REDACTED

# UNITIL ENERGY SYSTEMS, INC.
# DE 22-___
# PETITION FOR APPROVAL OF INVESTMENT IN AND RATE RECOVERY OF A DISTRIBUTED ENERGY RESOURCE PURSUANT TO RSA 374-G

***TABLE OF CONTENTS***

| | Page |
|---|---|
| COVER LETTER | |
| MOTION FOR PROTECTIVE ORDER | |
| PETITION | |
| SPRAGUE TESTIMONY (INTRODUCTION OF FILING, PROJECT OVERVIEW AND OBJECTIVES, STATUTORY REQUIREMENTS REVIEW) | 000001 |
| DUSLING TESTIMONY AND EXHIBITS (PROJECT OVERVIEW, APPROACH AND OPERATIONS) | 000037 |
| FRANCOEUR, DIGGINS, GOULDING AND PENTZ TESTIMONY AND EXHIBITS (BENEFIT-COST ANALYSIS, ESTIMATED BILL IMPACTS) | 000172 |
| GILBERT AND PIERCE TESTIMONY AND EXHIBITS (INDIRECT BENEFITS) | 000247 |

Unitil

October 31, 2022

**BY E-MAIL[1]**

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

Re: Unitil Energy Systems, Inc., DE 22-______
Petition for Authorization to Construct Kingston Solar Project

Chairman Goldner:

Unitil Energy Systems, Inc. ("UES" or the "Company") respectfully petitions the New Hampshire Public Utilities Commission ("the Commission") to: (1) approve a two-stage framework for the Commission's review of UES's proposal to construct, own, and operate a 4.99 megawatt utility-scale photovoltaic generating facility located in Kingston, New Hampshire (the "Kingston Solar Project" or the "Project"); (2) find that the Company's filing meets the minimum requirements set forth in NH RSA 374-G:5, I; (3) find that the Kingston Solar Project is in the public interest pursuant to RSA 374-G:5, II and authorize construction of the Project; (4) authorize UES to seek recovery of Project costs in the Company's next base distribution rate case; and (5) approve recovery by the Company of its reasonable costs associated with this filing through the Company's Schedule EDC.

UES's filing includes the following Exhibits:

1. Exhibit KES-1: Direct Testimony of Kevin E. Sprague. Mr. Sprague's testimony summarizes and supports the Company's Kingston Solar Project proposal.
2. Exhibits JSD-1 through JSD-7: Direct Testimony and Exhibits of Jacob S. Dusling. Mr. Dusling's testimony and exhibits explain, among other things, the development and technical aspects of the Kingston Solar Project.
3. Exhibits FDGP-1 through FDGP-3: Direct Testimony and Exhibit of Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz. The testimony of these witnesses presents the Company's analysis of the benefits and costs of proposed Kingston Solar Project and the associated rate implications
4. Exhibits GPP-1 through GPP-4: Direct Testimony and Exhibits of Carolyn C. Gilbert and Kevin R. Pierce of Daymark Energy Advisors. The testimony of Ms. Gilbert and Mr. Pierce discusses and quantifies the economic benefits, emissions reduction

[1] This filing is made electronically in accordance with the Secretarial Letter dated March 17, 2020.

Patrick H. Taylor
Chief Regulatory Counsel
taylorp@unitil.com

6 Liberty Lane West
Hampton, NH 03842

T 603.773.6544

www.unitil.com

benefits, and Demand Reduction Induced Price Effects benefits of the Kingston Solar Project.

Pursuant to RSA 374-G:5, UES requests that the Commission render a decision on the Company's filing within six months of the filing date.

Please do not hesitate to contact me if you have any questions regarding this filing.

Sincerely,

Patrick H. Taylor

cc: New Hampshire Department of Energy
Office of the Consumer Advocate

**THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION**

**DG 22-_____**

**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 initial 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 JSD-1; Exhibit JSD-4(a); Exhibit JSD-4(b); Exhibit JSD-5; Exhibit JSD-7; Exhibit FDGP-1, and Exhibit FDGP-2 (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

Concurrent with this Motion, Unitil has filed a petition requesting, among other things, 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"). The Company is seeking the Commission's approval of the Kingston Solar 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 has prepared analyses of the costs and benefits of the Project, which rely upon cost estimates, billing rates, pricing information provided by several third party vendors. The Company's filing also contains a confidential and proprietary price quote for renewable energy certificates ("RECs") provided by a third party vendor.

The cost estimates and billing rates have been provided by third-party vendors in response to Requests for Proposals ("RFPs") and the negotiated pricing information is set forth in agreements between third-parties and the Company. The REC price quote in Exhibit FDGP-1 was provided by a third-party broker.

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 at 2 (Sept. 22, 2009). 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, the Commission should find the countervailing commercial interests for non-disclosure outweigh the public's interest in full disclosure.

**a. Cost Estimates, Billing Rates, and Pricing Information**

Disclosure of the cost estimates, billing rates, and negotiated pricing information (and information that can be used to derive this information) 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. 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 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).

For example, in this case, the Company is conducting a multistage RFP process to procure the services of a contractor to design and construct the Kingston Solar Project. The cost estimates for labor and materials in the Company's filing rely, in large part, on cost estimates provided in response to a Preliminary (Stage I) RFP. If the cost estimates provided in response to that Preliminary RFP were made public, it could unduly influence the responses to the Final RFP for the Project by other bidders. Moreover, it could dissuade contractors from bidding on the Project, which would result in a less robust solicitation.

The Company is providing redacted versions of the Confidential Attachments for the public record. Therefore, although the Company is requesting protective treatment for the cost estimates, billing rates, and negotiated pricing information for individual components of the Project, the public will still have access to information about total costs and bill impacts. *See EnergyNorth Natural Gas, Inc.*, Order No. 25,064 at (Jan. 15, 2010) at 12 ("publically 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 from vendors and potential vendors as confidential. *See e.g., 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, which 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."). For example, 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 and there is no reason for the Commission to depart from its long-established precedent in this proceeding.

**b. REC Price Quote**

Exhibit FDGP-1 contains a recent 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 State or local 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:

Patrick H. Taylor
Matthew C. Campbell
Unitil Service Corp
6 Liberty Lane West
Hampton, NH 03842
603-773-6544
603-773-653
taylorp@unitil.com
campbellm@unitil.com

Dated: October 31, 2022.

**CERTIFICATE OF SERVICE**

I hereby certify that on this 31st day of October, 2022, a copy of the foregoing Motion was electronically delivered to the New Hampshire Department of Energy and Office of the Consumer Advocate.

Matthew C. Campbell

# APPENDIX A
## SUMMARY OF CONFIDENTIAL INFORMATION IN THE CONFIDENTIAL ATTACHMENTS

| Exhibit Number | Description of Exhibit | Description of Confidential Information |
|---|---|---|
| Exh. FDGP-1 | Joint Testimony of Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz | • Estimated O&M cost provided in response to Preliminary RFP<br>• REC quote provided by REC broker |
| Exh. FDGP-2 | Benefit-Cost Analysis Model | • Estimated capital costs for facility construction provided in response to Preliminary RFP and information that can be used to derive these costs<br>• Cost for Site Due Diligence, Design and Permitting provided by the winning bidder<br>• Price for contingent purchase of real estate and information that can be used to derive the purchase price<br>• Estimated replacement cost for inverter provided in response to Preliminary RFP<br>• Price for appraisal services<br>• Estimated O&M cost provided in response to Preliminary RFP<br>• REC quote provided by REC broker |
| Exh. JSD-1 | Testimony of Jacob S. Dusling | • Price for contingent purchase of real estate and information that can be used to derive the purchase price<br>• Estimated capital costs for facility construction provided in response to Preliminary RFP<br>• Estimated costs and unit pricing to perform Site Evaluation and Permitting Scope of Work<br>• Price for appraisal services<br>• Estimated O&M costs provided in response to Preliminary RFP |
| Exh. JSD-4(a) | Response to Site Evaluation & Permitting RFP | • Estimated costs and unit pricing to perform Site Evaluation and Permitting Scope of Work |
| Exh. JSD-4(b) | Updated Pricing to Perform Site Evaluation & Permitting RFP | • Estimated costs and unit pricing to perform Site Evaluation and Permitting Scope of Work |
| Exh. JSD-5 | Purchase and Sale Agreement | • Price for contingent purchase of real estate and amount placed in escrow |
| Exh. JSD-7 | Agreement for Appraisal Services | • Price for appraisal services |

**THE STATE OF NEW HAMPSHIRE**

**BEFORE THE**

**PUBLIC UTILITIES COMMISSION**

**DE 22-_____**

**UNITIL ENERGY SYSTEMS, INC.**

**PETITION FOR APPROVAL OF INVESTMENT IN AND RATE RECOVERY OF A DISTRIBUTED ENERGY RESOURCE PURSUANT TO RSA 374-G**

NOW COMES Unitil Energy Systems, Inc. ("UES" or "the Company") and, pursuant to the provisions of NH RSA 374-G, respectfully petitions the New Hampshire Public Utilities Commission ("the Commission") to: (1) approve a two-stage framework for the Commission's review of UES's proposal to construct, own, and operate a 4.99 megawatt ("MW") utility-scale photovoltaic generating facility located in Kingston, New Hampshire (the "Kingston Solar Project" or the "Project"); (2) find that the Company's filing meets the minimum requirements set forth in RSA 374-G:5, I; (3) find that the Kingston Solar Project is in the public interest pursuant to RSA 374-G:5, II and authorize construction of the Project; (4) authorize UES to seek recovery of Project costs in the Company's next base distribution rate case; and (5) approve recovery by the Company of its reasonable costs associated with this filing through the Company's Schedule EDC. Pursuant to RSA 374-G:5, UES requests that the Commission render a decision on the Company's filing within six months of the filing date.

UES's filing includes the following Exhibits:

1. Exhibit KES-1: Direct Testimony of Kevin E. Sprague. Mr. Sprague's testimony summarizes and supports the Company's Kingston Solar Project proposal.

2. Exhibits JSD-1 through JSD-7: Direct Testimony and Exhibits of Jacob S. Dusling. Mr. Dusling's testimony and exhibits explain, among other things, the development and technical aspects of the Kingston Solar Project.

