor of or against any individual potential supplier who expressed interest in the solicitation, but endeavored to assist each interested bidder in their understanding of the transaction sought via the solicitation.

On March 16, 2021, UES received proposals from respondents that included detailed background information on the bidding entity, proposed changes to the contract terms and indicative pricing. UES reviewed the proposals and worked with the bidders to establish and evaluate their creditworthiness, their extension of adequate credit to UES to facilitate the transaction, their capability of performing the terms of the PSA in a reliable manner and their willingness to enter into contractual terms acceptable to UES. UES negotiated with all potential suppliers who submitted proposals to obtain the most favorable contract terms. All bidders were invited to submit final bids.

On March 30, 2021, UES received final pricing from bidders and conducted its evaluation. UES selected and notified Nextera that they were the winner of the small and medium default service requirement. Exelon was notified they were the winner of the large default service requirement. All other bidders were notified that they were not selected.

Selection of Winning Bidders

UES based its selection of the winning bidders on both quantitative and qualitative criteria. Indicative bids were compiled and ranked based upon weighted average prices using the evaluation loads that were issued to bidders and assessed for any outliers. UES coordinated with bidders to obtain the best non-price terms each bidder was willing to offer and to establish confidence in each bidder's ability to perform. Final bids were again ranked based on the weighted average prices using the evaluation loads. In addition to the bid price and ability to meet credit requirements, UES also performed a qualitative review of each bidder's ability to provide default service during the service period, including the following:

- The bidder's past experience in providing similar services to UES;
- The bidder's past experience in providing similar services to other companies in New England and other regions;
- The bidder's demonstrated understanding of the market rules related to the provision of Default Service;
- The bidder's demonstrated understanding of its obligations under the proposed Power Service Agreement;
- Whether there have been any past or are there any present events that are known that may adversely affect the bidder's ability to provide Default Service.

UES has significant prior direct experience and working relationships with all of the suppliers who participated in the RFP. For newer suppliers, UES seeks input from references in order to verify the capabilities of the supplier, as well as performing an internal review of the new suppliers' financials for creditworthiness. The comparison of bids, which is confidential and which includes materials documenting UES's rationale for its selection of the winning bidders, is contained in Tab A.

DE 21-041 – Unitil Energy Systems, Inc.

Default Service RFP
Bid Evaluation Report

Small Customers (100%): June 1, 2021 – November 30, 2021
Medium Customers (100%): June 1, 2021 – November 30, 2021
Large Customers (100%): June 1, 2021 – November 30, 2021

RFP Issue Date: March 2, 2021

REDACTED

TAB A
CONFIDENTIAL ATTACHMENT

Filing Date: April 2, 2021

Unitil Energy Systems, Inc. (“UES”)
Default Service RFP
Bid Evaluation Report

Tab A. Comparison of Bids

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Unitil Energy Systems, Inc.
Bid Evaluation Report - Tab A

Discussion of Results

On March 30, 2021 UES selected Nextera Energy Marketing, LLC ("Nextera") as the winning bidder of the small customer (Non-G1) supply requirement (100% share) and the medium customer (Non-G1) supply requirement (100% share). UES selected Exelon Generation Company, LLC ("Exelon") as the winner of the large customer (G1) supply requirement (100% share). The supply requirements are for the provision of default service power supplies beginning June 1, 2021. As shown in the attached pages, the winning bidders represent the results of an open, competitive solicitation process.

<u>Bidding Activity</u>

[redacted] The attached bidder key in Tab A(1) lists all the participating suppliers. UES reviewed the bids received, evaluated the pricing as competitive, and proceeded to contract with the winning suppliers.

<u>Selection of Winners</u>

The pricing comparison summaries shown in Tab A(2) list the bids received and ranks the bids according to price. The summaries also indicate the payment terms negotiated with each bidder and the interest costs associated with the payment terms calling for payment earlier than the end of the month after service is delivered. The total costs, and the deltas from the low price bidder's costs, listed in these sections include the interest costs associated accelerated payment terms.

Contract Provisions

To implement the transactions, UES executed an Amendment to the existing Power Supply Agreement ("PSA") with NextEra and Exelon. A Redlined version of the Amendment to the PSA issued with the RFP are attached as Tab A(8). The Amendment for Nextera and Exelon adds the new transactions to Appendices A and B of their existing PSA. The Amendments are subject to termination if UES is unable to obtain Commission approval of the Petition by April 16, 2021. UES respectfully submits that a Commission decision by April 9, 2021, in accordance with the schedule established in Order No. 24,511, is important to the ongoing vitality of the solicitation process.

The materials listed in the Table of Contents as Tab A(1) through Tab A(8) follow. UES welcomes feedback from the Commission on the value of the following materials in facilitating its review of the solicitation results.

Tab A(1). Bidder Key

The first item attached to this Comparison of Bids identifies the bidding entities who responded to UES's RFP for default service supplies. The materials that follow generally refer to the respondents as Bidder A, Bidder B, and so on.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Indexed Bidder List with Selected Winners

Index	Bidding Entity
[redacted]	

Winner	Customer Group and Supply Period
Bidder	Small Customers, 6 Months Starting Jun 1, 2021
Bidder	Medium Customers, 6 Months Starting Jun 1, 2021
Bidder	Large Customers, 6 Months Starting Jun 1, 2021

Tab A(2). Pricing Summaries

The second item attached to this Comparison of Bids shows summaries of the final bids received, including the total costs calculated on the basis of the evaluation loads and a ranking of the bids in terms of evaluated prices. The summaries list the cost delta and percentage of price delta of each bid compared to the lowest price bid. The summaries indicate the payment terms agreed to with each bidder and include the cost of differing payment terms among the bidders [redacted]

Pricing exhibits:

- G1 Bids, 6 Month Period
- Non-G1 Bids, 6 Month Period
- G1 Summary Pricing
- Non-G1 Summary Pricing

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Pricing Comparison

Bids for Small Customers (Asset 11451) - FINAL
Default Service Requirements for 6 Months ($/MWH)

Month of Service	Eval Loads (MWh)	[redacted]
Jun-21	35,472	
Jul-21	40,340	
Aug-21	48,822	
Sep-21	42,916	
Oct-21	31,225	
Nov-21	33,479	
PERIOD	232,254	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Pricing Comparison

Bids for Medium Customers (Asset 11452) - FINAL
Default Service Requirements for 6 Months ($/MWH)

Month of Service	Eval Loads (MWh)	
Jun-21	15,344	[redacted]
Jul-21	16,146	
Aug-21	18,243	
Sep-21	17,211	
Oct-21	13,957	
Nov-21	13,987	
PERIOD	94,888	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

for Corp Guaranty Coverage

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Pricing Comparison

Bids for Large Customers (Asset 10019)- FINAL

100% DS Requirements for 6 Months ($/MWH) - Variable Price Adder

Month of Service	Evaluation Loads (MWh)	
Jun-21	3,997	[redacted]
Jul-21	4,449	
Aug-21	4,622	
Sep-21	4,297	
Oct-21	3,856	
Nov-21	3,815	
PERIOD	25,037	
POWER COST ($000)		
PAYMENT TERMS		
INT. COST ($000)		
TOTAL COST ($000)		
COST DELTA ($000)		
PRICE RANKING		
PERCENT DELTA		

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Historical Pricing Comparison, G1 Customers

	G1 Supplier	G1 Pricing ($/MWH)	G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
May-16	CECG	$ 36.55	3,107			
Jun-16	CECG	$ 35.25	4,204	$ 39.22	-3.8%	-13 0%
Jul-16	CECG	$ 44.49	4,752			
Aug-16	CECG	$ 55.60	4,634			
Sep-16	CECG	$ 42.64	4,287	$ 45.84	16.9%	-20 5%
Oct-16	CECG	$ 37.32	3,702			
Nov-16	CECG	$ 38.45	3,446			
Dec-16	EXELON	$ 70.12	3,867	$ 54.07	18.0%	18.4%
Jan-17	EXELON	$ 51.77	3,558			
Feb-17	EXELON	$ 44.56	2,988			
Mar-17	EXELON	$ 48.13	3,259	$ 46.32	-14.3%	13.6%
Apr-17	EXELON	$ 46.11	3,060			
May-17	EXELON	$ 38.26	3,396			
Jun-17	Nextera	$ 52.15	3,363	$ 47.99	3.6%	22.4%
Jul-17	Nextera	$ 53.47	3,482			
Aug-17	Nextera	$ 51.90	3,536			
Sep-17	Nextera	$ 59.45	3,330	$ 57.74	20.3%	26.0%
Oct-17	Nextera	$ 62.36	3,238			
Nov-17	Nextera	$ 69.61	3,105			
Dec-17	EXELON	$ 116.93	3,302	$112.30	94.5%	107.7%
Jan-18	EXELON	$ 143.96	3,703			
Feb-18	EXELON	$ 68.24	3,082			
Mar-18	EXELON	$ 61.58	2,868	$ 67.49	-39.9%	45.7%
Apr-18	EXELON	$ 73.24	2,545			
May-18	EXELON	$ 61.17	3,135			
Jun-18	EXELON	$ 62.91	2,998	$ 65.46	-3.0%	36.4%
Jul-18	EXELON	$ 70.39	4,279			
Aug-18	EXELON	$ 77.72	4,065			
Sep-18	EXELON	$ 82.70	3,865	$ 79.97	22.2%	38.5%
Oct-18	EXELON	$ 79.61	3,896			
Nov-18	EXELON	$ 96.26	3,379			
Dec-18	NEXTERA	$ 79.40	3,622	$ 87.93	10.0%	-21.7%
Jan-19	NEXTERA	$ 88.71	3,584			
Feb-19	NEXTERA	$ 80.74	3,414			
Mar-19	NEXTERA	$ 78.71	3,425	$ 76.36	-13.2%	13.2%
Apr-19	NEXTERA	$ 69.41	3,303			
May-19	NEXTERA	$ 62.95	3,345			
Jun-19	DYNEGY	$ 52.82	3,702	$ 57.16	-25.2%	-12.7%
Jul-19	DYNEGY	$ 56.38	4,245			
Aug-19	DYNEGY	$ 51.22	4,030			
Sep-19	DYNEGY	$ 50.98	3,829	$ 51.49	-9.9%	-35 6%
Oct-19	DYNEGY	$ 52.27	3,861			
Nov-19	DYNEGY	$ 70.05	3,342			
Dec-19	NEXTERA	$ 76.10	3,586	$ 68.36	32.8%	-22 3%
Jan-20	NEXTERA	$ 58.71	3,461			
Feb-20	NEXTERA	$ 55.62	3,466			
Mar-20	NEXTERA	$ 51.14	3,478	$ 53.96	-21.1%	-29 3%
Apr-20	NEXTERA	$ 55.21	3,229			
May-20	NEXTERA	$ 53.79	3,244			
Jun-20	HQUS	$ 44.16	4,559	$ 47.14	-12.6%	-17 5%
Jul-20	HQUS	$ 45.54	4,995			
Aug-20	HQUS	$ 48.10	4,678			
Sep-20	HQUS	$ 45.30	4,726	$ 48.62	3.1%	-5.6%
Oct-20	HQUS	$ 53.06	4,073			
Nov-20	HQUS	[redacted]				
Dec-20	EXELON					
Jan-21	EXELON					
Feb-21	EXELON		4,405			
Mar-21	EXELON		4,261	N/A	N/A	N/A
Apr-21	EXELON	N/A	4,294			
May-21	EXELON		4,622			
Jun-21	EXELON	N/A	3,997	N/A	N/A	N/A
Jul-21	EXELON		4,449			
Aug-21	EXELON		4,622			
Sep-21	EXELON	N/A	4,297	N/A	N/A	N/A
Oct-21	EXELON		3,856			
Nov-21	EXELON	N/A	3,815	N/A	N/A	N/A

G1 Legal Estimates for this RFP: **$0**

Note: GIS costs are booked to a common account, not by customer group.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Historical Pricing Comparison, Non-G1 Customers

	Block A	Block B	Block C	Block D	Block A	Block B	Block C	Block D	Non-G1 Pricing ($/MWH)	Non-G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
Dec-15	CECG	(Small)	NEXTERA	(Medium)	$ 83.69	(Small)	$ 83.78	(Medium)	$ 83.74	52,831	$ 82.22	32.8%	-43.3%
Jan-16	CECG	(Small)	NEXTERA	(Medium)	$104.98	(Small)	$103.95	(Medium)	$ 104.47	56,963			
Feb-16	CECG	(Small)	NEXTERA	(Medium)	$103.71	(Small)	$102.18	(Medium)	$ 102.95	51,298			
Mar-16	CECG	(Small)	NEXTERA	(Medium)	$ 81.22	(Small)	$ 79.90	(Medium)	$ 80.56	48,543			
Apr-16	CECG	(Small)	NEXTERA	(Medium)	$ 61.81	(Small)	$ 60.32	(Medium)	$ 61.07	43,271			
May-16	CECG	(Small)	NEXTERA	(Medium)	$ 51.15	(Small)	$ 49.81	(Medium)	$ 50.48	44,517			
Jun-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 47.68	(Small)	$ 46.07	(Medium)	$ 46.88	49,761	$ 49.44	-39.9%	-20.2%
Jul-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 55.13	(Small)	$ 53.86	(Medium)	$ 54.50	64,852			
Aug-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 50.39	(Small)	$ 50.33	(Medium)	$ 50.36	65,322			
Sep-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 45.61	(Small)	$ 44.80	(Medium)	$ 45.21	48,103			
Oct-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 46.89	(Small)	$ 44.80	(Medium)	$ 45.85	44,255			
Nov-16	TCPM	(Small)	ENERGY AMERICA	(Medium)	$ 51.92	(Small)	$ 51.31	(Medium)	$ 51.62	46,744			
Dec-16	NEXTERA	(Small)	NEXTERA	(Medium)	$ 61.58	(Small)	$ 60.24	(Medium)	$ 60.91	58,606	$ 62.83	27.1%	-23.6%
Jan-17	NEXTERA	(Small)	NEXTERA	(Medium)	$ 82.33	(Small)	$ 80.81	(Medium)	$ 81.57	56,403			
Feb-17	NEXTERA	(Small)	NEXTERA	(Medium)	$ 82.47	(Small)	$ 80.38	(Medium)	$ 81.43	49,520			
Mar-17	NEXTERA	(Small)	NEXTERA	(Medium)	$ 60.87	(Small)	$ 58.50	(Medium)	$ 59.69	54,432			
Apr-17	NEXTERA	(Small)	NEXTERA	(Medium)	$ 46.89	(Small)	$ 44.17	(Medium)	$ 45.53	44,403			
May-17	NEXTERA	(Small)	NEXTERA	(Medium)	$ 43.95	(Small)	$ 41.19	(Medium)	$ 42.57	45,754			
Jun-17	DEBM	(Small)	TCPM	(Medium)	$ 67.42	(Small)	$ 62.12	(Medium)	$ 64.77	44,437	$ 67.69	7.7%	36.9%
Jul-17	DEBM	(Small)	TCPM	(Medium)	$ 67.50	(Small)	$ 67.72	(Medium)	$ 67.61	57,777			
Aug-17	DEBM	(Small)	TCPM	(Medium)	$ 69.35	(Small)	$ 66.71	(Medium)	$ 68.03	60,381			
Sep-17	DEBM	(Small)	TCPM	(Medium)	$ 69.87	(Small)	$ 65.41	(Medium)	$ 67.64	49,688			
Oct-17	DEBM	(Small)	TCPM	(Medium)	$ 69.06	(Small)	$ 64.35	(Medium)	$ 66.71	45,808			
Nov-17	DEBM	(Small)	TCPM	(Medium)	$ 72.27	(Small)	$ 70.01	(Medium)	$ 71.14	46,513			
Dec-17	VITOL	(Small)	EXELON	(Medium)	$ 83.93	(Small)	$ 87.38	(Medium)	$ 85.66	62,950	$ 86.72	28.1%	38.0%
Jan-18	VITOL	(Small)	EXELON	(Medium)	$107.62	(Small)	$120.02	(Medium)	$ 113.82	63,909			
Feb-18	VITOL	(Small)	EXELON	(Medium)	$109.40	(Small)	$ 89.11	(Medium)	$ 99.26	49,814			
Mar-18	VITOL	(Small)	EXELON	(Medium)	$ 83.28	(Small)	$ 90.10	(Medium)	$ 86.69	52,363			
Apr-18	VITOL	(Small)	EXELON	(Medium)	$ 71.59	(Small)	$ 55.09	(Medium)	$ 63.34	46,786			
May-18	VITOL	(Small)	EXELON	(Medium)	$ 69.01	(Small)	$ 52.13	(Medium)	$ 60.57	45,651			
Jun-18	EXELON	(Small)	NEXTERA	(Medium)	$ 72.77	(Small)	$ 62.52	(Medium)	$ 67.65	51,139	$ 71.41	-17.7%	5.5%
Jul-18	EXELON	(Small)	NEXTERA	(Medium)	$ 72.12	(Small)	$ 66.11	(Medium)	$ 69.12	56,755			
Aug-18	EXELON	(Small)	NEXTERA	(Medium)	$ 72.11	(Small)	$ 64.79	(Medium)	$ 68.45	67,382			
Sep-18	EXELON	(Small)	NEXTERA	(Medium)	$ 76.29	(Small)	$ 68.20	(Medium)	$ 72.25	55,483			
Oct-18	EXELON	(Small)	NEXTERA	(Medium)	$ 79.93	(Small)	$ 68.76	(Medium)	$ 74.35	52,395			
Nov-18	EXELON	(Small)	NEXTERA	(Medium)	$ 81.23	(Small)	$ 74.61	(Medium)	$ 77.92	49,433			
Dec-18	NEXTERA	(Small)	NEXTERA	(Medium)	$127.54	(Small)	$100.68	(Medium)	$ 114.11	56,898	$ 104.16	45.9%	20.1%
Jan-19	NEXTERA	(Small)	NEXTERA	(Medium)	$122.53	(Small)	$126.85	(Medium)	$ 124.69	66,712			
Feb-19	NEXTERA	(Small)	NEXTERA	(Medium)	$112.15	(Small)	$127.57	(Medium)	$ 119.86	59,779			
Mar-19	NEXTERA	(Small)	NEXTERA	(Medium)	$112.76	(Small)	$ 88.83	(Medium)	$ 100.80	53,969			
Apr-19	NEXTERA	(Small)	NEXTERA	(Medium)	$ 74.10	(Small)	$ 72.84	(Medium)	$ 73.47	50,767			
May-19	NEXTERA	(Small)	NEXTERA	(Medium)	$ 92.89	(Small)	$ 67.08	(Medium)	$ 79.99	46,986			
Jun-19	EXELON	(Small)	NEXTERA	(Medium)	$ 75.00	(Small)	$ 63.79	(Medium)	$ 69.40	46,681	$ 68.99	-33.8%	-3.4%
Jul-19	EXELON	(Small)	NEXTERA	(Medium)	$ 78.96	(Small)	$ 75.23	(Medium)	$ 77.10	62,361			
Aug-19	EXELON	(Small)	NEXTERA	(Medium)	$ 65.50	(Small)	$ 63.42	(Medium)	$ 64.46	67,002			
Sep-19	EXELON	(Small)	NEXTERA	(Medium)	$ 69.66	(Small)	$ 64.86	(Medium)	$ 67.26	52,879			
Oct-19	EXELON	(Small)	NEXTERA	(Medium)	$ 69.61	(Small)	$ 48.85	(Medium)	$ 59.23	54,993			
Nov-19	EXELON	(Small)	NEXTERA	(Medium)	$ 80.32	(Small)	$ 74.65	(Medium)	$ 77.49	48,082			
Dec-19	NEXTERA	(Small)	NEXTERA	(Medium)	$114.30	(Small)	$104.82	(Medium)	$ 109.56	55,151	$ 88.55	28.3%	-15.0%
Jan-20	NEXTERA	(Small)	NEXTERA	(Medium)	$106.82	(Small)	$100.94	(Medium)	$ 103.88	64,846			
Feb-20	NEXTERA	(Small)	NEXTERA	(Medium)	$107.17	(Small)	$102.83	(Medium)	$ 105.00	61,007			
Mar-20	NEXTERA	(Small)	NEXTERA	(Medium)	$ 91.94	(Small)	$ 72.50	(Medium)	$ 82.22	54,444			
Apr-20	NEXTERA	(Small)	NEXTERA	(Medium)	$ 60.41	(Small)	$ 47.11	(Medium)	$ 53.76	50,230			
May-20	NEXTERA	(Small)	NEXTERA	(Medium)	$ 73.62	(Small)	$ 57.29	(Medium)	$ 65.46	46,070			
Jun-20	NEXTERA	(Small)	EXELON	(Medium)	$ 54.13	(Small)	$ 40.76	(Medium)	$ 47.45	52,981	$ 50.42	-43.1%	-26.9%
Jul-20	NEXTERA	(Small)	EXELON	(Medium)	$ 51.78	(Small)	$ 45.48	(Medium)	$ 48.63	65,465			
Aug-20	NEXTERA	(Small)	EXELON	(Medium)	$ 51.71	(Small)	$ 43.85	(Medium)	$ 47.78	61,604			
Sep-20	NEXTERA	(Small)	EXELON	(Medium)	$ 56.11	(Small)	$ 43.52	(Medium)	$ 49.82	56,863			
Oct-20	NEXTERA	(Small)	EXELON	(Medium)	$ 58.43	(Small)	$ 44.42	(Medium)	$ 51.43	48,292			
Nov-20	NEXTERA	(Small)	EXELON	(Medium)	$ 64.21	(Small)	$ 54.14	(Medium)	$ 59.18	48,417			
Dec-20	NEXTERA	(Small)	EXELON	(Medium)	[redacted]	(Small)	[redacted]	(Medium)	[redacted]	62,281	[redacted]	[redacted]	[redacted]
Jan-21	NEXTERA	(Small)	EXELON	(Medium)		(Small)		(Medium)		62,839			
Feb-21	NEXTERA	(Small)	EXELON	(Medium)		(Small)		(Medium)		62,244			
Mar-21	NEXTERA	(Small)	EXELON	(Medium)		(Small)		(Medium)		54,524			
Apr-21	NEXTERA	(Small)	EXELON	(Medium)		(Small)		(Medium)		51,458			
May-21	NEXTERA	(Small)	EXELON	(Medium)		(Small)		(Medium)		47,389			
Jun-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		50,816			
Jul-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		56,487			
Aug-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		67,064			
Sep-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		60,128			
Oct-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		45,181			
Nov-21	NEXTERA	(Small)	NEXTERA	(Medium)		(Small)		(Medium)		47,466			

Non-G1 Legal Estimates for this RFP: $0

Note: GIS costs are booked to a common account, not by customer group.

Tab A(3). UES RECs Procurement Summary

The third item attached to this Comparison of Bids is a summary of REC purchases for the 2021 compliance year. This table details the Class of RECs purchased, the quantity purchased, the cost per REC, and the transaction date. The table also describes if the purchase was made through the REC RFP process or if the RECs were acquired independent of the REC RFP process.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Summary of REC Purchases for 2021 RPS Compliance

Transaction Date	Process	Vintage	Class I		Class 1 Thermal		Class II		Class III		Class IV	
			Volume	Price	Volume	Price	Volume	Price	Volume	Price	Volume	Price
[redacted]												
Purchase Summary		2021	[redacted]									

Estimated Requirements	2021	[redacted]
Percentage Purchased[1]	2021	

Notes:

1. Percentage Purchased **excludes** banked RECs from prior years and Class I and Class II Net Metering Credits. Purchased RECs have been contracted for but may not yet have been transferred to the Company's GIS subaccount.

Tab A(4). Comparisons to NYMEX Futures

The fourth item attached to this Comparison of Bids compares the winning final bids to both the NYMEX over-the-counter futures contracts for ISO New England averaged on-and-off peak electric futures ("NYMEX ISO") and the NYMEX natural gas futures contracts at Henry Hub ("NYMEX NG"). These tables generally show the proportion of the bid price that is associated with energy, typically the largest driver of wholesale costs, as opposed to other non-energy costs embedded in a bid price such as capacity and ancillary services. Lower bid to NYMEX ratios can be associated with a price for which energy comprises a greater component; conversely, higher bid to NYMEX ratios indicate the price is comprised of an increasing proportion of non-energy components.

The ratio of winning bid prices to the two NYMEX contracts was calculated for the upcoming default service procurement period and is compared to prior procurement periods (December 1, 2020 – May 31, 2021 and June 1, 2020 – November 30, 2020).

Hypothetical prices were then calculated by applying the current NYMEX pricing to the ratio of winning bid prices to NYMEX prices observed in previous procurements. These are what the prices would have been if the final bid price to NYMEX ratio was the same as the prior period to which it is being compared. A comparison was then made between the current winning bid prices and the hypothetical prices. Results of the comparison show that the current ratio of final bid prices to NYMEX ISO is [redacted] than the ratio of final bid prices to NYMEX ISO during the same 6-month period a year ago, and is [redacted] than the ratio for the prior 6-month period of December 2020 to May 2021.

For natural gas, the comparison shows that current ratio of final bid prices to NYMEX NG is [redacted] than the ratio of final bid prices during the same 6-month period a year ago, and [redacted] than the ratio for the prior 6-month period of December 2020 to May 2021.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC New England On-Peak Electric Futures (ISO)

	RFP for Service Beginning June 1, 2021				RFP for Service Beginning June 1, 2020					
	Evaluation Loads	$/MWH Final Bid	$/MWH NYMEX ISO	Ratio of Final Bid to NYMEX ISO	Evaluation Loads	$/MWH Final Bid	$/MWH NYMEX ISO	Ratio of Final Bid to	$/MWH Final Bid Price	$/MWH Calculation Result
		[redacted]	[redacted]			[redacted]	[redacted]	[redacted]		
Jun-20					52,981	[redacted]	[redacted]	[redacted]		
Jul-20					65,465	[redacted]	[redacted]	[redacted]		
Aug-20					61,604	[redacted]	[redacted]	[redacted]		
Sep-20					56,863	[redacted]	[redacted]	[redacted]		
Oct-20					48,292	[redacted]	[redacted]	[redacted]		
Nov-20					48,417	[redacted]	[redacted]	[redacted]		
Jun-21	50,816	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Jul-21	56,487	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Aug-21	67,064	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Sep-21	60,128	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Oct-21	45,181	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
Nov-21	47,466	[redacted]	[redacted]	[redacted]					[redacted]	[redacted]
PERIOD	327,142	[redacted]	[redacted]	[redacted]	333,622	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
						Final Bid Price v. Calculation Result			[redacted]	[redacted]

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC New England On-Peak Electric Futures (ISO)

	RFP for Service Beginning June 1, 2021				RFP for Service Beginning December 1, 2020					
	Evaluation Loads	$/MWH Final Bid	$/MWH NYMEX ISO	Ratio of Final Bid to NYMEX ISO	Evaluation Loads	$/MWH Final Bid	$/MWH NYMEX ISO	Ratio of Final Bid to NYMEX ISO	$/MWH Final Bid Price	$/MWH Calculation Result
		[redacted]	[redacted]			[redacted]				
Dec-20					62,281					
Jan-21					62,839					
Feb-21					62,244					
Mar-21					54,524					
Apr-21					51,458					
May-21					47,389				[redacted]	
Jun-21	50,816	[redacted]								
Jul-21	56,487									
Aug-21	67,064									
Sep-21	60,128									
Oct-21	45,181									
Nov-21	47,466									
PERIOD	327,142				340,735	[redacted]	[redacted]	[redacted]		

Final Bid Price v. Calculation Result

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC Natural Gas (NG) Henry Hub Futures

	RFP for Service Beginning June 1, 2021				RFP for Service Beginning June 1, 2020					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to NYMEX NG	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to	$/MWH Final Bid Price	$/MWH Calculation Result
Jun-20					52,981	[redacted]				
Jul-20					65,465					
Aug-20					61,604					
Sep-20					56,863					
Oct-20					48,292					
Nov-20					48,417				[redacted]	
Jun-21	50,816	[redacted]								
Jul-21	56,487									
Aug-21	67,064									
Sep-21	60,128									
Oct-21	45,181									
Nov-21	47,466									
PERIOD	327,142				333,622	[redacted]	[redacted]	[redacted]		

Final Bid Price v. Calculation Result

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

UES Default Service RFP Issued March 2, 2021

For Loads to be Served beginning June 1, 2021

Comparison of Winning Bids to NYMEX Futures - Non G1 Customers

UES 6-Month Non-G1 Customer Default Service Bids versus NYMEX OTC Natural Gas (NG) Henry Hub Futures

	RFP for Service Beginning June 1, 2021				RFP for Service Beginning December 1, 2020					
	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to NYMEX NG	Evaluation Loads	$/MWH Final Bid [redacted]	$/mmbtu NYMEX NG [redacted]	Ratio of Final Bid to NYMEX NG	$/MWH Final Bid Price	$/MWH Calculation Result
Dec-20					62,281	[redacted]				
Jan-21					62,839					
Feb-21					62,244					
Mar-21					54,524					
Apr-21					51,458					
May-21					47,389					
Jun-21	50,816	[redacted]							[redacted]	
Jul-21	56,487									
Aug-21	67,064									
Sep-21	60,128									
Oct-21	45,181									
Nov-21	47,466									
PERIOD	327,142				340,735	[redacted]	[redacted]	[redacted]		

Final Bid Price v. Calculation Result [redacted]

Note: NYMEX quotes list prior day close since bids were due at 10:00 am. Bids shown are winning bids and include the cost of capacity.

Tab A(5). Financial Security Requirements

The fifth item attached to this Comparison of Bids contains a summary of each bidder's financial security requirements of UES and each bidder's own provision of financial security and creditworthiness. Items listed include the amount of Shareholder Equity (if any) to be used as a credit test for UES, payment terms and estimated interest costs associated with accelerated payments for each service bid, agreed upon corporate guaranty amounts, credit ratings for suppliers or their parent companies and other credit support as may be required.

Also attached are sheets that describe the credit rating definitions used by Standard & Poor's and by Moody's.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Summary of Financial Security Requirements

Financial Security provided by Seller

[redacted]

Standard & Poor's Ratings Definitions
Long-Term Issue Credit Ratings

Issue credit ratings are based, in varying degrees, on S&P Global Ratings' analysis of the following considerations:

- The likelihood of payment--the capacity and willingness of the obligor to meet its financial commitments on an obligation in accordance with the terms of the obligation;
- The nature and provisions of the financial obligation, and the promise we impute; and
- The protection afforded by, and relative position of, the financial obligation in the event of a bankruptcy, reorganization, or other arrangement under the laws of bankruptcy and other laws affecting creditors' rights.

Issue ratings are an assessment of default risk but may incorporate an assessment of relative seniority or ultimate recovery in the event of default. Junior obligations are typically rated lower than senior obligations, to reflect the lower priority in bankruptcy, as noted above. (Such differentiation may apply when an entity has both senior and subordinated obligations, secured and unsecured obligations, or operating company and holding company obligations.)

Long-Term Issue Credit Ratings*	
Category	**Definition**
AAA	An obligation rated 'AAA' has the highest rating assigned by S&P Global Ratings. The obligor's capacity to meet its financial commitments on the obligation is extremely strong.
AA	An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitments on the obligation is very strong.
A	An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitments on the obligation is still strong.
BBB	An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments on the obligation.
BB, B, CCC, CC, and C	Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'C' the highest. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions.
BB	An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on the obligation.
B	An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation.

CCC	An obligation rated 'CCC' is currently vulnerable to nonpayment and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitments on the obligation. In the event of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitments on the obligation.
CC	An obligation rated 'CC' is currently highly vulnerable to nonpayment. The 'CC' rating is used when a default has not yet occurred but S&P Global Ratings expects default to be a virtual certainty, regardless of the anticipated time to default.
C	An obligation rated 'C' is currently highly vulnerable to nonpayment, and the obligation is expected to have lower relative seniority or lower ultimate recovery compared with obligations that are rated higher.
D	An obligation rated 'D' is in default or in breach of an imputed promise. For non-hybrid capital instruments, the 'D' rating category is used when payments on an obligation are not made on the date due, unless S&P Global Ratings believes that such payments will be made within five business days in the absence of a stated grace period or within the earlier of the stated grace period or 30 calendar days. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of similar action and where default on an obligation is a virtual certainty, for example due to automatic stay provisions. An obligation's rating is lowered to 'D' if it is subject to a distressed exchange offer.
NR	This indicates that no rating has been requested, or that there is insufficient information on which to base a rating, or that S&P Global Ratings does not rate a particular obligation as a matter of policy.
*The ratings from 'AA' to 'CCC' may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.	

Source: Use the following link. Select “Ratings Definitions” under the **Regulatory** category. Ratings were updated June 26, 2017.
http://www.standardandpoors.com/en_US/web/guest/home?pagename=sp/Page/FixedIncomeRatingsCriteriaPg&r=1&l=EN&b=2

Moody's Long-Term Rating Definitions
Long-Term Obligation Ratings

Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They address the possibility that a financial obligation will not be honored as promised. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default.

Aaa	Obligations rated Aaa are judged to be of the highest quality, with minimal credit risk.
Aa	Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.
A	Obligations rated A are considered upper-medium grade and are subject to low credit risk.
Baa	Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.
Ba	Obligations rated Ba are judged to have speculative elements and are subject to substantial credit risk.
B	Obligations rated B are considered speculative and are subject to high credit risk.
Caa	Obligations rated Caa are judged to be of poor standing and are subject to very high credit risk.
Ca	Obligations rated Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.
C	Obligations rated C are the lowest rated class of bonds and are typically in default, with little prospect for recovery of principal or interest.

Note: Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Source: After registering on Moody's website and agreeing to their Terms of Use, use the following link:

http://www.moodys.com/moodys/cust/AboutMoodys/AboutMoodys.aspx?topic=rdef&subtopic=moodys%20credit%20ratings&title=Long+Term+Obligation+Ratings htm

Tab A(6). Proposal Submission Forms

The sixth item attached to this Comparison of Bids contains the non-price information provided by each bidder upon submission of the proposal submission form, which is identified as Attachment A to the RFP.

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is	

authorized to do business and, if not, which states and the reason it is not.	[redacted]
If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor
Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.	[redacted]	
Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
Total net income for the most recent fiscal year.		

Total assets as of the close of the previous fiscal year.	[redacted]
DUNS Number and Federal Tax ID.	
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its	

debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	[redacted]
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	

Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. --- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	[redacted]

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	[redacted]
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

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Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	

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Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

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Please list Respondent's NEPOOL Participant ID.	[redacted]
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Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

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Date last fiscal year ended.		

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Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

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RESPONDENT: _[redacted]

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If Respondent is a limited liability company, the names of all direct owners.	[redacted]
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Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

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If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
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Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	[redacted]
Name of Parent or Guarantor (if any)	[redacted]
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	[redacted]
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	[redacted]
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	[redacted]
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	[redacted]

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	[redacted]
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	[redacted]

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Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
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DUNS Number and Federal Tax ID.		

Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.	[redacted]

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	[redacted]

	[redacted]
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	

Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	[redacted]

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	[redacted]
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If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
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Tab A(7). RFP Contact List

The seventh item attached to this Comparison of Bids contains the contact list used by UES during the RFP process. The contact list includes one contact from each entity, a summary of UES's communications with each supplier and UES's expectations with regard to each supplier's intention to bid prior to receipt of indicative bids. Contacts are identified as suppliers, brokers, other LDCs or consultants.

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
RFP Contacts List

[redacted]

Party	No.	Contact Name	Company	Contact Type	Communic.	Initital Expectation
[redacted]						

Tab A(8). Redlined Power Supply Agreements

The eighth and final item attached to this Comparison of Bids contains the redline version of the Amendments to the PSA with NextEra and Exelon.

AMENDMENT No. [redacted] ~~[X]~~
OF
POWER SALES AGREEMENT

This Amendment No. [redacted] ~~[X]~~ ("Amendment No. [redacted] ~~[X]~~"), dated and effective as of **March 31, 2021** (the "Effective Date"), amends the Power Sales Agreement, dated [redacted] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and Exelon Generation Company, LLC ~~[COMPANY NAME]~~ ("Seller") (collectively, the "Parties").

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. [redacted] ~~[X]~~ or the Agreement, the Parties' obligations under this Amendment No. [redacted] ~~[X]~~ are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. [redacted] ~~[X]~~, without material modification to the obligations of either Party under this Amendment No. [redacted] ~~[X]~~. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **April 16, 2021**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. [redacted] ~~[X]~~. If the Parties cannot agree as to how to continue such transaction, this Amendment No. [redacted] ~~[X]~~ shall terminate and be null and void without liability to either Party.

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No. [redacted] ~~[X]~~, which is the result of a competitive solicitation held by Buyer.

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on March 2, 2021.

2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on March 2, 2021.

3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load

Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. [redacted] ~~X]~~ to the Agreement effective as of the Effective Date.

Unitil Energy Systems, Inc.

