 REDACTED

February 20, 2023

BY E-MAIL[1]

Daniel Goldner, Chairman
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Re: DE 22-073, Unitil Energy Systems, Inc. (Supplemental Testimony and Exhibits)

Dear Chairman Goldner:

On October 30, 2022, Unitil Energy Systems, Inc. ("Unitil" or the "Company") filed a petition requesting that the New Hampshire Public Utilities Commission (the "Commission") find the Company's proposed 4.99 megawatt photovoltaic generating facility is in the public interest (the "Project") pursuant to New Hampshire Revised Statutes Annotated ("RSA") 374-G.

In its October 30th filing, Unitil explained that, consistent with the requirements of RSA 374-G:5, I(d)6 and 374-G, II(g), it is employing a two-stage, competitive Request for Proposals ("RFP") process to select an engineering, procurement, and construction ("EPC") contractor to design and build the Project. The Company conducted a Preliminary EPC RFP in Stage 1 of the procurement process and the results of that RFP are reflected in Exhibit FDGP-1 (Benefit-Cost Analysis) to the initial filing.

On November 30, 2022, Unitil issued the Final EPC RFP and received responses on January 20, 2023. Unitil has completed its evaluation of the RFP responses and selected an EPC contractor for the Project, subject to negotiating and executing a final contract.

To provide the Commission and the parties with the most up-to-date assumptions and inputs from the Final EPC RFP, the Company has updated its Benefit-Cost Analysis and prepared the enclosed supplemental testimony to explain each update.

In addition, at the prehearing conference the Commission expressed an interest in obtaining additional information concerning potential risks associated with the Project.

[1] Pursuant to the Commission's March 17, 2020, secretarial letter, the filing is being made in only an electronic version.

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The Commission and the intervenors also expressed an interest in understanding the sensitivity of the Benefit-Cost Analysis to certain assumptions and inputs. In the interest of being responsive to these requests, the enclosed supplemental testimony and exhibits provide additional qualitative and quantitative information and analysis concerning potential Project risks, and a discussion of the ways in which Unitil is measuring, managing, and mitigating those risks.

Please do not hesitate to contact me if you have any questions regarding the enclosed materials.

Thank you for your attention to this matter.

Sincerely,

Patrick H. Taylor, Esq.

Enclosures

cc: Service List

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DG 22-073

MOTION FOR CONFIDENTIAL TREATMENT AND PROTECTIVE ORDER

Unitil Energy Systems, Inc. ("Unitil" or the "Company") respectfully requests that the New Hampshire Public Utilities Commission (the "Commission") grant protection from public disclosure of certain confidential information submitted as part of the enclosed supplemental filing in this docket pursuant to Puc 203.08 and RSA 91-A:5. Specifically, the Company requests the Commission protect from public disclosure certain confidential, proprietary, and commercially sensitive information contained in the following exhibits: Exhibit SP-1, Exhibit SP-3, Exhibit SP-4, Exhibit SP-5, Exhibit SP-6, and Exhibit SP-7 (each a "Confidential Attachment" and collectively the "Confidential Attachments"). Appendix A summarizes the specific types of confidential information in each Confidential Attachment.

I. LEGAL STANDARD

Puc 203.08(a) states that the Commission shall, upon motion, "issue a protective order providing for the confidential treatment of one or more documents upon a finding that the document or documents are entitled to such treatment pursuant to RSA 91-A:5, or other applicable law." In determining whether confidential, commercial, or financial information within the meaning of RSA 91-A:5, IV is exempt from public disclosure, the Commission applies a three-step balancing test to determine whether a document, or the information contained within it, falls within the scope of RSA 91-A:5, IV. *Northern Utilities, Inc.*, DG 17-070, Order No. 26,129 (May 2, 2018) at 15 (*citing Liberty Utilities (EnergyNorth) Natural Gas Corp.*, Order No. 26,109 (March 5, 2018) at 23). First, the Commission inquires whether the information involves a privacy interest and then asks if there is a public interest in disclosure. *Id.* Next, the Commission balances those competing interests and decides whether disclosure is appropriate. *Id.* When the information involves a privacy interest, disclosure should inform the public of the conduct and activities of its government, but if the information does not serve that purpose, disclosure is not warranted. *Id*.

II. DISCUSSION

On October 30, 2022, Unitil filed a petition requesting that the Commission find the Company's proposed 4.99 megawatt photovoltaic generating facility is in the public interest (the "Kingston Solar Project" or the "Project") pursuant to New Hampshire Revised Statutes Annotated ("RSA") 374-G. RSA 374-G requires project proponents to provide an analysis of the costs and benefits of their proposal. Accordingly, the Company prepared analyses of the costs and benefits of the Project (and accompanying testimony), which chiefly relied upon cost estimates, billing rates, and pricing information provided by third party vendors in response to a preliminary Request for Proposals ("RFP") for an Engineering, Procurement, and Construction ("EPC") contractor (the "Preliminary EPC RFP"). The Company's filing also contained a confidential and proprietary price quote for renewable energy certificates ("RECs") provided by a third party vendor. The Company's initial filing was accompanied by a Motion for Confidential Treatment and Protective Order.

After the initial filing, Unitil moved to Stage 2 of its procurement process and issued a Final EPC RFP on November 30, 2022. The Company received responses to the Final EPC RFP on January 20, 2023 and selected ReVision Energy ("ReVision") as the Project's EPC contractor, subject to negotiating and executing a final contract. The Company has revised its Benefit-Cost Analysis with updated cost, pricing, and performance estimates from the Final

EPC RFP and prepared supplemental testimony to explain, among other things, the updates to the assumptions and inputs in the Benefit-Cost Analysis. The Confidential Attachments provided as part of the Company's supplemental filing contain the confidential, proprietary, and commercially sensitive information discussed below and summarized in Appendix A.

RSA 91-A:5(IV) expressly exempts from the public disclosure requirements any records pertaining to "confidential, commercial or financial information." RSA 91-A:5, IV; *Union Leader Corp. v. New Hampshire Housing Finance Authority*, 142 N.H. 540 (1997). Application of this exemption requires "analysis of both whether the information sought is confidential, commercial, or financial information, and whether disclosure would constitute an invasion of privacy." *Unitil Corp. and Northern Utilities, Inc.*, DG 08-048, Order No. 25,014 (Sept. 22, 2009) at 2. The Commission's rule on confidential treatment of public records, Puc 203.08, also recognizes that confidential commercial or financial information may be appropriately protected from public disclosure pursuant to an order of the Commission. The determination of whether to disclose confidential information involves a balancing of the public's interest in full disclosure with the countervailing commercial or private interests for non-disclosure.

For the reasons set forth below, public disclosure would invade the privacy interests at stake in each of the Confidential Attachments, and the privacy interests substantially outweigh any public interest in disclosure. Public disclosure of the Confidential Attachments is not warranted because such disclosure is not necessary to inform the public of the conduct and activities of its government.

a. Commercially Sensitive and Confidential Cost Estimates, Pricing Information, and Proposed Contract Terms

Exhibits SP-1, SP-4, SP-5, and SP-7 contain commercially sensitive and confidential cost estimates, pricing information, and proposed contract terms.

Disclosure of the cost estimates, pricing information (and information that can be used to derive this information), and proposed contract terms provided by third-party vendors would put them at a competitive disadvantage by revealing the commercial rates they charge for materials and services on a competitive basis and the contract terms they offer for those materials and services. It also would adversely affect the Company and its customers because third-party vendors would be discouraged from responding to the Company's RFPs and negotiating with the Company if doing so would result in the release of commercially sensitive and confidential business information. This could have the effect of increasing costs to the Company, and ultimately to customers, if the Company cannot procure or negotiate for cost-effective products and services because it cannot assure confidential, protective treatment of confidential pricing information. *See Granite State Electric Company*, DE 12-023 (Mar. 27, 2021) at 9 (finding that disclosing bidder price information would likely impede the utility company's ability to engage suppliers in competitive bidding in the future, which would, in turn, make it more difficult to obtain its supply needs at competitive prices and might thereby increase rates to customers). Simply put, pricing information and contract terms must remain confidential to preserve the Company's ability to cost-effectively procure products and services for the benefit of customers.

The Company is providing redacted versions of Exhibits SP-1, SP-4, SP-5, and SP-7 for the public record. Therefore, although the Company is requesting protective treatment for the cost estimates, pricing information, and contract terms for certain components of the Project, the public will still have access to information about estimated costs, benefits and bill impacts. *See EnergyNorth Natural Gas, Inc.*, Order No. 25,064 at (Jan. 15, 2010) at 12 ("[P]ublically available versions of all the documents contain a good deal of information concerning the costs of the underlying engagements”).

The Commission has historically treated pricing information and contract terms from vendors and potential vendors as confidential. *See e.g., Northern Utilities, Inc.*, Order No. 26,710 (Oct. 24, 2022) at 5 (finding a privacy interest in the details of the costs, pricing, and negotiated terms of the contract at issue); *Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 26,166 (Aug. 1, 2018) at 6 (finding that the terms of a gas supply agreement constitute sensitive commercial information that warrant confidential treatment); *Abenaki Water Co. Inc.*, Order No. 25,945 (Sept. 26, 2016) at 7 (protecting billing rates because it could damage competitive positions to the detriment of ratepayers); *Electric and Gas Utilities*, Order No. 25,189 (Dec. 30, 2010) at 20 (finding “that the harm of public disclosure of the competitive energy efficiency labor and materials pricing and commercially sensitive contract terms outweighs the benefits of disclosure.”); *Unitil Energy Systems, Inc.*, Order No. 25,303 (April 13, 2007) at 8 (finding that disclosing information provided in response to an RFP, including pricing information, would likely hamper Unitil’s ability to engage suppliers in competitive bidding in the future, and that would, in turn, make it more difficult to meet its needs at competitive prices and might thereby increase rates to customers); *Unitil Energy Systems, Inc.*, Order No. 24,742 (April 13, 2007) at 3-5 (finding that billing rate information is properly treated as confidential.); *National Grid plc, et al.*, Order No. 24,777 (July 12, 2007) at 86 (“If public disclosure of confidential, commercial or financial information would harm the competitive position of the person from whom the information was obtained, the balance would tend to tip in favor of non-disclosure.”).

In DE 17-189, the Commission granted protective treatment for pricing information that is similar to information the Company seeks to protect in this proceeding. In DE 17-189, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("*Liberty*") sought protection for proposed pricing for various components of systems, software, and other services submitted by Sunrun, Inc. ("Sunrun") as part of an informal RFP response. *Liberty*, Order No. 26,209 (Jan. 17, 2019) at 44. The Commission found that although the public may have some interest in disclosure of Sunrun's pricing information, the public interest was outweighed by the interests of Sunrun in maintaining the confidentiality of this proprietary, commercially sensitive, and non-public information. *Id*. The same logic applies to the Confidential Attachments in this case and there is no reason for the Commission to depart from its long-established precedent in this proceeding.

b. Commercially Sensitive and Proprietary Production Profile Information

Exhibits SP-4, SP-5, and SP-6 contain commercially sensitive and proprietary production profile information.

The production profile information (e.g., hourly energy produced) provided by ReVision and presented in Exhibits SP-4, SP-5, and SP-6 was produced by a subscription-based software tool called HelioScope. The business model for this commercial solar software product relies on providing it for a fee. If the Commission ordered dissemination of the data produced by the HelioScope model to the public, then it would harm the business interests of the vendor because individuals and entities who want access to this data and proprietary analysis would not need to pay for it. Consequently, disclosure would have a chilling effect on the Company's ability to engage product and service providers because those vendors may fear that the Commission will release their proprietary work product, data, methodologies, and analyses, which would undermine their businesses. This would disadvantage the Company, to the extent that product and service providers determine in the future not to bid on the Company's RFPs because of the potential commercial disadvantages that may arise should they do so.

In the Commission's privacy analysis, the privacy interest of the Company, ReVision, and the HelioScope vendor are aligned with the public interest because if the proprietary data and analysis produced by this software is disclosed, the Company could have difficulty procuring products and services in the future. The Company's difficultly in procuring products and services would ultimately harm customers due to the increased costs to procure or develop products and services through other limited means. For example, the Company may receive fewer responses from vendors willing to provide such products and services or vendors may increase the amount charged to the Company to compensate for the risk of disclosure of their proprietary work product and analysis. At the other end of the scale, the public's interest in disclosure of the proprietary, commercial data and analysis is slight because the information at issue has no bearing on the workings of government.

The Commission has historically treated proprietary software and the data produced by that software as confidential. *See e.g.*, *Pennichuck Water Works, Inc.*, Order No. 26,726 (Nov. 18, 2022) at 3-4 (finding that a proprietary business model and software formulae in that model constitutes confidential and sensitive commercial information); *Liberty*, Order No. 26,209 (Jan. 17, 2019) at 43-44 (protecting descriptions of how the vendor's proprietary software platform operates); *Northern Utilities, Inc.*, DG 20-078, Order No. 26,385 at 11 (July 28, 2020) ("We are cognizant that the analyses and related documents are copyright protected and were provided to the Company without authority to share the information publicly. Consequently, public release of the analyses could harm the Company's ability to obtain this type of information in the future, because it could violate the terms of its agreement with the publishers and would harm the competitive interests of the publishers of the copyrighted materials if such information were provided to the public free. Those factors make the interest in nondisclosure more substantial.").

c. Commercially Sensitive and Proprietary Response to RFP

Exhibit SP-3 is ReVision's commercially sensitive and proprietary narrative response to the Company's RFP. Exhibit SP-3 has economic and commercial value because ReVision's competition could use it to their benefit and to ReVision's detriment. That economic and commercial value is critical to the short and long-term business interests of ReVision. Thus, the privacy interest in Exhibit SP-3 is significant[1] and it should be protected as confidential, in its entirety, to preserve its economic and commercial value. At the other end of the scale, the public's interest in disclosure of Exhibit SP-3 is slight because the information at issue has no bearing on the workings of government.

Although there has been considerable residential solar development in New Hampshire, the development of large, utility-scale solar projects is still in a relatively nascent stage.[2] Therefore, the manner in which ReVision structures, compiles, and presents its bid package for utility-scale solar projects has substantial economic and commercial value. If Exhibit SP-3 is not protected, other companies would be granted detailed insight into ReVision's bidding and business strategy, competitors would be able to model their bid packages after ReVision's bid package, and/or companies could distinguish their bid packages to gain an unfair competitive advantage. Consequently, public disclosure of Exhibit SP-3 would result in significant commercial harm to ReVision and could potentially undermine the developing utility-scale solar market in which the state of New Hampshire has an economic development interest.

[1] Unitil has discussed the disclosure of Exhibit SP-3 with ReVision, and ReVision has informed the Company that it considers its narrative response to the RFP to be proprietary and confidential, in its entirety.

In addition, disclosure of Exhibit SP-3 would put bidders on notice that their bids may be made public in future solicitations. Rather than risk their competitive positions in the market, prospective bidders may determine not to bid on the Company's (or other regulated utilities') RFPs. That result would deprive the Company and its customers of robust, competitive procurements for products and services. The award of economic, competitively bid contracts can only be assured if potential suppliers of goods and services are confident that their proposals will remain confidential and do not become available, either directly or indirectly, to their competitors.

The Commission has previously found that information similar to Exhibit SP-3 is competitively sensitive and confidential. *See e.g.*, *Pennichuck Water Works, Inc.*, Order No. 26,726 (Nov. 18, 2022) at 3-4 (finding that a proprietary business model and software formulae in that model constitutes confidential and sensitive commercial information); *Liberty*, Order No. 26,376 (June 30, 2020) at 14 (finding that the consultant's work product was unlikely to inform the public of the Commission's regulatory activities and should be protected); *Liberty*, Order No. 26,209 (Jan. 17, 2019) at 43-44 (protecting descriptions of how the vendor's proprietary software platform operates); *Abenaki Water Company*, Order No. 25,840 (Nov. 13, 2015) at 2-3 (finding Abenaki's consultant has a privacy interest in his spreadsheets because they are his work product and could be used by competitors to his commercial disadvantage); *North Atlantic Energy Corporation*, Order No. 23,986 (June 5, 2022) at 10 ("[P]ublic disclosure of bids, bid analyses, financial assessments, and data related to the auction would chill future auction transactions, thereby limiting the results that might otherwise have been achieved."). There is no reason for the Commission to depart from past practice in this case.

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[2] *See* Exh. KES-1, at Bates pages 000006-000008.

Pursuant to Puc 201.04(b), all information within a document asserted to be confidential must be redacted. However, because the Company is seeking to protect Exhibit SP-3 in its entirety, a redacted version would have little to no practical value. Accordingly, the Company respectfully requests, pursuant to Puc 201.05, that the Commission waive the requirement to produce a redacted version of Exhibit SP-3.

d. Commercially Sensitive and Confidential REC Price Quote

Exhibit SP-7 contains a REC price quote from a price sheet provided to the Company by a third-party REC broker. The price sheet is copyright protected.

The REC price information has commercial value to the third-party REC broker. If the REC price was disclosed in this proceeding, it would impair the commercial value of that information because parties would have free and unrestricted access to that information. Thus, the REC broker plainly has a privacy interest in this information.

The Commission has previously determined that the public's interest in copyrighted, proprietary and confidential information was not as weighty as the countervailing interest in non-disclosure:

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

Northern Utilities, Inc., DG 20-078, Order No. 26,385 (July 28, 2020) at 11.

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

In summary, on balance, the substantial interest in obtaining cost-effective products and services from third-party vendors significantly outweighs the interest in public disclosure. Accordingly, a ruling in favor of this balance and granting this motion is in the best interest of customers. *See EnergyNorth Natural Gas, Inc.*, Order No. 25,064 (Jan. 15, 2010) at 12 (finding that disclosure of billing rate information may place the Company and its service providers at a disadvantage with respect to those with whom it would do business, ultimately causing harm to the Company's ratepayers in future rate cases).

III. CONCLUSION

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

WHEREFORE, Unitil respectfully requests that the Commission:

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

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

Respectfully Submitted,

UNITIL ENERGY SYSTEMS, INC.

By:

Matthew C. Campbell
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842
603-773-6543
campbellm@unitil.com

Dated: February 20, 2023.

CERTIFICATE OF SERVICE

I hereby certify that on this 20th day of February 2023, a copy of the foregoing Motion was electronically delivered to the Service List for this proceeding.

Matthew C. Campbell

APPENDIX A
SUMMARY OF CONFIDENTIAL INFORMATION IN THE CONFIDENTIAL ATTACHMENTS

Exhibit Number	Description of Exhibit	Description of Confidential Information
Exh. SP-1	Joint Testimony of Solar Panel	• Price for purchase of real estate • Estimated capital costs for Project construction provided in response to Preliminary EPC RFP and Final EPC RFP • Estimated O&M costs provided in response to Final EPC RFP • Estimated cost for decommissioning the Project provided in response to Final EPC RFP • REC quote provided by REC broker
Exh. SP-3	EPC contractor response to Final EPC RFP (narrative response)	• The structure, compilation, and presentation of the RFP response, in its entirety.
Exh. SP-4	EPC contractor response to Final EPC RFP (pricing and performance sheet)	• Estimated capital costs for Project construction • Estimated costs for spares • Estimated O&M costs • Production profile information
Exh. SP-5	EPC contractor response to RFP – related questions	• Contract terms • Estimated replacement cost for Project components • Estimated decommissioning cost • Production profile information • Construction support budget • Budget for pre-construction activities
Exh. SP-6	Peak Hour Calculation	• Production profile information
Exh. SP-7	Benefit-Cost Analysis Model	• Estimated capital costs for Project construction provided in response to Final EPC RFP and information that can be used to derive these costs • Cost for Site Due Diligence, Design and Permitting provided by the winning bidder • Price for purchase of real estate and information that can be used to derive the purchase price • Estimated replacement cost for inverters provided in response to Final EPC RFP • Price for appraisal services • Estimated O&M cost provided in response to Final EPC RFP • REC quote provided by REC broker and information that can be used to derive that price

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UNITIL ENERGY SYSTEMS, INC.

JOINT SUPPLEMENTAL TESTIMONY

OF

KEVIN E. SPRAGUE

JACOB S. DUSLING

ANDRE J. FRANCOEUR

TODD R. DIGGINS

CHRISTOPHER J. GOULDING

JEFFREY M. PENTZ

(Kingston Solar Project Panel)

Exhibit SP-1 (Supplemental)

New Hampshire Public Utilities Commission

Docket No. DE 22-073

February 20, 2023

Table of Contents

Exhibits:

I. INTRODUCTION

Q. Please introduce the members of the Kingston Solar Project Panel.

A. The members of the Kingston Solar Project Panel ("SP") and the sponsors of this Supplemental Testimony are Kevin E. Sprague, Jacob S. Dusling, Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz on behalf of Unitil Energy Systems, Inc. ("Unitil" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. We submitted direct testimony (individually and jointly) to the New Hampshire Public Utilities Commission (the "Commission") on October 31, 2022, in support of the Company's proposed 4.99 megawatt ("MW") alternating current ("AC")[1] utility-scale photovoltaic ("PV" or "solar") generating facility located in Kingston, New Hampshire (the "Kingston Solar Project," or the "Project"). We also appeared at the Commission's prehearing conference on January 18, 2023 and the technical session that followed immediately thereafter.

Q. Why is the Company filing Supplemental Testimony?

A. At the January 18, 2023 prehearing conference, the Commission expressed an interest in obtaining additional information concerning potential risks associated with the Kingston Solar Project. The Commission and intervenors also expressed

[1] Solar cells produce direct current ("DC") electricity, which is then converted to AC electricity by a solar power inverter, which allows the electricity to be delivered to the electric distribution system. The Project assumptions in both the initial filing and this supplemental update for system capacity are based on the proposal identified as the best overall value in each stage of the Company's two-stage competitive solicitation. As discussed herein, the updated design for the Project is 6.50 MW (DC) / 4.88 MW (AC).

an interest in understanding the sensitivity of the Benefit-Cost Analysis to certain assumptions and inputs. That interest is consistent with New Hampshire Revised Statutes Annotated ("RSA") 374-G:5 which requires, among other things, a discussion of the potential risks associated with a proposed project. Accordingly, this Supplemental Testimony provides additional qualitative and quantitative information concerning potential project risks, and a discussion of the ways in which Unitil is measuring, managing, and mitigating those risks.

In addition, Unitil explained in its initial filing that it planned to issue a final Engineering, Procurement and Construction ("EPC") Request for Proposals ("RFP") based on responses to its Preliminary EPC RFP.[2] As discussed in Section II, the Company has received and evaluated responses to its Final EPC RFP and has selected a winning bidder. Accordingly, the Company has revised its Benefit-Cost Analysis with updated cost and performance estimates drawn from the winning Final EPC RFP proposal. Our Supplemental Testimony explains how that information has been reflected in the Company's updated Benefit-Cost Analysis.

Based on updated information and analyses discussed throughout our testimony, the Project is highly likely to create positive net benefits for customers in particular, and the State of New Hampshire in general. That is the case looking solely at direct

2 Exh. JSD-1, at Bates pages 000051-000053.

benefits; it is even more so considering indirect benefits.[3] In keeping with the Company's proposed two-stage process,[4] the updated information and analyses further support the Company's request for a Commission finding that the Project is in the public interest.

Q. How is the balance of your testimony organized?

A. The remainder of our testimony is organized as follows:

- Section II updates the status of the EPC RFP process;
- Section III discusses the specific updates to the Benefit Cost Analysis, explains the increased Benefit-Cost ratio in the context of those updates, and provides an updated Bill Impact analysis;
- Section IV presents the stress test and a simulation analysis the Company performed to quantitatively assess Project risk; and
- Section V summarizes and concludes our testimony.

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[3] *See generally* Exhs. GPP-1 and GPP-2 (quantifying \$11.2 million (on an NPV basis) of direct, indirect, and induced economic benefits to New Hampshire, \$1.9 million (on an NPV basis) in avoided CO2 and NOx benefits, and \$566,963 in aggregate Demand Reduction Induced Prices Effects (DRIPE) benefits to New Hampshire load).

[4] Exhibit KES-1, at Bates pages 000033-000035.

II. STATUS OF THE EPC RFP PROCESS

Q. Please summarize the status of Unitil's EPC RFP process.

A. As discussed in our initial testimony, the Company conducted a Preliminary EPC RFP in Stage 1 of the procurement process,[5] the results of which are reflected in Exhibit FDGP-1 (Benefit-Cost Analysis) to the initial filing. After the initial filing, Unitil moved to Stage 2 of the procurement process and, on November 30, 2022, issued the Final EPC RFP (Exhibit SP-2). The Company received responses to the Final EPC RFP on January 20, 2023.

Q. Has the Company completed its evaluation of the Final EPC RFP proposals and did it select an EPC contractor?

A. Yes, Unitil has completed its evaluation and ReVision Energy's ("ReVision") proposal provided the best overall value and scored the highest of all the responses received.[6] Therefore, Unitil has selected ReVision as its EPC contractor for the Kingston Solar Project, subject to negotiating and executing a final contract.

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[5] Exhibit JSD-1, at Bates pages 000051-000052.

[6] Each proposal was evaluated and ranked on a quantitative and qualitative basis by criteria that included but was not limited to: Overall company background, history and key characteristics; Experience with similar sized PV projects; Ability to comply/meet the components of the RFP; Ability to execute the work as evidenced by the project execution plan and schedule; Overall pricing proposal; Major equipment warranty periods; Origin of manufacture of major equipment; and Involvement of local businesses and/or local labor.

III. UPDATED BENEFIT-COST ANALYSIS AND BILL IMPACTS

A. Updates to Assumptions and Inputs in the Benefit-Cost Analysis

Q. Please summarize the updates that have been made to the Benefit-Cost Analysis.

A. As summarized in Table 1 below, Unitil has updated and added new assumptions and variables to the Benefit-Cost Analysis (Exhibit SP-7) in five general categories: (1) Capital Costs; (2) Expenses; (3) Performance Characteristics; (4) Avoided Customer Cost Inputs; and (5) Federal Tax Credit.

Table 1: Summary of Updates to Benefit-Cost Analysis

Category	Update
Capital Costs	Initial Capital Costs Inverter Replacement Cost Capital Replacement Costs
Expenses	Operating & Maintenance ("O&M") Expense
	Decommissioning Expense
Performance Characteristics	Project Life (30-Year Project Life to 40-Year Project Life)
	Nameplate Capacity and Degradation Rate
	Annual Production (kWh)
	Capacity at Peak Hour (kW Monthly & Annual)
Avoided Customer Cost Inputs	Energy Rate Futures
	ISO-New England ("NE") Open Access Transmission Tariff ("OATT") Rates Where Applicable
Federal Tax Credit	From Investment Tax Credit to Production Tax Credit

The following sections discuss the updates to each of the five general categories.

Capital Costs

Q. Please summarize the updates that have been made to the capital costs and the purpose for those updated inputs and assumptions.

A. The updates that have been made to capital costs in the Benefit-Cost Analysis are summarized in Table 2, below.

Table 2: Summary of Updates to Capital Costs

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
Initial Investment Cost	Reflect updated costs provided in ReVision's RFP response Reflect refinements to System Upgrade and Land Acquisition Costs	"Capital Costs"
Inverter Replacement Cost	Reflect updated costs and timing of replacement provided in ReVision's RFP response	"Capital Costs"
Capital Replacement Cost Funding	Add capital costs for replacement of equipment based on information provided by ReVision	"Maintenance Capital Costs"

Q. How do the capital investment costs received in the Final EPC RFP compare to those received in the Preliminary RFP?

A. As shown in Table 3 (below), the updated capital costs provided in response to the Final EPC RFP are generally consistent with the total costs provided in response to the Preliminary EPC RFP.

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Table 3: Comparison of Capital Costs (Preliminary EPC RFP vs. Final EPC RFP)

Initial Capital Cost Element	Estimated Cost (Preliminary EPC RFP)[7]	Estimated Cost (Final EPC RFP)
PV Installation (Includes Inverter 1)	[redacted]	[redacted]
Electric System Upgrades	$600,000	$560,000
Land Improvements	[redacted]	[redacted]
Land Acquisition[8]	$857,938	$820,438
TOTAL	[redacted]	[redacted]

Q. Has the Project's Benefit-Cost ratio decreased as a result of the increased costs summarized in Table 3?

A. No, it has not. Rather (and as discussed below and in Section III.B), the combination of higher costs and increased benefits resulted in an increased Benefit-Cost ratio.

Q. Please provide additional detail regarding the updates to the initial capital costs summarized in Table 3.

A. First, the total PV installation cost increased by less than $700,000, about a 5 percent variance. This relatively modest increase is driven by changes to the design of the Project, which enhance overall reliability, production, and performance, and all of which translate into increased customer benefits. Second, the increase in the Inverter Replacement cost is driven by a higher estimated cost for the equipment, due largely to the change in the design from the initial filing (i.e., using a string inverter design instead of central inverters)[9] and moving the replacement year from Year 15 to Year

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[7] Exh. FDGP-2 (CONFIDENTIAL), "Capital Costs" tab.

[8] Assumes 50 percent of total Land Acquisition Costs are allocated to the Kingston Solar Project.

[9] A string inverter design typically requires more inverters because each, individual inverter is converting less power for fewer PV modules. A central inverter design, on the other hand, requires a smaller number of total inverters because each, individual inverter is larger and converting power for a greater number of PV modules. Generally speaking, although the string inverter design being proposed for the Kingston Solar Project is more expensive than the central inverter design utilized in the initial filing, it helps mitigate production risk because if one string fails, the electricity output for the entire array is not lost, only the power being converted from the PV modules associated with that string.

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20 based on ReVision's guidance. Third, the Company made a downward adjustment to its estimated cost for system upgrades based on the estimate for the System Impact Study in ReVision's proposal. Lastly, the Company updated the land acquisition costs to reflect the lower agreed upon purchase price [redacted] for the property based on its appraised value.

Q. Please describe the purpose of the Capital Replacement Costs added to the Benefit-Cost Analysis and how the Company developed its estimate.

A. Apart from the inverters, Unitil's initial Benefit-Cost Analysis did not include costs for future capital replacements ("Maintenance Capital Costs"). Upon further analysis, the Company concluded that it is prudent and a more conservative approach to account for the replacement of equipment to avoid lost production outside of the warranty period. Accordingly, the Company updated its Benefit-Cost Analysis to include Maintenance Capital Costs for PV modules and the racking system.

As shown on the tab "Maintenance Capital Costs" in Exhibit SP-7, the Company estimates a Maintenance Capital Cost for PV modules and associated equipment of [redacted] beginning in Year 26, which escalates to an annual amount of [redacted] in Year 40. For racking, the Company estimates a Maintenance Capital Cost of [redacted] beginning in Year 21, which escalates to an annual amount of [redacted] in Year 40.[10]

[10] As shown on the tab "Maintenance Capital Costs" in Exhibit SP-7, the Company applied a 2 percent escalation rate to the estimated maintenance capital costs.

The Company also added Schedule 11, which was not included in the initial Benefit-Cost Analysis, to Exhibit SP-7. Schedule 11 calculates tax depreciation for the Maintenance Capital which was necessary due to the large number of cost vintage years.

The Company developed its estimate for Maintenance Capital Costs based on input from ReVision (*see* Exhibit SP-5, response to Question 3). That data indicates that the failure rate of racking, modules, and inverters (and other components) is extremely low, with a fraction of 1 percent of components requiring service in a given year. Taking that information into account, the Company assumed replacement costs of 0.5 percent of the original cost for modules and racking for the first ten years after the applicable warranty periods (*i.e.*, years 26 through 35 for modules and years 21 through 30 for racking). Thereafter, the Company assumed replacement costs of 1 percent of the original cost for years 36 to 40 for modules and years 31 to 40 for racking after the warranty period. In total, the Company has included Maintenance Capital Costs of approximately $2 million over the life of the project.

Expenses

Q. Please summarize the updates that have been made to expenses and the basis of those updates.

A. The updates that have been made to expenses in the Benefit-Cost Analysis are summarized in Table 4, below.

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Table 4: Summary of Updates to Expenses

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
Maintenance O&M Expense	Reflect ReVision's RFP Response	"O&M Expense"
Decommissioning Expense	Add decommissioning expense based on estimate provided by ReVision in RFP process	"Decommissioning Expense"

Q. What is driving the update to the estimate for Maintenance Expense?

A. As shown in Exhibit FDGP-2, Schedule 3 of Unitil's initial filing, based on a response to the Preliminary EPC RFP, the Company estimated an O&M cost of [redacted] in Year 1. The Company adjusted that estimate for inflation over the balance of the Project's expected 30-year design life. The Company revised its O&M estimate based on information provided by ReVision in response to the Final EPC RFP. The revised estimate is [redacted] starting in Year 1 for vegetation management with additional maintenance costs of [redacted] beginning in Year 6 to continue the inspection, monitoring, and maintenance contract.[11] As shown on the tab "Capital Costs" in Exhibit SP-7, the first five years of O&M are included in the initial capital costs.

Q. Please now explain the purpose of the Decommissioning Expense and how the Company developed its estimate.

A. The Company did not include an estimate for decommissioning expense in its initial Benefit-Cost Analysis because the guidance it received in the Preliminary EPC RFP

[11] The Company assumed O&M expense will escalate at 2 percent annually based on ReVision's proposal (*see* Exh. SP-4).

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was that salvage value would exceed decommissioning costs. However, upon further consideration, the Company determined that it would be prudent and a more conservative approach to include decommissioning expenses in its model. Unitil therefore requested that ReVision provide an estimate of decommissioning costs as part of the Final EPC RFP bid process (*see* Exh. SP-5).

As explained by ReVision, given the low volume of solar arrays that have reached or are approaching the end of their useful life, and the steady advances being made in solar panel recycling, it is not possible to provide a firm estimate of decommissioning costs at this time. Nonetheless, based on its analysis of numerous decommissioning agreements in the public domain for megawatt-scale solar arrays in Massachusetts and Vermont that were approved by municipal Planning Boards, ReVision recommended a conservative estimate of [redacted] for decommissioning the Project. The Company has incorporated ReVision's estimate of [redacted] (current dollars) into the Benefit-Cost Analysis and escalated this value by 2 percent over the life of the Project to estimate the future decommissioning cost of [redacted]. The analysis includes [redacted] as an annual decommissioning expense (spread evenly over the Project's estimated life) as a component of the revenue requirement.

Performance Characteristics

Q. Please summarize the updates that have been made to the Project's performance characteristics and the purpose for those updated inputs and assumptions.

A. The updates to the Project's performance characteristics in the Benefit-Cost Analysis are based on ReVision's response to the Final EPC RFP and are summarized in Table 5 below.

Table 5: Summary of Updates to Performance Characteristics

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
30-Year Project Life to 40-Year Project Life	Reflect ReVision's RFP Response	*All*
Capacity Nameplate and Degradation Rate	Reflect ReVision's RFP Response	"Direct Customer Benefits"
Annual Production (kWh)	Reflect ReVision's RFP Response	"Direct Customer Benefits"
Capacity at Peak Hour (kW Monthly & Annual)	Reflect ReVision's RFP Response	"Direct Customer Benefits"

Q. Please provide additional detail regarding the updates to the inputs for the Project life, system capacity, and degradation rate.

A. The assumptions in both the initial filing (based on the Preliminary EPC RFP) and this update (based on the Final EPC RFP) for Project life, system capacity, and degradation rates are based on the proposal identified as the best overall value in the Preliminary EPC RFP and the Final EPC RFP, respectively. The components, design, and the engineering inputs in the updated Benefit-Cost Analysis (Exh. SP-7) reflect ReVision's proposal.

Table 6: Updates to Design Characteristics

Input	**Input (Initial Filing)**	**Input (Supplemental Filing)**
Expected Life of Project	30 years	40 years
System Capacity	6.15 MW (DC) / 4.99 MW (AC)	6.50 MW (DC) / 4.88 MW (AC)
Degradation Rate	0.5% reduction from Year 1 to Year 2 (0.5%) annually	2% reduction from Year 1 to Year 2 (0.5%) annually
Capacity Factor	21.96%	22.78%
Capacity at Peak Hour (kW – Annual)	37.1%	48.8%
Capacity at Peak Hour (kW – Monthly)	12.0%	16.8%

The increase in capacity factor and estimated production at the peak hours is due to several factors. First, the DC capacity of the system is greater than originally proposed for a smaller AC capacity. This increases output during non-peak production hours, allowing the system to produce more AC output throughout the production hours. Second, the proposed tracking system in the ReVision design has a 120 (+/-60) degree range of motion opposed to a 110 degree range of motion. This provides additional output in the early morning and later evening hours.

The Year 1 degradation rate changed because the PV modules (and the attendant performance characteristics and specifications) assumed in the Company's initial filing is different than those provided in ReVision's proposed design.

Q. Please provide additional detail regarding the updates to annual Production (kWh) and capacity at the Peak Hour (kW Monthly and Annual).

A. The estimated capacity factor and the associated production at the peak hours is drawn from ReVision's analysis using the HelioScope tool that considers the characteristics of the specific equipment being proposed (*i.e.*, inverters, solar panels, tracking system, etc.), local historical weather conditions (Concord, New Hampshire), and specific sources of system losses (*i.e.*, inverters, wiring, temperature, soiling, shading, etc.) (*see* Exhs. SP-3; SP-6).