3. Exhibits FDGP-1 through FDGP-3: Direct Testimony and Exhibit of Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz. The testimony of these witnesses presents the Company's analysis of the benefits and costs of proposed Kingston Solar Project and the associated rate implications

4. Exhibits GPP-1 through GPP-4: Direct Testimony and Exhibits of Carolyn C. Gilbert and Kevin R. Pierce of Daymark Energy Advisors. The testimony of Ms. Gilbert and Mr. Pierce discusses and quantifies the economic benefits, emissions reduction benefits, and Demand Reduction Induced Price Effects ("DRIPE") benefits of the Kingston Solar Project.

In support of its Petition, UES states as follows:

## I. RSA 374-G Permits and Encourages Utility Ownership of Distributed Energy Resources, Including Solar Generating Facilities

5. The New Hampshire legislature has recognized that distributed energy resources ("DERs") provide myriad benefits to the State by "eliminating, displacing, or better managing traditional fossil fuel energy deliveries from the centralized bulk power grid, in keeping with the objectives of RSA 362-F:1."[1] RSA 374-G:1. Having made this finding, the legislature concluded that it is in the "public interest" to stimulate investment

[1] "Renewable energy generation technologies can provide fuel diversity to the state and New England generation supply through use of local renewable fuels and resources that serve to displace and thereby lower regional dependence on fossil fuels. This has the potential to lower and stabilize future energy costs by reducing exposure to rising and volatile fossil fuel prices. The use of renewable energy technologies and fuels can also help to keep energy and investment dollars in the state to benefit our own economy. In addition, employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change. It is therefore in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire, whether at new or existing facilities." RSA 362-F: 1.

in such resources in New Hampshire in diverse ways, "including by encouraging New Hampshire electric public utilities to invest in renewable and clean distributed energy resources." Id.

6. Notwithstanding the provisions of RSA 374-F, which generally requires the separation of power generation and transmission and distribution services, New Hampshire electric distribution companies ("EDCs") are permitted to "invest in or own *distributed energy resources*, located on or inter-connected to the local electric distribution system." RSA 374-G:4, I (emphasis added); see also RSA 374-F:3, III ("[EDCs] should not be absolutely precluded from owning small scale distributed generation resources as part of a strategy for minimizing transmission and distribution costs.").

7. "Distributed energy resources" are defined under RSA 374-G to include "*electric generation equipment* including clean and renewable generation . . . located on or interconnected to the local electric distribution system for purposes including but not limited to reducing line losses, supporting voltage regulation, or peak load shaving, as part of a strategy for minimizing transmission and distribution costs as provided in RSA 374-F:3, III." RSA 374-G:2, I(b) (emphasis added). "Electric generation equipment' means "devices that produce electric power from sources of primary energy," including solar energy. RSA 374-G:2, I(c)-(d). The energy produced by such electric generation equipment, if owned by an EDC, "shall be used to benefit low-income customers, . . . as an offset to distribution system losses or the public utility company's own use, or any other use as approved by the commission." RSA 374-G:3, I.

8. Though RSA 374-G permits EDCs to invest in and own DERs including electric generation equipment, ownership of individual generation projects is capped at 5 MW. RSA 374-G:2, II(a) ("'Distributed Energy Resources' . . . shall exclude electric generation equipment interconnected with the local electric distribution system at a single point . . . that is in excess of 5 MW."). However, an EDC may own or invest in multiple distributed electric generation facilities up to a cumulative maximum of 6 percent of the utility's total distribution peak load in megawatts. RSA 374-G:4, II.

## II. <u>The Kingston Solar Project is a Distributed Energy Resource Under RSA 374-G</u>

9. UES proposes to construct, own, and operate a 4.99 MW alternating current (AC) utility-scale solar generating facility located at 2 Mill Road / 24 Towle Road in Kingston, New Hampshire. The Kingston Solar Project will optimize energy production through the use of single-axis tracking solar panels that rotate on a single point throughout the course of a day, adjusting position to track the sun from east to west. The annual energy output of the facility is expected to average 8,904 MWh over the projected 30-year life of the project, at an assumed capacity factor of approximately 22 percent.

10. The Kingston Solar Project is a "distributed energy resource" as defined in RSA 374-G:2. The Project will comprise "electric generation equipment" in the form of single-axis tracking solar panels that produce electric power from solar energy, a "primary energy" form "found in nature that has not been subject to any human engineered conversion process." RSA 374-G:2, I(b)-(d). Moreover, the Project's output will be limited to 4.99 MW, and thus included as a "distributed energy resource" that an EDC may invest in and own.

11. Utility-scale renewable energy projects such as the Kingston Solar Project provide tangible benefits to customers, the electric distribution system, and the environment. These benefits include reductions to purchased energy, peak demand, and lines losses, and offsets to greenhouse gas emissions that otherwise would be emitted from the burning of fossil fuels.

12. The Kingston Solar Project will realize a number of direct benefits that will accrue to customers over the course of the Project's anticipated 30-year life. These benefits, which are described at length in the Exhibits accompanying this Petition, include avoided purchased power; avoided transmission costs; local transmission savings; regional transmission savings; and renewable energy certificate (REC) savings. UES performed a robust Benefit-Cost Analysis incorporating project cost estimates developed through a combination of information provided in response to competitive requests for information and proposals from potential developers, input from the Company's site assessment contractor,[2] and the experience of UES's Massachusetts affiliate in constructing and operating a 1.3 MW solar facility. The Company's Benefit-Cost Analysis shows that the Project has a positive Benefit-Cost Ratio of 1.09 and a Net Present Value of approximately $1.4 million. The benefits of the Kingston Solar Project will accrue to all customers, including low-income customers who otherwise might not have the means to access the benefits of solar energy. RSA 374-G:3, I.

13. UES plans to operate the Kingston Solar Project as a "load reducer," meaning that the energy produced by the Project will be delivered directly into the Company's electric distribution system, and the Project will not participate in the ISO-

[2] The Company selected its site assessment contractor through a competitive bidding process.

NE wholesale market. The Project will reduce energy received by UES from the transmission system and is therefore a strategic asset for the purposes of minimizing transmission and distribution costs. RSA 374-G:2, I(b); RSA 374-G:3, I. Moreover, by reducing energy that otherwise would be received from the transmission system, the Project directly offsets distribution system losses. RSA 374-G:3, I.

14. The Kingston Solar Project is a "distributed energy resource" within the definition and requirements set forth in RSA 374-G, and represents the very type of project in which the New Hampshire legislature intended to encourage utility investment.

## III. <u>The Two-Stage Review Process</u>

15. Pursuant to RSA 374-G:5, III, "*[a]uthorized* and prudently incurred investments shall be recovered . . . in a utility's base distribution rates as a component of rate base." (Emphasis added). Cost recovery under this provision "shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment." RSA 374-G:5, III.

16. UES proposes, as it did in DE 09-137, that the Commission apply a two-stage regulatory process to review the Kingston Solar Project. In Stage I (this proceeding), the Commission will review the Company's Kingston Solar Project proposal to determine (1) whether the Project meets the minimum filing requirements of RSA 374-G:5, I and (2) whether the Project is in the public interest and thus recoverable in rates as required by RSA 374-G:5, II. If the Commission were to find that the Kingston Solar Project meets the statutory requirements of RSA 374-G:5, the Company would be

"authorized" to proceed with the Project and seek recovery of rates after the Project is placed into service. Thus, in Stage II of the process, the Company will seek to recover the cost of the "authorized" Project in base distribution rates. UES plans to request such rate recovery in its next base distribution rate case or in a subsequent step adjustment.

17. As noted above, UES proposed a similar regulatory process in DE 09-137, the Company's first petition for approval to invest in DERs under RSA 374-G. The Commission concluded that RSA 374-G does not preclude such a two-stage process, and that it is reasonable for the Commission to use such a process in reviewing DER investments. DE 09-137, Unitil Energy Systems, Inc., Order No. 25,111 at 32 (June 1, 2010). It further found it in the public interest to approve the two stage process. Id.[3]

18. The Commission should similarly adopt a two-stage process to review the Kingston Solar Project. This process will allow for the thorough and efficient review of the process to determine whether it is in the public interest and thus "authorized," after which the Company will proceed to construct the Project and seek recovery in base distribution rates.

## IV. The Company's Filing Meets the Requirements of RSA 374-G:5

### *a. The Company's filing meets the minimum statutory requirements of RSA 374-G:5, I*

19. Any filing made under RSA 374-G:5 must include certain minimum filing requirements, including:

a. A detailed description and economic and environmental evaluation of the proposed investment;
b. A discussion of the costs, benefits, and risks of the proposal with specific reference to the nine public interest factors, including an analysis of the costs, benefits, and rate implications to the participating customers, to the

[3] Though RSA 374-G:5 was repealed and re-enacted in 2013, the language of the statute was not altered in a way that would affect the Commission's decision or necessitate a different outcome.

company's default service customers, and to the utility's distribution customers;
c. A description of any equipment or installation specifications, solicitations, and procurements it has or intends to implement;
d. A showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers;
e. A showing that it has made reasonable efforts to involve local businesses in its program;
f. Evidence of compliance with any applicable emission limitations; and
g. A copy of any customer contracts or agreements to be executed as part of the program.

20. All of these requirements are satisfied through the testimonies and exhibits of the Company's witnesses.[4] The testimony of Kevin E. Sprague provides a summary of how the various testimonies satisfy the statutory requirements of RSA 374-G:5,I.

***b. The Kingston Solar Project meets the public interest criteria set forth in RSA 374-G:5, II***

21. RSA 374-G:5 also requires the Commission, when considering whether a proposed distributed energy resource is in the "public interest," to give balanced consideration and proportional weight to a series of nine factors, including:.

a. The effect on the reliability, safety, and efficiency of electric service;
b. The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3;
c. The energy security benefits of the investment to New Hampshire;
d. The environmental benefits of the investment to the state of New Hampshire;
e. The economic development benefits and liabilities of the investment to New Hampshire;
f. The effect on competition within the region's electricity markets and the state's energy services market;
g. The costs and benefits to the utility's customers, including but not limited to a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project;
h. Whether the expected value of the economic benefits of the investment to

[4] Solar generation does not produce any emissions and therefore this requirement is not applicable to the Company's planned Kingston Solar Project; moreover, there are no customer contracts to be executed as part of the Company's proposed Project.

the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers; and

i. The costs and benefits to any participating customer or customers.