BY: ______________________________________

Robert S. Furino

Vice President

~~[Seller]~~Exelon Generation Company, LLC

BY: ______________________________________

Its______________________________

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

For service pursuant to Buyer's RFP issued on **August 25, 2020**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Medium Default Load	Medium Customer Group, 11452	100%	December 1, 2020	May 31, 2021
UES Large Customer Group	UES Large Default Load, 10019	100%	December 1, 2020	May 31, 2021

~~[List All Active Transactions]~~

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Large Customer Group	UES Large Default Load, 10019	100%	June 1, 2021	November 30, 2021

APPENDIX B

Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **August 25, 2020**

Service Requirement	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21
100% UES Medium Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21
100% UES Large Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

~~[List All Active Transactions]~~

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Large Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For service pursuant to Buyer's RFP issued on **March 2, 2021**

~~Service Requirement~~	~~Jun-21~~	~~Jul-21~~	~~Aug-21~~	~~Sep-21~~	~~Oct-21~~	~~Nov-21~~
~~100% UES Small Customer Group (6 months)~~						

~~Service Requirement~~	~~Jun-21~~	~~Jul-21~~	~~Aug-21~~	~~Sep-21~~	~~Oct-21~~	~~Nov-21~~
~~100% UES Medium Customer Group (6 months)~~						

~~*The following are Fixed Monthly Adders.*~~ ~~*Please refer to Section 5.1 for calculation of Contract Rate*~~						
~~Service Requirement~~	~~Jun-21~~	~~Jul-21~~	~~Aug-21~~	~~Sep-21~~	~~Oct-21~~	~~Nov-21~~
~~100% UES Large Customer Group (6 months)~~						

AMENDMENT No. ~~[X]~~[redacted]

OF

POWER SALES AGREEMENT

This Amendment No. ~~[X]~~[redacted] ("Amendment No. ~~[X]"~~[redacted]), dated and effective as of **March 31, 2021** (the "Effective Date"), amends the Power Sales Agreement, dated ~~[DATE]~~[redacted] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and ~~[COMPANY NAME]~~NEXTERA ENERGY MARKETING, LLC ("Seller") (collectively, the "Parties").

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. ~~[X]~~[redacted] or the Agreement, the Parties' obligations under this Amendment No. ~~[X]~~[redacted] are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. ~~[X],~~[redacted], without material modification to the obligations of either Party under this Amendment No. ~~[X]~~[redacted]. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **April 16, 2021**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. ~~[X]~~[redacted]. If the Parties cannot agree as to how to continue such transaction, this Amendment No. ~~[X~~[redacted] shall terminate and be null and void without liability to either Party.

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No. ~~[X],~~[redacted], which is the result of a competitive solicitation held by Buyer.

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on March 2, 2021.
2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on March 2, 2021.
3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load

Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 1}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. ~~[X~~[redacted] to the Agreement effective as of the Effective Date.

Unitil Energy Systems, Inc.

BY: ____

Robert S. Furino

Vice President

~~[Seller]~~

NextEra Energy Marketing, LLC

BY: ____

Its______________________________

APPENDIX A

Service Requirements Matrix
By Service Requirement, Load Asset Name and ID, Load Responsibility,
and Applicable Period

~~[List All Active Transactions]~~

For service pursuant to Buyer's RFP issued on **August 25, 2020**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	100%	December 1, 2020	May 31, 2021

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	100%	June 1, 2021	November 30, 2021
UES Medium Default Load	Medium Customer Group, 11452	100%	June 1, 2021	November 30, 2021
~~UES Large Customer Group~~	~~UES Large Default Load, 10019~~	~~100%~~	~~June 1, 2021~~	~~November 30, 2021~~

APPENDIX B
Monthly Contract Rate by Service Requirement
Dollars per MWh

~~[List All Active Transactions]~~

For service pursuant to Buyer's RFP issued on **August 25, 2020**

Service Requirement	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21
100% UES Small Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Small Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Medium Customer Group (6 months)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

~~*The following are Fixed Monthly Adders.*~~ ~~*Please refer to Section 5.1 for calculation of Contract Rate*~~						
~~Service Requirement~~	~~Jun-21~~	~~Jul-21~~	~~Aug-21~~	~~Sep-21~~	~~Oct-21~~	~~Nov-21~~

~~100% UES~~ ~~Large Customer Group~~ ~~(6 months)~~						

Unitil Energy Systems, Inc. ("UES")

Default Service
Request for Proposals

<u>UES Service Requirements</u>

Small Customers (100%): June 1, 2021 – November 30, 2021

Medium Customers (100%): June 1, 2021 – November 30, 2021

Large Customers (100%): June 1, 2021 – November 30, 2021

Issue Date: March 2, 2021

Unitil Energy Systems, Inc. ("UES")

Default Service
Request for Proposals
Table of Contents

Request for Proposals
To Provide
Default Service Supply
To All Customers of Unitil Energy Systems, Inc

I. Introduction

Unitil Energy Systems, Inc. ("UES") is a local electric distribution company located in New Hampshire. New Hampshire Legislation, RSA 374-F et seq., and the Settlement Agreement for Restructuring the Unitil Companies[1] ("Settlement Agreement") provided retail access for all of UES' retail customers beginning on May 1, 2003.

On September 9, 2005, the NHPUC approved UES' plan for procurement of default service supply, including the solicitation process, for the period beginning May 1, 2006[2]. Subsequently, on July 31, 2012, the NHPUC approved modifications to the timing and structure of UES' default service procurement plan, for the period beginning November 1, 2012[3]. Pursuant to these Orders, UES procures the power supply required to meet its default service obligations for three customer groups comprised of small, medium and large customers through full requirements contracts for 100% of the service requirements for six month contract periods.

Via this request for proposals ("RFP"), UES seeks competing fixed monthly price offers for 100% of the load requirements of its small and medium customer groups for the six month period beginning June 1, 2021. UES also seeks variable monthly price offers, as defined herein, for 100% of the load requirements of its large customer group for the six month period beginning June 1, 2021. Variable monthly prices are comprised of a pass-through of energy costs at the real-time locational marginal price ("LMP") plus fixed monthly adders, which respondents are asked to bid during the RFP process. The fixed adders are intended to cover all non-energy costs, including capacity, ancillary services, and administration charges. Please see the Proposed Pricing portion of Section V for more information.

This RFP provides background information and historical data, details the service requirements and commercial terms, and elaborates on the procedures to be employed by UES to select the winning suppliers. The complete RFP is available as a single ZIP file ("UES_DS_RFP_Package_2021-03.zip"). In addition, the RFP and its appendices, including the submission form, proposed contract, non-disclosure agreement, as well as the pricing bid sheets have been included as separate, editable electronic files. A number of electronic data files have also been included in Microsoft Excel format. The contents of each file are described in this document. Please contact Jeff Pentz at (603) 773-6473 or at pentzj@unitil.com with any questions regarding these materials.

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[1] See Docket DE 01-247.
[2] See Docket DE 05-064.
[3] See Docket DE 12-003.

II. Description of Default Service

UES is soliciting load-following power supply offers to meet the needs of its customers who take service under its default service tariff for the periods listed in the table in the Supply Obligation Period portion of Section IV. Default service is the only utility-provided supply service and will be available to all UES customers not receiving supply service from a competitive supplier at any time for any reason.

For the purpose of default service procurement, the specified customer groups shall consist of the various rate classes listed in the table below. The default service loads associated with these customer groups are modeled in the ISO Settlement System using the load asset numbers listed in the table. Bidding power suppliers ("Respondents") may submit bids to provide service to any or all customer groups for which a contract is sought via this RFP. Bids to supply each customer group will be evaluated and awarded separately.

Load Asset Description	Customer Rate Classes	Load Asset #
UES Small Default Load	D	11451
UES Medium Default Load	G2, OL	11452
UES Large Default Load	G1	10019

The amount of default service to be supplied by the winning bidder(s) will be determined in accordance with the retail load associated with those customers who rely on default service. UES cannot predict the number of customers that will rely on default service, how much load will be represented by these customers, or how long they will continue to take default service. UES expressly reserves the right to encourage customers to choose their own supplier from the competitive marketplace instead of taking default service.

Data Provided

To assist respondents in determining the potential load requirements, a variety of data has been provided with this RFP. The provided data includes the following:

Historical Hourly Loads and Capacity Tag Values are provided for the default service loads by customer group and in aggregate for competitive generation service loads. The hourly loads are measured at the PTF level and are provided for the period of January 1, 2015 through February, 2021. The capacity tag values are the daily sum of the capacity tags for all customers assigned to the supply service being reported. Please see the file named "UES_Historic_Hourly_Loads_Cap_Tags_2021-03.xls."

Historic Retail Monthly Sales Report provides monthly sales data from January 2015 through January 2021 have been compiled and provided. The retail sales report documents retail sales and customer counts by customer rate class and supply type: default service or competitive generation. Please see the file named "UES_Retail_Sales_Report_2021-03.xls."

Class Average Load Shapes (8760 hours), as measured at the customer meter level, are available. Please see the file named "UES_Profiles_2021-03.xls."

Distribution System Loss Factor for each rate class is shown in the following table. The distribution loss factors enable one to estimate the retail usage at the customer meter associated with a given quantity of wholesale supply, or to convert the class average load shapes to wholesale values. Please note that the supplies sought via this RFP will be wholesale supplies measured at the PTF level.

Customer Group	Rate Class	Distribution Loss Factor
Small Customers	D (Domestic)	6.468%
Medium Customers	G2 (Regular General)	6.392%
Medium Customers	OL (Outdoor Lighting)	6.468%
Large Customers	G1 (Large General)	4.591%

Evaluation Loads that UES will use to calculate weighted average prices of bids received from respondents for the purpose of comparing competing bids on the basis of price are provided. These estimated loads may be instructive to respondents, but should in no way be construed to represent any contract quantity or billing determinant or to create any obligation to any party. Evaluation Loads are included on the bid sheets. Please see the file named "UES_Bid_Form_2021-03.xls."

III. General Provisions

Terms and Conditions

For the small and medium customer group default service loads that respondents choose to bid, respondents must offer fixed monthly prices, and for the large customer default service load respondents must offer variable prices in the form of fixed monthly adders to the NH load zone RT LMP for the entire supply periods listed in the table in the Supply Obligation Period portion of Section IV, and shown on the bid sheets. Pricing requirements are further detailed in the Proposed Pricing portion of Section V.

Power Supply Contract

Along with this RFP, UES has provided a proposed Power Sales Agreement ("PSA") which details the contractual terms and conditions under which default service as sought herein will be provided. Respondents who have not previously signed a PSA, or who do not wish to amend a prior PSA, must execute the PSA in Appendix B ("App_B_UES_Power_Sales_Agreement_2021-03.doc").

Respondents who have previously executed a PSA with UES for the provision of Default Service supply may amend their existing PSA with UES in order to implement the proposed transaction. UES has provided a proposed PSA Amendment in Appendix B1 ("App_B1_UES_PSA_Amendment_2021-03.doc").

Bidders may propose contract language modifications. UES will consider proposed contract language modifications to the extent the language clarifies each party's obligations associated with the transactions sought under this solicitation process, and to the extent that any modified contract represents the best non-price terms each party is willing to offer UES.

The obligations of UES and the winning bidder(s) are subject to and conditioned upon NHPUC approval of the solicitation results and the inclusion in retail rates of the costs derived from the transactions sought in this solicitation. UES will use its best efforts to obtain NHPUC's approval, which is expected five (5) business days after filing. Please see schedule below. Winning suppliers should expect their identity to be announced by the NHPUC in its order on the results of the RFP.

Proposal Process and Submission Dates

The following table outlines key dates associated with this procurement process. All times are in Eastern Prevailing Time (EPT).

Process Step	Date
Issue Default Service RFP	Tuesday, March 2, 2021
Non-Disclosure Agreement Due	Tuesday, March 16, 2021, 3:00 p.m.
Proposal Forms & Indicative Pricing Due (including proposed contract changes)	Tuesday, March 16, 2021
Final Pricing Due	Tuesday, March 30, 2021, 10:00 a.m.
Winning Supplier Notified	Tuesday, March 30, 2021, 1:00 p.m.
Contracts Executed	Thursday, April 1, 2021
File for Approval of Rates	Friday, April 2, 2021
Anticipated Approval of Rates	Friday, April 16, 2021
UES DS Commences	Tuesday, June 1, 2021

Respondents to this RFP for Default Service must submit a completed Proposal Submission Form, including any proposed contract modifications, a non-disclosure agreement, indicative pricing and then final pricing according to the schedule shown above.

All submissions should be marked "UES Default Service RFP" and sent via e-mail to Jeff Pentz at pentzj@unitil.com and to energy_contracts@unitil.com.

Please direct any questions to Jeff Pentz at (603) 773-6473or to pentzj@unitil.com.

Non-Disclosure Agreement ("NDA") must be completed in order for UES to provide its financial information to bidders as well as to protect the confidentiality of bid information. Respondents who have previously signed an NDA with UES for the provision of Default Service supply do not need to execute a new NDA. Respondents who have not previously signed an NDA with UES must execute the NDA in Appendix C ("App_C_UES_NDA_2021_03.doc"). A partially executed NDA or redline version with proposed changes is due by **3:00 p.m. on March 16, 2021**.

Proposal Submission Form must be completed and is attached as Appendix A. Please see the file named "App_A_UES_Submission_Form_2021-03.doc." Submission Forms are due on **March 16, 2021**.

Indicative Pricing is due along with the Proposal Submission Form. Indicative pricing should be submitted on the "Indicative" sheet of the Bid Form ("UES_Bid_Form_2021-03.xls"). Pricing must meet the requirements described in the Proposed Pricing portion of Section V. Indicative pricing is due by **5:00 p.m. EPT on March 16, 2021.**

Proposed contract modifications, on either the full Power Supply Agreement or on the PSA Amendment, are also due along with the Proposal Submission Form on **March 16, 2021**. If respondents propose any changes to the Power Supply Agreement or the Amendment, respondents must provide an electronic copy of the Power Supply Agreement or the Amendment that is marked to show proposed language in a reviewable format. UES will consider the contractual terms and conditions accepted by each bidder as part of its evaluation criteria, as described in Section VI. When final bid prices are received and confirmed, UES intends to conduct its evaluation and select winning bidder(s) within a few hours. For these reasons, it is to each bidder's advantage to resolve contractual issues prior to final bidding.

Final Pricing should be submitted on the "Final" sheet of the Bid Form ("UES_Bid_Form_2021-03.xls"). Respondent's name must be clearly marked. Final pricing is due by **10:00 a.m. EPT on March 30, 2021**.

Winner Notified. UES intends to confirm final pricing, evaluate competing bids as described in Section VI, Evaluation Criteria, and select and notify the winning bidder(s) by **1:00 p.m. EPT on March 30, 2021**. Other bidders will be notified they were not selected by close of business.

UES, at its sole discretion, reserves the right to issue additional instructions or requests for additional information, to extend the due date, to modify any provision in this RFP or any appendix hereto or to withdraw this RFP.

Contact Person and Questions

Questions regarding this RFP should be submitted to Jeff Pentz at (603) 773-6473 or pentzj@unitil.com.

Right to Select Supplier

UES shall have the exclusive right to select or reject any and/or all of the proposals submitted at any time, for any reason and to disregard any submission not prepared according to the requirements contained in this RFP.

Customer Billing and Customer Service

The default service power supplies procured under this RFP will be wholesale supplies. As such, the winning supplier will have no retail customer contact in any form. All customers taking default service will be retail customers of UES. As the retail provider of such service, UES will provide billing and customer service to customers receiving default service. In addition, UES will assume responsibility for the ultimate collection of moneys owed by customers in accordance with rules and regulations approved by the NHPUC.

IV. Service Features

Supply Obligation Period

The supply obligation period for each supply contract will commence at 0001 hours on the dates listed under "Period Begins" in the following table and will terminate at 2400 hours on the dates listed under "Period Ends" in the following table.

Customer Group	Requirements	Period Begins	Period Ends
UES Small Default Load	100%	June 1, 2021	November 30, 2021
UES Medium Default Load	100%	June 1, 2021	November 30, 2021
UES Large Default Load	100%	June 1, 2021	November 30, 2021

Delivery Point

Supplier(s) will be responsible for all settlement obligations associated with the load assets. UES load assets are currently settled at the New Hampshire Load Zone (4002). In the event that NEPOOL implements nodal settlement of load obligations, supplier(s) will be responsible for all settlement obligations at the node where the load assets are settled. The UES load physically exists and is metered at the substations listed in Appendix C of the Power Supply Agreement. The delivery points are at the PTF level.

Form of Service

The winning bidder(s) ("Seller") shall provide firm, load-following power for delivery to ultimate customers taking service under UES' default service tariff, as amended from time to time. The obligations and responsibilities associated with providing default service shall be transferred to the Seller via an Ownership Share for Load Asset, utilizing the NEPOOL Asset Registration Process for load assets 11451 (Small Customer Group), 11452 (Medium Customer Group) and 10019 (Large Customer Group). The percentage Ownership Share for each load asset shall be as listed on the table above under Supply Obligation Period under the column heading "Requirements." The quantity of service that the Seller will be responsible to deliver, and that UES will be responsible to purchase, will be the volumes measured at the delivery points.

Seller shall be responsible for providing and paying for all energy and capacity services and for all ancillary services associated with the Day-Ahead Load Obligation and the Real-Time Load Obligation (as defined in Market Rule 1, Section III of ISO New England Inc.'s Transmission, Markets and Services Tariff (the "ISO Tariff")), associated with the load assets, as required by the ISO Tariff as may be amended or superseded from time to time. UES shall be responsible for providing and paying for the transmission of the power across NEPOOL PTF and for all ancillary services associated with the Regional Network Load (as defined in the Open Access Transmission Tariff, Section III of the ISO Tariff), associated with the load assets. The specific requirements regarding the provision of energy, capacity and ancillary services by the Seller, and regarding the provision of transmission service by UES, are detailed in Article 4 of the proposed Power Supply Agreement, attached as Appendix B.

UES will report the hourly default service load associated with the load assets to ISO-NE on a daily basis in accordance with the reporting practices in New England. The reported loads will incorporate appropriate load allocation and estimation techniques and available meter readings for customers receiving default service from UES. Month end adjustments, based on customer meter readings, will be made to loads approximately 45 days after each month. Such adjustments will be priced at the contract price in effect for the month the load was served.

Renewable Portfolio Standards

In 2007 the State of New Hampshire enacted an Electric Renewable Portfolio Standards law ("NH-RPS Law") (RSA 362-F) to foster the development of renewable energy sources to meet New Hampshire's energy needs. The Supplier(s) of Load Following Service are not required to provide UES' renewable energy obligations resulting from the NH-RPS Law. These requirements will be managed separately by UES

V. Proposal Requirements

Requested Information

Respondents to this RFP must provide the information identified in the Proposal Submission Form attached as Appendix A. Please see the file named "App_A_UES_Submission_Form_2021-03.doc." Respondents are asked to complete the submission form and return it to Jeff Pentz as indicated in Section III. Proposals should contain explanatory, descriptive and/or supporting materials as necessary.

Respondents will find that UES requests on the Proposal Submission Form that bidders indicate whether they will extend sufficient financial credit to UES in order to facilitate the transactions sought. UES will provide a copy of its most recent financials upon completion of the Mutual Confidential Non-Disclosure Agreement attached as Appendix C. UES has proposed financial security terms in the Power Supply Agreement. Respondents are asked to indicate their acceptance of the proposed financial security terms, along with any contract language modifications they propose. Proposed contract language modifications must be provided in a reviewable and editable manner, such as is obtained using the "track changes" features of Microsoft Word. Respondents are also asked to indicate whether they agree that the Power Supply Agreement is subject to NHPUC approval of supporting retail rates as sought by UES.

UES will treat all information received from respondents in a confidential manner and will not, except as required by law or regulatory authority, disclose such information to any third party or use such information for any purpose other than to evaluate the respondent's ability to provide the services sought in this RFP. Respondents bidding to serve UES default service loads should expect that the identity of the winning bidder(s) will be announced by the NHPUC in its order on the results of the RFP.

Proposed Pricing

For the Small and Medium Customer Groups, UES seeks fixed monthly price offers for the six month period. Respondents must specify the prices, in $/MWh, at which they will provide default service for each month of the supply obligation period associated with the default service loads they choose to bid. Proposed prices may vary by calendar month, but must be uniform for the entire calendar month and must cover the entire supply obligation period sought. Purchases will be made on an "as-delivered" energy basis with prices stated on a fixed $/MWh basis for all MWh reported to the ISO for the load assets. No maximum price is specified; however the resulting retail rates are subject to the review and acceptance of the NHPUC.

For the Large Customer Group, UES seeks variable monthly price offers for a six month period. Respondents must specify the monthly fixed adders, in $/MWh, at which, in addition to the load-weighted average real-time NH LMP, they will provide default service to the Large Customer Group. Proposed monthly adder prices may vary by calendar month, but must be uniform for the entire calendar month and must cover the entire supply obligation period sought. Purchases will be made on an "as-delivered" energy basis with the monthly contract price equaling the sum of the load-weighted average real-time NH LMP plus the monthly fixed adder as bid during the RFP process. UES and the supplier will be required to confirm the calculation of the final contract price as soon as practical following the month of service in order to facilitate billing under the contract. The final contract price will be stated on a $/MWh basis and will apply to all MWh reported to ISO New England for Load Asset 10019 (Large Customer Group). No maximum price is specified; however the resulting retail rates are subject to the review and acceptance of the NHPUC.

Bidder Requirements

In order to secure reliable, low cost default service power for its customers, UES wishes to include all qualified power suppliers in this solicitation.

Bidders must have access to the ISO settlement process for the entire term of the sale, either as a signatory to the Market Participant Service Agreement ("MPSA") or via arrangements with a signatory to the MPSA to utilize their settlement process.

Respondents are encouraged to establish complete contract language, including financial security arrangements, with UES prior to submission of final pricing.

VI. Evaluation Criteria

The principal criteria to be used in evaluating proposals will include, but may not be limited to:

- Lowest evaluated bid price over the supply obligation period;

- Financial and operational viability of the power supplier, including the establishment of mutually acceptable financial security arrangements; and
- Responsiveness to non-price requirements, including the reasonable extension of financial credit to UES, and agreement that the proposed transactions are subject to NHPUC approval of retail rates as sought by UES.
- Each customer load group supply contract sought will be evaluated and awarded separately.

Respondent pricing will be evaluated by weighting the fixed monthly pricing according to the Evaluation Loads provided on the bid sheets ("UES_Bid_Form_2021-03.xls") and as described at the end of Section II.

Appendix A: Proposal Submission Form

See file named "App_A_UES_Submission_Form_2021-03.doc"

Appendix B: Power Sales Agreement

See file named "App_B_UES_Power_Sales_Agreement_2021-03.doc"

Appendix B1: Power Sales Agreement Amendment

See file named "App_B1_UES_PSA_Amendment_2021-03.doc"

Appendix C: Mutual Confidential Non-Disclosure Agreement

See file named “App_C_UES_NDA_2021-03.doc”

RESPONDENT: ____________________________

APPENDIX A: PROPOSAL SUBMISSION FORM

1. General Information

Name of Respondent	
Name of Parent or Guarantor (if any)	
Principal contact person < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Secondary contact person (if any) < Name < Title < Company < Mailing address < Telephone number (office) < Telephone number (cell) < Fax number < E-mail address	
Legal form of business organization of Respondent (e.g., sole proprietorship, partnership, limited partnership, joint venture, or corporation)	
State(s) of incorporation, residency or organization Indicate whether Respondent is in good standing in all states in which Respondent is authorized to do business and, if not, which states and the reason it is not.	

If Respondent is a partnership, the names of all general and limited partners. If Respondent is a limited liability company, the names of all direct owners.	
Description of Respondent and all affiliated entities and joint ventures transacting business in the energy sector.	

2. Financial Information

Please provide the following for Respondent and/or Parent/Guarantor (as appropriate)	Respondent	Parent/Guarantor
Current debt ratings, including names of rating agencies and dates of ratings. If entity is not rated, please indicate.		
Date last fiscal year ended.		
Total revenue for the most recent fiscal year.		
Total net income for the most recent fiscal year.		
Total assets as of the close of the previous fiscal year.		
DUNS Number and Federal Tax ID.		
Please provide a copy of the most recent financials including balance sheet, income statement and cash flow statement.		

RESPONDENT: ____________________________

3. Defaults and Adverse Situations

Describe, in detail, any situation in which Respondent (either alone or as part of a joint venture), or an affiliate of Respondent, defaulted or was deemed to be in noncompliance of its contractual obligations to deliver energy and/or capacity at wholesale within the past five years. Explain the situation, its outcome and all other relevant facts associated with the event described. Identify the name, title and telephone number of the principal manager of the customer/client who asserted the event of default or noncompliance.	
Has Respondent, or any affiliate of Respondent, in the last five years, (a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, (b) filed a bankruptcy petition in any bankruptcy court proceeding, (c) answered, consented or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, (d) admitted in writing of its inability to pay its debts when due, (e) made a general assignment for the benefit of creditors, (f) was the subject of an involuntary proceeding seeking to adjudicate that Party bankrupt or insolvent, (g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency or reorganization or relief of debtors.	
Describe any facts presently known to Respondent that might adversely affect its ability to provide the service(s) bid herein as provided for in the Request for Proposals.	

RESPONDENT: ___________________________

4. NEPOOL and Power Supply Experience

Is Respondent a member of NEPOOL?	YES or NO
Please list Respondent's NEPOOL Participant ID.	
If Respondent is NOT a NEPOOL member, list the name and Participant ID of the NEPOOL member who will carry Respondent's obligations in its settlement account. Please provide a supporting statement and contact information from such member.	
Please describe Respondent's experience and record of performance in the areas of power marketing, brokering, sales, and/or contracting, for the last five years within NEPOOL and/or the New England region.	
Has Respondent previously provided Default Service to UES? If response is "NO", please provide references as requested below. -- Please provide three references (name, title and contact information) who have contracted with the Respondent for load-following services or who can attest to Respondent's ability in the areas of power supply portfolio management within the past 2 years.	YES or NO -- 1. 2. 3.

RESPONDENT: ______________________________

5. Non Price Terms

Does Respondent extend sufficient financial credit to UES to facilitate the transactions sought via this RFP?	YES or NO
Please indicate what, if any, financial security requirements Respondent has of UES in order to secure the extension of credit. Please attach any proposed contractual language.	
Does Respondent agree that the obligations of both parties are subject to and conditioned upon the NHPUC's approval of the retail rates derived from the transaction sought in this solicitation?	YES or NO
Please list all regulatory approvals required before service can commence.	
Is Respondent willing to enter into contractual terms substantially as proposed in the Power Supply Agreement contained in Appendix B?	YES or NO
Provide any proposed modifications to the Power Supply Agreement provided in Appendix B or to the PSA Amendment in Appendix B1. Please briefly list issues here and provide proposed language changes in the document using the "track changes" feature of Microsoft Word, or other reviewable revision marking process.	

POWER SUPPLY AGREEMENT

This POWER SUPPLY AGREEMENT ("Agreement") is dated as of **March 31**, **2021** and is by and between UNITIL ENERGY SYSTEMS, INC. ("UES" or "Buyer"), a New Hampshire corporation, and [Company] ("Seller"), a [what]. This Agreement provides for the sale by Seller of Default Service, as defined herein, to the Buyer. The Buyer and Seller are referred to herein individually as a "Party" and collectively as the "Parties".

ARTICLE 1. BASIC UNDERSTANDINGS

Seller, in response to a Request for Proposals issued on **March 2, 2021** by the Buyer, has been selected to be the supplier of firm, load-following power to meet the Buyer's Service Requirements as defined in the Service Requirements Matrix found in Appendix A. This Agreement sets forth the terms under which Seller will supply, and Buyer will purchase, Default Service during the Delivery Term.

ARTICLE 2. DEFINITIONS

As used in this Agreement, the following terms shall have the meanings specified in this Article. In addition, except as otherwise expressly provided, terms with initial capitalization used in this Agreement and not defined herein shall have the meaning as defined in the ISO Rules.

Affiliate means, with respect to any Party, any person (other than an individual) that, directly or indirectly, controls, or is controlled by such Party. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

Average Weighted RT LMP (real time locational marginal price) is the value determined each month during the Delivery Term of the Large Customer Group Service Requirement. The Average Weighted RT LMP is added to the Fixed Monthly Adder to calculate the Contract Rate per MWH for the Large Customer Group Service Requirement. The calculation of the Average Weighted RT LMP is detailed in Section 5.1.

Business Day means a 24-hour period ending at 5:00 p.m. EPT, other than Saturday, Sunday and any day which is a legal holiday or a day on which banking institutions in Boston, Massachusetts are authorized by law or other governmental action to close.

Buyer means Unitil Energy Systems, Inc., its successors, assigns, employees, agents and authorized representatives.

Buyer's System means the electrical transmission and distribution system of the Buyer.

Commencement Date means, with respect to a Service Requirement, the period beginning at the start of HE 0100 EPT on the date set forth for such Service Requirement on Schedule 1 of Appendix A.

Commission means the Federal Energy Regulatory Commission.

Competitive Supplier Terms means the Terms and Conditions for Competitive Suppliers, which are a part of the Retail Delivery Tariff, as may be amended from time to time.

Conclusion Date means the end of the HE 2400 EPT on the date set forth for the Service Requirement on Schedule 2 of Appendix A.

Contract Rate means the value expressed in $/MWh as set forth in Appendix B, as applicable to each Service Requirement, during a month in the Delivery Term.

Credit Rating means (i) the lower of the ratings assigned to an entity's unsecured, senior long-term debt obligations (not supported by third party credit enhancements) by S&P and Moody's, (ii) in the event the entity does not have a rating for its senior unsecured long-term debt, the lower of the rating assigned to the entity as an issuer rating by S&P and Moody's, or the rating assigned to the entity as an issuer rating by any other rating agency agreed to by both Parties in each Party's sole and exclusive judgment.

Credit Requirements mean the satisfaction of any and all financial measures and/or Credit Rating status so as to avoid a Downgrade Event, as defined in Section 7.3(a).

Customer Disconnection Date means the date when a Default Service Customer is disconnected from service, as determined by the Buyer in accordance with the Retail Delivery Tariff.

Customer Group means the Small Customer Group or the Large Customer Group, as the case may be.

Customer Initiation Date means the date a retail customer of the Buyer begins taking service pursuant to the Schedule DS of the Buyer's Retail Delivery Tariff, as determined by the Buyer.

Customer Termination Date means the date when a Default Service Customer ceases to take service pursuant to Schedule DS under the Retail Delivery Tariff.

Default Service means the provision of Requirements by Seller at the Delivery Point to the Buyer to meet all needs of Default Service Customers.

Default Service Customer(s) means the retail customer(s) in each Customer Group identified in Appendix A taking service pursuant to Schedule DS of the Retail Delivery Tariff during the applicable Delivery Term.

Delivered Energy means the quantity of energy, expressed in MWh, provided by Seller under the terms of this Agreement. This quantity shall be the sum of energy reported to the ISO by the Buyer for each of the Load Assets identified in Section 6.4, with such quantity determined by the Buyer in accordance with Section 6.3 of this Agreement. Such quantity shall not include any allocation of PTF losses up to and including the Delivery Point (which the ISO may assess to Seller in relation to such energy), but shall include transmission and distribution losses on the Buyer's System from the Delivery Point to the meters of Default Service Customers.

Delivery Point means the PTF location where Requirements are settled under ISO Rules. UES load assets are currently settled at the New Hampshire Load Zone (4002). The UES load physically exists and is metered at the substations listed in Appendix C.

Delivery Term(s) means the applicable period associated with a Service Requirement beginning at the start of HE 0100 EPT in Schedule 1 through and including the end of the HE 2400 EPT in Schedule 2 of Appendix A.

EPT means Eastern Prevailing Time.

Fixed Monthly Adder means the dollar per MWH price specified in Appendix B. The Fixed Monthly Adder is added to the Average Weighted RT LMP each month during the Delivery Term of the Large Customer Group Service Requirement in order to calculate the monthly Contract Rate per MWH for the Large Customer Group Service Requirement.

GAAP means Generally Accepted Accounting Principles promulgated by the Financial Accounting Standards Board at the time of issuance of the financial statements.

Governing Documents means, with respect to any particular entity, (a) if a corporation, the (i) articles of organization, articles of incorporation or certificate of incorporation and (ii) the bylaws; (b) if a general partnership, the partnership agreement and any statement of partnership; (c) if a limited partnership, the limited partnership agreement and the certificate of limited partnership; (d) if a limited liability company, the articles or certificate of organization or formation and operating agreement; (e) if another type of entity, any other charter or similar document adopted or filed in connection with the creation, formation or organization of such entity; (f) all equity holders' agreements, voting agreements, voting trust agreements, joint venture agreements, registration rights agreements or other agreements or documents relating to the organization, management or operation of any entity or relating to the rights, duties and obligations of the equity holders of any entity; and (g) any amendment or supplement to any of the foregoing.

Interest Rate means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in The Wall Street Journal under "Money Rates" on such day (or if not published on such day, on the most recent preceding day on which published), plus two percent (2%) and (b) the maximum rate permitted by applicable law.

Investment Grade means (i) if an entity has a Credit Rating from both S&P and Moody's then, a Credit Rating from S&P equal to or better than "BBB-" and a Credit Rating from Moody's equal to or better than "Baa3"; or (ii) if an entity has a Credit Rating from only one of S&P and Moody's, then a Credit Rating from S&P equal to or better than "BBB-" or a Credit Rating from Moody's equal to or better than "Baa3 or (iii) if the Parties have mutually agreed in writing on an additional or alternative rating agency, then a Credit Rating from S&P (if applicable) equal to or better than "BBB-" and/or a Credit Rating from Moody's (if applicable) equal to or better than "Baa3", and with respect to the additional or alternative rating agency, a credit rating equal to or better than that mutually agreed to by the Parties in each Party's sole and exclusive judgment.

ISO means ISO New England Inc., the Independent System Operator / Regional Transmission Organization established in accordance with the NEPOOL Agreement, and any successor.

ISO Rules means all rules adopted by the ISO or NEPOOL, as such rules may be amended, added, superseded and restated from time to time, including the NEPOOL Agreement, ISO New England Inc. Transmission, Markets and Services Tariff FERC Electric Tariff No. 3, the Transmission Operating Agreement, and the Participants Agreement, the ISO Manuals, and the NEPOOL Operating Procedures.

kWh means kilowatt-hour.

Large Customer Group means the retail customers assigned to the following customer rate class: Large General Service Schedule G1.

Material Adverse Effect means, with respect to a Party, any change in or effect on such Party after the date of this Agreement that is materially adverse to the transactions contemplated hereby, excluding any change or effect resulting from (a) changes in the international, national, regional or local wholesale or retail markets for electric power; (b) changes in the international, national, regional or local markets for any fuel; (c) changes in the North American, national, regional or local electric transmission or distribution systems; and (d) any action or inaction by a governmental authority, but in any such case not affecting the Parties or the transactions contemplated hereby in any manner or degree significantly different from others in the industry as a whole.

Medium Customer Group means the retail customers assigned to the following customer rate classes: Regular General Service Schedule G2, and Outdoor Lighting Service Schedule OL.

Moody's means Moody's Investors Service Inc., its successors and assigns.

MWh means Megawatt-hour.

NE-GIS means the NEPOOL Generation Information System, which includes a generation information database and certificate system, operated by ISO, its designee or successor entity, that accounts for generation attributes of electricity consumed within New England.

NE-GIS Certificates means a document produced by the NE-GIS that identifies the relevant generation attributes of each MWh accounted for in the NE-GIS from a generation unit.

NEPOOL means the New England Power Pool, or its successor.

NEPOOL Agreement means the Second Restated New England Power Pool Agreement effective on February 1, 2005, as amended or accepted by the Commission and as may be amended, superseded and/or restated from time to time.

NHPUC means the New Hampshire Public Utilities Commission.

NH Load Zone means the New Hampshire Reliability Region as defined in the ISO Rules.

PTF means facilities categorized as Pool Transmission Facilities under ISO Rules.

Requirements shall be defined in Section 4.2(c).

Retail Delivery Tariff means UES' Tariff for Electric Delivery in the State of New Hampshire.

S&P means Standard & Poor's Rating Group, its successors and assigns.

Service Requirement means a load-following, wholesale power supply requirement, defined by a unique combination of Customer Group, load responsibility and Delivery Term as listed in Appendix A.

Small Customer Group means the retail customers assigned to the following customer rate classes: Domestic Delivery Service Schedule D.

ARTICLE 3. TERM, SERVICE PROVISIONS AND REGISTRATION REQUIREMENTS

Section 3.1 Term

This Agreement shall be effective immediately upon execution by the Parties and shall continue in effect until the Service Requirements listed in Appendix A have been fully performed and final payment made hereunder or this Agreement has been otherwise terminated as provided herein by reason of an uncured Event of Default. As of the expiration of this Agreement or, if earlier, its termination, the Parties shall no longer be bound by the terms and provisions hereof, except (a) to the extent necessary to enforce the rights and obligations of the Parties arising under this Agreement before such expiration or termination and (b) the obligations of the Parties hereunder with respect to audit rights, remedies for default, damages claims, indemnification and defense of claims shall survive the termination or expiration of this Agreement to the full extent necessary for their enforcement and the protection of the Party in whose favor they run, subject to any time limits specifically set forth in this Agreement.

Section 3.2 Commencement of Supply

(a) Beginning as of the Commencement Date applicable to the Customer Group set forth on Appendix A, Seller shall provide Requirements to the Buyer. For purposes of certainty: Seller's obligations on the Commencement Date shall be to provide Requirements for all Default Service Customers taking service as of and including the Commencement Date.