Avoided Customer Cost Inputs

Q. Please summarize the updates to avoided customer cost inputs, and the purpose for those updates.

A. Updates to the avoided customer cost inputs are summarized in Table 7 below.

Table 7: Summary of Updates to Customer Cost Inputs

Update	Purpose	Tab in Benefit-Cost Analysis Model (Exh. SP-7)
ISO NE OATT Rates Where Applicable	Use most up-to-date ISO-NE OATT rates where applicable	"Direct Customer Benefits"
Updated Energy Futures	Using more recent ISO-NE Futures	"Direct Customer Benefits"

Q. What is driving the updates to the avoided customer cost inputs summarized in the table above?

A. The Company updated the analysis to ensure the direct customer benefits are calculated using the most up-to-date ISO-NE OATT rates as shown in Table 8 below.

Table 8: Updates to Regional Transmission Rates

Rate	Initial Benefit-Cost Analysis	Supplemental Benefit-Cost Analysis
ISO-NE Section 4A, Schedule 1 Rate ($ kW-Mo.)	$0.1918	$0.2048
ISO-NE Section 4A, Schedule 5 Rate ($ kW-Mo.)	$0.0074	$0.0070
ISO-NE Section 2, Schedule 1 Rate ($ kW-Mo.)	$0.1459	$0.1459
ISO-NE Section 2, Schedule 9 Rate ($ kW-Mo.)	$11.7453	$11.7453

Similarly, the Company updated its energy rates assumption with a more recent, lower (February 2023) futures forecast.

Federal Tax Credits

Q. Please provide an overview the federal tax credits available pursuant to the Inflation Reduction Act ("IRA").

A. The IRA extended federal tax credits for solar electricity production facilities beginning construction before January 1, 2025. There are two categories of tax credits available under the IRA. The Production Tax Credit ("PTC") provides a corporate tax credit for each kilowatt-hour of electricity produced by a qualifying facility for the first 10 years of operations. There is also an Investment Tax Credit ("ITC"), which provides a corporate tax credit of up to 30 percent of the installed cost of qualified facilities.[12] Stated simply, the PTC is earned over time based on production whereas the ITC is earned when the facility goes into service. Solar projects have a choice between the ITC and the PTC; developers cannot use both.

[12] Projects that satisfy a domestic content requirement are entitled to a 10 percent bonus credit. To qualify for this bonus, the taxpayer must certify that the steel or iron used in the project is produced in the United States and a "required percentage" of the total costs of manufactured products (including components) of the facility are mined, produced, or manufactured in the United States.

Q. What is the rationale for the normalization rules and what are the consequences of violating them?

A. Generally speaking, normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of ITCs in accordance with the Internal Revenue Code of 1986, as amended. The normalization rules dictate that the benefit of the federal tax credits must be passed back to customers ratably over the life of the investment that produces the credits.

There are two principles underpinning the Internal Revenue Service ("IRS") Normalization Rules. First, Congress wanted to preserve the utility's incentive to invest, and ensure that the ITC was not purely subsidizing the services provided by the utility. IRS Normalization Rules ensure both shareholders and customers benefit from the ITC.

The second principle is to protect the government's tax revenue. If the utility immediately lowered rates for the ITC without normalization, the federal government would experience lower income tax revenue. In such a case, the federal government would be losing tax revenue both for the ITC and lower income due to lower distribution rates.[13]

Violating the normalization rules results in the loss of income tax deductions such as accelerated depreciation or the recapture of tax credits, eliminating tax benefits available including accumulated depreciation.

[13] *See* 2017-38 I.R.B. (Sept. 18, 2017), *available at* https://www.irs.gov/pub/irs-irbs/irb17-38.pdf.

Q. Please describe the Company's modified approach to the federal tax credits.

A. Upon further analysis, the Company revised its approach to assume the PTC rather than the ITC because, as explained below, the PTC is expected to improve the overall economics of the Project from the perspective of customers.[14]

Q. Why would applying the PTC, as compared to the ITC, potentially enhance the Project's net benefits?

A. Unlike the ITC, the PTC is not subject to IRS Normalization rules. This means the PTC can be used to offset the revenue requirement, including a tax gross up, as it is earned. This has the effect of front-loading the benefits of the tax credits relative to the ITC which, under normalization rules, is flowed back to customers evenly over the Project's life. In short, under the PTC approach customers are able to realize a greater time value of money benefit than compared to the ITC approach.

Q. Will the Company continue to consider options to maximize the value of federal tax credits?

A. Yes. As discussed in our initial testimony,[15] the IRA allows companies to transfer the ITC to other taxpayers in exchange for cash. However, final guidance from the IRS regarding these new ITC provisions has not yet been published. In the meantime, Unitil will continue to investigate options to ensure customers receive the maximum economic value from the federal tax credit.

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[14] In both the initial and supplemental Benefit-Cost Analyses, the federal tax credit is included in the Net Present Value ("NPV") by flowing back the credit and associated benefits through the annual revenue requirement, thereby decreasing the revenue requirement.

[15] Exhibit FDGP-1, at Bates pages 000189-000190.

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B. <u>Results of Updated Benefit-Cost Analysis</u>

Q. Does the Company believe the assumptions and inputs used in the Benefit-Cost Analysis are reasonable and conservative?

A. Yes. The base inputs and assumptions in the Benefit-Cost Analysis represent the Company's best estimates and the process the Company employed to develop those estimates is reasonable and conservative. Specific examples of the Company's conservative approach include:

- The inputs and assumptions in the Benefit-Cost analysis are thoroughly documented and based on objective, third-party data and sources:
    - The capital cost, O&M expense, decommissioning cost, Maintenance Capital Costs, performance characteristics, and energy production estimates are based on ReVision's proposal, which was developed and submitted through a competitive solicitation process.
    - Avoided transmission costs are based on ISO-NE Tariff rates.
    - The Company used the "ISO New England MASS HUB 5 MW 5 LMP Futures" to extrapolate electricity prices for the first four years of the Project and escalated these prices beginning in Year 5 by the long-run annual growth rate included in Energy Information Administration's 2022 Annual Energy Outlook for end-use prices.
- The Renewable Energy Certificates ("REC") price assumption is based on the New Hampshire Class II REC for the 2023 term. The [redacted] REC price is a conservative estimate given the current Alternative Compliance Payment rate of

$61.18 for compliance year 2023. Increases in future market demand associated with increasing electrification may result in higher demand for Class II RECs as retail electric sales increase. In addition, the estimated REC pricing is valued in 2023 dollars and not escalated by an inflation factor, such as the Consumer Price Index. To the extent RECs are susceptible to inflation, the potential REC value may be significantly higher in future years.

- There is a 10 percent bonus tax credit if a Project meets the domestic content requirements (*i.e.*, all steel or iron used must be produced in the United States and a "required percentage" of the total costs of manufactured products need to be mined, produced, or manufactured in the United States). Although the Project may be eligible for this bonus tax credit, the Company has not included it in the Benefit-Cost Analysis.
- When calculating estimated peak output, the Company looked to historical peak hours from 2012 to 2021 and did not include years prior to 2012 as this would have inflated the calculation due to the ISO-NE peak shifting later in the day after 2011 (*see* Exh. SP-6).
- The Company has not included indirect benefits in the Benefit-Cost Analysis. When indirect benefits are considered, the Project's already positive net benefits are meaningfully enhanced supporting a finding that the Project is in the public interest.

On balance, the Company believes its Benefit-Cost Analysis is based on reasonable and conservative assumptions.

Q. Please summarize the results of the Company's updated Benefit-Cost Analysis.

A. As shown in Exhibit SP-7, the present value of the Project's benefits is approximately $19.3 million and the present value of the costs is approximately $16.7 million. This produces a net present value benefit of $2.5 million with a Benefit-Cost ratio of 1.15, a meaningful increase relative to the NPV of $1.4 million and Benefit-Cost ratio of 1.09 presented in the Company's initial filing. To be clear, the updated Benefit-Cost ratio (*i.e.*, 1.15) does not include either indirect benefits, or the option value of potential energy storage.

Table 9 below summarizes the respective contributions to the Benefit-Cost ratio and NPV generated by the updates to key assumptions and inputs in the Benefit-Cost Analysis.

Table 9: Respective Contributions to Benefit-Cost Ratio and NPV

	NPV[16]	BCR[17]	Description
	$1.4	**1.09**	
Federal Tax Credit	$1.1	0.08	Switch from ITC to PTC
Peak Output	$1.0	0.06	Higher Peak Output based on RFP response
Longer Facility Life	$0.8	0.05	Expected life of 40 years relative to 30 years in initial filing
Annual Production	$0.7	0.04	Higher capacity factor based on RFP response
Higher Year Two Degradation	($0.3)	-0.02	2% degradation in year 2 relative to 0.5% in initial filing
Higher Capital Costs	($0.9)	-0.06	Higher initial capital costs and included Maintenance Capital Costs
Lower Energy Futures Prices	($1.0)	-0.06	Updated Energy Futures since initial filing
Other	($0.3)	-0.03	Higher O&M, added Decommissioning Expense, and updated regional transmission rates
Updated Benefit-Cost Analysis	**$2.5**	**1.15**	

C. Bill Impacts

Q. Has the Company provided an updated bill impact analysis?

A. Yes, the Company has calculated and provided updated bill impacts by rate class in Exhibit SP-8.

As shown on page 1, line 7, column c of Exhibit SP-8, an average Residential customer would see an increase in their monthly bill of $0.05 per month in Year 1 after accounting for the cost and the direct benefits of the project. In Year 40, an average Residential customer would see a decrease in their monthly bill of $0.53 per

16 Dollars in millions.

17 The Benefit Cost Ratio (BCR) is a function of the NPV. To calculate the incremental effect on the BCR, the NPV of each factor is added to the Benefits or removed from the Costs provided in the initial Benefit Cost Analysis.

month. Overall, the discounted benefit of the project is estimated to accrue to customers in Year 7.

Q. Do the Project's offsetting benefits (transmission, energy, and RECs) flow to all customers or only to default service customers?

A. The offsetting benefits in the bill impact analysis flow to all customers. As explained in our initial testimony, the Kingston Solar Project will be operated as a "load reducer," meaning the energy produced by the facility will offset energy that otherwise would be received by Unitil from the transmission system.[18] In other words, the amount of wholesale power imported from the bulk transmission system (tie points) to meet customer demand will be reduced by the amount of electricity produced by the Kingston Project. This is a reduction in total wholesale system load, and not directly attributable to any specific supplier on the system, such as default service or competitive supply. Further, any production from the Project that is coincident with the monthly peak hour will reduce transmission costs. The cost of transmission is recovered via the External Delivery Charge ("EDC"), which is assessed as a per kWh charge billed to all customers.

The Project will generate RECs that will be retained to either meet Unitil's Default Service Renewable Portfolio Standard ("RPS") obligations or sold into the market and credited back to customers. If the RECs are used the satisfy Unitil's RPS obligations, a transfer price will be established and charged to default service

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[18] Exhs. KES-1, at Bates pages 000023-000024; JSD-1, at Bates pages 000058-000059; FDGP-1, at Bates pages 000191-000196.

customers and a credit for the transfer price will be included in the EDC. If the RECs are sold into the market, the REC revenue would be included in the EDC. In both cases, the benefit of the RECs generated by the Project go to all customers.

IV. QUALITATIVE RISK ASSESSMENT

Q. Did the Company identify and discuss potential project risks in its initial filing?

A. Yes. The Company explained in its initial filing that it has not identified any material risks to the Project and described the steps it is taking to manage and mitigate operating and financial risk.[19]

For example, the Company explained that utility-scale solar projects are well established and the market is mature, which lowers technology risk.[20] This risk is further lowered by fact that the Company's affiliate, Fitchburg Gas and Electric Light Company has already developed a utility-scale solar project in Massachusetts.[21] In other words, Unitil has first-hand experience with the development, operation, and maintenance of utility-scale solar technology.

Unitil also explained in its initial testimony that supply chain and cost escalation risks could affect the Benefit-Cost Analysis.[22] The Company further explained that it is mitigating this risk by working through a multi-stage, competitive bidding

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19 Exh. KES-1, at Bates page 000020.
20 *Id*.
21 *Id*. at 000011-000012.
22 *Id*.

process to gather the most up to date pricing and schedule information for the Project.[23] To provide the Commission and intervenors with the best estimate of expected Project costs, the Company has updated its Benefit-Cost Analysis as presented in Section III above.

A further example is the risk mitigation measures built into in the Purchase and Sale ("P&S") agreement that the Company discussed in its initial testimony. Specifically, these provisions make the P&S agreement contingent upon site due diligence, title examination, and the appraised value.[24]

Although the Company identified and assessed Project risks in its initial filing, we appreciate the interest in this subject expressed by the Commission and intervenors at the January 18, 2023 prehearing conference. The following portions of our testimony therefore expands on that discussion by identifying broad categories of risk, discussing the specific risks within each category, and describing the actions the Company is taking to manage and mitigate those risks.

Q. Please identify the categories of potential risks to the Project.

A. Unitil has identified five general categories of potential Project risk: Site Control Risk; Construction and Cost Risk; Permitting Risk; Financing and Financial Risk; and Performance and Operational Risk.

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[23] *Id*.

[24] Exh. JSD-1, at Bates pages 00045-00046.

Site Control Risk

Q. What are the risks associated with site control?

A. A significant risk in the development of any renewable project is securing the rights to use property to construct and operate the facility for its useful life. Private developers typically establish an interest in land for their projects through an easement or a lease (or some combination thereof) and those agreements are commonly pledged as collateral to project lenders. Although leases and easements are a reasonable approach, they can present challenges as developers must negotiate with the landowner (and in some cases multiple landowners) to secure the full scope of rights necessary to develop their projects. An alternative to easements and leases is to buy the property, and acquire fee title, which entitles the purchaser to exclusive possession of the land and an unconditional and unlimited interest of perpetual duration. Unitil has taken this lower-risk approach to site control for the Kingston Solar Project.[25]

Q. What additional steps is the Company taking to mitigate site control risk?

A. As noted above, and discussed in Unitil's initial filing,[26] the P&S agreement has a number a built-in mitigation measures. Specifically, the P&S is contingent upon a title examination and the completion of site due diligence, including the receipt of all necessary construction permits. In addition, to ensure the property is acquired at

[25] Unitil Realty Corporation, an unregulated subsidiary of Unitil Corporation, entered into the P&S agreement on August 25, 2022 for the Kingston Solar Project site. The P&S Agreement was attached to the initial filing as Exhibit JSD-5 (CONFIDENTIAL). Unitil Realty Corporation will transfer the parcel ultimately used for the Kingston Solar Project to UES and retain the remaining parcel for future development.

[26] Exh. JSD-1, at Bates pages 000044-000045.

a fair price, the P&S is contingent upon the property appraising at or above the purchase price. This appraisal clause is the reason the purchase price for the property has been reduced, as noted earlier.

Construction and Cost Risk

Q. What are the potential construction and cost risks for the project?

A. A potential risk for a renewable energy project, or any construction project for that matter, is unforeseen cost escalations that may be driven by estimates that later prove to be inaccurate, inflation, market demand, shipping and freight costs, supply chain disruptions, or other unforeseeable circumstances.

Q. What is the Company doing to mitigate this risk?

A. Certain risks are naturally mitigated by the Project's technology. The upfront costs for PV arrays have declined dramatically over the past several years.[27] Also, over the long term, the Kingston Solar Project will not have any fuel costs, which means that it is insulated from the risk of rising and volatile fossil fuel costs.

Regarding the potential for cost escalation during construction, the Company is managing that risk through several measures. First, the Company has conducted a multi-stage, competitive RFP process to ensure its Project cost estimates are reasonably accurate and robust. As part of that process, the Company has thoroughly

[27] New Hampshire Department of Energy, New Hampshire 10-Year Energy Strategy at 47, 51 (July 2022) (stating the cost of new utility-scale solar has fallen by 90 percent in the last 12 years).

vetted the proposed EPC contractor teams, their technical capabilities, and their prior experience developing similar projects.

ReVision has local project experience, which includes municipal arrays awarded via competitive bid by the Town of Kingston and the surrounding towns of Exeter and Brentwood (where ReVision's office is based). ReVision is currently working with Town of Kingston to develop a 6.2 MW municipal array on the Kingston capped landfill. In addition to the 6.2 MW Kingston landfill project, ReVision is currently working with a local educational institution on a 4.7 MW solar farm and is ready to commence construction (pending utility study) on New Hampshire's largest solar array to date, a 4.3 MW solar farm at the Rockingham County Complex in Brentwood, New Hampshire.

Second, the Company is employing a turnkey, EPC project delivery model, and will remain actively involved throughout the design, engineering, procurement and construction phases of the Project. Notably, ReVision is planning to use Ayer Electric (IBEW), a local firm based in Barrington, New Hampshire, as its primary electrical subcontractor for the Kingston Solar Project.

Third, ReVision places bulk orders for tens of megawatts of solar modules through the Amicus purchasing group approximately two times per year and will include the Kingston Solar Project in a bulk order after contract signing. By aggregating its buying power with other member companies nationwide, ReVision negotiates directly with equipment manufacturers and is able to attain better pricing on equipment.

Fourth, Unitil plans to negotiate and enter into an EPC contract with ReVision that will appropriately allocate construction and cost risk between the parties.

Q. Do project risks generally increase with time?

A. Yes, time is a key concern because pricing estimates are less reliable as time passes. However, the Company does not view time as a significant risk factor because the Commission has approved a six-month procedural schedule for this docket consistent with RSA 374-G:5, V.

Financial and Financing Risk

Q. What are the potential financial risks associated with the Project?

A. One of the risks commonly associated with renewable energy projects is insufficient access to low-cost capital. For this reason, many privately developed renewable energy projects are highly leveraged, which translates into default risk, and the tax benefits often flow, at a discount, to a third-party tax equity investor. In this case, the Company is proposing to finance the Project at its most recently approved cost of capital and to offset the revenue requirement with federal tax credits.

Q. Are there any other financial risks that are absent because the Project is being developed by a public utility instead of a private developer?

A. Yes. In the context of many privately developed projects, project cash flows are derived from a long-term offtake or power purchase agreement ("PPA"), which essentially determine the Project's economics. A PPA introduces the risk of non-payment (and the associated litigation risk), which is absent from the Company's proposed Project. As explained in our initial testimony (and as noted earlier), the Kingston Solar Project is a load reducer and there are no customer contracts to be executed. This is a favorable, lower-risk structure, because the Company and its customers do not need to assume the duties and obligations of a contract in order to receive the benefits produced by the Kingston Solar Project.

Another revenue stream typically associated with solar projects are state incentives, which commonly take the form of net metering credits. This revenue stream is subject to the risk of a future change in state policy, discontinuing these incentive programs. The Kingston Solar Project is not reliant upon any state subsidies and therefore this risk does not apply to this Project.

Permitting Risk

Q. What are the permitting risks associated with the Project?

A. Permitting risk can be viewed along a spectrum. On one end are permitting delays and at the extreme opposite end is the denial of necessary approvals. As discussed in our initial filing, several local, state, and federal permits are required for the Kingston Solar Project.[28]

[28] Exh. JSD-1, at Bates pages 000047-000048.

Q. How is Unitil managing permitting risk for the Kingston Solar Project?

A. As explained in our initial filing, Unitil has hired TF Moran, Inc. ("TFM"), a New-Hampshire based Land Planning firm to perform Site Due Diligence and obtain all the necessary permits to construct the Project. TFM has extensive experience completing site assessment and permit application projects in New Hampshire. In addition, ReVision has local, state, and federal permitting experience and could assist TFM, as necessary.

Lastly, the Company is insulating the Project from permitting risk because it will not authorize the procurement of equipment and materials until we have strong confidence that all necessary local, state, and federal permits will be obtained.

<u>Performance/Operational Risk</u>

Q. What are the potential risks associated with performance and operation of the Project?

A. Energy production is a key driver of Project benefits. Accordingly, once the Project achieves commercial operation, equipment failures and diminished capacity factors are potential risks.

Q. How is the Company mitigating performance and operational risks?

A. The Company plans to manage this risk by several means.

First, the Company plans to enter into an O&M agreement with ReVision to ensure the system generates at its maximum capacity over the projected design life. As part of the final system design, ReVision will develop a detailed, site-specific O&M

plan. The ReVision O&M plan will include daily monitoring of system performance so it can quickly mobilize in-house service personnel either remotely or onsite to address issues that may arise, in accordance with guaranteed response times. The O&M Plan will also include 80-point annual electrical and mechanical inspections and associated preventive maintenance, accompanied by a detailed inspection and production report.

Second, the Project is designed with proven, high-quality components with long-term and robust warranties from manufacturers to ensure the performance and reliability of the equipment. The warranty periods and expected lifespan of major system components provided by ReVision in response to the Final EPC RFP are summarized in Table 10 below.

Table 10: Warranty Periods and Commercial Lifespan

Major Component	Warranty Period (Years)	Commercial Lifespan (Years)
Qcells QPEAK DUO XL 580W Bifacial Solar Modules	25	40
Solectria XGI 1500/125 kW Solar Inverters	20	20
TerraSmart TerraTrack Single-Axis Tracking System	20	40

The 25-year linear performance warranty for the solar modules ensures at least 98 percent of nominal power during the first year and maximum 0.5 percent degradation per year thereafter, resulting in at least 86 percent of nominal power output in Year 25. Qcells is a leading Tier 1 solar panel manufacturer based in the

United States (Georgia) and over the past decade, ReVision has installed large volumes of Qcells modules across northern New England.

Third, the energy production estimates in the Company's Benefit-Cost Analysis are based on data provided by ReVision, which is derived from the industry-standard HelioScope Production software using specific equipment and local weather characteristics. ReVision's production estimates consider the specific pitch, azimuth and other design features of the Project, as well as external factors such as irradiance, soiling conditions, and temperature derived from the nearest TMY2[29] federal weather dataset (Concord Municipal Airport).

Fourth, as discussed above, Unitil has updated its Benefit-Cost Analysis to include Maintenance Capital Costs for PV modules and the racking system. Although the Company expects the capital equipment to operate well beyond the warranty periods, these costs would support the replacement of equipment if necessary to avoid lost production.

Fifth, the Company plans to maintain a limited stock of spare material, including PV modules, a step-up transformer and an inverter that will be utilized when needed to limit downtime.

[29] Typical meteorological year ("TMY") is a collection of selected weather data for a specific location. The first TMY collection was based on 229 locations in the United States and was collected between 1948 and 1980. The second edition of the TMY is called "TMY2".

Sixth, the Project will be a string inverter design as opposed to a central inverter design. Specifically, the Project is designed to utilize approximately 39 125kW inverters instead of a few larger central inverters. This design should reduce replacement costs in the event of an inverter failure, and minimize the reduction in production impacts when inverters and/or PV modules need to be removed for maintenance.

Conclusion

Q. Please summarize the Company's qualitative discussion of potential Project risks.

A. The Company is actively managing the Project to keep the level of spending low in the early development stages when development risk is relatively high. Considering the additional information received in the final EPC RFP process, the Company's view with respect to Project risk remains unchanged from its initial filing. Although Unitil has identified potential risks, it views their effect on the Project's net benefits to be limited, and, as discussed above, is taking prudent steps to measure, manage, and mitigate them.

V. QUANTITATIVE RISK ASSESSMENT

Q. Has the Company performed a quantitative assessment of potential Project risk?

A. Yes. The Company has conducted a stress test and a simulation analysis to quantitatively assess Project risk.

<u>Stress Test Analysis</u>

Q. Please briefly describe the purpose of the stress test analysis.

A. A stress test is useful for understanding the sensitivity of a result to changes in certain variables. In this case, the Company performed a stress test analysis to find the level to which key inputs in the Benefit-Cost Analysis must change such that the Project's net benefits are zero (*i.e.*, the breakeven point).

Q. Please identify the assumptions and inputs upon which the Company performed the stress test analysis.

A. Unitil performed stress tests on the most critical assumptions and inputs summarized in Table 11 below. For each assumption, we found the extent to which it must change (holding the others constant) to create a net benefit of zero.

Table 11: Summary of Stress Test Results

Variable	Base Assumption	Stress Test Value
Annual Capacity Factor	22.78%	19.66%
Initial Depreciable Capital Cost	$13.9 Million	$15.8 Million
REC Price	[redacted]	$16.32
Direct Benefits Escalation Rate	2.00%	-0.09%
ISO-NE Futures (Average Year 1-4)	$0.0784	$0.0571

Q. What conclusions do you draw from the stress test analysis?

A. Simply put, the variables would have to change to levels the Company considers to be low-probability before the Kingston Solar Project no longer produces positive net benefits.

The Company further notes that it has limited the stress test analysis to only direct benefits. When indirect benefits are considered, those benefits serve to further increase the Project's already positive benefits and reinforce a finding that the Project is in the public interest.[30]

Simulation Analysis

Q. Please briefly summarize the benefits associated with simulation analyses.

A. As noted above, stress tests measure the extent to which a given variable must change for the Project to no longer provide positive net benefits. In effect, it changes one variable while holding all others constant. Although that approach is valuable in assessing the sensitivity of analytical results to a given variable, it does not reflect the extent to which variables may, or may not, move together. Simulation analyses (sometimes referred to as "Monte Carlo" analyses) provide the ability to consider such correlations across variables, and to define the statistical properties (for example, the shape and dispersion of potential outcomes) for individual variables. Moreover, by combing those attributes (correlations across variables and the statistical properties of individual variables) we are able to simulate thousands of scenarios, and develop probabilities of outcomes (in this case, the probability that the BCR is greater than 1.00, or the NPV is greater than zero).

[30] In DE 09-137, the Commission held that it is appropriate to include indirect benefits in the Benefit-Cost Analysis after first considering direct and readily quantifiable benefits. In addition, the Commission held that in situations where projects may be marginally uneconomic based on direct benefits alone, it will allow reasonable estimates of indirect benefits to be considered and, if appropriate, to support a public interest finding.

Q. Did the Company perform a simulation analysis?

A. Yes. The Company performed a simulation analysis using @Risk, an add-in tool for Microsoft Excel, to analyze the economic risk of the Project using Monte Carlo simulations. The Company included 9 key assumptions in the simulations, which unlike in the stress test discussed above, can be changed independent of one another. The simulation was conducted with 100,000 unique iterations of the key inputs subject to the established parameters.

Q. Please identify the key inputs included in the simulation analysis.

A. The inputs included in the simulation analysis include: the annual capacity factor, the monthly and annual peak capacity, change in the modeled depreciable capital costs, REC prices, Energy Rates in the initial years which are based on Energy Futures, the escalation rate used for the calculation of Direct Customer Benefits, and the escalation rate used for all other assumptions. Lastly, the Company included the probability that the Project will meet the requirements for the ten percent Domestic Content bonus for the PTC rate.

Q. Please explain how the simulation was arranged.

A. Each of the above variables was assigned a distribution with various parameters. The distributions used were triangular, normal distribution, and binomial distribution. The triangular distributions were provided parameters for the minimum, maximum, and most likely value. The triangular distribution is useful when there is limited data available and there is relatively more subjectivity. For example, for the Depreciable Capital Cost input the Company used its most likely value to be 100% of the modeled cost, the minimum to be 95%, and the maximum to be 115%. However, for better established data sets with less subjectivity, the Company was able to define those data sets as normally distributed and assign a mean and standard deviation. The Company used a binomial distribution for the PTC rate and applied an 80% probability that the Project will qualify for the Domestic Content bonus and a 20% probability that the Project will only qualify for the base PTC rate.

Q. What were the results of the Monte Carlo simulations?

A. The simulation was processed with 100,000 unique iterations and indicates an 84.3% probability that the project will be NPV positive and yield a benefit-cost ratio of 1.0 or greater for customers. The results of the simulation have an average NPV of $4.3 million and a median NPV of $4.1 million. The results of the simulation show an average BCR of 1.26 and a median BCR of 1.24. The skewness of the simulation is positive, between 0.2 and 0.3 indicating fairly symmetrical results with slightly more observations above the mean than below. A negative skew value indicates a higher probability for observations less than the mean while a positive skew value indicates a higher probability for observations greater than the mean. The kurtosis of the simulation, which is a measurement of the “tails” or “flatness” of a distribution, is approximately 3.0 and indicates the dataset is normally distributed. A kurtosis greater than 3.0 is Leptokurtic and less than 3.0 is Platykurtic. Higher kurtosis values indicate that more of the observations are in the “tails” of the curve, while lower kurtosis values indicate observations relatively more concentrated around the mean. Given that the mean and median of the simulations are similar, the results are largely symmetrical as indicated by the skewness, and the kurtosis is approximately 3.0 the Company concludes the results of the simulation are "normally distributed". The 90th percentile of the results show the possibility of an NPV of $9.9 million and a BCR of 1.59 or better, while the 10th percentile shows the potential for an NPV of ($1.0 million) and a BCR of 0.94 or worse. Figure 1 and Figure 2 below illustrate the distribution of the results of the 100,000 unique iterations included in the scenario.

Figure 1: Simulation Results of Net Present Value

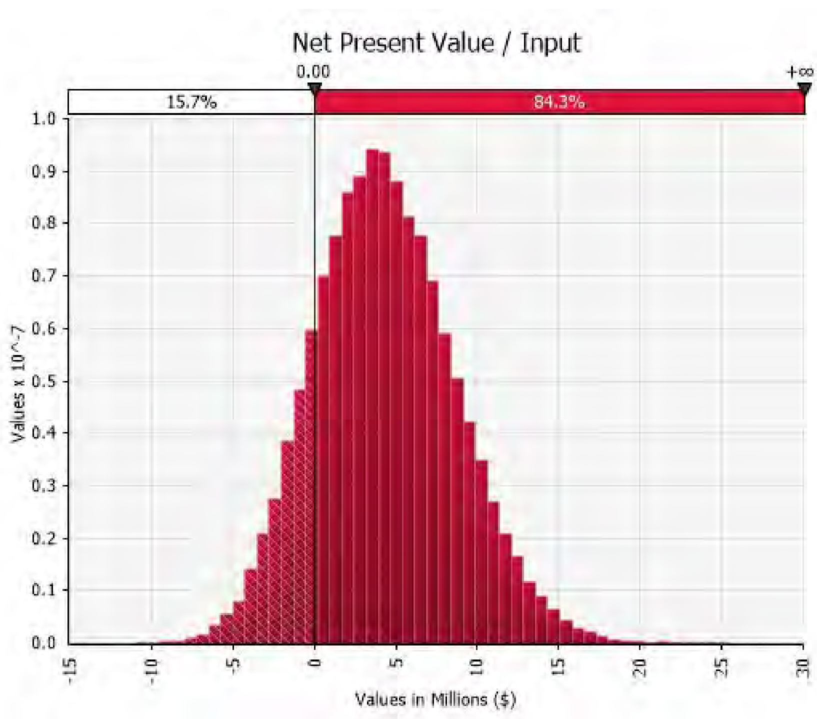
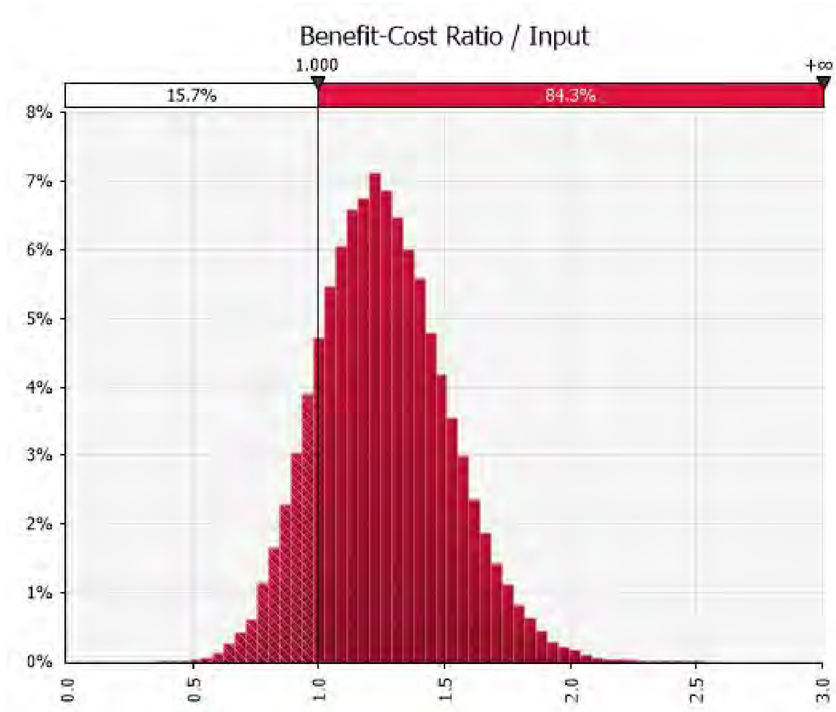


Figure 2: Simulation Results of Benefit-Cost Ratio



Q. Please provide the results of the simulation by ranked percentiles.

A. Table 12, shown below, illustrates the ranked NPV and BCR results by percentile. The 50th percentile represents the median data point of $4.1 million for the NPV and 1.24 for the BCR. The average of the results are slightly higher as a result of the positive skew value. Notably, the results in Exhibit SP-7 are similar to the 35th percentile in Table 12 reflecting the conservative assumptions included in the Benefit-Cost model.

Table 12: Simulation Results Ranked by Percentile

Percentile	Net Present Value	Benefit-Cost Ratio
1.0%	(4,807,353)	0.72
2.5%	(3,526,266)	0.80
5.0%	(2,401,678)	0.86
10.0%	(1,045,952)	0.94
20.0%	641,349	1.04
25.0%	1,316,598	1.08
30.0%	1,934,745	1.11
35.0%	2,503,388	1.15
40.0%	3,070,847	1.18
45.0%	3,607,570	1.21
50.0%	4,132,047	1.24
55.0%	4,671,899	1.27
60.0%	5,232,628	1.31
65.0%	5,838,370	1.34
70.0%	6,457,532	1.38
75.0%	7,124,508	1.42
80.0%	7,879,678	1.47
90.0%	9,933,677	1.59
95.0%	11,645,432	1.69
97.5%	13,149,104	1.79
99.0%	14,850,923	1.90

Q. Which inputs have the greatest impact on the economics of the Project?

A. The REC prices, Energy Rates, and escalation rate used for the direct benefits have the most variability on the results. The capacity at monthly and annual peaks have relatively less variability on the results. Figures 3 and 4 shown below, rank the variability of each input and display the largest impacts each assumption had on the NPV and BCR.

Figure 3: Tornado Graph of Net Present Value

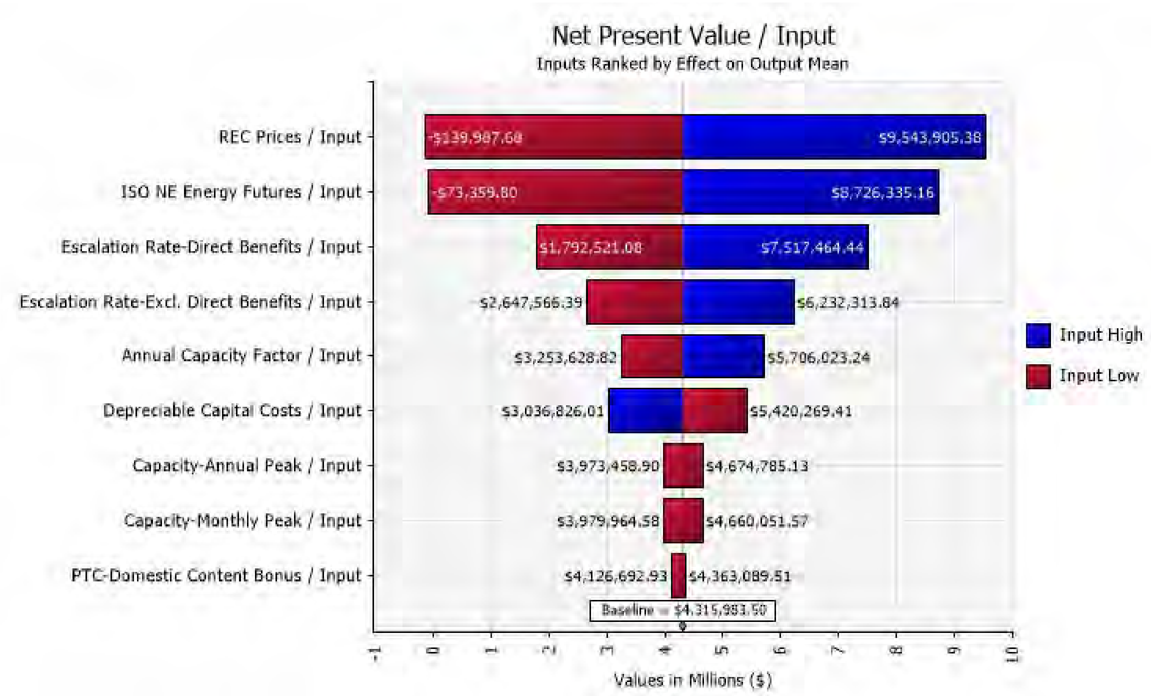
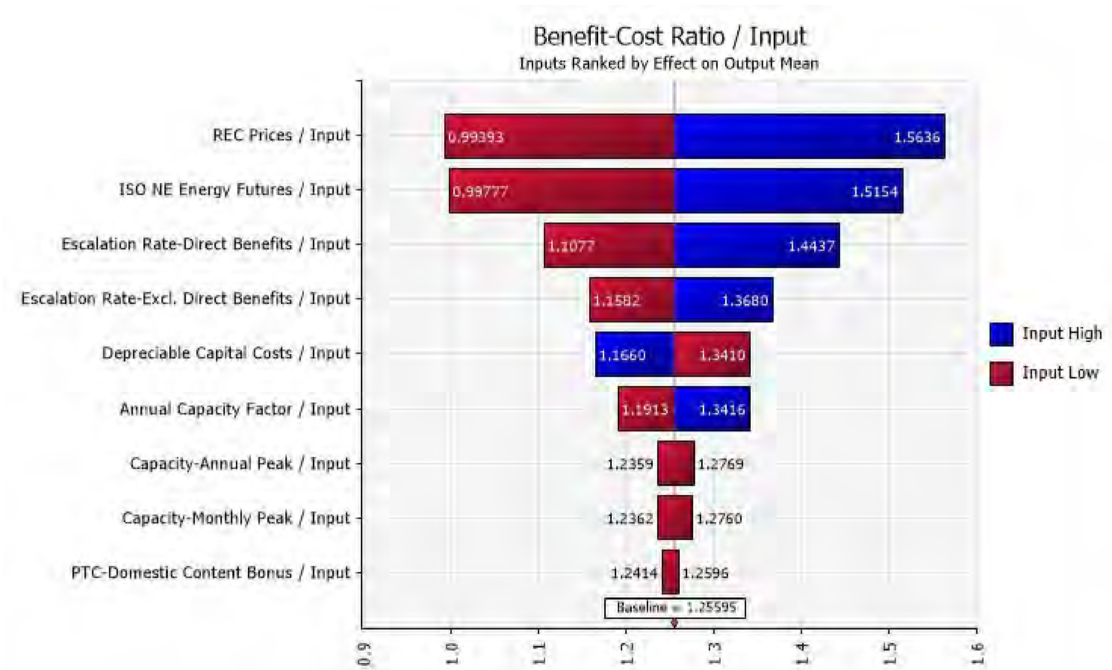


Figure 4: Tornado Graph of Benefit-Cost Ratio



Q. Please provide any other comments on the simulation analysis.

A. The simulation analysis was conducted with reasonable distributions and parameters, which resulted in reasonable results. The simulations included conservative assumptions such as the potential for up to 15% depreciable capital cost overruns as well as a minimum REC price of zero dollars. The results show a strong probability that the Project will yield positive results for customers purely on direct benefits. These favorable results would be further supported if indirect benefits and the value of the future option to add energy storage were included. The Company has a high degree of confidence that the Project will yield positive economic results for customers as supported by the results of the simulation.