22. As with the minimum statutory requirements, these factors are addressed in the UES witnesses' respective testimonies and exhibits. The testimony of Kevin E. Sprague provides a summary of how the various testimonies satisfy the statutory requirements of RSA 374-G:5,II. Generally speaking, the Company's Benefit-Costs analysis shows that the Kingston Solar Project has a favorable Benefit / Cost ratio and will result in the accrual of direct benefits to customers over the course of the Project's 30-year planned timeframe. *See generally*, Exhibit KES-1 at 22-30.

23. Furthermore, the Company has engaged Daymark Energy Advisors to quantify the estimated indirect benefits of the Project, including economic benefits, emissions reduction benefits, and DRIPE benefits. While the Kingston Solar Project stands on its own solely through the delivery of direct benefits to customers, these additional benefits reinforce that the Project is in the public interest and should be approved by the Commission for construction and, ultimately, rate recovery.

## V. Recovery of Reasonable Costs Associated With the Company's Filing

24. A utility may recover "all reasonable costs" associated with a filing under RSA 374-G:5, "whether or not the application is approved by the Commission." RSA 374-G:5, III.

25. As explained in this Petition and its accompanying exhibits, the Kingston Solar Project meets the criteria set forth in RSA 374-G and is in the public interest, and therefore should be approved. Regardless of the Commission's decision in this docket,

however, UES should be permitted to recover all reasonable costs associated with this filing.

26. UES therefore requests that the Commission approve recovery of all reasonable costs associated with this filing. The Company proposes to recover such costs through its Schedule EDC. As costs related to this filing will continue to accrue throughout the course of the docket, the Company proposes to provide an accounting of such costs, subject to update, at a time agreed to by the parties and the Commission at the prehearing conference in this matter.

## VI. Timing of the Commission's Decision

27. The Commission must approve, disapprove, or approve with conditions a utility rate filing under RSA 374-G:5 within six months of the date of the filing for an investment that exceeds $1,000,000. RSA 374-G:5, V. Though UES is requesting that the Commission proceed with a bifurcated, two-stage regulatory process in connection with the Kingston Solar Project (which exceeds $1,000,000 in project costs), the Company believes that the Commission must still adhere to the six month timeline for the purposes of determining, in Stage I, that the Kingston Solar Project meets the minimum filing requirements of RSA 374-G and is in the public interest.

28. It is only logical that the six month timeline would apply to Stage I of the proceeding. The statute clearly contemplates that the Commission will make all necessary findings – including the adequacy of a filing, whether a project is in the public interest, and the recovery of project costs through rates – within a period of six months for projects exceeding $1,000,000. In this instance, the Company is requesting only that the Commission "authorize" the Kingston Solar Project in Stage I of the proceeding, and

defer recovery of project costs to a future time after project completion. In other words, UES is not requesting that the Commission make *more* findings than it otherwise would be required to make in a six month time frame under RSA 374-G:5 in Stage I; it is requesting that the Commission make fewer findings. As such, the Commission should render a decision on the Company's filing within six months of the date of this filing.

WHEREFORE, UES respectfully requests that the Commission:

A. Approve a two-stage framework for the Commission's review of UES's proposal to construct, own, and operate the Kingston Solar Project;

B. Find that the Company's filing meets the minimum requirements set forth in RSA 374-G:5, I;

C. Find that the Kingston Solar Project is in the public interest pursuant to RSA 374-G:5, II and authorize construction of the Project;

D. Authorize UES to seek recovery of Project costs in the Company's next base distribution rate case;

E. Approve recovery by the Company of its reasonable costs associated with this filing through the Company's Schedule EDC;

F. Render a decision on the Company's filing within six months of the filing date, consistent with RSA 374-F:5; and

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

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.

By its Attorneys:

Patrick H. Taylor
Chief Regulatory Counsel

Matthew C. Campbell
Senior Counsel

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

Dated: October 31, 2022

**Certificate of Service**

I hereby certify that on this 31st day of October, 2022, a copy of the foregoing Petition was electronically delivered to the New Hampshire Department of Energy and Office of the Consumer Advocate.

Patrick H. Taylor

**UNITIL ENERGY SYSTEMS, INC.**

**DIRECT TESTIMONY**

**OF**

**KEVIN E. SPRAGUE**

**EXHIBIT KES-1**

**New Hampshire Public Utilities Commission**

**Docket No. DE 22-_____**

# Table of Contents

I. INTRODUCTION ........................................................................................................ 1
II. PROJECT OVERVIEW AND OBJECTIVES ........................................................... 4
III. OVERVIEW OF STATUTORY REQUIREMENTS ............................................... 13
IV. COMPLIANCE WITH STATUTORY REQUIREMENTS ..................................... 17
V. PROPOSAL FOR TWO-STAGE REGULATORY REVIEW PROCESS .............. 30
VI. CONCLUSION........................................................................................................ 33

## I. INTRODUCTION

**Q. Mr. Sprague, would you please state your name and business address?**

A. My name is Kevin E. Sprague. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

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

A. I am Vice President of Engineering for Unitil Service Corporation, which is a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal utility subsidiaries, including Unitil Energy Systems, Inc. ("UES" or the "Company"). In this capacity, I manage all of the Company's engineering functions, including electric engineering, gas engineering, computer-aided design and drafting, Geographic Information Systems, and management of utility-owned land and property.

**Q. Please describe your business and educational background.**

A. I have been employed by Unitil Service Corporation for approximately 26 years. I was originally hired as an Associate Engineer in the Electric Distribution Engineering group. I have held the positions of Engineer, Distribution Engineer, Manager of Distribution Engineering, Director of Engineering and now Vice President of Engineering. I accepted the Vice President of Engineering position in January of 2019. I hold a Bachelor of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration degree from the University of New Hampshire.

**Q. Do you have any licenses that qualify you to speak to issues related to engineering?**

A. Yes. I am a registered Professional Engineer in the State of New Hampshire and the Commonwealth of Massachusetts.

**Q. Have you previously testified before the New Hampshire Public Utilities Commission (the "Commission"), or other regulatory agencies?**

A. Yes, I have testified on several occasions before the Commission, the Maine Public Utilities Commission, and the Massachusetts Department of Public Utilities. Most recently, I testified in Docket No. DE 21-030, the Company's distribution rate case; DE 22-026, the Company's Petition for Approval of Step adjustment; DG 21-104, Northern Utilities Inc.'s distribution rate case; and DG 22-020, Northern Utilities Inc.'s Petition for Approval of Step Adjustment.

**Q. What is the purpose of your testimony, and how is it organized?**

A. My testimony summarizes and supports the Company's proposed 4.99 megawatt ("MW") alternating current ("AC" or "ac") utility-scale photovoltaic ("PV" or "solar") generating facility located in Kingston, New Hampshire (the "Kingston Solar Project," or the "Project"). As discussed throughout this filing, the Company seeks the Commission's approval of the proposed Project, which UES will construct, operate, and own pursuant to New Hampshire Revised Statutes Annotated ("RSA") 374-G. Specifically, UES requests:

1. A finding by the Commission that this filing meets the minimum

requirements set forth in RSA 374-G:5, I;

2. A finding that the proposed Kingston Solar Project is in the public interest pursuant to RSA 374-G:5, II; and

3. Approval of the Company's proposed two-stage regulatory review framework.

Section II of my testimony provides an overview of the proposed Kingston Solar Project and the Company's purpose and objectives in undertaking this investment. Section III provides an overview of RSA 374-G and its specific requirements. Section IV explains how the Project meets the requirements of RSA 374-G. Section V describes the Company's proposal for a two-stage regulatory review framework for the Project and Section VI is the conclusion.

**Q. Please identify the witnesses presented by UES in this proceeding and the areas that will be addressed by their testimony.**

A. In addition to my testimony, the Company is submitting testimony, with accompanying exhibits, by the following witnesses:

<u>Jacob S. Dusling (Exhibit JSD-1)</u>: Mr. Dusling is a Principal Engineer for Unitil Service Corporation. Mr. Dusling's testimony presents an overview of the Kingston Solar Project, a description of the process undertaken to select the proposed location for the facility, the competitively procured design, permitting, and construction process the Company intends to use to complete the project, a high-level review of the expected costs and benefits, and an overview of the operational aspects of the Project.

Andre J. Francoeur, Todd R. Diggins, Christopher J. Goulding, and Jeffrey M. Pentz (Exhibit FDGP-1): Mr. Francoeur is the Manager of Financial Planning and Analysis for Unitil Service Corporation. Mr. Diggins is the Treasurer and Director of Finance for Unitil Service Corporation. Mr. Goulding is the Director of Rates & Revenue Requirements for Unitil Service Corporation. And Mr. Pentz is a Senior Energy Analyst with Unitil Service Corporation. The joint testimony and exhibits of Messrs. Francoeur, Diggins, Goulding, and Pentz present the Benefit-Cost Analysis for the Kingston Solar Project, a discussion of the Project's estimated costs and direct benefits, and a calculation of the estimated bill impacts.

Carrie Gilbert and Kevin Pierce (Exhibit GPP-1): Ms. Gilbert is a Managing Consultant with Daymark Energy Advisors ("Daymark") and Mr. Pierce is a Senior Consultant with Daymark. The joint testimony and exhibits of Ms. Gilbert and Mr. Pierce presents a detailed discussion of the estimated indirect benefits derived from the Project and provides a quantification of those benefits.