(b) With respect to each person or entity that becomes a Default Service Customer subsequent to the Commencement Date, Seller shall provide Requirements to the Buyer to meet the needs of the Default Service Customer(s) as of and including the Customer Initiation Date for such customer initiating such service during the Delivery Term.

(c) During the Delivery Term that Seller provides Default Service to the Buyer's Large Customer Group, Buyer shall make its best efforts to notify Seller promptly of all Customer Initiation Dates of retail customers in the Large Customer Group. Upon such notice, Buyer shall also provide historic annual (prior billed 12 months) peak kVa and total kWh consumption for such customers.

Section 3.3 Termination and Conclusion of Supply

(a) With respect to each Default Service Customer that terminates Default Service, during the Delivery Term, Seller shall not provide Requirements for such customer as of the Customer Termination Date.

(b) During the Delivery Term that Seller provides Default Service to the Buyer's Large Customer Group, Buyer shall make best efforts to notify Seller promptly of all Customer Termination Dates and Customer Disconnection Dates of retail customers in the Large Customer Group. Upon such notice, Buyer shall also provide historic annual (prior billed 12 months) peak kVa and total kWh consumption for such customers.

(c) Seller's obligation to provide Requirements shall cease at the Conclusion Date.

Section 3.4 Distribution Service Interruptions

Seller acknowledges that interruptions in distribution service occur and may reduce the load served hereunder. Seller further acknowledges and agrees that the Buyer may interrupt distribution service to customers consistent with the Distribution Service Terms and the Competitive Supplier Terms. In no event shall a Party have any liability or obligation to the other Party in respect of any such interruptions in distribution service.

Section 3.5 Release of Customer Information

The Buyer will not issue any customer information to Seller unless Seller has first obtained the necessary authorization in accordance with the provisions of the Competitive Supplier Terms.

Section 3.6 Change in Supply; No Prohibition on Programs

(a) Seller acknowledges and agrees that the number of customers and the Requirements to meet the needs of such customers will fluctuate throughout the Delivery Term and may equal zero. The Buyer shall not be liable to Seller for any losses Seller may incur, lost revenues, and losses that may result from any change in Requirements, number or location of customers taking service, the location of the Delivery Point(s), the composition or components of market products or Requirements, or the market for electricity, or change in the Retail Delivery Tariff. Seller further acknowledges and agrees that there is no limit on the number of Customer Initiation Dates, Customer Termination Dates and Customer Disconnection Dates.

(b) Seller acknowledges and agrees that the Buyer has the right but not the obligation to continue, initiate, support or participate in any programs, promotions, or initiatives designed to or with the effect of encouraging customers to leave Default Service for any reason ("Programs"). Nothing in this Agreement shall be construed to require notice to or approval of Seller in order for the Buyer to take any action in relation to Programs.

(c) Seller acknowledges and agrees that the Buyer and Affiliates of the Buyer will not provide Seller preferential access to or use of the Buyer's System and that Seller's sole and exclusive rights and remedies with regard to access to, use or availability of the Buyer's System, and the Buyer's or Affiliates of the Buyer's obligation to transmit electricity are those rights, remedies and obligations provided under the Retail Delivery Tariff, the ISO Rules, and the Buyer's Open Access Transmission Tariff.

Section 3.7 Disclosure Requirements

In the event that the NHPUC implements a disclosure label requirement, which requires the Buyer to document its power supply attributes, then the Seller shall provide the Buyer information pertaining to power plant emissions, fuel types, labor information and any other information required by the Buyer to comply.

Section 3.8 Regulatory Approvals

Notwithstanding Section 21(d) below, or anything else to the contrary herein, the Parties' obligations under this Agreement are subject to Buyer obtaining approval from NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Agreement, without material modification to the obligations of either Party under this Agreement. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **October 4**, **2019** Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Agreement. If the Parties cannot agree as to how to continue such transaction, this Agreement shall terminate without liability to either Party.

ARTICLE 4. SALE AND PURCHASE

Section 4.1 Provision Delivery and Receipt

Seller shall provide and deliver to the Delivery Point and the Buyer shall receive at the Delivery Point the percent of the Requirements applicable to each Service Requirement as set forth on Appendix A during the Delivery Term.

Section 4.2 Responsibilities

(a) Buyer shall be responsible for arranging and paying for the transmission of the power across NEPOOL PTF and for any ancillary services, allocated to the Network Load, associated with the Service Requirements. Arranging and paying for transmission across NEPOOL PTF, required of the Buyer, includes, but is not limited to taking Regional Network Service under the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff"). Arranging and paying for ancillary services, required by the Buyer, includes, but is not limited to any transmission dispatch or power administration services, as may be allocated to Network Load in accordance with ISO Rules. Arranging and paying for transmission from NEPOOL PTF to Buyer's distribution facilities includes, but is not limited to, taking Network Integration Transmission Service under the Service Agreement for Network Integration Transmission Service between Northeast Utilities Service Company and UES.

(b) Seller shall be responsible for all present and future obligations, requirements, and costs associated with the Requirements.

(c) The term "Requirements" means the provision of energy at the Delivery Point as set forth in Section 4.2(e), capacity as set forth in Section 4.2(f) and ancillary services as set forth in Section 4.2(g), in each case associated with the Service Requirements as set forth in Appendix A.

(d) If ISO Rules are modified during the Term of this Agreement, which change the allocation of currently existing charges and obligations from the Load Asset, associated with the Service Requirements to the Network Load, associated with the Buyer's transmission responsibilities, then, if possible, the charges or obligations shall be transferred back to the Seller through the ISO and/or ISO settlement process. If such transfer is not possible, then the Seller shall compensate the Buyer for any additional cost. If ISO Rules are modified during the Term of this Agreement, which change the allocation of currently existing charges and obligations from the Network Load, associated with the Buyer's transmission responsibilities to the Load Asset, associated with the Service Requirements, then, if possible, the charges or obligations shall be transferred back to the Buyer through the ISO and/or ISO settlement process. If such transfer is not possible, then the Buyer shall compensate the Seller for such charges. If ISO Rules are changed after the date of this Agreement, which create new charges or obligations, associated with the Service Requirements, then the Seller shall be responsible for such new charges or obligations. Likewise, if ISO Rules are changed during the Term of this Agreement, which create new charges or obligations, associated with the Network Load, associated with the Buyer's transmission responsibilities, then the Buyer shall be responsible for such charges or obligations.

(e) Provision of energy includes, but is not limited to the following. Seller shall have the Day-Ahead Load Obligation and the Real-Time Load Obligation, associated with the Service Requirements at the Delivery Point. Currently, the Energy Settlement Obligation, associated with the Service Requirements at the Delivery Point, is settled at the New Hampshire Load Zone. In the event that NEPOOL or the ISO implements nodal settlement of load obligations of the Day-Ahead Energy Market and Real-Time Energy Market, the Seller shall continue to be responsible for Day-Ahead and Real-Time Load Obligations at the appropriate settlement location(s), associated with the Service Requirements at the Delivery Point.

(f) Provision of capacity includes, but is not limited to the following. Seller shall have the ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point. Currently, the ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point, can be satisfied with any ICAP resource, recognized by the ISO in the NEPOOL control-area or imported into the NEPOOL control-area. In the event that ISO implements a locational capacity requirement, including that which was proposed in the Commission's docket number ER03-563, then the Seller will be responsible for providing ICAP at the location, required to meet the Locational ICAP Settlement Obligation, associated with the Service Requirements at the Delivery Point.

(g) Provision of ancillary services, required of the Seller, includes, but is not limited to Regulation, Operating Reserves, Local Second-Contingency-Protection Resource ("LSCPR") other than LSCPR Operating Reserve charges that are monthly fixed-cost charges paid to Special Constraint Resources pursuant to agreements negotiated pursuant to Schedule 19 of Section II - Open Access Transmission Tariff, Net Commitment Period Compensation ("NCPC") other than LSCPR NCPC charges that are monthly fixed-cost charges paid to Specialty Constraint resources pursuant to agreements negotiated under Schedule 19 of Section II – Open Access Transmission Tariff, Forward Reserves, and any transmission dispatch or power administration services, as may be allocated to the Owner of the Load Assets, associated with the Service Requirements in accordance with ISO Rules. If ISO Rules are changed such that locational ancillary services are required, then the Seller shall be responsible for meeting the locational ancillary services requirement, associated with the Service Requirements at the Delivery Point.

(h) It is the intent of the Parties that for each Financial Transmission Rights Auction ("FTR Auction") conducted by the ISO for months within the Delivery Terms(s), those Auction Revenue Rights ("ARRs") associated solely with the Service Requirement shall be assigned or paid to Seller, provided, however, Buyer shall be under no obligation to participate in any manner in any FTR Auction in order to increase Auction Revenue Right quantities.

ARTICLE 5. AMOUNT, BILLING and PAYMENT

Section 5.1 <u>Amount</u>

The amount payable by the Buyer to Seller for Delivered Energy in a month shall be the product of (a) the sum of the Delivered Energy for each Customer Group, as identified in Appendix A in each month during the applicable Delivery Term; and (b) the Contract Rate for such Service Requirement as identified in Appendix B for such month during the applicable Delivery Term.

Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load Asset number 10019, and the hourly real time locational marginal prices ("RT LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

Section 5.2 Billing and Payment

(a) On or before the twentieth (20th) day of each month ("Invoice Date") during the term of this Agreement, Seller shall calculate the amount due and payable to Seller pursuant to this Article 5, for Delivered Energy with respect to the preceding month (the "Calculation"). Seller shall provide the Calculation to the Buyer and such Calculation shall include sufficient detail for the Buyer to verify its formulation and computation. Calculations under this paragraph shall be subject to recalculation in accordance with Article 6 and shall be subject to adjustment (positive or negative) based upon such recalculation (a "Reconciliation Adjustment"). Seller shall promptly calculate the Reconciliation Adjustment upon receiving data described in Section 6.3 and shall include the adjustment, if any, in the next month's Invoice. A Reconciliation Adjustment based upon a change in the quantity for an earlier month shall be calculated using the applicable Contract Rate for the month in which the Delivered Energy was received.

(b) Seller shall submit to the Buyer an invoice with such Calculation as provided for in paragraph (a) of this Section (the "Invoice") and the respective amounts due under this Agreement on the Invoice Date. The Buyer shall pay Seller the amount of the Invoice (including the Reconciliation Adjustment, if any, as a debit or credit) less any amounts disputed in accordance with Section 5.3, on or before the later of the last Business Day of each month, or the tenth (10th) day after receipt of the Invoice, or, if such day is not a Business Day, then on the next following Business Day, (the "Due Date"). Except for amounts disputed in accordance with Section 5.3, if all or any part of the Invoice remains unpaid after the Due Date, interest shall accrue after but not including the Due Date and be payable to Seller on such unpaid amount at the Interest Rate in effect on the Due Date. The Due Date for a Reconciliation Adjustment shall be the Due Date of the Invoice in which it is included.

(c) Each Party shall notify the other Party upon becoming aware of an error in an Invoice, Calculation or Reconciliation Adjustment (whether the amount is paid or not) and Seller shall promptly issue a corrected Invoice. Overpayments shall be returned by the receiving Party upon request or deducted by the receiving Party from subsequent invoices, with interest accrued at the Interest Rate from the date of the receipt of the overpayment until the date paid or deducted.

Section 5.3 Challenge to Invoices

Either Party may challenge, in writing, the accuracy of Calculations, Invoices, Reconciliation Adjustments and data no later than twenty-four (24) months after the Due Date of the Invoice in which the disputed information is contained. If a Party does not challenge the accuracy within such twenty-four (24) month period, such Invoice shall be binding upon that Party and shall not be subject to challenge. If any amount in dispute is ultimately determined (under the terms herein) to be due to the other Party, it shall be paid or returned (as the case may be) to the other Party within three (3) Business Days of such determination along with interest accrued at the Interest Rate from the (i) date due and owing in accordance with the Invoice until the date paid or (ii) if the amount was paid and is to be returned, from the date paid, until the date returned.

Section 5.4 Taxes, Fees and Levies

Seller shall be obligated to pay all present and future taxes, fees and levies ("Taxes") which may be assessed by any entity upon the Seller's performance under this Agreement the purchase and sale of Requirements. Seller shall pay all Taxes with respect to the Requirements up to and at the Delivery Point, and the Buyer will pay all Taxes with respect to the Requirements after the Delivery Point. All Requirements, including electricity and other related market products delivered hereunder by Seller to the Buyer shall be sales for resale with the Buyer reselling such electricity and products.

Section 5.5 Netting and Setoff

Except for security provided pursuant to Section 7.3 (which shall not be considered for purposes of this Section 5.5) and unless otherwise specified in another agreement between the Parties, if the Parties are required to pay an amount in the same month each to the other under this Agreement or any other agreement between the Parties, or if any costs that are a Party's responsibility under this Agreement are incorrectly or inappropriately charged to the Party by the ISO, such amounts shall be netted, and the Party owing the greater aggregate amount shall pay to the other Party any difference between the amounts owed. Each Party reserves all rights, setoffs, counterclaims and other remedies and defenses (to the extent not expressly herein or therein waived or denied) that such Party has or to which such Party may be entitled arising from or out of this Agreement or the other agreement. Further, if the Buyer incurs any costs or charges that are the responsibility of Seller under this Agreement, such costs or charges may, at the Buyer's election, be netted against any amount due to Seller under this Agreement. All outstanding obligations to make payment under this Agreement or any other agreement between the Parties may be netted against each other, set off or recouped there from, or otherwise adjusted.

ARTICLE 6. QUALITY; LOSSES and QUANTITIES REQUIRED; DETERMINATION AND REPORTING OF HOURLY LOADS

Section 6.1 Quality

All electricity shall be delivered to the Buyer in the form of three-phase sixty-hertz alternating current at the Delivery Point.

Section 6.2 Losses

Seller shall be responsible for any transmission losses up to and including the Delivery Point. Losses beyond the Delivery Point are included in Delivered Energy and are paid for by the Buyer at the applicable Contract Rate.

Section 6.3 Determination and Reporting of Hourly Loads

The Buyer will estimate the Delivered Energy for Default Service provided by Seller pursuant to this Agreement based upon average load profiles developed for each of the Buyer's customer classes, actual metered data, as available, and the Buyer's actual total hourly load. The Buyer shall report to the ISO and Seller, the estimated Delivered Energy. In accordance with the ISO Rules, the Buyer will normally report to the ISO and to Seller, the Seller's estimated Delivered Energy by 1:00 P.M EPT of the second following Business Day after delivery. The Buyer shall have the right but not the obligation, in its sole and exclusive judgment, to modify the Estimation Process from time to time, provided that any such modification is designed with the objective of improving the accuracy of the Estimation Process.

Each month, the Buyer shall reconcile the Buyer's estimate of the Delivered Energy based upon the Buyer's meter reads (such meter reads as provided for in the Retail Delivery Tariff). The reconciliation, including all losses, shall be the adjusted Delivered Energy. In accordance with the ISO Rules the Buyer will normally notify the ISO of any resulting adjustment (debit or credit) to Seller's account for the Load Assets (set forth in Section 6.4) no later than the last day of the third month following the billing month.

Section 6.4 ISO Settlement Power System Model Implementation

The Default Service provided by Seller pursuant to this Agreement will be initially represented within the ISO Settlement Power System Model as described in Appendix A.

As soon as possible after the execution of this Agreement and before the Commencement Date, the Buyer shall assign to Seller, and Seller shall accept assignment of an Ownership Share for each Load Asset identified in Appendix A. Such assignment shall be effective beginning on the Commencement Date. Seller shall take any and all actions necessary to effectuate such assignment including executing documents required by ISO Rules. Once Seller's provision of Default Service terminates (at the end of a Delivery Term or otherwise), the Buyer and Seller will terminate Seller's Ownership Shares of the aforementioned Load Assets.

The Buyer shall have the right to change the Load Asset designations (identified above) from time to time, consistent with the definition and provision of Default Service. If and to the extent such designations change, the Buyer and Seller shall cooperate to timely put into effect the necessary documents that may be required to implement the new designations and terminate the prior designations.

ARTICLE 7. DEFAULT AND TERMINATION

Section 7.1 Events of Default

(a) Any one or more of the following events shall constitute an "Event of Default" hereunder with respect to the Buyer:

(i) Failure of the Buyer

(A) in any material respect to comply with, observe or perform any covenant, warranty or obligation under this Agreement (but excluding events that are otherwise specifically covered in this Section as a separate Event of Default and except due to causes excused by Force Majeure or attributable to Seller's' in breach of this Agreement); and

(B) After receipt of written notice from Seller such failure continues for a period of five (5) Business Days, or, if such failure cannot be reasonably cured within such five (5) Business Day period, such further period as shall reasonably be required to effect such cure (but in no event longer than thirty (30) days), provided that the Buyer commences within such five (5) Business Day period to effect a cure and at all times thereafter proceed diligently to complete the cure as quickly as possible and provides to Seller written documentation of its efforts and plan to cure and estimated time for completion of the cure.

(ii) Failure of the Buyer to (A) make when due any undisputed payment due to Seller hereunder; and (B) after receipt of written notice from Seller such failure continues for a period of three (3) Business Days.

(iii) Failure of the Buyer to accept Default Service in accordance with Article 3 (unless excused by Force Majeure or attributable to the Seller's breach of this Agreement, or otherwise in accordance with this Agreement).

(b) Any one or more of the following events shall constitute an "Event of Default" hereunder with respect to Seller:

(i) Failure of Seller

(A) in any material respect to comply with, observe, or perform any covenant, warranty or obligation under this Agreement (but excluding events that are otherwise specifically covered in this Section as a separate Event of Default and except due to causes excused by Force Majeure or attributable to the Buyer's in breach of this Agreement); and

(B) after receipt of written notice from the Buyer such failure continues for a period of five (5) Business Days, or, if such failure cannot be reasonably cured within such five (5) Business Day period, such further period as shall reasonably be required to effect a cure (but in no event longer than thirty (30) days), provided that Seller commences within such five (5) Business Day period to effect such cure and at all times thereafter proceeds diligently to complete the cure as quickly as possible and provides to the Buyer written documentation of its efforts and plan to cure and estimated time for completion of the cure;

(ii) Failure of Seller to provide Requirements in accordance with Articles 3 and 4

(c) Any one or more of the following events with respect to either Party shall constitute an "Event of Default" hereunder with respect to such Party:

(i) The entry by a court having jurisdiction in the premises of (A) a decree or order for relief in respect of such Party in an involuntary case or proceeding under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law, or (B) a decree or order adjudging such Party as bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of or in respect of such Party under any applicable federal or state law, or appointing a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of such Party or of any substantial part of its property, or ordering the winding up or liquidation of its affairs;

(ii) The commencement by such Party of a voluntary case or proceeding, or any filing by a third party of an involuntary case or proceeding against a Party that is not dismissed within forty-five (45) days of such filing, under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law, or of any other case or proceeding to be adjudicated as bankrupt or insolvent, or the consent by it to the entry of a decree or order for relief in respect of such Party in an involuntary case or proceeding under any applicable federal or state bankruptcy, insolvency, reorganization or other similar law or to the commencement of any bankruptcy or insolvency case or proceeding against it, or the filing by it of a petition or answer or consent seeking reorganization or relief under any applicable federal or state law, or the consent by it to the filing of such petition or to the appointment of or taking possession by a custodian, receiver, liquidator, assignee, trustee, sequestrator or other similar official of a Party or of any substantial part of its property, or the making by it of an assignment for the benefit of creditors, or the admission by it in writing of its inability to pay its debts generally as they become due, or the taking of corporate action by such Party in furtherance of any such action;

(iii) Any representation or warranty made by a Party is or becomes false or misleading in any material respect.

(iv) Failure of such Party to deliver Performance Assurance when due in accordance with Section 7.3 if such failure is not remedied within three (3) Business Days after written notice.

Section 7.2 Remedies Upon Default

The Parties shall have the following remedies available to them with respect to the occurrence of an Event of Default with respect to the other Party hereunder:

(a) Upon the occurrence of an Event of Default, the non-defaulting Party shall have the right to (i) continue performance under this Agreement and exercise such rights and remedies as it may have at law, in equity or under this Agreement and seek remedies as may be necessary or desirable to enforce performance and observation of any obligations and covenants under this Agreement, so long as such rights and remedies are not duplicative of any other rights and remedies hereof, and do not otherwise enable the non-defaulting Party to obtain performance or payments in excess of the performance and payments to which it is otherwise entitled pursuant to this Agreement, or (ii) at its option, give such defaulting Party a written notice (a "Termination Notice") terminating this Agreement. Upon a termination for an Event of Default under Section 7.1(a), (b) or (c)(iii) and (iv), such termination shall be effective as of the date specified in the Termination Notice, which date shall be no earlier than the date such notice is effective and no later than thirty (30) days after the date of such notice is provided to the defaulting Party in accordance with Article 8. Upon a termination for an Event of Default under Section 7.1(c)(i) or (ii), such termination shall be effective as of the Event of Default, upon notice being provided to the defaulting Party in accordance with Article 8. Any attempted cure by a defaulting Party after a Termination Notice has been provided or the effective termination under Section 7.1(c)(i) or (ii) shall be void and of no effect. The Parties' obligations under this Agreement, in general and under this Section 7.2 in particular, are subject to the duty to mitigate damages as provided under common law.

(b) At any time after the occurrence of an Event of Default, or the delivery of a Termination Notice to the defaulting Party by the non-defaulting Party, the non-defaulting Party may exercise any rights it may have pursuant to the Section 7.3 (Security).

(c) In the event of termination for an Event of Default as provided in Section 7.1, in addition to any amounts owed for performance (or failure to perform) hereunder prior to such termination, the non-defaulting Party may recover, without duplication, its direct damages resulting from such Event of Default; such damages shall include the positive (if any) present value of this Agreement to the non-defaulting Party for the portion of the Delivery Term remaining at the time of such termination, to be determined by reference to market prices, transaction costs and load reasonably projected for the remaining portion of the Delivery Term ("Termination Damages"). The Termination Damages shall include all reasonably incurred transaction costs and expenses that otherwise would not have been incurred by the non-defaulting Party. In determining its Termination Damages, the non-defaulting Party shall offset its losses and costs by any gains or savings realized by the non-defaulting Party as a result of the termination.

Payment of Termination Damages, if any, shall be made by the defaulting Party to the non-defaulting Party within five (5) days after calculation of such Termination Damages and receipt of a notice including such calculation of the amounts owed hereunder and a written statement showing in reasonable detail the calculation and a summary of the method used to determine such amounts. Upon the reasonable request of the defaulting Party, the non-defaulting Party shall provide reasonable documentation to verify the costs underlying the Termination Damages. If the defaulting Party disputes the non-defaulting Party's calculation of the Termination Damages, in whole or in part, the defaulting Party shall, within five (5) days of receipt of the non-defaulting Party's calculation of the Termination Damages, provide to the non-defaulting Party a detailed written explanation of the basis for such dispute; provided, however, that, the defaulting Party shall first pay the Termination Damages, if any, to the non-defaulting Party in accordance with the preceding sentence, and the non-defaulting Party shall then deposit such disputed amount into an interest bearing escrow account for the benefit of the prevailing Party and the dispute shall be resolved in accordance with Section 15.2.

(d) Notwithstanding any other provision of this Agreement, the cure of any default or failure to comply with, observe or perform any covenant, warranty or obligation under this Agreement within the period provided therefor in this Article shall not release such defaulting Party from its obligations under Section 9.2 of this Agreement.

(e) Upon termination the Buyer shall, and upon the occurrence of an Event of Default by Seller, the Buyer shall have the right to, immediately notify the ISO that (i) the assignment from the Buyer to Seller of the applicable Ownership Share has been terminated, (ii) the Load Assets shall be removed from Seller's account and placed in the account of the Buyer and (iii) Seller consents to such action. In the event the Buyer so notifies the ISO, Seller shall immediately take any and all actions that may be required by the ISO to remove the Load Assets from Seller's account and place them in the account of the Buyer. If the Agreement has not been terminated, the Buyer, in its sole discretion with 5 Business Days prior notice to Seller, may elect to assign the applicable Ownership Share of the Load Assets to the account of Seller and Seller shall accept such assignment, consistent with the actions required by Section 6.4 of this Agreement.

Section 7.3 Security

(a) If the Credit Rating of either Party is downgraded by Moody's and S&P, such that its Credit Rating is below an Investment Grade (a "Downgrade Event"), then within three (3) Business Days after a request of the other Party, the downgraded Party shall deliver the applicable amount of performance assurance required pursuant to this Article 7 ("Performance Assurance") to the other Party ("Compliant Party").

(b) If Performance Assurance is required to be posted by a Party pursuant to the immediately preceding paragraph, the following Sections 7.3(b)(i) through 7.3(b)(iv) shall apply:

(i) The Compliant Party shall calculate its exposure under this Agreement as soon as practicable after the Downgrade Event, and on a monthly basis thereafter ("Performance Assurance Calculation Date").

(ii) All Performance Assurance shall be delivered in the form of: (i) U.S. Dollars delivered by wire transfer of immediately available funds ("Funds"); or (ii) a Letter of Credit from a Qualified Institution (as defined herein). For purposes of determining the amount of Performance Assurance held at any time, a Letter of Credit shall be valued at zero unless it expires more than thirty (30) days after the date of valuation. For purposes of this Agreement, the Parties acknowledge that any Performance Assurance provided by Buyer shall be in the form of Funds as defined in this Section 7.3. For purposes hereof, "Letter(s) of Credit" means one or more irrevocable, transferable standby letters of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (which is not an affiliate of either Party) with such bank having a credit rating of at least A- from S&P and A3 from Moody's, having $1,000,000,000 in assets (a "Qualified Institution"), and otherwise being in a form acceptable to the Party in whose favor the letter of credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

(iii) For purposes hereof, it shall be a Letter of Credit Default ("Letter of Credit Default") with respect to an outstanding Letter of Credit, upon the occurrence of any of the following events: (i) the bank issuing the Letter of Credit shall fail to maintain a credit rating of at least "A-" by S&P and "A3" by Moody's, (ii) the bank issuing the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (iii) the bank issuing the Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of such Letter of Credit; (iv) such Letter of Credit shall fail or cease to be in full force and effect at any time during the term of any outstanding transaction; or (v) the pledgor or the bank issuing the Letter of Credit shall fail to cause the renewal or replacement of the Letter of Credit to the secured party at least thirty (30) Business Days prior to the expiration of such Letter of Credit; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be canceled or returned to the pledgor in accordance with the terms of this Agreement. If a Letter of Credit Default occurs, then the Party which applied for such Letter of Credit shall have five (5) Business Days to cure the event(s) causing the Letter of Credit Default or to replace the Letter of Credit with a substitute Letter of Credit or Funds. Any failure to cure the event(s) causing the Letter of Credit Default or to provide a substitute Letter of Credit or Funds within five (5) Business Days of the event(s) leading to the Letter of Credit Default shall be an Event of Default under Section 7.1(c)(iv).

(iv) The Compliant Party will be entitled to hold posted Performance Assurance, provided that the following conditions applicable to it are satisfied: (1) the Compliant Party is not a defaulting Party; (2) the Compliant Party has and maintains an Investment Grade Credit Rating required in Section 7.3(a), as applicable; and (3) the posted Performance Assurance is held only in the United States. For funds held as Performance Assurance by the Compliant Party, the Interest Rate will be the Federal Funds Rate as from time to time in effect. "Federal Funds Rate" means, for the relevant determination date, the rate opposite the caption "Federal Funds (Effective)" as set forth in the weekly statistical release designated as H.15 (519), or any successor publication, published by the Board of Governors of the Federal Reserve System. Such interest shall be calculated commencing on the date Performance Assurance in the form of cash is received by a Party but excluding the earlier of: (i) the date Performance Assurance in the form of cash is returned to a Party; or (ii) the date Performance Assurance in the form of cash is applied to a pledgor's obligations pursuant to Section 7.3 with the net amount of interest accrued monthly being payable on the third Business Day of the following month. A Party holding Performance Assurance may apply such Performance Assurance, without prior notice to the other party, to satisfy the obligations of the other Party in accordance with Section 7.2. Each Party hereby covenants and agrees that it shall be entitled herein to hold posted Performance Assurance as custodian on its own behalf as a secured party if it meets the criteria set forth above in this Section 7.3. However, if the Party holding Performance Assurance is not eligible to hold posted Performance Assurance pursuant to this Section 7.3, then such Party shall be considered ineligible to hold posted Performance Assurance as a secured party and such posted Performance Assurance shall be maintained as follows: the ineligible secured party will cause all posted Performance Assurance received from the other Party to be segregated from the secured party's own property and identified clearly as Performance Assurance and to be held in an account in which no property of the secured party is held (a "Collateral Account") with a domestic office of a Qualified Institution, each of which accounts may include property of other parties which have delivered posted Performance Assurance to the secured party under other agreements, but will bear a title indicating that the secured party's interest in said account is as a holder of collateral. Such accounts will bear interest at the rate offered by the Qualified Institution. In addition, the secured party may direct the pledgor to transfer or deliver eligible Performance Assurance directly into the secured party's Collateral Account. The secured party shall cause statements concerning the posted Performance Assurance transferred or delivered by the pledgor to be sent to the pledgor on request, which may not be made more frequently than once in each calendar month.

(c) Prior to the Commencement Date and at any time upon the request by Buyer of Seller or by Seller of Buyer, the Party to whom the request is made shall establish that it meets the Credit Requirements by providing (x) a certificate of one of its authorized officers, accompanied by supporting certified financial statements and (y) documentation of its Credit Rating, as applicable. Buyer and Seller shall inform the other Party within one (1) Business Day of any failure to satisfy the Credit Requirements, provided that, in no event, shall the failure of a Party to provide the notice required pursuant to this sentence constitute a default or an Event of Default pursuant to Section 7.1.

Section 7.4 <u>Forward Contract</u>

Each Party represents and warrants to the other that it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code, that this Agreement is a "forward contract" within the meaning of the United States Bankruptcy Code, and that the remedies identified in this Agreement, including those specified in Section 7, shall be "contractual rights" as provided for in 11 U.S.C. § 556 as that provision may be amended from time to time.

ARTICLE 8. NOTICES, REPRESENTATIVES OF THE PARTIES

Section 8.1 Notices

Any notice, demand, or request required or authorized by this Agreement to be given by one Party to another Party shall be in writing. It shall either be sent by facsimile (with receipt confirmed by telephone), courier, personally delivered (including overnight delivery service) or mailed, postage prepaid, to the representative of the other Party designated in accordance with this Article. Any such notice, demand, or request shall be deemed to be given (i) when sent by facsimile confirmed by telephone, (ii) when actually received if delivered by courier or personal delivery (including overnight delivery service) or (iii) seven (7) days after deposit in the United States mail, if sent by first class mail return receipt requested.

Notices and other communications by Seller to the Buyer shall be addressed to:

Mr. Robert S. Furino
Vice President
Unitil Energy Systems, Inc.
6 Liberty Lane West
Hampton, NH 03842
(603) 773-6452 (phone)
(603) 773-6652 (fax)

and

Notices concerning Article 7 shall also be sent to:

Mr. Todd Diggins
Director of Finance
Unitil Energy Systems, Inc.
6 Liberty Lane West
Hampton, NH 03842
(603) 773-6612 (phone)
(603) 773-6812 (fax)

Notices and other communications by the Buyer to Seller shall be addressed to:

[Name]

[Company]

[Address]

[City, State & Zip]

[Phone]

[FAX]

Any Party may change its representative or address for notices by written notice to the other Party; however such notice shall not be effective until it is received by the other Party.

Section 8.2 Authority of Representative

The Parties' representatives shall have full authority to act for their respective Party in all matters relating to the performance of this Agreement. Notwithstanding the foregoing, a Party's representative shall not have the authority to amend, modify, or waive any provision of this Agreement unless they are duly authorized officers of their respective entities and such amendment, modification or waiver is made in accordance to Article 17.

ARTICLE 9. LIABILITY; INDEMNIFICATION; RELATIONSHIP OF PARTIES

Section 9.1 Limitation on Consequential, Incidental and Indirect Damages

EXCEPT AS EXPRESSLY PROVIDED IN THIS AGREEMENT, TO THE FULLEST EXTENT PERMISSIBLE BY LAW, NEITHER THE BUYER NOR SELLER, NOR THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, EMPLOYEES, PARENT OR AFFILIATES, SUCCESSOR OR ASSIGNS, OR THEIR RESPECTIVE OFFICERS, DIRECTORS, AGENTS, OR EMPLOYEES, SUCCESSORS, OR ASSIGNS, SHALL BE LIABLE TO THE OTHER PARTY OR ITS PARENT, SUBSIDIARIES, AFFILIATES, OFFICERS, DIRECTORS, AGENTS, EMPLOYEES, SUCCESSORS OR ASSIGNS, FOR CLAIMS, SUITS, ACTIONS OR CAUSES OF ACTION FOR INCIDENTAL, INDIRECT, SPECIAL, PUNITIVE, MULTIPLE OR CONSEQUENTIAL DAMAGES (INCLUDING ATTORNEY'S FEES OR LITIGATION COSTS EXCEPT AS EXPRESSLY PROVIDED IN 15.2) CONNECTED WITH OR RESULTING FROM PERFORMANCE OR NON-PERFORMANCE OF THIS AGREEMENT, OR ANY ACTIONS UNDERTAKEN IN CONNECTION WITH OR RELATED TO THIS AGREEMENT, INCLUDING ANY SUCH DAMAGES WHICH ARE BASED UPON CAUSES OF ACTION FOR BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE AND MISREPRESENTATION), BREACH OF WARRANTY, STRICT LIABILITY, STATUTE, OPERATION OF LAW, OR ANY OTHER THEORY OF RECOVERY. THE PROVISIONS OF THIS SECTION SHALL APPLY REGARDLESS OF FAULT AND SHALL SURVIVE TERMINATION, CANCELLATION, SUSPENSION, COMPLETION OR EXPIRATION OF THIS AGREEMENT.

Section 9.2 Indemnification

(a) Seller agrees to defend, indemnify and save the Buyer, its officers, directors, employees, agents, successors assigns, and Affiliates and their officers, directors, employees and agents harmless from and against any and all third-party claims, suits, actions or causes of action and any resulting losses, damages, charges, costs or expenses, (including reasonable attorneys' fees and court costs), arising from or in connection with any (a) breach of a representation or warranty or failure to perform any covenant or agreement in this Agreement by Seller, (b) any violation of applicable law, regulation or order by Seller, (c) any act or omission by Seller with respect to this Agreement, first arising, occurring or existing during the term of this Agreement, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement, except to the extent caused by an act of gross negligence or willful misconduct by an officer, director, agent, employee, or Affiliate of the Buyer or its respective successors or assigns.

(b) The Buyer agrees to defend, indemnify and save Seller, its officers, directors, employees, agents, successor, assigns, and Affiliates and their officers, directors, employees and agents harmless from and against any and all third-party claims, suits, actions or causes of action and any resulting losses, damages, charges, costs or expenses, (including reasonable attorneys' fees and court costs), arising from or in connection with any (a) breach of representation or warranty or failure to perform any covenant or agreement in this Agreement by said Buyer, (b) any violation of applicable law, regulation or order by said Buyer, (c) any act or omission by the Buyer, with respect to this Agreement first arising, occurring or existing during the term of this Agreement, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement, except to the extent caused by an act of gross negligence or willful misconduct by an officer, director, agent, employee or Affiliate of Seller or its respective successors or assigns.

(c) If any Party intends to seek indemnification under this Section from the other Party with respect to any action or claim, the Party seeking indemnification shall give the other Party notice of such claim or action within thirty (30) days of the later of the commencement of, or actual knowledge of, such claim or action; provided, however, that in the event such notice is delivered more than thirty (30) days after the Party seeking indemnification knows of such claim or action, the indemnifying Party shall be relieved of its indemnity hereunder only if and to the extent such indemnifying Party was actually prejudiced by the delay. The Party seeking indemnification shall have the right, at its sole cost and expense, to participate in the defense of any such claim or action. The Party seeking indemnification shall not compromise or settle any such claim or action without the prior consent of the other Party, which consent shall not be unreasonably withheld.

Section 9.3 Independent Contractor Status

Nothing in this Agreement shall be construed as creating any relationship between the Buyer and Seller other than that of independent contractors for the sale and delivery of Requirements for Default Service.

ARTICLE 10. ASSIGNMENT

Section 10.1 General Prohibition Against Assignments

Except as provided in Section 10.2, neither Party shall assign, pledge or otherwise transfer this Agreement or any right or obligation under this Agreement without first obtaining the other Party’s written consent, which consent shall not be unreasonably withheld.

Section 10.2 Exceptions to Prohibition Against Assignments

(a) Seller may, without the Buyer’s prior written consent, collaterally assign this Agreement in connection with financing arrangements provided that any such collateral assignment that provides for the Buyer to direct payments to the collateral agent (i) shall be in writing, (ii) shall not be altered or amended without prior written notice to the Buyer from both Seller and the collateral agent, and (iii) provided that any payment made by the Buyer to the collateral agent shall discharge the Buyer's obligation as fully and to the same extent as if it had been made to the Seller. Seller must provide the Buyer at least ten (10) days advance written notice of collateral assignment and provide copies of any such assignment and relevant agreements or writings.