VI. CONCLUSION

Q. Please summarize your Supplemental Testimony.

A. The Kingston Solar Project is a meaningful long-term commitment to addressing New Hampshire’s climate objectives in a manner that provides tangible benefits to the Company’s customers, is cost-effective, and enables economic growth in the state. The updated Benefit-Cost Analysis presented in this Joint Supplemental Testimony continues to demonstrate that the direct benefits of the Project outweigh the costs over the investment horizon. The Kingston Solar Project is good for customers and good for the state of New Hampshire. Accordingly, the Commission should find the Kingston Solar Project is in the public interest.

Q. Does this conclude your Supplemental Testimony?

A. Yes, it does.

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1 Project Description

Unitil views renewable energy as a valuable resource that provides benefits to the electric grid and the environment. Unitil is under agreement to purchase the properties of 2 Mill Road and 24 Towle Road in Kingston, NH and is currently performing due diligence exploration on the parcels. It is Unitil's intent to install a utility scale photovoltaic generating (PV) facility on the property.

To assist in this effort Unitil is issuing this Request for Proposal (RFP) for the engineering, procurement and construction (EPC) of the PV facility. It is Unitil's intention to "partner" with a vendor that will not only engineer, procure and design the facility, but also assist Unitil's site engineering consultants with the design and permitting of the facility and perform the necessary impact studies to interconnect the facility to the Unitil electric distribution system.

2 Property Description

2 Mill Road, Kingston, NH is a 63 acre vacant parcel that has two 34.5 kV "subtransmission" lines running through it and is adjacent to Unitil's Kingston 115-34.5 kV substation. 24 Towle Road, Kingston, NH is a 33 acre vacant parcel located directly adjacent to and to the northwest of 2 Mill Road. It is Unitil's intent to eventually site two PV facilities on these parcels, one as part of this RFP and another in the future after the first facility is complete.

Unitil has hired TF Moran, Inc. (TFM), a New-Hampshire based land planning firm specializing in civil and structural engineering to perform site due diligence activities, site plan development and construction permitting. Attached is the existing conditions plan for both parcels that indicates wetlands and the existing utility easement that contains the Unitil "subtransmission" lines that cross the property.

It is Unitil's intent to perform all site engineering, design (access road, drainage facilities, final site grading, etc.) utilizing TFM, but is looking to engage with a PV facility EPC vender that can assist Unitil and TFM in the site engineering and permitting components specific the PV facility. Unitil also intends to utilize its typical, local tree clearing and local site construction contractors for the site construction (access road, drainage facilities, final site grading, etc.), but will entertain options in which the PV facility EPC vendor performs/subcontracts those activities.

3 Pre-Procurement and Construction Activities

It is Unitil's expectation that the awarded vendor will support Unitil and Unitil's contractors/consultants with the site design and permitting processes as well as assist with developing/reviewing assumptions (facility generation expectations, facility installation and operating costs, etc.) used in the economic analysis for the justification of the project.

3.1 Facility Layout and Site Design Assistance

Develop an initial facility design (fence details, equipment location and spacing, conduit locations, etc.) that can be incorporated into the TFM site design and permitting package. Assist TFM in the development of the final site layout and provide PV facility specific information that is required in the permitting process.

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Assist TFM in developing the soil boring and geotechnical evaluation testing requirements.

3.2 Unitil System Impact Study

The selected vendor shall be responsible for performing or contracting a system impact study (SIS) for the Unitil electric system of the PV facility. The purpose of this SIS is to analyze the impacts that the facility may have on the Unitil electric distribution system and recommend system improvements to mitigate any adverse effects caused by the facility on Unitil's equipment, personnel and customers.

The SIS will review four possible interconnection circuits/lines all of which emanate from Unitil's Kingston 115-34.5 kV substation. Unitil will review the impacts and costs of interconnection of each of the four possible interconnection circuits/lines to determine which interconnection location is the most cost effective.

The SIS shall include the following analyses for each of the four interconnection circuits/lines:

- Load Flow Studies utilizing PSSE and/or Cyme. Unitil will provide existing conditions model(s) and it will be the responsibility of the vendor to update those models to include the PV facility.
  - Review and address voltage drop, regulation and flicker concerns and well as any operational effects on the electric power system under basecase and N-1 conditions.
- Protection and Short Circuit Analysis from Kingston Substation to the Point of Interconnection (POI) utilizing ASPEN OneLiner. Unitil will provide the existing conditions model and it will be the responsibility of the vendor to update the model to include the PV facility.
  - Review and address impacts on fault sensitivity, equipment interrupting ratings and protective device coordination.
- Analyze the risk of islanding and perform anti-islanding studies as necessary.
- Analyze the risk of transient over voltage (TOV) and perform TOV studies as necessary.
- Grounding Analyses
  - Risk of temporary overvoltage and transient issues.
  - Transformer winding evaluation at the POI
  - Verify effective grounding of the facility.
- Provide recommendations and project estimates of modifications to the Unitil electric system to address concerns identified due to the interconnection of the facility.

3.3 Transmission Study

The selected vendor shall represent Unitil and provide required information to ISO-NE and applicable neighboring transmission owners during the ISO-NE I.3.9 PPA application and transmission study process as necessary.

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3.4 Economic Modelling Assumption Development and Review

Assist Unitil in the development of facility specific economic modelling assumptions, including but not limited to estimated annual generation output, estimated generation output at typical system peak hours, capacity factors, efficiency degradation rates, etc.

The selected vendor will also be requested to assist Unitil in ensuring that the project qualifies for the maximum possible Investment Tax Credits (ITC) and other possible rebates and credits.

3.5 Regulatory Support

It is expected that the selected vendor will provide the supporting data and possibly act as an expert witness on Unitil's behalf regarding the responsibilities of the selected vendor as outlined in this RFP.

4 PV Facility Design Requirements

All components of the PV facility up to the POI, including PV modules, inverters, controllers, step-up transformers, equipment racking and foundations, facility fencing, site and fence grounding, etc., shall be considered in scope and included in responses to this RFP.

For the purposes of this RFP the POI shall be considered the utility side of the step-up transformer(s). Construction of the interconnection to the Unitil electric system, including the POI and up to the utility side of the step-up transformer(s) will be the responsibility of Unitil.

In an effort to improve capacity factor and output at typical system peak hours Unitil plans to "upsize" the DC side of the facility and will utilize single-axis tracking PV module mounting/racking systems. Unitil is also open to exploring other design options that may increase capacity factor and output at peak hours.

4.1 Ratings:

Maximum Nameplate AC Capacity:	4.99 MW AC (facility AC rating shall be less than 5 MW)
Nameplate DC Capacity:	Between 6 MW DC and 7 MW DC
Utility System at POI:	34.5 kV three-phase, four-wire, effectively grounded
	200 kV BIL

A reasonable DC capacity of the facility shall be recommended by each vendor based on their past experience and knowledge.

4.2 General Design Requirements

- The facility and all its components shall be designed and installed in accordance with the latest versions of the 2023 National Electrical Safety Code (NESC), 2023 National Electrical Code (NEC), UL-1741, IEEE Standard 1547, International Building Code (IBC) and all other applicable local and state codes and standards.
- The final design, including all drawings and technical documents shall be approved and stamped by a registered professional engineer(s) that is licensed to practice engineering in the state of New Hampshire for the applicable disciplines (i.e. civil, electrical). The

professional engineer shall certify that the system is designed and built in accordance with the NESC, NEC, IBC, and all local, state and federal codes.

4.3 Conduit and Junction Box Requirements

- Conduit shall be rigid (hot-dipped) galvanized steel (RGS) for all above-grade installations and transitions (e.g., 90-degree sweeps from below-grade to above-grade).
- Gray electrical grade Schedule 40 or 80 PVC conduit shall be utilized for all below-grade installations unless otherwise approved.
- Conduit fasteners and hardware throughout the system shall be stainless steel or materials of equivalent corrosion resistance
- Outdoor electrical equipment and enclosures, including but not limited to, disconnects and combiners shall have NEMA Type 3R or NEMA Type 4 ratings and be UL Listed. All other equipment enclosures shall be suitable for outdoor installation in New England, subject to sun, rain, wind, snow, etc.

4.4 Electrical Design Requirements

- Electrical engineering and design shall meet or exceed the current versions of all applicable industry standards such as the NESC, NEC, UL-1741, IEEE Standard 1547, and all other applicable local and state codes and standards.
- All equipment and enclosures, including but not limited to disconnects and combiners, shall be bonded and grounded as required by the NESC and NEC. String combiner boxes shall include properly-sized fusing.
- All protection equipment throughout the system shall be sized and specified to reduce damage on all components and the interconnection point in case of electrical failure.
- The design shall include the appropriate sizing of all cabling (above and below ground) that will connect the PV modules, arrays, inverters, transformer and switchgear to the POI. Wire sizing and layout should result in no more than 1.0% drop in the AC voltage between the inverter and the point of interconnection.
- The electrical systems, wiring, conduits, cables shall be neatly routed to facilitate access, troubleshooting, maintenance, etc.
- The electrical design shall include the design of equipment grounding, and lightning/surge protection for the entire PV installation up to the point of connection.
- PV facility site shall be effectively grounded including conduits, fencing, cabinets, structural steel, inverters, modules, and all other applicable equipment.
- A convenience outlet (120 V, 20 A) to provide power for test equipment and other diagnostic equipment shall be installed within fifteen feet of each inverter.

4.5 Structural Design Requirements

- Structural analysis and design of the photovoltaic arrays, mounting systems, foundations and/or piers shall be based upon the requirements of the applicable codes and standards as well as the data supplied by the PV module, inverter, switchgear and mounting suppliers. At a minimum all equipment shall be suitable to withstand 110 mi/h winds and up to 1" of ice accretion. The Vender shall provide a professional engineer's stamped report describing and confirming that the final design meets the requirements of the applicable codes and standards.

4.6 Facility Fencing

The entirety of the PV facility shall be fenced per NESC section 110 and grounded per NESC section 9. The cost associated with the grounding design and installation of the fence and its grounding system shall be included in proposals to this RPF. The PV facility fence shall meet or exceed the following requirements.

- Fabric shall be #9 (minimum) steel wire gauge and 2" (maximum) diamond mesh chain link, 6' in width.
- Fabric shall be attached to posts and rails by means of #9 gauge galvanized steel 'Easy Twist Ties'.
- From height of the fence fabric (6' above final grade), three evenly spaced strands (totaling 1' in vertical height) of aluminum barbed wire tied with easy twist ties shall be attached to the posts at an angle of 45 degrees outward from the protected property. Top strand of barbed wire shall be a minimum of 7' above final grade.
- All corner posts and gate posts shall be a minimum of 4" schedule 40 galvanized steel pipe and shall be installed in 18" diameter sonotubes to a depth of 5'-0" (minimum) below finished grade.
- Line posts shall be a minimum 2'-1/2" schedule 40 galvanized steel pipe and shall be installed in 8" diameter sonotubes to a depth of 5'-0" (minimum) below finished grade.
- Rivets shall be stainless steel.
- Steel parts, including fence fabric shall be hot-dipped galvanized after fabrication.
- Outside diameter of top rails, bottom rails, and bracing rails shall be a minimum of 1-5/8".
- Assume two (2) 30' vehicle gates and two (2) 4' personnel gates.
- All gates shall match the height of the main fence and barb wire.
- Gates shall be provided with fork and turn latches that have provisions for padlocking.
- Gate rests shall be castings and shall not be pipe.
- All gates shall swing in both directions.
- Maximum spacing of posts shall be 10', except where wider gate openings are required.
- Gaps of no more than 2" between the bottom rail and final grade shall be allowed.
- All components (posts, fabric, gates, etc.) of the fence shall be per NESC requirements. It is the responsibility of the selected vender to design and install the fence grounding system.

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4.7 Other Design Requirements

- All fasteners and hardware throughout the system shall be stainless steel or materials of equivalent corrosion resistance with an expected life expectancy of at least 30 years.
- All non-metallic exposed materials shall be sunlight and UV resistant (30 year, minimum, life expectancy)

5 PV Facility Equipment Requirements

The manufacturers of all equipment shall have at least 10 years of experience manufacturing the selected components of the type and size proposed for this applications. All equipment shall be newly manufactured (not refurbished or reconditioned) from a reputable manufacturer, experienced in providing equipment for the application and site conditions. Preference will be given to equipment manufactured and assembled in the United States.

The PV facility as a whole shall be compliant with the requirements defined in IEEE 1547-2018.

5.1 Inverters

- Inverters shall be compliant with current versions of UL 1741, IEEE Standard 1547 and all other applicable codes and standards.
- Inverters must carry a UL 1741SB or equivalent certification.
- Inverters shall have the capability of accepting an additional DC input from a future DC coupled energy storage system (ESS).
- It is Unitil's intent to integrate the inverters and/or controllers with its SCADA system via DNP communications for remote monitoring (status, error/diagnostics codes, instantaneous AC and DC voltage and current, instantaneous AC power, daily cumulative kWh, etc.) and control (voltage control, power factor management, etc.).
  - Any equipment integrated with Unitil's SCADA system will be need to be secure, and at the least meet all the requirements of the NIST guidelines and NERC/CIP standards. Unitil expects the RFP responses to describe the type of security included in the inverters and/or controllers that will be integrated with SCADA and confirm that all components comply with the applicable cyber security standards.
- On-site commissioning of the inverters and/or controllers including their SCADA functionality, shall be included in the proposals.
- The proposed systems should have a CEC weighted efficiency of 97.5 % or higher.
- All inverters shall be warrantied for a minimum of 12 years (15 years or more is preferred) after energization.
- Inverter Configuration
  - Include integral AC and DC disconnects.
  - Provide galvanic isolation between AC and DC system conductors.
  - The cumulative inverter AC nameplate rating shall be less than 5 MW DC.

- The inverters must have ground fault detection (GFDI) system on the DC side to protect the system from a PV ground-fault. The inverter must be able to detect, notify (store and show fault codes), and interrupt PV ground-faults.

5.2 PV Modules/Panels

- Solar Modules should be compliant with current versions of IEEE Standard 1547 UL 1703, ISO9001, IEC 61215, IEC 61730 and all other applicable codes and standards.
- Solar panels shall be mounted and installed for single-axis tracking.
- PV modules should be installed in a single contiguous area, with no more than 2% DC loss from the array to inverter equipment.
- The expected rating of the modules shall not fall below the cumulative rating of the inverter(s) throughout the expected life of the facility.
- Power loss due to module power mismatch is to be less than 2%. The Vendor is to provide Unitil with a strategy for achieving this. The modules shall be selected to eliminate output reduction by voltage mismatch within a string.
- The following details shall be provided:
  - Snow weight resistance – provide the maximum weight that the solar panels/frames/fixings can withstand before breaking or bending.
  - Wind resistance – provide the maximum wind speed that the panels/frames/fixings can withstand before breakage. Wind impacting on the upper and lower surfaces should be considered.
- All solar modules shall be warrantied for a minimum of 25 years (30 years or more is preferred) after energization.

5.3 Racking Requirements

- All structural materials shall have adequate corrosion and grounding protection for the soils (if ground mounted) and environment in which it is placed.
- Racking components shall be anodized aluminum, hot-dipped galvanized steel, or material of equivalent corrosion resistance with an expected life expectancy of 30 years or more in typical northern New England environmental conditions.
- All structural and nonstructural components will be designed to resist the effects of gravity, seismic, wind, weather and other applicable loads (including snow and ice) in accordance with the requirements of the ASCE Standard for Minimum Design Loads for Building and Other Structures and all other applicable codes and standards.
- All final structural drawings associated with the project must be stamped by a Professional Structural Engineer registered within the State of New Hampshire.

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5.4 Step-Up Transformer(s)

The step-up transformer(s) shall be padmounted with the following requirements:

- Rating Information:

High-Voltage:	34.5/19.92 kV
High-Voltage BIL:	200kV (dead-front bushings may be 150 kV BIL)
Neutral H_0 BIL:	200 kV (if applicable)

- Transformer shall be oil filled, Class ONAN, 60 cycle, 65°C rise at rated kVA.
- Transformer shall be filled with highly refined mineral oil suitable for electric insulation. The oil shall meet or exceed the requirements of ANSI/ASTM D3487 for Inhibited Type II.
- The transformer oil shall be certified "Non-PCB" in accordance with current EPA regulations and shall contain PCB levels which are considered non-detectable. The transformer nameplates shall be permanently engraved with a statement that the transformer oil contained less than 1 ppm PCB's at the time of manufacture.
- The color of the unit shall be Munsell green or equivalent.
- Transformer shall be equipped with a standard dial type liquid level indicator located in the high voltage compartment. The indicator shall have the 25ºC level permanently marked on the gauge and have a range of at least 100ºC.
- Transformer shall be equipped with a standard dial type liquid temperature indicator located in the primary voltage compartment. The indicator shall be factory calibrated to indicate the top liquid temperature in degrees Celsius up to at least 120ºC and shall include a maximum reading pointer with an external reset.
- A combination drain and lower filter valve shall be provided for complete drainage of the oil to within one inch of the bottom of the tank. The drain valve shall be a 2” ball-type valve with NPT threads and a pipe plug in the open end. The valve shall be equipped with a built-in 3/8” sampling device located in the side of the valve between the main valve seat and the pipe plug. This valve shall be located in the high-voltage compartment and should be placed so as not to interfere with the training of cables to the bushings.
- An upper filter valve located below the 25ºC liquid level shall also be located in the high voltage compartment. This filter valve shall be a 1” ball-type valve, suitable for the return of filtered oil, with NPT threads and a pipe plug in the open end.
- Unit shall be supplied with an automatic, self-resealing, pressure relief system to prevent tank failure.
- The high-voltage terminals shall be of loop-feed design. The primary phase terminals shall be one piece, bolted-on, dead-front, load-break bushings three-phase rated (21.1/36.6) conforming to ANSI/IEEE 386 for 35kV class large interface load-break bushings (plum nose piece) and configured as per ANSI C57.12.34, Figure 18.

- The step-up transformer winding configuration should comply with the following table.

Utility Side	Generator Side	Added Requirements
Wye-Grounded	Delta	NGR (if necessary)
Wye-Grounded	Wye-Grounded	Effectively Grounded DER Source
Wye-Grounded	Wye-Grounded	Secondary Grounding Transformer

Table 1
Permitted Transformer Winding Configurations for Multi-Grounded Circuits

6 Energy Storage System

The PV facility shall be designed and constructed to accommodate a future DC coupled ESS of at least 2 MW/8 MWh in size.

6.1 ESS Option

Vendors may submit an option to include the design, procurement, installation and commissioning of an ESS that will be utilized to increase facility output during typical peak hours (3 to 4 hour period per day). The ESS shall only be capable of being charged from the solar modules/DC side of the PV facility.

Vendors shall propose a reasonable ESS size based on their past experience.

7 Project Manager

It is Unitil's desire to have one primary point of contact, Project Manager, for the coordination and completion of all tasks described in this RFP. Unitil will require routine updates regarding the progression of the Work to be provided by the Vendor's assigned Project Manager. This Project Manager should be experienced in Work of this nature and the importance of communicating with customers regarding the project's progress.

The Project Manager shall participate in routine project meetings to review the status of the construction project. The frequency of such meetings will be dependent on the on-going tasks being performed. For convenience remote meeting call-in information will be provided. Proposals shall include the assumed number of hours included for communication with the Company and the hourly rate in which this will billed.

8 Construction Field Representative

Vendor shall provide a construction field representative that will serve as the Company's on-site representation throughout the duration of construction of the facility. This individual shall have a good understanding of the various aspects of the project and have a broad understanding of current construction practices.

This effort shall include the monitoring of the quality and progress of construction, assisting the construction contractor(s) in understanding the intent of the construction documents, confirming the site is constructed as designed and submitting weekly progress reports to the Company. Proposals shall include the assumed number of hours included for the construction field services representative's responsibilities and the hourly rate in which this will billed.

9 Contract Structure and Terms

Unitil is considering awarding the EPC contract for the construction of the PV facility prior to receiving regulatory approval and/or construction permits. This will allow the selected Vendor to assist Unitil in the pre-procurement aspects of the project. However, it is Unitil's intent to not order any PV facility material or execute any construction contracts until the NHPUC finds that the project is in the public interest and all construction permits are eminent.

It is Unitil's expectation that any contract executed in accordance with this RFP will include "re-quote"/"re-pricing" requirements for the procurement and construction components detailed in this RFP. At which time, Unitil at is sole discretion may elect to terminate this agreement for any reason including, but not limited to pricing changes that no longer make the project economically feasible, construction permit rejections, regulatory rejection, etc.

As part of their proposals vendors shall include contract terms and conditions as well as a "re-quoting"/"re-pricing" mechanism and payment schedule, if applicable for the pre-procurement components of the project in the event the procurement and construction of the facility does not move forward.

10 Proposal Requirements

Each proposal shall include the following as well as any additional information vendors would like to provide.

10.1 Vender Information

- Form of legal entity and year entity was established
- Location
- Describe any changes in ownership over past 10 years
- Outstanding Lawsuits and Disputes
- Describe general reputation and performance capabilities of firm.
- Number of year's Vendor has been engaged in providing services
- Number of full-time employees and full-time local (New Hampshire and New England) employees
- Accreditations or qualifications for work of those to be involved in the proposed project

10.2 Construction, Commissioning and Maintenance

- Detailed description of the proposed PV system – proposed technology, scope of work, features, installed capacity, equipment (inverters, transformer, PV modules, etc.) foundations/mounting details, and "cut-sheets" of major equipment (e.g., inverters, modules, transformer, etc.) to be installed.
- Preliminary layout and one-line of the proposed facility.

- Environmental loading facility is/will be designed for.
- Description of all below grade equipment.
- Detail description of racking equipment, equipment pads and other structural support elements.
- Estimated clear area in acres required for the proposed facility.
- Expected life of the facility in years and anticipated inverter, PV module and ESS (if applicable) component replacements over the expected life of the facility.
- Equipment cutout sheets for all major equipment (inverters, OV modules, racking equipment, step-up transformer, etc.
- Inverter, PV modules, racking equipment, and (ESS if applicable) warranty terms and conditions.
- Expected life in years of the proposed inverters, PV module, racking equipment and ESS (if applicable).
- Estimated annual energy production and method utilized to perform the calculation for each year of the next 30 years.
- Estimated hourly energy production per day for each month of the year for the following hours and method utilized to perform the calculation:

  15:00-16:00
  16:00-17:00
  17:00-18:00
  18:00-19:00
  19:00-20:00
- Facility production curves.
- List of recommended spare equipment.
- Recommended periodic maintenance requirements.
- Sample testing and commissioning plan
- Country of manufacture of all major equipment (e.g., inverters, modules, transformers, racking equipment, etc.)
- Detailed schedule for engineering, procurement and construction
- Describe capability and cost to provide 5 years of PV and ESS (if applicable) facility operation and maintenance.
- Listing of all applicable statutes, ordinances, codes, standards, and/or regulations the facility will be designed to comply with.

10.3 Pricing Proposals

Price proposals shall be based on and will be evaluated on the information provided within this document. All pricing proposals shall be completed in the excel document entitled “2022 Kington Solar Project EPC RFP – Pricing Response”.

Utility Scale PV – Facility Engineering, Procurement and Construction
Kingston Solar Project
Request for Proposal – Scope of Services
November 30, 2022

Per section 9 above vendors shall include contract terms and conditions as well as a "re-quoting"/"re-pricing" mechanism and payment schedule, if applicable for the pre-procurement components of the project in the event the procurement and construction of the facility does not move forward.

10.4 Lead Time

Provide current lead time for all major equipment (PV modules, racking equipment, inverters, step-up transformer, etc.) and anticipated construction timeline.

10.5 Exceptions, Omissions, Additions or Modifications

Any and all exceptions, omission, additions or modifications to what is outlined in this RFP shall be clearly identified, including a detailed explanation of the reason(s) for the proposed exception/change.

10.6 Questions to Vendors

Each vendor is required to provide complete and detailed responses to all information requested, including responses to the questions below.

10.6.1 Experience

Describe at least 5 examples of previous projects installing "utility scale" PV facilities similar to the size and type specified in this RFP. Your response should include your responsibilities as well as the responsibilities of others.

10.6.2 References

Provide a listing of at least 3 clients that have engaged your organization in projects associated with the installation of "utility scale" PV facilities of similar size and type specified in this RFP on vacant land to be used as references. Please include company, name, address, phone number and contact person, along with a description of the projects completed and your company's role. It is preferred that the contacts be people who worked closely with your company on a daily basis.

10.6.3 Supply Chain

Indicate supply chain trends, including product pricing and lead times, of major equipment (PV modules, inverters, step-up transformer, ESS, etc.) over the past twelve months. Provide any insight on those trends continuing, stabilizing or improving over the next twelve months.

10.6.4 NESC

With this being a utility owned facility it is Unitil's understanding that it will need to comply with all applicable portions of the NESC. Describe your experience designing and constructing facilities that comply with the NESC.

10.6.5 Local Businesses

Briefly describe if/how you plan to involve local businesses and/or local labor in the design and/or construction of the facility.

10.6.6 Investment Tax Credit

Briefly describe any known requirements for Unitil to achieve the maximum federal Investment Tax Credit (ITC)/Inflation Reduction Act (IRA) incentives and other tax incentives for this project and how your proposal assists in meeting those requirements.

The description shall include details on how your proposal will meet the IRS wage, apprentice requirements for Unitil to achieve the maximum IRA incentives for the project.

10.6.7 Work Planning

Discuss your plan to deliver the work described in the RFP throughout completion.

11 Attachments

- 2 Mill Road/24 Towle Road, Kingston, NH – Existing Conditions Plan – Progress Print
- 2022 Kington Solar Project EPC RFP – Pricing Response Spreadsheet

REVISION ENERGY

Kingston Solar Project EPC Proposal

Response to Request for Proposal for Utility Scale PV Facility Engineering, Procurement and Construction

January 20, 2023

ReVision Energy Inc.
An Employee-Owned Solar Company
New Hampshire, Maine, & Massachusetts
www.ReVisionEnergy.com
(603) 679-1777

Certified B Corporation

General Information

AC Nameplate Capacity	4875.0	kWh
Total Nameplate Capacity of PV Modules	6505.0	kWh
Estimated Required Clear Space	33	Acres
Expected Life of the Facility	40	Years

Equipment Life and Warranty Information

	Warrenty Term		Expected Life	
Inverters	20	Years	20	Years
PV Modules	25	Years	40	Years
Racking Equipment	20	Years	40	Years

Estimated Energy Production

Estimated Annual Energy Generated - Year 1	9,729,412	kWh
% Reduction from Year 1 to Year 2	2.0%	%
Annual % Reduction Year 2 to the End of Life of the Facility	0.5%	%

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Estimated Hourly Energy Produced per day 15:00-16:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	kWh
Estimated Hourly Energy Produced per day 16:00-17:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	kWh
Estimated Hourly Energy Produced per day 17:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	kWh
Estimated Hourly Energy Produced per day 18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	kWh
Estimated Hourly Energy Produced per day 19:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	kWh

REDACTED

Pricing Information:

	$
Pre-Procurement and Construction Activities (excluding SIS)	$ [redacted]
SIS	$ [redacted]
Site Construction	$ [redacted]
Inverters and Associated Material	$ [redacted]
PV Modules and Associated Material	$ [redacted]
Racking Equipment and Associated Material	$ [redacted]
Step-up Transformer and Associated Material	$ [redacted]
Fence Material	$ [redacted] incl. installation labor
All Other Material (excluding fence)	$ [redacted]
Labor to Install and Commission Facility	$ [redacted]

	Hours	$/hr
Project Management	[redacted]	$ [redacted]
Construction Field Representative	[redacted]	$ [redacted]

One (1) Spare Step-Up Transformer	$ [redacted]
One (1) Spare Inverter	$ [redacted]
Five (5) Spare PV Modules	$ [redacted]
Other Recommended Spare Equipment	$ [redacted]
Total Project Cost (excluding maintenance plan)	$ [redacted] $ [redacted]
5 Year Maintenance Plan	$ [redacted]

Option BESS Information:

Nameplate Capacity of BESS	kWh	kW

	Warrenty Term	Expected Life
BESS	Years	Years

	$
BESS	
All other material	
Labor to Install and Commission BESS	

	Hours	$/hr
BESS Project Management		
BESS Construction Field Representative		

BESS Recommended Spare Equipment	
Total Project Adder for BESS (excluding maintenance plan)	
BESS 5 Year Maintenance Plan	

12% OH

Notes and Comments

[redacted]

REDACTED

Initial Question to ReVision Energy

Responses Submitted January 26, 2023
Dan Weeks, VP of Business Development
dweeks@revisionenergy.com
Direct: (603) 264-2877

1. Could you provide an example of contract terms for a project such as this when pre-procurement activities will take place prior to the purchase of equipment with the purchase of equipment being contingent upon regulatory approval and/or final economic analysis? See section 9 of the RFP.

ReVision understands the importance of deferring equipment purchases and construction until after the project has been fully or substantially de-risked by obtaining the requisite regulatory/permitting approvals and ensuring the financial viability of the project. As stated on page 26 of our RPF proposal, ReVision's industry-standard EPC contract contains a Notice to Proceed (NTP) clause, which [redacted] Our standard NTP clause reads as follows (equipment procurement is contained within the definition of Construction Work):

[redacted]

In the event the Kingston Solar Project did not reach NTP and move to procurement and construction, ReVision would only charge Unitil for [redacted] as stipulated in our EPC contract, in accordance with the scope of pre-procurement development activities agreed upon in advance by both parties.

2. What type of foundations are proposed for Racking/Modules – Driven Pile, Ground Screw or concrete ballast?

ReVision proposes to use ground screws as the solar array foundation. As we noted on page 19 of the RFP, "ReVision's single-axis tracker (SAT) racking system, provided by our longtime US-based racking partner TerraSmart (UL 3703), is uniquely suited to uneven and environmentally sensitive terrain like the two Kingston parcels. ReVision's experience installing hundreds of ground-mounted solar arrays throughout New Hampshire and in neighboring states has made us keenly aware of the costly impact of ledge, frost heaves, and other sub-surface conditions limiting site development when using conventional driven pile foundations. We therefore favor TerraSmart's ground screw foundation, with its corrosion resistant galvanized coating, which eliminates 100% refusal risks while also reducing the amount of expensive land grading and related civil work."

3. Can you provide an estimated replacement cost for each of the following components for each year in the life of the facility?

The replacement cost of major components naturally depends on the extent of replacements required as well as future equipment cost inflation and the availability of specific components and compatible successor technologies in the future. It is therefore not possible to provide accurate guidance regarding replacement costs in each future year over the 40-year expected commercial life of the facility. That said, we would refer Unitil to the itemized pricing included in the Pricing Response sheet for an accurate representation of the year 1 pricing, which we are showing on a per-unit basis below (including industry-standard overhead), and recommend Unitil apply a 3% annual inflation index for future-year estimates.

- Racking equipment incl. tracking motors: [redacted] per kilowatt (approx. 2 modules)
- PV modules: [redacted] per module
- Inverters: [redacted] per inverter

Fortunately, over the course of ReVision's more than 14,000 clean energy system installations in northern New England since 2003, the failure rate of our racking, modules, and inverters (and other components) has been extremely low, with a fraction of 1% of components requiring service in a given year. In almost all such cases, the replacement or repair is covered by the manufacturer's warranty, and ReVision serves as the manufacturer point of contact and service provider on behalf of our clients. This high performance rate is particularly true for commercial systems that are regularly maintained by ReVision's in-house Service team under an Operations and Maintenance (O&M) contract such as the one recommended in the RFP. We therefore advise that Unitil proceed with confidence in the future performance of the PV system, knowing ReVision provides comprehensive O&M services and a 5-year wraparound workmanship warranty on top of the 5-25 year warranties on major components.

4. Can you provide and estimated cost to remove and dispose of all equipment associated with the facility (minus salvage cost) at the end of the facility life?

Given the very low quantity of installed solar arrays that have reached or are approaching their end of life, as well as the steady advances being made in solar panel recycling, it is not possible to provide a confident estimate of decommissioning costs. We recommend [redacted] as a placeholder value for the Kingston solar array. This is based on analysis of numerous decommissioning agreements in the public domain for megawatt-scale solar arrays in Massachusetts and Vermont that were approved by municipal Planning Boards, which carried an average decommissioning cost of [redacted] per MW. We believe these values are conservative based on the emerging secondary market for recycled solar equipment, which is expected to grow significantly over the next few decades as global adoption of solar increases exponentially and demand for lower-cost refurbished solar modules in developing countries continues to rise.

ReVision already recycles solar panels with a locally-based recycling operation, on favorable terms, in the rare instances when a module is damaged and needs to be replaced.

5. Please confirm Estimated Hourly Energy Produced is watt-hours for a single day for the month/hour specified? The values provided are about 25% higher than what Unitil had been assuming previously.

Yes, the estimate hourly energy produced is in watt-hours for the average hour and day of the month shown. We apologize for erroneously noting *kilowatt*-hours in Figure 4 of the RFP and are supplying the updated table with kWh as follows:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
3pm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4pm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5pm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6pm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7pm	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As noted on page 12 of the RFP response, these production data are taken directly from the Helioscope production report's 8,760-Hour Annual Generation Profile, which shows the watt-hours of electricity produced each hour of the year based on the specific system components, design characteristics, and thirty years of federal weather data from the nearest Typical Meteorological Year (TMY2) weather station at Concord Municipal Airport. The only missing input in the solar production model is local shade conditions, which will be dependent on the final site plan and permitting conditions (esp. extent of tree removal); based on the site layout and our experience permitting similar sites for solar, we anticipate only nominal shade losses which are likely to be offset through increased bifacial gain relative to the very conservative 4% bifacial factor we modeled (see page 11 of the RPF response). Although the modeled production is substantially higher than that of an equivalently-sized fixed-tilt solar array (the most common form of ground-mounted solar installation by far), the production premium is consistent with industry data showing single-axis trackers produce 15-20% more power than fixed-tilt arrays on an annual basis. That production premium rises to 25% or more during the early morning and late afternoon hours, especially in summer, when single-axis trackers attain optimal eastern and western orientation compared to the standard south-facing fixed-tilt array, that only receives sunlight at a slant.

6. Could you please provide a list of what is included in site construction costs?

Recognizing that Unitil plans to utilize its local tree clearing and other civil contractors for the bulk of site preparation/construction work, and that specific permitting requirements for the work are unknown at this stage, ReVision chose to include a conservative site construction support budget of [redacted]. This placeholder figure is meant to cover portions of the solar-specific site preparation/construction work that may fall outside the core competencies of Unitil's site contractors, such as geotechnical survey work for earth screw foundations, trenching earthworks, and landscape reseeding for animal grazing/pollinator habitat, as well as substantial site construction coordination work between Unitil's site contractors and our Project Manager and Construction Field Representative.

REDACTED

We wish to provide Unitil maximum flexibility/optionality. We are fully capable of owning the complete site construction scope, if Unitil prefers to delegate this authority, and we are also prepared to reduce the foregoing budget substantially to focus on basic coordination if Unitil and its site contractors manage the full site construction scope in accordance with the system mechanical and electrical specifications. We look forward to entering into detailed discussions regarding the optimal scope and budget for site construction.