## II. PROJECT OVERVIEW AND OBJECTIVES

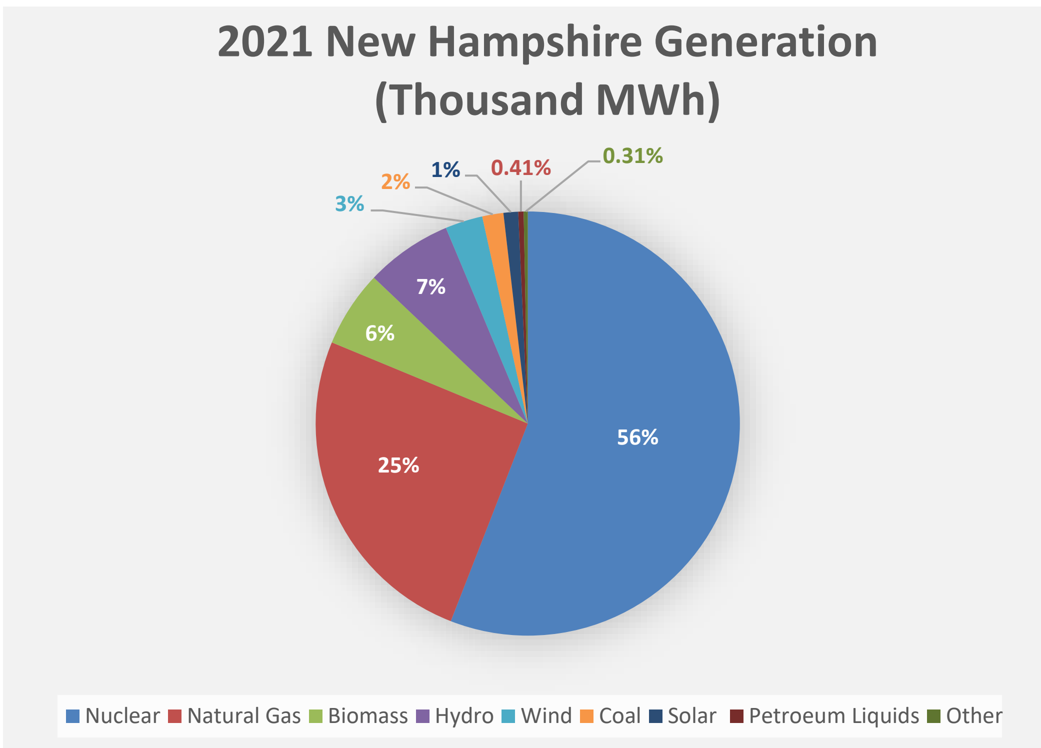
**Q. What is the current state of solar development in New Hampshire?**

A. According to ISO New England ("ISO-NE") there was 157 MWs of solar generation capacity installed in New Hampshire in 2021.[1] Of that amount, the vast majority

[1] ISO-NE, 2022 CELT Report, *available at* https://www.iso-ne.com/system-planning/system-plans-studies/celt.

(136 MWs) was comprised of small capacity, behind-the-meter solar facilities.[2]

As shown in the chart below, solar generation currently represents only a very small portion (1.1 percent) of New Hampshire's electricity generation. Conversely, over half is generated by nuclear energy and approximately 25 percent is generated by natural gas.




*Source: EIA, Electricity Data Browser*[3]

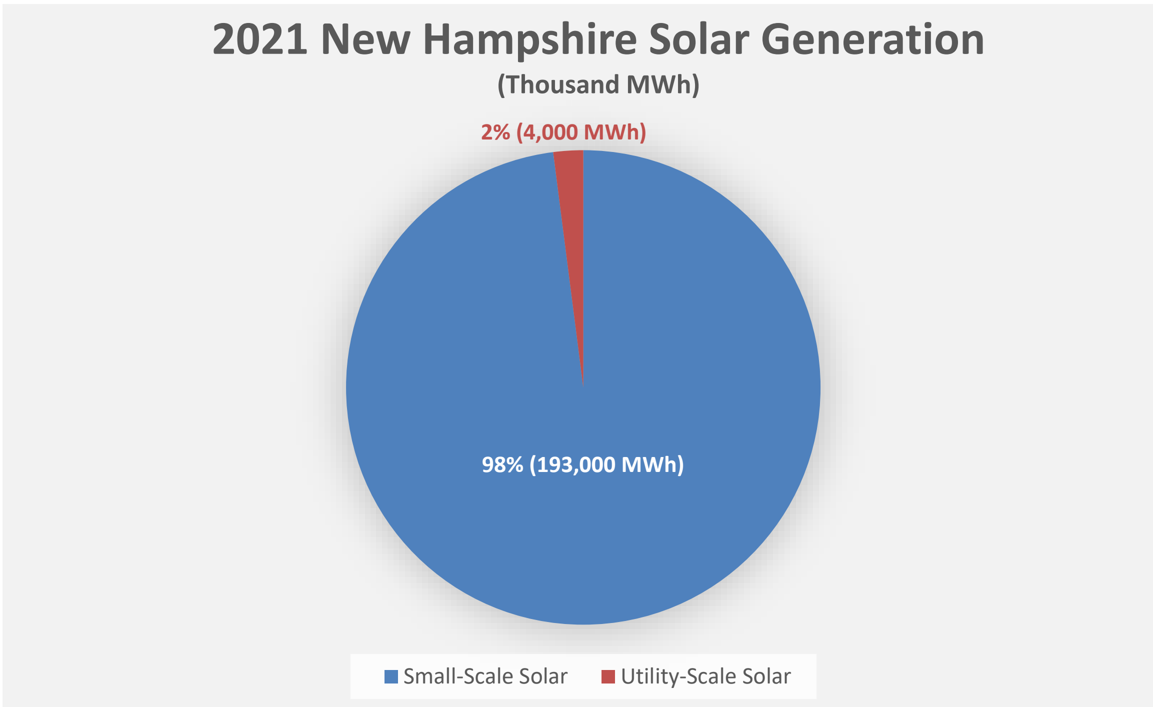
Unsurprisingly, because most of the solar capacity installed in New Hampshire is comprised of small-capacity projects (as noted above), most solar electricity

---

[2] Id.

[3] https://www.eia.gov/electricity/data/browser/

generated (MWh) in the Granite State comes from them.




*Source: EIA, Electricity Data Browser*[4]

Taking a broader view, according to data from the United States Energy Information Administration, New Hampshire ranks 47th among all states (and Washington D.C.) in the amount of electricity produced by large capacity, utility-scale solar projects.[5] In short, New Hampshire has significant untapped potential in the utility-scale solar sector that remains to be unlocked for the benefit of customers.

---

[4] https://www.eia.gov/electricity/data/browser/

[5] EIA, Electricity Data Browser, https://www.eia.gov/electricity/data/browser/ (Net Generation for Utility-Scale Solar). EIA defines utility scale solar as installations with a capacity greater than 1 MW. Through Q2 2022, the Solar Energy Industries Association ("SEIA") ranks New Hampshire 40th out of all 50 states and Washington D.C., for solar development. SEIA, Solar State By State, https://www.seia.org/states-map.

**Q. How does the cost of small capacity, behind-the-meter solar compare with large, utility scale projects?**

A. One of the goals set forth in the Department of Energy's ("DOE") Ten-Year Energy Strategy for New Hampshire ("Energy Strategy") is to achieve environmental protection that is cost-effective and promotes economic growth.[6] According to DOE's Energy Strategy, the cost of new utility-scale solar has fallen by 90 percent in the last 12 years.[7] And as of 2021, the "all in" unsubsidized cost of utility-scale solar is significantly less than the estimated cost for small capacity rooftop solar projects.[8] Thus, generally speaking, utility-scale PV projects are more cost-effective than small-scale solar installations.

**Q. Why is the Company undertaking the Project at this time?**

A. The Kingston Solar Project supports Unitil Corporation's approach to developing a sustainable future. That approach encompasses a broad set of objectives, including providing superior customer service, affordable rates, and service to our communities; environmental stewardship; a steadfast commitment to safety; and the growth and well-being of our employees. The Company's proposal in this proceeding is an extension of that approach, and a meaningful long-term commitment to addressing New Hampshire's climate objectives in a manner that is

[6] DOE, New Hampshire 10-Year Energy Strategy at 7, 18, 21-22 (July 2022)
[7] DOE, New Hampshire 10-Year Energy Strategy at 47, 51 (July 2022).
[8] DOE, New Hampshire 10-Year Energy Strategy at 46 (July 2022) citing Lazard, "Lazard's Levelized Cost of Energy Analysis – Version 15.0".

cost-effective and enables economic growth.

Utility-scale renewable energy projects provide tangible benefits to customers, the electric distribution system, and the environment. These benefits include reductions to purchased energy, peak demand and lines losses, and offsets to greenhouse gas (“GHG”) emissions that otherwise would be emitted from the burning of fossil fuels.

As I noted above, utility-scale solar is more cost-effective than small capacity, residential PV installations. Also, solar projects developed and owned by regulated utility companies provide transparency to regulators and other stakeholders in terms of development and construction costs, and allow customers to receive benefits that otherwise would flow to a private developer or a tax equity investor.

The Company has core competencies in engineering, electrical design, and interconnection, which can all be brought to bear in the development of a utility-scale solar project for the benefit of customers. In addition, utility-owned solar is an efficient way to deploy solar generation because the Company can cost-effectively procure, finance, and construct large-scale PV facilities.

Lastly, utility-scale solar provides customers that might not otherwise have the financial resources or access to the necessary space to develop a project of their own with the benefits of solar generation.

In summary, the Company is in a unique position to provide customers with the benefits of clean, renewable generation at a lower cost than small capacity, residential installations—which have been the predominant source of solar generation in the Granite State—and deliver benefits that would not otherwise be available if the Project were developed by a private entity.

**Q. Are there any specific factors contributing to the timing of this proposed investment?**

A. Yes. The Inflation Reduction Act ("IRA"), signed into law on August 16, 2022, extends energy investment tax credit ("ITC") for solar electricity production facilities beginning construction **<u>before</u>** January 1, 2025. The ITC solidifies the economics of utility-owned solar projects by increasing the overall benefit flowing to customers.

As discussed in the testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz, the Company has modeled the ITC as a credit to customers on a ratable basis over the projected life the asset. However, the Company continues to explore options to maximize the value of the ITC for customers. For example, the IRA authorizes taxpayers to transfer the ITC to other taxpayers in exchange for cash. This structure could potentially reduce the amount of capital that UES would otherwise include in rate base, which in turn would increase the Project's already positive benefits to customers.

**Q. Does the Company have experience in developing utility-scale solar projects?**

A. Yes. The Company has a demonstrated track record of developing utility-scale solar. The Company's affiliate, Fitchburg Gas and Electric Light Company ("FG&E"),

developed a 1.3 MW solar generating facility, consisting of over 3,700 solar panels, on FG&E property located at 115 Sawyer Passway in Fitchburg Massachusetts (the "Sawyer Passway Project").