(b) The Buyer may assign all or a portion of its rights and obligations under this Agreement to any Affiliate of the Buyer without consent of Seller.

(c) Either Party may, upon written notice to the other Party, assign its rights and obligations hereunder, or transfer such rights and obligations by operation of law, to any entity with which or into which such Party shall merge or consolidate or to which such Party shall transfer all or substantially all of its assets, provided that such other entity agrees to assume the rights and obligations hereunder and be bound by the terms hereof and provided further, that such other entity's creditworthiness is equal to or higher than that of the assignor, in which case the assignor shall be relieved of any obligation or liability hereunder as a result of such assignment.

ARTICLE 11. SUCCESSORS AND ASSIGNS

This Agreement shall inure to the benefit of and shall be binding upon the Parties hereto and their respective successors and permitted assigns.

ARTICLE 12. FORCE MAJEURE

(a) Force Majeure shall include but not be limited to acts of God, earthquakes, fires, floods, storms, strikes, labor disputes, riots, insurrections, acts of war (whether declared or otherwise), acts of governmental, regulatory or judicial bodies, but if and only to the extent that such event or circumstance (i) directly affects the availability of the transmission or distribution facilities of NEPOOL, the Buyer or an Affiliate of the Buyer necessary to provide service to the Buyer's customers which are taking service pursuant to the Retail Delivery Tariff and (ii) it is not within the reasonable control of, or the result of the negligence of, the claiming Party, and which, by the exercise of due diligence, the claiming Party is unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (A) fluctuations in Default Service, (B) the cost to a Party to overcome or avoid, or cause to be avoided, the event or circumstance affecting such Party's performance or (C) events affecting the availability or cost of operating any generating facility.

(b) To the extent that either Party is prevented by Force Majeure from carrying out, in whole or in part, its obligations hereunder and (i) such Party gives notice and detail of the Force Majeure to the other Party as soon as practicable after the onset of the Force Majeure, including an estimate of its expected duration and the probable impact on the performance of its obligations hereunder; (ii) the suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure, and (iii) the Party claiming Force Majeure uses commercially reasonable efforts to remedy or remove the inability to perform caused by Force Majeure, then the affected Party shall be excused from the performance of its obligations prevented by Force Majeure. However, neither Party shall be required to pay for any obligation the performance of which is excused by Force Majeure. This paragraph shall not require the settlement of any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute are contrary to its interest. It is understood and agreed that the settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party involved in the dispute.

(c) No obligations of either Party which arose before the Force Majeure occurrence causing the suspension of performance shall be excused as a result of the Force Majeure.

(d) Prior to the resumption of performance suspended as a result of a Force Majeure occurrence, the Party claiming the Force Majeure shall give the other Party written notice of such resumption.

ARTICLE 13. WAIVERS

No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. The waiver of any single breach or default of any term or condition of this Agreement shall not be deemed to constitute the waiver of any other prior or subsequent breach or default of the Agreement or any other term or condition.

ARTICLE 14. LAWS AND REGULATIONS

(a) This Agreement and all rights, obligations, and performances of the Parties hereunder, are subject to all applicable federal and state laws, and to all duly promulgated orders and other duly authorized action of governmental authorities having jurisdiction hereof.

(b) The rates, terms and conditions contained in this Agreement are not subject to change under Section 205 of the Federal Power Act as that section may be amended or superseded, absent the mutual written agreement of the Parties. Each Party irrevocably waives its rights, including its rights under §§ 205-206 of the Federal Power Act, unilaterally to seek or support a change in the rate(s), charges, classifications, terms or conditions of this Agreement or any other agreements entered into in connection with this Agreement. By this provision, each Party expressly waives its right to seek or support: (i) an order from FERC finding that the market-based rate(s), charges, classifications, terms or conditions agreed to by the Parties in the Agreement are unjust and unreasonable; or (ii) any refund with respect thereto. Each Party agrees not to make or support such a filing or request, and that these covenants and waivers shall be binding notwithstanding any regulatory or market changes that may occur hereafter.

(c) Absent the agreement of all Parties to a proposed change, the standard of review for changes to this Agreement proposed by a non-party or the Commission acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

ARTICLE 15. INTERPRETATION, DISPUTE RESOLUTION

Section 15.1 Governing Law

The Agreement shall be governed by and construed and performed in accordance with the laws of the State of New Hampshire, without giving effect to its conflict of laws principles.

Section 15.2 Dispute Resolution

All disputes between the Buyer and Seller under this Agreement shall be referred, upon notice by one Party to the other Party, to a senior manager of Seller designated by Seller, and a senior manager of the Buyer designated by the Buyer, for resolution on an informal basis as promptly as practicable. In the event the designated senior managers are unable to resolve the dispute within ten (10) days of receipt of the notice, or such other period to which the Parties may jointly agree, such dispute shall be submitted to arbitration and resolved in accordance with the arbitration procedure set forth in this Section. The arbitration shall be conducted in Concord, New Hampshire before a single neutral arbitrator mutually agreed to and appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, Seller and the Buyer shall each choose one arbitrator, who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within ten (10) days select a third arbitrator to act as chairman of the arbitration panel. In either case, the arbitrator(s) shall be knowledgeable in electric utility matters, including wholesale power transactions and power market issues, and shall not have any current or past material business or financial relationships with either Party or a witness for either Party and shall not have a direct or indirect interest in any Party or the subject matter of the arbitration. The arbitrator(s) shall afford each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the then-current arbitration rules of the CPR Institute for Dispute Resolution (formerly known as the Center for Public Resources), unless otherwise mutually agreed by the Parties. There shall be no formal discovery conducted in connection with the arbitration unless otherwise mutually agreed by the Parties; provided, however, that the Parties shall exchange witness lists and copies of any exhibits that they intend to utilize in their direct presentations at any hearing before the arbitrator(s) at least ten (10) days prior to such hearing, along with any other information or documents specifically requested by the arbitrator(s) prior to the hearing. Any offer made and the details of any negotiations to resolve the dispute shall not be admissible in the arbitration or otherwise. Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of his, her or their appointment and shall notify the Parties in writing of such decision and the reasons therefore, and shall make an award apportioning the payment of the costs and expenses of arbitration among the Parties; provided, however, that each Party shall bear the costs and expenses of its own attorneys, expert witnesses and consultants unless the arbitrator(s), based upon a determination of good cause, awards attorneys fees and legal and other costs to the prevailing Party. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this Agreement and shall have no power to modify or change the Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction, subject expressly to Section 15.3. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute

Resolution Act. Nothing in this paragraph shall impair the ability of a Party to exercise any right or remedy it has under this Agreement, including those in Article 7.

Section 15.3 Venue; Waiver of Jury Trial

Each Party hereto irrevocably (i) submits to the exclusive jurisdiction of the federal and state courts located in the State of New Hampshire; (ii) waives any objection which it may have to the laying of venue of any proceedings brought in any such court; and (iii) waives any claim that such proceedings have been brought in an inconvenient forum. EACH PARTY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR PROCEEDING RELATING TO THIS AGREEMENT.

ARTICLE 16. SEVERABILITY

Any provision declared or rendered unlawful by any applicable court of law or regulatory agency or deemed unlawful because of a statutory change will not otherwise affect the remaining provisions and lawful obligations that arise under this Agreement. If any provision of this Agreement, or the application thereof to any Party or any circumstance, is invalid or unenforceable, (a) a suitable and equitable provision shall be substituted therefor in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid or unenforceable provision, and (b) the remainder of this Agreement and the application of such provision or circumstances shall not be affected by such invalidity or unenforceability.

ARTICLE 17. MODIFICATIONS

No modification or amendment of this Agreement will be binding on any Party unless it is in writing and signed by both Parties.

ARTICLE 18. ENTIRE AGREEMENT

This Agreement, including the Appendices, the tariffs and agreements referred to herein or therein, embody the entire agreement and understanding of the Parties in respect of the transactions contemplated by this Agreement. There are no restrictions, promises, representations, warranties, covenants or undertakings, other than those expressly set forth or referred to herein or therein. It is expressly acknowledged and agreed that there are no restrictions, promises, representations, warranties, covenants or undertakings contained in any material provided or otherwise made available by the Seller or the Buyer to each other. This Agreement supersedes all prior agreements and understandings between the Parties with respect to the transactions contemplated hereby.

ARTICLE 19. COUNTERPARTS

This Agreement may be executed in any number of counterparts, and each executed counterpart shall have the same force and effect as an original instrument.

ARTICLE 20. INTERPRETATION; CONSTRUCTION

The article and section headings contained in this Agreement are solely for the purpose of reference, are not part of the agreement of the Parties and shall not in any way affect the meaning or interpretation of this Agreement. For purposes of this Agreement, the term "including" shall mean "including, without limitation". The Parties acknowledge that, each Party and its counsel have reviewed and or revised this Agreement and that any rule of construction to the effect that any ambiguities are to be resolved against the drafting Party shall not be employed in the interpretation of this Agreement, and it is the result of joint discussion and negotiation.

ARTICLE 21. REPRESENTATIONS; WARRANTIES AND COVENANTS

Each Party represents to the other Party, upon execution and continuing throughout the term of this Agreement, as follows:

(a) It is duly organized in the form of business entity set forth in the first paragraph of this Agreement, validly existing and in good standing under the laws of its state of its organization and has all requisite power and authority to carry on its business as is now being conducted, including all regulatory authorizations as necessary for it to legally perform its obligations hereunder.

(b) It has full power and authority to execute and deliver this Agreement and to consummate and perform the transactions contemplated hereby. This Agreement has been duly and validly executed and delivered by it, and, assuming that this Agreement constitutes a valid and binding agreement of the other Party, constitutes its valid and binding agreement, enforceable against it in accordance with its terms, subject to bankruptcy, insolvency, fraudulent transfer, reorganization, moratorium and similar laws of general applicability relating to or affecting creditors' rights and to general equity principles.

(c) Such execution, delivery and performance do not violate or conflict with any law applicable to it, any provision of its constitutional documents, or the terms of any note, bond, mortgage, indenture, deed of trust, license, franchise, permit, concession, contract, lease or other instrument to which it is bound, any order or judgment of any court or other agency of government applicable to it or any of its assets or any contractual restriction binding on or affecting it or any of its assets.

(d) No declaration, filing with, notice to, or authorization, permit, consent or approval of any governmental authority is required for the execution and delivery of this Agreement by it or the performance by it of its obligations hereunder, other than such declarations, filings, registrations, notices, authorizations, permits, consents or approvals which, if not obtained or made, will not, in the aggregate, have a Material Adverse Effect.

(e) Neither the execution and delivery of this Agreement by it will nor the performance by it of its obligations under this Agreement will or does (i) conflict with or result in any breach of any provision of its Governing Documents, (ii) result in a default (or give rise to any right of termination, cancellation or acceleration) under any of the terms, conditions or provisions of any note, bond, mortgage, indenture, license, agreement or other instrument or obligation to which it or any of its subsidiaries is a party or by which it or any of its subsidiaries is bound, except for such defaults (or rights of termination, cancellation or acceleration) as to which requisite waivers or consents have been obtained or which, in the aggregate, would not have a Material Adverse Effect; or (iii) violate any order, writ, injunction, decree, statute, rule or regulation applicable to it, which violation would have a Material Adverse Effect.

(f) There are no claims, actions, proceedings or investigations pending or, to its knowledge, threatened against or relating to it before any governmental authority acting in an adjudicative capacity relating to the transactions contemplated hereby that could have a Material Adverse Effect. It is not subject to any outstanding judgment, rule, order, writ, injunction or decree of any court or governmental authority which, individually or in the aggregate, would create a Material Adverse Effect.

(g) There are no bankruptcy, insolvency, reorganization, receivership or other similar proceedings pending or being contemplated by it, or of its knowledge threatened against it.

(h) It is a signatory to the Market Participant Service Agreement and is in compliance with all ISO Rules, including the ISO Financial Assurance Policy.

(i) It is acting for its own account, has made its own independent decision to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party hereto, and is capable of assessing the merits of and understanding, and understands and accepts, the terms, conditions and risks of this Agreement.

ARTICLE 22. CONSENTS AND APPROVALS

The Parties shall cooperate so that each Party may take such actions as necessary and required for the other Party to effectuate and comply with this Agreement including to (i) promptly prepare and file all necessary documentation, (ii) effect all necessary applications, notices, petitions and filings and execute all agreements and documents, and (iii) use all commercially reasonable efforts to obtain all necessary consents, approvals and authorizations of all other entities, in the case of each of the foregoing clauses (i), (ii) and (iii), necessary or advisable to consummate the transactions contemplated by this Agreement. The Buyer shall have the right to review and approve in advance all characterizations of the information relating to the transactions contemplated by this Agreement which appear in any filing, press release or public announcement made in connection with the transactions contemplated hereby.

ARTICLE 23. CONFIDENTIALITY

Seller acknowledges that Seller’s identity will be publicly disclosed in the NHPUC order approving or denying the Buyer’s inclusion in retail rates of the amounts payable by Buyer to Seller under this Agreement as described in Section 3.8. Neither Seller nor the Buyer shall provide copies of this Agreement or disclose the contents thereof (the “Confidential Terms”) to any third party without the prior written consent of the other Party; provided, however, that either Party may provide a copy of the Confidential Terms, in whole or in part to (1) any regulatory agency requesting and/or requiring such Confidential Terms, provided that any such disclosure must include a request for confidential treatment of the Confidential Terms, and (2) an Affiliate if related to the Party’s performance of its obligations hereunder, provided that such Affiliate agrees to treat the Confidential Terms as confidential in accordance with this clause.

[Remainder of Page Intentionally Left Blank]

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

UNITIL ENERGY SYSTEMS, INC.

BY: ______________________________________

Robert S. Furino

Vice President

[COMPANY]

BY: ______________________________________

Its ______________________________________

APPENDIX A

Service Requirements Matrix

By Service Requirement, Load Asset Name and ID, Load Responsibility, and Applicable Period

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
UES Small Default Load	Small Customer Group, 11451	100%	June 1, 2021	November 30, 2021
UES Medium Default Load	Medium Customer Group, 11452	100%	June 1, 2021	November 30, 2021
UES Large Customer Group	UES Large Default Load, 10019	100%	June 1, 2021	November 30, 2021

APPENDIX B

Monthly Contract Rate by Service Requirement
Dollars per MWh

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Small Customer Group (6 months)						

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Medium Customer Group (6 months)						

The following are Fixed Monthly Adders. *Please refer to Section 5.1 for calculation of Contract Rate*						
Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Large Customer Group (6 months)						

APPENDIX C

POINTS OF INTERCONNECTION, REFERRED TO AS DELIVERY POINT

Points of Interconnection	Nominal Delivery Voltage	Metering Point	Nominal Metering Voltage
Garvins (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
New Hampshire Hydro			
Lower Penacook Falls (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Upper Penacook Falls (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Briar Hydro (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
SES Concord Company L.P. (2)	3ϕ, 4 wire, 19.9/34.5 kV	At Connection Point	3ϕ, 4 wire, 19.9/34.5 kV
Broken Ground	3ϕ, 115 kV	At Curtisville Sending Point	3ϕ, 115 kV
Penacook (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Guinea (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Kingston (1)	3ϕ, 115 kV	At Peaslee Sending Point	3ϕ, 115 kV
Timber Swamp (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV
Great Bay (1)	3ϕ, 4 wire, 19.9/34.5 kV	At Delivery Point	3ϕ, 4 wire, 19.9/34.5 kV

(1) Substation delivery point

(2) Small power producer purchase delivery points.

AMENDMENT No. [X]
OF
POWER SALES AGREEMENT

This Amendment No. [X] ("Amendment No. [X]"), dated and effective as of **March 31, 2021** (the "Effective Date"), amends the Power Sales Agreement, dated [DATE] (the "Agreement") between UNITIL ENERGY SYSTEMS, INC. ("Buyer") and [COMPANY NAME] ("Seller") (collectively, the "Parties").

Notwithstanding Article 21(d) of the Agreement or anything else to the contrary in either this Amendment No. [X] or the Agreement, the Parties' obligations under this Amendment No. [X] are subject to Buyer obtaining approval from the NHPUC of the inclusion in retail rates of the amounts payable by Buyer to Seller under this Amendment No. [X], without material modification to the obligations of either Party under this Amendment No. [X]. Buyer shall use its best efforts to obtain prompt approval of such rates. If Buyer is unable to obtain NHPUC approval by **April 16, 2021**, Buyer and Seller agree to review the status of such approval process and determine whether to continue to pursue the transaction contemplated in this Amendment No. [X]. If the Parties cannot agree as to how to continue such transaction, this Amendment No. [X] shall terminate and be null and void without liability to either Party.

Buyer shall bear the cost of the NHPUC filing described above except for any costs associated with Seller's intervention. Buyer shall request that the NHPUC give confidential treatment to the terms of this Amendment No. [X], which is the result of a competitive solicitation held by Buyer.

The Parties hereby agree to further amend the Agreement as follows:

1. Appendix A is amended as attached hereto. The amendment adds a new section reflecting the results of the RFP issued by Buyer on March 2, 2021.
2. Appendix B is amended as attached hereto. The amendment adds pricing associated with the results of the RFP issued by Buyer on March 2, 2021.
3. Appendix B indicates that the prices listed for the Large Customer Group are Fixed Monthly Adders, therefore the Contract Rate will be calculated as the sum of the Average Weighted RT LMP and the Fixed Monthly Adder as shown in Equation 1. The Average Weighted RT LMP is calculated in accordance with Equation 2.

Equation 1

$$Contract\ Rate = Average\ Weighted\ RT\ LMP + Fixed\ Monthly\ Adder$$

The Average Weighted RT LMP shall be calculated using the MWH of Delivered Energy reported for the Large Customer Group default service load asset, Load Asset number 10019, and the hourly real time locational marginal prices ("RT

LMP") for the settlement location of Load Asset 10019, which is currently the New Hampshire Load Zone (4002). The Average Weighted RT LMP equals the sum of the products of the RT LMP and the Delivered Energy (MWH) of Load Asset 10019 in each hour of the month of service, divided by the sum of Delivered Energy (MWH) of Load Asset 10019 for the month of service, as shown in Equation 2.

Equation 2

$$Average\ Weighted\ RT\ LMP = \frac{Sum\ [hourly\ RT\ LMP\ *\ hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 1(}{Sum\ [hourly\ Delivered\ Energy\ (MWH)\ of\ Load\ Asset\ 10019]}$$

The Large Customer Group prices listed in Appendix B are Fixed Monthly Adders requiring the Contract Rate to be calculated as described in Equation 1 and Equation 2, and the Contract Rate will be determined and affirmed by both Buyer and Seller by the third business day following the month of service. Once agreed upon, the Contract Rate for the month of service shall be final and shall not be subject to change in the event that either the New Hampshire RT LMP or the Delivered Energy (MWH) of Load Asset 10019 are subsequently revised or restated.

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute and deliver this Amendment No. [X] to the Agreement effective as of the Effective Date.

Unitil Energy Systems, Inc.

BY: ____

Robert S. Furino

Vice President

[Seller]

BY: ____

Its______________________________

APPENDIX A

Service Requirements Matrix

By Service Requirement, Load Asset Name and ID, Load Responsibility, and Applicable Period

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Load Asset Name and ID	Load Responsibility	Schedule 1	Schedule 2
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UES Medium Default Load	Medium Customer Group, 11452	100%	June 1, 2021	November 30, 2021
UES Large Customer Group	UES Large Default Load, 10019	100%	June 1, 2021	November 30, 2021

APPENDIX B

Monthly Contract Rate by Service Requirement
Dollars per MWh

[List All Active Transactions]

For service pursuant to Buyer's RFP issued on **March 2, 2021**

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Small Customer Group (6 months)						

Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Medium Customer Group (6 months)						

The following are Fixed Monthly Adders. Please refer to Section 5.1 for calculation of Contract Rate						
Service Requirement	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21
100% UES Large Customer Group (6 months)						

MUTUAL CONFIDENTIAL NON-DISCLOSURE AGREEMENT

This MUTUAL CONFIDENTIAL NON-DISCLOSURE AGREEMENT is made as of __________________, 201_ between ___________________________ ("Company"), having a place of business at _________________________________, and Unitil Energy Systems, Inc. ("Unitil") having a principal place of business at 6 Liberty Lane West, Hampton, NH 03842, (together "the Parties," individually "a Party"). The Parties hereby agree that disclosures of Confidential Information shall be governed by the following terms and conditions. A Party receiving Confidential Information under this Agreement is referred to as "Recipient," and a Party disclosing Information is referred to as "Discloser."

1. **Definition of Confidential Information**. "Confidential Information" means any oral, written, graphic or machine-readable information including, but not limited to, any and all confidential and proprietary information relating to the Purpose, the Discloser, its affiliates or subsidiaries, and including all information or material that has or could have commercial value or other use in the business or the prospective business of the Discloser, disclosed by the Discloser to the Recipient in connection with this Agreement and the Purpose, whether committed to memory or embodied in writing or other tangible form. Confidential Information includes, without limitation, contracts, fees, accounts, records, customer and client information, agreements and any other incident of the Discloser's business disclosed to the Recipient, in each case provided in connection with this Agreement and Purpose. Confidential Information does not include any information which Recipient can document: (a) is known to Recipient or any of its Representatives on the non-confidential basis prior to the time of disclosure; (b) is independently developed by Recipient without use of the Confidential Information; (c) becomes known to Recipient from another source without confidentiality restriction on subsequent disclosure or use; (d) is or becomes part of the public domain through no wrongful act of Recipient; or (e) is information approved for disclosure or release by the Recipient by written authorization from the Discloser. Confidential Information does not include any source code or technical information subject to a license that meets the requirements of the Open source Definition. The Open Source Definition is found at http://www.opensource.org/osd.html.

2. **Purpose for Disclosure.** The parties may only use Confidential Information for the following purposes (the "Purpose"):
    - Negotiation of potential power supply and/or renewable energy credits purchase and sales transactions ("Transactions").
    - Negotiation of a potential base contract(s) or master agreement(s) pertaining to any Transactions ("Base Contracts").
    - Evaluation of either Parties creditworthiness in the context of either potential or existing Transactions and/or Base Contracts.
3. **Non-Disclosure of Confidential Information.** Recipient agrees: (i) to use the same degree of care, but no less than a reasonable degree of care, to protect against the unauthorized disclosure of Discloser's Confidential Information as it uses to protect its own Confidential Information; (ii) not to divulge any such Confidential Information or any information derived therefrom to any third person; (iii) not to make any use whatsoever at any time of such Confidential Information except as necessary in accordance with the Purpose; (iv) not to copy or reverse engineer any such Confidential Information; and (v) not to export or re-export (within the meaning of U.S. or other export control laws or regulations) any such Confidential Information or product thereof. Recipient agrees to disclose Confidential Information only to its directors, officers, employees, consultants, agents or independent contractors (its "Representatives") with a direct need to know to effect the Purpose, and who are bound by legally enforceable obligations of confidentiality no less restrictive than the terms of this Agreement. Recipient shall not remove the proprietary notices from Confidential Information. Each Party agrees to promptly notify the other Party in writing of any misuse or misappropriation of Confidential Information of the other Party of which it becomes aware.
4. **Mandatory Disclosure**. In the event that Recipient or its Representatives is requested or required by any competent judicial, governmental or regulatory body or by legal process or applicable regulations or laws to disclose any of the Confidential Information of Discloser, Recipient shall give prompt notice so that Discloser may seek a protective order or other appropriate relief. If such protective order is not

obtained, Recipient shall disclose only that portion of the Confidential Information that its counsel advises that it is legally required to disclose.

5. **Remedies.** Recipient acknowledges and agrees that due to the unique nature of Discloser's Confidential Information, there may be no adequate remedy at law for any breach of Recipient's obligations hereunder, which breach may result in irreparable harm to the Discloser and therefore, that upon any such breach of any threat thereof, the Discloser shall be entitled to seek appropriate equitable relief in addition to whatever remedies it might have at law.
6. **Term.** The foregoing commitments of each Party shall survive any termination of the Purpose, and shall remain in effect with respect to any particular Confidential Information unless and until the Recipient can document that one of the exceptions stated in Section 1 applies, or unless mutually agreed, as evidenced by writing, to a shorter period.
7. **No Additional Agreements; No Prohibition on Agreements**. Nothing herein shall obligate either Party to disclose any Confidential Information or negotiate or enter into any agreement or relationship with the other Party. Nothing herein shall prohibit a Party from entering into any arrangement or agreement with a third party.
8. **No Warranty**. The Parties understand and agree that Confidential Information is provided "as is"; neither Party shall have any responsibility to the other based on any claim that any information furnished hereunder was incorrect, incomplete, or defective in any way. Neither Party makes any warranties, whether express, implied or statutory, regarding the sufficiency of the information disclosed for any purpose, including warranties of merchantability, fitness for a particular purpose, and non-infringement.
9. **General.** (a) Assignment. This Agreement is not assignable or transferable by either Party; any attempted assignment will be void and without effect, unless such assignment is agreed to in writing by both Parties. (b) No Other Rights. No rights, title, license of any kind in any Confidential Information is provided hereunder, either expressly or by implication, estoppel or otherwise. (c) No Agency. This Agreement does not create any agency or partnership relationship. (d) No Waiver. No waiver of

any provision of this Agreement, or a breach of this Agreement shall be effective unless it is in writing, signed by the Party waiving the provision or the breach. No waiver of a breach of this Agreement (whether express or implied) shall constitute a waiver of a subsequent breach of this Agreement. (e) Choice of Law. This Agreement will be governed by and interpreted in accordance with the laws of the State of New Hampshire, excluding its choice of laws rules. (f) Complete Agreement. This Agreement constitutes the complete agreement between the Parties on the subject matter identified herein. Any modifications to this Agreement must be made in writing and signed by both Parties.

Unitil Energy Systems, Inc.	**(Company)**
By:________________________________	By:________________________________
___________________________________	___________________________________
NAME (PRINT OR TYPE)	NAME (PRINT OR TYPE)
TITLE:_____________________________	TITLE:_____________________________
Date:______________________________	Date:______________________________

Unitil Energy Systems, Inc.
Customer Migration Report

RETAIL SALES (kWh) by CUSTOMER CLASS
Competitive Generation Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	4,233,583	11,382,280	22,956,780	291,501	38,864,144
Mar-20	4,036,246	11,321,289	23,087,184	290,032	38,734,751
Apr-20	3,539,194	8,641,381	19,396,839	286,692	31,864,106
May-20	3,308,273	8,554,861	19,276,377	290,675	31,430,186
Jun-20	3,878,229	11,001,923	22,795,270	287,960	37,963,382
Jul-20	4,703,510	12,537,785	24,066,683	288,762	41,596,740
Aug-20	5,025,157	12,585,000	24,802,949	285,841	42,698,947
Sep-20	3,830,566	11,844,205	24,763,811	277,727	40,716,309
Oct-20	2,804,991	9,315,571	20,682,774	257,999	33,061,335
Nov-20	3,120,292	9,377,219	20,508,686	260,739	33,266,936
Dec-20	4,062,226	10,580,209	21,594,681	261,598	36,498,714
Jan-21	4,278,597	10,629,570	21,446,857	265,177	36,620,201
Feb-21	4,170,059	10,982,775	21,550,828	264,772	36,968,434

RETAIL SALES (kWh) by CUSTOMER CLASS
Total Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	43,447,320	26,398,419	27,360,368	649,722	97,855,829
Mar-20	41,788,394	25,809,231	27,375,056	646,784	95,619,465
Apr-20	36,919,734	19,238,284	23,199,379	642,890	80,000,287
May-20	34,845,155	18,473,609	23,230,381	643,978	77,193,123
Jun-20	43,074,211	23,359,730	27,500,834	645,353	94,580,128
Jul-20	53,371,480	27,260,601	29,386,736	646,121	110,664,938
Aug-20	57,715,834	28,262,781	29,935,971	644,251	116,558,837
Sep-20	44,979,721	26,172,290	29,722,799	635,198	101,510,008
Oct-20	32,009,393	20,170,721	24,642,676	609,062	77,431,852
Nov-20	34,896,989	20,497,099	24,432,498	605,624	80,432,210
Dec-20	45,042,699	23,449,935	25,817,785	597,605	94,908,024
Jan-21	48,326,828	23,804,287	25,351,429	582,966	98,065,510
Feb-21	47,028,445	24,511,887	25,812,410	580,023	97,932,765

RETAIL SALES (kWh) by CUSTOMER CLASS
Competitive Generation Sales as a Percentage of Total Sales

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	9.7%	43.1%	83.9%	44.9%	39.7%
Mar-20	9.7%	43.9%	84.3%	44.8%	40.5%
Apr-20	9.6%	44.9%	83.6%	44.6%	39.8%
May-20	9.5%	46.3%	83.0%	45.1%	40.7%
Jun-20	9.0%	47.1%	82.9%	44.6%	40.1%
Jul-20	8.8%	46.0%	81.9%	44.7%	37.6%
Aug-20	8.7%	44.5%	82.9%	44.4%	36.6%
Sep-20	8.5%	45.3%	83.3%	43.7%	40.1%
Oct-20	8.8%	46.2%	83.9%	42.4%	42.7%
Nov-20	8.9%	45.7%	83.9%	43.1%	41.4%
Dec-20	9.0%	45.1%	83.6%	43.8%	38.5%
Jan-21	8.9%	44.7%	84.6%	45.5%	37.3%
Feb-21	8.9%	44.8%	83.5%	45.6%	37.7%

Unitil Energy Systems, Inc.
Customer Migration Report

CUSTOMER COUNT by CLASS
Customers Served by Competitive Generation

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	5,857	2,711	123	271	8,962
Mar-20	5,846	2,705	123	271	8,945
Apr-20	5,806	2,703	124	271	8,904
May-20	5,763	2,705	125	271	8,864
Jun-20	5,730	2,701	126	272	8,829
Jul-20	5,694	2,694	126	270	8,784
Aug-20	5,640	2,686	126	270	8,722
Sep-20	5,592	2,687	126	273	8,678
Oct-20	5,530	2,692	126	277	8,625
Nov-20	5,611	2,723	125	280	8,739
Dec-20	5,584	2,769	125	296	8,774
Jan-21	5,581	2,773	125	298	8,777
Feb-21	5,576	2,781	125	297	8,779

CUSTOMER COUNT by CLASS
Total Customers

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	66,474	10,699	163	1,557	78,893
Mar-20	66,526	10,697	163	1,555	78,941
Apr-20	66,634	10,712	163	1,552	79,061
May-20	67,703	10,830	164	1,551	80,248
Jun-20	67,810	10,839	164	1,550	80,363
Jul-20	67,853	10,844	164	1,549	80,410
Aug-20	67,919	10,874	164	1,548	80,505
Sep-20	67,770	10,862	164	1,546	80,342
Oct-20	67,025	10,740	164	1,546	79,475
Nov-20	66,955	10,722	163	1,543	79,383
Dec-20	66,977	10,783	163	1,542	79,465
Jan-21	66,995	10,791	163	1,540	79,489
Feb-21	67,019	10,792	163	1,539	79,513

CUSTOMER COUNT by CLASS
Percentage of Customers Served by Competitive Generation

Month	DOMESTIC	REGULAR GENERAL	LARGE GENERAL	OUTDOOR LIGHTING	TOTAL
Feb-20	8.8%	25.3%	75.5%	17.4%	11.4%
Mar-20	8.8%	25.3%	75.5%	17.4%	11.3%
Apr-20	8.7%	25.2%	76.1%	17.5%	11.3%
May-20	8.5%	25.0%	76.2%	17.5%	11.0%
Jun-20	8.5%	24.9%	76.8%	17.5%	11.0%
Jul-20	8.4%	24.8%	76.8%	17.4%	10.9%
Aug-20	8.3%	24.7%	76.8%	17.4%	10.8%
Sep-20	8.3%	24.7%	76.8%	17.7%	10.8%
Oct-20	8.3%	25.1%	76.8%	17.9%	10.9%
Nov-20	8.4%	25.4%	76.7%	18.1%	11.0%
Dec-20	8.3%	25.7%	76.7%	19.2%	11.0%
Jan-21	8.3%	25.7%	76.7%	19.4%	11.0%
Feb-21	8.3%	25.8%	76.7%	19.3%	11.0%

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
RPS Compliance Cost Estimates, Non-G1 Customers

RPS Obligation

		2		3	4	5
Year	**Month**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**
2021	Jun-21	9.6%	1.80%	0.70%	8.0%	1.5%
2021	Jul-21	9.6%	1.80%	0.70%	8.0%	1.5%
2021	Aug-21	9.6%	1.80%	0.70%	8.0%	1.5%
2021	Sep-21	9.6%	1.80%	0.70%	8.0%	1.5%
2021	Oct-21	9.6%	1.80%	0.70%	8.0%	1.5%
2021	Nov-21	9.6%	1.80%	0.70%	8.0%	1.5%

Market Price Assumptions

		2		3	4	5
Year	**Month**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**
2021	Jun-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25
2021	Jul-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25
2021	Aug-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25
2021	Sep-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25
2021	Oct-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25
2021	Nov-21	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25

Non-G1 Customer Costs

		7							
Year	**Month**	**Non-G1 Sales (MWH)**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**RPS Cost**	**Cost $/MWH**
2021	Jun-21	47,739	$ 198,211	$ 22,643	$ 15,038	$ 133,630	$ 16,649	$ 386,171	$ 8.09
2021	Jul-21	53,065	$ 220,328	$ 25,169	$ 16,716	$ 148,541	$ 18,507	$ 429,260	$ 8.09
2021	Aug-21	63,002	$ 261,585	$ 29,882	$ 19,846	$ 176,356	$ 21,972	$ 509,640	$ 8.09
2021	Sep-21	56,486	$ 234,530	$ 26,791	$ 17,793	$ 158,116	$ 19,699	$ 456,929	$ 8.09
2021	Oct-21	42,446	$ 176,234	$ 20,132	$ 13,370	$ 118,814	$ 14,803	$ 343,353	$ 8.09
2021	Nov-21	44,592	$ 185,144	$ 21,150	$ 14,046	$ 124,821	$ 15,551	$ 360,713	$ 8.09

*Class I is the net requirement which is the gross requirement less the Class I Thermal Carve-Out requirement.
2020 = 10.5% - 1.6% 2021 = 11.4%-1.8%

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
RPS Compliance Cost Estimates, G1 Customers

RPS Obligation							**Market Price Assumptions**					**G1 Customer Costs**							
		2		3	4	5	2		3	4	5	7							
Year	**Month**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**G1 Sales (MWH)**	**Class I***	**Class I Carve Out**	**Class II**	**Class III**	**Class IV**	**RPS Cost**	**Cost $/MWH**
2021	Jun-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	3,822	$ 15,869	$ 1,813	$ 1,204	$ 10,698	$ 1,333	$ 30,917	$ 8.09
2021	Jul-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	4,254	$ 17,662	$ 2,018	$ 1,340	$ 11,908	$ 1,484	$ 34,411	$ 8.09
2021	Aug-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	4,419	$ 18,347	$ 2,096	$ 1,392	$ 12,369	$ 1,541	$ 35,745	$ 8.09
2021	Sep-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	4,109	$ 17,060	$ 1,949	$ 1,294	$ 11,501	$ 1,433	$ 33,237	$ 8.09
2021	Oct-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	3,687	$ 15,307	$ 1,749	$ 1,161	$ 10,320	$ 1,286	$ 29,823	$ 8.09
2021	Nov-21	9.6%	1.80%	0.70%	8.0%	1.5%	$ 43.25	$ 26.35	$ 45.00	$ 34.99	$ 23.25	3,648	$ 15,145	$ 1,730	$ 1,149	$ 10,210	$ 1,272	$ 29,507	$ 8.09

*Class I is the net requirement which is the gross requirement less the Class I Thermal Carve-Out requirement.
2020 = 10.5% - 1.6%   2021 = 11.4%-1.8%

UES Default Service RFP Issued March 2, 2021
For Loads to be Served beginning June 1, 2021
Historical Pricing by Customer Group, No Longer Confidential*

	Non-G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year	G1 Purchases (MWH)	Wtd Avg Price	Change Prior Period	Change Prior Year
May-15	46,508				3,607			
Jun-15	49,079				3,681	$ 44.99	-50.3%	-14.0%
Jul-15	61,195	$ 59.41	-58.8%	-14.6%	4,279			
Aug-15	62,773				4,419			
Sep-15	52,341				4,075	$ 57.71	28.3%	13.8%
Oct-15	45,499				3,503			
Nov-15	46,736				3,101			
Dec-15	52,831				3,138	$ 45.68	-20.9%	-37%
Jan-16	56,963	$ 86.10	45%	-40%	2,964			
Feb-16	51,298				2,702			
Mar-16	48,543				2,999	$ 40.78	-11%	-55%
Apr-16	43,271				2,798			
May-16	44,517				3,107			
Jun-16	49,761				4,204	$ 39.22	-4%	-13%
Jul-16	64,852	$ 49.26	-43%	-17%	4,752			
Aug-16	65,322				4,634			
Sep-16	48,103				4,287	$ 45.84	17%	-20%
Oct-16	44,255				3,702			
Nov-16	46,744				3,446			
Dec-16	58,606				3,867	$ 54.07	18%	18%
Jan-17	56,403	$ 64.13	30%	-26%	3,558			
Feb-17	49,520				2,988			
Mar-17	54,432				3,259	$ 46.32	-14%	14%
Apr-17	44,403				3,060			
May-17	45,754				3,396			
Jun-17	44,437				3,363	$ 47.99	4%	22%
Jul-17	57,777	$ 63.38	-1%	29%	3,482			
Aug-17	60,381				3,536			
Sep-17	49,688				3,330	$ 57.74	20%	26%
Oct-17	45,808				3,238			
Nov-17	46,513				3,105			
Dec-17	62,950				3,302	$ 112.30	94%	108%
Jan-18	63,909	$ 88.18	39%	38%	3,703			
Feb-18	49,814				3,082			
Mar-18	52,363				2,868	$ 67.49	-40%	46%
Apr-18	46,786				2,545			
May-18	45,651				3,135			
Jun-18	51,139				2,998	$ 65.46	-3%	36%
Jul-18	56,755	$ 68.93	-22%	9%	4,279			
Aug-18	67,382				4,065			
Sep-18	55,483				3,865	$ 79.97	22%	39%
Oct-18	52,395				3,896			
Nov-18	49,433				3,379			
Dec-18	56,898				3,622	$ 87.93	10%	-22%
Jan-19	66,712	$ 103.68	50%	18%	3,584			
Feb-19	59,779				3,414			
Mar-19	53,969				3,425	$ 76.36	-13%	13%
Apr-19	50,767				3,303			
May-19	46,986				3,345			
Jun-19	46,681				3,702	$ 57.16	-25%	-13%
Jul-19	62,361	$ 69.32	-33%	1%	4,245			
Aug-19	67,002				4,030			
Sep-19	52,879				3,829	$ 51.49	-10%	-36%
Oct-19	54,993				3,861			
Nov-19	48,082				3,342			
Dec-19	55,151				3,586	$ 68.36	33%	-22%
Jan-20	64,846	$ 90.14	30%	-13%	3,461			
Feb-20	61,007				3,466			
Mar-20	54,444				3,478	$ 53.96	-21%	-29%
Apr-20	50,230				3,229			
May-20	46,070				3,244			
Jun-20	52,981				4,559	$ 47.14	-13%	-18%
Jul-20	65,465	$ 51.23	-43%	-26%	4,995			
Aug-20	61,604				4,678			
Sep-20	56,863				4,726	$ 48.62	3%	-6%
Oct-20	48,292				4,073			
Nov-20	48,417	$ 67.95	33%	-25%	3,690			
Dec-20	62,281				4,667	$ 66.69	37%	-2%

* Historical pricing shown has previously been required to be submitted to FERC under its Electronic Quarterly Reporting requirements.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

LINDA S. MCNAMARA

New Hampshire Public Utilities Commission

Docket No. DE 21-041

April 2, 2021

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Linda S. McNamara. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("USC"), which provides centralized management and administrative services to all Unitil Corporation's affiliates including Unitil Energy Systems, Inc. ("UES").