7. Could you provide a list of what is included in the Pre-Construction Activities?

Because the RFP called for Engineering, Procurement and Construction (EPC) pricing and noted that Unitil has already commenced pre-construction development activities with TJ Moran, including site surveying for environmental permitting, ReVision did not carry our standard full scope of development work. Instead, our more limited proposed [redacted] budget for pre-construction activities includes but is not limited to:

- Conducting professional site visits of the two parcels by our Project Manager (master electrician), Project Designer and other staff to verify project feasibility and collect necessary information to inform full system mechanical and electrical designs;
- Developing multiple iterations of the PV system engineering design and Helioscope production report by ReVision's in-house Engineering team (incl. Project Designer, CAD specialists, and electrical engineers) based on site visits and TF Moran surveys for Unitil's final approval;
- Developing multiple comprehensive EPC pricing estimates (in the event of design changes) by our in-house estimators consisting of detailed vendor and subcontractor pricing for all major equipment suppliers and contractors;
- Producing full mechanical and electrical engineering drawings of the approved solar PV system, stamped by our in-house Professional Engineers, to enable TF Moran to obtain all local, state, and federal permits;
- Providing active coordination and support for TF Moran throughout the permitting process by our Project Manager and Project Designer, with additional support as needed from our electrical engineers, Director of Development, Director of Construction, and Chief Operating Officer;
- Providing active policy and regulatory support for Unitil and TF Moran, as needed, throughout the design and interconnection process by our Director of Regulatory Affairs, Director of Policy and Advocacy, and Vice President of Business Development who are actively involved in all relevant proceedings at the state legislature, Public Utilities Commission, Department of Energy, Department of Environmental Services, US Army Corps of Engineers, and US Fish & Wildlife Service[1];

[1] The recent federal reclassification of the Northern Long-Eared Bat (NLEB) from threatened to endangered provides a relevant case in point of ReVision's ability to deliver substantial (unanticipated) regulatory support, at no additional cost to our clients. Within days of the federal reclassification, which threatened to delay or derail one of our utility scale solar projects, ReVision had obtained expert opinions from multiple bat biologists, conservation professionals, and environmental attorneys (including a former DES commissioner); assembled relevant desktop and physical site survey data concerning the potential existence of bat hibernacula on the solar site in question; initiated substantive consultations with the relevant permitting agencies including US Fish & Wildlife Service (FWS), US Army Corps of Engineers, and state Department of Environmental Services in advance of FWS guidelines being released; developed and submitted a detailed report with our environmental engineering consultant concerning NLEB impacts; and obtained the first negative determination showing no adverse NLEB impacts provided by FWS under their new (beta) determination key. The prompt and successful outcome of this unanticipated pre-construction activity

- Attending and actively participating in local Planning Board, Zoning Board of Adjustment, and other permitting proceedings by our Project Manager and senior staff members as appropriate (including our Chief Operating Officer who resides in Kingston and maintains active involvement with the relevant local boards and commissions);
- Providing active support for the utility System Impact Study contractor by our in-house electrical engineers and Director of Development, who have collaborated extensively with Unitil and other utilities on prior System Impact Studies (including value engineering solutions to reduce interconnection costs while fully adhering to NESC and other safety and reliability requirements.

8. Please confirm all quoted costs include standard warranties and not optional extensions.

Confirmed

9. Would the project still qualify for the 10% bonus ITC (40% total) is construction began in 2023 and was completed in 2024 or would all construction activities need to take place in 2024?

Yes, we are confident the project would still qualify for the 10% bonus ITC, assuming domestic content requirements are met, if construction began in 2023 and was completed in 2024. Nothing in the Inflation Reduction Act (IRA) indicates construction must be completed within a single calendar year to qualify, which is rarely the case with utility scale solar projects. As noted on page 31 of ReVision's RFP response, the US Treasury Department has yet to release its detailed guidelines concerning domestic content so we cannot be certain of the precise requirements in terms of construction schedules and equipment eligibility at this time. We are actively tracking the federal IRA rulemaking anticipate receiving final guidance in the next few months.

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was made possible by our extensive in-house development and permitting capabilities (as the most experienced full-service commercial solar development and EPC contractor in the region) as well as our strong and extensive connections with all relevant local/state/federal permitting authorities. At the conclusion of the process, which enabled our utility scale solar farm to proceed, we were commended by the federal authorities for providing them with a level of insight into NLEB impacts and permitting that they had not been able to obtain from official or other sources. The experience reinforced ReVision's longstanding commitment to approach all development (as well as EPC) activities with the utmost diligence, in deference to both our clients and the numerous permitting authorities charged with protecting our natural environment.

REDACTED

Estimated Hourly Energy Produced per Day from Vendor

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Estimated Hourly Energy Produced 15:00-16:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 16:00-17:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 17:00-18:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 18:00-19:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 19:00-20:00	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh

Historical ISO Peak

	Peak Hour Begin	Peak Hour End
8/09/2001	14:00	15:00
8/14/2002	14:00	15:00
8/22/2003	14:00	15:00
8/30/2004	15:00	16:00
7/27/2005	14:00	15:00
8/02/2006	14:00	15:00
8/03/2007	14:00	15:00
6/10/2008	14:00	15:00
8/18/2009	14:00	15:00
7/06/2010	14:00	15:00
7/22/2011	14:00	15:00
7/17/2012	16:00	17:00
7/19/2013	16:00	17:00
7/02/2014	14:00	15:00
7/29/2015	16:00	17:00
8/12/2016	14:00	15:00
6/13/2017	16:00	17:00
8/29/2018	16:00	17:00
7/30/2019	17:00	18:00
7/27/2020	17:00	18:00
6/29/2021	16:00	17:00

\# from 2012-2021

	June	July	Aug
1400-1500		1	1
1500-1600			
1600-1700	2	3	1
1700-1800		2	

Calculated Estimated Output at the ISO Peak Hour

	Wh	kWh	% of AC Capacit	AC Capacity (MW)
Average of Estimated Output at Historical Month/Hour	2,885,581	2,886	59.2%	4.875 Utilized 15:00-16:00 for 14:00-15:00 ISO Peak Hour
Average of Estimated Output at Historical Month/Hour (excluding 14:00-15:00)	2,761,470	2,761	56.6%	
Average of 16:00-17:00 and 17:00-18:00 for months of June, July and August)	2,379,122	2,379	48.8%	

REDACTED

Estimated Hourly Energy Produced per Day from Vender

	Hour Ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
Estimated Hourly Energy Produced 15:00-16:00	16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 16:00-17:00	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 17:00-18:00	18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 18:00-19:00	19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh
Estimated Hourly Energy Produced 19:00-20:00	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Wh

Historical Eversource Peak

Time of Peak Hour (hour ending @)

Month	1	2	3	4	5	6	7	8	9	10	11	12
2017				18	18	16	17	17	17	19	18	18
2018	18	18	19	20	18	17	17	17	15		18	18
2019	18	19	19		18	18	18	16	18	15	18	19
2020	18	19	18	18	18	18	18	18	18	19	18	18
2021	19	18	19	20	18	18	17	18	18	19	18	18
2022	18	19	19	20								

Estimates Output at Historical Eversource Peak Hour

Time of Peak Hour (hour ending @)

Month	1	2	3	4	5	6	7	8	9	10	11	12
2017				795,788	1,408,428	3,319,212	3,101,147	2,735,347	1,594,315	0	0	0
2018	0	15,611	1,284	0	1,408,428	3,047,611	3,101,147	2,735,347		0	0	0
2019	0	0	1,284		1,408,428	2,039,929	1,978,873	3,263,253	210,922	0	0	0
2020	0	0	244,161	795,788	1,408,428	2,039,929	1,978,873	1,371,822	210,922	0	0	0
2021	0	15,611	1,284	0	1,408,428	2,039,929	3,101,147	1,371,822	210,922	0	0	0
2022	0	0	1,284	0								

Historical ISO-NE Peak

Time of Peak Hour (hour ending @)

Month	1	2	3	4	5	6	7	8	9	10	11	12
2017				18	18	17	18	17	17	19	18	18
2018	18	18	19	20	18	17	18	17	16	19	18	18
2019	18	19	19	20	18	18	18	16	17		18	18
2020	18	19	19	18	18	18	18	18	18	19	18	18
2021	18	18	19		18	16	16	18	17	19	18	18
2022	18	18	19	20								

Estimates Output at Historical ISO-NE Peak Hour

Time of Peak Hour (hour ending @)

Month	1	2	3	4	5	6	7	8	9	10	11	12
2017				795,788	1,408,428	3,047,611	1,978,873	2,735,347	1,594,315	0	0	0
2018	0	15,611	1,284	0	1,408,428	3,047,611	1,978,873	2,735,347	2,758,121	0	0	0
2019	0	0	1,284	0	1,408,428	2,039,929	1,978,873	3,263,253	1,594,315	0	0	0
2020	0	0	1,284	795,788	1,408,428	2,039,929	1,978,873	1,371,822	210,922	0	0	0
2021	0	15,611	1,284		1,408,428	3,319,212	3,500,796	1,371,822	1,594,315	0	0	0
2022	0	15,611	1,284	0								

Calculated Estimated Output at the ISO Peak Hour

	Wh	kWh	% of AC Capacity	AC Capacity (MW)	
Average of Estimated Output at Historical Month/Hour (Eversource)	819,775	820	16.8%	4.875	Excludes 14:00-15:00 Peak Hour
Average of Estimated Output at Historical Month/Hour (ISO-NE)	880,452	880	18.1%		Excludes 14:00-15:00 Peak Hour
Average of Estimated Output at Historical Month/Hour (ISO-NE and Eversource)	850,368	850	17.4%		Excludes 14:00-15:00 Peak Hour

REDACTED

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis

Table of Contents

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 1
Summary

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Direct Customer Benefits											
2	Avoided Energy Costs	Direct Customer Benefits, Line 12	$ 882,458	$ 725,600	$ 701,977	$ 686,108	$ 696,223	$ 706,468	$ 716,844	$ 727,353	$ 737,995	$ 748,773
3	Avoided Capacity Costs	Direct Customer Benefits, Line 19	100,203	98,199	97,698	97,197	96,696	96,195	95,694	95,193	94,692	94,191
4	Local Transmission Benefits	Direct Customer Benefits, Line 27	16,103	16,096	16,335	16,576	16,820	17,068	17,318	17,572	17,829	18,090
5	Regional Transmission Benefits	Direct Customer Benefits, Line 37	118,949	118,901	120,660	122,442	124,247	126,076	127,927	129,803	131,702	133,625
6	Renewable Energy Credit Savings	Direct Customer Benefits, Line 42	357,556	350,405	348,617	346,829	345,041	343,254	341,466	339,678	337,890	336,103
7	Total Direct Customer Benefits	Sum Lines 2 through 6	$ 1,475,268	$ 1,309,202	$ 1,285,287	$ 1,269,153	$ 1,279,028	$ 1,289,060	$ 1,299,250	$ 1,309,599	$ 1,320,109	$ 1,330,781
8												
9	Costs											
10	Revenue Requirement	Rate Base & Revenue Requirement, Line 28	$ 1,571,340	$ 1,461,528	$ 1,347,158	$ 1,263,995	$ 1,192,492	$ 1,154,353	$ 1,109,591	$ 1,073,564	$ 1,037,476	$ 1,001,326
11	Total Costs	Line 10	$ 1,571,340	$ 1,461,528	$ 1,347,158	$ 1,263,995	$ 1,192,492	$ 1,154,353	$ 1,109,591	$ 1,073,564	$ 1,037,476	$ 1,001,326
12												
13	Net Benefit (Cost) to Customers	Line 7 - Line 11	$ (96,071)	$ (152,326)	$ (61,871)	$ 5,158	$ 86,536	$ 134,708	$ 189,659	$ 236,035	$ 282,633	$ 329,456
14												
15	Required Rate of Return	Cost of Capital, Line 8, Column (h)	6.71%									
16												
17	Present Value (PV)											
18	PV of Direct Customer Benefits	PV of Line 7	$ 19,291,559									
19	PV of Costs	PV of Line 11	16,747,851									
20	Net Present Value	Line 18 - Line 19	$ 2,543,708									
21												
22	Internal Rate of Return	Internal Rate of Return of Line 13	28.90%									
23												
24	Benefit-Cost Ratio (BCR)	Line 18 ÷ Line 19	1.15									

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 1
Summary

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Direct Customer Benefits											
2	Avoided Energy Costs	Direct Customer Benefits, Line 12	$ 759,685	$ 770,735	$ 781,924	$ 793,251	$ 804,719	$ 816,328	$ 828,079	$ 839,974	$ 852,014	$ 864,199
3	Avoided Capacity Costs	Direct Customer Benefits, Line 19	93,690	93,189	94,542	95,912	97,298	98,702	100,123	101,561	103,017	104,490
4	Local Transmission Benefits	Direct Customer Benefits, Line 27	18,353	18,620	18,891	19,164	19,441	19,722	20,006	20,293	20,584	20,878
5	Regional Transmission Benefits	Direct Customer Benefits, Line 37	135,573	137,545	139,541	141,563	143,609	145,681	147,778	149,901	152,050	154,224
6	Renewable Energy Credit Savings	Direct Customer Benefits, Line 42	334,315	332,527	330,739	328,951	327,164	325,376	323,588	321,800	320,013	318,225
7	Total Direct Customer Benefits	Sum Lines 2 through 6	$ 1,341,617	$ 1,352,617	$ 1,365,637	$ 1,378,841	$ 1,392,231	$ 1,405,808	$ 1,419,574	$ 1,433,529	$ 1,447,676	$ 1,462,016
8												
9	Costs											
10	Revenue Requirement	Rate Base & Revenue Requirement, Line 28	$ 1,399,120	$ 1,369,157	$ 1,339,210	$ 1,309,279	$ 1,279,364	$ 1,249,466	$ 1,219,585	$ 1,189,722	$ 1,159,876	$ 1,195,418
11	Total Costs	Line 10	$ 1,399,120	$ 1,369,157	$ 1,339,210	$ 1,309,279	$ 1,279,364	$ 1,249,466	$ 1,219,585	$ 1,189,722	$ 1,159,876	$ 1,195,418
12												
13	Net Benefit (Cost) to Customers	Line 7 - Line 11	$ (57,504)	$ (16,541)	$ 26,427	$ 69,562	$ 112,867	$ 156,342	$ 199,988	$ 243,807	$ 287,800	$ 266,598
14												
15	Required Rate of Return	Cost of Capital, Line 8, Column (h)										
16												
17	Present Value (PV)											
18	PV of Direct Customer Benefits	PV of Line 7										
19	PV of Costs	PV of Line 11										
20	Net Present Value	Line 18 - Line 19										
21												
22	Internal Rate of Return	Internal Rate of Return of Line 13										
23												
24	Benefit-Cost Ratio (BCR)	Line 18 ÷ Line 19										

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 1
Summary

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Direct Customer Benefits											
2	Avoided Energy Costs	Direct Customer Benefits, Line 12	$ 876,531	$ 889,010	$ 901,638	$ 914,416	$ 927,344	$ 940,423	$ 953,655	$ 967,039	$ 980,578	$ 994,271
3	Avoided Capacity Costs	Direct Customer Benefits, Line 19	105,981	107,490	109,017	110,562	112,125	113,706	115,306	116,924	118,561	120,217
4	Local Transmission Benefits	Direct Customer Benefits, Line 27	21,176	21,478	21,783	22,091	22,404	22,720	23,039	23,363	23,690	24,021
5	Regional Transmission Benefits	Direct Customer Benefits, Line 37	156,425	158,652	160,906	163,186	165,493	167,827	170,188	172,577	174,993	177,437
6	Renewable Energy Credit Savings	Direct Customer Benefits, Line 42	316,437	314,649	312,861	311,074	309,286	307,498	305,710	303,923	302,135	300,347
7	Total Direct Customer Benefits	Sum Lines 2 through 6	$ 1,476,550	$ 1,491,279	$ 1,506,205	$ 1,521,328	$ 1,536,651	$ 1,552,174	$ 1,567,898	$ 1,583,826	$ 1,599,956	$ 1,616,292
8												
9	Costs											
10	Revenue Requirement	Rate Base & Revenue Requirement, Line 28	$ 1,219,712	$ 1,186,708	$ 1,153,641	$ 1,122,735	$ 1,092,613	$ 1,065,845	$ 1,042,833	$ 1,020,243	$ 997,536	$ 974,749
11	Total Costs	Line 10	$ 1,219,712	$ 1,186,708	$ 1,153,641	$ 1,122,735	$ 1,092,613	$ 1,065,845	$ 1,042,833	$ 1,020,243	$ 997,536	$ 974,749
12												
13	Net Benefit (Cost) to Customers	Line 7 - Line 11	$ 256,838	$ 304,571	$ 352,563	$ 398,593	$ 444,038	$ 486,329	$ 525,065	$ 563,583	$ 602,420	$ 641,543
14												
15	Required Rate of Return	Cost of Capital, Line 8, Column (h)										
16												
17	Present Value (PV)											
18	PV of Direct Customer Benefits	PV of Line 7										
19	PV of Costs	PV of Line 11										
20	Net Present Value	Line 18 - Line 19										
21												
22	Internal Rate of Return	Internal Rate of Return of Line 13										
23												
24	Benefit-Cost Ratio (BCR)	Line 18 ÷ Line 19										

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 1
Summary

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Direct Customer Benefits											
2	Avoided Energy Costs	Direct Customer Benefits, Line 12	$ 1,008,120	$ 1,022,125	$ 1,036,287	$ 1,050,606	$ 1,065,084	$ 1,079,721	$ 1,094,517	$ 1,109,473	$ 1,124,590	$ 1,139,867
3	Avoided Capacity Costs	Direct Customer Benefits, Line 19	121,891	123,585	125,297	127,028	128,779	130,549	132,338	134,146	135,974	137,821
4	Local Transmission Benefits	Direct Customer Benefits, Line 27	24,355	24,694	25,036	25,382	25,731	26,085	26,443	26,804	27,169	27,538
5	Regional Transmission Benefits	Direct Customer Benefits, Line 37	179,908	182,407	184,935	187,490	190,074	192,686	195,327	197,996	200,693	203,420
6	Renewable Energy Credit Savings	Direct Customer Benefits, Line 42	298,559	296,771	294,984	293,196	291,408	289,620	287,832	286,045	284,257	282,469
7	Total Direct Customer Benefits	Sum Lines 2 through 6	$ 1,632,834	$ 1,649,582	$ 1,666,538	$ 1,683,702	$ 1,701,076	$ 1,718,661	$ 1,736,456	$ 1,754,463	$ 1,772,683	$ 1,791,115
8												
9	Costs											
10	Revenue Requirement	Rate Base & Revenue Requirement, Line 28	$ 954,377	$ 936,235	$ 917,911	$ 899,490	$ 881,002	$ 865,838	$ 853,717	$ 841,345	$ 828,834	$ 816,227
11	Total Costs	Line 10	$ 954,377	$ 936,235	$ 917,911	$ 899,490	$ 881,002	$ 865,838	$ 853,717	$ 841,345	$ 828,834	$ 816,227
12												
13	Net Benefit (Cost) to Customers	Line 7 - Line 11	$ 678,456	$ 713,347	$ 748,627	$ 784,213	$ 820,074	$ 852,823	$ 882,739	$ 913,119	$ 943,849	$ 974,888
14												
15	Required Rate of Return	Cost of Capital, Line 8, Column (h)										
16												
17	Present Value (PV)											
18	PV of Direct Customer Benefits	PV of Line 7										
19	PV of Costs	PV of Line 11										
20	Net Present Value	Line 18 - Line 19										
21												
22	Internal Rate of Return	Internal Rate of Return of Line 13										
23												
24	Benefit-Cost Ratio (BCR)	Line 18 ÷ Line 19										

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 2
Direct Customer Benefits

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Capacity - Nameplate	Exhibit SP-4	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW
2	Degradation Rate	Exhibit SP-4		2.0%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
3	Efficiency Rate	PY Line 3 - CY Line 2	100.0%	98.0%	97.5%	97.0%	96.5%	96.0%	95.5%	95.0%	94.5%	94.0%
4	Capacity - Adjusted for Efficiency Rate	Line 1 x Line 3	4.88 MW	4.78 MW	4.75 MW	4.73 MW	4.70 MW	4.68 MW	4.66 MW	4.63 MW	4.61 MW	4.58 MW
5												
6	EIA Energy Outlook 2022 - Escalation Rate [1]	Annual Escalation Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
7												
8	Avoided Energy Costs											
9	Annual Capacity Factor	Exhibit SP-4	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%
10	Annual Production (kWh)	Line 4 x Line 9 x 1000 x 365 x 24	9,729,412	9,534,824	9,486,177	9,437,530	9,388,883	9,340,236	9,291,588	9,242,941	9,194,294	9,145,647
11	Energy Rate ($ Per kWh) [2]	See Footnote	$ 0.0907	$ 0.0761	$ 0.0740	$ 0.0727	$ 0.0742	$ 0.0756	$ 0.0771	$ 0.0787	$ 0.0803	$ 0.0819
12	Annual Avoided Energy Costs	Line 10 x Line 11	$ 882,458	$ 725,600	$ 701,977	$ 686,108	$ 696,223	$ 706,468	$ 716,844	$ 727,353	$ 737,995	$ 748,773
13												
14	Avoided Capacity Costs											
15	PV Capacity at Annual Peak	Exhibit SP-6	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%
16	Capacity at Peak Hour (kW)	Line 4 x Line 15 x 1000	2,379	2,331	2,320	2,308	2,296	2,284	2,272	2,260	2,248	2,236
17	Capacity Clearing Price ($ kW-Month) [3]	See Footnote	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51	$ 3.51
18	Monthly Avoided Capacity Costs	Line 16 x Line 17	$ 8,350	$ 8,183	$ 8,142	$ 8,100	$ 8,058	$ 8,016	$ 7,975	$ 7,933	$ 7,891	$ 7,849
19	Annual Avoided Capacity Costs	Line 18 x 12	$ 100,203	$ 98,199	$ 97,698	$ 97,197	$ 96,696	$ 96,195	$ 95,694	$ 95,193	$ 94,692	$ 94,191
20												
21	Local Transmission Benefits											
22	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
23	Capacity at Peak Hour (MW-Month)	Line 4 x Line 22	0.82	0.80	0.80	0.79	0.79	0.79	0.78	0.78	0.77	0.77
24	Transmission Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	$ 1,630.95	$ 1,663.57	$ 1,696.84	$ 1,730.78	$ 1,765.39	$ 1,800.70	$ 1,836.71	$ 1,873.45	$ 1,910.92	$ 1,949.14
25	Ancillary Services Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	7.51	7.66	7.81	7.97	8.13	8.29	8.46	8.63	8.80	8.98
26	Monthly Local Transmission Benefits	Line 23 x (Line 24 + Line 25)	$ 1,342	$ 1,341	$ 1,361	$ 1,381	$ 1,402	$ 1,422	$ 1,443	$ 1,464	$ 1,486	$ 1,507
27	Annual Local Transmission Benefits	Line 26 x 12	$ 16,103	$ 16,096	$ 16,335	$ 16,576	$ 16,820	$ 17,068	$ 17,318	$ 17,572	$ 17,829	$ 18,090
28												
29	Regional Transmission Benefits											
30	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
31	Capacity at Peak Hour (kW-Month)	Line 4 x Line 30 x 1000	819	803	799	794	790	786	782	778	774	770
32	ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) [5]	Annual Escalation, Line 5	$ 0.2048	$ 0.2088	$ 0.2130	$ 0.2173	$ 0.2216	$ 0.2261	$ 0.2306	$ 0.2352	$ 0.2399	$ 0.2447
33	ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) [6]	Annual Escalation, Line 5	0.0070	0.0072	0.0073	0.0074	0.0076	0.0077	0.0079	0.0081	0.0082	0.0084
34	ISO NE Section 2, Schedule 1 Rate ($ kW-Month) [7]	Annual Escalation, Line 5	0.1459	0.1489	0.1518	0.1549	0.1580	0.1611	0.1643	0.1676	0.1710	0.1744
35	ISO NE Section 2, Schedule 9 Rate ($ kW-Month) [8]	Annual Escalation, Line 5	11.7453	11.9802	12.2198	12.4642	12.7135	12.9678	13.2272	13.4917	13.7615	14.0368
36	Monthly Regional Transmission Benefits	Line 31 x (Sum Lines 32 through 35)	$ 9,912	$ 9,908	$ 10,055	$ 10,204	$ 10,354	$ 10,506	$ 10,661	$ 10,817	$ 10,975	$ 11,135
37	Annual Regional Transmission Benefits	Line 36 x 12	$ 118,949	$ 118,901	$ 120,660	$ 122,442	$ 124,247	$ 126,076	$ 127,927	$ 129,803	$ 131,702	$ 133,625
38												
39	Renewable Energy Credits (REC) Savings											
40	Annual Production (MWh)	Line 10 ÷ 1000	9,729	9,535	9,486	9,438	9,389	9,340	9,292	9,243	9,194	9,146
41	REC II Rate ($ Per MWh) [9]	New England Power Pool	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	Annual REC Savings	Line 40 x Line 41	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43												
44	Total Direct Customer Benefits	Line 12 + Line 19 + Line 27 + Line 37 + Line 42	$ 1,475,268	$ 1,309,202	$ 1,285,287	$ 1,269,153	$ 1,279,028	$ 1,289,060	$ 1,299,250	$ 1,309,599	$ 1,320,109	$ 1,330,781

Notes
(1) EIA Annual Energy Outlook 2022, Table 8. End-Use Price, All Sectors Average
(2) Using ISO New England Futures from Year 1 through Year 4. Annual escalation beginning in Year 5
(3) 'Avoided Energy Supply Components in New England' 2021 Report, Page 123, Table 40. Counter-factual #1: 15-year Levelized Cost. Annual escalation beginning in Year 13
(4) Eversource, Schedule 21-ES (Part A) ISO-NE Transmission Markets and Services Tariff, Rates effective January 1, 2023
(5) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 1. Scheduling, System Control and Dispatch Service, Rates effective January 1, 2023
(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2023
(7) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 1. Scheduling, System Control and Dispatch Service, Rates effective June 1, 2022. Divided by 12
(8) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 9. Regional Network Service (RNS), Rates effective January 1, 2023. Divided by 12
(9) NH Class II REC 2023 Term

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Schedule 2
Direct Customer Benefits

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Capacity - Nameplate	Exhibit SP-4	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW
2	Degradation Rate	Exhibit SP-4	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
3	Efficiency Rate	PY Line 3 - CY Line 2	93.5%	93.0%	92.5%	92.0%	91.5%	91.0%	90.5%	90.0%	89.5%	89.0%
4	Capacity - Adjusted for Efficiency Rate	Line 1 x Line 3	4.56 MW	4.53 MW	4.51 MW	4.49 MW	4.46 MW	4.44 MW	4.41 MW	4.39 MW	4.36 MW	4.34 MW
5												
6	EIA Energy Outlook 2022 - Escalation Rate [1]	Annual Escalation Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
7												
8	Avoided Energy Costs											
9	Annual Capacity Factor	Exhibit SP-4	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%
10	Annual Production (kWh)	Line 4 x Line 9 x 1000 x 365 x 24	9,097,000	9,048,353	8,999,706	8,951,059	8,902,412	8,853,765	8,805,118	8,756,471	8,707,824	8,659,177
11	Energy Rate ($ Per kWh) [2]	See Footnote	$ 0.0835	$ 0.0852	$ 0.0869	$ 0.0886	$ 0.0904	$ 0.0922	$ 0.0940	$ 0.0959	$ 0.0978	$ 0.0998
12	Annual Avoided Energy Costs	Line 10 x Line 11	$ 759,685	$ 770,735	$ 781,924	$ 793,251	$ 804,719	$ 816,328	$ 828,079	$ 839,974	$ 852,014	$ 864,199
13												
14	Avoided Capacity Costs											
15	PV Capacity at Annual Peak	Exhibit SP-6	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%
16	Capacity at Peak Hour (kW)	Line 4 x Line 15 x 1000	2,224	2,212	2,201	2,189	2,177	2,165	2,153	2,141	2,129	2,117
17	Capacity Clearing Price ($ kW-Month) [3]	See Footnote	$ 3.51	$ 3.51	$ 3.58	$ 3.65	$ 3.72	$ 3.80	$ 3.88	$ 3.95	$ 4.03	$ 4.11
18	Monthly Avoided Capacity Costs	Line 16 x Line 17	$ 7,808	$ 7,766	$ 7,878	$ 7,993	$ 8,108	$ 8,225	$ 8,344	$ 8,463	$ 8,585	$ 8,707
19	Annual Avoided Capacity Costs	Line 18 x 12	$ 93,690	$ 93,189	$ 94,542	$ 95,912	$ 97,298	$ 98,702	$ 100,123	$ 101,561	$ 103,017	$ 104,490
20												
21	Local Transmission Benefits											
22	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
23	Capacity at Peak Hour (MW-Month)	Line 4 x Line 22	0.77	0.76	0.76	0.75	0.75	0.75	0.74	0.74	0.73	0.73
24	Transmission Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	$ 1,988.12	$ 2,027.88	$ 2,068.44	$ 2,109.81	$ 2,152.00	$ 2,195.04	$ 2,238.94	$ 2,283.72	$ 2,329.40	$ 2,375.99
25	Ancillary Services Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	9.15	9.34	9.52	9.71	9.91	10.11	10.31	10.52	10.73	10.94
26	Monthly Local Transmission Benefits	Line 23 x (Line 24 + Line 25)	$ 1,529	$ 1,552	$ 1,574	$ 1,597	$ 1,620	$ 1,643	$ 1,667	$ 1,691	$ 1,715	$ 1,740
27	Annual Local Transmission Benefits	Line 26 x 12	$ 18,353	$ 18,620	$ 18,891	$ 19,164	$ 19,441	$ 19,722	$ 20,006	$ 20,293	$ 20,584	$ 20,878
28												
29	Regional Transmission Benefits											
30	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
31	Capacity at Peak Hour (kW-Month)	Line 4 x Line 30 x 1000	766	762	758	753	749	745	741	737	733	729
32	ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) [5]	Annual Escalation, Line 5	$ 0.2496	$ 0.2546	$ 0.2597	$ 0.2649	$ 0.2702	$ 0.2756	$ 0.2811	$ 0.2867	$ 0.2924	$ 0.2983
33	ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) [6]	Annual Escalation, Line 5	0.0085	0.0087	0.0089	0.0091	0.0092	0.0094	0.0096	0.0098	0.0100	0.0102
34	ISO NE Section 2, Schedule 1 Rate ($ kW-Month) [7]	Annual Escalation, Line 5	0.1779	0.1814	0.1851	0.1888	0.1926	0.1964	0.2003	0.2043	0.2084	0.2126
35	ISO NE Section 2, Schedule 9 Rate ($ kW-Month) [8]	Annual Escalation, Line 5	14.3175	14.6038	14.8959	15.1938	15.4977	15.8077	16.1238	16.4463	16.7752	17.1107
36	Monthly Regional Transmission Benefits	Line 31 x (Sum Lines 32 through 35)	$ 11,298	$ 11,462	$ 11,628	$ 11,797	$ 11,967	$ 12,140	$ 12,315	$ 12,492	$ 12,671	$ 12,852
37	Annual Regional Transmission Benefits	Line 36 x 12	$ 135,573	$ 137,545	$ 139,541	$ 141,563	$ 143,609	$ 145,681	$ 147,778	$ 149,901	$ 152,050	$ 154,224
38												
39	Renewable Energy Credits (REC) Savings											
40	Annual Production (MWh)	Line 10 ÷ 1000	9,097	9,048	9,000	8,951	8,902	8,854	8,805	8,756	8,708	8,659
41	REC II Rate ($ Per MWh) [9]	New England Power Pool	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	Annual REC Savings	Line 40 x Line 41	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43												
44	Total Direct Customer Benefits	Line 12 + Line 19 + Line 27 + Line 37 + Line 42	$ 1,341,617	$ 1,352,617	$ 1,365,637	$ 1,378,841	$ 1,392,231	$ 1,405,808	$ 1,419,574	$ 1,433,529	$ 1,447,676	$ 1,462,016

Notes
(1) EIA Annual Energy Outlook 2022, Table 8. End-Use Price, All Sectors Average
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(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2023
(7) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 1. Scheduling, System Control and Dispatch Service, Rates effective June 1, 2022. Divided by 12
(8) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 9. Regional Network Service (RNS), Rates effective January 1, 2023. Divided by 12
(9) NH Class II REC 2023 Term

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 2
Direct Customer Benefits

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Capacity - Nameplate	Exhibit SP-4	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW
2	Degradation Rate	Exhibit SP-4	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
3	Efficiency Rate	PY Line 3 - CY Line 2	88.5%	88.0%	87.5%	87.0%	86.5%	86.0%	85.5%	85.0%	84.5%	84.0%
4	Capacity - Adjusted for Efficiency Rate	Line 1 x Line 3	4.31 MW	4.29 MW	4.27 MW	4.24 MW	4.22 MW	4.19 MW	4.17 MW	4.14 MW	4.12 MW	4.10 MW
5												
6	EIA Energy Outlook 2022 - Escalation Rate [(1)]	Annual Escalation Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
7												
8	Avoided Energy Costs											
9	Annual Capacity Factor	Exhibit SP-4	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%
10	Annual Production (kWh)	Line 4 x Line 9 x 1000 x 365 x 24	8,610,530	8,561,883	8,513,235	8,464,588	8,415,941	8,367,294	8,318,647	8,270,000	8,221,353	8,172,706
11	Energy Rate ($ Per kWh) [(2)]	See Footnote	$ 0.1018	$ 0.1038	$ 0.1059	$ 0.1080	$ 0.1102	$ 0.1124	$ 0.1146	$ 0.1169	$ 0.1193	$ 0.1217
12	Annual Avoided Energy Costs	Line 10 x Line 11	$ 876,531	$ 889,010	$ 901,638	$ 914,416	$ 927,344	$ 940,423	$ 953,655	$ 967,039	$ 980,578	$ 994,271
13												
14	Avoided Capacity Costs											
15	PV Capacity at Annual Peak	Exhibit SP-6	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%
16	Capacity at Peak Hour (kW)	Line 4 x Line 15 x 1000	2,105	2,094	2,082	2,070	2,058	2,046	2,034	2,022	2,010	1,998
17	Capacity Clearing Price ($ kW-Month) [(3)]	See Footnote	$ 4.19	$ 4.28	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.82	$ 4.91	$ 5.01
18	Monthly Avoided Capacity Costs	Line 16 x Line 17	$ 8,832	$ 8,957	$ 9,085	$ 9,213	$ 9,344	$ 9,476	$ 9,609	$ 9,744	$ 9,880	$ 10,018
19	Annual Avoided Capacity Costs	Line 18 x 12	$ 105,981	$ 107,490	$ 109,017	$ 110,562	$ 112,125	$ 113,706	$ 115,306	$ 116,924	$ 118,561	$ 120,217
20												
21	Local Transmission Benefits											
22	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
23	Capacity at Peak Hour (MW-Month)	Line 4 x Line 22	0.72	0.72	0.72	0.71	0.71	0.70	0.70	0.70	0.69	0.69
24	Transmission Rate ($ Per MW-Month) [(4)]	Annual Escalation, Line 5	$ 2,423.51	$ 2,471.98	$ 2,521.42	$ 2,571.84	$ 2,623.28	$ 2,675.75	$ 2,729.26	$ 2,783.85	$ 2,839.52	$ 2,896.31
25	Ancillary Services Rate ($ Per MW-Month) [(4)]	Annual Escalation, Line 5	11.16	11.38	11.61	11.84	12.08	12.32	12.57	12.82	13.08	13.34
26	Monthly Local Transmission Benefits	Line 23 x (Line 24 + Line 25)	$ 1,765	$ 1,790	$ 1,815	$ 1,841	$ 1,867	$ 1,893	$ 1,920	$ 1,947	$ 1,974	$ 2,002
27	Annual Local Transmission Benefits	Line 26 x 12	$ 21,176	$ 21,478	$ 21,783	$ 22,091	$ 22,404	$ 22,720	$ 23,039	$ 23,363	$ 23,690	$ 24,021
28												
29	Regional Transmission Benefits											
30	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
31	Capacity at Peak Hour (kW-Month)	Line 4 x Line 30 x 1000	725	721	717	713	708	704	700	696	692	688
32	ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) [(5)]	Annual Escalation, Line 5	$ 0.3042	$ 0.3103	$ 0.3165	$ 0.3229	$ 0.3293	$ 0.3359	$ 0.3426	$ 0.3495	$ 0.3565	$ 0.3636
33	ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) [(6)]	Annual Escalation, Line 5	0.0104	0.0106	0.0108	0.0111	0.0113	0.0115	0.0117	0.0120	0.0122	0.0124
34	ISO NE Section 2, Schedule 1 Rate ($ kW-Month) [(7)]	Annual Escalation, Line 5	0.2168	0.2212	0.2256	0.2301	0.2347	0.2394	0.2442	0.2491	0.2541	0.2592
35	ISO NE Section 2, Schedule 9 Rate ($ kW-Month) [(8)]	Annual Escalation, Line 5	17.4529	17.8020	18.1580	18.5212	18.8916	19.2695	19.6549	20.0480	20.4489	20.8579
36	Monthly Regional Transmission Benefits	Line 31 x (Sum Lines 32 through 35)	$ 13,035	$ 13,221	$ 13,409	$ 13,599	$ 13,791	$ 13,986	$ 14,182	$ 14,381	$ 14,583	$ 14,786
37	Annual Regional Transmission Benefits	Line 36 x 12	$ 156,425	$ 158,652	$ 160,906	$ 163,186	$ 165,493	$ 167,827	$ 170,188	$ 172,577	$ 174,993	$ 177,437
38												
39	Renewable Energy Credits (REC) Savings											
40	Annual Production (MWh)	Line 10 ÷ 1000	8,611	8,562	8,513	8,465	8,416	8,367	8,319	8,270	8,221	8,173
41	REC II Rate ($ Per MWh) [(9)]	New England Power Pool	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	Annual REC Savings	Line 40 x Line 41	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43												
44	Total Direct Customer Benefits	Line 12 + Line 19 + Line 27 + Line 37 + Line 42	$ 1,476,550	$ 1,491,279	$ 1,506,205	$ 1,521,328	$ 1,536,651	$ 1,552,174	$ 1,567,898	$ 1,583,826	$ 1,599,956	$ 1,616,292