In August 2016, the Company petitioned the Massachusetts Department of Public Utilities ("MDPU") for approval of the Sawyer Passway Project pursuant to G.L. c. 164, § 1A(f).[9] FG&E, the Attorney General of Massachusetts, and the Low-Income Weatherization and Fuel Assistance Program Network entered into a settlement agreement for approval of the Sawyer Passway Project, which the MDPU approved on November 9, 2016. The Sawyer Passway Project began generating electricity on November 22, 2017 and the facility has been operating as designed, and providing benefits to our Massachusetts customers since then.

**Q. Please provide an overview of the Kingston Solar Project.**

A. The proposed Project is a 4.99 MWac utility-scale solar generating facility that will be located at 2 Mill Road in Kingston, New Hampshire.[10] This property is located adjacent to the Company's Kingston substation. The Company plans to deploy single axis tracking technology[11] and the Project's annual energy output is expected

---

[9] The MDPU docketed this matter as D.P.U. 16-148.

[10] As discussed in the testimony of Mr. Dusling, the estimated direct current capacity for the Kingston Solar Project is 6.15 MW.

[11] Single-axis solar trackers rotate on a single point over the course of the day, adjusting the position of the solar modules to track the sun from east to west. Single axis tracker technology increases energy production, and the attendant benefits, compared to a fixed-tilt solar system.

to average 8,904 MWh over the life of the project, at an assumed capacity factor[12] of approximately 22 percent.

As demonstrated throughout this filing, the Project's benefits outweigh its costs, and it is in the public interest. The Project will generate revenues and credits from renewable energy certificates ("RECs") and the federal ITC, all of which will accrue to the Company's customers. The Project also will generate additional tax revenue for the local community and environmental benefits for all customers, and the State, in the form of reduced GHG emissions.

In addition, the Company plans to operate the Kingston Solar Project as a "load reducer," which means the Project's electric generation output will be delivered directly into the UES electric distribution system. In that respect, the Project will not participate in the ISO-NE wholesale market.[13] As a result, the Kingston Solar Project will yield benefits to customers by reducing energy received by UES from the transmission system for a given level of customer demand, thereby reducing overall supply and transmission costs. As such, the Kingston Solar Project will be a valuable asset in the context of the Company's overall transmission and

[12] As discussed in the testimony of Mr. Dusling, capacity factor is the ratio of actual electrical energy produced by a generating unit to the electrical energy that could have been produced at continuous full power operation during the same period.

[13] ISO-NE's Operating Procedure No. 14 allows any generating facility with a nameplate capacity between one to five megawatts to operate as a load reducer in the region as long as the facility does not participate in any ISO-NE markets. ISO New England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (Effective May 13, 2022).

distribution strategy. The Company provides a more detailed discussion of these transmission and distribution benefits in the testimony of Mr. Dusling and a quantification of these benefits in the testimony and accompanying exhibits of Messrs. Francoeur, Diggins, Goulding, and Pentz.

**Q. Could this investment defer any distribution or transmission project investment?**

A. Yes, the added capacity of the Project will have the effect of deferring the next capacity addition. However, in the short term, it is not designed to directly defer transmission or distribution investment. Siting a utility-scale PV facility involves balancing two competing interests: (1) constructing the facility closer to the source substation (thereby reducing interconnection costs), and (2) locating the facility further out on the distribution system where a capacity constraint may exist (thereby increasing interconnection costs). In this case, the Project is located directly adjacent to UES's Kingston Substation, which minimizes the cost for interconnection, and the costs of the Project overall. The Benefit-Cost Analysis presented in the joint testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz does not include any estimated benefit for deferring capital investment.

**Q. Has the Company conducted a Benefit-Cost Analysis to determine whether the benefits of the proposed investment are greater than the costs?**

A. Yes. As discussed in the joint testimony of Messrs. Francoeur, Diggins, and Goulding, and Pentz, and shown in Exhibit FDGF-2, Schedule 1, the present value of the project's direct benefits is approximately $17.73 million and the present value of the costs is approximately $16.31 million. This produces a Benefit-Cost ratio of 1.09, which demonstrates that this is a sound investment and in the best interest of customers. When indirect benefits are also considered, those (indirect) benefits further enhance the Project's viability.

## III. OVERVIEW OF STATUTORY REQUIREMENTS

**Q. Would you please provide an overview of RSA 374-G.**

A. The New Hampshire General Court enacted RSA 374-G to encourage public electric utilities to invest in Distributed Energy Resources ("DERs"), which can increase overall energy efficiency and provide energy security and diversity to New Hampshire's electricity supply by eliminating or displacing traditional fossil fuels.[14]

The law permits utilities to own electric generation equipment, including solar generation, with a limit of 5 MW on individual projects and a total cap on deployments at 6 percent of the utility's peak load in megawatts.[15] RSA 374-G

[14] RSA 374-G:1.
[15] RSA 374-G:2(I)(b), (d); RSA 374-G:4.

further provides that the purposes of a solar generation project include, but are not limited to, reducing line losses, supporting voltage regulation, or peak load shaving, as part of a strategy for minimizing transmission and distribution costs.[16] In addition, the energy produced by a solar generation project must be used for one of the following three purposes: (1) to benefit low-income customers, (2) as an offset to distribution system losses or the utility's own use, or (3) any other use as approved by the Commission.[17]

Utilities are authorized to recover their investment in DERs through base distribution rates, provided the Commission determines the investment is in the "public interest."[18] Utilities are also authorized to recover all reasonable costs associated with filing for approval of a proposed DER project.[19]

**Q. Have there been any DER investments proposed and approved pursuant to RSA 374-G?**

A. Although the statute has been used sparingly, there are two examples of DER projects that have been proposed and approved by the Commission pursuant to RSA 374-G. UES was the first public utility to propose DER projects pursuant to RSA 374-G.

---

[16] RSA 374-G:2(I)(b). In accordance with this provision, the Company is seeking recovery for the costs associated with filing for approval of the Kingston Solar Project through Schedule EDC.

[17] RSA 374-G:3, I.

[18] RSA 374-G:5, II, III.

[19] RSA 364-G:5, III.

In 2009, UES filed for approval to develop three DER projects pursuant RSA 374-G: (1) a solar water heating system; (2) a 39 kW solar PV facility; and (3) a combined 100 kW solar PV facility and 65 kW micro-turbine.[20] UES later withdrew the proposed solar water heating system from the case and the 39 kW solar PV facility was not approved because, among other things, its benefit/cost ratio (0.52 with only direct benefits and 0.84 including indirect benefits) was found to be too low.[21] The Commission found the combined solar PV-micro-turbine project to be in the public interest and approved it.[22]

More recently, in 2017, Granite State Electric Corp. d/b/a Liberty Utilities ("Liberty") filed the second proposal pursuant to RSA 374-G, and requested approval of a battery storage pilot program designed to achieve customer savings through peak load reductions. On January 17, 2019, the Commission approved Liberty's proposal (subject to certain conditions and limitations) as part of a settlement agreement.[23]

**Q. Does RSA 374-G provide specific criteria that the Commission must consider to determine if a DER project is in the "public interest"?**

A. Yes. Section II of RSA 374-G:5 provides that in determining whether a proposed DER project is in the public interest, the Commission must give balanced

---

[20] DE 09-137, Order No. 25,111, at 7, 8, 11, 37.

[21] DE 09-137, Order No. 25,111, at 11, 37.

[22] DE 09-137, Order No. 25,111, at 37; Attachment 2 of 2. Unitil invested approximately $200,000 in the 100 kW solar array located at a high-school in Exeter. *Unitil Invests in the Community through Exeter Solar Array*, https://unitil.com/news/unitil-invests-community-through-exeter-solar-array.

[23] DE 17-189, Order No. 26,209, at 39-40.

consideration and proportional weight to the following nine factors:

a. The effect on the reliability, safety, and efficiency of electric service;
b. The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3;
c. The energy security benefits of the investment to New Hampshire;
d. The environmental benefits of the investment to the state of New Hampshire;
e. The economic development benefits and liabilities of the investment to New Hampshire;
f. The effect on competition within the region's electricity markets and the state's energy services market;
g. The costs and benefits to the utility's customers, including but not limited to a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project;
h. Whether the expected value of the economic benefits of the investment to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers; and
i. The costs and benefits to any participating customer or customers.

**Q. Does RSA 374-G set forth any additional requirements for seeking rate recovery for DER investments?**

A. Yes. Section I of RSA 374-G:5 provides that, at a minimum, the filing must include the following seven elements:

a. A detailed description and economic and environmental evaluation of the proposed investment;
b. A discussion of the costs, benefits, and risks of the proposal with specific reference to the nine public interest factors, including an analysis of the costs, benefits, and rate implications to the participating customers, to the company's default service customers, and to the utility's distribution customers;
c. A description of any equipment or installation specifications, solicitations, and procurements it has or intends to implement;
d. A showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers;
e. A showing that it has made reasonable efforts to involve local businesses in its program;

f. Evidence of compliance with any applicable emission limitations; and
g. A copy of any customer contracts or agreements to be executed as part of the program.

## IV. COMPLIANCE WITH STATUTORY REQUIREMENTS

**Q. Does the Company's filing meet the minimum requirements set forth in RSA 374-G:5, I?**

A. Yes, as summarized below and described in the testimonies and exhibits submitted with this filing, the Company's proposal meets each of the seven minimum filing requirements set forth in Section I of RSA 374-G:5.

***RSA 374-G:5, I(a), A detailed description and economic and environmental evaluation of the proposed investment.***

The Company has conducted a detailed Benefit-Cost Analysis, which includes the economic costs and benefits of the Kingston Solar Project as well as the expected environmental benefits. Consistent with this statutory requirement, this "economic and environmental evaluation" is described in Exhibit FDGP-1 and the quantitative analysis is provided as Exhibit FDGP-2. In addition, the Company's consultant (Daymark) has quantified the avoided $CO_2$ and $NO_x$ benefits of the Project in Exhibit GPP-1 and GPP-2.