Q. Please describe your business and educational background.

A. In 1994 I graduated *cum laude* from the University of New Hampshire with a Bachelor of Science Degree in Mathematics. Since joining USC in June 1994, I have been responsible for the preparation of various regulatory filings, including changes to the default service charges, price analysis, and tariff changes.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present and explain the proposed changes to UES's Default Service Charge ("DSC") effective June 1, 2021 as reflected in the redline tariffs provided as Schedule LSM-1.

Q. Is UES proposing any other tariff changes for effect June 1, 2021?

A. Yes. UES's Summary of Low-Income Electric Assistance Program Discounts, incorporating the proposed June 1 Non-G1 (Residential) DSC, would also be affected by this change. However, because other changes that will affect this page are currently pending in DE 18-036 for effect May 1, 2021, UES plans to file this in compliance with a Commission order.[1]

III. RETAIL RATE CALCULATIONS

Q. What are the proposed Non-G1 Class DSC?

A. As shown on Schedule LSM-1, Page 1, the proposed Residential Class fixed Non-G1 DSC is $0.07091, or 7.091¢, per kWh and the proposed G2 and Outdoor Lighting ("OL") Class fixed Non-G1 DSC is $0.05992, or 5.992¢, per kWh for the period June 1, 2021 through November 30, 2021. The proposed Residential Class variable Non-G1 DSC and the proposed G2 and OL Class variable Non-G1 DSC for this same period are also shown on this page.

[1] The Company notes that, under separate cover, it is filing today for an increase in annual base revenues in docket DE 21-030. In its Petition in that case, the Company is requesting an increase in revenues through the setting of temporary rates effective June 1, 2021, pursuant to RSA 378:27.

The proposed DSC are comprised of two components, as shown on Schedule LSM-1, Page 1: A Power Supply Charge and a Renewable Portfolio Standard ("RPS") Charge.

Q. What are the proposed Power Supply Charges and RPS Charge?

A. For the period June 1, 2021 through November 30, 2021, the proposed Residential Class fixed Non-G1 Power Supply Charge is $0.06332, or 6.332¢, per kWh, the proposed G2 and OL Class fixed Non-G1 Power Supply Charge is $0.05233, or 5.233¢ per kWh, and the proposed fixed Non-G1 RPS Charge is $0.00759, or 0.759¢ per kWh. These figures, as well as the variable amounts for the same period, are shown on Schedule LSM-1, Page 1.

Q. How do the proposed Non-G1 fixed DSC rates compare to the Non-G1 fixed DSC rates in effect last summer?

A. The Residential Class fixed Non-G1 DSC in effect last summer, June 2020 through November 2020, was $0.06987, or 6.987¢, per kWh. The proposed Residential Class fixed Non-G1 DSC of $0.07091, or 7.091¢, per kWh is an increase of $0.00104, or 0.104¢ per kWh.

The G2 and OL Class fixed Non-G1 DSC in effect last summer, June 2020 through November 2020, was $0.05874, or 5.874¢, per kWh. The proposed G2 and OL Class fixed Non-G1 DSC of $0.05992, or 5.992¢, per kWh is an increase of $0.00118, or 0.118¢, per kWh.

Q. How do the proposed Non-G1 fixed DSC rates compare to the current rate?

A. The proposed Residential Class fixed Non-G1 DSC of $0.07091, or 7.091¢, per kWh is a decrease of $0.02224, or 2.224¢, per kWh from the current DSC of $0.09315, or 9.315¢, per kWh. The proposed G2 and OL Class fixed Non-G1 DSC of $ $0.05992, or 5.992¢, per kWh is a decrease of $0.02710, or 2.710¢, per kWh from the current DSC of $0.08702, or 8.702¢, per kWh. These decreases reflect lower contract costs for the period June 1, 2021 through November 30, 2021 compared to the contract costs for the current period December 1, 2020 through May 31, 2021.

Q. Please describe the calculation of the Non-G1 class DSC.

A. The rate calculations for the Non-G1 class Power Supply Charges, fixed and variable, are provided on Schedule LSM-2, Page 1. The rate calculations for the Non-G1 class RPS Charges, fixed and variable, are provided on Schedule LSM-3, Page 1. Both charges are calculated in a similar manner.

Variable pricing is calculated by dividing the total costs for the month, including a partial reconciliation of costs and revenues through February 28, 2021, by the estimated monthly kWh purchases for the Residential Class and the G2 and OL Class. An estimated loss factor of 6.4% is then added to arrive at the proposed retail variable charges. Fixed pricing is calculated in a similar manner, except that the calculation is based on each class's total for the entire six month period.

Q. Have you made any adjustments to the reconciliation balances included in the Power Supply and RPS charges?

A. In order to determine the reconciliation amount included in the Non-G1 class power supply charge, the reconciliation balance as of February 28, 2021 was adjusted to recognize that estimated revenue in March, April, and May 2021 should excede costs for this same period by an estimated $1,607,893. This adjustment recognizes that estimated costs for March, April and May 2021 are below the average cost for the entire period, December 2020-May 2021, while revenue will be primarily based on the fixed Power Supply Charge, of which most Non-G1 customers pay, and is determined using an average of costs for the entire December 2020-May 2021 period. This adjustment brings the expected reconciliation balance from $454,159 to ($1,153,734).

In order to determine the reconciliation amounts included in the Non-G1 class RPS, the reconciliation balance as of February 28, 2021 was adjusted to recognize that the current RPS charges, in effect through May 31, 2021, include a charge for an undercollection.

Since UES reconciles its costs on an annual basis, only a portion of the total reconciliation balances are reflected in the proposed Power Supply and RPS rates. UES apportioned the Power Supply balance and the RPS balance based on kWh over the twelve month period June 2021 through May 2022. The Power Supply reconciliation balance is further divided between the Residential Class and the G2/OL Class, based on kWh. This calculation is provided on Page 1 of Schedule LSM-2 for Power Supply and Page 1 of Schedule LSM-3 for RPS.

Q. Have you provided details on the reconciliation?

A. Support for the February 28, 2021 Non-G1 class power supply reconciliation balance is provided on Schedule LSM-2, Page 2. Support for the February 28, 2021 Non-G1 class RPS reconciliation balance is provided on Schedule LSM-3, Page 2. As described above, those figures have been adjusted in order to arrive at the figures for collecton beginning June 1, 2021. Details for costs for the period March 2020 through February 2021 are provided on Page 3 of Schedule LSM-2 and LSM-3. Page 4 of Schedule LSM-2 and LSM-3 provides revenue details.

Q. How does UES account for credits to net metering customers?

A. The Company includes in the Total Non-G1 Class DS Supplier Charges, in the Non-G1 Class Power Supply Charge, the amounts credited to, or paid to, small customer generator net metering customers with an excess of 600 kWh banked at the end of the March billing cycle who opt to be credited or paid in accordance with the PUC 900 rules. In addition, UES includes any monthly amounts credited to, or paid to, large customer generators or group net metering customers including any required annual credit reconciliation in accordance with PUC 900. For the period March 2020 through February 2021, these amounts totaled $70,753.51.

Q. Have you provided support for the total forecast costs shown on Page 1, lines 2 and 10 of Schedule LSM-2?

A. The details of forecasted costs for the period June 1, 2021 through November 30, 2021 are provided on Schedule LSM-2, Page 5. Line items for the various costs included in default service are shown and include: Non-G1 Class (Residential) DS Supplier Charges, Non-G1 Class (G2 and OL) DS Supplier Charges, GIS Support Payments, Supply Related Working Capital, Provision for Uncollected Accounts, Internal Company Administrative Costs, Legal Charges, Consulting Outside Service Charges, and the default service portion of the annual PUC Assessment allocated to the Non-G1 Class.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-3?

A. The details of forecasted costs for the period June 1, 2021 through November 30, 2021 are provided on Schedule LSM-3, Page 5. Costs include RECs and the associated working capital.

Q. How is working capital calculated?

A. Working capital included in the Power Supply Charge equals the sum of working capital for Non-G1 Class (Residential) DS Supplier Charges, plus

Non-G1 Class (G2 and OL) DS Supplier Charges[2], plus GIS Support Payments, as shown on Schedule LSM-2, Pages 3 and 5. It is calculated by taking the product of Non-G1 Class (Residential) DS Supplier Charges plus Non-G1 Class (G2 and OL) DS Supplier Charges plus GIS Support Payments and the number of days lag divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital for RECs is included in the RPS Charge and is shown on Schedule LSM-3, Pages 3 and 5. It is calculated by taking the product of RECs and the number of days lead divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital included in the Power Supply Charge and the RPS Charge for the period beginning June 1, 2021 both rely on the results of the 2020 Default Service and Renewable Energy Credits Lead Lag Study, presented by Mr. Nawazelski. The Non-G1 class Power Supply Charge working capital calculation uses 22.80 days and the Non-G1 class RPS Charge working capital calculation uses (228.65) days.

Q. What is the proposed G1 Class DSC?

[2] In actuals, the supplier charges are provided in total in the column "Total Non-G1 Class DS Supplier Charges".

A. The proposed G1 class DSC are comprised of two components, as shown on Schedule LSM-1, Page 3: A Power Supply Charge and a Renewable Portfolio Standard ("RPS") Charge. The wholesale supplier charge included in the Power Supply Charge will be determined each month based on the sum of fixed monthly adders and variable energy prices, and therefore, the total DSC for the G1 class is not known at this time.

Q. What is the proposed Power Supply Charge, exclusive of supplier charges, and RPS Charge?

A. Schedule LSM-1, Page 3, shows the proposed G1 Power Supply Charges, excluding the supplier charge component, of $0.00336, or 0.336¢, per kWh in June 1, 2021 through November 30, 2021. The wholesale supply charge determined each month will be added to this amount to yield the monthly G1 class Power Supply Charge.

Also shown on Schedule LSM-1, Page 3, is the proposed G1 RPS Charge of $0.00734, or 0.734¢, per kWh in June 1, 2021 through November 30, 2021.

Q. Have you prepared a comparison of the proposed G1 DSC to the current rate?

A. No. As the total G1 class DSC is not yet known, a comparison to current rates was not performed.

Q. Please describe the calculation of the G1 class DSC.

A. The rate calculations for the Power Supply Charges, exclusing wholesale supplier charges, are provided on Schedule LSM-4, Page 1. The rate calculations for the RPS Charges are provided on Schedule LSM-5, Page 1. Both charges are calculated in the same manner.

Each charge is calculated by dividing the costs for each month, including a partial reconciliation of costs and revenues through February 28, 2021, by the estimated G1 kWh purchases for the corresponding month. An estimated loss factor of 4.591% is then added to arrive at the proposed retail charges.

Similar to the Non-G1 power supply and RPS balances, the G1 class power supply and RPS reconciliation balances as of February 28, 2021 were adjusted in order to determine the reconcilation amount for this filing. Adjustments were made to reflect that the current DSC include reconciliation of the February 29, 2020 power supply and RPS balances, and to incorporate the difference between the estimated supplier cost and revenue in March 2021. These adjustments are shown on Page 1 of Schedule LSM-4 and LSM-5.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-4?

A. The details of forecasted costs included in the Power Supply Charge for the period June 1, 2021 through November 30, 2021 are provided on Schedule

LSM-4, Page 5. Line items for the various costs included in default service are shown and include: Total G1 Class DS Supplier Charges, GIS Support Payments, Supply Related Working Capital, Provision for Uncollected Accounts, Internal Company Administrative Costs, Legal Charges, Consulting Outside Service Charges, and the default service portion of the annual PUC Assessment allocated to the G1 Class. At the end of each month, UES will determine the supplier charge to be added to the monthly Power Supply Charge.

Q. Have you provided support for the total forecast costs shown on Page 1, line 2 of Schedule LSM-5?

A. The details of forecasted costs included in the RPS Charge for the period June 1, 2021 through November 30, 2021 are provided on Schedule LSM-5, Page 5. Costs include Renewable Energy Credits ("RECs") and the associated Working Capital.

Q. How is working capital calculated?

A. Working capital included in the Power Supply Charge equals the sum of working capital for Total G1 Class DS Supplier Charges plus GIS Support Payments and is shown on Schedule LSM-4, Pages 3 and 5. It is calculated by taking the product of Total G1 Class DS Supplier Charges plus GIS Support Payments and the number of days lag divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate. As the

Total G1 Class DS Supplier Charges for the upcoming rate period are not yet known, UES has estimated power supply costs for the purpose of estimating working capital. The estimate of power supply costs is based on the forecasted G1 class kWh purchases and an estimated price per kWh. The estimated price per kWh was determined by comparing a historical relationship between G1 and Non-G1 class supplier pricing and then applying that relationship to the current average Non-G1 supplier price per kWh. Actual working capital will be determined using the actual supplier charges in each month.

The calculation of working capital for RECs is included in the RPS Charge and is shown on Schedule LSM-5, Pages 3 and 5. It is calculated by taking the product of RECs and the number of days lead divided by 365 days (i.e. the working capital requirement) and multiplying it by the prime rate.

The calculation of working capital included in the Power Supply Charge and the RPS Charge, effective June 1, 2021, both rely on the results of the 2020 Default Service and Renewable Energy Credits Lead Lag Study. The G1 class Power Supply Charge working capital calculation uses 0.89 days and the G1 class RPS Charge working capital calculation uses (231.61) days.

IV. BILL IMPACTS

Q. Have you included any bill impacts associated with the proposed DSC rate changes?

A. Typical bill impacts for Non-G1 customers taking default service have been provided on Schedule LSM-6. Total bill impacts to G1 customers are unknown at this time and have therefore been excluded from Schedule LSM-6.

Pages 1 and 2 provide a table comparing the existing rates to the proposed rates for the residential and General Service rate classes. These pages also show the impact on a typical bill for each class in order to identify the effect of each rate component on a typical bill.

Page 3 shows bill impacts versus current rates to the residential class based on the mean and median use. Page 3 is provided in a format similar to Pages 1 and 2.

Page 4 provides the overall average class bill impacts as a result of changes to the DSC versus current rates. As shown, for customers on Default Service, the residential class will decrease by approximately 11.2%, general service will decrease by approximately 14.9%, and outdoor lighting will decrease by approximately 7.5%.

Pages 5 through 9 of Schedule LSM-6 provide typical bill impacts versus current rates for all classes, excluding G1, for a range of usage levels.

Pages 10 and 11 provide a table comparing rates in effect in June 2020 to the proposed rates for the residential and General Service rate classes. These pages also show the impact on a typical bill for each class in order to identify the effect of each rate component on a typical bill. Residential customers taking fixed default service will see increases of approximately 7.3% compared to last summer. G2 and outdoor lighting customers taking fixed default service will see increases of roughly 4-9% compared to last summer. These increases are primarily due to the increase in the External Delivery Charge that went into effect on August 1, 2020.

V. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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

Thirtieth~~Twenty-Ninth~~ Revised Page 74
Superseding Twenty-Ninth~~Eighth~~ Revised Page 74

CALCULATION OF THE DEFAULT SERVICE CHARGE

Non-G1 Class Default Service:

		Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Total
	Power Supply Charge							
	Residential Class							
1	Reconciliation	($61,983)	($70,489)	($85,309)	($74,990)	($54,561)	($58,500)	($405,832)
2	Total Costs	$2,121,275	$3,144,895	$2,577,883	$1,591,244	$2,090,157	$2,702,014	$14,227,468
3	Reconciliation plus Total Costs (L.1 + L.2)	$2,059,293	$3,074,406	$2,492,574	$1,516,254	$2,035,596	$2,643,514	$13,821,636
4	kWh Purchases	35,472,149	40,340,064	48,821,671	42,916,322	31,224,716	33,479,006	232,253,928
5	Total, Before Losses (L.3 / L.4)	$0.05805	$0.07621	$0.05105	$0.03533	$0.06519	$0.07896	$0.05951
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.06177	$0.08109	$0.05432	$0.03759	$0.06936	$0.08401	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.06332
	G2 and OL Class							
9	Reconciliation	($26,817)	($28,220)	($31,884)	($30,081)	($24,393)	($24,446)	($165,843)
10	Total Costs	$723,474	$988,640	$895,023	$614,918	$693,911	$916,263	$4,832,229
11	Reconciliation plus Total Costs (L.9 + L.10)	$696,656	$960,420	$863,139	$584,837	$669,518	$891,816	$4,666,386
12	kWh Purchases	15,343,711	16,146,441	18,242,695	17,211,180	13,956,596	13,987,101	94,887,723
13	Total, Before Losses (L.11 / L.12)	$0.04540	$0.05948	$0.04731	$0.03398	$0.04797	$0.06376	$0.04918
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.04831	$0.06329	$0.05034	$0.03615	$0.05104	$0.06784	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.05233
	Renewable Portfolio Standard (RPS) Charge							
17	Reconciliation	($15,814)	($17,579)	($20,871)	($18,712)	($14,061)	($14,772)	($101,810)
18	Total Costs	$378,309	$420,521	$499,264	$447,627	$336,363	$353,369	$2,435,452
19	Reconciliation plus Total Costs (L.17 + L.18)	$362,494	$402,941	$478,393	$428,914	$322,302	$338,597	$2,333,642
20	kWh Purchases	50,815,860	56,486,505	67,064,366	60,127,502	45,181,311	47,466,107	327,141,651
21	Total, Before Losses (L.19 / L.20)	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713
22	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
23	Total Retail Rate - Variable RPS Charge (L.21 * (1+L.22))	$0.00759	$0.00759	$0.00759	$0.00759	$0.00759	$0.00759	
24	Total Retail Rate - Fixed RPS Charge (L.21 * (1+L.22))							$0.00759
	TOTAL DEFAULT SERVICE CHARGE							
25	**Total Retail Rate - Residential Variable Default Service Charge (L.7 + L.23)**	**$0.06936**	**$0.08868**	**$0.06191**	**$0.04518**	**$0.07695**	**$0.09160**	
26	**Total Retail Rate - Residential Fixed Default Service Charge (L.8+L.24)**							**$0.07091**
27	**Total Retail Rate - G2 and OL Variable Default Service Charge (L.15 + L.23)**	**$0.05590**	**$0.07088**	**$0.05793**	**$0.04374**	**$0.05863**	**$0.07543**	
28	**Total Retail Rate - G2 and OL Fixed Default Service Charge (L.16+L.24)**							**$0.05992**

Authorized by NHPUC Order No. ~~26,414~~ in Case No. DE 21-041 ~~20-039~~, dated ~~October 6, 2020~~

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

Issued By: Robert B. Hevert
Sr. Vice President

~~CALCULATION OF THE DEFAULT SERVICE CHARGE~~

~~**Non-G1 Class Default Service:**~~

		Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Total
	Power Supply Charge							
	Residential Class							
1	Reconciliation	($12,769)	($13,334)	($12,978)	($11,022)	($10,276)	($9,224)	($69,603)
2	Total Costs	$3,299,176	$4,160,801	$4,119,482	$2,777,440	$2,331,020	$1,921,616	$18,609,535
3	Reconciliation plus Total Costs (L.1 + L.2)	$3,286,407	$4,147,467	$4,106,505	$2,766,418	$2,320,743	$1,912,393	$18,539,932
4	kWh Purchases	43,671,716	45,602,551	44,384,498	37,697,479	35,146,323	31,546,281	238,048,847
5	Total, Before Losses (L.3 / L.4)	$0.07525	$0.09095	$0.09252	$0.07338	$0.06603	$0.06062	$0.07788
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.08007	$0.09677	$0.09844	$0.07808	$0.07026	$0.06450	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.08287
	G2 and OL Class							
9	Reconciliation	($5,442)	($5,041)	($5,223)	($4,921)	($4,770)	($4,633)	($30,029)
10	Total Costs	$1,393,921	$1,515,261	$1,557,580	$1,155,251	$960,188	$853,974	$7,436,175
11	Reconciliation plus Total Costs (L.9 + L.10)	$1,388,479	$1,510,221	$1,552,357	$1,150,331	$955,418	$849,341	$7,406,146
12	kWh Purchases	18,609,202	17,236,402	17,859,385	16,826,397	16,312,166	15,842,438	102,685,991
13	Total, Before Losses (L.11 / L.12)	$0.07461	$0.08762	$0.08692	$0.06836	$0.05857	$0.05361	$0.07212
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.07939	$0.09323	$0.09248	$0.07274	$0.06232	$0.05704	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.07674

		Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Total
	Renewable Portfolio Standard (RPS) Charge							
17	Reconciliation	$144,698	$145,994	$144,612	$126,676	$119,554	$110,099	$791,632
18	Total Costs	$440,506	$464,610	$460,214	$403,141	$380,478	$350,391	$2,499,340
19	Reconciliation plus Total Costs (L.17 + L.18)	$585,204	$610,604	$604,826	$529,817	$500,032	$460,489	$3,290,972
20	kWh Purchases	62,280,917	62,838,953	62,243,883	54,523,876	51,458,489	47,388,719	340,734,838
21	Total, Before Losses (L.19 / L.20)	$0.00940	$0.00972	$0.00972	$0.00972	$0.00972	$0.00972	$0.00966
22	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
23	Total Retail Rate - Variable RPS Charge (L.21 * (1+L.22))	$0.01000	$0.01034	$0.01034	$0.01034	$0.01034	$0.01034	
24	Total Retail Rate - Fixed RPS Charge (L.21 * (1+L.22))							$0.01028

		Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Total
	TOTAL DEFAULT SERVICE CHARGE							
25	**Total Retail Rate - Residential Variable Default Service Charge (L.7 + L.23)**	**$0.09007**	**$0.10711**	**$0.10878**	**$0.08842**	**$0.08060**	**$0.07484**	
26	**Total Retail Rate - Residential Fixed Default Service Charge (L.8+L.24)**							**$0.09315**
27	**Total Retail Rate - G2 and OL Variable Default Service Charge (L.15 + L.23)**	**$0.08939**	**$0.10357**	**$0.10282**	**$0.08308**	**$0.07266**	**$0.06738**	
28	**Total Retail Rate - G2 and OL Fixed Default Service Charge (L.16+L.24)**							**$0.08702**

CALCULATION OF THE DEFAULT SERVICE CHARGE

G1 Class Default Service:

		Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Total
	Power Supply Charge							
1	Reconciliation							$50,380
2	Total Costs excl. wholesale supplier charge							$30,135
3	Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)							$80,516
4	kWh Purchases							25,037,023
5	Total, Before Losses (L.3 / L.4)							$0.00322
6	Losses							4.591%
7	Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6))	$0.00336	$0.00336	$0.00336	$0.00336	$0.00336	$0.00336	$0.00336
8a	Wholesale Supplier Charge	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	
8b	Losses	4.591%	4.591%	4.591%	4.591%	4.591%	4.591%	
8	Retail Rate - Wholesale Supplier Charge (L.8a * (1+L.8b))	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	
9	Total Retail Rate - Power Supply Charge (L.7 + L. 8)	MARKET	MARKET	MARKET	MARKET	MARKET	MARKET	
	Renewable Portfolio Standard (RPS) Charge							
10	Reconciliation	($2,228)	($2,480)	($2,576)	($2,395)	($2,149)	($2,126)	($13,954)
11	Total Costs	$30,279	$33,702	$35,008	$32,552	$29,208	$28,898	$189,647
12	Reconciliation plus Total Costs (L.10+ L.11)	$28,051	$31,222	$32,432	$30,157	$27,059	$26,772	$175,693
13	kWh Purchases	3,997,435	4,449,271	4,621,728	4,297,467	3,856,019	3,815,103	25,037,023
14	Total, Before Losses (L.12 / L.13)	$0.00702	$0.00702	$0.00702	$0.00702	$0.00702	$0.00702	
15	Losses	4.591%	4.591%	4.591%	4.591%	4.591%	4.591%	
16	Total Retail Rate - RPS Charge (L.14 * (1+L.15))	$0.00734	$0.00734	$0.00734	$0.00734	$0.00734	$0.00734	
	TOTAL DEFAULT SERVICE CHARGE							
17	Total Retail Rate - Default Service Charge (L.9 + L.16)	**MARKET**	**MARKET**	**MARKET**	**MARKET**	**MARKET**	**MARKET**	

Authorized by NHPUC Order No. ~~26,414~~ in Case No. DE 21-041 ~~20-039~~, dated ~~October 6, 2020~~

~~CALCULATION OF THE DEFAULT SERVICE CHARGE~~

	~~G1 Class Default Service:~~	~~Dec-20~~	~~Jan-21~~	~~Feb-21~~	~~Mar-21~~	~~Apr-21~~	~~May-21~~	~~Total~~
	~~***Power Supply Charge***~~							
~~1~~	~~Reconciliation~~							~~($89,141)~~
~~2~~	~~Total Costs excl. wholesale supplier charge~~							~~$29,101~~
~~3~~	~~Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)~~							~~($60,040)~~
~~4~~	~~kWh Purchases~~							~~26,552,825~~
~~5~~	~~Total, Before Losses (L.3 / L.4)~~							~~($0.00226)~~
~~6~~	~~Losses~~							~~4.591%~~
~~7~~	~~Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6))~~	~~($0.00236)~~	~~($0.00236)~~	~~($0.00236)~~	~~($0.00236)~~	~~($0.00236)~~	~~($0.00236)~~	~~($0.00236)~~
~~8a~~	~~Wholesale Supplier Charge~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	
~~8b~~	~~Losses~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	
~~8~~	~~Retail Rate - Wholesale Supplier Charge (L.8a * (1+L.8b))~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	
~~9~~	~~Total Retail Rate - Power Supply Charge (L.7 + L.8)~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	~~MARKET~~	
	~~***Renewable Portfolio Standard (RPS) Charge***~~							
~~10~~	~~Reconciliation~~	~~$5,950~~	~~$5,487~~	~~$5,615~~	~~$5,433~~	~~$5,474~~	~~$5,893~~	~~$33,852~~
~~11~~	~~Total Costs~~	~~$33,578~~	~~$32,365~~	~~$33,125~~	~~$32,049~~	~~$32,290~~	~~$34,763~~	~~$198,170~~
~~12~~	~~Reconciliation plus Total Costs (L.10+ L.11)~~	~~$39,528~~	~~$37,852~~	~~$38,740~~	~~$37,482~~	~~$37,764~~	~~$40,656~~	~~$232,022~~
~~13~~	~~kWh Purchases~~	~~4,667,298~~	~~4,303,549~~	~~4,404,570~~	~~4,261,443~~	~~4,293,552~~	~~4,622,413~~	~~26,552,825~~
~~14~~	~~Total, Before Losses (L.12 / L.13)~~	~~$0.00847~~	~~$0.00880~~	~~$0.00880~~	~~$0.00880~~	~~$0.00880~~	~~$0.00880~~	
~~15~~	~~Losses~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	~~4.591%~~	
~~16~~	~~Total Retail Rate - RPS Charge (L.14 * (1+L.15))~~	~~$0.00886~~	~~$0.00920~~	~~$0.00920~~	~~$0.00920~~	~~$0.00920~~	~~$0.00920~~	
	~~***TOTAL DEFAULT SERVICE CHARGE***~~							
~~17~~	~~Total Retail Rate - Default Service Charge (L.9 + L.16)~~	~~**MARKET**~~	~~**MARKET**~~	~~**MARKET**~~	~~**MARKET**~~	~~**MARKET**~~	~~**MARKET**~~	

		Jun-21 Estimated	Jul-21 Estimated	Aug-21 Estimated	Sep-21 Estimated	Oct-21 Estimated	Nov-21 Estimated	Total
	Residential Class							
1	Reconciliation (1)	($61,983)	($70,489)	($85,309)	($74,990)	($54,561)	($58,500)	($405,832)
2	Total Costs (Page 5)	$2,121,275	$3,144,895	$2,577,883	$1,591,244	$2,090,157	$2,702,014	$14,227,468
3	Reconciliation plus Total Costs (L.1 + L.2)	$2,059,293	$3,074,406	$2,492,574	$1,516,254	$2,035,596	$2,643,514	$13,821,636
4	kWh Purchases	35,472,149	40,340,064	48,821,671	42,916,322	31,224,716	33,479,006	232,253,928
5	Total, Before Losses (L.3 / L.4)	$0.05805	$0.07621	$0.05105	$0.03533	$0.06519	$0.07896	$0.05951
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Residential Variable Power Supply Charge (L.5 * (1+L.6))	$0.06177	$0.08109	$0.05432	$0.03759	$0.06936	$0.08401	
8	Total Retail Rate - Residential Fixed Power Supply Charge (L.5 * (1+L.6))							$0.06332
	G2 and OL Class							
9	Reconciliation (1)	($26,817)	($28,220)	($31,884)	($30,081)	($24,393)	($24,446)	($165,843)
10	Total Costs (Page 5)	$723,474	$988,640	$895,023	$614,918	$693,911	$916,263	$4,832,229
11	Reconciliation plus Total Costs (L.9 + L.10)	$696,656	$960,420	$863,139	$584,837	$669,518	$891,816	$4,666,386
12	kWh Purchases	15,343,711	16,146,441	18,242,695	17,211,180	13,956,596	13,987,101	94,887,723
13	Total, Before Losses (L.11 / L.12)	$0.04540	$0.05948	$0.04731	$0.03398	$0.04797	$0.06376	$0.04918
14	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
15	Total Retail Rate - G2 and OL Variable Power Supply Charge (L.13 * (1+L.14))	$0.04831	$0.06329	$0.05034	$0.03615	$0.05104	$0.06784	
16	Total Retail Rate - G2 and OL Fixed Power Supply Charge (L.13 * (1+L.14))							$0.05233

(1) Balance as of February 28, 2021 modified, as detailed below, to include the reconciliation of estimated costs and revenues for March, April and May 2021. Figure is then allocated between rate periods (June-November 2021 and December 2021-May 2022) and rate classes (Residential and G2/OL), and then to each month, June through November 2021, on equal per kWh basis.

a	February 28, 2021 balance - Schedule LSM-2, Page 2	$454,159
b	less: Estimated remaining prior period reconciliation - Mar, Apr, May 2021:	
c	Estimated costs - Mar, Apr, May 2021	$9,682,315
d	Estimated revenue-Mar, Apr, May 2021	$11,290,208
e	line c - line d	($1,607,893)
f	Reconciliation for June 1, 2021-May 31, 2022 (line a + line e)	($1,153,734)

		Non-G1 total kWh purchases	% per period	Reconciliation per period
g	Rate period: June-November 2021	327,141,651	49.55%	($571,675)
h	Rate period: December 2021-May 2022	333,083,695	50.45%	($582,059)
i	Total	660,225,345		($1,153,734)

		Jun-Nov 2021 kWh purchases	% by class	Jun-Nov 2021 Reconciliation by class
j	Residential class	232,253,928	70.99%	($405,832)
k	G2 and OL class	94,887,723	29.01%	($165,843)
l	Total	327,141,651		($571,675)

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
Mar-20	$2,010,459	$4,306,081	$4,777,907	$1,538,633	$1,774,546	4.75%	31	$7,139	$1,545,772
Apr-20	$1,545,772	$2,492,390	$4,209,525	($171,363)	$687,205	4.75%	30	$2,676	($168,687)
May-20	($168,687)	$3,322,547	$4,053,981	($900,121)	($534,404)	4.75%	31	($2,150)	($902,271)
Jun-20	($902,271)	$3,030,551	$3,381,756	($1,253,476)	($1,077,873)	4.75%	30	($4,197)	($1,257,673)
Jul-20	($1,257,673)	$3,847,415	$3,952,378	($1,362,635)	($1,310,154)	3.25%	31	($3,607)	($1,366,242)
Aug-20	($1,366,242)	$3,526,985	$3,479,079	($1,318,336)	($1,342,289)	3.25%	31	($3,695)	($1,322,031)
Sep-20	($1,322,031)	$2,826,851	$2,959,460	($1,454,639)	($1,388,335)	3.25%	30	($3,698)	($1,458,338)
Oct-20	($1,458,338)	$2,730,415	$2,516,348	($1,244,270)	($1,351,304)	3.25%	31	($3,720)	($1,247,990)
Nov-20	($1,247,990)	$3,147,107	$2,804,866	($905,749)	($1,076,870)	3.25%	30	($2,869)	($908,618)
Dec-20	($908,618)	$4,573,730	$4,652,789	($987,677)	($948,148)	3.25%	31	($2,610)	($990,287)
Jan-21	($990,287)	$5,761,935	$4,924,385	($152,738)	($571,513)	3.25%	31	($1,578)	($154,316)
Feb-21	($154,316)	$4,980,936	$4,372,835	$453,786	$149,735	3.25%	28	$373	$454,159
Total		$44,546,943	$46,085,308					($17,934)	

			Calculation of Working Capital Supplier Charges and GIS Support Payments										
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	Total Non-G1 Class DS Supplier Charges	GIS Support Payments	Number of Days of Lag / 365 (1)	Working Capital Requirement ((a+b)*c)	Prime Rate	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total Costs (sum a + b + f + g + h + i + j + k)
Mar-20	$4,261,652	$367	7.49%	$319,360	3.78%	$12,072	$28,308	$2,911	$0	$0	$771	$4,306,081
Apr-20	$2,464,315	$332	7.49%	$184,680	3.25%	$6,002	$18,061	$2,911	$0	$0	$768	$2,492,390
May-20	$3,302,857	$408	7.49%	$247,519	3.25%	$8,044	$7,102	$2,911	$463	$0	$762	$3,322,547
Jun-20	$3,007,761	$277	5.98%	$179,905	3.25%	$5,847	$12,989	$2,911	$0	$0	$765	$3,030,551
Jul-20	$3,816,604	$296	5.98%	$228,282	3.25%	$7,419	$19,415	$2,911	$0	$0	$770	$3,847,415
Aug-20	$3,485,126	$1,066	5.98%	$208,503	3.25%	$6,776	$30,329	$2,911	$0	$0	$776	$3,526,985
Sep-20	$2,789,949	$462	5.98%	$166,890	3.25%	$5,424	$27,339	$2,911	$0	$0	$766	$2,826,851
Oct-20	$2,696,217	$407	5.98%	$161,280	3.25%	$5,242	$24,879	$2,911	$0	$0	$760	$2,730,415
Nov-20	$3,116,761	$415	5.98%	$186,433	3.25%	$6,059	$20,197	$2,911	$0	$0	$765	$3,147,107
Dec-20	$4,540,156	$309	5.98%	$271,557	3.25%	$8,826	$20,489	$3,176	$0	$0	$774	$4,573,730
Jan-21	$5,700,623	$835	5.98%	$340,994	3.25%	$11,082	$45,437	$3,176	$0	$0	$781	$5,761,935
Feb-21	$4,946,735	$989	5.98%	$295,915	3.25%	$9,617	$19,642	$3,176	$0	$0	$776	$4,980,936
Total	$44,128,756	$6,164				$92,410	$274,186	$35,730	$463	$0	$9,233	$44,546,943

(1) For the months Mar-May 2020, number of days lag equals 27.35. Calculated using revenue lag of 63.94 days less cost lead of 36.59 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 19-049 filed April 5, 2019.