Notes
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(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2023
(7) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 1. Scheduling, System Control and Dispatch Service, Rates effective June 1, 2022. Divided by 12
(8) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 9. Regional Network Service (RNS), Rates effective January 1, 2023. Divided by 12
(9) NH Class II REC 2023 Term

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 2
Direct Customer Benefits

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Capacity - Nameplate	Exhibit SP-4	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW	4.88 MW
2	Degradation Rate	Exhibit SP-4	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
3	Efficiency Rate	PY Line 3 - CY Line 2	83.5%	83.0%	82.5%	82.0%	81.5%	81.0%	80.5%	80.0%	79.5%	79.0%
4	Capacity - Adjusted for Efficiency Rate	Line 1 x Line 3	4.07 MW	4.05 MW	4.02 MW	4.00 MW	3.97 MW	3.95 MW	3.92 MW	3.90 MW	3.88 MW	3.85 MW
5												
6	EIA Energy Outlook 2022 - Escalation Rate [1]	Annual Escalation Rate	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
7												
8	Avoided Energy Costs											
9	Annual Capacity Factor	Exhibit SP-4	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%	22.78%
10	Annual Production (kWh)	Line 4 x Line 9 x 1000 x 365 x 24	8,124,059	8,075,412	8,026,765	7,978,118	7,929,471	7,880,824	7,832,177	7,783,530	7,734,883	7,686,235
11	Energy Rate ($ Per kWh) [2]	See Footnote	$ 0.1241	$ 0.1266	$ 0.1291	$ 0.1317	$ 0.1343	$ 0.1370	$ 0.1397	$ 0.1425	$ 0.1454	$ 0.1483
12	Annual Avoided Energy Costs	Line 10 x Line 11	$ 1,008,120	$ 1,022,125	$ 1,036,287	$ 1,050,606	$ 1,065,084	$ 1,079,721	$ 1,094,517	$ 1,109,473	$ 1,124,590	$ 1,139,867
13												
14	Avoided Capacity Costs											
15	PV Capacity at Annual Peak	Exhibit SP-6	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%	48.8%
16	Capacity at Peak Hour (kW)	Line 4 x Line 15 x 1000	1,986	1,975	1,963	1,951	1,939	1,927	1,915	1,903	1,891	1,879
17	Capacity Clearing Price ($ kW-Month) [3]	See Footnote	$ 5.11	$ 5.22	$ 5.32	$ 5.43	$ 5.53	$ 5.65	$ 5.76	$ 5.87	$ 5.99	$ 6.11
18	Monthly Avoided Capacity Costs	Line 16 x Line 17	$ 10,158	$ 10,299	$ 10,441	$ 10,586	$ 10,732	$ 10,879	$ 11,028	$ 11,179	$ 11,331	$ 11,485
19	Annual Avoided Capacity Costs	Line 18 x 12	$ 121,891	$ 123,585	$ 125,297	$ 127,028	$ 128,779	$ 130,549	$ 132,338	$ 134,146	$ 135,974	$ 137,821
20												
21	Local Transmission Benefits											
22	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
23	Capacity at Peak Hour (MW-Month)	Line 4 x Line 22	0.68	0.68	0.68	0.67	0.67	0.66	0.66	0.66	0.65	0.65
24	Transmission Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	$ 2,954.24	$ 3,013.32	$ 3,073.59	$ 3,135.06	$ 3,197.76	$ 3,261.72	$ 3,326.95	$ 3,393.49	$ 3,461.36	$ 3,530.59
25	Ancillary Services Rate ($ Per MW-Month) [4]	Annual Escalation, Line 5	13.60	13.88	14.15	14.44	14.72	15.02	15.32	15.63	15.94	16.26
26	Monthly Local Transmission Benefits	Line 23 x (Line 24 + Line 25)	$ 2,030	$ 2,058	$ 2,086	$ 2,115	$ 2,144	$ 2,174	$ 2,204	$ 2,234	$ 2,264	$ 2,295
27	Annual Local Transmission Benefits	Line 26 x 12	$ 24,355	$ 24,694	$ 25,036	$ 25,382	$ 25,731	$ 26,085	$ 26,443	$ 26,804	$ 27,169	$ 27,538
28												
29	Regional Transmission Benefits											
30	PV Capacity at Monthly Peak	Exhibit SP-6	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
31	Capacity at Peak Hour (kW-Month)	Line 4 x Line 30 x 1000	684	680	676	672	667	663	659	655	651	647
32	ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) [5]	Annual Escalation, Line 5	$ 0.3709	$ 0.3783	$ 0.3859	$ 0.3936	$ 0.4014	$ 0.4095	$ 0.4177	$ 0.4260	$ 0.4345	$ 0.4432
33	ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) [6]	Annual Escalation, Line 5	0.0127	0.0130	0.0132	0.0135	0.0137	0.0140	0.0143	0.0146	0.0149	0.0152
34	ISO NE Section 2, Schedule 1 Rate ($ kW-Month) [7]	Annual Escalation, Line 5	0.2643	0.2696	0.2750	0.2805	0.2861	0.2918	0.2977	0.3036	0.3097	0.3159
35	ISO NE Section 2, Schedule 9 Rate ($ kW-Month) [8]	Annual Escalation, Line 5	21.2750	21.7005	22.1346	22.5773	23.0288	23.4894	23.9592	24.4383	24.9271	25.4257
36	Monthly Regional Transmission Benefits	Line 31 x (Sum Lines 32 through 35)	$ 14,992	$ 15,201	$ 15,411	$ 15,624	$ 15,839	$ 16,057	$ 16,277	$ 16,500	$ 16,724	$ 16,952
37	Annual Regional Transmission Benefits	Line 36 x 12	$ 179,908	$ 182,407	$ 184,935	$ 187,490	$ 190,074	$ 192,686	$ 195,327	$ 197,996	$ 200,693	$ 203,420
38												
39	Renewable Energy Credits (REC) Savings											
40	Annual Production (MWh)	Line 10 ÷ 1000	8,124	8,075	8,027	7,978	7,929	7,881	7,832	7,784	7,735	7,686
41	REC II Rate ($ Per MWh) [9]	New England Power Pool	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	Annual REC Savings	Line 40 x Line 41	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43												
44	Total Direct Customer Benefits	Line 12 + Line 19 + Line 27 + Line 37 + Line 42	$ 1,632,834	$ 1,649,582	$ 1,666,538	$ 1,683,702	$ 1,701,076	$ 1,718,661	$ 1,736,456	$ 1,754,463	$ 1,772,683	$ 1,791,115

Notes
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(7) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 1. Scheduling, System Control and Dispatch Service, Rates effective June 1, 2022. Divided by 12
(8) ISO New England Tariff Rates, Section 2. ISO New England Open Access Transmission Tariff (OATT), Schedule 9. Regional Network Service (RNS), Rates effective January 1, 2023. Divided by 12
(9) NH Class II REC 2023 Term

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 3
Rate Base & Revenue Requirement

Line No.	Description	Reference	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Investments												
2	PV Modules	Capital Costs, Line 46, Maintenance Capital Costs, Line 7	$ [redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Racking Equipment	Capital Costs, Line 47, Maintenance Capital Costs, Line 14	[redacted]	-	-	-	-	-	-	-	-	-	-
4	Balance of Plant	Capital Costs, Line 48	[redacted]										
5	Electric System Upgrades	Capital Costs, Line 49	560,000										
6	Solar Inverter 1	Capital Costs, Line 50	[redacted]										
7	Solar Inverter 2	Capital Costs, Line 51											
8	Land Improvements	Capital Costs, Line 55	[redacted]										
9	Land Acquisition	Capital Costs, Line 56	820,438										
10	Total Investments	Sum Lines 2 through 9	$ 13,918,488	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11													
12	Rate Base Calculation												
13	Gross Plant (1)	CY Line 10 + PY Line 13	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488
14	Accumulated Depreciation (1)	Book Depreciation Schedule, Line 44		(323,772)	(647,543)	(971,315)	(1,295,086)	(1,618,858)	(1,942,629)	(2,266,401)	(2,590,172)	(2,913,944)	(3,237,715)
15	Net Plant	Line 13 + Line 14	13,918,488	13,594,716	13,270,945	12,947,173	12,623,402	12,299,630	11,975,859	11,652,087	11,328,316	11,004,544	10,680,773
16	Deferred Income Tax	Deferred Tax Calculation, Line - 27		(578,124)	(1,555,428)	(2,106,941)	(2,402,978)	(2,699,015)	(2,803,446)	(2,716,271)	(2,629,095)	(2,541,920)	(2,454,744)
17	Year End Rate Base	Line 15 + Line 16	$ 13,918,488	$ 13,016,592	$ 11,715,516	$ 10,840,233	$ 10,220,424	$ 9,600,615	$ 9,172,413	$ 8,935,817	$ 8,699,221	$ 8,462,625	$ 8,226,029
18													
19	Revenue Requirement												
20	Average Rate Base	(CY Line 17 + PY Line 17) ÷ 2		$ 13,467,540	$ 12,366,054	$ 11,277,875	$ 10,530,328	$ 9,910,520	$ 9,386,514	$ 9,054,115	$ 8,817,519	$ 8,580,923	$ 8,344,327
21	Pre-Tax Rate of Return	Cost of Capital, Line 8, Column (f)		9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%
22	Return and Taxes	Line 20 x Line 21		$ 1,236,576	$ 1,135,439	$ 1,035,523	$ 966,884	$ 909,974	$ 861,860	$ 831,340	$ 809,616	$ 787,892	$ 766,168
23	Operations & Maintenance	O&M Expense, Line 7		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Decommissioning Expense	Decommissioning Expense, Line 2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Book Depreciation	Book Depreciation Schedule, Line 43		323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772
26	Property Taxes	Property Tax Expense, Line 4		379,021	369,994	360,967	351,940	342,914	333,887	324,860	315,833	306,807	297,780
27	Production Tax Credit & Tax Gross up	Production Tax Credit, Line - 11		(380,788)	(380,636)	(386,268)	(391,973)	(397,751)	(403,604)	(409,532)	(415,536)	(421,616)	(427,773)
28	Annual Revenue Requirement	Sum Lines 22 through 27		$ 1,571,340	$ 1,461,528	$ 1,347,158	$ 1,263,995	$ 1,192,492	$ 1,154,353	$ 1,109,591	$ 1,073,564	$ 1,037,476	$ 1,001,326

Notes
(1) Beginning in Year 20 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

Unitil Energy Systems d/b/a Unitil
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Schedule 3
Rate Base & Revenue Requirement

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Investments											
2	PV Modules	Capital Costs, Line 46, Maintenance Capital Costs, Line 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Racking Equipment	Capital Costs, Line 47, Maintenance Capital Costs, Line 14	-	-	-	-	-	-	-	-	-	-
4	Balance of Plant	Capital Costs, Line 48										
5	Electric System Upgrades	Capital Costs, Line 49										
6	Solar Inverter 1	Capital Costs, Line 50										$ (596,177)
7	Solar Inverter 2	Capital Costs, Line 51										$ 885,887
8	Land Improvements	Capital Costs, Line 55										
9	Land Acquisition	Capital Costs, Line 56										
10	Total Investments	Sum Lines 2 through 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 289,710
11												
12	Rate Base Calculation											
13	Gross Plant [1]	CY Line 10 + PY Line 13	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 13,918,488	$ 14,208,198
14	Accumulated Depreciation [1]	Book Depreciation Schedule, Line 44	(3,561,487)	(3,885,258)	(4,209,030)	(4,532,802)	(4,856,573)	(5,180,345)	(5,504,116)	(5,827,888)	(6,151,659)	(5,879,254)
15	Net Plant	Line 13 + Line 14	10,357,001	10,033,230	9,709,458	9,385,686	9,061,915	8,738,143	8,414,372	8,090,600	7,766,829	8,328,944
16	Deferred Income Tax	Deferred Tax Calculation, Line - 27	(2,367,569)	(2,280,393)	(2,193,218)	(2,106,042)	(2,018,867)	(1,931,691)	(1,844,516)	(1,757,340)	(1,670,165)	(1,582,989)
17	Year End Rate Base	Line 15 + Line 16	$ 7,989,432	$ 7,752,836	$ 7,516,240	$ 7,279,644	$ 7,043,048	$ 6,806,452	$ 6,569,856	$ 6,333,260	$ 6,096,664	$ 6,745,955
18												
19	Revenue Requirement											
20	Average Rate Base	(CY Line 17 + PY Line 17) ÷ 2	$ 8,107,731	$ 7,871,134	$ 7,634,538	$ 7,397,942	$ 7,161,346	$ 6,924,750	$ 6,688,154	$ 6,451,558	$ 6,214,962	$ 6,421,310
21	Pre-Tax Rate of Return	Cost of Capital, Line 8, Column (f)	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%
22	Return and Taxes	Line 20 x Line 21	$ 744,444	$ 722,720	$ 700,996	$ 679,272	$ 657,548	$ 635,824	$ 614,100	$ 592,376	$ 570,652	$ 589,598
23	Operations & Maintenance	O&M Expense, Line 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Decommissioning Expense	Decommissioning Expense, Line 2										
25	Book Depreciation	Book Depreciation Schedule, Line 43	323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772	323,772
26	Property Taxes	Property Tax Expense, Line 4	288,753	279,726	270,700	261,673	252,646	243,619	234,593	225,566	216,539	232,211
27	Production Tax Credit & Tax Gross up	Production Tax Credit, Line - 11	-	-	-	-	-	-	-	-	-	-
28	Annual Revenue Requirement	Sum Lines 22 through 27	$ 1,399,120	$ 1,369,157	$ 1,339,210	$ 1,309,279	$ 1,279,364	$ 1,249,466	$ 1,219,585	$ 1,189,722	$ 1,159,876	$ 1,195,418

Notes
(1) Beginning in Year 20 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

Unitil Energy Systems d/b/a Unitil
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Schedule 3
Rate Base & Revenue Requirement

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Investments											
2	PV Modules	Capital Costs, Line 46, Maintenance Capital Costs, Line 7	$ -	$ -	$ -	$ -	$ -	$ 38,720	$ 39,494	$ 40,284	$ 41,090	$ 41,911
3	Racking Equipment	Capital Costs, Line 47, Maintenance Capital Costs, Line 14	28,425	28,993	29,573	30,164	30,768	31,383	32,011	32,651	33,304	33,970
4	Balance of Plant	Capital Costs, Line 48										
5	Electric System Upgrades	Capital Costs, Line 49										
6	Solar Inverter 1	Capital Costs, Line 50										
7	Solar Inverter 2	Capital Costs, Line 51										
8	Land Improvements	Capital Costs, Line 55										
9	Land Acquisition	Capital Costs, Line 56										
10	Total Investments	Sum Lines 2 through 9	$ 28,425	$ 28,993	$ 29,573	$ 30,164	$ 30,768	$ 70,103	$ 71,505	$ 72,935	$ 74,394	$ 75,881
11												
12	Rate Base Calculation											
13	Gross Plant (1)	CY Line 10 + PY Line 13	$ 14,236,623	$ 14,265,616	$ 14,295,189	$ 14,325,353	$ 14,356,121	$ 14,426,224	$ 14,497,729	$ 14,570,663	$ 14,645,057	$ 14,720,938
14	Accumulated Depreciation (1)	Book Depreciation Schedule, Line 44	(6,217,511)	(6,556,479)	(6,896,171)	(7,236,603)	(7,577,789)	(7,919,744)	(8,263,452)	(8,608,947)	(8,956,266)	(9,305,445)
15	Net Plant	Line 13 + Line 14	8,019,112	7,709,137	7,399,018	7,088,750	6,778,332	6,506,480	6,234,277	5,961,716	5,688,791	5,415,494
16	Deferred Income Tax	Deferred Tax Calculation, Line - 27	(1,541,149)	(1,530,220)	(1,490,115)	(1,432,485)	(1,375,664)	(1,307,574)	(1,228,815)	(1,151,851)	(1,075,919)	(1,001,039)
17	Year End Rate Base	Line 15 + Line 16	$ 6,477,963	$ 6,178,917	$ 5,908,903	$ 5,656,265	$ 5,402,668	$ 5,198,905	$ 5,005,462	$ 4,809,865	$ 4,612,872	$ 4,414,455
18												
19	Revenue Requirement											
20	Average Rate Base	(CY Line 17 + PY Line 17) ÷ 2	$ 6,611,959	$ 6,328,440	$ 6,043,910	$ 5,782,584	$ 5,529,467	$ 5,300,786	$ 5,102,183	$ 4,907,663	$ 4,711,368	$ 4,513,664
21	Pre-Tax Rate of Return	Cost of Capital, Line 8, Column (f)	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%
22	Return and Taxes	Line 20 x Line 21	$ 607,103	$ 581,071	$ 554,946	$ 530,951	$ 507,710	$ 486,713	$ 468,477	$ 450,617	$ 432,593	$ 414,440
23	Operations & Maintenance	O&M Expense, Line 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Decommissioning Expense	Decommissioning Expense, Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Book Depreciation	Book Depreciation Schedule, Line 43	338,257	338,968	339,693	340,432	341,186	341,955	343,708	345,495	347,319	349,179
26	Property Taxes	Property Tax Expense, Line 4	223,573	214,931	206,285	197,634	188,980	181,401	173,812	166,213	158,603	150,984
27	Production Tax Credit & Tax Gross up	Production Tax Credit, Line - 11	-	-	-	-	-	-	-	-	-	-
28	Annual Revenue Requirement	Sum Lines 22 through 27	$ 1,219,712	$ 1,186,708	$ 1,153,641	$ 1,122,735	$ 1,092,613	$ 1,065,845	$ 1,042,833	$ 1,020,243	$ 997,536	$ 974,749

Notes
(1) Beginning in Year 20 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 3
Rate Base & Revenue Requirement

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Investments											
2	PV Modules	Capital Costs, Line 46, Maintenance Capital Costs, Line 7	$ 42,750	$ 43,605	$ 44,477	$ 45,366	$ 46,274	$ 94,398	$ 96,286	$ 98,212	$ 100,176	$ 102,180
3	Racking Equipment	Capital Costs, Line 47, Maintenance Capital Costs, Line 14	69,299	70,685	72,099	73,540	75,011	76,512	78,042	79,603	81,195	82,819
4	Balance of Plant	Capital Costs, Line 48										
5	Electric System Upgrades	Capital Costs, Line 49										
6	Solar Inverter 1	Capital Costs, Line 50										
7	Solar Inverter 2	Capital Costs, Line 51										
8	Land Improvements	Capital Costs, Line 55										
9	Land Acquisition	Capital Costs, Line 56										
10	Total Investments	Sum Lines 2 through 9	$ 112,048	$ 114,289	$ 116,575	$ 118,907	$ 121,285	$ 170,910	$ 174,328	$ 177,814	$ 181,371	$ 184,998
11												
12	Rate Base Calculation											
13	Gross Plant (1)	CY Line 10 + PY Line 13	$ 14,832,987	$ 14,947,276	$ 15,063,852	$ 15,182,758	$ 15,304,043	$ 15,474,953	$ 15,649,281	$ 15,827,095	$ 16,008,466	$ 16,193,464
14	Accumulated Depreciation (1)	Book Depreciation Schedule, Line 44	(9,656,520)	(10,010,397)	(10,367,131)	(10,726,779)	(11,089,400)	(11,455,054)	(11,824,979)	(12,199,264)	(12,577,993)	(12,961,257)
15	Net Plant	Line 13 + Line 14	5,176,467	4,936,879	4,696,721	4,455,979	4,214,643	4,019,899	3,824,301	3,627,831	3,430,473	3,232,207
16	Deferred Income Tax	Deferred Tax Calculation, Line - 27	(928,496)	(858,625)	(790,284)	(722,787)	(656,151)	(592,398)	(532,255)	(474,168)	(417,202)	(361,379)
17	Year End Rate Base	Line 15 + Line 16	$ 4,247,970	$ 4,078,254	$ 3,906,437	$ 3,733,192	$ 3,558,491	$ 3,427,501	$ 3,292,046	$ 3,153,663	$ 3,013,271	$ 2,870,828
18												
19	Revenue Requirement											
20	Average Rate Base	(CY Line 17 + PY Line 17) ÷ 2	$ 4,331,213	$ 4,163,112	$ 3,992,345	$ 3,819,814	$ 3,645,842	$ 3,492,996	$ 3,359,773	$ 3,222,854	$ 3,083,467	$ 2,942,049
21	Pre-Tax Rate of Return	Cost of Capital, Line 8, Column (f)	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%	9.18%
22	Return and Taxes	Line 20 x Line 21	$ 397,688	$ 382,253	$ 366,573	$ 350,731	$ 334,757	$ 320,723	$ 308,491	$ 295,919	$ 283,121	$ 270,136
23	Operations & Maintenance	O&M Expense, Line 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Decommissioning Expense	Decommissioning Expense, Line 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Book Depreciation	Book Depreciation Schedule, Line 43	351,076	353,877	356,734	359,648	362,621	365,653	369,926	374,284	378,729	383,264
26	Property Taxes	Property Tax Expense, Line 4	144,320	137,640	130,945	124,233	117,504	112,075	106,622	101,144	95,642	90,114
27	Production Tax Credit & Tax Gross up	Production Tax Credit, Line - 11	-	-	-	-	-	-	-	-	-	-
28	Annual Revenue Requirement	Sum Lines 22 through 27	$ 954,377	$ 936,235	$ 917,911	$ 899,490	$ 881,002	$ 865,838	$ 853,717	$ 841,345	$ 828,834	$ 816,227

Notes
(1) Beginning in Year 20 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 4
Production Tax Credit

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Production Tax Credit (PTC)											
4	Annual Production (kWh)	Direct Customer Benefits, Line 10	9,729,412	9,534,824	9,486,177	9,437,530	9,388,883	9,340,236	9,291,588	9,242,941	9,194,294	9,145,647
5	PTC Base Credit (per kWh) [1]	Annual Escalation, Line 1	$ 0.0286	$ 0.0292	$ 0.0298	$ 0.0304	$ 0.0310	$ 0.0316	$ 0.0322	$ 0.0329	$ 0.0335	$ 0.0342
6	PTC Base Credit (Annual)	Line 4 x Line 5	$ 278,261	$ 278,150	$ 282,265	$ 286,434	$ 290,657	$ 294,934	$ 299,266	$ 303,653	$ 308,096	$ 312,595
7												
8	Tax Gross Up											
9	Production Tax Credit Tax Gross Up	Line 6 x (Cost of Capital, Line 20 - 1)	$ 102,527	$ 102,486	$ 104,003	$ 105,539	$ 107,095	$ 108,670	$ 110,267	$ 111,883	$ 113,520	$ 115,178
10												
11	Total PTC & Tax Gross Up	Line 6 + Line 9	$ 380,788	$ 380,636	$ 386,268	$ 391,973	$ 397,751	$ 403,604	$ 409,532	$ 415,536	$ 421,616	$ 427,773

Notes
(1) The Internal Revenue Service published a 2022 PTC Rate of 2.75 cents per kWh. Year 1 (2024) is the future value of the current PTC rate of 2.75 cents per kWh with 2% annual escalation rate. This does not include the 10% Bonus Credit for Domestic Content qualification

Unitil Energy Systems d/b/a Unitil
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Schedule 4
Production Tax Credit

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Production Tax Credit (PTC)											
4	Annual Production (kWh)	Direct Customer Benefits, Line 10	9,097,000	9,048,353	8,999,706	8,951,059	8,902,412	8,853,765	8,805,118	8,756,471	8,707,824	8,659,177
5	PTC Base Credit (per kWh) (1)	Annual Escalation, Line 1										
6	PTC Base Credit (Annual)	Line 4 x Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7												
8	Tax Gross Up											
9	Production Tax Credit Tax Gross Up	Line 6 x (Cost of Capital, Line 20 - 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10												
11	Total PTC & Tax Gross Up	Line 6 + Line 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) The Internal Revenue Service published a 2022 PTC Rate of 2.75 cents per kWh. Year 1 (2024) is the future value of the current PTC rate of 2.75 cents per kWh with 2% annual escalation rate. This does not include the 10% Bonus Credit for Domestic Content qualification

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 4
Production Tax Credit

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Production Tax Credit (PTC)											
4	Annual Production (kWh)	Direct Customer Benefits, Line 10	8,610,530	8,561,883	8,513,235	8,464,588	8,415,941	8,367,294	8,318,647	8,270,000	8,221,353	8,172,706
5	PTC Base Credit (per kWh) (1)	Annual Escalation, Line 1										
6	PTC Base Credit (Annual)	Line 4 x Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7												
8	Tax Gross Up											
9	Production Tax Credit Tax Gross Up	Line 6 x (Cost of Capital, Line 20 - 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10												
11	Total PTC & Tax Gross Up	Line 6 + Line 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) The Internal Revenue Service published a 2022 PTC Rate of 2.75 cents per kWh. Year 1 (2024) is the future value of the current PTC rate of 2.75 cents per kWh with 2% annual escalation rate. This does not include the 10% Bonus Credit for Domestic Content qualification

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 4
Production Tax Credit

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Production Tax Credit (PTC)											
4	Annual Production (kWh)	Direct Customer Benefits, Line 10	8,124,059	8,075,412	8,026,765	7,978,118	7,929,471	7,880,824	7,832,177	7,783,530	7,734,883	7,686,235
5	PTC Base Credit (per kWh) (1)	Annual Escalation, Line 1										
6	PTC Base Credit (Annual)	Line 4 x Line 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7												
8	Tax Gross Up											
9	Production Tax Credit Tax Gross Up	Line 6 x (Cost of Capital, Line 20 - 1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10												
11	Total PTC & Tax Gross Up	Line 6 + Line 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) The Internal Revenue Service published a 2022 PTC Rate of 2.75 cents per kWh. Year 1 (2024) is the future value of the current PTC rate of 2.75 cents per kWh with 2% annual escalation rate. This does not include the 10% Bonus Credit for Domestic Content qualification

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 5
O&M Expense

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Vegetation Management Expense[1]	Annual Escalation Rate, Line 1	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Annual Maintenance Expense[2]	Annual Escalation Rate, Line 1						$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6												
7	O&M Expense	Line 3 + Line 5	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Exhibit SP-1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 5
O&M Expense

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Vegetation Management Expense(1)	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Annual Maintenance Expense(2)	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6												
7	O&M Expense	Line 3 + Line 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Exhibit SP-1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 5
O&M Expense

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Vegetation Management Expense[1]	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Annual Maintenance Expense[2]	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6												
7	O&M Expense	Line 3 + Line 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Exhibit SP-1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 5
O&M Expense

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	Vegetation Management Expense[1]	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Annual Maintenance Expense[2]	Annual Escalation Rate, Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6												
7	O&M Expense	Line 3 + Line 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Exhibit SP-1

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 6
Decommissioning Expense

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Net Decommissioning Cost(1)	Exhibit SP-5	[redacted]									
2	Annual Decommissioning Expense(2)	Annual Expense of Line 1 Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Assumed [redacted] decommissioning cost is net of of salvage value. Future value of expected decommissioning cost of [redacted] in 40 years at 2.0% escalation rate.
(2) Future value of Decommissioning cost expensed evenly over 40 year life of the project

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 6
Decommissioning Expense

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Net Decommissioning Cost(1)	Exhibit SP-5										
2	Annual Decommissioning Expense(2)	Annual Expense of Line 1 Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Assumed [redacted] decommissioning cost is net of of salvage value. Future value of expected decommissioning cost of [redacted] in 40 years at 2.0% escalation rate.
(2) Future value of Decommissioning cost expensed evenly over 40 year life of the project

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 6
Decommissioning Expense

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Net Decommissioning Cost(1)	Exhibit SP-5										
2	Annual Decommissioning Expense(2)	Annual Expense of Line 1 Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Assumed [redacted] decommissioning cost is net of of salvage value. Future value of expected decommissioning cost of [redacted] in 40 years at 2.0% escalation rate.
(2) Future value of Decommissioning cost expensed evenly over 40 year life of the project

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 6
Decommissioning Expense

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Net Decommissioning Cost(1)	Exhibit SP-5										[redacted]
2	Annual Decommissioning Expense(2)	Annual Expense of Line 1 Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Assumed [redacted] decommissioning cost is net of of salvage value. Future value of expected decommissioning cost of [redacted] in 40 years at 2.0% escalation rate.
(2) Future value of Decommissioning cost expensed evenly over 40 year life of the project

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 7
Property Tax Expense

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Property Tax Expense											
2	Net Plant	Rate Base & Revenue Requirement, Line 15	$ 13,594,716	$ 13,270,945	$ 12,947,173	$ 12,623,402	$ 12,299,630	$ 11,975,859	$ 11,652,087	$ 11,328,316	$ 11,004,544	$ 10,680,773
3	Property Tax Rate per $1000	Kingston, NH Rate of $21.28 + NH State Rate $6.60	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88
4	Annual Property Tax	Line 2 x (Line 3 ÷ 1000)	$ 379,021	$ 369,994	$ 360,967	$ 351,940	$ 342,914	$ 333,887	$ 324,860	$ 315,833	$ 306,807	$ 297,780

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 7
Property Tax Expense

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Property Tax Expense											
2	Net Plant	Rate Base & Revenue Requirement, Line 15	$ 10,357,001	$ 10,033,230	$ 9,709,458	$ 9,385,686	$ 9,061,915	$ 8,738,143	$ 8,414,372	$ 8,090,600	$ 7,766,829	$ 8,328,944
3	Property Tax Rate per $1000	Kingston, NH Rate of $21.28 + NH State Rate $6.60	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88
4	Annual Property Tax	Line 2 x (Line 3 ÷ 1000)	$ 288,753	$ 279,726	$ 270,700	$ 261,673	$ 252,646	$ 243,619	$ 234,593	$ 225,566	$ 216,539	$ 232,211

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 7
Property Tax Expense

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Property Tax Expense											
2	Net Plant	Rate Base & Revenue Requirement, Line 15	$ 8,019,112	$ 7,709,137	$ 7,399,018	$ 7,088,750	$ 6,778,332	$ 6,506,480	$ 6,234,277	$ 5,961,716	$ 5,688,791	$ 5,415,494
3	Property Tax Rate per $1000	Kingston, NH Rate of $21.28 + NH State Rate $6.60	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88
4	Annual Property Tax	Line 2 x (Line 3 ÷ 1000)	$ 223,573	$ 214,931	$ 206,285	$ 197,634	$ 188,980	$ 181,401	$ 173,812	$ 166,213	$ 158,603	$ 150,984

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 7
Property Tax Expense

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Property Tax Expense											
2	Net Plant	Rate Base & Revenue Requirement, Line 15	$ 5,176,467	$ 4,936,879	$ 4,696,721	$ 4,455,979	$ 4,214,643	$ 4,019,899	$ 3,824,301	$ 3,627,831	$ 3,430,473	$ 3,232,207
3	Property Tax Rate per $1000	Kingston, NH Rate of $21.28 + NH State Rate $6.60	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88	27.88
4	Annual Property Tax	Line 2 x (Line 3 ÷ 1000)	$ 144,320	$ 137,640	$ 130,945	$ 124,233	$ 117,504	$ 112,075	$ 106,622	$ 101,144	$ 95,642	$ 90,114

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 8
Deferred Tax Calculation

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Deferred Tax Calculation											
2	Annual Federal Tax Depreciation	Tax Depreciation Schedule 10, Line 32 + Tax Depreciation Schedule 11, Line 91	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -
3	Cumulative Federal Tax Depreciation	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Total Annual State Tax Depreciation	Tax Depreciation Schedule 10, Line 34 + Tax Depreciation Schedule 11, Line 92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -
6	Cumulative State Tax Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7												
8	Book Depreciation: PV Modules	Book Depreciation Schedule, Line 5	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Book Depreciation: Racking Equipment	Book Depreciation Schedule, Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Book Depreciation: Balance of Plant	Book Depreciation Schedule, Line 19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Book Depreciation: Electric System Upgrades	Book Depreciation Schedule, Line 26	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
12	Book Depreciation: Solar Inverter 1	Book Depreciation Schedule, Line 33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Book Depreciation: Solar Inverter 2	Book Depreciation Schedule, Line 40	-	-	-	-	-	-	-	-	-	-
14	Total Book Depreciation	Sum Lines 8 through 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Cumulative Book Depreciation	CY Line 14 + PY Line 15	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16												
17	Cumulative Book / Tax Timer	Line 3 - Line 15	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Federal Tax Rate	Cost of Capital, Line 14 Column (a)	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
19	Deferred Federal Tax Reserve	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Less: Federal Deduction for Deferred State Taxes	Line 18 x - Line 25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Net Deferred Federal Tax Reserve	Line 19 + Line 20	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22												
23	Cumulative Book / Tax Timer	Line 6 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	State Tax Rate	Cost of Capital, Line 12 Column (a)	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%
25	Deferred State Tax Reserve	Line 23 x Line 24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26												
27	Total Deferred Taxes	Line 21 + Line 25	$ 578,124	$ 1,555,428	$ 2,106,941	$ 2,402,978	$ 2,699,015	$ 2,803,446	$ 2,716,271	$ 2,629,095	$ 2,541,920	$ 2,454,744

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 8
Deferred Tax Calculation

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Deferred Tax Calculation											
2	Annual Federal Tax Depreciation	Tax Depreciation Schedule 10, Line 32 + Tax Depreciation Schedule 11, Line 91	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Cumulative Federal Tax Depreciation	CY Line 2 + PY Line 3	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Total Annual State Tax Depreciation	Tax Depreciation Schedule 10, Line 34 + Tax Depreciation Schedule 11, Line 92	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Cumulative State Tax Depreciation	CY Line 5 + PY Line 6	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7												
8	Book Depreciation: PV Modules	Book Depreciation Schedule, Line 5	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Book Depreciation: Racking Equipment	Book Depreciation Schedule, Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Book Depreciation: Balance of Plant	Book Depreciation Schedule, Line 19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Book Depreciation: Electric System Upgrades	Book Depreciation Schedule, Line 26	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
12	Book Depreciation: Solar Inverter 1	Book Depreciation Schedule, Line 33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Book Depreciation: Solar Inverter 2	Book Depreciation Schedule, Line 40	-	-	-	-	-	-	-	-	-	-
14	Total Book Depreciation	Sum Lines 8 through 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Cumulative Book Depreciation	CY Line 14 + PY Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16												
17	Cumulative Book / Tax Timer	Line 3 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Federal Tax Rate	Cost of Capital, Line 14 Column (a)	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
19	Deferred Federal Tax Reserve	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Less: Federal Deduction for Deferred State Taxes	Line 18 x - Line 25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Net Deferred Federal Tax Reserve	Line 19 + Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22												
23	Cumulative Book / Tax Timer	Line 6 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	State Tax Rate	Cost of Capital, Line 12 Column (a)	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%	7 50%
25	Deferred State Tax Reserve	Line 23 x Line 24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26												
27	Total Deferred Taxes	Line 21 + Line 25	$ 2,367,569	$ 2,280,393	$ 2,193,218	$ 2,106,042	$ 2,018,867	$ 1,931,691	$ 1,844,516	$ 1,757,340	$ 1,670,165	$ 1,582,989

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 8
Deferred Tax Calculation

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	<u>Deferred Tax Calculation</u>											
2	Annual Federal Tax Depreciation	Tax Depreciation Schedule 10, Line 32 + Tax Depreciation Schedule 11, Line 91	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Cumulative Federal Tax Depreciation	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Total Annual State Tax Depreciation	Tax Depreciation Schedule 10, Line 34 + Tax Depreciation Schedule 11, Line 92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative State Tax Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7												
8	Book Depreciation: PV Modules	Book Depreciation Schedule, Line 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Book Depreciation: Racking Equipment	Book Depreciation Schedule, Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Book Depreciation: Balance of Plant	Book Depreciation Schedule, Line 19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Book Depreciation: Electric System Upgrades	Book Depreciation Schedule, Line 26	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
12	Book Depreciation: Solar Inverter 1	Book Depreciation Schedule, Line 33	-	-	-	-	-	-	-	-	-	-
13	Book Depreciation: Solar Inverter 2	Book Depreciation Schedule, Line 40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Total Book Depreciation	Sum Lines 8 through 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Cumulative Book Depreciation	CY Line 14 + PY Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16												
17	Cumulative Book / Tax Timer	Line 3 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Federal Tax Rate	Cost of Capital, Line 14 Column (a)	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
19	Deferred Federal Tax Reserve	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Less: Federal Deduction for Deferred State Taxes	Line 18 x - Line 25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Net Deferred Federal Tax Reserve	Line 19 + Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22												
23	Cumulative Book / Tax Timer	Line 6 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	State Tax Rate	Cost of Capital, Line 12 Column (a)	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
25	Deferred State Tax Reserve	Line 23 x Line 24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26												
27	Total Deferred Taxes	Line 21 + Line 25	$ 1,541,149	$ 1,530,220	$ 1,490,115	$ 1,432,485	$ 1,375,664	$ 1,307,574	$ 1,228,815	$ 1,151,851	$ 1,075,919	$ 1,001,039