***RSA 374-G:5, I(b), A discussion of the costs, benefits, and risks of the proposal with specific reference to the nine public interest factors, including an analysis of the costs, benefits, and rate implications to the participating customers, to the company's default service customers, and to the utility's distribution customers.***

As noted above, the Company provides a discussion of the costs and benefits of the Kingston Solar Project in Exhibit FDGP-1 and the accompanying quantitative analysis is presented in Exhibit FDGP-2. The Kingston Solar Project will benefit all customers, including low-income customers who otherwise might not have the means to access the benefits of solar energy.

With regard to risks, the Company has not identified any material risks to the proposal. Utility-scale solar projects are well established and the technology is mature, reliable, proven, and well understood. Also, as noted above, in recent years solar costs have declined significantly.

The Company is aware that supply chain challenges and cost escalation could have an impact on the Benefit-Cost Analysis (Exhibit FDGP-2). The Company has attempted to minimize this risk by working through a competitive bidding process, including a request for information and preliminary request for proposals, to gather the most up to date pricing and schedule information for use in the Benefit-Cost Analysis.

Regarding estimated bill impacts, those are discussed in Exhibit FDGP-1 in Section V and the supporting calculations are presented in Exhibit FDGP-3.

***RSA 374-G:5, I(c), A description of any equipment or installation specifications, solicitations, and procurements it has or intends to implement.***

The Company conducted a competitive request for proposals ("RFP") process to procure the services of a firm to assess potential development sites, conduct site due diligence, obtain the necessary permits, and design a "pad-ready" site that will include the specifications and construction requirements for tree clearing, access road construction, drainage, and final site grading.

The Company issued a Request for Information ("RFI") in February 2022. In response, several engineering, procurement, and contracting ("EPC") bidders provided descriptions of equipment and installation examples of layout, design, and construction packages. The Company used this information to perform a preliminary analysis to determine the feasibility of the Project.

The Company then issued a Preliminary RFP in September 2022 to obtain updated, detailed cost estimates for this filing, which are reflected in the testimony and exhibits presented by Messrs. Francoeur, Diggins, Goulding, and Pentz.

The Company plans to issue a "Civil Construction RFP" for a contractor to make the site "pad-ready," which includes tree clearing, access road construction, drainage, and final site grading.

The Company will issue a Final RFP to select an EPC contractor to construct the facility if the Commission finds that the Kingston Solar Project is in the public interest in this first stage.

Mr. Dusling's testimony (Exhibit JSD-1) provides additional detail regarding both completed and future, planned procurements and describes the equipment the Company intends to install as part of the Kingston Solar Project.

***RSA 374-G:5, I(d), A showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers.***

This factor overlaps with the preceding criterion in that both focus, in part, on competitive solicitations. As summarized above, and discussed in detail in Mr. Dusling's testimony, the Company conducted a competitive RFP process and procured the services of a firm to assess potential development sites, conduct site due diligence, obtain the necessary permits, and design a "pad-ready" site that will include the specifications and construction requirements for tree clearing, access road construction, a drainage facility, and final site grading. The Company will also issue a "Civil Construction RFP" for a contractor to make the site "pad-ready" and a final RFP for an EPC contractor to build the PV facility.

***RSA 374-G:5, I(e), A showing that it has made reasonable efforts to involve local businesses in its program.***

The Company has contacted the Town of Kingston Select Board to provide an overview of the planned Kingston Solar Project and will continue to engage with the Town of Kingston through design and permitting, and keep local officials apprised of project status.

Through the competitive bidding process, the Company selected TF Moran, a New Hampshire based firm, to assess potential development sites, conduct site due diligence, obtain the necessary permits, and design a "pad-ready" site that will include the specifications and construction requirements for tree clearing, access road construction, drainage, and final site grading.

The Company intends to use local civil and land clearing contractors for the civil portion (e.g., land clearing, grading, etc.) of facility construction. Further, the Company will require all prospective EPC contractors to provide a plan to utilize local employees, suppliers, and contractors to construct the facility.

***RSA 374-G:5, I(f), Evidence of compliance with any applicable emission limitations.***

Solar generation does not produce any emissions and therefore this requirement is not applicable to the Company's planned Kingston Solar Project.

***RSA 374-G:5, I(g), A copy of any customer contracts or agreements to be executed as part of the program.***

There are no customer contracts to be executed as part of the Company's proposed Project. The Company views this as a favorable structure because customers do not need to affirmatively enter into contracts, and assume the attendant duties and obligations, in order to receive the benefits produced by the Kingston Solar Project.

The Company plans to operate the Kingston Solar Project as a load reducer, meaning the energy produced by the facility will be delivered directly into the Company's electric distribution system and used to reduce energy received by UES from the transmission system. The Project will generate RECs that will be used to meet Electric Renewable Portfolio Standard ("RPS") obligations or sold into the market.[24] As discussed in the joint testimony of Messrs. Francoeur, Diggins, Goulding and Pentz, revenues received from the sale of the project's RECs will be credited to all customers.

**Q. Does the proposed Kingston Solar Project meet the public interest standard set forth in RSA-G:5, II?**

A. Yes, as summarized below, and presented in the other testimonies and exhibits in the Company's filing, the Kingston Solar Project meets each of the nine public interest factors set forth in Section II of RSA 374-G:5.

***RSA 374-G:5, II(a), The effect on the reliability, safety, and efficiency of electric service.***

One of the goals set-forth in DOE's Ten-Year Energy Plan is to ensure a secure, reliable, and resilient energy system.[25] Consistent with this goal, the Company is committed to ensure that its customers continue to receive high quality, safe, and reliable electric service. As discussed in the testimony of Mr. Dusling, the Company will take all appropriate steps to ensure the Kingston Solar Project does not adversely impact the reliability, efficiency, and safety of electric service. The Company will complete a System Impact Study to identify any system improvements required to ensure the safe and reliable interconnection of the Project with the Company's distribution system. A System Impact Study is a standard

---

[24] New Hampshire's RPS statute, RSA 362-F, requires each electricity provider to meet customer load by purchasing or acquiring certificates representing generation from renewable energy based on total megawatt-hours supplied.

[25] DOE, New Hampshire 10-Year Energy Strategy at 47, 51 (July 2022).

approach for any facility of this size interconnecting with the Company's distribution system.

The Company also intends to install protective devices at the point of interconnection to determine whether any additional protection upgrades/relays are necessary, and to ensure all system components are compliant with industry standards, applicable codes and safety standards.

The Company is confident, through its experience with its utility scale solar installation in Massachusetts as well as the many customer-owned solar facilities connected to the distribution system, that the Kingston Solar Project will be operated in a safe, reliable and efficient manner.

***RSA 374-G:5, II(b), The efficient and cost-effective realization of the purposes of the renewable portfolio standards of RSA 362-F and the restructuring policy principles of RSA 374-F:3.***

The General Court described the objectives of the state's renewable portfolio standard as "displac[ing] and thereby lower[ing] regional dependence on fossil fuels," which "has the potential to lower and stabilize future energy costs by reducing exposure to rising and volatile fossil fuel prices." RSA 362-F:1. The General Court further stated that "employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change." Id. The Kingston Solar Project is consistent with these purposes because it will displace fossil fuel generation with clean renewable electricity, reduce GHG emissions, and help mitigate against the risk of climate change.

Also, with regard to RSA 362-F, and the state RPS in particular, the Project will generate Class II RECs, which supports the REC market. As explained in the testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz, revenues from the sale of RECs will be credited to all customers.

With regard to restructuring policy principles, the Kingston Solar Project plainly advances the principles of environmental sustainability and improvement (RSA 374-F:3, VIII), and increased use of cost-effective renewable energy technologies (RSA 374-F:3, IX). As proposed, the Project does not interfere with customer choice (RSA 374-F:3, II), and benefits all consumers equitably (RSA 374-F:3, VI). The Project is also, as discussed above, consistent with a strategy for minimizing transmission and distribution costs (RSA 374-F:3, III).

***RSA 374-G:5, II(c), The energy security benefits of the investment to New Hampshire.***

Reduced reliance on fossil fuels furthers the objective of energy security because solar generation—once constructed—is not subject to volatile fuel prices, such as natural gas.

Natural gas is the predominant fuel used for electric generation in New England, representing 53 percent of the electricity produced in 2021.[26] Consequently, the price of natural gas sets the electricity market price most of the time in ISO-NE. Volatile natural gas prices, particularly in the winter, have an immediate effect on wholesale electricity prices, and due to constrained pipeline capacity into the New England region and the resulting dependence on imported liquefied natural gas, natural gas prices are likely to remain volatile unless and until regional supply and demand for natural gas comes more into balance.[27]

Furthermore, as I discussed above, more than 80 percent of New Hampshire's generation fleet is comprised of nuclear and natural gas resources. The addition of more solar generation capacity expands the Granite State's portfolio of renewables and enhances the fuel and technology diversity of the State's generation fleet.[28]

***RSA 374-G:5, II(d), The environmental benefits of the investment to the state of New Hampshire.***

The New Hampshire legislature has recognized that renewable energy projects, like the Kingston Solar Project, "reduce the amount of greenhouse gases, nitrogen

---

[26] ISO-NE, ISO Newswire, September 2, 2022, https://isonewswire.com/2022/09/02/monthly-wholesale-electricity-prices-and-demand-in-new-england-july-2022/#:~:text=Natural%20gas%20is%20the%20predominant,wholesale%20electricity%20in%20the%20region.

[27] "The second half of 2021 and first half of 2022 saw dramatic increases in the price of natural gas for a variety of reasons, including lower US domestic production because of the COVID-19 pandemic, national energy policy, increased European demand due to lower than average reserves due to a longer and colder 2020 winter, poor performance of renewable resources due to weather, the Russian invasion of Ukraine, and increased demand from China as it shifts away from its reliance on coal. Taken all together, these factors are placing enormous upward pressure on natural gas prices. The US spot market price in May 2022 increased by 208% over the pre-pandemic May 2019 spot price." DOE, New Hampshire 10-Year Energy Strategy at 39 (July 2022) (citations omitted).

[28] "Having a diverse resource mix can help ensure a secure, reliable, and resilient energy system." DOE, New Hampshire 10-Year Energy Strategy at 39 (July 2022).

oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change." RSA 362-F:1. The Company has quantified the expected environmental benefits from the Kingston Solar Project, and as discussed in the joint testimony of Ms. Gilbert and Mr. Pierce, the Project is expected to displace 57,300 tons of $CO_2$ emissions over the expected life of the Project. These are significant environmental benefits for the state of New Hampshire.