For the months June 2020-February 2020, number of days lag equals 21.83. Calculated using revenue lag of 58.69 days less cost lead of 36.86 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 20-039 filed April 3, 2020.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Total Residential Class Billed Default Service kWh (1)	Unbilled Factor (2)	Residential Class Unbilled kWh (a * b)	Effective Fixed Power Supply Charge	Residential Class Unbilled Power Supply Charge Revenue (c * d)	Total G2/OL Class Billed Default Service kWh (1)	Unbilled Factor (2)	G2/OL Class Unbilled kWh (f * g)	Effective Fixed Power Supply Charge	G2/OL Class Unbilled Power Supply Charge Revenue (h * i)	Reversal of prior month unbilled	Total Billed Non-G1 Class Power Supply Charge Revenue (1)	Total Revenue (e + j + k + l)
Mar-20	37,752,148	40.3%	15,210,639	$0.09989	$1,519,391	15,456,489	40.3%	6,227,542	$0.08646	$538,433	($2,405,350)	$5,125,433	$4,777,907
Apr-20	33,380,540	47.0%	15,693,034	$0.09989	$1,567,577	11,485,744	47.0%	5,399,738	$0.08646	$466,861	($2,057,824)	$4,232,910	$4,209,525
May-20	31,536,882	51.8%	16,333,886	$0.09989	$1,631,592	10,801,788	51.8%	5,594,566	$0.08646	$483,706	($2,034,439)	$3,973,121	$4,053,981
Jun-20	39,195,982	53.8%	21,101,529	$0.06006	$1,267,358	13,377,855	53.8%	7,202,095	$0.04893	$352,399	($2,115,298)	$3,877,297	$3,381,756
Jul-20	48,667,970	51.1%	24,861,110	$0.06006	$1,493,158	15,834,973	51.1%	8,088,996	$0.04893	$395,795	($1,619,756)	$3,683,181	$3,952,378
Aug-20	52,690,677	35.0%	18,461,998	$0.06006	$1,108,828	16,811,389	35.0%	5,890,450	$0.04893	$288,220	($1,888,953)	$3,970,985	$3,479,079
Sep-20	41,149,155	35.3%	14,528,836	$0.06006	$872,602	15,399,386	35.3%	5,437,175	$0.04893	$266,041	($1,397,047)	$3,217,864	$2,959,460
Oct-20	29,204,402	56.7%	16,563,068	$0.06006	$994,778	11,788,910	56.7%	6,685,996	$0.04893	$327,146	($1,138,643)	$2,333,067	$2,516,348
Nov-20	31,776,697	64.4%	20,468,239	$0.06006	$1,229,322	12,037,235	64.4%	7,753,512	$0.04893	$379,379	($1,321,924)	$2,518,088	$2,804,866
Dec-20	40,980,473	55.1%	22,568,008	$0.08287	$1,870,211	13,811,341	55.1%	7,605,926	$0.07674	$583,679	($1,608,702)	$3,807,602	$4,652,789
Jan-21	44,048,231	55.3%	24,369,660	$0.08287	$2,019,514	14,025,454	55.3%	7,759,575	$0.07674	$595,470	($2,453,890)	$4,763,292	$4,924,385
Feb-21	42,858,386	48.4%	20,757,290	$0.08287	$1,720,157	14,394,378	48.4%	6,971,524	$0.07674	$534,995	($2,614,983)	$4,732,667	$4,372,835
Total	473,241,543				$17,294,487	165,224,942				$5,212,123	($22,656,808)	$46,235,507	$46,085,308

(1) Per billing system
(2) Detail of Unbilled Factors for the Residential, Regular General, and Outdoor Lighting Classes:

	Non-G1 Class Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Mar-20	71,098,945	28,646,328	40.3%
Apr-20	58,985,799	27,730,712	47.0%
May-20	55,974,489	28,990,847	51.8%
Jun-20	69,462,218	37,395,645	53.8%
Jul-20	83,956,804	42,887,742	51.1%
Aug-20	89,400,114	31,324,416	35.0%
Sep-20	74,520,769	26,311,599	35.3%
Oct-20	55,142,312	31,273,568	56.7%
Nov-20	58,456,746	37,653,588	64.4%
Dec-20	71,840,899	39,562,891	55.1%
Jan-21	75,427,727	41,730,349	55.3%
Feb-21	74,913,490	36,282,306	48.4%

Unitil Energy Systems, Inc.
Itemized Costs for Non-G1 Class Default Service Charge

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
				Calculation of Working Capital Supplier Charges and GIS Support Payments												
	Non-G1 Class (Residential) DS Supplier Charges (1)	Non-G1 Class (G2 and OL) DS Supplier Charges (1)	GIS Support Payments	Number of Days of Lag / 365 (2)	Working Capital Requirement ((a+b+c)*d)	Prime Rate	Supply Related Working Capital (e * f)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Non-G1 Class (Residential) DS Supplier Charges (col. a)	Non-G1 Class (G2 and OL) DS Supplier Charges (col. b)	Total Remaining Costs (sum col. c + g + h + i + j + k + l)	Total All Costs (sum col. m + n + o)
Jun-21	[redacted]		$352	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$2,844,749
Jul-21	[redacted]		$390	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$4,133,535
Aug-21	[redacted]		$434	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$3,472,906
Sep-21	[redacted]		$515	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$2,206,162
Oct-21	[redacted]		$462	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$2,784,068
Nov-21	[redacted]		$347	6.25%	[redacted]	3.25%	[redacted]	[redacted]	$3,176	$0	$0	$773	[redacted]			$3,618,277
Total	[redacted]		$2,500				[redacted]	[redacted]	$19,056	$0	$0	$4,640	[redacted]			$19,059,697

Total Costs Allocated to the Residential Class and the G2/OL Class

	Non-G1 Class (Residential) DS Supplier Charges (col. a)	Allocation of Remaining Costs (col. o) to Residential Class (3)	Total Non-G1 Class (Residential) Power Supply Charges	Non-G1 Class (G2 and OL) DS Supplier Charges (col. b)	Allocation of Remaining Costs (col. o) to G2 and OL Class (3)	Total Non-G1 Class (G2 and OL) Power Supply Charges
	(i)	(ii)	(iii) = (i) + (ii)	(iv)	(v)	(vi) = (iv) + (v)
Jun-21	[redacted]		$2,121,275	[redacted]		$723,474
Jul-21	[redacted]		$3,144,895	[redacted]		$988,640
Aug-21	[redacted]		$2,577,883	[redacted]		$895,023
Sep-21	[redacted]		$1,591,244	[redacted]		$614,918
Oct-21	[redacted]		$2,090,157	[redacted]		$693,911
Nov-21	[redacted]		$2,702,014	[redacted]		$916,263
Total	[redacted]		$14,227,468	[redacted]		$4,832,229

(1) Estimates based on monthly average wholesale rate times estimated monthly purchases.
(2) Number of days lag equals 22.80. Calculated using revenue lag of 59.97 days less cost lead of 37.17 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 21-041 filed April 2, 2021.
(3) Remaining Costs (column o) allocated between the Residential Class and the G2 and Outdoor Lighting Class based on estimated monthly kWh purchases, as shown below:

	Estimated kWh Purchases - Residential Class	Estimated kWh Purchases - G2 and OL Class	Total Non-G1 Class kWh Purchases	Residential Class kWh Purchases / Total Non-G1 Class kWh Purchases	G2 and OL Class kWh Purchases / Total Non-G1 Class kWh Purchases
Jun-21	35,472,149	15,343,711	50,815,860	69.8%	30.2%
Jul-21	40,340,064	16,146,441	56,486,505	71.4%	28.6%
Aug-21	48,821,671	18,242,695	67,064,366	72.8%	27.2%
Sep-21	42,916,322	17,211,180	60,127,502	71.4%	28.6%
Oct-21	31,224,716	13,956,596	45,181,311	69.1%	30.9%
Nov-21	33,479,006	13,987,101	47,466,107	70.5%	29.5%
Total	232,253,928	94,887,723	327,141,651		

		Jun-21 Estimated	Jul-21 Estimated	Aug-21 Estimated	Sep-21 Estimated	Oct-21 Estimated	Nov-21 Estimated	Total
1	Reconciliation (1)	($15,814)	($17,579)	($20,871)	($18,712)	($14,061)	($14,772)	($101,810)
2	Total Costs (Page 5)	$378,309	$420,521	$499,264	$447,627	$336,363	$353,369	$2,435,452
3	Reconciliation plus Total Costs (L.1 + L.2)	$362,494	$402,941	$478,393	$428,914	$322,302	$338,597	$2,333,642
4	kWh Purchases	50,815,860	56,486,505	67,064,366	60,127,502	45,181,311	47,466,107	327,141,651
5	Total, Before Losses (L.3 / L.4)	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713	$0.00713
6	Losses	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%	6.40%
7	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	$0.00759	$0.00759	$0.00759	$0.00759	$0.00759	$0.00759	
8	Total Retail Rate - Fixed RPS Charge (L.5 * (1+L.6))							$0.00759

(1) Balance as of February 28, 2021 modified, as detailed below, to reflect that current rates include a reconciliation through May 31, 2021. Figure is then allocated between rate periods (June-November 2021 and December 2021-May 2022) and then to each month, June through November 2021, on equal per kWh basis.

a	February 28, 2021 actual balance - Schedule LSM-3, Page 2			$150,570
b	less: Estimated remaining prior period reconciliation - Mar, Apr, May 2021:			
c	Estimated kWh Sales Mar-May 2021			144,145,756
d	Amount of reconciliation in current RPS Charge			$0.00247
e	Estimated amount of reconciliation - Mar-May 2021			$356,040
f	Total reconciliation for June 1, 2021-May 31, 2022 (line a - line e)			($205,470)
		Non-G1 total kWh purchases	% per period	Reconciliation per period
g	Rate period: June-November 2021	327,141,651	49.55%	($101,810)
h	Rate period: December 2021-May 2022	333,083,695	50.45%	($103,660)
i	Total	660,225,345		($205,470)

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
Mar-20	$1,094,251	$408,489	$169,065	$1,333,674	$1,213,962	4.75%	31	$4,884	$1,338,558
Apr-20	$1,338,558	$373,129	$151,768	$1,559,919	$1,449,239	4.75%	30	$5,643	$1,565,562
May-20	$1,565,562	$373,129	$147,196	$1,791,494	$1,678,528	4.75%	31	$6,753	$1,798,247
Jun-20	$1,798,247	($82,117)	$567,848	$1,148,283	$1,473,265	4.75%	30	$5,736	$1,154,019
Jul-20	$1,154,019	$342,579	$678,331	$818,266	$986,143	3.25%	31	$2,715	$820,981
Aug-20	$820,981	$342,579	$597,489	$566,071	$693,526	3.25%	31	$1,909	$567,980
Sep-20	$567,980	$466,027	$511,722	$522,284	$545,132	3.25%	30	$1,452	$523,737
Oct-20	$523,737	$789,057	$434,405	$878,389	$701,063	3.25%	31	$1,930	$880,319
Nov-20	$880,319	$399,571	$478,606	$801,284	$840,801	3.25%	30	$2,240	$803,524
Dec-20	$803,524	$224,323	$582,873	$444,974	$624,249	3.25%	31	$1,718	$446,693
Jan-21	$446,693	$431,104	$616,586	$261,210	$353,952	3.25%	31	$977	$262,187
Feb-21	$262,187	$431,498	$543,629	$150,056	$206,122	3.25%	28	$514	$150,570
Total		$4,499,368	$5,479,519					$36,471	

	(a)	*Calculation of Working Capital* (b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits	Number of Days of Lag / 365 (1)	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Mar-20	$419,812	(71.35%)	($299,550)	3.78%	($11,323)	$408,489
Apr-20	$381,987	(71.35%)	($272,561)	3.25%	($8,858)	$373,129
May-20	$381,987	(71.35%)	($272,561)	3.25%	($8,858)	$373,129
Jun-20	($83,265)	(42.44%)	$35,334	3.25%	$1,148	($82,117)
Jul-20	$347,370	(42.44%)	($147,408)	3.25%	($4,791)	$342,579
Aug-20	$347,370	(42.44%)	($147,408)	3.25%	($4,791)	$342,579
Sep-20	$472,544	(42.44%)	($200,527)	3.25%	($6,517)	$466,027
Oct-20	$800,092	(42.44%)	($339,524)	3.25%	($11,035)	$789,057
Nov-20	$405,159	(42.44%)	($171,932)	3.25%	($5,588)	$399,571
Dec-20	$227,460	(42.44%)	($96,524)	3.25%	($3,137)	$224,323
Jan-21	$437,132	(42.44%)	($185,500)	3.25%	($6,029)	$431,104
Feb-21	$437,532	(42.44%)	($185,670)	3.25%	($6,034)	$431,498
Total	$4,575,180				($75,812)	$4,499,368

(1) For the months March-May 2020, number of days lag equals (260.44). Calculated using revenue lag of 63.94 days less cost lead of 324.38 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 19-049 filed April 5, 2019.

For the months June 2020-February 2021, number of days lag equals (154.89). Calculated using revenue lag of 58.69 days less cost lead of 213.58 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 20-039 filed April 3, 2020.

	(a) Total Non-G1 Class Billed Default Service kWh (1)	(b) Unbilled Factor (2)	(c) Non-G1 Class Unbilled kWh (a * b)	(d) Effective Fixed RPS Charge	(e) Non-G1 Class Unbilled RPS Charge Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed Non-G1 Class RPS Charge Revenue (1)	(h) Total Revenue (e + f + g)
Mar-20	53,208,637	40.3%	21,438,181	$0.00341	$73,104	($85,436)	$181,397	$169,065
Apr-20	44,866,284	47.0%	21,092,772	$0.00341	$71,926	($73,104)	$152,946	$151,768
May-20	42,338,670	51.8%	21,928,452	$0.00341	$74,776	($71,926)	$144,347	$147,196
Jun-20	52,573,837	53.8%	28,303,624	$0.00981	$277,659	($74,776)	$364,965	$567,848
Jul-20	64,502,943	51.1%	32,950,106	$0.00981	$323,241	($277,659)	$632,750	$678,331
Aug-20	69,502,066	35.0%	24,352,448	$0.00981	$238,898	($323,241)	$681,832	$597,489
Sep-20	56,548,541	35.3%	19,966,011	$0.00981	$195,867	($238,898)	$554,753	$511,722
Oct-20	40,993,312	56.7%	23,249,064	$0.00981	$228,073	($195,867)	$402,198	$434,405
Nov-20	43,813,932	64.4%	28,221,752	$0.00981	$276,855	($228,073)	$429,824	$478,606
Dec-20	54,791,814	55.1%	30,173,934	$0.01028	$310,188	($276,855)	$549,540	$582,873
Jan-21	58,073,685	55.3%	32,129,235	$0.01028	$330,289	($310,188)	$596,485	$616,586
Feb-21	57,252,764	48.4%	27,728,815	$0.01028	$285,052	($330,289)	$588,866	$543,629
Total	638,466,485				$2,685,927	($2,486,311)	$5,279,903	$5,479,519

(1) Per billing system
(2) Detail of Unbilled Factors for the Residential, Regular General, and Outdoor Lighting Classes:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Mar-20	71,098,945	28,646,328	40.3%
Apr-20	58,985,799	27,730,712	47.0%
May-20	55,974,489	28,990,847	51.8%
Jun-20	69,462,218	37,395,645	53.8%
Jul-20	83,956,804	42,887,742	51.1%
Aug-20	89,400,114	31,324,416	35.0%
Sep-20	74,520,769	26,311,599	35.3%
Oct-20	55,142,312	31,273,568	56.7%
Nov-20	58,456,746	37,653,588	64.4%
Dec-20	71,840,899	39,562,891	55.1%
Jan-21	75,427,727	41,730,349	55.3%
Feb-21	74,913,490	36,282,306	48.4%

	(a)	*Calculation of Working Capital* (b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits (1)	Number of Days of Lag / 365 (2)	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Jun-21	$386,171	(62.64%)	($241,912)	3.25%	($7,862)	$378,309
Jul-21	$429,260	(62.64%)	($268,905)	3.25%	($8,739)	$420,521
Aug-21	$509,640	(62.64%)	($319,258)	3.25%	($10,376)	$499,264
Sep-21	$456,929	(62.64%)	($286,238)	3.25%	($9,303)	$447,627
Oct-21	$343,353	(62.64%)	($215,090)	3.25%	($6,990)	$336,363
Nov-21	$360,713	(62.64%)	($225,964)	3.25%	($7,344)	$353,369
Total	$2,486,067				($50,614)	$2,435,452

(1) Schedule JMP-4.

(2) Number of days lag equals (228.65). Calculated using revenue lag of 59.97 days less cost lead of 288.62 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 22 of 23, DE 21-041 filed April 2, 2021.

Unitil Energy Systems, Inc.
Calculation of G1 Large General Service Class Default Service Power Supply Charge

		Total Jun21-Nov21
1	Reconciliation (1)	$50,380
2	Total Costs excl. wholesale supplier charge (Page 5)	$30,135
3	Reconciliation plus Total Costs excl. wholesale supplier charge (L.1 + L.2)	$80,516
4	kWh Purchases	25,037,023
5	Total, Before Losses (L.3 / L.4)	$0.00322
6	Losses	4.591%
7	Power Supply Charge excl. wholesale supplier charge (L.5 * (1+L.6)) (2)	$0.00336

(1) Balance as of February 28, 2021 modified, as detailed below, to reflect that current rates include a reconciliation through May 31, 2021 and to incorporate the difference between the estimated supplier cost and revenue in March 2021. Figure is then allocated between rate periods (June-November 2021 and December 2021-May 2022) and then to each month, June through November 2021, on equal per kWh basis.

a	February 28, 2021 actual balance - Schedule LSM-4, Page 2		$233,485	
b	less: Estimated remaining prior period reconciliation - Mar, Apr, May 2021:			
c	Estimated kWh Sales March-May 2021		12,631,301	
d	Amount of reconciliation in current rate		($0.00351)	
e	Estimated amount of reconciliation - Mar-May 2021		($44,336)	
f	plus: Difference between the estimated supplier cost and revenue for March 2021		($179,676)	
g	Total reconciliation for June 1, 2021-May 31, 2022 (line a - line e + line f)		$98,145	
h	kWh purchases forecast June-November 2021		25,037,023	51.33%
i	kWh purchases forecast December 2021-May 2022		23,737,244	48.67%
j	Total		48,774,267	
k	Reconciliation amount for June-November 2021	(line g * line h%)	$50,380	
l	Reconciliation amount for December 2021-May 2022	(line g * line i%)	$47,765	
m	Total	(line k + line l)	$98,145	

(2) The total G1 Power Supply Charge will equal the sum of Line 7 plus a wholesale supplier charge which shall be determined at the end of each month. The wholesale supply charges will be determined as the sum of the average ISO-New England real time hourly locational marginal prices for the New Hampshire load zone, weighted by the wholesale hourly kWh volumes of the Company's G1 Default Service customers, and charges for capacity, ancillary services, and other supplier costs established through a competitive bidding process.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Beginning Balance	Total Costs (Page 3)	Total Revenue (Page 4)	Ending Balance Before Interest (a + b - c)	Average Monthly Balance ((a+d) / 2)	Interest Rate	Number of Days / Month	Computed Interest	Ending Balance with Interest (d + h)
Mar-20	($213,125)	$294,111	$230,452	($149,466)	($181,296)	4.75%	31	($729)	($150,195)
Apr-20	($150,195)	$148,992	$224,010	($225,214)	($187,705)	4.75%	30	($731)	($225,945)
May-20	($225,945)	$243,571	$239,591	($221,965)	($223,955)	4.75%	31	($901)	($222,866)
Jun-20	($222,866)	$226,044	$161,684	($158,507)	($190,687)	4.75%	30	($742)	($159,249)
Jul-20	($159,249)	$271,995	$253,010	($140,264)	($149,757)	3.25%	31	($412)	($140,676)
Aug-20	($140,676)	$274,157	$234,344	($100,863)	($120,770)	3.25%	31	($332)	($101,196)
Sep-20	($101,196)	$217,426	$227,611	($111,381)	($106,288)	3.25%	30	($283)	($111,664)
Oct-20	($111,664)	$242,236	$185,949	($55,377)	($83,520)	3.25%	31	($230)	($55,607)
Nov-20	($55,607)	$216,664	$191,297	($30,240)	($42,923)	3.25%	30	($114)	($30,354)
Dec-20	($30,354)	$320,804	$259,500	$30,950	$298	3.25%	31	$1	$30,951
Jan-21	$30,951	$333,340	$269,408	$94,883	$62,917	3.25%	31	$174	$95,056
Feb-21	$95,056	$434,125	$296,105	$233,076	$164,066	3.25%	28	$409	$233,485
Total		$3,223,464	$2,772,961					($3,892)	

Redacted

Calculation of Working Capital
Supplier Charges and GIS Support Payments

	(a) Total G1 Class DS Supplier Charges	(b) GIS Support Payments	(c) Number of Days of Lag / 365 (1)	(d) Working Capital Requirement	(e) Prime Rate	(f) Supply Related Working Capital (d * e)	(g) Provision for Uncollected Accounts	(h) Internal Company Administrative	(i) Legal Charges	(j) Consulting Outside Service Charges	(k) Default Service Portion of the annual PUC	(l) Total Costs (sum a + b + f + g + h + i + j + k)
Mar-20	[redacted]	$30	(4.84%)	[redacted]	3.78%	[redacted]	[redacted]	$4,509	$0	$0	$62	$294,111
Apr-20		$28	(4.84%)		3.25%			$4,509	$0	$0	$65	$148,992
May-20		$38	(4.84%)		3.25%			$4,509	$43	$0	$71	$243,571
Jun-20		$25	(2.07%)		3.25%			$4,509	$0	$0	$68	$226,044
Jul-20		$24	(2.07%)		3.25%			$4,509	$0	$0	$63	$271,995
Aug-20		$79	(2.07%)		3.25%			$4,509	$0	$0	$57	$274,157
Sep-20		$41	(2.07%)		3.25%			$4,509	$0	$0	$67	$217,426
Oct-20		$39	(2.07%)		3.25%			$4,509	$0	$0	$73	$242,236
Nov-20		$37	(2.07%)		3.25%			$4,509	$0	$0	$69	$216,664
Dec-20		$24	(2.07%)		3.25%			$4,917	$0	$0	$60	$320,804
Jan-21		$56	(2.07%)		3.25%			$4,917	$0	$0	$53	$333,340
Feb-21		$74	(2.07%)		3.25%			$4,917	$0	$0	$58	$434,125
Total		$494						$55,330	$43	$0	$767	$3,223,464

(1) For the months March-May 2020, number of days lag equals (17.66). Calculated using revenue lag of 39.90 days less cost lead of 57.56 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 19-049 filed April 5, 2019.

For the months June 2020-February 2021, number of days lag equals (7.56). Calculated using revenue lag of 39.31 days less cost lead of 46.87 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 20-039 filed April 3, 2020.

	(a) Total G1 Class Billed Default Service kWh (1)	(b) Unbilled Factor (2)	(c) G1 Class Unbilled kWh (a * b)	(d) Effective Variable Power Supply Charge	(e) G1 Class Unbilled Power Supply Charge Revenue (c * d)	(f) Reversal of prior month unbilled	(g) Total Billed G1 Class Power Supply Charge Revenue (1)	(h) Total Revenue (e + f + g)
Mar-20	4,287,872	41.0%	1,760,047	$0.05902	$103,878	($137,046)	$263,619	$230,452
Apr-20	3,802,540	47.4%	1,803,186	$0.05832	$105,162	($103,878)	$222,727	$224,010
May-20	3,954,004	51.8%	2,047,896	$0.05716	$117,058	($105,162)	$227,695	$239,591
Jun-20	4,705,564	41.3%	1,942,328	$0.03633	$70,565	($117,058)	$208,177	$161,684
Jul-20	5,320,053	44.0%	2,339,437	$0.04413	$103,239	($70,565)	$220,335	$253,010
Aug-20	5,133,022	51.5%	2,641,586	$0.04319	$114,090	($103,239)	$223,494	$234,344
Sep-20	4,958,988	40.0%	1,985,445	$0.05162	$102,489	($114,090)	$239,213	$227,611
Oct-20	3,959,902	56.7%	2,245,830	$0.04484	$100,703	($102,489)	$187,734	$185,949
Nov-20	3,923,812	59.0%	2,313,729	$0.04763	$110,203	($100,703)	$181,797	$191,297
Dec-20	4,223,104	51.5%	2,175,133	$0.06197	$134,793	($110,203)	$234,910	$259,500
Jan-21	3,904,572	53.2%	2,075,541	$0.06956	$144,375	($134,793)	$259,826	$269,408
Feb-21	4,261,582	49.4%	2,103,948	$0.06941	$146,035	($144,375)	$294,444	$296,105
Total	52,435,015				$1,352,589	($1,343,600)	$2,763,972	$2,772,961

(1) Per billing system
(2) Detail of Unbilled Factors for the Large General Class:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Mar-20	27,375,056	11,236,663	41.0%
Apr-20	23,199,379	11,001,277	47.4%
May-20	23,230,381	12,031,703	51.8%
Jun-20	27,500,834	11,351,590	41.3%
Jul-20	29,386,736	12,922,506	44.0%
Aug-20	29,935,971	15,405,825	51.5%
Sep-20	29,722,799	11,900,207	40.0%
Oct-20	24,642,676	13,975,918	56.7%
Nov-20	24,432,498	14,406,953	59.0%
Dec-20	25,817,785	13,297,591	51.5%
Jan-21	25,351,429	13,475,980	53.2%
Feb-21	25,812,410	12,743,614	49.4%

Unitil Energy Systems, Inc.
Itemized Costs for G1 Class Default Service Power Supply Charge

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			Calculation of Working Capital Supplier Charges and GIS Support Payments									
	Total G1 Class DS Supplier Charges (1)	GIS Support Payments	Number of Days of Lag / 365 (2)	Working Capital Requirement (3)	Prime Rate	Supply Related Working Capital (d * e)	Provision for Uncollected Accounts	Internal Company Administrative Costs	Legal Charges	Consulting Outside Service Charges	Default Service Portion of the annual PUC Assessment	Total Costs (sum a + b + f + g + h + i + j + k)
Jun-21		$29	0.24%	$385	3.25%	$12	$0	$4,917	$0	$0	$60	$5,018
Jul-21		$31	0.24%	$560	3.25%	$18	$0	$4,917	$0	$0	$60	$5,026
Aug-21		$34	0.24%	$421	3.25%	$14	$0	$4,917	$0	$0	$60	$5,025
Sep-21		$35	0.24%	$277	3.25%	$9	$0	$4,917	$0	$0	$60	$5,021
Oct-21		$33	0.24%	$399	3.25%	$13	$0	$4,917	$0	$0	$60	$5,023
Nov-21		$30	0.24%	$498	3.25%	$16	$0	$4,917	$0	$0	$60	$5,023
Total		$192				$83	$0	$29,501	$0	$0	$360	$30,135

(1) DS Supplier Charges to be determined at the end of each month.

(2) Number of days lag equals 0.89. Calculated using revenue lag of 41.89 days less cost lead of 41.00 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 21-041 filed April 2, 2021.

(3) The working capital requirement equals the supplier charge plus GIS Support payment times the number of days lag divided by 365. As the G1 class supplier charge is not determined using a contract price, estimates of the G1 class power supply costs were calculated based on the forecasted G1 class kWh purchases and an estimated price per kWh. The estimated price per kWh was determined by comparing a historical relationship between G1 and Non-G1 class supplier pricing and then applying that relationship to the current average Non-G1 supplier price per kWh. Actual working capital will be determined using the actual supplier charges in each month.

		Jun-21 Estimated	Jul-21 Estimated	Aug-21 Estimated	Sep-21 Estimated	Oct-21 Estimated	Nov-21 Estimated	Total
1	Reconciliation (1)	($2,228)	($2,480)	($2,576)	($2,395)	($2,149)	($2,126)	($13,954)
2	Total Costs (Page 5)	$30,279	$33,702	$35,008	$32,552	$29,208	$28,898	$189,647
3	Reconciliation plus Total Costs (L.1 + L.2)	$28,051	$31,222	$32,432	$30,157	$27,059	$26,772	$175,693
4	kWh Purchases	3,997,435	4,449,271	4,621,728	4,297,467	3,856,019	3,815,103	25,037,023
5	Total, Before Losses (L.3 / L.4)	$0.00702	$0.00702	$0.00702	$0.00702	$0.00702	$0.00702	
6	Losses	4.591%	4.591%	4.591%	4.591%	4.591%	4.591%	
7	Total Retail Rate - Variable RPS Charge (L.5 * (1+L.6))	$0.00734	$0.00734	$0.00734	$0.00734	$0.00734	$0.00734	

(1) Balance as of February 28, 2021 modified, as detailed below, to reflect that current rates include a reconciliation through May 31, 2021. Figure is then allocated between rate periods (June-November 2021 and December 2021-May 2022) and then to each month, June through November 2021, on equal per kWh basis.

a	February 28, 20210 actual balance - Schedule LSM-5, Page 2		($10,385)	
b	less: Estimated remaining prior period reconciliation - Mar, Apr, May 2021:			
c	Estimated kWh Sales Mar-May 2021		12,631,301	
d	Amount of reconciliation in current rate		$0.00133	
e	Estimated amount of reconciliation - Mar-May 2021		$16,800	
f	Total reconciliation for June 1, 2021-May 31, 2022 (line a - Line e)		($27,185)	
g	kWh purchases forecast June-November 2021		25,037,023	51.33%
h	kWh purchases forecast December 2021-May 2022		23,737,244	48.67%
i	Total		48,774,267	
j	Reconciliation amount for June-November 2021	(line f * line g%)	($13,954)	
k	Reconciliation amount for December 2021-May 2022	(line f * line h%)	($13,231)	
l	Total	(line j + line k)	($27,185)	

	(a) Beginning Balance	(b) Total Costs (Page 3)	(c) Total Revenue (Page 4)	(d) Ending Balance Before Interest (a + b - c)	(e) Average Monthly Balance ((a+d) / 2)	(f) Interest Rate	(g) Number of Days / Month	(h) Computed Interest	(i) Ending Balance with Interest (d + h)
Mar-20	$39,887	$28,596	$13,092	$55,390	$47,639	4.75%	31	$192	$55,582
Apr-20	$55,582	$26,125	$12,691	$69,016	$62,299	4.75%	30	$243	$69,259
May-20	$69,259	$26,125	$13,856	$81,528	$75,393	4.75%	31	$303	$81,831
Jun-20	$81,831	($5,752)	$42,109	$33,970	$57,901	4.75%	30	$225	$34,195
Jul-20	$34,195	$23,998	$50,540	$7,654	$20,924	3.25%	31	$58	$7,711
Aug-20	$7,711	$23,998	$48,047	($16,338)	($4,313)	3.25%	31	($12)	($16,350)
Sep-20	($16,350)	$53,321	$38,037	($1,066)	($8,708)	3.25%	30	($23)	($1,089)
Oct-20	($1,089)	$60,362	$37,307	$21,965	$10,438	3.25%	31	$29	$21,994
Nov-20	$21,994	$30,567	$35,287	$17,274	$19,634	3.25%	30	$52	$17,326
Dec-20	$17,326	$17,160	$36,198	($1,711)	$7,807	3.25%	31	$21	($1,690)
Jan-21	($1,690)	$32,979	$35,611	($4,322)	($3,006)	3.25%	31	($8)	($4,330)
Feb-21	($4,330)	$32,979	$39,016	($10,367)	($7,349)	3.25%	28	($18)	($10,385)
Total		$350,456	$401,790					$1,061	

	(a)	*Calculation of Working Capital* (b)	(c)	(d)	(e)	(f)
	Renewable Energy Credits	Number of Days of Lag / 365 (1)	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Mar-20	$29,425	(74.58%)	($21,944)	3.78%	($829)	$28,596
Apr-20	$26,774	(74.58%)	($19,967)	3.25%	($649)	$26,125
May-20	$26,774	(74.58%)	($19,967)	3.25%	($649)	$26,125
Jun-20	($5,836)	(44.17%)	$2,578	3.25%	$84	($5,752)
Jul-20	$24,347	(44.17%)	($10,754)	3.25%	($349)	$23,998
Aug-20	$24,347	(44.17%)	($10,754)	3.25%	($349)	$23,998
Sep-20	$54,097	(44.17%)	($23,893)	3.25%	($777)	$53,321
Oct-20	$61,241	(44.17%)	($27,048)	3.25%	($879)	$60,362
Nov-20	$31,012	(44.17%)	($13,697)	3.25%	($445)	$30,567
Dec-20	$17,410	(44.17%)	($7,690)	3.25%	($250)	$17,160
Jan-21	$33,459	(44.17%)	($14,778)	3.25%	($480)	$32,979
Feb-21	$33,459	(44.17%)	($14,778)	3.25%	($480)	$32,979
Total	$356,510				($6,054)	$350,456

(1) For the months March-May 2020, number of days lag equals (272.20). Calculated using revenue lag of 39.90 days less cost lead of 312.10 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 19-049 filed April 5, 2019.

For the months June 2020-February 2021, number of days lag equals (161.21). Calculated using revenue lag of 39.31 days less cost lead of 200.52 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 20-039 filed April 3, 2020.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Total G1 Class Billed Default Service kWh (1)	Unbilled Factor (2)	G1 Class Unbilled kWh (a * b)	Effective Variable RPS Charge	G1 Class Unbilled RPS Charge Revenue (c * d)	Reversal of prior month unbilled	Total Billed G1 Class RPS Charge Revenue (1)	Total Revenue (e + f + g)
Mar-20	4,287,872	41.0%	1,760,047	$0.00330	$5,808	($6,866)	$14,150	$13,092
Apr-20	3,802,540	47.4%	1,803,186	$0.00330	$5,951	($5,808)	$12,548	$12,691
May-20	3,954,004	51.8%	2,047,896	$0.00330	$6,758	($5,951)	$13,048	$13,856
Jun-20	4,705,564	41.3%	1,942,328	$0.00884	$17,170	($6,758)	$31,697	$42,109
Jul-20	5,320,053	44.0%	2,339,437	$0.00884	$20,681	($17,170)	$47,029	$50,540
Aug-20	5,133,022	51.5%	2,641,586	$0.00884	$23,352	($20,681)	$45,376	$48,047
Sep-20	4,958,988	40.0%	1,985,445	$0.00884	$17,551	($23,352)	$43,837	$38,037
Oct-20	3,959,902	56.7%	2,245,830	$0.00884	$19,853	($17,551)	$35,006	$37,307
Nov-20	3,923,812	59.0%	2,313,729	$0.00884	$20,453	($19,853)	$34,686	$35,287
Dec-20	4,223,104	51.5%	2,175,133	$0.00886	$19,272	($20,453)	$37,379	$36,198
Jan-21	3,904,572	53.2%	2,075,541	$0.00920	$19,095	($19,272)	$35,787	$35,611
Feb-21	4,261,582	49.4%	2,103,948	$0.00920	$19,356	($19,095)	$38,754	$39,016
Total	52,435,015				$195,300	($182,809)		$401,790

(1) Per billing system
(2) Detail of Unbilled Factors for the Large General Class:

	Billed kWh	Direct Estimate of Unbilled kWh	Unbilled kWh / Billed kWh
Mar-20	27,375,056	11,236,663	41.0%
Apr-20	23,199,379	11,001,277	47.4%
May-20	23,230,381	12,031,703	51.8%
Jun-20	27,500,834	11,351,590	41.3%
Jul-20	29,386,736	12,922,506	44.0%
Aug-20	29,935,971	15,405,825	51.5%
Sep-20	29,722,799	11,900,207	40.0%
Oct-20	24,642,676	13,975,918	56.7%
Nov-20	24,432,498	14,406,953	59.0%
Dec-20	25,817,785	13,297,591	51.5%
Jan-21	25,351,429	13,475,980	53.2%
Feb-21	25,812,410	12,743,614	49.4%

	(a)	(b)	(c)	(d)	(e)	(f)
		Calculation of Working Capital				
	Renewable Energy Credits (1)	Number of Days of Lag / 365 (2)	Working Capital Requirement (a*b)	Prime Rate	Supply Related Working Capital (c * d)	Total Costs (sum a + e)
Jun-21	$30,917	(63.45%)	($19,618)	3.25%	($638)	$30,279
Jul-21	$34,411	(63.45%)	($21,836)	3.25%	($710)	$33,702
Aug-21	$35,745	(63.45%)	($22,682)	3.25%	($737)	$35,008
Sep-21	$33,237	(63.45%)	($21,091)	3.25%	($685)	$32,552
Oct-21	$29,823	(63.45%)	($18,924)	3.25%	($615)	$29,208
Nov-21	$29,507	(63.45%)	($18,723)	3.25%	($609)	$28,898
Total	$193,641				($3,993)	$189,647

(1) Schedule JMP-4.