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 8
Deferred Tax Calculation

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Deferred Tax Calculation											
2	Annual Federal Tax Depreciation	Tax Depreciation Schedule 10, Line 32 + Tax Depreciation Schedule 11, Line 91	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Cumulative Federal Tax Depreciation	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4												
5	Total Annual State Tax Depreciation	Tax Depreciation Schedule 10, Line 34 + Tax Depreciation Schedule 11, Line 92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative State Tax Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7												
8	Book Depreciation: PV Modules	Book Depreciation Schedule, Line 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Book Depreciation: Racking Equipment	Book Depreciation Schedule, Line 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Book Depreciation: Balance of Plant	Book Depreciation Schedule, Line 19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Book Depreciation: Electric System Upgrades	Book Depreciation Schedule, Line 26	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
12	Book Depreciation: Solar Inverter 1	Book Depreciation Schedule, Line 33	-	-	-	-	-	-	-	-	-	-
13	Book Depreciation: Solar Inverter 2	Book Depreciation Schedule, Line 40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Total Book Depreciation	Sum Lines 8 through 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Cumulative Book Depreciation	CY Line 14 + PY Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16												
17	Cumulative Book / Tax Timer	Line 3 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Federal Tax Rate	Cost of Capital, Line 14 Column (a)	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%	21.00%
19	Deferred Federal Tax Reserve	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Less: Federal Deduction for Deferred State Taxes	Line 18 x - Line 25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Net Deferred Federal Tax Reserve	Line 19 + Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22												
23	Cumulative Book / Tax Timer	Line 6 - Line 15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	State Tax Rate	Cost of Capital, Line 12 Column (a)	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
25	Deferred State Tax Reserve	Line 23 x Line 24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26												
27	Total Deferred Taxes	Line 21 + Line 25	$ 928,496	$ 858,625	$ 790,284	$ 722,787	$ 656,151	$ 592,398	$ 532,255	$ 474,168	$ 417,202	$ 361,379

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
1	<u>40 Year Property</u>										
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ [redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7											
8	<u>40 Year Property</u>										
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ [redacted]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14											
15	<u>40 Year Property</u>										
16	Balance of Plant	Capital Costs, Line 48	$ [redacted]								
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21											
22	<u>40 Year Property</u>										
23	Electric System Upgrades	Capital Costs, Line 49	$ 560,000								
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 14,000	$ 28,000	$ 42,000	$ 56,000	$ 70,000	$ 84,000	$ 98,000	$ 112,000	$ 126,000
28											
29	<u>20 Year Property</u>										
30	Solar Inverter 1	Capital Costs, Line 50	$ [redacted]								
31	Cumulative Capital Investment	CY Line 30 + PY Line 31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
33	Annual Book Depreciation	Line 31 x Line 32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35											
36	<u>20 Year Property</u>										
37	Solar Inverter 2	Capital Costs, Line 51									
38	Cumulative Capital Investment	CY Line 37 + PY Line 38									
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%									
40	Annual Book Depreciation	Line 38 x Line 39									
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41									
42											
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 323,772	$ 647,543	$ 971,315	$ 1,295,086	$ 1,618,858	$ 1,942,629	$ 2,266,401	$ 2,590,172	$ 2,913,944

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Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference		Year 10
1	40 Year Property			
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$	-
3	Cumulative Capital Investment	CY Line 2 + PY Line 3		[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%		2.5%
5	Annual Book Depreciation	Line 3 x Line 4		[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	$	[redacted]
7				
8	40 Year Property			
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$	-
10	Cumulative Capital Investment	CY Line 9 + PY Line 10		[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%		2.5%
12	Annual Book Depreciation	Line 10 x Line 11		[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	$	[redacted]
14				
15	40 Year Property			
16	Balance of Plant	Capital Costs, Line 48		
17	Cumulative Capital Investment	CY Line 16 + PY Line 17		[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%		2.5%
19	Annual Book Depreciation	Line 17 x Line 18		[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$	[redacted]
21				
22	40 Year Property			
23	Electric System Upgrades	Capital Costs, Line 49		
24	Cumulative Capital Investment	CY Line 23 + PY Line 24		560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%		2.5%
26	Annual Book Depreciation	Line 24 x Line 25		14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$	140,000
28				
29	20 Year Property			
30	Solar Inverter 1	Capital Costs, Line 50		
31	Cumulative Capital Investment	CY Line 30 + PY Line 31		[redacted]
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%		5.0%
33	Annual Book Depreciation	Line 31 x Line 32		[redacted]
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	$	[redacted]
35				
36	20 Year Property			
37	Solar Inverter 2	Capital Costs, Line 51		
38	Cumulative Capital Investment	CY Line 37 + PY Line 38		
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%		
40	Annual Book Depreciation	Line 38 x Line 39		
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41		
42				
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$	323,772
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$	3,237,715

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19
1	40 Year Property										
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7											
8	40 Year Property										
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14											
15	40 Year Property										
16	Balance of Plant	Capital Costs, Line 48									
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21											
22	40 Year Property										
23	Electric System Upgrades	Capital Costs, Line 49									
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 154,000	$ 168,000	$ 182,000	$ 196,000	$ 210,000	$ 224,000	$ 238,000	$ 252,000	$ 266,000
28											
29	20 Year Property										
30	Solar Inverter 1	Capital Costs, Line 50									
31	Cumulative Capital Investment	CY Line 30 + PY Line 31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
33	Annual Book Depreciation	Line 31 x Line 32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35											
36	20 Year Property										
37	Solar Inverter 2	Capital Costs, Line 51									
38	Cumulative Capital Investment	CY Line 37 + PY Line 38									
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%									
40	Annual Book Depreciation	Line 38 x Line 39									
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41									
42											
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772	$ 323,772
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 3,561,487	$ 3,885,258	$ 4,209,030	$ 4,532,802	$ 4,856,573	$ 5,180,345	$ 5,504,116	$ 5,827,888	$ 6,151,659

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 20
1	40 Year Property		
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ -
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	$ [redacted]
7			
8	40 Year Property		
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ -
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	$ [redacted]
14			
15	40 Year Property		
16	Balance of Plant	Capital Costs, Line 48	
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$ [redacted]
21			
22	40 Year Property		
23	Electric System Upgrades	Capital Costs, Line 49	
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 280,000
28			
29	20 Year Property		
30	Solar Inverter 1	Capital Costs, Line 50	
31	Cumulative Capital Investment	CY Line 30 + PY Line 31	[redacted]
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%
33	Annual Book Depreciation	Line 31 x Line 32	[redacted]
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	$ [redacted]
35			
36	20 Year Property		
37	Solar Inverter 2	Capital Costs, Line 51	
38	Cumulative Capital Investment	CY Line 37 + PY Line 38	
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	
40	Annual Book Depreciation	Line 38 x Line 39	
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41	
42			
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 323,772
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 6,475,431

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29
1	40 Year Property										
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ -	$ -	$ -	$ -	$ -	$ -	$ [redacted]	[redacted]	[redacted]
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7											
8	40 Year Property										
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ -	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14											
15	40 Year Property										
16	Balance of Plant	Capital Costs, Line 48									
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21											
22	40 Year Property										
23	Electric System Upgrades	Capital Costs, Line 49									
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 294,000	$ 308,000	$ 322,000	$ 336,000	$ 350,000	$ 364,000	$ 378,000	$ 392,000	$ 406,000
28											
29	20 Year Property										
30	Solar Inverter 1	Capital Costs, Line 50									
31	Cumulative Capital Investment	CY Line 30 + PY Line 31									
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%									
33	Annual Book Depreciation	Line 31 x Line 32									
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34									
35											
36	20 Year Property										
37	Solar Inverter 2	Capital Costs, Line 51	[redacted]								
38	Cumulative Capital Investment	CY Line 37 + PY Line 38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
40	Annual Book Depreciation	Line 38 x Line 39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42											
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 338,257	$ 338,968	$ 339,693	$ 340,432	$ 341,186	$ 341,955	$ 343,708	$ 345,495	$ 347,319
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 6,813,688	$ 7,152,655	$ 7,492,348	$ 7,832,780	$ 8,173,966	$ 8,515,921	$ 8,859,629	$ 9,205,124	$ 9,552,443

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 30
1	<u>40 Year Property</u>		
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ [redacted]
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	$ [redacted]
7			
8	<u>40 Year Property</u>		
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ [redacted]
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	$ [redacted]
14			
15	<u>40 Year Property</u>		
16	Balance of Plant	Capital Costs, Line 48	
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$ [redacted]
21			
22	<u>40 Year Property</u>		
23	Electric System Upgrades	Capital Costs, Line 49	
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 420,000
28			
29	<u>20 Year Property</u>		
30	Solar Inverter 1	Capital Costs, Line 50	
31	Cumulative Capital Investment	CY Line 30 + PY Line 31	
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	
33	Annual Book Depreciation	Line 31 x Line 32	
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	
35			
36	<u>20 Year Property</u>		
37	Solar Inverter 2	Capital Costs, Line 51	
38	Cumulative Capital Investment	CY Line 37 + PY Line 38	[redacted]
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%
40	Annual Book Depreciation	Line 38 x Line 39	[redacted]
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41	$ [redacted]
42			
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 349,179
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 9,901,621

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39
1	<u>40 Year Property</u>										
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7											
8	<u>40 Year Property</u>										
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14											
15	<u>40 Year Property</u>										
16	Balance of Plant	Capital Costs, Line 48									
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21											
22	<u>40 Year Property</u>										
23	Electric System Upgrades	Capital Costs, Line 49									
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 434,000	$ 448,000	$ 462,000	$ 476,000	$ 490,000	$ 504,000	$ 518,000	$ 532,000	$ 546,000
28											
29	<u>20 Year Property</u>										
30	Solar Inverter 1	Capital Costs, Line 50									
31	Cumulative Capital Investment	CY Line 30 + PY Line 31									
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%									
33	Annual Book Depreciation	Line 31 x Line 32									
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34									
35											
36	<u>20 Year Property</u>										
37	Solar Inverter 2	Capital Costs, Line 51									
38	Cumulative Capital Investment	CY Line 37 + PY Line 38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
40	Annual Book Depreciation	Line 38 x Line 39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42											
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 351,076	$ 353,877	$ 356,734	$ 359,648	$ 362,621	$ 365,653	$ 369,926	$ 374,284	$ 378,729
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 10,252,697	$ 10,606,573	$ 10,963,307	$ 11,322,956	$ 11,685,577	$ 12,051,230	$ 12,421,156	$ 12,795,440	$ 13,174,170

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 9
Book Depreciation Schedule

Line No.	Description	Reference	Year 40
1	<u>40 Year Property</u>		
2	PV Modules	Capital Costs, Line 46 + Maintenance Capital Costs, Line 7	$ [redacted]
3	Cumulative Capital Investment	CY Line 2 + PY Line 3	[redacted]
4	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
5	Annual Book Depreciation	Line 3 x Line 4	[redacted]
6	Cumulative Book Depreciation	CY Line 5 + PY Line 6	$ [redacted]
7			
8	<u>40 Year Property</u>		
9	Racking Equipment	Capital Costs, Line 47 + Maintenance Capital Costs, Line 14	$ [redacted]
10	Cumulative Capital Investment	CY Line 9 + PY Line 10	[redacted]
11	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
12	Annual Book Depreciation	Line 10 x Line 11	[redacted]
13	Cumulative Book Depreciation	CY Line 12 + PY Line 13	$ [redacted]
14			
15	<u>40 Year Property</u>		
16	Balance of Plant	Capital Costs, Line 48	
17	Cumulative Capital Investment	CY Line 16 + PY Line 17	[redacted]
18	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
19	Annual Book Depreciation	Line 17 x Line 18	[redacted]
20	Cumulative Book Depreciation	CY Line 19 + PY Line 20	$ [redacted]
21			
22	<u>40 Year Property</u>		
23	Electric System Upgrades	Capital Costs, Line 49	
24	Cumulative Capital Investment	CY Line 23 + PY Line 24	560,000
25	Annual Depreciation Rate	Annual Depreciation Rate @ 2.5%	2.5%
26	Annual Book Depreciation	Line 24 x Line 25	14,000
27	Cumulative Book Depreciation	CY Line 26 + PY Line 27	$ 560,000
28			
29	<u>20 Year Property</u>		
30	Solar Inverter 1	Capital Costs, Line 50	
31	Cumulative Capital Investment	CY Line 30 + PY Line 31	
32	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	
33	Annual Book Depreciation	Line 31 x Line 32	
34	Cumulative Book Depreciation	CY Line 33 + PY Line 34	
35			
36	<u>20 Year Property</u>		
37	Solar Inverter 2	Capital Costs, Line 51	
38	Cumulative Capital Investment	CY Line 37 + PY Line 38	[redacted]
39	Annual Depreciation Rate	Annual Depreciation Rate @ 5.0%	5.0%
40	Annual Book Depreciation	Line 38 x Line 39	[redacted]
41	Cumulative Book Depreciation	CY Line 40 + PY Line 41	$ [redacted]
42			
43	Total Annual Book Depreciation	Sum Lines 5, 12, 19, 26, 33, and 40	$ 383,264
44	Total Cumulative Book Depreciation	CY Line 43 + PY Line 44	$ 13,557,433

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 10
Tax Depreciation Schedule 10 (Excludes Maintenance Capital Cost)

Line No.	Description	Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1												
2	PV Modules and Associated Materials	Capital Costs, Line 46	$ [redacted]									
3	Cumulative Investment Tax Basis	CY Line 2 + PY Line 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
4	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
5	Tax Depreciation	Line 3 x Line 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
6												
7	Racking Equipment and Associated Materials	Capital Costs, Line 47	$ [redacted]									
8	Cumulative Investment Tax Basis	CY Line 7 + PY Line 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
9	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
10	Tax Depreciation	Line 8 x Line 9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
11												
12	Balance of Plant	Capital Costs, Line 48	$ [redacted]									
13	Cumulative Investment Tax Basis	CY Line 12 + PY Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
14	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
15	Tax Depreciation	Line 13 x Line 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
16												
17	Electric System Upgrades	Capital Costs, Line 49	$ 560,000									
18	Cumulative Investment Tax Basis	CY Line 17 + PY Line 18	560,000	560,000	560,000	560,000	560,000	560,000				
19	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
20	Tax Depreciation	Line 18 x Line 19	112,000	179,200	107,520	64,512	64,512	32,256				
21												
22	Solar Inverter 1	Capital Costs, Line 50	$ [redacted]									
23	Cumulative Investment Tax Basis	CY Line 22 + PY Line 23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
24	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
25	Tax Depreciation	Line 23 x Line 24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
26												
27	Solar Inverter 2	Capital Costs, Line 51										
28	Cumulative Investment Tax Basis	CY Line 27 + PY Line 28										
29	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
30	Tax Depreciation	Line 28 x Line 29										
31												
32	Total Federal Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -
33												
34	Total State Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -

Notes
(1) Federal & State Tax are calculated at the same MACRS rate on Tax Depreciation Schedule

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 10
Tax Depreciation Schedule 10 (Excludes Maintenance Capital Cost)

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1												
2	PV Modules and Associated Materials	Capital Costs, Line 46										
3	Cumulative Investment Tax Basis	CY Line 2 + PY Line 3										
4	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
5	Tax Depreciation	Line 3 x Line 4										
6												
7	Racking Equipment and Associated Materials	Capital Costs, Line 47										
8	Cumulative Investment Tax Basis	CY Line 7 + PY Line 8										
9	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
10	Tax Depreciation	Line 8 x Line 9										
11												
12	Balance of Plant	Capital Costs, Line 48										
13	Cumulative Investment Tax Basis	CY Line 12 + PY Line 13										
14	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
15	Tax Depreciation	Line 13 x Line 14										
16												
17	Electric System Upgrades	Capital Costs, Line 49										
18	Cumulative Investment Tax Basis	CY Line 17 + PY Line 18										
19	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
20	Tax Depreciation	Line 18 x Line 19										
21												
22	Solar Inverter 1	Capital Costs, Line 50										
23	Cumulative Investment Tax Basis	CY Line 22 + PY Line 23										
24	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
25	Tax Depreciation	Line 23 x Line 24										
26												
27	Solar Inverter 2	Capital Costs, Line 51										
28	Cumulative Investment Tax Basis	CY Line 27 + PY Line 28										
29	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
30	Tax Depreciation	Line 28 x Line 29										
31												
32	Total Federal Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33												
34	Total State Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) Federal & State Tax are calculated at the same MACRS rate on Tax Depreciation Schedule

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 10
Tax Depreciation Schedule 10 (Excludes Maintenance Capital Cost)

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1												
2	PV Modules and Associated Materials	Capital Costs, Line 46										
3	Cumulative Investment Tax Basis	CY Line 2 + PY Line 3										
4	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
5	Tax Depreciation	Line 3 x Line 4										
6												
7	Racking Equipment and Associated Materials	Capital Costs, Line 47										
8	Cumulative Investment Tax Basis	CY Line 7 + PY Line 8										
9	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
10	Tax Depreciation	Line 8 x Line 9										
11												
12	Balance of Plant	Capital Costs, Line 48										
13	Cumulative Investment Tax Basis	CY Line 12 + PY Line 13										
14	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
15	Tax Depreciation	Line 13 x Line 14										
16												
17	Electric System Upgrades	Capital Costs, Line 49										
18	Cumulative Investment Tax Basis	CY Line 17 + PY Line 18										
19	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
20	Tax Depreciation	Line 18 x Line 19										
21												
22	Solar Inverter 1	Capital Costs, Line 50										
23	Cumulative Investment Tax Basis	CY Line 22 + PY Line 23										
24	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
25	Tax Depreciation	Line 23 x Line 24										
26												
27	Solar Inverter 2	Capital Costs, Line 51	$ [redacted]									
28	Cumulative Investment Tax Basis	CY Line 27 + PY Line 28		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
29	Annual 5 Year MACRS	MACRS Rate Table, Line 2	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%				
30	Tax Depreciation	Line 28 x Line 29	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
31												
32	Total Federal Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -
33												
34	Total State Tax Depreciation[1]	Sum Lines 5, 10, 15, 20, 25, and 30	$ [redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -	$ -	$ -	$ -

Notes
(1) Federal & State Tax are calculated at the same MACRS rate on Tax Depreciation Schedule

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 10
Tax Depreciation Schedule 10 (Excludes Maintenance Capital Cost)

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1												
2	PV Modules and Associated Materials	Capital Costs, Line 46										
3	Cumulative Investment Tax Basis	CY Line 2 + PY Line 3										
4	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
5	Tax Depreciation	Line 3 x Line 4										
6												
7	Racking Equipment and Associated Materials	Capital Costs, Line 47										
8	Cumulative Investment Tax Basis	CY Line 7 + PY Line 8										
9	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
10	Tax Depreciation	Line 8 x Line 9										
11												
12	Balance of Plant	Capital Costs, Line 48										
13	Cumulative Investment Tax Basis	CY Line 12 + PY Line 13										
14	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
15	Tax Depreciation	Line 13 x Line 14										
16												
17	Electric System Upgrades	Capital Costs, Line 49										
18	Cumulative Investment Tax Basis	CY Line 17 + PY Line 18										
19	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
20	Tax Depreciation	Line 18 x Line 19										
21												
22	Solar Inverter 1	Capital Costs, Line 50										
23	Cumulative Investment Tax Basis	CY Line 22 + PY Line 23										
24	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
25	Tax Depreciation	Line 23 x Line 24										
26												
27	Solar Inverter 2	Capital Costs, Line 51										
28	Cumulative Investment Tax Basis	CY Line 27 + PY Line 28										
29	Annual 5 Year MACRS	MACRS Rate Table, Line 2										
30	Tax Depreciation	Line 28 x Line 29										
31												
32	Total Federal Tax Depreciation(1)	Sum Lines 5, 10, 15, 20, 25, and 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33												
34	Total State Tax Depreciation(1)	Sum Lines 5, 10, 15, 20, 25, and 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) Federal & State Tax are calculated at the same MACRS rate on Tax Depreciation Schedule

Unitil Energy Systems d/b/a Unitil
Exhibit SP 7, Updated Benefit Cost Analysis
Schedule 11
Tax Depreciation Schedule 11 (Maintenance Capital Cost)

Line No.	Description	(a) Maintenance Capital Costs	(b) Reference	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	5 Year MACRS		MACRS Rate Table, Line 2	20.0%	32.0%	19.2%	11.5%	11.5%	5.8%				
2													
3	PV Modules Vintage Year	Maintenance Capital Costs, Line 7											
4	Year 1	$	Column (a) depreciated by Line 1	$	$	$	$	$	$				
5	Year 2		Column (a) depreciated by Line 1										
6	Year 3		Column (a) depreciated by Line 1										
7	Year 4		Column (a) depreciated by Line 1										
8	Year 5		Column (a) depreciated by Line 1										
9	Year 6		Column (a) depreciated by Line 1										
10	Year 7		Column (a) depreciated by Line 1										
11	Year 8		Column (a) depreciated by Line 1										
12	Year 9		Column (a) depreciated by Line 1										
13	Year 10		Column (a) depreciated by Line 1										
14	Year 11		Column (a) depreciated by Line 1										
15	Year 12		Column (a) depreciated by Line 1										
16	Year 13		Column (a) depreciated by Line 1										
17	Year 14		Column (a) depreciated by Line 1										
18	Year 15		Column (a) depreciated by Line 1										
19	Year 16		Column (a) depreciated by Line 1										
20	Year 17		Column (a) depreciated by Line 1										
21	Year 18		Column (a) depreciated by Line 1										
22	Year 19		Column (a) depreciated by Line 1										
23	Year 20		Column (a) depreciated by Line 1										
24	Year 21		Column (a) depreciated by Line 1										
25	Year 22		Column (a) depreciated by Line 1										
26	Year 23		Column (a) depreciated by Line 1										
27	Year 24		Column (a) depreciated by Line 1										
28	Year 25		Column (a) depreciated by Line 1										
29	Year 26	[redacted]	Column (a) depreciated by Line 1										
30	Year 27	[redacted]	Column (a) depreciated by Line 1										
31	Year 28	[redacted]	Column (a) depreciated by Line 1										
32	Year 29	[redacted]	Column (a) depreciated by Line 1										
33	Year 30	[redacted]	Column (a) depreciated by Line 1										
34	Year 31	[redacted]	Column (a) depreciated by Line 1										
35	Year 32	[redacted]	Column (a) depreciated by Line 1										
36	Year 33	[redacted]	Column (a) depreciated by Line 1										
37	Year 34	[redacted]	Column (a) depreciated by Line 1										
38	Year 35	[redacted]	Column (a) depreciated by Line 1										
39	Year 36	[redacted]	Column (a) depreciated by Line 1										
40	Year 37	[redacted]	Column (a) depreciated by Line 1										
41	Year 38	[redacted]	Column (a) depreciated by Line 1										
42	Year 39	[redacted]	Column (a) depreciated by Line 1										
43	Year 40	$ [redacted]	Column (a) depreciated by Line 1										
44	Federal Tax Depreciation(1)		Sum Lines 4 through 43										
45	State Tax Depreciation(1)		Sum Lines 4 through 43										
46													
47	Racking Equipment Vintage Year	Maintenance Capital Costs, Line 14											
48	Year 1	$	Column (a) depreciated by Line 1	$	$	$	$	$	$				
49	Year 2		Column (a) depreciated by Line 1										
50	Year 3		Column (a) depreciated by Line 1										
51	Year 4		Column (a) depreciated by Line 1										
52	Year 5		Column (a) depreciated by Line 1										
53	Year 6		Column (a) depreciated by Line 1										
54	Year 7		Column (a) depreciated by Line 1										
55	Year 8		Column (a) depreciated by Line 1										
56	Year 9		Column (a) depreciated by Line 1										
57	Year 10		Column (a) depreciated by Line 1										
58	Year 11		Column (a) depreciated by Line 1										
59	Year 12		Column (a) depreciated by Line 1										
60	Year 13		Column (a) depreciated by Line 1										
61	Year 14		Column (a) depreciated by Line 1										
62	Year 15		Column (a) depreciated by Line 1										
63	Year 16		Column (a) depreciated by Line 1										
64	Year 17		Column (a) depreciated by Line 1										
65	Year 18		Column (a) depreciated by Line 1										
66	Year 19		Column (a) depreciated by Line 1										
67	Year 20		Column (a) depreciated by Line 1										
68	Year 21	[redacted]	Column (a) depreciated by Line 1										
69	Year 22	[redacted]	Column (a) depreciated by Line 1										
70	Year 23	[redacted]	Column (a) depreciated by Line 1										
71	Year 24	[redacted]	Column (a) depreciated by Line 1										
72	Year 25	[redacted]	Column (a) depreciated by Line 1										
73	Year 26	[redacted]	Column (a) depreciated by Line 1										
74	Year 27	[redacted]	Column (a) depreciated by Line 1										
75	Year 28	[redacted]	Column (a) depreciated by Line 1										
76	Year 29	[redacted]	Column (a) depreciated by Line 1										
77	Year 30	[redacted]	Column (a) depreciated by Line 1										
78	Year 31	[redacted]	Column (a) depreciated by Line 1										
79	Year 32	[redacted]	Column (a) depreciated by Line 1										
80	Year 33	[redacted]	Column (a) depreciated by Line 1										
81	Year 34	[redacted]	Column (a) depreciated by Line 1										
82	Year 35	[redacted]	Column (a) depreciated by Line 1										
83	Year 36	[redacted]	Column (a) depreciated by Line 1										
84	Year 37	[redacted]	Column (a) depreciated by Line 1										
85	Year 38	[redacted]	Column (a) depreciated by Line 1										
86	Year 39	[redacted]	Column (a) depreciated by Line 1										
87	Year 40	$ [redacted]	Column (a) depreciated by Line 1										
88	Federal Tax Depreciation(1)		Sum Lines 48 through 87										
89	State Tax Depreciation(1)		Sum Lines 48 through 87										
90													
91	Total Federal Tax Depreciation(1)		Line 44 + Line 88	$	$	$	$	$	$	$	$	$	$
92	Total State Tax Depreciation(1)		Line 45 + Line 89	$	$	$	$	$	$	$	$	$	$

Unitil Energy Systems d/b/a Unitil
Exhibit SP 7, Updated Benefit Cost Analysis
Schedule 11
Tax Depreciation Schedule 11 (Maintenance Capital Cost)

Line No.	Description	(a) Maintenance Capital Costs	(b) Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	5 Year MACRS		MACRS Rate Table, Line 2										
2													
3	PV Modules Vintage Year	Maintenance Capital Costs, Line 7											
4	Year 1	$	Column (a) depreciated by Line 1										
5	Year 2		Column (a) depreciated by Line 1										
6	Year 3		Column (a) depreciated by Line 1										
7	Year 4		Column (a) depreciated by Line 1										
8	Year 5		Column (a) depreciated by Line 1										
9	Year 6		Column (a) depreciated by Line 1										
10	Year 7		Column (a) depreciated by Line 1										
11	Year 8		Column (a) depreciated by Line 1										
12	Year 9		Column (a) depreciated by Line 1										
13	Year 10		Column (a) depreciated by Line 1										
14	Year 11		Column (a) depreciated by Line 1										
15	Year 12		Column (a) depreciated by Line 1										
16	Year 13		Column (a) depreciated by Line 1										
17	Year 14		Column (a) depreciated by Line 1										
18	Year 15		Column (a) depreciated by Line 1										
19	Year 16		Column (a) depreciated by Line 1										
20	Year 17		Column (a) depreciated by Line 1										
21	Year 18		Column (a) depreciated by Line 1										
22	Year 19		Column (a) depreciated by Line 1										
23	Year 20		Column (a) depreciated by Line 1										
24	Year 21		Column (a) depreciated by Line 1										
25	Year 22		Column (a) depreciated by Line 1										
26	Year 23		Column (a) depreciated by Line 1										
27	Year 24		Column (a) depreciated by Line 1										
28	Year 25		Column (a) depreciated by Line 1										
29	Year 26	[redacted]	Column (a) depreciated by Line 1										
30	Year 27		Column (a) depreciated by Line 1										
31	Year 28		Column (a) depreciated by Line 1										
32	Year 29		Column (a) depreciated by Line 1										
33	Year 30		Column (a) depreciated by Line 1										
34	Year 31		Column (a) depreciated by Line 1										
35	Year 32		Column (a) depreciated by Line 1										
36	Year 33		Column (a) depreciated by Line 1										
37	Year 34		Column (a) depreciated by Line 1										
38	Year 35		Column (a) depreciated by Line 1										
39	Year 36		Column (a) depreciated by Line 1										
40	Year 37		Column (a) depreciated by Line 1										
41	Year 38		Column (a) depreciated by Line 1										
42	Year 39		Column (a) depreciated by Line 1										
43	Year 40	$	Column (a) depreciated by Line 1										
44	Federal Tax Depreciation(1)		Sum Lines 4 through 43										
45	State Tax Depreciation(1)		Sum Lines 4 through 43										
46													
47	Racking Equipment Vintage Year	Maintenance Capital Costs, Line 14											
48	Year 1	$	Column (a) depreciated by Line 1										
49	Year 2		Column (a) depreciated by Line 1										
50	Year 3		Column (a) depreciated by Line 1										
51	Year 4		Column (a) depreciated by Line 1										
52	Year 5		Column (a) depreciated by Line 1										
53	Year 6		Column (a) depreciated by Line 1										
54	Year 7		Column (a) depreciated by Line 1										
55	Year 8		Column (a) depreciated by Line 1										
56	Year 9		Column (a) depreciated by Line 1										
57	Year 10		Column (a) depreciated by Line 1										
58	Year 11		Column (a) depreciated by Line 1										
59	Year 12		Column (a) depreciated by Line 1										
60	Year 13		Column (a) depreciated by Line 1										
61	Year 14		Column (a) depreciated by Line 1										
62	Year 15		Column (a) depreciated by Line 1										
63	Year 16		Column (a) depreciated by Line 1										
64	Year 17		Column (a) depreciated by Line 1										
65	Year 18		Column (a) depreciated by Line 1										
66	Year 19		Column (a) depreciated by Line 1										
67	Year 20		Column (a) depreciated by Line 1										
68	Year 21	[redacted]	Column (a) depreciated by Line 1										
69	Year 22		Column (a) depreciated by Line 1										
70	Year 23		Column (a) depreciated by Line 1										
71	Year 24		Column (a) depreciated by Line 1										
72	Year 25		Column (a) depreciated by Line 1										
73	Year 26		Column (a) depreciated by Line 1										
74	Year 27		Column (a) depreciated by Line 1										
75	Year 28		Column (a) depreciated by Line 1										
76	Year 29		Column (a) depreciated by Line 1										
77	Year 30		Column (a) depreciated by Line 1										
78	Year 31		Column (a) depreciated by Line 1										
79	Year 32		Column (a) depreciated by Line 1										
80	Year 33		Column (a) depreciated by Line 1										
81	Year 34		Column (a) depreciated by Line 1										
82	Year 35		Column (a) depreciated by Line 1										
83	Year 36		Column (a) depreciated by Line 1										
84	Year 37		Column (a) depreciated by Line 1										
85	Year 38		Column (a) depreciated by Line 1										
86	Year 39		Column (a) depreciated by Line 1										
87	Year 40	$	Column (a) depreciated by Line 1										
88	Federal Tax Depreciation(1)		Sum Lines 48 through 87										
89	State Tax Depreciation(1)		Sum Lines 48 through 87										
90													
91	Total Federal Tax Depreciation(1)		Line 44 + Line 88	$	$	$	$	$	$	$	$	$	$
92	Total State Tax Depreciation(1)		Line 45 + Line 89	$	$	$	$	$	$	$	$	$	$

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Unitil Energy Systems d/b/a Unitil
Exhibit SP 7, Updated Benefit Cost Analysis
Schedule 11
Tax Depreciation Schedule 11 (Maintenance Capital Cost)

Line No.	Description	(a) Maintenance Capital Costs	(b) Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	5 Year MACRS		MACRS Rate Table, Line 2										
2													
3	PV Modules Vintage Year	Maintenance Capital Costs, Line 7											
4	Year 1	$	Column (a) depreciated by Line 1										
5	Year 2		Column (a) depreciated by Line 1										
6	Year 3		Column (a) depreciated by Line 1										
7	Year 4		Column (a) depreciated by Line 1										
8	Year 5		Column (a) depreciated by Line 1										
9	Year 6		Column (a) depreciated by Line 1										
10	Year 7		Column (a) depreciated by Line 1										
11	Year 8		Column (a) depreciated by Line 1										
12	Year 9		Column (a) depreciated by Line 1										
13	Year 10		Column (a) depreciated by Line 1										
14	Year 11		Column (a) depreciated by Line 1										
15	Year 12		Column (a) depreciated by Line 1										
16	Year 13		Column (a) depreciated by Line 1										
17	Year 14		Column (a) depreciated by Line 1										
18	Year 15		Column (a) depreciated by Line 1										
19	Year 16		Column (a) depreciated by Line 1										
20	Year 17		Column (a) depreciated by Line 1										
21	Year 18		Column (a) depreciated by Line 1										
22	Year 19		Column (a) depreciated by Line 1										
23	Year 20		Column (a) depreciated by Line 1										
24	Year 21		Column (a) depreciated by Line 1										
25	Year 22		Column (a) depreciated by Line 1										
26	Year 23		Column (a) depreciated by Line 1										
27	Year 24		Column (a) depreciated by Line 1										
28	Year 25		Column (a) depreciated by Line 1										
29	Year 26	[redacted]	Column (a) depreciated by Line 1						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Year 27	[redacted]	Column (a) depreciated by Line 1							[redacted]	[redacted]	[redacted]	[redacted]
31	Year 28	[redacted]	Column (a) depreciated by Line 1								[redacted]	[redacted]	[redacted]
32	Year 29	[redacted]	Column (a) depreciated by Line 1									[redacted]	[redacted]
33	Year 30	[redacted]	Column (a) depreciated by Line 1										[redacted]
34	Year 31	[redacted]	Column (a) depreciated by Line 1										
35	Year 32	[redacted]	Column (a) depreciated by Line 1										
36	Year 33	[redacted]	Column (a) depreciated by Line 1										
37	Year 34	[redacted]	Column (a) depreciated by Line 1										
38	Year 35	[redacted]	Column (a) depreciated by Line 1										
39	Year 36	[redacted]	Column (a) depreciated by Line 1										
40	Year 37	[redacted]	Column (a) depreciated by Line 1										
41	Year 38	[redacted]	Column (a) depreciated by Line 1										
42	Year 39	[redacted]	Column (a) depreciated by Line 1										
43	Year 40	$ [redacted]	Column (a) depreciated by Line 1										
44	Federal Tax Depreciation[1]		Sum Lines 4 through 43						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	State Tax Depreciation[1]		Sum Lines 4 through 43						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46													
47	Racking Equipment Vintage Year	Maintenance Capital Costs, Line 14											
48	Year 1	$	Column (a) depreciated by Line 1										
49	Year 2		Column (a) depreciated by Line 1										
50	Year 3		Column (a) depreciated by Line 1										
51	Year 4		Column (a) depreciated by Line 1										
52	Year 5		Column (a) depreciated by Line 1										
53	Year 6		Column (a) depreciated by Line 1										
54	Year 7		Column (a) depreciated by Line 1										
55	Year 8		Column (a) depreciated by Line 1										
56	Year 9		Column (a) depreciated by Line 1										
57	Year 10		Column (a) depreciated by Line 1										
58	Year 11		Column (a) depreciated by Line 1										
59	Year 12		Column (a) depreciated by Line 1										
60	Year 13		Column (a) depreciated by Line 1										
61	Year 14		Column (a) depreciated by Line 1										
62	Year 15		Column (a) depreciated by Line 1										
63	Year 16		Column (a) depreciated by Line 1										
64	Year 17		Column (a) depreciated by Line 1										
65	Year 18		Column (a) depreciated by Line 1										
66	Year 19		Column (a) depreciated by Line 1										
67	Year 20		Column (a) depreciated by Line 1										
68	Year 21	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
69	Year 22	[redacted]	Column (a) depreciated by Line 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
70	Year 23	[redacted]	Column (a) depreciated by Line 1			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
71	Year 24	[redacted]	Column (a) depreciated by Line 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
72	Year 25	[redacted]	Column (a) depreciated by Line 1					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
73	Year 26	[redacted]	Column (a) depreciated by Line 1						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
74	Year 27	[redacted]	Column (a) depreciated by Line 1							[redacted]	[redacted]	[redacted]	[redacted]
75	Year 28	[redacted]	Column (a) depreciated by Line 1								[redacted]	[redacted]	[redacted]
76	Year 29	[redacted]	Column (a) depreciated by Line 1									[redacted]	[redacted]
77	Year 30	[redacted]	Column (a) depreciated by Line 1										[redacted]
78	Year 31	[redacted]	Column (a) depreciated by Line 1										
79	Year 32	[redacted]	Column (a) depreciated by Line 1										
80	Year 33	[redacted]	Column (a) depreciated by Line 1										
81	Year 34	[redacted]	Column (a) depreciated by Line 1										
82	Year 35	[redacted]	Column (a) depreciated by Line 1										
83	Year 36	[redacted]	Column (a) depreciated by Line 1										
84	Year 37	[redacted]	Column (a) depreciated by Line 1										
85	Year 38	[redacted]	Column (a) depreciated by Line 1										
86	Year 39	[redacted]	Column (a) depreciated by Line 1										
87	Year 40	$ [redacted]	Column (a) depreciated by Line 1										
88	Federal Tax Depreciation[1]		Sum Lines 48 through 87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	State Tax Depreciation[1]		Sum Lines 48 through 87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
90													
91	Total Federal Tax Depreciation[1]		Line 44 + Line 88	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	Total State Tax Depreciation[1]		Line 45 + Line 89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Unitil Energy Systems d/b/a Unitil
Exhibit SP 7, Updated Benefit Cost Analysis
Schedule 11
Tax Depreciation Schedule 11 (Maintenance Capital Cost)