***RSA 374-G:5, II(e), The economic development benefits and liabilities of the investment to New Hampshire***

The Kingston Solar Project will generate economic benefits for the state of New Hampshire in a variety of ways. First, as discussed in the testimony of Mr. Dusling, the Project has already generated economic benefits by virtue of the Company's engagement of several New Hampshire-based firms to assist in the development process: TF Moran Inc. (land planning, permitting, and civil engineering - Bedford, NH); Capital Appraisal Associates, Inc. (land appraisal – Concord, NH); and Ransmeier & Spellman, P.C. (title examinations – Concord, NH). Second, the Company has entered into a Purchase & Sale Agreement for property located in the town of Kingston, New Hampshire and the productive reuse of that land for purposes of the Kingston Solar Project will generate economic benefits for all UES customers. Third, the Project is expected to generate significant property tax revenues (approximately $6.1 million over the life of the project) for the town of Kingston, and property taxes represent a major source of revenue for most New Hampshire municipalities. Fourth, as Mr. Dusling explains in his testimony, UES intends to use local civil and land clearing contractors for construction of the "pad-ready" site for the project. Fifth, the Company expects to award the electrical interconnection work to a local line contractor following an RFP process. Sixth, the Project will encourage other utility-scale solar projects by demonstrating that a large-scale solar facility can be cost-effectively constructed for the benefit of customers by a New Hampshire utility company pursuant to RSA 374-G.

In addition to all of these economic benefits, the Company's consultant, Daymark, has performed a quantitative analysis of the indirect economic benefits that will be generated by the Kingston Solar Project, which is described in Exhibits GPP-1 and GPP-2. As discussed in those Exhibits, the Project will generate approximately $11.2 million in direct, indirect, and induced economic impacts on a present value basis. In addition, Daymark estimates the Project can be expected to support approximately 87 direct, indirect, and induced jobs in the State through the projected 30-year operational life.

Apart from the costs of the project, which are outweighed by the benefits as shown in Exhibit FDGP-2, the Company has not identified any liabilities associated with the Kingston Solar Project.

***RSA 374-G:5, II(f), The effect on competition within the region's electricity markets and the state's energy services market.***

As discussed above, the Company plans to operate the Kingston Solar Project as a "load reducer" and the electric generation output will be delivered directly into the

UES electric distribution system. By operating as a load reducer, the Project will not participate in the ISO-NE wholesale market. Therefore, the Kingston Solar Project will have no effect on competition in the region's electricity market. At the retail level, as explained in the testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz, the benefits of reduced supply and transmission costs and the revenue from REC sales will accrue to all customers regardless of whether the customer relies on Default Service supply or purchases their supply from a Competitive Electric Power Supplier. Thus, the Project will have no negative impact on the State's energy services market.

With regard to the competitive market for utility-scale solar, as I noted above there has been relatively little utility-scale solar development in the New Hampshire market to date. Therefore, the Kingston Solar Project will not impede the market for utility-scale solar generation and, in fact, may help stimulate additional solar development.

***RSA 374-G:5, II(g), The costs and benefits to the utility's customers, including but not limited to a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project.***

The joint testimony and exhibits presented by Messrs. Francoeur, Diggins, Goulding, and Pentz provide a comprehensive discussion and analysis of the projected costs and direct benefits of the project to the Company's customers. The testimony and exhibits presented by Ms. Gilbert and Mr. Pierce provide a comprehensive discussion and analysis of the estimated indirect benefits of the Kingston Solar Project.

As discussed in Exhibit FDGP-1, the direct benefits of the project include avoided energy costs, RECs, avoided capacity costs, and avoided costs of regional and local transmission charges. As discussed in Exhibit GPP-1, the indirect benefits of the Project include the avoided cost of $CO_2$ and NOx, demand reduction induced price effects ("DRIPE"), and economic development benefits.

The costs of the Kingston Solar Project include the capital investment costs for the PV facility installation and electric system upgrades, expenditures for site work and permitting, and land costs.

As discussed in the testimony of Mr. Dusling, the Company has employed competitive processes to reasonably minimize the costs of the Kingston Solar Project. I summarized these processes above in discussing the Company's compliance with RSA 374-G:5, I(c).

***RSA 374-G:5, II(h), Whether the expected value of the economic benefits of the investment to the utility's ratepayers over the life of the investment outweigh the economic costs to the utility's ratepayers.***

This factor overlaps with the preceding criterion in that they both focus on the Benefit-Cost Analysis. As discussed in the joint testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz, the Company has estimated the costs and benefits of the Kingston Solar Project over the 30-year projected life of the Project and discounted those estimates to calculate their present value so they may compared and a benefit-cost ratio can be calculated. As shown in Exhibit FDGP-2, the present value of the project's direct benefits is approximately $17.73 million and the present value of the costs is approximately $16.31 million. This produces a Benefit-Cost ratio of 1.09, which demonstrates that this is a sound investment and in the best interest of customers. When indirect benefits are considered, the Project's economics are further improved. As discussed in Exhibits GPP-1 and GPP-2, Daymark has estimated, on an NPV basis, economic benefits of $11.2 million, $CO_2$ and NOx savings of $1.8 million, and DRIPE benefits of $566,963.

***RSA 374-G:5, II(i), The costs and benefits to any participating customer or customers.***

This factor overlaps with the two preceding criteria (RSA 374-G:5, II(g) and RSA 374-G:5, II(h)), in their common focus on the Benefit-Cost Analysis. As noted earlier, the Company has provided a comprehensive description of its Benefit-Cost Analysis in Exhibit FDGP-1 and presented its Benefit-Cost Analysis as Exhibit FDGP-2. The Company's Benefit-Cost Analysis demonstrates the Kingston Solar Project is expected to result in an overall positive net present value over its life.

The Company did not perform a Benefit-Cost Analysis for any particular subset of customers because the Kingston Solar Project is designed to benefit all UES customers. The Company has provided a Bill Impact analysis in Exhibit FDGP-3 for all customer classes.

## V. PROPOSAL FOR TWO-STAGE REGULATORY REVIEW PROCESS

**Q. What direction does RSA 374-G provide with respect to the regulatory process the Commission should follow in its review of DER projects?**

A. As noted above, Section I of RSA 374-G:5 establishes the minimum information required in a utility filing and Section II sets forth the elements to be considered in the Commission's public interest determination. Section III of RSA 374-G:5 provides that "authorized" and prudently incurred investments shall be recovered in a utility's base distribution rates as a component of rate base, and cost recovery shall include the recovery of depreciation, a return on investment, taxes, and other operating and maintenance expenses directly associated with the investment, net of any offsetting revenues received by the utility directly attributable to the investment.

**Q. Does the structure of RSA 374-G:5 suggest an efficient regulatory review process?**

A. Yes. Because only "authorized" investments are recoverable through rates, it is reasonable to bifurcate the "authorization" of the investment and the rate recovery proceeding into separate stages. In Stage I (this proceeding), the Commission would review the Company's petition to determine whether it meets the minimum filing requirement of RSA 374-G:5, I and the public interest showing required by RSA 374-G:5, II. Assuming the Commission finds this petition meets the requirements of RSA 374-G:5, the Company would to proceed with the Kingston Solar Project. In Stage II, the Company would file to recover the cost of the Project in rates pursuant to 374-G:5, III. As discussed in Exhibit FDGP-1, the Company plans to request rate recovery in the context of its next base distribution rate case or in a subsequent step adjustment.

**Q. Is there precedent for a two-stage review process?**

A. Yes. As I noted above, on August 5, 2009, UES filed the first proposal with the Commission pursuant RSA 374-G to develop three DER projects.[29] Similar to the Company's proposal in the instant docket, UES petitioned the Commission for approval of a two-stage regulatory review process. Stage I would focus on whether the proposed DER projects were in the public interest (i.e., approval of the proposed projects). And if the Commission found the projects to be in the public interest, UES would file to recover the costs and expenses related to the DER projects in Stage II (i.e., review and approval of cost recovery).[30] The Commission approved the two-stage regulatory review process proposed by UES, finding RSA 374-G does not preclude this framework and it is in the public interest.[31]

---

[29] *Unitil Energy Systems, Inc.*, DE 09-137, Order No. 25,111 (June 11, 2010).

[30] In DE 09-137, UES proposed to recover costs and expenses through a fully reconciling distribution charge—the DER Investment Charge (or "DERIC")—billed to all customers taking delivery service. The Company proposed to establish the DERIC annually based on a forecast of costs and any over or under-recoveries in the prior year would be reconciled with interest. The Commission denied UES's proposed reconciling mechanism and adopted Staff's recommendation to recover actual project costs through an annual step adjustment to base distribution rates. Order No. 25,111 at 38.

[31] Order No. 25,111, at 32.

## VI. CONCLUSION

**Q. Please restate what the Company is asking the Commission to approve in this proceeding.**

A. Pursuant to RSA 374-G, it is the public policy of New Hampshire that utilities should be encouraged to make investments in DERs. As demonstrated in this filing, the Kingston Solar Project meets the minimum filing requirements and the public interest standard set forth in RSA 374-G. Accordingly, the Company respectfully requests that the Commission find:

1. The Company's filing meets the minimum requirements set forth in RSA 374-G:5, I;
2. The Kingston Solar Project is in the public interest pursuant to RSA 374-G:5, II, and the Company is authorized to proceed with the project; and
3. The two-stage regulatory review framework proposed by the Company is in the public interest and is approved.

**Q. Is the Company requesting a decision from the Commission within a certain timeframe?**

A. Pursuant to RSA 374-G:5, V, the Commission must approve, disapprove, or approve with conditions a utility filing within 90 days. However, the Commission may extend this deadline to 6 months at its discretion for any filing involving an investment in excess of $1 million. In this case, the Company's proposed investment is greater than $1 million and therefore the Company respectfully requests approval within the 6 month statutory timeframe. The Company further notes that time is of essence as factors beyond the Company's control, such as market dynamics and supply-chain issues may impact the Project's costs.

**Q. Please confirm the Company will wait for a finding that the Project is in the public interest before proceeding further with development?**

A. Yes. The Company will not begin site work and construction until the Commission issues an order finding the Kingston Solar Project is in the public interest.