(2) Number of days lag equals (231.61). Calculated using revenue lag of 41.89 days less cost lead of 273.50 days. Revenue lag per Schedule DTN-1, Page 4 of 23 and cost lead per Schedule DTN-1, Page 20 of 23, DE 21-041 filed April 2, 2021.

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Residential Rate D 650 kWh Bill

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.03558	$0.03558	$0.00000	$23.13	$23.13	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$23.48	$23.48	$0.00	0.0%
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000	($0.16)	($0.16)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.55	$0.55	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$4.89	$4.89	$0.00	0.0%
Default Service Charge	$0.09315	$0.07091	($0.02224)	$60.55	$46.09	($14.46)	(11.2%)
Total kWh Charges	$0.17297	$0.15073	($0.02224)				
Total Bill				$128.65	$114.19	($14.46)	(11.2%)

Regular General G2 Demand, 11 kW, 2,800 kWh Typical Bill

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$29.19	$29.19	$0.00	$29.19	$29.19	$0.00	0.0%
	All kW	**All kW**					
Distribution Charge	$10.51	$10.51	$0.00	$115.61	$115.61	$0.00	0.0%
Stranded Cost Charge	($0.05)	($0.05)	$0.00	($0.55)	($0.55)	$0.00	0.0%
Total kW Charges	$10.46	$10.46	$0.00	$115.06	$115.06	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$101.16	$101.16	$0.00	0.0%
Stranded Cost Charge	($0.00005)	($0.00005)	$0.00000	($0.14)	($0.14)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$2.35	$2.35	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$21.06	$21.06	$0.00	0.0%
Default Service Charge	$0.08702	$0.05992	($0.02710)	$243.66	$167.78	($75.88)	(14.8%)
Total kWh Charges	$0.13146	$0.10436	($0.02710)	$368.09	$292.21	($75.88)	(14.8%)
Total Bill				$512.34	$436.46	($75.88)	(14.8%)

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Regular General G2 Quick Recovery Water Heating and Space Heating 1,660 kWh Typical Bill

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$9.73	$9.73	$0.00	$9.73	$9.73	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.03204	$0.03204	$0.00000	$53.19	$53.19	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$59.98	$59.98	$0.00	0.0%
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000	($0.42)	($0.42)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$1.39	$1.39	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$12.48	$12.48	$0.00	0.0%
Default Service Charge	$0.08702	$0.05992	($0.02710)	$144.45	$99.47	($44.99)	(16.0%)
Total kWh Charges	$0.16330	$0.13620	($0.02710)	$271.08	$226.09	($44.99)	(16.0%)
Total Bill				$280.81	$235.82	($44.99)	(16.0%)

Regular General G2 kWh Meter 115 kWh Typical Bill

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$18.38	$18.38	$0.00	$18.38	$18.38	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.00883	$0.00883	$0.00000	$1.02	$1.02	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$4.15	$4.15	$0.00	0.0%
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000	($0.03)	($0.03)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.10	$0.10	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$0.86	$0.86	$0.00	0.0%
Default Service Charge	$0.08702	$0.05992	($0.02710)	$10.01	$6.89	($3.12)	(9.0%)
Total kWh Charges	$0.14009	$0.11299	($0.02710)	$16.11	$12.99	($3.12)	(9.0%)
Total Bill				$34.49	$31.37	($3.12)	(9.0%)

Unitil Energy Systems, Inc.
Typical Bill Impacts for Residential Rate Class based on Mean and Median Usage

Residential Rate D 650 kWh Bill - Mean Use*

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge	$0.03558	$0.03558	$0.00000	$23.13	$23.13	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$23.48	$23.48	$0.00	0.0%
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000	($0.16)	($0.16)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.55	$0.55	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$4.89	$4.89	$0.00	0.0%
Default Service Charge	$0.09315	$0.07091	($0.02224)	$60.55	$46.09	($14.46)	(11.2%)
Total kWh Charges	$0.17297	$0.15073	($0.02224)				
Total Bill				$128.65	$114.19	($14.46)	(11.2%)

Residential Rate D 526 kWh Bill - Median Use*

Rate Components	4/1/2021 Current Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%
	$/kWh	$/kWh					
Distribution Charge	$0.03558	$0.03558	$0.00000	$18.72	$18.72	$0.00	0.0%
External Delivery Charge	$0.03613	$0.03613	$0.00000	$19.00	$19.00	$0.00	0.0%
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000	($0.13)	($0.13)	$0.00	0.0%
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.44	$0.44	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$3.96	$3.96	$0.00	0.0%
Default Service Charge	$0.09315	$0.07091	($0.02224)	$49.00	$37.30	($11.70)	(10.9%)
Total kWh Charges	$0.17297	$0.15073	($0.02224)				
Total Bill				$107.20	$95.50	($11.70)	(10.9%)

* Based on billing period January through December 2020.

Unitil Energy Systems, Inc.
Average Class Bill Impacts
Due to Proposed Default Service Rate Changes Effective June 1, 2021

(A) Class of Service	(B) Annual Number of Customers (luminaires for Outdoor Lighting)	(C) Annual kWh Sales	(D) Annual kW / kVA Sales	(E) Proposed DSC Change $	(F) Estimated Annual Revenue $ Under Present Rates	(G) Estimated Annual Revenue $ Under Proposed Rates	(H) Proposed Net Change Revenue $	(I) % Change DSC Revenue
Residential	785,306	497,875,828	n/a	($11,072,758)	$98,855,249	$87,782,491	($11,072,758)	(11.2%)
General Service	131,872	354,161,409	1,348,556	($9,597,774)	$64,552,405	$54,954,631	($9,597,774)	(14.9%)
Outdoor Lighting	110,850	8,241,454	n/a	($223,343)	$2,961,373	$2,738,030	($223,343)	(7.5%)
Total	1,028,028	860,278,690		($20,893,876)	$166,369,027	$145,475,151	($20,893,876)	(12.6%)

(B), (C), (D) Test year billing determinants in DE 16-384.
(E) Difference in proposed rate and current rate, times the billing determinants shown in Column (C).
(F) Based on current rates times billing determinants shown in Columns (B), (C) and (D).
(G) Sum of Columns (E) and (F)
(H) Column (G) minus Column (F)
(I) Column (H) divided by Column (F)

Unitil Energy Systems, Inc.
Typical Bill Impacts - April 1, 2021 vs. June 1, 2021
Due to Changes in the Default Service Charge
Impact on D Rate Customers

Average kWh	Total Bill Using Rates 4/1/2021	Total Bill Using Rates 6/1/2021	Total Difference	% Total Difference
125	$37.84	$35.06	($2.78)	(7.3%)
150	$42.17	$38.83	($3.34)	(7.9%)
200	$50.81	$46.37	($4.45)	(8.8%)
250	$59.46	$53.90	($5.56)	(9.4%)
300	$68.11	$61.44	($6.67)	(9.8%)
350	$76.76	$68.98	($7.78)	(10.1%)
400	$85.41	$76.51	($8.90)	(10.4%)
450	$94.06	$84.05	($10.01)	(10.6%)
500	$102.71	$91.59	($11.12)	(10.8%)
525	$107.03	$95.35	($11.68)	(10.9%)
550	$111.35	$99.12	($12.23)	(11.0%)
575	$115.68	$102.89	($12.79)	(11.1%)
600	$120.00	$106.66	($13.34)	(11.1%)
625	$124.33	$110.43	($13.90)	(11.2%)
650	$128.65	$114.19	($14.46)	(11.2%)
675	$132.97	$117.96	($15.01)	(11.3%)
700	$137.30	$121.73	($15.57)	(11.3%)
725	$141.62	$125.50	($16.12)	(11.4%)
750	$145.95	$129.27	($16.68)	(11.4%)
775	$150.27	$133.04	($17.24)	(11.5%)
825	$158.92	$140.57	($18.35)	(11.5%)
925	$176.22	$155.65	($20.57)	(11.7%)
1,000	$189.19	$166.95	($22.24)	(11.8%)
1,250	$232.43	$204.63	($27.80)	(12.0%)
1,500	$275.68	$242.32	($33.36)	(12.1%)
2,000	$362.16	$317.68	($44.48)	(12.3%)
3,500	$621.62	$543.78	($77.84)	(12.5%)
5,000	$881.07	$769.87	($111.20)	(12.6%)

	Rates - Effective April 1, 2021	Rates - Proposed June 1, 2021	Difference
Customer Charge	**$16.22**	**$16.22**	**$0.00**
	kWh	kWh	kWh
Distribution Charge:	$0.03558	$0.03558	$0.00000
External Delivery Charge	$0.03613	$0.03613	$0.00000
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000
Storm Recovery Adjustment Factor	$0.00084	$0.00084	$0.00000
System Benefits Charge	$0.00752	$0.00752	$0.00000
Default Service Charge	$0.09315	$0.07091	($0.02224)
TOTAL	**$0.17297**	**$0.15073**	**($0.02224)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - April 1, 2021 vs. June 1, 2021
Due to Changes in the Default Service Charge
Impact on G2 Rate Customers

Load Factor	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates 4/1/2021	Total Bill Using Rates 6/1/2021	Total Difference	% Total Difference
20%	5	730	$177.46	$157.67	($19.78)	(11.1%)
20%	10	1,460	$325.72	$286.16	($39.57)	(12.1%)
20%	15	2,190	$473.99	$414.64	($59.35)	(12.5%)
20%	25	3,650	$770.52	$671.60	($98.92)	(12.8%)
20%	50	7,300	$1,511.85	$1,314.02	($197.83)	(13.1%)
20%	75	10,950	$2,253.18	$1,956.43	($296.75)	(13.2%)
20%	100	14,600	$2,994.51	$2,598.85	($395.66)	(13.2%)
20%	150	21,900	$4,477.16	$3,883.67	($593.49)	(13.3%)
36%	5	1,314	$254.23	$218.62	($35.61)	(14.0%)
36%	10	2,628	$479.27	$408.05	($71.22)	(14.9%)
36%	15	3,942	$704.31	$597.48	($106.83)	(15.2%)
36%	25	6,570	$1,154.38	$976.34	($178.05)	(15.4%)
36%	50	13,140	$2,279.57	$1,923.48	($356.09)	(15.6%)
36%	75	19,710	$3,404.77	$2,870.63	($534.14)	(15.7%)
36%	100	26,280	$4,529.96	$3,817.77	($712.19)	(15.7%)
36%	150	39,420	$6,780.34	$5,712.06	($1,068.28)	(15.8%)
50%	5	1,825	$321.40	$271.95	($49.46)	(15.4%)
50%	10	3,650	$613.62	$514.70	($98.92)	(16.1%)
50%	15	5,475	$905.83	$757.46	($148.37)	(16.4%)
50%	25	9,125	$1,490.26	$1,242.98	($247.29)	(16.6%)
50%	50	18,250	$2,951.34	$2,456.76	($494.58)	(16.8%)
50%	75	27,375	$4,412.41	$3,670.55	($741.86)	(16.8%)
50%	100	36,500	$5,873.48	$4,884.33	($989.15)	(16.8%)
50%	150	54,750	$8,795.63	$7,311.90	($1,483.73)	(16.9%)

	Rates - Effective April 1, 2021	Rates - Proposed June 1, 2021	Difference
Customer Charge	**$29.19**	**$29.19**	**$0.00**
	All kW	**All kW**	**All kW**
Distribution Charge	$10.51	$10.51	$0.00
Stranded Cost Charge	($0.05)	($0.05)	$0.00
TOTAL	**$10.46**	**$10.46**	**$0.00**
	kWh	**kWh**	**kWh**
Distribution Charge	$0.00000	$0.00000	$0.00000
External Delivery Charge	$0.03613	$0.03613	$0.00000
Stranded Cost Charge	($0.00005)	($0.00005)	$0.00000
Storm Recovery Adj. Factor	$0.00084	$0.00084	$0.00000
System Benefits Charge	$0.00752	$0.00752	$0.00000
Default Service Charge	$0.08702	$0.05992	($0.02710)
TOTAL	**$0.13146**	**$0.10436**	**($0.02710)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - April 1, 2021 vs. June 1, 2021
Due to Changes in the Default Service Charge
Impact on G2 kWh Meter Rate Customers

Average Monthly kWh	Total Bill Using Rates 4/1/2021	Total Bill Using Rates 6/1/2021	Total Difference	% Total Difference
15	$20.48	$20.07	($0.41)	(2.0%)
75	$28.89	$26.85	($2.03)	(7.0%)
150	$39.39	$35.33	($4.07)	(10.3%)
250	$53.40	$46.63	($6.78)	(12.7%)
350	$67.41	$57.93	($9.49)	(14.1%)
450	$81.42	$69.23	($12.20)	(15.0%)
550	$95.43	$80.52	($14.91)	(15.6%)
650	$109.44	$91.82	($17.62)	(16.1%)
750	$123.45	$103.12	($20.33)	(16.5%)
900	$144.46	$120.07	($24.39)	(16.9%)

	Rates - Effective April 1, 2021	Rates - Proposed June 1, 2021	Difference
kWh Meter Customer Charge	**$18.38**	**$18.38**	**$0.00**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.00883	$0.00883	$0.00000
External Delivery Charge	$0.03613	$0.03613	$0.00000
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000
Storm Recovery Adjustment Factor	$0.00084	$0.00084	$0.00000
System Benefits Charge	$0.00752	$0.00752	$0.00000
Default Service Charge	$0.08702	$0.05992	($0.02710)
TOTAL	**$0.14009**	**$0.11299**	**($0.02710)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - April 1, 2021 vs. June 1, 2021
Due to Changes in the Default Service Charge
Impact on G2 QRWH and SH Rate Customers

Average kWh	Total Bill Using Rates 4/1/2021	Total Bill Using Rates 6/1/2021	Total Difference	% Total Difference
100	$26.06	$23.35	($2.71)	(10.4%)
200	$42.39	$36.97	($5.42)	(12.8%)
300	$58.72	$50.59	($8.13)	(13.8%)
400	$75.05	$64.21	($10.84)	(14.4%)
500	$91.38	$77.83	($13.55)	(14.8%)
750	$132.21	$111.88	($20.33)	(15.4%)
1,000	$173.03	$145.93	($27.10)	(15.7%)
1,500	$254.68	$214.03	($40.65)	(16.0%)
2,000	$336.33	$282.13	($54.20)	(16.1%)
2,500	$417.98	$350.23	($67.75)	(16.2%)

	Rates - Effective April 1, 2021	Rates - Proposed June 1, 2021	Difference
Customer Charge	**$9.73**	**$9.73**	**$0.00**
	All kWh	**All kWh**	**All kWh**
Distribution Charge	$0.03204	$0.03204	$0.00000
External Delivery Charge	$0.03613	$0.03613	$0.00000
Stranded Cost Charge	($0.00025)	($0.00025)	$0.00000
Storm Recovery Adjustment Factor	$0.00084	$0.00084	$0.00000
System Benefits Charge	$0.00752	$0.00752	$0.00000
Default Service Charge	$0.08702	$0.05992	($0.02710)
TOTAL	**$0.16330**	**$0.13620**	**($0.02710)**

Unitil Energy Systems, Inc.
Typical Bill Impacts - April 1, 2021 vs. June 1, 2021
Due to Changes in the Default Service Charge
Impact on OL Rate Customers *

	Nominal Watts	Lumens	Type	Average Monthly kWh	Total Bill Using Rates 4/1/2021	Total Bill Using Rates 6/1/2021	Total Difference	% Total Difference
	Mercury Vapor:							
1	100	3,500	ST	43	$18.92	$17.76	($1.17)	(6.2%)
2	175	7,000	ST	71	$25.07	$23.15	($1.92)	(7.7%)
3	250	11,000	ST	100	$30.98	$28.27	($2.71)	(8.7%)
4	400	20,000	ST	157	$41.86	$37.60	($4.25)	(10.2%)
5	1,000	60,000	ST	372	$91.02	$80.94	($10.08)	(11.1%)
6	250	11,000	FL	100	$32.15	$29.44	($2.71)	(8.4%)
7	400	20,000	FL	157	$43.36	$39.10	($4.25)	(9.8%)
8	1,000	60,000	FL	380	$87.58	$77.28	($10.30)	(11.8%)
9	100	3,500	PB	48	$19.71	$18.41	($1.30)	(6.6%)
10	175	7,000	PB	71	$24.19	$22.27	($1.92)	(8.0%)
	High Pressure Sodium:							
11	50	4,000	ST	23	$16.54	$15.92	($0.62)	(3.8%)
12	100	9,500	ST	48	$21.52	$20.22	($1.30)	(6.0%)
13	150	16,000	ST	65	$23.81	$22.05	($1.76)	(7.4%)
14	250	30,000	ST	102	$32.53	$29.76	($2.76)	(8.5%)
15	400	50,000	ST	161	$45.26	$40.90	($4.36)	(9.6%)
16	1,000	140,000	ST	380	$91.54	$81.24	($10.30)	(11.2%)
17	150	16,000	FL	65	$26.14	$24.38	($1.76)	(6.7%)
18	250	30,000	FL	102	$34.15	$31.38	($2.76)	(8.1%)
19	400	50,000	FL	161	$44.71	$40.35	($4.36)	(9.8%)
20	1,000	140,000	FL	380	$91.91	$81.61	($10.30)	(11.2%)
21	50	4,000	PB	23	$15.53	$14.91	($0.62)	(4.0%)
22	100	95,000	PB	48	$20.34	$19.04	($1.30)	(6.4%)
	Metal Halide:							
23	175	8,800	ST	74	$29.62	$27.62	($2.01)	(6.8%)
24	250	13,500	ST	102	$35.04	$32.27	($2.76)	(7.9%)
25	400	23,500	ST	158	$43.19	$38.91	($4.28)	(9.9%)
26	175	8,800	FL	74	$32.71	$30.71	($2.01)	(6.1%)
27	250	13,500	FL	102	$38.22	$35.45	($2.76)	(7.2%)
28	400	23,500	FL	158	$45.62	$41.34	($4.28)	(9.4%)
29	1,000	86,000	FL	374	$81.31	$71.18	($10.14)	(12.5%)
30	175	8,800	PB	74	$28.34	$26.34	($2.01)	(7.1%)
31	250	13,500	PB	102	$33.20	$30.43	($2.76)	(8.3%)
32	400	23,500	PB	158	$41.91	$37.63	($4.28)	(10.2%)
	Light Emitting Diode:							
33	42	3,600	AL	15	$15.13	$14.72	($0.41)	(2.7%)
34	57	5,200	AL	20	$15.84	$15.29	($0.54)	(3.4%)
35	25	3,000	CH	9	$14.29	$14.05	($0.24)	(1.7%)
36	88	8,300	CH	30	$17.24	$16.42	($0.81)	(4.7%)
37	108	11,500	CH	37	$18.22	$17.21	($1.00)	(5.5%)
38	193	21,000	CH	67	$22.41	$20.60	($1.82)	(8.1%)
39	123	12,180	FL	43	$19.05	$17.89	($1.17)	(6.1%)
40	194	25,700	FL	67	$22.41	$20.60	($1.82)	(8.1%)
41	297	38,100	FL	103	$27.45	$24.66	($2.79)	(10.2%)

Luminaire Charges For Year Round Service:

Rates - Effective April 1, 2021		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$13.28	11	$13.52	23	$19.91	33	$13.16
		2	$15.75	12	$15.22	24	$21.65	34	$13.21
	All kWh	3	$17.85	13	$15.28	25	$22.45	35	$13.11
Distribution Charge	$0.00000	4	$21.25	14	$19.14	26	$23.00	36	$13.30
External Delivery Charge	$0.03613	5	$42.19	15	$24.13	27	$24.83	37	$13.36
Stranded Cost Charge	($0.00025)	6	$19.02	16	$41.66	28	$24.88	38	$13.62
Storm Recovery Adj. Factor	$0.00084	7	$22.75	17	$17.61	29	$32.22	39	$13.41
System Benefits Charge	$0.00752	8	$37.70	18	$20.76	30	$18.63	40	$13.62
Default Service Charge	$0.08702	9	$13.41	19	$23.58	31	$19.81	41	$13.93
		10	$14.87	20	$42.03	32	$21.17		
TOTAL	**$0.13126**			21	$12.51				
				22	$14.04				

Rates - Proposed June 1, 2021		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$13.28	11	$13.52	23	$19.91	33	$13.16
		2	$15.75	12	$15.22	24	$21.65	34	$13.21
	All kWh	3	$17.85	13	$15.28	25	$22.45	35	$13.11
Distribution Charge	$0.00000	4	$21.25	14	$19.14	26	$23.00	36	$13.30
External Delivery Charge	$0.03613	5	$42.19	15	$24.13	27	$24.83	37	$13.36
Stranded Cost Charge	($0.00025)	6	$19.02	16	$41.66	28	$24.88	38	$13.62
Storm Recovery Adj. Factor	$0.00084	7	$22.75	17	$17.61	29	$32.22	39	$13.41
System Benefits Charge	$0.00752	8	$37.70	18	$20.76	30	$18.63	40	$13.62
Default Service Charge	$0.05992	9	$13.41	19	$23.58	31	$19.81	41	$13.93
		10	$14.87	20	$42.03	32	$21.17		
TOTAL	**$0.10416**			21	$12.51				
				22	$14.04				

Difference		Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.	
Customer Charge	**$0.00**	1	$0.00	11	$0.00	23	$0.00	33	$0.00
		2	$0.00	12	$0.00	24	$0.00	34	$0.00
	All kWh	3	$0.00	13	$0.00	25	$0.00	35	$0.00
Distribution Charge	$0.00000	4	$0.00	14	$0.00	26	$0.00	36	$0.00
External Delivery Charge	$0.00000	5	$0.00	15	$0.00	27	$0.00	37	$0.00
Stranded Cost Charge	$0.00000	6	$0.00	16	$0.00	28	$0.00	38	$0.00
Storm Recovery Adj. Factor	$0.00000	7	$0.00	17	$0.00	29	$0.00	39	$0.00
System Benefits Charge	$0.00000	8	$0.00	18	$0.00	30	$0.00	40	$0.00
Default Service Charge	($0.02710)	9	$0.00	19	$0.00	31	$0.00	41	$0.00
		10	$0.00	20	$0.00	32	$0.00		
TOTAL	**($0.02710)**			21	$0.00				
				22	$0.00				

* Luminaire charges based on All-Night Service option.

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Residential Rate D 650 kWh Bill

Rate Components	6/1/2020 Prior Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$16.22	$16.22	$0.00	$16.22	$16.22	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.03558	$0.03558	$0.00000	$23.13	$23.13	$0.00	0.0%
External Delivery Charge	$0.02502	$0.03613	$0.01111	$16.26	$23.48	$7.22	6.8%
Stranded Cost Charge	($0.00012)	($0.00025)	($0.00013)	($0.08)	($0.16)	($0.08)	(0.1%)
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.55	$0.55	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$4.89	$4.89	$0.00	0.0%
Default Service Charge	$0.06987	$0.07091	$0.00104	$45.42	$46.09	$0.68	0.6%
Total kWh Charges	$0.13871	$0.15073	$0.01202				
Total Bill				$106.38	$114.19	$7.81	7.3%

Regular General G2 Demand, 11 kW, 2,800 kWh Typical Bill

Rate Components	6/1/2020 Prior Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$29.19	$29.19	$0.00	$29.19	$29.19	$0.00	0.0%
	All kW	**All kW**					
Distribution Charge	$10.51	$10.51	$0.00	$115.61	$115.61	$0.00	0.0%
Stranded Cost Charge	($0.02)	($0.05)	($0.03)	($0.22)	($0.55)	($0.33)	(0.1%)
Total kW Charges	$10.49	$10.46	($0.03)	$115.39	$115.06	($0.33)	(0.1%)
	$/kWh	**$/kWh**					
Distribution Charge	$0.00000	$0.00000	$0.00000	$0.00	$0.00	$0.00	0.0%
External Delivery Charge	$0.02502	$0.03613	$0.01111	$70.06	$101.16	$31.11	7.7%
Stranded Cost Charge	($0.00002)	($0.00005)	($0.00003)	($0.06)	($0.14)	($0.08)	(0.0%)
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$2.35	$2.35	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$21.06	$21.06	$0.00	0.0%
Default Service Charge	$0.05874	$0.05992	$0.00118	$164.47	$167.78	$3.30	0.8%
Total kWh Charges	$0.09210	$0.10436	$0.01226	$257.88	$292.21	$34.33	8.5%
Total Bill				$402.46	$436.46	$34.00	8.4%

Unitil Energy Systems, Inc.
Typical Bill Impacts by Rate Component

Regular General G2 Quick Recovery Water Heating and Space Heating 1,660 kWh Typical Bill

Rate Components	6/1/2020 Prior Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$9.73	$9.73	$0.00	$9.73	$9.73	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.03204	$0.03204	$0.00000	$53.19	$53.19	$0.00	0.0%
External Delivery Charge	$0.02502	$0.03613	$0.01111	$41.53	$59.98	$18.44	8.6%
Stranded Cost Charge	($0.00012)	($0.00025)	($0.00013)	($0.20)	($0.42)	($0.22)	(0.1%)
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$1.39	$1.39	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$12.48	$12.48	$0.00	0.0%
Default Service Charge	$0.05874	$0.05992	$0.00118	$97.51	$99.47	$1.96	0.9%
Total kWh Charges	$0.12404	$0.13620	$0.01216	$205.91	$226.09	$20.19	9.4%
Total Bill				$215.64	$235.82	$20.19	9.4%

Regular General G2 kWh Meter 115 kWh Typical Bill

Rate Components	6/1/2020 Prior Rate	6/1/2021 As Revised	Difference	Current Bill	As Revised Bill	Difference	% Difference to Total Bill
Customer Charge	$18.38	$18.38	$0.00	$18.38	$18.38	$0.00	0.0%
	$/kWh	**$/kWh**					
Distribution Charge	$0.00883	$0.00883	$0.00000	$1.02	$1.02	$0.00	0.0%
External Delivery Charge	$0.02502	$0.03613	$0.01111	$2.88	$4.15	$1.28	4.3%
Stranded Cost Charge	($0.00012)	($0.00025)	($0.00013)	($0.01)	($0.03)	($0.01)	(0.0%)
Storm Recovery Adj.	$0.00084	$0.00084	$0.00000	$0.10	$0.10	$0.00	0.0%
System Benefits Charge	$0.00752	$0.00752	$0.00000	$0.86	$0.86	$0.00	0.0%
Default Service Charge	$0.05874	$0.05992	$0.00118	$6.76	$6.89	$0.14	0.5%
Total kWh Charges	$0.10083	$0.11299	$0.01216	$11.60	$12.99	$1.40	4.7%
Total Bill				$29.98	$31.37	$1.40	4.7%

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

DANIEL T. NAWAZELSKI

New Hampshire Public Utilities Commission
Docket No. DE 21-041

TABLE OF CONTENTS

LIST OF SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. Daniel T. Nawazelski, 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Lead Financial Analyst for Unitil Service Corp., a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal subsidiaries: Fitchburg Gas and Electric Light Company, Granite State Gas Transmission, Inc., Northern Utilities, Inc., and Unitil Energy Systems, Inc. ("UES" or the "Company"). 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 educational and professional background.

A. I began working for Unitil Service Corp. in June of 2012 as an Associate Financial Analyst. Since then I have held progressing positions in the Finance department and am currently Lead Financial Analyst. 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.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I will discuss the development of the 2020 UES Default Service and Renewable Energy Credits Lead Lag Study ("2020 Study"), which is integral to the calculation of cash working capital to be recovered in Default Service rates for G1 and Non-G1 customers.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony presents and supports UES' 2020 Default Service ("DS") and Renewable Energy Credits ("RECs") Lead Lag Study. The 2020 Study, presented in this filing as Schedule DTN-1, is based upon data for the period January 1, 2020 through December 31, 2020 and calculates the net lead period for G1 customers to be 23.33 days and net lead period for Non-G1 customers to be 0.50 days.

Q. Are the results of the 2020 Study included in the DS rates proposed in this filing?

A. Yes, the 2020 Study results are used to derive supply-related working capital costs included in DS rates beginning June 1, 2021, as described in the testimony of UES witness Linda S. McNamara.

IV. LEAD LAG STUDY METHODOLOGY

Q. How was the 2020 Study conducted?

A. The 2020 Study follows similar methodology as in UES' 2019 Default Service and Renewable Energy Credits Lead Lag Study ("2019 Study") that was submitted in Docket No. DE 20-039. The 2020 Study determines the number of days between the time funds are required to pay for DS purchased power and REC purchases (expense lead) and the time that those funds are available from the payment of customer bills (revenue lag). The revenue lag period includes four calculations: "receipt of electric service to meter reading", "meter reading to recording of accounts receivable", "billing to collection", and "collection to receipt of available funds". The expense lead period consists of the lead in payment of DS purchased power costs and REC costs based upon the following calculations: lead period, average days lead, weighted cost, days lead and weighted days lead. Each of these steps is explained in more detail below. UES based its 2020 Study upon data for the twelve months ended December 31, 2020, and calculated net lead lag days separately for the G1 and Non-G1 customer classes.

Q. Does the 2020 Study incorporate the requirements of the Lead Lag Settlement Letter dated July 16, 2009, under docket DE 09-009?

A. Yes, the 2020 Study conforms to the requirements specified in the Settlement Letter under Docket No. DE 09-009. The 2020 Study follows the same methodology as used in the 2009 - 2019 Studies which conform to the requirements of the Settlement.

V. 2020 STUDY RESULTS

Q. Please define the terms "lag days" and "lead days."

A. Lag days are the number of days between delivery of electric service by UES to its customers and the receipt by the Company of available funds from customers' payments (revenue lag). Lead days are the number of days between the mid-point of the energy delivery period to UES and the payment date by UES to DS suppliers or for RECs (expense lead).

Q. How is revenue lag computed?

A. Revenue lag is computed in days, consisting of four time components: (1) days from receipt of electric service to meter reading; (2) days from meter reading to recording of accounts receivable; (3) days from billing to collection; and (4) days from collection to receipt of available funds. The sum of the days associated with these four lag components is the total revenue lag. The calculations are performed separately for G1 and Non-G1 customer classes, as appropriate. Refer to Schedule DTN-1, pages 4 through 19 of 23.

Q. What is the lag period for the component "receipt of electric service to meter reading" in the 2020 Study?

A. The 2020 average lag for "receipt of electric service to meter reading" is 15.25 days. This lag was obtained by dividing the number of days in the test year (366 days) by 24 to determine the average monthly service period. This result is applicable to both the G1 and Non-G1 customer classes. See Schedule DTN-1, page 5 of 23.

Q. What is the lag period for the component "meter reading to recording of accounts receivable?"

A. The 2020 average "meter reading to recording of accounts receivable" lag is 1.01 days, which is applicable to both the G1 and the Non-G1 customer classes. This lag determines the time required to process the meter reading data and record accounts receivable. See Schedule DTN-1, pages 6 through 10 of 23.

Q. What is the lag period for the component "billing to collection?"

A. The 2020 average "billing to collection" lag is 23.95 days for G1 customers and 42.03 days for Non-G1 customers. This component was calculated separately for the G1 and Non-G1 customer groups and is derived by the accounts receivable turnover method. The lag reflects the time delay between the mailing of customer bills and the receipt of the billed revenues from customers. See Schedule DTN-1, pages 11 and 12 of 23 for G1 and Non-G1 results, respectively.

Q. What is the lag period for the component "collection to receipt of available funds?"

A. The 2020 average "collection to receipt of available funds" lag is 1.68 days. This represents the average weighted check-float period, or the lag that takes place during the period from when payment is received from customers to the time such funds are available for use by the Company. This result is applicable to both the G1 and Non-G1 customer classes. See Schedule DTN-1, pages 13 through 19 of 23.

Q. Is the total revenue lag computed from these separate lag calculations?

A. Yes. The total revenue lag of 41.89 days for G1 customers and 59.97 days for Non-G1 customers is computed by adding the number of days associated with each of the four revenue lag components described above. 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. See Schedule DTN-1, page 4, line 6.

Q. Please turn to the lead periods in the 2020 Study. In determining the expense lead period, how is the weighted days lead in payment of DS purchased power costs determined?

A. First, the monthly expense lead for each DS power supply vendor is determined by aggregating (1) the average days in the period that the energy or service is received and (2) the additional billing period including the payment day.

The aggregate lead days are then weighted by the dollar amount of the billings. Weighted days lead are calculated separately for G1 and Non-G1 customers, by supplier, and are shown in the Confidential Workpapers to the 2020 Study, Schedule DTN-2.

As of March 25, 2021, prior period adjustments made in 2021 related to 2020 were included in the calculation. Prior year adjustments made in 2020 that relate to 2019 were not included in the calculation.

Q. How is the weighted days lead in payment for RECs determined?

A. The weighted days lead in payment for RECs was determined using the same methodology applicable to DS power suppliers described above. In applying this methodology to 2020 RECs, three assumptions were made to reflect actual payment activity towards the Company's 2020 REC commitment. First, the monthly cost of the RECs was assumed to be equivalent to the estimated costs of RECs included in rates in 2020. Second, actual payment activity as of March 25, 2021 towards the Company's 2020 REC commitment was applied in chronological order to the earliest month's estimated cost. Third, a payment date of July 1, 2021 was used for all remaining 2020 REC commitments, which is the last day to obtain 2020 RECs and/or make alternative compliance payments. See Schedule DTN-1, page 21 of 23 for the REC summary related to G1 customers and page 23 of 23 for the REC summary related to Non-G1 customers.

Q. What are the combined weighted days lead in payment of DS purchased power costs and RECs for G1 and Non-G1 customers?

A. The weighted days lead for G1 customers is 65.22 days, as shown on Schedule DTN-1, page 20 of 23. The weighted days lead for Non-G1 customers is 60.47 days, as shown on Schedule DTN-1, page 22 of 23.

Q. How is the total DS and REC lead lag determined?

A. For G1 customers, the DS and REC expense lead of 65.22 days is subtracted from the lag in receipt of revenue of 41.89 days to produce the total DS and REC net lead of 23.33 days. For Non-G1 customers, the DS and REC expense lead of 60.47 days is subtracted from the lag in receipt of revenue of 59.97 days to produce the total DS and REC net lead of 0.50 days. See Schedule DTN-1, page 4 of 23.

Q. How do the results of the 2020 Study compare to the 2019 Study for G1 customers?

A. For G1 customers, the net lead in the 2020 Study of 23.33 days represents an increase of 8.50 days from the net lead in the 2019 Study of 14.83 days. The difference was driven by an increase in total DS and REC expense lead of 11.08 days offset by an overall revenue lag increase of 2.58 days.

The revenue lag component, "billing to collection" in the 2020 Study is 23.95 days compared to 21.37 days in the 2019 Study, an increase of 2.58 days. All of the other components in revenue lag net to a total change of 0.00 days in the 2020 Study compared to the 2019 Study. The combined change in all of the revenue lag components resulted in an overall revenue lag increase of 2.58 days.

The DS and REC expense lead is 65.22 days in the 2020 Study compared to 54.14 days in the 2019 Study, an increase of 11.08 days. In 2020, the DS portion of the expense lead decreased 7.92 weighted days which was driven by a decrease in the average days lead. The REC portion of the expense lead increased 19.00 weighted days which was primarily driven by an increase in the average days lead.

Q. How do the results of the 2020 Study compare to the 2019 Study for Non-G1 customers?

A. For Non-G1 customers, the net lead in the 2020 Study of 0.50 days is 15.32 days more lead than the net lag in the 2019 Study of 14.82 days. The decrease in net lag is attributable to a 16.60 day increase in the DS and REC expense lead offset by a 1.28 day increase in revenue lag.

The revenue lag component, "billing to collection" in the 2020 Study is 42.03 days compared to 40.75 days in the 2019 Study, an increase of 1.28 days. All other revenue lag components net to a change of 0.00 days in the 2020 Study compared to the 2019 Study. The net effect of all of the changes in the revenue lag components resulted in a 1.28 day increase in the 2020 revenue lag compared to 2019.

The DS and REC expense lead is 16.60 days higher in 2020 compared to 2019. In 2020, the DS portion of the expense lead decreased 1.68 weighted days which was driven by a decrease in the DS portion of total costs offset by an increase in the average days lead. The REC portion of the expense lead increased 18.28 weighted days which was driven by an increase in the average days lead as well as the REC portion of total costs.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

UNITIL ENERGY SYSTEMS, INC.

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2020

Unitil Energy Systems, Inc.
Default Service Costs and Renewable Energy Credits Lead / Lag Study
For the Period January 1, 2020 Through December 31, 2020
Summary of Results

The results of the Unitil Energy Systems, Inc. Default Service ("DS") and Renewable Energy Credits ("RECs") Lead / Lag Study ("Study") indicate a net lead period for DS and REC costs of 23.33 days for G1 Customers and a net lead period of 0.50 days for Non-G1 Customers. The procedures used to develop the Study are as follows:

I. Determination of Revenue Lag Period

The revenue lag period includes four calculations in determining the total lag – receipt of electric service to meter reading, meter reading to recording of accounts receivable, billing to collection, and collection to receipt of available funds.