Line No.	Description	(a) Maintenance Capital Costs	(b) Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	5 Year MACRS		MACRS Rate Table, Line 2										
2													
3	PV Modules _ Vintage Year	Maintenance Capital Costs, Line 7											
4	Year 1	$	Column (a) depreciated by Line 1										
5	Year 2		Column (a) depreciated by Line 1										
6	Year 3		Column (a) depreciated by Line 1										
7	Year 4		Column (a) depreciated by Line 1										
8	Year 5		Column (a) depreciated by Line 1										
9	Year 6		Column (a) depreciated by Line 1										
10	Year 7		Column (a) depreciated by Line 1										
11	Year 8		Column (a) depreciated by Line 1										
12	Year 9		Column (a) depreciated by Line 1										
13	Year 10		Column (a) depreciated by Line 1										
14	Year 11		Column (a) depreciated by Line 1										
15	Year 12		Column (a) depreciated by Line 1										
16	Year 13		Column (a) depreciated by Line 1										
17	Year 14		Column (a) depreciated by Line 1										
18	Year 15		Column (a) depreciated by Line 1										
19	Year 16		Column (a) depreciated by Line 1										
20	Year 17		Column (a) depreciated by Line 1										
21	Year 18		Column (a) depreciated by Line 1										
22	Year 19		Column (a) depreciated by Line 1										
23	Year 20		Column (a) depreciated by Line 1										
24	Year 21		Column (a) depreciated by Line 1										
25	Year 22		Column (a) depreciated by Line 1										
26	Year 23		Column (a) depreciated by Line 1										
27	Year 24		Column (a) depreciated by Line 1										
28	Year 25		Column (a) depreciated by Line 1										
29	Year 26	[redacted]	Column (a) depreciated by Line 1	[redacted]									
30	Year 27	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]								
31	Year 28	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]							
32	Year 29	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]						
33	Year 30	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
34	Year 31	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
35	Year 32	[redacted]	Column (a) depreciated by Line 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
36	Year 33	[redacted]	Column (a) depreciated by Line 1			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
37	Year 34	[redacted]	Column (a) depreciated by Line 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
38	Year 35	[redacted]	Column (a) depreciated by Line 1					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Year 36	[redacted]	Column (a) depreciated by Line 1						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	Year 37	[redacted]	Column (a) depreciated by Line 1							[redacted]	[redacted]	[redacted]	[redacted]
41	Year 38	[redacted]	Column (a) depreciated by Line 1								[redacted]	[redacted]	[redacted]
42	Year 39	[redacted]	Column (a) depreciated by Line 1									[redacted]	[redacted]
43	Year 40	$ [redacted]	Column (a) depreciated by Line 1										[redacted]
44	Federal Tax Depreciation[1]		Sum Lines 4 through 43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	State Tax Depreciation[1]		Sum Lines 4 through 43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46													
47	Racking Equipment _ Vintage Year	Maintenance Capital Costs, Line 14											
48	Year 1	$	Column (a) depreciated by Line 1										
49	Year 2		Column (a) depreciated by Line 1										
50	Year 3		Column (a) depreciated by Line 1										
51	Year 4		Column (a) depreciated by Line 1										
52	Year 5		Column (a) depreciated by Line 1										
53	Year 6		Column (a) depreciated by Line 1										
54	Year 7		Column (a) depreciated by Line 1										
55	Year 8		Column (a) depreciated by Line 1										
56	Year 9		Column (a) depreciated by Line 1										
57	Year 10		Column (a) depreciated by Line 1										
58	Year 11		Column (a) depreciated by Line 1										
59	Year 12		Column (a) depreciated by Line 1										
60	Year 13		Column (a) depreciated by Line 1										
61	Year 14		Column (a) depreciated by Line 1										
62	Year 15		Column (a) depreciated by Line 1										
63	Year 16		Column (a) depreciated by Line 1										
64	Year 17		Column (a) depreciated by Line 1										
65	Year 18		Column (a) depreciated by Line 1										
66	Year 19		Column (a) depreciated by Line 1										
67	Year 20		Column (a) depreciated by Line 1										
68	Year 21	[redacted]	Column (a) depreciated by Line 1										
69	Year 22	[redacted]	Column (a) depreciated by Line 1										
70	Year 23	[redacted]	Column (a) depreciated by Line 1										
71	Year 24	[redacted]	Column (a) depreciated by Line 1										
72	Year 25	[redacted]	Column (a) depreciated by Line 1										
73	Year 26	[redacted]	Column (a) depreciated by Line 1	[redacted]									
74	Year 27	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]								
75	Year 28	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]							
76	Year 29	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]						
77	Year 30	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					
78	Year 31	[redacted]	Column (a) depreciated by Line 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]				
79	Year 32	[redacted]	Column (a) depreciated by Line 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			
80	Year 33	[redacted]	Column (a) depreciated by Line 1			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		
81	Year 34	[redacted]	Column (a) depreciated by Line 1				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
82	Year 35	[redacted]	Column (a) depreciated by Line 1					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
83	Year 36	[redacted]	Column (a) depreciated by Line 1						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
84	Year 37	[redacted]	Column (a) depreciated by Line 1							[redacted]	[redacted]	[redacted]	[redacted]
85	Year 38	[redacted]	Column (a) depreciated by Line 1								[redacted]	[redacted]	[redacted]
86	Year 39	[redacted]	Column (a) depreciated by Line 1									[redacted]	[redacted]
87	Year 40	$ [redacted]	Column (a) depreciated by Line 1										[redacted]
88	Federal Tax Depreciation[1]		Sum Lines 48 through 87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	State Tax Depreciation[1]		Sum Lines 48 through 87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
90													
91	Total Federal Tax Depreciation[1]		Line 44 + Line 88	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	Total State Tax Depreciation[1]		Line 45 + Line 89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 12
Capital Cost Estimate Schedule

Line No.	Description	Reference		(a)	(b)
1	Detailed Capital Cost Estimates				
2					
3	Facility Costs			Cost	Labor & Engineering Adjustment
4	Solar Inverter 1 and Associated Material	Exhibit SP-4	$	[redacted]	5.1%
5	PV Modules and Associated Material	Exhibit SP-4		[redacted]	39.2%
6	Racking Equipment and Associated Materials	Exhibit SP-4		[redacted]	31.8%
7	Step-up Transformer and Associated Material	Exhibit SP-4		[redacted]	7.9%
8	Fencing	Exhibit SP-4		[redacted]	3.2%
9	All Other Material	Exhibit SP-4		[redacted]	5.9%
10	Project Management	Exhibit SP-4		[redacted]	1.8%
11	5-Year Maintenance	Exhibit SP-4		[redacted]	1.5%
12	Construction Field Representative	Exhibit SP-4		[redacted]	1.7%
13	Spare Step-Up Transformer	Exhibit SP-4		[redacted]	1.7%
14	Spare Inverter	Exhibit SP-4		[redacted]	0.1%
15	Spare PV Modules (5)	Exhibit SP-4		[redacted]	0.0%
16	Other Rec Spare Equipment	Exhibit SP-4		[redacted]	0.2%
17	Labor & Engineering	Exhibit SP-4		[redacted]	
18	Total Facility Costs	Sum Lines 4 through 17	$	[redacted]	100.0%
19					
20	Electric System Upgrades			Cost	
21	System Impact Study	Exhibit SP-4	$	35,000	
22	POI Material & Installation	Exhibit JSD-1		350,000	
23	Tap 3345 Line with GOAB	Exhibit JSD-1		50,000	
24	Kingston Relaying Upgrades	Exhibit JSD-1		125,000	
25	Total Electric System Upgrades	Sum Lines 21 through 24	$	560,000	
26					
27	Land Improvements			Cost	
28	Site Due Diligence, Design and Permitting	Exhibit JSD-4(b)	$	[redacted]	
29	Site Work	Exhibit JSD-1		550,000	
30	Total Land Improvements	Line 28 + Line 29	$	[redacted]	
31					
32	Land Acquisition Costs			Cost	
33	Site Identification	Exhibit SP-4	$	25,000	
34	Purchase Price	Exhibit SP-1		[redacted]	
35	Transfer Tax	Exhibit JSD-1		[redacted]	
36	Commission covered by Unitil	Exhibit JSD-1		[redacted]	
37	CU Penalty	Exhibit JSD-1		[redacted]	
38	Title Search	Exhibit JSD-1		10,500	
39	Appraisal	Exhibit JSD-7		[redacted]	
40	Total Land Acquisitions Costs		$	1,640,876	
41					
42	Total Capital Costs	Line 18 + Line 25 + Line 30 + Line 40	$	14,738,926	

Line No.	Description	Reference		(a)
43	Summarized Capital Cost Estimates			
44				
45	Depreciable Plant Additions			Cost
46	PV Modules and Associated Materials	Line 5, Column (c)	$	[redacted]
47	Racking Equipment and Associated Materials	Line 6, Column (c)		[redacted]
48	Balance of Plant	Sum Column (c) Lines 7 through 16		[redacted]
49	Electric System Upgrades	Line 25, Column (a)		560,000
50	Solar Inverter 1	Line 4, Column (c)		[redacted]
51	Solar Inverter 2 (Year 20) (2)	Future Value of Solar Inverter 1		[redacted]
52	Total	Sum Lines 46 through 51	$	13,240,572
53				
54	Non-Depreciable Plant Additions			Cost
55	Land Improvements	Line 30	$	[redacted]
56	Land Acquisition Costs(3)	Line 40 x 50%		820,438
57	Total	Line 55 + Line 56	$	[redacted]

Notes
(1) Labor and Facility Engineering allocated based on proportional cost of line item
(2) Assumes a 20-year life with a 2.00% annual escalation rate
(3) Including 50% of total Land Acquisition Costs to estimate cost transferred to UES

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 12
Capital Cost Estimate Schedule

Line No.	Description	Reference	(c)
1	Detailed Capital Cost Estimates		
2			
3	Facility Costs		Adjusted Cost [1]
4	Solar Inverter 1 and Associated Material	Exhibit SP-4	$ [redacted]
5	PV Modules and Associated Material	Exhibit SP-4	
6	Racking Equipment and Associated Materials	Exhibit SP-4	
7	Step-up Transformer and Associated Material	Exhibit SP-4	
8	Fencing	Exhibit SP-4	
9	All Other Material	Exhibit SP-4	
10	Project Management	Exhibit SP-4	
11	5-Year Maintenance	Exhibit SP-4	
12	Construction Field Representative	Exhibit SP-4	
13	Spare Step-Up Transformer	Exhibit SP-4	
14	Spare Inverter	Exhibit SP-4	
15	Spare PV Modules (5)	Exhibit SP-4	
16	Other Rec Spare Equipment	Exhibit SP-4	
17	Labor & Engineering	Exhibit SP-4	
18	Total Facility Costs	Sum Lines 4 through 17	$ [redacted]
19			
20	Electric System Upgrades		
21	System Impact Study	Exhibit SP-4	
22	POI Material & Installation	Exhibit JSD-1	
23	Tap 3345 Line with GOAB	Exhibit JSD-1	
24	Kingston Relaying Upgrades	Exhibit JSD-1	
25	Total Electric System Upgrades	Sum Lines 21 through 24	
26			
27	Land Improvements		
28	Site Due Diligence, Design and Permitting	Exhibit JSD-4(b)	
29	Site Work	Exhibit JSD-1	
30	Total Land Improvements	Line 28 + Line 29	
31			
32	Land Acquisition Costs		
33	Site Identification	Exhibit SP-4	
34	Purchase Price	Exhibit SP-1	
35	Transfer Tax	Exhibit JSD-1	
36	Commission covered by Unitil	Exhibit JSD-1	
37	CU Penalty	Exhibit JSD-1	
38	Title Search	Exhibit JSD-1	
39	Appraisal	Exhibit JSD-7	
40	Total Land Acquisitions Costs		
41			
42	Total Capital Costs	Line 18 + Line 25 + Line 30 + Line 40	

Line No.	Description	Reference
43	Summarized Capital Cost Estimates	
44		
45	Depreciable Plant Additions	
46	PV Modules and Associated Materials	Line 5, Column (c)
47	Racking Equipment and Associated Materials	Line 6, Column (c)
48	Balance of Plant	Sum Column (c) Lines 7 through 16
49	Electric System Upgrades	Line 25, Column (a)
50	Solar Inverter 1	Line 4, Column (c)
51	Solar Inverter 2 (Year 20) [2]	Future Value of Solar Inverter 1
52	Total	Sum Lines 46 through 51
53		
54	Non-Depreciable Plant Additions	
55	Land Improvements	Line 30
56	Land Acquisition Costs[3]	Line 40 x 50%
57	Total	Line 55 + Line 56

Notes
(1) Labor and Facility Engineering allocated based on proportional cost of line item
(2) Assumes a 20-year life with a 2.00% annual escalation rate
(3) Including 50% of total Land Acquisition Costs to estimate cost transferred to UES

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 13
Maintenance Capital Costs

Line No.	Description	Reference	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
1	Annual Escalation Rate	2% Escalation Rate		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2													
3	PV Modules & Associated Materials												
4	Original Cost	Capital Cost Estimate Schedule, Line 46	$ [redacted]										
5	Expected Replacement % [1]	Exhibit SP-1		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	Time Value Factor	Annual Escalation Rate, Line 1		1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22
7	Annual Maintenance Cost	Line 4 x Line 5 x Line 6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8													
9													
10	Racking Equipment & Associated Materials												
11	Original Cost	Capital Cost Estimate Schedule, Line 47	[redacted]										
12	Expected Replacement %[1]	Exhibit SP-1		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Time Value Factor	Annual Escalation Rate, Line 1		1.02	1.04	1.06	1.08	1.10	1.13	1.15	1.17	1.20	1.22
14	Annual Maintenance Cost	Line 11 x Line 12 x Line 13		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15													
16	Total Annual Maintenance Capital	Line 7 + Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) Expected maintenance capital begins after warranty period ends

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 13
Maintenance Capital Costs

Line No.	Description	Reference	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	PV Modules & Associated Materials											
4	Original Cost	Capital Cost Estimate Schedule, Line 46	$ [redacted]									
5	Expected Replacement % (1)	Exhibit SP-1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	Time Value Factor	Annual Escalation Rate, Line 1	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49
7	Annual Maintenance Cost	Line 4 x Line 5 x Line 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8												
9												
10	Racking Equipment & Associated Materials											
11	Original Cost	Capital Cost Estimate Schedule, Line 47	[redacted]									
12	Expected Replacement %(1)	Exhibit SP-1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Time Value Factor	Annual Escalation Rate, Line 1	1.24	1.27	1.29	1.32	1.35	1.37	1.40	1.43	1.46	1.49
14	Annual Maintenance Cost	Line 11 x Line 12 x Line 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15												
16	Total Annual Maintenance Capital	Line 7 + Line 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes
(1) Expected maintenance capital begins after warranty period ends

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 13
Maintenance Capital Costs

Line No.	Description	Reference	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	PV Modules & Associated Materials											
4	Original Cost	Capital Cost Estimate Schedule, Line 46	[redacted]									
5	Expected Replacement % (1)	Exhibit SP-1	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%	0.5%	0.5%	0.5%
6	Time Value Factor	Annual Escalation Rate, Line 1	1.52	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78	1.81
7	Annual Maintenance Cost	Line 4 x Line 5 x Line 6	$ -	$ -	$ -	$ -	$ -	$ 38,720	$ 39,494	$ 40,284	$ 41,090	$ 41,911
8												
9												
10	Racking Equipment & Associated Materials											
11	Original Cost	Capital Cost Estimate Schedule, Line 47	[redacted]									
12	Expected Replacement %(1)	Exhibit SP-1	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
13	Time Value Factor	Annual Escalation Rate, Line 1	1.52	1.55	1.58	1.61	1.64	1.67	1.71	1.74	1.78	1.81
14	Annual Maintenance Cost	Line 11 x Line 12 x Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15												
16	Total Annual Maintenance Capital	Line 7 + Line 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Expected maintenance capital begins after warranty period ends

REDACTED

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 13
Maintenance Capital Costs

Line No.	Description	Reference	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
1	Annual Escalation Rate	2% Escalation Rate	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
2												
3	PV Modules & Associated Materials											
4	Original Cost	Capital Cost Estimate Schedule, Line 46	[redacted]									
5	Expected Replacement % [1]	Exhibit SP-1	0.5%	0.5%	0.5%	0.5%	0.5%	1.0%	1.0%	1.0%	1.0%	1.0%
6	Time Value Factor	Annual Escalation Rate, Line 1	1.85	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.21
7	Annual Maintenance Cost	Line 4 x Line 5 x Line 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8												
9												
10	Racking Equipment & Associated Materials											
11	Original Cost	Capital Cost Estimate Schedule, Line 47	[redacted]									
12	Expected Replacement %[1]	Exhibit SP-1	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
13	Time Value Factor	Annual Escalation Rate, Line 1	1.85	1.88	1.92	1.96	2.00	2.04	2.08	2.12	2.16	2.21
14	Annual Maintenance Cost	Line 11 x Line 12 x Line 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15												
16	Total Annual Maintenance Capital	Line 7 + Line 14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes
(1) Expected maintenance capital begins after warranty period ends

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 14
Cost of Capital

			(a)	(b)	(c) = (a) x (b)	(e)	(f) = (c) x (e)	(g)	(h) = (a) x (g)
Line						PRE-TAX		AFTER-TAX	
No.	Description	Reference	Capital Structure	Cost of Capital	Weighted Cost of Capital	Tax Factor	Weighted Cost of Capital	Adjusted Capital Structure (1)	Weighted Cost of Capital
1	Cost of Capital Calculation								
2	Common Stock Equity	DE 21-030	52.00%	9.20%	4.78%	1.3685	6.55%	9.20%	4.78%
3									
4	Preferred Stock Equity	DE 21-030	0.00%	6.00%	0.00%	1.0000	0.00%	6.00%	0.00%
5									
6	Long Term Debt	DE 21-030	48.00%	5.49%	2.64%	1.0000	2.64%	4.01%	1.93%
7									
8	Total	Line 2 + Line 4 + Line 6	100.00%		7.42%		9.18%		6.71%
9									
10			(a)						
11	Tax Rate Calculation		Rate						
12	State - NH (2)		7.50%						
13									
14	Federal		21.00%						
15									
16	Federal Benefit of State Income Tax	- (Line 12 x Line 14)	-1.58%						
17									
18	Effective Tax Rate	Line 12 + Line 14 + Line 16	26.93%						
19									
20	Gross-Up Factor	(1 ÷ (1 - Line 18)	1.3685						

Notes
(1) Tax Effected Cost of Long-Term Debt
(2) N.H. Business Profit Tax rate on or after 12/31/2023

Unitil Energy Systems d/b/a Unitil
Exhibit SP-7, Updated Benefit-Cost Analysis
Schedule 15
IRS Publication 946 Table A-1
MACRS Half Year Depreciation Rates

Line No.	Recovery Year	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21
1	3	33.33%	44.45%	14.81%	7.41%																	
2	5	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%															
3	7	14.29%	24.49%	17.49%	12.49%	8.93%	8.92%	8.93%	4.46%													
4	10	10.00%	18.00%	14.40%	11.52%	9.22%	7.37%	6.55%	6.55%	6.56%	6.55%	3.28%										
5	15	5.00%	9.50%	8.55%	7.70%	6.93%	6.23%	5.90%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	5.90%	5.91%	2.95%					
6	20	3.75%	7.22%	6.68%	6.18%	5.71%	5.29%	4.89%	4.52%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	4.46%	2.23%

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
YEAR 1 THROUGH YEAR 40

Line #	Rate Class	Source	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	Residential:															
2	Customer Charge	Page 3, Line 13 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Distribution kWh Charge	Page 3, Line 14 Change over Current Rates	$ 0.00135	$ 0.00126	$ 0.00116	$ 0.00109	$ 0.00103	$ 0.00099	$ 0.00096	$ 0.00093	$ 0.00089	$ 0.00086	$ 0.00121	$ 0.00118	$ 0.00115	$ 0.00113
4	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
5	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
6	Average Usage kWh	Page 3, Line 16 / Line 15	633	633	633	633	633	633	633	633	633	633	633	633	633	633
7	**Average Residential Monthly Bill Impact**	**(Line 3 + Line 4 + Line 5) * Line 6**	**$ 0.05**	**$ 0.08**	**$ 0.03**	**$ (0.00)**	**$ (0.05)**	**$ (0.07)**	**$ (0.10)**	**$ (0.13)**	**$ (0.15)**	**$ (0.18)**	**$ 0.03**	**$ 0.01**	**$ (0.01)**	**$ (0.04)**
8	Regular General (G2 kWh):															
9	Customer Charge	Page 3, Line 21 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Distribution kWh Charge	Page 3, Line 22 Change over Current Rates	$ 0.00135	$ 0.00126	$ 0.00116	$ 0.00109	$ 0.00103	$ 0.00099	$ 0.00096	$ 0.00093	$ 0.00089	$ 0.00086	$ 0.00121	$ 0.00118	$ 0.00115	$ 0.00113
11	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
12	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
13	Average Usage kWh	Page 3, Line 24 / Line 23	97	97	97	97	97	97	97	97	97	97	97	97	97	97
14	**Average Regular General (G2 kWh) Monthly Bill Impact**	**(Line 10 + Line 11 + Line 12) * Line 13**	**$ 0.01**	**$ 0.01**	**$ 0.01**	**$ (0.00)**	**$ (0.01)**	**$ (0.01)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.03)**	**$ 0.00**	**$ 0.00**	**$ (0.00)**	**$ (0.01)**
15	Regular General (G2 QR WH/SH):															
16	Customer Charge	Page 3, Line 29 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Distribution kWh Charge	Page 3, Line 30 Change over Current Rates	$ 0.00135	$ 0.00126	$ 0.00116	$ 0.00109	$ 0.00103	$ 0.00099	$ 0.00096	$ 0.00093	$ 0.00089	$ 0.00086	$ 0.00121	$ 0.00118	$ 0.00115	$ 0.00113
18	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
19	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
20	Average Usage kWh	Page 3, Line 32 / Line 31	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451
21	**Average Regular General (G2 QR WH/SH) Monthly Bill Impact**	**(Line 17 + Line 18 + Line 19) * Line 20**	**$ 0.12**	**$ 0.19**	**$ 0.08**	**$ (0.01)**	**$ (0.11)**	**$ (0.17)**	**$ (0.24)**	**$ (0.30)**	**$ (0.35)**	**$ (0.41)**	**$ 0.07**	**$ 0.02**	**$ (0.03)**	**$ (0.09)**
22	Regular General (G2 Demand):															
23	Customer Charge	Page 3, Line 37 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Distribution kWh Charge	Page 3, Line 38 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Distribution kW Demand Charge	Page 3, Line 39 Change over Current Rates	$ 0.34237	$ 0.31844	$ 0.29352	$ 0.27540	$ 0.25982	$ 0.25151	$ 0.24176	$ 0.23391	$ 0.22605	$ 0.21817	$ 0.30485	$ 0.29832	$ 0.29179	$ 0.28527
26	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
27	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
28	Average Usage kWh	Page 3, Line 42 / Line 41	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463
29	Average Usage kW	Page 3, Line 43 / Line 41	10	10	10	10	10	10	10	10	10	10	10	10	10	10
30	**Average Regular General (G2 Demand) Monthly Bill Impact**	**(Line 26 + Line 27) * Line 28 + Line 25 * Line 29**	**$ 0.20**	**$ 0.32**	**$ 0.13**	**$ (0.01)**	**$ (0.18)**	**$ (0.29)**	**$ (0.40)**	**$ (0.50)**	**$ (0.60)**	**$ (0.70)**	**$ 0.12**	**$ 0.04**	**$ (0.06)**	**$ (0.15)**
31	Large General (G1 Demand):															
32	Customer Charge	Page 3, Line 51 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Distribution kWh Charge	Page 3, Line 52 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution kVA Demand Charge	Page 3, Line 53 Change over Current Rates	$ 0.43288	$ 0.40263	$ 0.37112	$ 0.34821	$ 0.32851	$ 0.31801	$ 0.30567	$ 0.29575	$ 0.28581	$ 0.27585	$ 0.38544	$ 0.37718	$ 0.36893	$ 0.36069
35	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
36	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
37	Average Usage kWh	Page 3, Line 56 / Line 55	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088
38	Average Usage kVA	Page 3, Line 57 / Line 55	498	498	498	498	498	498	498	498	498	498	498	498	498	498
39	**Average Large General (G1 Demand) Monthly Bill Impact**	**(Line 35 + Line 36) * Line 37 + Line 34 * Line 54**	**$ 13.17**	**$ 20.88**	**$ 8.48**	**$ (0.71)**	**$ (11.86)**	**$ (18.47)**	**$ (26.00)**	**$ (32.36)**	**$ (38.75)**	**$ (45.17)**	**$ 7.88**	**$ 2.27**	**$ (3.62)**	**$ (9.54)**
40	Outdoor Lighting (OL):															
41	Average Luminaire Charge	Page 3, Line 65 Change over Current Rates	$ 0.10	$ 0.09	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06	$ 0.06	$ 0.08	$ 0.08	$ 0.08	$ 0.08
42	Distribution kWh Charge ($/kWh)	Page 3, Line 66 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)
44	Default Service	Page 2, Line 8	$ (0.00085)	$ (0.00071)	$ (0.00069)	$ (0.00068)	$ (0.00068)	$ (0.00069)	$ (0.00070)	$ (0.00071)	$ (0.00072)	$ (0.00073)	$ (0.00074)	$ (0.00074)	$ (0.00076)	$ (0.00077)
45	Average Usage kWh	Page 3, Line 68 / Line 67	70	70	70	70	70	70	70	70	70	70	70	70	70	70
46	**Average Outdoor Lighting (OL) Monthly Bill Impact**	**(Line 43 + Line 44) * Line 45 + Line 40**	**$ 0.01**	**$ 0.01**	**$ 0.00**	**$ (0.00)**	**$ (0.01)**	**$ (0.01)**	**$ (0.01)**	**$ (0.01)**	**$ (0.02)**	**$ (0.02)**	**$ 0.00**	**$ 0.00**	**$ (0.00)**	**$ (0.00)**

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
YEAR 1 THROUGH YEAR 40

Line #	Rate Class	Source	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28
	(a)	(b)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)
1	Residential:															
2	Customer Charge	Page 3, Line 13 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Distribution kWh Charge	Page 3, Line 14 Change over Current Rates	$ 0.00110	$ 0.00108	$ 0.00105	$ 0.00103	$ 0.00100	$ 0.00103	$ 0.00105	$ 0.00102	$ 0.00099	$ 0.00097	$ 0.00094	$ 0.00092	$ 0.00090	$ 0.00088
4	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
5	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
6	Average Usage kWh	Page 3, Line 16 / Line 15	633	633	633	633	633	633	633	633	633	633	633	633	633	633
7	**Average Residential Monthly Bill Impact**	**(Line 3 + Line 4 + Line 5) * Line 6**	**$ (0.06)**	**$ (0.09)**	**$ (0.11)**	**$ (0.13)**	**$ (0.16)**	**$ (0.15)**	**$ (0.14)**	**$ (0.17)**	**$ (0.19)**	**$ (0.22)**	**$ (0.24)**	**$ (0.27)**	**$ (0.29)**	**$ (0.31)**
8	Regular General (G2 kWh):															
9	Customer Charge	Page 3, Line 21 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Distribution kWh Charge	Page 3, Line 22 Change over Current Rates	$ 0.00110	$ 0.00108	$ 0.00105	$ 0.00103	$ 0.00100	$ 0.00103	$ 0.00105	$ 0.00102	$ 0.00099	$ 0.00097	$ 0.00094	$ 0.00092	$ 0.00090	$ 0.00088
11	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
12	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
13	Average Usage kWh	Page 3, Line 24 / Line 23	97	97	97	97	97	97	97	97	97	97	97	97	97	97
14	**Average Regular General (G2 kWh) Monthly Bill Impact**	**(Line 10 + Line 11 + Line 12) * Line 13**	**$ (0.01)**	**$ (0.01)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.03)**	**$ (0.03)**	**$ (0.03)**	**$ (0.04)**	**$ (0.04)**	**$ (0.04)**	**$ (0.05)**
15	Regular General (G2 QR WH/SH):															
16	Customer Charge	Page 3, Line 29 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Distribution kWh Charge	Page 3, Line 30 Change over Current Rates	$ 0.00110	$ 0.00108	$ 0.00105	$ 0.00103	$ 0.00100	$ 0.00103	$ 0.00105	$ 0.00102	$ 0.00099	$ 0.00097	$ 0.00094	$ 0.00092	$ 0.00090	$ 0.00088
18	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
19	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
20	Average Usage kWh	Page 3, Line 32 / Line 31	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451
21	**Average Regular General (G2 QR WH/SH) Monthly Bill Impact**	**(Line 17 + Line 18 + Line 19) * Line 20**	**$ (0.14)**	**$ (0.20)**	**$ (0.25)**	**$ (0.30)**	**$ (0.36)**	**$ (0.33)**	**$ (0.32)**	**$ (0.38)**	**$ (0.44)**	**$ (0.50)**	**$ (0.56)**	**$ (0.61)**	**$ (0.66)**	**$ (0.70)**
22	Regular General (G2 Demand):															
23	Customer Charge	Page 3, Line 37 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Distribution kWh Charge	Page 3, Line 38 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Distribution kW Demand Charge	Page 3, Line 39 Change over Current Rates	$ 0.27875	$ 0.27224	$ 0.26573	$ 0.25922	$ 0.25272	$ 0.26046	$ 0.26576	$ 0.25856	$ 0.25136	$ 0.24463	$ 0.23806	$ 0.23223	$ 0.22722	$ 0.22229
26	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
27	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
28	Average Usage kWh	Page 3, Line 42 / Line 41	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463
29	Average Usage kW	Page 3, Line 43 / Line 41	10	10	10	10	10	10	10	10	10	10	10	10	10	10
30	**Average Regular General (G2 Demand) Monthly Bill Impact**	**(Line 26 + Line 27) * Line 28 + Line 25 * Line 29**	**$ (0.24)**	**$ (0.33)**	**$ (0.42)**	**$ (0.52)**	**$ (0.61)**	**$ (0.57)**	**$ (0.55)**	**$ (0.65)**	**$ (0.75)**	**$ (0.85)**	**$ (0.94)**	**$ (1.03)**	**$ (1.11)**	**$ (1.20)**
31	Large General (G1 Demand):															
32	Customer Charge	Page 3, Line 51 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Distribution kWh Charge	Page 3, Line 52 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution kVA Demand Charge	Page 3, Line 53 Change over Current Rates	$ 0.35244	$ 0.34421	$ 0.33598	$ 0.32775	$ 0.31953	$ 0.32932	$ 0.33601	$ 0.32692	$ 0.31781	$ 0.30930	$ 0.30100	$ 0.29362	$ 0.28728	$ 0.28106
35	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
36	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
37	Average Usage kWh	Page 3, Line 56 / Line 55	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088
38	Average Usage kVA	Page 3, Line 57 / Line 55	498	498	498	498	498	498	498	498	498	498	498	498	498	498
39	**Average Large General (G1 Demand) Monthly Bill Impact**	**(Line 35 + Line 36) * Line 37 + Line 34 * Line 54**	**$ (15.47)**	**$ (21.43)**	**$ (27.42)**	**$ (33.42)**	**$ (39.46)**	**$ (36.55)**	**$ (35.21)**	**$ (41.76)**	**$ (48.33)**	**$ (54.65)**	**$ (60.88)**	**$ (66.67)**	**$ (71.98)**	**$ (77.26)**
40	Outdoor Lighting (OL):															
41	Average Luminaire Charge	Page 3, Line 65 Change over Current Rates	$ 0.08	$ 0.08	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.06	$ 0.06	$ 0.06
42	Distribution kWh Charge ($/kWh)	Page 3, Line 66 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	External Delivery Charge	Page 2, Line 5	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00042)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)
44	Default Service	Page 2, Line 8	$ (0.00078)	$ (0.00079)	$ (0.00080)	$ (0.00081)	$ (0.00082)	$ (0.00083)	$ (0.00085)	$ (0.00086)	$ (0.00087)	$ (0.00088)	$ (0.00090)	$ (0.00091)	$ (0.00092)	$ (0.00093)
45	Average Usage kWh	Page 3, Line 68 / Line 67	70	70	70	70	70	70	70	70	70	70	70	70	70	70
46	**Average Outdoor Lighting (OL) Monthly Bill Impact**	**(Line 43 + Line 44) * Line 45 + Line 40**	**$ (0.01)**	**$ (0.01)**	**$ (0.01)**	**$ (0.01)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.02)**	**$ (0.03)**	**$ (0.03)**	**$ (0.03)**	**$ (0.03)**

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
YEAR 1 THROUGH YEAR 40

Line #	Rate Class	Source	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
	(a)	(b)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)	(ap)
1	Residential:													
2	Customer Charge	Page 3, Line 13 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Distribution kWh Charge	Page 3, Line 14 Change over Current Rates	$ 0.00086	$ 0.00084	$ 0.00082	$ 0.00081	$ 0.00079	$ 0.00078	$ 0.00076	$ 0.00075	$ 0.00074	$ 0.00073	$ 0.00071	$ 0.00070
4	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
5	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
6	Average Usage kWh	Page 3, Line 16 / Line 15	633	633	633	633	633	633	633	633	633	633	633	633
7	**Average Residential Monthly Bill Impact**	**(Line 3 + Line 4 + Line 5) * Line 6**	**$ (0.33)**	**$ (0.35)**	**$ (0.37)**	**$ (0.39)**	**$ (0.41)**	**$ (0.43)**	**$ (0.45)**	**$ (0.47)**	**$ (0.48)**	**$ (0.50)**	**$ (0.51)**	**$ (0.53)**
8	Regular General (G2 kWh):													
9	Customer Charge	Page 3, Line 21 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Distribution kWh Charge	Page 3, Line 22 Change over Current Rates	$ 0.00086	$ 0.00084	$ 0.00082	$ 0.00081	$ 0.00079	$ 0.00078	$ 0.00076	$ 0.00075	$ 0.00074	$ 0.00073	$ 0.00071	$ 0.00070
11	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
12	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
13	Average Usage kWh	Page 3, Line 24 / Line 23	97	97	97	97	97	97	97	97	97	97	97	97
14	**Average Regular General (G2 kWh) Monthly Bill Impact**	**(Line 10 + Line 11 + Line 12) * Line 13**	**$ (0.05)**	**$ (0.05)**	**$ (0.06)**	**$ (0.06)**	**$ (0.06)**	**$ (0.07)**	**$ (0.07)**	**$ (0.07)**	**$ (0.07)**	**$ (0.08)**	**$ (0.08)**	**$ (0.08)**
15	Regular General (G2 QR WH/SH):													
16	Customer Charge	Page 3, Line 29 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Distribution kWh Charge	Page 3, Line 30 Change over Current Rates	$ 0.00086	$ 0.00084	$ 0.00082	$ 0.00081	$ 0.00079	$ 0.00078	$ 0.00076	$ 0.00075	$ 0.00074	$ 0.00073	$ 0.00071	$ 0.00070
18	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
19	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
20	Average Usage kWh	Page 3, Line 32 / Line 31	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451	1,451
21	**Average Regular General (G2 QR WH/SH) Monthly Bill Impact**	**(Line 17 + Line 18 + Line 19) * Line 20**	**$ (0.75)**	**$ (0.80)**	**$ (0.85)**	**$ (0.89)**	**$ (0.94)**	**$ (0.98)**	**$ (1.03)**	**$ (1.07)**	**$ (1.10)**	**$ (1.14)**	**$ (1.18)**	**$ (1.22)**
22	Regular General (G2 Demand):													
23	Customer Charge	Page 3, Line 37 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Distribution kWh Charge	Page 3, Line 38 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Distribution kW Demand Charge	Page 3, Line 39 Change over Current Rates	$ 0.21735	$ 0.21238	$ 0.20794	$ 0.20399	$ 0.20000	$ 0.19598	$ 0.19196	$ 0.18865	$ 0.18601	$ 0.18332	$ 0.18059	$ 0.17784
26	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
27	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
28	Average Usage kWh	Page 3, Line 42 / Line 41	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463	2,463
29	Average Usage kW	Page 3, Line 43 / Line 41	10	10	10	10	10	10	10	10	10	10	10	10
30	**Average Regular General (G2 Demand) Monthly Bill Impact**	**(Line 26 + Line 27) * Line 28 + Line 25 * Line 29**	**$ (1.28)**	**$ (1.36)**	**$ (1.44)**	**$ (1.51)**	**$ (1.59)**	**$ (1.66)**	**$ (1.74)**	**$ (1.81)**	**$ (1.87)**	**$ (1.94)**	**$ (2.00)**	**$ (2.07)**
31	Large General (G1 Demand):													
32	Customer Charge	Page 3, Line 51 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Distribution kWh Charge	Page 3, Line 52 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Distribution kVA Demand Charge	Page 3, Line 53 Change over Current Rates	$ 0.27481	$ 0.26853	$ 0.26292	$ 0.25792	$ 0.25287	$ 0.24780	$ 0.24270	$ 0.23852	$ 0.23519	$ 0.23178	$ 0.22833	$ 0.22486
35	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
36	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
37	Average Usage kWh	Page 3, Line 56 / Line 55	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088	159,088
38	Average Usage kVA	Page 3, Line 57 / Line 55	498	498	498	498	498	498	498	498	498	498	498	498
39	**Average Large General (G1 Demand) Monthly Bill Impact**	**(Line 35 + Line 36) * Line 37 + Line 34 * Line 54**	**$ (82.59)**	**$ (87.95)**	**$ (93.01)**	**$ (97.80)**	**$ (102.63)**	**$ (107.51)**	**$ (112.43)**	**$ (116.92)**	**$ (121.02)**	**$ (125.18)**	**$ (129.40)**	**$ (133.65)**
40	Outdoor Lighting (OL):													
41	Average Luminaire Charge	Page 3, Line 65 Change over Current Rates	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05
42	Distribution kWh Charge ($/kWh)	Page 3, Line 66 Change over Current Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	External Delivery Charge	Page 2, Line 5	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00043)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)	$ (0.00044)
44	Default Service	Page 2, Line 8	$ (0.00095)	$ (0.00096)	$ (0.00097)	$ (0.00099)	$ (0.00100)	$ (0.00101)	$ (0.00103)	$ (0.00104)	$ (0.00106)	$ (0.00107)	$ (0.00109)	$ (0.00110)
45	Average Usage kWh	Page 3, Line 68 / Line 67	70	70	70	70	70	70	70	70	70	70	70	70
46	**Average Outdoor Lighting (OL) Monthly Bill Impact**	**(Line 43 + Line 44) * Line 45 + Line 40**	**$ (0.04)**	**$ (0.04)**	**$ (0.04)**	**$ (0.04)**	**$ (0.05)**	**$ (0.05)**	**$ (0.05)**	**$ (0.05)**	**$ (0.05)**	**$ (0.06)**	**$ (0.06)**	**$ (0.06)**

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
CUSTOMER BENEFIT ESTIMATED RATE IMPACT

Line #	Customer Benefits	Recovery Mechanism	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Reduction in Allocated LNS Cost		$ 16,103	$ 16,096	$ 16,335	$ 16,576	$ 16,820	$ 17,068	$ 17,318	$ 17,572	$ 17,829	$ 18,090
2	Reduction in Allocated RNS Cost		118,949	118,901	120,660	122,442	124,247	126,076	127,927	129,803	131,702	133,625
3	Total Transmission Cost Savings(1)	External Delivery Charge ("EDC")	$ 135,051	$ 134,997	$ 136,995	$ 139,018	$ 141,067	$ 143,143	$ 145,246	$ 147,375	$ 149,531	$ 151,715
4	REC Revenues(2)	External Delivery Charge ("EDC")	357,556	350,405	348,617	346,829	345,041	343,254	341,466	339,678	337,890	336,103
5	**External Delivery Charge Impact $/kWh**		**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**
6	Reduction in Energy Cost		$ 882,458	$ 725,600	$ 701,977	$ 686,108	$ 696,223	$ 706,468	$ 716,844	$ 727,353	$ 737,995	$ 748,773
7	Reduction in Capacity Cost		100,203	98,199	97,698	97,197	96,696	96,195	95,694	95,193	94,692	94,191
8	Total Avoided Cost of Energy/Capacity	Energy Service for All Customers	$ 982,661	$ 823,799	$ 799,675	$ 783,306	$ 792,920	$ 802,663	$ 812,539	$ 822,546	$ 832,688	$ 842,964
9	**Average Energy Service Impact $/kWh**		**$ (0.00085)**	**$ (0.00071)**	**$ (0.00069)**	**$ (0.00068)**	**$ (0.00068)**	**$ (0.00069)**	**$ (0.00070)**	**$ (0.00071)**	**$ (0.00072)**	**$ (0.00073)**
10	2020 TY Billing Units (kWh)											
11	Residential		515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
12	Regular General		317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821
13	Larger General		319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
14	Outdoor Lighting		7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
15	Total Sales		1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601

(1) Lower Allocated Costs based on lower peak load
(2) Lower wholesale supplier costs
(3) No impact to Default b/c transferring at market price

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
CUSTOMER BENEFIT ESTIMATED RATE IMPACT

Line #	Customer Benefits	Recovery Mechanism	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
	(a)	(b)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1	Reduction in Allocated LNS Cost		$ 18,353	$ 18,620	$ 18,891	$ 19,164	$ 19,441	$ 19,722	$ 20,006	$ 20,293	$ 20,584	$ 20,878
2	Reduction in Allocated RNS Cost		135,573	137,545	139,541	141,563	143,609	145,681	147,778	149,901	152,050	154,224
3	Total Transmission Cost Savings[1]	External Delivery Charge ("EDC")	$ 153,926	$ 156,165	$ 158,432	$ 160,727	$ 163,051	$ 165,403	$ 167,784	$ 170,194	$ 172,633	$ 175,102
4	REC Revenues[2]	External Delivery Charge ("EDC")	334,315	332,527	330,739	328,951	327,164	325,376	323,588	321,800	320,013	318,225
5	**External Delivery Charge Impact $/kWh**		**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00042)**	**$ (0.00043)**
6	Reduction in Energy Cost		$ 759,685	$ 770,735	$ 781,924	$ 793,251	$ 804,719	$ 816,328	$ 828,079	$ 839,974	$ 852,014	$ 864,199
7	Reduction in Capacity Cost		93,690	93,189	94,542	95,912	97,298	98,702	100,123	101,561	103,017	104,490
8	Total Avoided Cost of Energy/Capacity	Energy Service for All Customers	$ 853,376	$ 863,925	$ 876,466	$ 889,162	$ 902,017	$ 915,029	$ 928,202	$ 941,535	$ 955,030	$ 968,689
9	**Average Energy Service Impact $/kWh**		**$ (0.00074)**	**$ (0.00074)**	**$ (0.00076)**	**$ (0.00077)**	**$ (0.00078)**	**$ (0.00079)**	**$ (0.00080)**	**$ (0.00081)**	**$ (0.00082)**	**$ (0.00083)**
10	2020 TY Billing Units (kWh)											
11	Residential		515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
12	Regular General		317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821
13	Larger General		319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
14	Outdoor Lighting		7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
15	Total Sales		1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601

(1) Lower Allocated Costs based on lower peak load
(2) Lower wholesale supplier costs
(3) No impact to Default b/c transferring at market price

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
CUSTOMER BENEFIT ESTIMATED RATE IMPACT

Line #	Customer Benefits	Recovery Mechanism	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30
	(a)	(b)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)
1	Reduction in Allocated LNS Cost		$ 21,176	$ 21,478	$ 21,783	$ 22,091	$ 22,404	$ 22,720	$ 23,039	$ 23,363	$ 23,690	$ 24,021
2	Reduction in Allocated RNS Cost		156,425	158,652	160,906	163,186	165,493	167,827	170,188	172,577	174,993	177,437
3	Total Transmission Cost Savings[(1)]	External Delivery Charge ("EDC")	$ 177,601	$ 180,130	$ 182,688	$ 185,277	$ 187,897	$ 190,547	$ 193,228	$ 195,940	$ 198,683	$ 201,457
4	REC Revenues[(2)]	External Delivery Charge ("EDC")	316,437	314,649	312,861	311,074	309,286	307,498	305,710	303,923	302,135	300,347
5	**External Delivery Charge Impact $/kWh**		**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**	**$ (0.00043)**
6	Reduction in Energy Cost		$ 876,531	$ 889,010	$ 901,638	$ 914,416	$ 927,344	$ 940,423	$ 953,655	$ 967,039	$ 980,578	$ 994,271
7	Reduction in Capacity Cost		105,981	107,490	109,017	110,562	112,125	113,706	115,306	116,924	118,561	120,217
8	Total Avoided Cost of Energy/Capacity	Energy Service for All Customers	$ 982,512	$ 996,500	$ 1,010,655	$ 1,024,977	$ 1,039,468	$ 1,054,129	$ 1,068,960	$ 1,083,963	$ 1,099,139	$ 1,114,488
9	**Average Energy Service Impact $/kWh**		**$ (0.00085)**	**$ (0.00086)**	**$ (0.00087)**	**$ (0.00088)**	**$ (0.00090)**	**$ (0.00091)**	**$ (0.00092)**	**$ (0.00093)**	**$ (0.00095)**	**$ (0.00096)**
10	2020 TY Billing Units (kWh)											
11	Residential		515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
12	Regular General		317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821
13	Larger General		319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
14	Outdoor Lighting		7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
15	Total Sales		1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601

(1) Lower Allocated Costs based on lower peak load
(2) Lower wholesale supplier costs
(3) No impact to Default b/c transferring at market price

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
CUSTOMER BENEFIT ESTIMATED RATE IMPACT

Line #	Customer Benefits	Recovery Mechanism	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
	(a)	(b)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)	(ap)
1	Reduction in Allocated LNS Cost		$ 24,355	$ 24,694	$ 25,036	$ 25,382	$ 25,731	$ 26,085	$ 26,443	$ 26,804	$ 27,169	$ 27,538
2	Reduction in Allocated RNS Cost		179,908	182,407	184,935	187,490	190,074	192,686	195,327	197,996	200,693	203,420
3	Total Transmission Cost Savings(1)	External Delivery Charge ("EDC")	$ 204,263	$ 207,101	$ 209,971	$ 212,872	$ 215,805	$ 218,771	$ 221,769	$ 224,799	$ 227,862	$ 230,958
4	REC Revenues(2)	External Delivery Charge ("EDC")	298,559	296,771	294,984	293,196	291,408	289,620	287,832	286,045	284,257	282,469
5	**External Delivery Charge Impact $/kWh**		**$ (0.00043)**	**$ (0.00043)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**	**$ (0.00044)**
6	Reduction in Energy Cost		$ 1,008,120	$ 1,022,125	$ 1,036,287	$ 1,050,606	$ 1,065,084	$ 1,079,721	$ 1,094,517	$ 1,109,473	$ 1,124,590	$ 1,139,867
7	Reduction in Capacity Cost		121,891	123,585	125,297	127,028	128,779	130,549	132,338	134,146	135,974	137,821
8	Total Avoided Cost of Energy/Capacity	Energy Service for All Customers	$ 1,130,011	$ 1,145,709	$ 1,161,584	$ 1,177,635	$ 1,193,863	$ 1,210,269	$ 1,226,855	$ 1,243,619	$ 1,260,563	$ 1,277,688
9	**Average Energy Service Impact $/kWh**		**$ (0.00097)**	**$ (0.00099)**	**$ (0.00100)**	**$ (0.00101)**	**$ (0.00103)**	**$ (0.00104)**	**$ (0.00106)**	**$ (0.00107)**	**$ (0.00109)**	**$ (0.00110)**
10	2020 TY Billing Units (kWh)											
11	Residential		515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
12	Regular General		317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821	317,056,821
13	Larger General		319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
14	Outdoor Lighting		7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
15	Total Sales		1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601	1,160,418,601

(1) Lower Allocated Costs based on lower peak load
(2) Lower wholesale supplier costs
(3) No impact to Default b/c transferring at market price

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
ESTIMATED DISTRIBUTION RATE IMPACT

Line #	Customer Benefits	Calculation/Rate	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	Annual Revenue Requirement		$ 1,571,340	$ 1,461,528	$ 1,347,158	$ 1,263,995	$ 1,192,492	$ 1,154,353	$ 1,109,591	$ 1,073,564	$ 1,037,476	$ 1,001,326	$ 1,399,120	$ 1,369,157
2	Revenue Requirement Change		$ 1,571,340	$ (109,812)	$ (114,370)	$ (83,162)	$ (71,503)	$ (38,139)	$ (44,762)	$ (36,027)	$ (36,088)	$ (36,150)	$ 397,794	$ (29,963)
3	**Allocation based on 2020 TY kWh:**													
4	Residential (Rate D)		$ 698,681	$ (48,827)	$ (50,854)	$ (36,977)	$ (31,793)	$ (16,958)	$ (19,903)	$ (16,019)	$ (16,046)	$ (16,074)	$ 176,875	$ (13,323)
5	Regular General (Rate G2-kWh)		594	(42)	(43)	(31)	(27)	(14)	(17)	(14)	(14)	(14)	150	(11)
6	Regular General (Rate G2 - QR WH/SH)		6,071	(424)	(442)	(321)	(276)	(147)	(173)	(139)	(139)	(140)	1,537	(116)
7	Regular General (Rate G2)		422,666	(29,538)	(30,764)	(22,369)	(19,233)	(10,259)	(12,040)	(9,691)	(9,707)	(9,724)	107,001	(8,060)
8	Large General (Rate G1)		433,002	(30,260)	(31,516)	(22,916)	(19,704)	(10,510)	(12,335)	(9,928)	(9,945)	(9,962)	109,617	(8,257)
9	Outdoor Lighting (Rate OL)		10,326	(722)	(752)	(547)	(470)	(251)	(294)	(237)	(237)	(238)	2,614	(197)
10	**Total**		$ 1,571,340	$ (109,812)	$ (114,370)	$ (83,162)	$ (71,503)	$ (38,139)	$ (44,762)	$ (36,027)	$ (36,088)	$ (36,150)	$ 397,794	$ (29,963)
11	**Approved Rates (DE 22-026)**													
12	**Residential Rate D**													
13	Customer Charge	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22
14	Distribution kWh Charge ($/kWh)	$ 0.04511	$ 0.04646	$ 0.04637	$ 0.04627	$ 0.04620	$ 0.04614	$ 0.04611	$ 0.04607	$ 0.04604	$ 0.04600	$ 0.04597	$ 0.04632	$ 0.04629
15	TY 2020 Customer Bills	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280
16	TY 2020 kWh Billing Determinants	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
17	Customer Charge Revenues	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834
18	Distribution kWh Charge Revenues	23,275,483	23,974,163	23,925,336	23,874,483	23,837,505	23,805,712	23,788,754	23,768,851	23,752,832	23,736,786	23,720,712	23,897,587	23,884,265
19	Total Rate D Revenues	$ 36,499,316	$ 37,197,997	$ 37,149,170	$ 37,098,316	$ 37,061,339	$ 37,029,546	$ 37,012,588	$ 36,992,685	$ 36,976,666	$ 36,960,620	$ 36,944,546	$ 37,121,421	$ 37,108,098
20	**Regular General Rate G2-kWh**													
21	Customer Charge	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38
22	Distribution kWh Charge ($/kWh)	$ 0.02933	$ 0.03068	$ 0.03059	$ 0.03049	$ 0.03042	$ 0.03036	$ 0.03032	$ 0.03029	$ 0.03026	$ 0.03022	$ 0.03019	$ 0.03054	$ 0.03051
23	TY 2020 Customer Bills	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543
24	TY 2020 kWh Billing Determinants	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744
25	Customer Charge Revenues	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500
26	Distribution kWh Charge Revenues	12,868	13,463	13,421	13,378	13,346	13,319	13,305	13,288	13,274	13,261	13,247	13,397	13,386
27	Total Rate G2-kWh Revenues	$ 96,369	$ 96,963	$ 96,921	$ 96,878	$ 96,847	$ 96,820	$ 96,805	$ 96,788	$ 96,775	$ 96,761	$ 96,747	$ 96,898	$ 96,886
28	**Regular General Rate G2 QR WH/SH**													
29	Customer Charge	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73
30	Distribution kWh Charge ($/kWh)	$ 0.03599	$ 0.03734	$ 0.03725	$ 0.03715	$ 0.03708	$ 0.03701	$ 0.03698	$ 0.03694	$ 0.03691	$ 0.03688	$ 0.03685	$ 0.03719	$ 0.03717
31	TY 2020 Customer Bills	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089
32	TY 2020 kWh Billing Determinants	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579
33	Customer Charge Revenues	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056
34	Distribution kWh Charge Revenues	161,350	167,421	166,997	166,555	166,233	165,957	165,810	165,637	165,498	165,358	165,219	166,755	166,640
35	Total Rate G2 Qr W/H Revenues	$ 191,406	$ 197,477	$ 197,053	$ 196,611	$ 196,289	$ 196,013	$ 195,866	$ 195,693	$ 195,554	$ 195,414	$ 195,274	$ 196,811	$ 196,696
36	**Regular General Rate G2 Demand**													
37	Customer Charge	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19
38	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Distribution kW Charge ($/kW)	$ 11.91	$ 12.25	$ 12.23	$ 12.20	$ 12.19	$ 12.17	$ 12.16	$ 12.15	$ 12.14	$ 12.14	$ 12.13	$ 12.22	$ 12.21
40	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
41	TY 2020 Customer Bills	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712
42	TY 2020 kWh Billing Determinants	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498
43	TY 2020 kW Billing Determinants	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532
44	Transformer Units	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843
45	Customer Charge Revenues	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724
46	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Distribution Demand Revenues	14,704,548	15,127,214	15,097,676	15,066,912	15,044,543	15,025,310	15,015,051	15,003,010	14,993,320	14,983,613	14,973,889	15,080,889	15,072,830
48	Transformer Ownership Credit	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)
49	Total Rate G2 Demand Revenues	$ 18,384,850	$ 18,807,516	$ 18,777,978	$ 18,747,215	$ 18,724,845	$ 18,705,612	$ 18,695,353	$ 18,683,313	$ 18,673,622	$ 18,663,915	$ 18,654,191	$ 18,761,192	$ 18,753,132
50	**Large General Rate G1 Demand**													
51	Customer Charge (Average)	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31
52	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Distribution kVA Charge ($/kVA)	$ 8.40	$ 8.83	$ 8.80	$ 8.77	$ 8.75	$ 8.73	$ 8.72	$ 8.71	$ 8.70	$ 8.69	$ 8.68	$ 8.79	$ 8.78
54	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
55	TY 2020 Customer Bills	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010
56	TY 2020 kWh Billing Determinants	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
57	TY 2020 kVA Billing Determinants	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283
58	Transformer Units	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647
59	Customer Charge Revenues	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084
60	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Distribution Demand Revenues	8,404,156	8,837,157	8,806,897	8,775,381	8,752,465	8,732,761	8,722,252	8,709,917	8,699,989	8,690,045	8,680,083	8,789,700	8,781,444
62	Transformer Ownership Credit	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)
63	Total Rate G1 Demand Revenues	$ 8,538,416	$ 8,971,418	$ 8,941,158	$ 8,909,642	$ 8,886,726	$ 8,867,022	$ 8,856,512	$ 8,844,178	$ 8,834,250	$ 8,824,305	$ 8,814,344	$ 8,923,961	$ 8,915,704
64	**Outdoor Lighting (Rate OL)**													
65	Average Luminaire Charge	$ 16.71	$ 16.81	$ 16.80	$ 16.80	$ 16.79	$ 16.79	$ 16.78	$ 16.78	$ 16.78	$ 16.78	$ 16.78	$ 16.80	$ 16.80
66	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
67	TY 2020 Luminaires	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600
68	TY 2020 kWh Billing Determinants	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
69	Luminaire Charge Revenues	$ 1,815,201	$ 1,825,527	$ 1,824,805	$ 1,824,054	$ 1,823,507	$ 1,823,037	$ 1,822,787	$ 1,822,492	$ 1,822,256	$ 1,822,019	$ 1,821,781	$ 1,824,395	$ 1,824,198
70	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Pole Charges	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639
72	Total Rate OL Revenues	$ 1,823,840	$ 1,834,166	$ 1,833,444	$ 1,832,693	$ 1,832,146	$ 1,831,676	$ 1,831,426	$ 1,831,132	$ 1,830,895	$ 1,830,658	$ 1,830,420	$ 1,833,034	$ 1,832,837

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
ESTIMATED DISTRIBUTION RATE IMPACT

Line #	Customer Benefits	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26
	(a)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)
1	Annual Revenue Requirement	$ 1,339,210	$ 1,309,279	$ 1,279,364	$ 1,249,466	$ 1,219,585	$ 1,189,722	$ 1,159,876	$ 1,195,418	$ 1,219,712	$ 1,186,708	$ 1,153,641	$ 1,122,735	$ 1,092,613	$ 1,065,845
2	Revenue Requirement Change	$ (29,947)	$ (29,931)	$ (29,915)	$ (29,898)	$ (29,881)	$ (29,864)	$ (29,846)	$ 35,541	$ 24,294	$ (33,004)	$ (33,067)	$ (30,906)	$ (30,122)	$ (26,768)
3	**Allocation based on 2020 TY kWh:**														
4	Residential (Rate D)	$ (13,316)	$ (13,309)	$ (13,301)	$ (13,294)	$ (13,286)	$ (13,279)	$ (13,271)	$ 15,803	$ 10,802	$ (14,675)	$ (14,703)	$ (13,742)	$ (13,394)	$ (11,902)
5	Regular General (Rate G2-kWh)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	13	9	(12)	(13)	(12)	(11)	(10)
6	Regular General (Rate G2 - QR WH/SH)	(116)	(116)	(116)	(116)	(115)	(115)	(115)	137	94	(128)	(128)	(119)	(116)	(103)
7	Regular General (Rate G2)	(8,055)	(8,051)	(8,047)	(8,042)	(8,038)	(8,033)	(8,028)	9,560	6,535	(8,877)	(8,895)	(8,313)	(8,102)	(7,200)
8	Large General (Rate G1)	(8,252)	(8,248)	(8,243)	(8,239)	(8,234)	(8,229)	(8,224)	9,794	6,695	(9,095)	(9,112)	(8,517)	(8,301)	(7,376)
9	Outdoor Lighting (Rate OL)	(197)	(197)	(197)	(196)	(196)	(196)	(196)	234	160	(217)	(217)	(203)	(198)	(176)
10	**Total**	$ (29,947)	$ (29,931)	$ (29,915)	$ (29,898)	$ (29,881)	$ (29,864)	$ (29,846)	$ 35,541	$ 24,294	$ (33,004)	$ (33,067)	$ (30,906)	$ (30,122)	$ (26,768)
11	**Approved Rates (DE 22-026)**														
12	**Residential Rate D**														
13	Customer Charge	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22
14	Distribution kWh Charge ($/kWh)	$ 0.04626	$ 0.04624	$ 0.04621	$ 0.04619	$ 0.04616	$ 0.04614	$ 0.04611	$ 0.04614	$ 0.04616	$ 0.04613	$ 0.04610	$ 0.04608	$ 0.04605	$ 0.04603
15	TY 2020 Customer Bills	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280
16	TY 2020 kWh Billing Determinants	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
17	Customer Charge Revenues	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834
18	Distribution kWh Charge Revenues	23,870,949	23,857,640	23,844,339	23,831,045	23,817,759	23,804,481	23,791,210	23,807,013	23,817,815	23,803,141	23,788,438	23,774,695	23,761,302	23,749,400
19	Total Rate D Revenues	$ 37,094,783	$ 37,081,474	$ 37,068,173	$ 37,054,879	$ 37,041,593	$ 37,028,314	$ 37,015,043	$ 37,030,847	$ 37,041,649	$ 37,026,974	$ 37,012,271	$ 36,998,529	$ 36,985,135	$ 36,973,233
20	**Regular General Rate G2-kWh**														
21	Customer Charge	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38
22	Distribution kWh Charge ($/kWh)	$ 0.03048	$ 0.03046	$ 0.03043	$ 0.03041	$ 0.03038	$ 0.03036	$ 0.03033	$ 0.03036	$ 0.03038	$ 0.03035	$ 0.03032	$ 0.03030	$ 0.03027	$ 0.03025
23	TY 2020 Customer Bills	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543
24	TY 2020 kWh Billing Determinants	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744
25	Customer Charge Revenues	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500
26	Distribution kWh Charge Revenues	13,375	13,363	13,352	13,341	13,330	13,318	13,307	13,320	13,330	13,317	13,305	13,293	13,281	13,271
27	Total Rate G2-kWh Revenues	$ 96,875	$ 96,864	$ 96,852	$ 96,841	$ 96,830	$ 96,819	$ 96,807	$ 96,821	$ 96,830	$ 96,817	$ 96,805	$ 96,793	$ 96,782	$ 96,772
28	**Regular General Rate G2 QR WH/SH**														
29	Customer Charge	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73
30	Distribution kWh Charge ($/kWh)	$ 0.03714	$ 0.03712	$ 0.03709	$ 0.03706	$ 0.03704	$ 0.03701	$ 0.03699	$ 0.03702	$ 0.03704	$ 0.03701	$ 0.03698	$ 0.03695	$ 0.03693	$ 0.03691
31	TY 2020 Customer Bills	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089
32	TY 2020 kWh Billing Determinants	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579
33	Customer Charge Revenues	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056
34	Distribution kWh Charge Revenues	166,524	166,408	166,293	166,177	166,062	165,946	165,831	165,968	166,062	165,935	165,807	165,688	165,571	165,468
35	Total Rate G2 Qr W/H Revenues	$ 196,580	$ 196,464	$ 196,349	$ 196,233	$ 196,118	$ 196,002	$ 195,887	$ 196,024	$ 196,118	$ 195,991	$ 195,863	$ 195,744	$ 195,627	$ 195,524
36	**Regular General Rate G2 Demand**														
37	Customer Charge	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19
38	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Distribution kW Charge ($/kW)	$ 12.20	$ 12.20	$ 12.19	$ 12.18	$ 12.18	$ 12.17	$ 12.16	$ 12.17	$ 12.18	$ 12.17	$ 12.16	$ 12.16	$ 12.15	$ 12.14
40	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
41	TY 2020 Customer Bills	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712
42	TY 2020 kWh Billing Determinants	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498
43	TY 2020 kW Billing Determinants	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532
44	Transformer Units	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843
45	Customer Charge Revenues	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724
46	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Distribution Demand Revenues	15,064,774	15,056,723	15,048,677	15,040,635	15,032,597	15,024,564	15,016,536	15,026,096	15,032,631	15,023,754	15,014,859	15,006,546	14,998,444	14,991,243
48	Transformer Ownership Credit	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)
49	Total Rate G2 Demand Revenues	$ 18,745,077	$ 18,737,026	$ 18,728,979	$ 18,720,937	$ 18,712,900	$ 18,704,867	$ 18,696,839	$ 18,706,399	$ 18,712,934	$ 18,704,056	$ 18,695,162	$ 18,686,848	$ 18,678,746	$ 18,671,546
50	**Large General Rate G1 Demand**														
51	Customer Charge (Average)	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31
52	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Distribution kVA Charge ($/kVA)	$ 8.77	$ 8.76	$ 8.75	$ 8.75	$ 8.74	$ 8.73	$ 8.72	$ 8.73	$ 8.74	$ 8.73	$ 8.72	$ 8.71	$ 8.70	$ 8.70
54	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
55	TY 2020 Customer Bills	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010
56	TY 2020 kWh Billing Determinants	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
57	TY 2020 kVA Billing Determinants	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283
58	Transformer Units	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647
59	Customer Charge Revenues	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084
60	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Distribution Demand Revenues	8,773,191	8,764,943	8,756,700	8,748,461	8,740,227	8,731,998	8,723,774	8,733,568	8,740,262	8,731,168	8,722,056	8,713,539	8,705,238	8,697,862
62	Transformer Ownership Credit	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)
63	Total Rate G1 Demand Revenues	$ 8,907,452	$ 8,899,204	$ 8,890,961	$ 8,882,722	$ 8,874,488	$ 8,866,259	$ 8,858,034	$ 8,867,828	$ 8,874,523	$ 8,865,428	$ 8,856,316	$ 8,847,799	$ 8,839,499	$ 8,832,123
64	**Outdoor Lighting (Rate OL)**														
65	Average Luminaire Charge	$ 16.80	$ 16.79	$ 16.79	$ 16.79	$ 16.79	$ 16.79	$ 16.78	$ 16.79	$ 16.79	$ 16.79	$ 16.78	$ 16.78	$ 16.78	$ 16.78
66	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	TY 2020 Luminaires	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600
68	TY 2020 kWh Billing Determinants	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
69	Luminaire Charge Revenues	$ 1,824,001	$ 1,823,805	$ 1,823,608	$ 1,823,412	$ 1,823,215	$ 1,823,019	$ 1,822,823	$ 1,823,056	$ 1,823,216	$ 1,822,999	$ 1,822,782	$ 1,822,579	$ 1,822,381	$ 1,822,205
70	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Pole Charges	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639
72	Total Rate OL Revenues	$ 1,832,641	$ 1,832,444	$ 1,832,247	$ 1,832,051	$ 1,831,854	$ 1,831,658	$ 1,831,462	$ 1,831,696	$ 1,831,855	$ 1,831,638	$ 1,831,421	$ 1,831,218	$ 1,831,020	$ 1,830,844

UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL
BILL IMPACT ANALYSIS
ESTIMATED DISTRIBUTION RATE IMPACT

Line #	Customer Benefits	Year 27	Year 28	Year 29	Year 30	Year 31	Year 32	Year 33	Year 34	Year 35	Year 36	Year 37	Year 38	Year 39	Year 40
	(a)	(ac)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)	(ap)
1	Annual Revenue Requirement	$ 1,042,833	$ 1,020,243	$ 997,536	$ 974,749	$ 954,377	$ 936,235	$ 917,911	$ 899,490	$ 881,002	$ 865,838	$ 853,717	$ 841,345	$ 828,834	$ 816,227
2	Revenue Requirement Change	$ (23,012)	$ (22,590)	$ (22,706)	$ (22,788)	$ (20,372)	$ (18,143)	$ (18,324)	$ (18,421)	$ (18,487)	$ (15,164)	$ (12,120)	$ (12,373)	$ (12,511)	$ (12,607)
3	**Allocation based on 2020 TY kWh:**														
4	Residential (Rate D)	$ (10,232)	$ (10,045)	$ (10,096)	$ (10,132)	$ (9,058)	$ (8,067)	$ (8,148)	$ (8,191)	$ (8,220)	$ (6,743)	$ (5,389)	$ (5,501)	$ (5,563)	$ (5,605)
5	Regular General (Rate G2-kWh)	(9)	(9)	(9)	(9)	(8)	(7)	(7)	(7)	(7)	(6)	(5)	(5)	(5)	(5)
6	Regular General (Rate G2 - QR WH/SH)	(89)	(87)	(88)	(88)	(79)	(70)	(71)	(71)	(71)	(59)	(47)	(48)	(48)	(49)
7	Regular General (Rate G2)	(6,190)	(6,076)	(6,108)	(6,129)	(5,480)	(4,880)	(4,929)	(4,955)	(4,973)	(4,079)	(3,260)	(3,328)	(3,365)	(3,391)
8	Large General (Rate G1)	(6,341)	(6,225)	(6,257)	(6,279)	(5,614)	(4,999)	(5,049)	(5,076)	(5,094)	(4,179)	(3,340)	(3,409)	(3,447)	(3,474)
9	Outdoor Lighting (Rate OL)	(151)	(148)	(149)	(150)	(134)	(119)	(120)	(121)	(121)	(100)	(80)	(81)	(82)	(83)
10	**Total**	$ (23,012)	$ (22,590)	$ (22,706)	$ (22,788)	$ (20,372)	$ (18,143)	$ (18,324)	$ (18,421)	$ (18,487)	$ (15,164)	$ (12,120)	$ (12,373)	$ (12,511)	$ (12,607)
11	**Approved Rates (DE 22-026)**														
12	**Residential Rate D**														
13	Customer Charge	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22	$ 16.22
14	Distribution kWh Charge ($/kWh)	$ 0.04601	$ 0.04599	$ 0.04597	$ 0.04595	$ 0.04593	$ 0.04592	$ 0.04590	$ 0.04589	$ 0.04587	$ 0.04586	$ 0.04585	$ 0.04584	$ 0.04582	$ 0.04581
15	TY 2020 Customer Bills	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280	815,280
16	TY 2020 kWh Billing Determinants	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592	515,968,592
17	Customer Charge Revenues	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834	$ 13,223,834
18	Distribution kWh Charge Revenues	23,739,168	23,729,123	23,719,027	23,708,895	23,699,837	23,691,770	23,683,622	23,675,432	23,667,211	23,660,469	23,655,080	23,649,578	23,644,015	23,638,410
19	Total Rate D Revenues	$ 36,963,002	$ 36,952,957	$ 36,942,861	$ 36,932,729	$ 36,923,670	$ 36,915,604	$ 36,907,456	$ 36,899,265	$ 36,891,045	$ 36,884,302	$ 36,878,913	$ 36,873,412	$ 36,867,849	$ 36,862,244
20	**Regular General Rate G2-kWh**														
21	Customer Charge	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38	$ 18.38
22	Distribution kWh Charge ($/kWh)	$ 0.03023	$ 0.03021	$ 0.03019	$ 0.03017	$ 0.03015	$ 0.03014	$ 0.03012	$ 0.03011	$ 0.03009	$ 0.03008	$ 0.03007	$ 0.03006	$ 0.03004	$ 0.03003
23	TY 2020 Customer Bills	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543	4,543
24	TY 2020 kWh Billing Determinants	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744	438,744
25	Customer Charge Revenues	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500	$ 83,500
26	Distribution kWh Charge Revenues	13,263	13,254	13,246	13,237	13,229	13,222	13,215	13,208	13,201	13,196	13,191	13,186	13,182	13,177
27	Total Rate G2-kWh Revenues	$ 96,763	$ 96,754	$ 96,746	$ 96,737	$ 96,730	$ 96,723	$ 96,716	$ 96,709	$ 96,702	$ 96,696	$ 96,692	$ 96,687	$ 96,682	$ 96,677
28	**Regular General Rate G2 QR WH/SH**														
29	Customer Charge	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73	$ 9.73
30	Distribution kWh Charge ($/kWh)	$ 0.03689	$ 0.03687	$ 0.03685	$ 0.03683	$ 0.03681	$ 0.03679	$ 0.03678	$ 0.03676	$ 0.03675	$ 0.03673	$ 0.03672	$ 0.03671	$ 0.03670	$ 0.03669
31	TY 2020 Customer Bills	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089	3,089
32	TY 2020 kWh Billing Determinants	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579	4,483,579
33	Customer Charge Revenues	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056	$ 30,056
34	Distribution kWh Charge Revenues	165,379	165,292	165,204	165,116	165,037	164,967	164,896	164,825	164,754	164,695	164,648	164,600	164,552	164,503
35	Total Rate G2 Qr W/H Revenues	$ 195,435	$ 195,348	$ 195,260	$ 195,172	$ 195,093	$ 195,023	$ 194,952	$ 194,881	$ 194,810	$ 194,751	$ 194,704	$ 194,656	$ 194,608	$ 194,559
36	**Regular General Rate G2 Demand**														
37	Customer Charge	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19	$ 29.19
38	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Distribution kW Charge ($/kW)	$ 12.14	$ 12.13	$ 12.13	$ 12.12	$ 12.12	$ 12.12	$ 12.11	$ 12.11	$ 12.10	$ 12.10	$ 12.10	$ 12.09	$ 12.09	$ 12.09
40	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
41	TY 2020 Customer Bills	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712	126,712
42	TY 2020 kWh Billing Determinants	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498	312,134,498
43	TY 2020 kW Billing Determinants	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532	1,234,532
44	Transformer Units	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843	36,843
45	Customer Charge Revenues	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724	$ 3,698,724
46	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Distribution Demand Revenues	14,985,054	14,978,977	14,972,870	14,966,740	14,961,260	14,956,380	14,951,451	14,946,496	14,941,524	14,937,445	14,934,184	14,930,856	14,927,491	14,924,100
48	Transformer Ownership Credit	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)	(18,421)
49	Total Rate G2 Demand Revenues	$ 18,665,356	$ 18,659,280	$ 18,653,172	$ 18,647,042	$ 18,641,563	$ 18,636,683	$ 18,631,754	$ 18,626,799	$ 18,621,826	$ 18,617,747	$ 18,614,487	$ 18,611,159	$ 18,607,794	$ 18,604,403
50	**Large General Rate G1 Demand**														
51	Customer Charge (Average)	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31	$ 147.31
52	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Distribution kVA Charge ($/kVA)	$ 8.69	$ 8.68	$ 8.68	$ 8.67	$ 8.66	$ 8.66	$ 8.65	$ 8.65	$ 8.64	$ 8.64	$ 8.64	$ 8.63	$ 8.63	$ 8.63
54	Transformer Ownership Credit	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
55	TY 2020 Customer Bills	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010	2,010
56	TY 2020 kWh Billing Determinants	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459	319,767,459
57	TY 2020 kVA Billing Determinants	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283	1,000,283
58	Transformer Units	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647	323,647
59	Customer Charge Revenues	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084	$ 296,084
60	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Distribution Demand Revenues	8,691,521	8,685,296	8,679,039	8,672,760	8,667,146	8,662,147	8,657,097	8,652,021	8,646,927	8,642,748	8,639,408	8,635,998	8,632,551	8,629,077
62	Transformer Ownership Credit	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)	(161,824)
63	Total Rate G1 Demand Revenues	$ 8,825,782	$ 8,819,557	$ 8,813,300	$ 8,807,020	$ 8,801,407	$ 8,796,407	$ 8,791,358	$ 8,786,282	$ 8,781,187	$ 8,777,008	$ 8,773,668	$ 8,770,259	$ 8,766,812	$ 8,763,338
64	**Outdoor Lighting (Rate OL)**														
65	Average Luminaire Charge	$ 16.78	$ 16.78	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.77	$ 16.76	$ 16.76
66	Distribution kWh Charge ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	TY 2020 Luminaires	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600	108,600
68	TY 2020 kWh Billing Determinants	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729	7,625,729
69	Luminaire Charge Revenues	$ 1,822,054	$ 1,821,905	$ 1,821,756	$ 1,821,606	$ 1,821,472	$ 1,821,353	$ 1,821,233	$ 1,821,112	$ 1,820,990	$ 1,820,891	$ 1,820,811	$ 1,820,730	$ 1,820,647	$ 1,820,565
70	Distribution kWh Charge Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Pole Charges	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639	8,639
72	Total Rate OL Revenues	$ 1,830,693	$ 1,830,544	$ 1,830,395	$ 1,830,245	$ 1,830,112	$ 1,829,992	$ 1,829,872	$ 1,829,751	$ 1,829,629	$ 1,829,530	$ 1,829,450	$ 1,829,369	$ 1,829,287	$ 1,829,204