A. <u>Receipt of Electric Service to Meter Reading</u>
There are 365 days in the test year January through December 2020, including one 29 day month, four 30 day months, and seven 31 day months. The weighted average day delay is 15.25 days between the time a customer receives service until the meter is read. See page 5 of this Study.

B. <u>Meter Reading to Recording of Accounts Receivable</u>
The average delay time from meter reading to recording of accounts receivable is 1.01 days. See pages 6 - 10 of this Study.

C. <u>Billing to Collection</u>
Billing to Collection lag days are determined by dividing accounts receivable sales by daily electric revenues. The daily average revenues are obtained from the monthly electric sales revenues divided by the number of days in the month. This weighted average delay period from Billing to Collection is 23.95 days for G1 customers and 42.03 days for Non-G1 customers. See pages 11 and 12 of this Study.

D. <u>Collection to Receipt of Available Funds</u>
On average, 1.68 days are required for checks deposited at the Company's banks to be considered available funds for banking transaction purposes. See pages 13 - 19 of this Study.

The sum of all revenue lag periods is 41.89 days for G1 customers and 59.97 days for Non-G1 customers. See page 4 of this Study.

Unitil Energy Systems, Inc.
Default Service Costs and Renewable Energy Credits Lead / Lag Study
For the Period January 1, 2020 Through December 31, 2020
Summary of Results

II. Determination of the Expense Lead Period

The expense lead period consists of the lead in payment of DS supplier costs and RECs, and is calculated for the G1 and Non-G1 customer classes based upon the following calculations: lead period, average days lead, weighted cost, days lead and weighted days lead.

A. Lead Period
The lead period is generally based on a montly cycle and consists of (1) the average days in the period that DS purchases were provided or RECs were required; and (2) the billing period from the end of the period up to and including the payment date. See pages 20 through 23 of the Study.

B. Average Days Lead
The bills for each G-1 and Non-G-1 DS supplier are analyzed to determine the days lead. The REC days lead are also analyzed. Average days lead is calculated by multiplying the lead period by the weighted percentage of aggregate costs. The weighted days are then totaled to obtain the average days lead period for DS suppliers and for the RECs. See pages 20 and 22 of this Study.

C. Weighted Cost
The cost of purchasing default service and RECs is divided by the total combined costs to determine a weighted cost. See pages 20 and 22 of this Study.

D. Weighted Days Lead
The weighted cost is multiplied by the average days lead to calculate the weighted days lead, resulting in 65.22 days for G1 customers and 60.47 days for Non-G1 customers. See pages 20 and 22 of this Study.

III. Summary

The results of the Study indicate a net Purchased Power lead period of 23.33 days for G1 customers and net lead period of 0.50 days for Non-G1 customers. See page 4 of this Study.

Unitil Energy Systems, Inc.
Number of Days Delay Between Receipt of Revenue and
Payment of Default Service Costs and Renewable Energy Credits
Based on 2020 Data

		G1 Customers		Non-G1 Customers	
Line No.	Descripton	Page Reference	Number of Days Delay	Page Reference	Number of Days Delay
1	Revenue Lag:				
2	Receipt of Electric Service to Meter Reading	5	15.25 days	5	15.25 days
3	Meter Reading to Recording of Accounts Receivable	6 - 10	1.01 days	6 - 10	1.01 days
4	Billing to Collection	11	23.95 days	12	42.03 days
5	Collection to Receipt of Available Funds	13 - 19	1.68 days	13 - 19	1.68 days
6	Subtotal Revenue Lag Days		41.89 days		59.97 days
7	Less: Lead in Payment of Default Service Costs and Renewable Energy Credits	20	65.22 days	22	60.47 days
8	Total Default Service and Renewable Energy Credit Lag (Line 6 Less Line 7)		-23.33 days		-0.50 days

Receipt of Electric Service to Meter Reading
Average Days Delay

January 1, 2020 to December 31, 2020 Number of Days

January	31
February	29
March	31
April	30
May	31
June	30
July	31
August	31
September	30
October	31
November	30
December	31

1 29 Day Month	1*29	29	
4 30 Day Months	4*30	120	
7 31 Day Months	7*31	217	
	Total	366	days

366 Days / 12 Months / 2 = 15.25 days

Unitil Energy Systems, Inc
Meter Reading to Recording of
Accounts Receivable

Month	Average Days
January 2020	1.02
February 2020	1.01
March 2020	1.01
April 2020	1.01
May 2020	1.01
June 2020	1.01
July 2020	1.01
August 2020	1.01
September 2020	1.02
October 2020	1.01
November 2020	1.01
December 2020	1.01
Average	1.01

Unitil Energy Systems, Inc.
Meter Reading to Recording of
Accounts Receivable
Monthly Detail

January 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	75,161	99.19%	1	0.99
2	259	0.34%	2	0.01
3	273	0.36%	3	0.01
4	48	0.06%	4	0.00
5	10	0.01%	5	0.00
6	6	0.01%	6	0.00
7	1	0.00%	7	0.00
8-14	13	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	75,771	100.00%		1.02

February 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	75,634	99.56%	1	1.00
2	193	0.25%	2	0.01
3	61	0.08%	3	0.00
4	54	0.07%	4	0.00
5	3	0.00%	5	0.00
6	1	0.00%	6	0.00
7	6	0.01%	7	0.00
8 to 14	13	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	75,965	100.00%		1.01

March 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,701	99.62%	1	1.00
2	212	0.28%	2	0.01
3	37	0.05%	3	0.00
4	17	0.02%	4	0.00
5	14	0.02%	5	0.00
6	3	0.00%	6	0.00
7	2	0.00%	7	0.00
8 to 14	1	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	75,987	100.00%		1.01

Unitil Energy Systems, Inc.
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	75,727	99.64%	1	1.00
2	190	0.25%	2	0.01
3	51	0.07%	3	0.00
4	23	0.03%	4	0.00
5	4	0.01%	5	0.00
6	-	0.00%	6	-
7	-	0.00%	7	-
8 to 14	4	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	75,999	100.00%		1.01

May 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,603	99.72%	1	1.00
2	60	0.08%	2	0.00
3	42	0.06%	3	0.00
4	10	0.01%	4	0.00
5	26	0.03%	5	0.00
6	4	0.01%	6	0.00
7	1	0.00%	7	0.00
8 to 14	70	0.09%	11	0.01
Over 14	-	0.00%	14	-
Total	75,816	100.00%		1.01

June 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,606	99.60%	1	1.00
2	141	0.19%	2	0.00
3	61	0.08%	3	0.00
4	34	0.04%	4	0.00
5	43	0.06%	5	0.00
6	21	0.03%	6	0.00
7	1	0.00%	7	0.00
8 to 14	2	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	75,909	100.00%		1.01

Unitil Energy Systems, Inc.
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	75,676	99.43%	1	0.99
2	178	0.23%	2	0.00
3	34	0.04%	3	0.00
4	134	0.18%	4	0.01
5	43	0.06%	5	0.00
6	21	0.03%	6	0.00
7	6	0.01%	7	0.00
8 to 14	14	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	76,106	100.00%		1.01

August 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,911	99.51%	1	1.00
2	281	0.37%	2	0.01
3	46	0.06%	3	0.00
4	12	0.02%	4	0.00
5	13	0.02%	5	0.00
6	8	0.01%	6	0.00
7	4	0.01%	7	0.00
8 to 14	10	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	76,285	100.00%		1.01

September 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,142	99.42%	1	0.99
2	225	0.29%	2	0.01
3	26	0.03%	3	0.00
4	57	0.07%	4	0.00
5	52	0.07%	5	0.00
6	23	0.03%	6	0.00
7	24	0.03%	7	0.00
8 to 14	36	0.05%	11	0.01
Over 14	1	0.00%	14	0.00
Total	76,586	100.00%		1.02

Unitil Energy Systems, Inc.
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	75,724	99.18%	1	0.99
2	497	0.65%	2	0.01
3	74	0.10%	3	0.00
4	38	0.05%	4	0.00
5	15	0.02%	5	0.00
6	2	0.00%	6	0.00
7	1	0.00%	7	0.00
8 to 14	2	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	76,353	100.00%		1.01

November 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,959	99.60%	1	1.00
2	221	0.29%	2	0.01
3	28	0.04%	3	0.00
4	21	0.03%	4	0.00
5	16	0.02%	5	0.00
6	3	0.00%	6	0.00
7	7	0.01%	7	0.00
8 to 14	7	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	76,262	100.00%		1.01

December 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,066	99.50%	1	0.99
2	275	0.36%	2	0.01
3	67	0.09%	3	0.00
4	24	0	4	0.00
5	4	0.01%	5	0.00
6	5	0.01%	6	0.00
7	3	0.00%	7	0.00
8 to 14	6	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	76,450	100.00%		1.01

Unitil Energy Systems, Inc. Number Of Days Lag In Billing To Collection Twelve Months Average 1/20 - 12/20 G1 Customers				
Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2020				
January	31	2,465,550	79,534	1,586,461
February	29	2,466,969	85,068	1,741,681
March	31	2,405,512	77,597	1,723,008
April	30	2,072,387	69,080	1,561,058
May	31	2,072,416	66,852	1,679,346
June	30	2,360,799	78,693	1,747,494
July	31	2,514,784	81,122	2,008,702
August	31	2,758,209	88,974	2,274,835
September	30	2,881,134	96,038	2,574,522
October	31	2,483,141	80,101	1,973,323
Novemeber	30	2,451,529	81,718	2,080,795
December	31	2,572,141	82,972	2,223,825
Total		29,504,570	967,749	23,175,049
Average		2,458,714	80,646	1,931,254
Payment Lag Days (3/2)				23.95

Unitil Energy Systems, Inc.
Number Of Days Lag In Billing To Collection
Twelve Months Average 1/20 - 12/20
Non-G1 Customers

Month	Days in Month	Electric Sales Revenues	Daily Average (1/Days)	Accounts Receivable Electric Sales
		(1)	(2)	(3)
2020				
January	31	14,208,241	458,330	16,498,235
February	29	13,440,247	463,457	17,150,801
March	31	13,012,338	419,753	17,332,855
April	30	11,072,933	369,098	15,837,737
May	31	10,592,590	341,696	15,689,278
June	30	11,880,875	396,029	17,411,870
July	31	13,092,949	422,353	17,560,174
August	31	14,411,068	464,873	19,314,747
September	30	12,634,383	421,146	18,466,431
October	31	9,901,050	319,389	15,530,629
Novemeber	30	10,319,520	343,984	15,190,474
December	31	12,841,532	414,243	17,225,217
Total		$ 147,407,727	$ 4,834,352	$ 203,208,449
Average		$ 12,283,977	$ 402,863	$ 16,934,037
Payment Lag Days (3/2)				42.03

Unitil Energy Systems, Inc.
Collection to Receipt of Available Funds

Revenue Classification by Bank

Revenue is deposited into the remittance account on the day that the revenue is recorded as received.
The following day, the bank statement reflects the prior day's bank availability of funds.

Total Lag Days from Receipt of Funds to Notification of Availability of Funds 1.00 day

Availability of Funds as reported on suceeding business day.
Source: Report on Previous Day Data, Citizens Bank

	Percent of Funds				Weighted Lag Days		
2020	Available Same Day 0 Days Lag	1 Day Float 1 Day Lag	2-Day Float 2 Days Lag	Total	1 Day	2 Days	Total
January	34%	61%	5%	100%	0.61	0.09	0.71
February	39%	57%	5%	100%	0.57	0.09	0.66
March	38%	58%	4%	100%	0.58	0.08	0.66
April	36%	59%	5%	100%	0.59	0.10	0.69
May	35%	61%	4%	100%	0.61	0.09	0.69
June	33%	62%	5%	100%	0.62	0.10	0.71
July	34%	61%	5%	100%	0.61	0.09	0.70
August	37%	58%	5%	100%	0.58	0.10	0.68
September	37%	59%	4%	100%	0.59	0.08	0.67
October	35%	60%	4%	100%	0.60	0.09	0.69
November	36%	59%	5%	100%	0.59	0.10	0.69
December	37%	59%	3%	100%	0.59	0.07	0.66

Average Weighted Lag Days for Availability of Funds 0.68 days

Summary

Total Lag Days from Receipt of Funds to Notification of Availability of Funds	1.00	day
Average Weighted Lag Days for Availability of Funds	0.68	days
Total Lag Days from Collection to Availability of Funds:	**1.68**	**days**

Unitil Energy Systems, Inc.
Remmitance Accounts

January, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	253,340	296,459	10,754	
3	72,996	170,411	13,517	
6	204,244	688,934	43,812	
7	533,373	86,435	38,854	
8	121,679	400,179	28,409	
9	7,363	172,171	18,387	
10	82,713	423,975	6,836	
13	291,390	682,527	54,224	
14	453,204	289,357	41,738	
15	182,326	242,780	8,720	
16	(6,047)	139,016	10,461	
17	70,779	114,294	4,151	
21	72,195	412,062	38,604	
22	266,554	157,817	10,197	
23	96,360	237,284	5,971	
24	90,425	95,605	5,158	
27	226,462	358,025	46,750	
28	73,181	73,635	13,165	
29	37,145	452,376	16,956	
30	86,639	210,054	19,886	
31	102,733	280,432	19,279	
	3,319,052	5,983,828	455,829	9,758,709
% of Available Funds	34%	61%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.71

February, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	96,883	580,175	74,074	
4	(11,855)	66,288	61,466	
5	(8,146)	397,668	8,408	
6	485,089	599,975	16,624	
7	146,315	291,410	22,862	
10	376,356	532,348	18,499	
11	504,634	179,412	18,899	
12	188,840	249,334	44,881	
13	(22,280)	433,595	9,432	
14	246,683	127,112	6,411	
18	34,390	292,836	17,078	
19	852,315	63,977	2,977	
20	35,645	340,704	4,411	
21	76,071	48,061	10,368	
24	335,134	411,403	36,794	
25	141,326	35,459	10,286	
26	107,848	233,570	19,276	
27	23,630	150,422	42,814	
28	54,156	374,252	7,158	
	3,663,034	5,408,001	432,718	9,503,753
% of Available Funds	39%	57%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.57	0.09	0.66

Unitil Energy Systems, Inc.
Remmitance Accounts

March, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	163,646	547,861	81,117	
3	(33,288)	99,455	49,202	
4	(659)	429,743	19,412	
5	156,415	275,586	12,332	
6	113,841	325,578	20,914	
9	249,084	883,102	23,814	
10	591,973	142,297	15,884	
11	167,234	242,430	13,350	
12	39,841	144,209	5,545	
13	105,588	156,022	3,627	
16	307,739	528,149	12,273	
17	598,236	229,231	10,032	
18	245,774	200,763	12,862	
19	9,244	87,347	10,834	
20	62,987	68,711	5,427	
23	201,195	219,905	13,844	
24	393,439	49,599	3,720	
25	117,315	199,709	5,700	
26	9,673	60,091	13,906	
27	43,356	74,025	10,831	
30	108,925	570,368	9,094	
31	3,359	42,901	9,289	
	3,654,917	5,577,082	363,009	9,595,008
% of Available Funds	38%	58%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.58	0.08	0.66

April, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	33,772	326,384	12,229	
2	54,279	134,946	29,088	
3	43,403	167,927	22,831	
6	139,606	705,627	46,454	
7	211,775	59,867	11,991	
8	279,073	433,126	28,474	
9	25,971	180,635	14,632	
10	95,246	180,313	40,334	
13	311,882	526,964	73,936	
14	385,208	71,774	37,368	
15	95,345	389,026	17,420	
16	134,955	263,229	12,464	
17	89,590	265,676	4,633	
20	241,259	464,552	27,408	
21	(17,606)	190,893	4,994	
22	658,467	226,495	3,799	
23	13,705	149,830	7,218	
24	81,596	174,103	8,250	
27	221,117	341,084	13,866	
28	157,959	36,562	8,278	
29	172,758	224,116	13,362	
30	41,809	205,796	22,166	
	3,471,168	5,718,925	461,195	9,651,288
% of Available Funds	36%	59%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.10	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

May, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	74,497	222,490	39,216	
4	62,136	644,922	36,186	
5	(26,669)	136,709	37,966	
6	228,575	368,906	38,287	
7	(14,600)	179,605	9,135	
8	105,047	170,129	9,287	
11	248,360	694,414	38,634	
12	356,645	67,189	28,180	
13	219,190	293,601	13,617	
14	4,734	135,527	5,919	
15	84,535	218,330	3,345	
18	149,202	248,906	7,038	
19	527,410	134,367	3,390	
20	186,777	405,495	7,625	
21	8,005	94,874	16,330	
22	55,631	110,401	2,992	
26	155,633	407,572	16,386	
27	263,924	22,572	8,169	
28	56,247	245,016	5,223	
29	72,889	118,729	21,601	
	2,818,166	4,919,754	348,526	8,086,446
% of Available Funds	35%	61%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.69

June, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	83,354	614,728	53,832	
2	(44,068)	50,159	38,791	
3	20,121	324,932	15,162	
4	128,178	264,775	6,800	
5	78,723	198,818	6,802	
8	262,934	608,608	43,486	
9	384,798	74,739	30,109	
10	110,236	214,454	8,444	
11	73,613	100,485	9,357	
12	74,449	126,152	28,112	
15	189,708	589,955	21,430	
16	383,433	180,841	18,635	
17	251,539	149,907	13,002	
18	57,755	338,857	9,147	
19	48,879	91,651	7,312	
22	48,759	266,000	16,413	
23	318,082	51,797	4,054	
24	91,435	431,154	2,629	
25	43,203	72,778	4,550	
26	59,755	81,477	23,204	
29	210,634	406,687	31,706	
30	(19,228)	43,647	23,356	
	2,856,291	5,282,601	416,333	8,555,225
% of Available Funds	33%	62%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.62	0.10	0.71

Unitil Energy Systems, Inc.
Remmitance Accounts

July, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	22,604	309,884	5,895	
2	28,521	199,500	8,444	
3	57,162	152,715	8,972	
6	112,634	510,198	18,501	
7	290,526	93,448	13,267	
8	210,262	311,467	14,438	
9	12,530	169,205	67,545	
10	57,906	254,111	78,957	
13	162,541	886,129	39,071	
14	421,533	190,020	11,685	
15	175,135	142,477	3,515	
16	19,047	189,438	13,946	
17	58,376	74,862	5,803	
20	208,263	356,400	20,110	
21	(7,600)	139,908	8,715	
22	722,154	182,291	10,812	
23	7,048	118,502	5,736	
24	67,761	107,775	6,003	
27	216,318	316,023	27,317	
28	138,258	103,274	12,683	
29	23,537	328,329	8,753	
30	13,151	181,011	6,914	
31	90,211	163,595	23,799	
Total	3,107,878	5,480,562	420,881	9,009,321
% of Available Funds	34%	61%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.70

August, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	100,181	745,448	37,087	
4	(29,987)	54,489	15,848	
5	58,162	280,082	7,271	
6	22,561	210,858	10,902	
7	192,037	248,079	15,173	
10	339,741	723,551	79,897	
11	429,678	94,065	64,442	
12	125,167	363,502	9,109	
13	13,998	132,254	23,658	
14	83,641	173,746	10,008	
17	224,726	527,666	18,723	
18	527,618	52,247	12,632	
19	244,447	309,989	9,047	
20	57,081	194,732	18,160	
21	74,792	119,394	6,506	
24	235,823	342,981	12,266	
25	376,141	40,098	25,965	
26	210,034	262,089	25,318	
27	(4,383)	161,644	9,722	
28	65,262	151,988	9,118	
31	267,890	427,031	47,848	
Total	3,614,610	5,615,933	468,700	9,699,243
% of Available Funds	37%	58%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.58	0.10	0.68

Unitil Energy Systems, Inc.
Remmitance Accounts

September, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(36,736)	24,176	37,004	
2	46,015	358,781	8,837	
3	26,623	326,862	16,597	
4	142,727	427,959	8,327	
8	283,243	813,025	84,185	
9	721,091	133,226	67,823	
10	(4,445)	799,184	16,999	
11	86,756	195,947	13,776	
14	216,399	709,986	40,667	
15	526,874	120,247	9,215	
16	286,411	230,099	1,998	
17	17,256	76,318	4,212	
18	82,967	68,866	3,163	
21	292,201	348,543	16,321	
22	425,617	36,897	8,518	
23	108,945	126,415	13,259	
24	56,299	132,461	6,801	
25	70,730	92,355	9,573	
28	137,481	355,680	26,265	
29	(4,793)	47,982	6,516	
30	116,563	247,694	3,267	
	3,598,225	5,672,703	403,323	9,674,251
% of Available Funds	37%	59%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.08	0.67

October, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	22,696	126,407	15,742	
2	86,063	153,413	8,534	
5	232,368	727,222	23,501	
6	126,202	33,461	47,980	
7	198,901	303,095	46,462	
8	(17,689)	483,050	19,866	
9	94,693	230,147	11,758	
13	105,752	1,205,309	13,004	
14	659,314	26,228	3,226	
15	80,650	319,890	33,622	
16	78,758	170,029	23,806	
19	197,878	372,543	58,991	
20	609,865	135,742	33,183	
21	109,884	235,703	9,625	
22	49,248	125,626	5,886	
23	75,731	177,802	7,749	
26	148,692	337,950	21,066	
27	407,060	36,330	5,125	
28	22,394	364,907	25,638	
29	69,665	225,623	6,147	
30	97,587	130,551	19,252	
	3,455,711	5,921,028	440,163	9,816,902
% of Available Funds	35%	60%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.60	0.09	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

November, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	74,895	534,179	47,083	
3	10,959	158,028	26,455	
4	203,588	193,701	6,379	
5	24,494	260,123	22,400	
6	74,887	295,117	11,220	
9	407,384	681,241	22,085	
10	503,979	102,221	51,719	
12	134,524	259,448	55,009	
13	29,921	116,285	10,594	
16	165,063	715,599	13,357	
17	506,056	267,682	6,122	
18	133,334	285,947	9,708	
19	8,391	97,318	5,974	
20	95,258	117,121	9,393	
23	133,229	223,977	29,308	
24	258,770	18,018	21,655	
25	37,465	108,454	6,673	
27	165,701	216,286	41,338	
30	(339)	172,403	20,773	
	2,967,560	4,823,148	417,245	8,207,953
% of Available Funds	36%	59%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.10	0.69

December, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	92,147	166,309	18,715	
2	45,461	207,174	4,339	
3	23,133	222,847	8,529	
4	77,905	363,613	7,004	
7	469,364	615,172	53,545	
8	261,399	77,879	43,492	
9	90,049	349,572	8,727	
10	13,440	120,491	4,431	
11	72,178	233,939	8,746	
14	274,914	419,500	12,099	
15	522,780	147,362	11,077	
16	169,636	90,751	2,489	
17	10,575	89,372	12,100	
18	50,007	66,446	11,506	
21	146,115	272,950	19,864	
22	240,207	94,609	4,403	
23	25,709	127,237	4,417	
24	63,942	165,758	6,842	
28	72,178	233,939	8,746	
29	169,313	7,864	2,782	
30	87,629	524,031	7,325	
31	88,581	260,237	8,592	
	3,066,664	4,857,052	269,770	8,193,486
% of Available Funds	37%	59%	3%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.07	0.66

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
G1 Default Service Supplier Costs	Schedule DTN-2	$ 2,896,058	89.58%	41.00 days	36.73 days
G1 Renewable Energy Credits	21	$ 336,782	10.42%	273.50 days	28.49 days
Total		$ 3,232,840	100.00%		65.22 days

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

G1	2020												
	JAN	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
RECs*													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	
Period End	1/31/2020	2/28/2020	3/31/2020	4/30/2020	5/31/2020	6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020	12/31/2020	
$ Amount	$23,090	$23,122	$23,202	$21,543	$21,638	$32,437	$35,542	$33,283	$33,625	$28,979	$26,254	$34,067	
REC Purchase Applied	($23,090)	($23,122)	($23,202)	($21,543)	($21,638)	($8,526)	$0	$0	$0	$0	$0	$0	
Net $ Amount	$0	$0	$0	$0	$0	$23,911	$35,542	$33,283	$33,625	$28,979	$26,254	$34,067	$215,661
% to Total	0.00%	0.00%	0.00%	0.00%	0.00%	7.10%	10.55%	9.88%	9.98%	8.60%	7.80%	10.12%	64.04%
Payment Date**	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	
Lead Period	532.50	503.00	472.50	442.00	411.50	381.00	350.50	319.50	289.00	258.50	228.00	197.50	
Weighted Days	-	-	-	-	-	27.05	36.99	31.58	28.85	22.24	17.77	19.98	184.46 days
REC Purchases***													
Period Begin	1/1/2020	1/1/2020	1/1/2020	2/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020	5/1/2020	6/1/2020	6/1/2020		
Period End	1/31/2020	1/31/2020	1/31/2020	2/28/2020	2/28/2020	3/31/2020	4/30/2020	5/31/2020	5/31/2020	6/30/2020	6/30/2020		
$ Amount	$7,039	$10,535	$5,516	$5,113	$18,008	$23,202	$21,543	$21,358	$280	$3,400	$5,126		$121,121
% to Total	2.09%	3.13%	1.64%	1.52%	5.35%	6.89%	6.40%	6.34%	0.08%	1.01%	1.52%		35.96%
Payment Date	7/22/2020	7/27/2020	11/4/2020	11/4/2020	12/15/2020	12/15/2020	12/15/2020	12/15/2020	1/20/2021	1/20/2021	1/27/2021		
Lead Period	188.50	193.50	293.50	264.00	305.00	274.50	244.00	213.50	249.50	219.00	226.00		
Weighted Days	3.94	6.05	4.81	4.01	16.31	18.91	15.61	13.54	0.21	2.21	3.44		89.04 days
Total $ Amount													$336,782
Weighted Days													273.50 days

* Estimated cost of RECs included in rates in 2020
** The last day to acquire 2020 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2021
*** Actual purchasing activity for 2020 RECs applied in chronological order to estimated cost of RECs included in rates in 2020

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Non-G1 Default Service Supplier Costs	Schedule DTN-2	$ 44,955,177	90.73%	37.17 days	33.72 days
Non-G1 Renewable Energy Credits	23	$ 4,592,152	9.27%	288.62 days	26.75 days
Total		$ 49,547,329	100.00%		60.47 days

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF RENEWABLE ENERGY CREDITS

NON-G1	2020												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
RECs*													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	
Period End	1/31/2020	2/28/2020	3/31/2020	4/30/2020	5/31/2020	6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020	12/31/2020	
$ Amount	$425,027	$399,864	$356,854	$329,239	$301,975	$370,423	$457,696	$430,702	$397,563	$337,636	$338,508	$446,666	
REC Purchase Applied	($425,027)	($399,864)	($356,854)	($329,239)	($71,432)	$0	$0	$0	$0	$0	$0	$0	
Net $ Amount	$0	$0	$0	$0	$230,543	$370,423	$457,696	$430,702	$397,563	$337,636	$338,508	$446,666	$3,009,737
% to Total	0.00%	0.00%	0.00%	0.00%	5.02%	8.07%	9.97%	9.38%	8.66%	7.35%	7.37%	9.73%	65.54%
Payment Date**	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	7/1/2021	
Lead Period	532.50	503.00	472.50	442.00	411.50	381.00	350.50	319.50	289.00	258.50	228.00	197.50	
Weighted Days	-	-	-	-	20.66	30.73	34.93	29.97	25.02	19.01	16.81	19.21	196.34 days
REC Purchases***													
Period Begin	1/1/2020	1/1/2020	1/1/2020	1/1/2020	2/1/2020	3/1/2020	4/1/2020	4/1/2020	5/1/2020	5/1/2020			
Period End	1/31/2020	1/31/2020	1/31/2020	1/31/2020	2/28/2020	3/31/2020	4/30/2020	4/30/2020	5/31/2020	5/31/2020			
$ Amount	$91,961	$137,638	$138,869	$56,558	$399,864	$356,854	$285,613	$43,626	$4,458	$66,974			$1,582,415
% to Total	2.00%	3.00%	3.02%	1.23%	8.71%	7.77%	6.22%	0.95%	0.10%	1.46%			34.46%
Payment Date	7/22/2020	7/27/2020	11/4/2020	12/15/2020	12/15/2020	12/15/2020	12/15/2020	1/20/2021	1/20/2021	1/27/2021			
Lead Period	188.50	193.50	293.50	334.50	305.00	274.50	244.00	280.00	249.50	256.50			
Weighted Days	3.77	5.80	8.88	4.12	26.56	21.33	15.18	2.66	0.24	3.74			92.28 days
Total $ Amount													$4,592,152

Weighted Days	288.62 days

* Estimated cost of RECs included in rates in 2020
** The last day to acquire 2020 Renewable Energy Credits and/or make alternative compliance payments is July 1, 2021
*** Actual purchasing activity for 2020 RECs applied in chronological order to estimated cost of RECs included in rates in 2020

UNITIL ENERGY SYSTEMS, INC.

REDACTED WORKPAPERS

FOR THE

DEFAULT SERVICE AND RENEWABLE ENERGY CREDITS

LEAD/LAG STUDY

FOR G1 AND NON-G1 CUSTOMERS

2020

REDACTED

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Summary					
Total G1 Default Service Supplier Costs	Detail below	$ 2,896,058	89.58%	41.00 days	36.73 days
G1 Renewable Energy Credits	Schedule DTN-1 p 21	$ 336,782	10.42%	273.50 days	28.49 days
Total		$ 3,232,840	100.00%		65.22 days
Detail for G1 Default Service Supplier Costs					
Supplier A	3	$ 1,400,766	48.37%	[redacted]	
Supplier B	4	$ 1,178,117	40.68%		
Supplier C	5	$ 317,175	10.95%		
Total G1 Default Service Supplier Costs		$ 2,896,058	100.00%		41.00 days

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

	MONTH ENERGY PURCHASES DELIVERED												
G1	2020												
SUPPLIERS	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier A													
Normal Service													
Period Begin						6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020		
Period End						6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020		
$ Amount						$ 217,203	$ 258,883	$ 263,521	$ 214,939	$ 240,153	$ 212,530		$ 1,407,228
% to Total						15.51%	18.48%	18.81%	15.34%	17.14%	15.17%		100.46%
Payment Date						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Lead Period						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
Weighted Days						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]
Prior Period Adjustments (shown in billing period in 2020)													
Period Begin						6/1/2020	7/1/2020						
Period End						6/30/2020	7/31/2020						
$ Amount						$ (338)	$ (6,125)						$ (6,463)
% to Total						-0.02%	-0.44%						-0.46%
Payment Date						[redacted]	[redacted]						
Lead Period						[redacted]	[redacted]						
Weighted Days						[redacted]	[redacted]						[redacted]
Total $ Amount	$ -	$ -	$ -	$ -	$ -	$ 216,865	$ 252,758	$ 263,521	$ 214,939	$ 240,153	$ 212,530	$ -	$ 1,400,766
Weighted Days													[redacted]

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

	MONTH ENERGY PURCHASES DELIVERED												
G1	**2020**												
SUPPLIERS	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier B													
Normal Service													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020								
Period End	1/31/2020	2/28/2020	3/30/2020	4/30/2020	5/31/2020								
$ Amount	$ 263,027	$ 227,494	$ 215,030	$ 224,149	$ 235,578								$ 1,165,277
% to Total	22.33%	19.31%	18.25%	19.03%	20.00%								98.91%
Payment Date	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Lead Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Weighted Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								[redacted]
Prior Period Adjustments													
(shown in billing period in 2020)													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020								
Period End	1/31/2020	2/28/2020	3/30/2020	4/30/2020	5/31/2020								
$ Amount	$ 2,336	$ 8,696	$ 6,173	$ (1,986)	$ (2,379)								$ 12,840
% to Total	0.20%	0.74%	0.52%	-0.17%	-0.20%								1.09%
Payment Date	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Lead Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Weighted Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								[redacted]
Total $ Amount	$ 265,363	$ 236,190	$ 221,203	$ 222,163	$ 233,199	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,178,117
Weighted Days													[redacted]

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

	MONTH ENERGY PURCHASES DELIVERED												
G1	2020												
SUPPLIERS	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier C													
Normal Service													
Period Begin												12/1/2020	
Period End												12/31/2020	
$ Amount												$ 317,175	$ 317,175
% to Total												100.00%	100.00%
Payment Date												[redacted]	
Lead Period												[redacted]	
Weighted Days												[redacted]	[redacted]
Prior Period Adjustments (shown in billing period in 2020)													
Period Begin													
Period End													
$ Amount													$ -
% to Total													0.00%
Payment Date													
Lead Period													
Weighted Days													[redacted]
Total $ Amount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 317,175	$ 317,175
Weighted Days													[redacted]

REDACTED

UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF DEFAULT SERVICE COSTS AND RENEWABLE ENERGY CREDITS

	Reference Page	Cost	% of Total	Average Days Lead	Weighted Days Lead
Summary					
Total Non-G1 Default Service Supplier Costs	see below	$ 44,955,177	90.73%	37.17 days	33.72 days
Renewable Energy Credits	Schedule DTN-1 p 23	$ 4,592,152	9.27%	288.62 days	26.75 days
Total		$ 49,547,329	100.00%		60.47 days
Detail for Non-G1 Default Service Supplier Costs					
Supplier D	7	$ 39,633,719	88.16%	[redacted]	
Supplier E	8	$ 5,321,458	11.84%		
Total Non-G1 Default Service Supplier Costs		$ 44,955,177	100.00%		37.17 days

REDACTED
UNITIL ENERGY SYSTEMS, INC
LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

NON-G1 SUPPLIERS	MONTH ENERGY PURCHASES DELIVERED 2020												
	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
Supplier D													
Normal Service													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020	6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	
Period End	1/31/2020	2/28/2020	3/30/2020	4/30/2020	5/31/2020	6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020	12/31/2020	
$ Amount	$ 6,119,440	$ 5,612,420	$ 4,241,066	$ 2,439,702	$ 3,165,415	$ 2,378,141	$ 3,030,637	$ 2,560,206	$ 1,935,720	$ 1,943,826	$ 2,424,435	$ 3,402,456	$ 39,253,464
% to Total	15.44%	14.16%	10.70%	6.16%	7.99%	6.00%	7.65%	6.46%	4.88%	4.90%	6.12%	8.58%	99.04%
Payment Date	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prior Period Adjustments (shown in billing period in 2020)													
Period Begin	1/1/2020	2/1/2020	3/1/2020	4/1/2020	5/1/2020	6/1/2020	7/1/2020		9/1/2020	10/1/2020			
Period End	1/31/2020	2/28/2020	3/30/2020	4/30/2020	5/31/2020	6/30/2020	7/31/2020		9/30/2020	10/31/2020			
$ Amount	$ 49,025	$ 32,460	$ 183,849	$ 191,550	$ 117,739	$ (62,634)	$ (123,159)		$ 14,000	$ (22,575)			$ 380,255
% to Total	0.12%	0.08%	0.46%	0.48%	0.30%	-0.16%	-0.31%		0.04%	-0.06%			0.96%
Payment Date	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]			
Lead Period	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]			
Weighted Days	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]			[redacted]
Total $ Amount	$ 6,168,465	$ 5,644,880	$ 4,424,916	$ 2,631,251	$ 3,283,154	$ 2,315,507	$ 2,907,478	$ 2,560,206	$ 1,949,719	$ 1,921,251	$ 2,424,435	$ 3,402,456	$ 39,633,719
Weighted Days													[redacted]

REDACTED

UNITIL ENERGY SYSTEMS, INC

LEAD IN PAYMENT OF ELECTRIC COSTS

DS SERVICE POWER SUPPLY CONTRACTS

	MONTH ENERGY PURCHASES DELIVERED												
NON-G1	2020												
SUPPLIERS	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**TOTAL**
Supplier E													
Normal Service													
Period Begin						6/1/2020	7/1/2020	8/1/2020	9/1/2020	10/1/2020	11/1/2020	12/1/2020	
Period End						6/30/2020	7/31/2020	8/31/2020	9/30/2020	10/31/2020	11/30/2020	12/31/2020	
$ Amount						$ 573,990	$ 739,996	$ 734,795	$ 656,280	$ 631,161	$ 700,267	$ 1,153,368	$ 5,189,857
% to Total						10.79%	13.91%	13.81%	12.33%	11.86%	13.16%	21.67%	97.53%
Payment Date						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Lead Period						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Weighted Days						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Prior Period Adjustments (shown in billing period in 2020)													
Period Begin						6/1/2020	7/1/2020		9/1/2020	10/1/2020			
Period End						6/30/2020	7/31/2020		9/30/2020	10/31/2020			
$ Amount						$ 52,394	$ 106,070		$ (23,775)	$ (3,088)			$ 131,601
% to Total						0.98%	1.99%		-0.45%	-0.06%			2.47%
Payment Date						[redacted]	[redacted]		[redacted]	[redacted]			
Lead Period						[redacted]	[redacted]		[redacted]	[redacted]			
Weighted Days						[redacted]	[redacted]		[redacted]	[redacted]			[redacted]
Total $ Amount	$ -	$ -	$ -	$ -	$ -	$ 626,384	$ 846,065	$ 734,795	$ 632,505	$ 628,073	$ 700,267	$ 1,153,368	$ 5,321,458
Weighted Days													[redacted]