**Q. Does this conclude your testimony?**

A. Yes, it does.

**REDACTED**

**UNITIL ENERGY SYSTEMS, INC.**

**DIRECT TESTIMONY**

**OF**

**JACOB S. DUSLING**

**EXHIBIT JSD-1**

**New Hampshire Public Utilities Commission**

**Docket No. DE 22-_____**

## Table of Contents

I. INTRODUCTION .......... 1
II. OVERVIEW OF PROJECT DEVELOPMENT AND SITE SELECTION PROCESS .......... 2
III. PERMITTING, PROCUREMENT, AND PROJECT CONSTRUCTION APPROACH .......... 9
IV. EXPECTED PROJECT COSTS AND BENEFITS .......... 15
V. PROJECT OPERATIONS .......... 23
VI. CONCLUSION .......... 29

<u>Exhibits</u>

- Exhibit JSD-2: Request for Information
- Exhibit JSD-3: Request for Proposals – Site Evaluation
- Exhibit JSD-4(a) [CONFIDENTIAL]: Response to Request for Proposals from Selected Vendor – Site Evaluation
- Exhibit JSD-4(b) [CONFIDENTIAL]: Refreshed Pricing – Site Evaluation
- Exhibit JSD-5 [CONFIDENTIAL]: Purchase and Sale Agreement
- Exhibit JSD-6: Preliminary EPC Request for Proposals
- Exhibit JSD-7 [CONFIDENTIAL]: Quote for Appraisal

## I. INTRODUCTION

**Q. Mr. Dusling, would you please state your name and business address?**

A. My name is Jacob S. Dusling. My business address is 30 Energy Way, Exeter, New Hampshire 03833.

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

A. I am a Principal Engineer for Unitil Service Corporation. In this capacity, I have responsibility over system and distribution planning activities as well as reliability planning for Unitil Energy Systems, Inc. ("UES" or the "Company").

**Q. Please describe your business and educational background.**

A. I have been employed by Unitil Service Corporation for approximately 18 years. I was originally hired as an Associate Engineer in the Distribution Engineering group. I have held the positions of Engineer, Distribution Engineer, Design Engineer, and Senior Engineer. I hold a Bachelor of Science in Electric Engineering from the University of New Hampshire and a Master of Science in Power Systems Management from Worcester Polytechnic Institute.

**Q. Do you have any licenses that qualify you to speak to issues related to engineering?**

A. Yes. I am a registered Professional Engineer in the State of New Hampshire and the Commonwealth of Massachusetts.

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

A. Yes, I testified before the Commission in DE 20-002, the Company's 2020 Electric LCIRP.

**Q. What is the purpose of your testimony and how is it organized?**

A. The purpose of my testimony is to describe the Company's proposal to construct, own, and operate a 4.99 megawatt ("MW") utility-scale photovoltaic ("PV" or "solar") generating facility in Kingston, New Hampshire (the "Kingston Solar Project" or the "Project"). Section II of my testimony provides an overview of the proposed Project and a description of the process undertaken to select the location for the facility. Section III describes the design, permitting, and construction process the Company intends to use to complete the Project. Section IV provides a discussion of the expected Project costs and benefits. Section V provides an overview of the operational aspects of the Project, and Section VI is the conclusion.

## II. OVERVIEW OF PROJECT DEVELOPMENT AND SITE SELECTION PROCESS

**Q. Please provide an overview of the proposed project.**

A. As discussed in the testimony of Mr. Sprague (Exhibit KES-1), the New Hampshire General Court enacted Revised Statute Annotated ("RSA") 374-G to encourage public electric utilities to invest in Distributed Energy Resources ("DERs"), which can increase overall energy efficiency and provide energy security and diversity to

New Hampshire's electricity supply by eliminating or displacing traditional fossil fuels. Pursuant to RSA 374-G, the Company proposes to construct a 4.99 MW alternating current ("AC" or "ac") utility-scale solar generating facility that will be located at 2 Mill Road / 24 Towle Road in Kingston, New Hampshire. The Kingston Solar Project's annual energy output is anticipated to average 8,904 MWh over its expected 30-year life, at an assumed capacity factor of approximately 22 percent. At that level of output, the Project is expected to offset 57,300 tons of $CO_2$ emissions.

**Q. Please describe the process the Company used to identify and select the Kingston Solar Project site.**

A. The Company undertook a comprehensive, multi-step process to identify a suitable site for the Kingston Solar Project.

First, the Company used internal resources to review all of its parcels to determine whether there were any sites already owned by Unitil that would be suitable for PV development. Based on that review, UES identified two possible Company-owned sites for development. Those sites, however, ultimately were deemed unsuitable for PV development based on further evaluation by an outside contractor (as discussed below).

Second, consistent with the requirements of RSA 374-G:5, I(d)[1] and 374-G, II(g),[2] the Company issued a Request for Proposals ("RFP") on January 28, 2022, for a firm to assess the two Company-owned parcels identified for PV development, as well as private and municipally owned property within the Company's service territory that could be suitable for PV development ("Site Assessment RFP"). The scope of work for the Site Assessment RFP also included: (1) ranking potential properties based on their ability to support a PV facility; (2) providing a detailed assessment and developing a preliminary layout for the top ranked parcel(s); (3) developing final site plans once the final location for the PV facility is selected by the Company; (4) assisting UES in the construction permitting process; and (5) providing construction oversight and permit compliance of the site work. UES received responses to the Site Assessment RFP on February 25, 2022 from four bidders. The Company selected TF Moran, Inc. ("TFM") as the winning bidder. TFM is a New-Hampshire based Land Planning firm specializing in Civil Engineering and Structural Engineering. The Site Assessment RFP and TFM's response are attached as Exhibits JSD-3 and JSD-4(a) (CONFIDENTIAL), respectively.[3]

---

[1] RSA 374-G:5, I(d) requires a showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers.

[2] RSA 374-G, II(g) is one of the public interest factors that must be considered by the Commission and includes, among other thing, a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project.

[3] The Company asked TFM to refresh its pricing once the location for the Kingston Solar Project was identified. The refreshed pricing submitted by TFM is provided as Exhibit JSD-4(b) (CONFIDENTIAL).

Once the work was awarded, TFM began its review with a list of parcels in the Company's service territory at least ten acres in size and within one quarter mile of UES's subtransmission system, or at least five acres in size and within one hundred feet of a three-phase 34.5 kV distribution line. The Company's geographic information system team generated this list, which included the two Company-owned sites noted above. TFM performed a screening to narrow down this list based on an initial environmental assessment (e.g., determining whether a parcel was situated in floodplains, wetlands) and topology review (e.g., the slope/degree of inclination of a parcel), among other considerations. This screen yielded a targeted list of sites, which TFM provided to UES. UES evaluated this targeted list of sites based on their interconnection locations relative to the electric system. Following that review, the list was narrowed down to approximately 25 potential sites.

Next, on behalf of UES, TFM engaged a real estate firm to determine the status of the privately owned parcels on the short-list, including whether the parcel was on the market and whether it had been recently sold (in which case it may be less likely to be sold again in the near term). Following that review, the 2 Mill Road parcel in Kingston was identified as being on the market and meeting all the viability criteria applied by the Company and TFM in the site screening process.

**Q. Has Unitil purchased the land for the Kingston Solar Project?**

A. Unitil Realty Corporation, an unregulated subsidiary of Unitil Corporation, entered into a Purchase and Sale Agreement (the "P&S Agreement") on August 25, 2022 for the Kingston Solar Project site. The P&S Agreement is attached as Exhibit JSD-5 (CONFIDENTIAL). The P&S Agreement is related to two parcels, both located in Kingston, New Hampshire. The Kingston Solar Project will be located on one of the two parcels, with the second parcel reserved for future development. The site due diligence process includes a determination of which portion of the property will be used for the Kingston Solar Project.

The purchase price for the two parcels is [redacted]. For purposes of its Benefit-Cost Analysis (Exhibit FDGP-2), the Company assumed that 50 percent of this cost is allocated to the Kingston Solar Project, because it will be located on only a portion of the property. Until Realty Corporation will transfer the parcel ultimately used for the Kingston Solar Project to UES and retain the remaining parcel for future development.

As shown in Exhibit JSD-5 (CONFIDENTIAL) at pages 3 and 5, the P&S Agreement is contingent upon:

- Title Examination
- Property Appraising at or above Purchase Price
- Site Due Diligence, including:
    - Environmental Assessment
    - Archeological Assessment
    - Rare & Endangered Species Studies
    - Full Site Engineering and Site Plan Development
    - All Necessary Construction Permits Received

**Q. With regard to the site due diligence items you identified above, please identify the status of that due diligence (<u>i.e.</u>, items that are complete and the expected timing to complete any remaining items).**

A. The site due diligence began shortly after Unitil Realty Corporation entered into the P&S Agreement. All items associated with the due diligence process are currently ongoing.

A title examination is being performed by Ransmeier & Spellman, P.C. ("R&S"), a general practice law firm with a real estate practice located in Concord, New Hampshire. The Company typically uses the services of R&S for land-related legal work such as title examinations. The title examination is expected to be completed by the end of November 2022.

The Company has retained Capital Appraisal Associates, Inc. ("Capital Appraisals"), a Concord New Hampshire firm, to perform the property appraisal. The Company has retained Capital Appraisals for other land appraisals in the past. The property appraisal is expected to be completed by the end of November 2022.

The Site Due Diligence is being performed by TFM and is a component of the Site Assessment RFP award described above. The site survey, wetlands delineation and initial site schematic are expected to be complete in November 2022. The initial environmental assessment, archeological assessment, and rare and endangered species review are expected to be complete by the end of November 2022. In the event these initial evaluations identify the need for major permitting or other issues, the Company may extend the Site Due Diligence period by sixty days. All final studies and plans are expected to be completed by the end of 2022 and all construction permits are expected to be received by February 2023 (if the sixty-day extension is not needed and by April 2023 if the extension is exercised).

**Q. Has the Company met with local government officials in the Town of Kingston?**

A. The Company has contacted the Town of Kingston Select Board to provide an overview of the planned Kingston Solar Project. The Company plans to continue to engage with the Town of Kingston through the design and permitting process, and keep local officials apprised of project status through construction and energization.

**Q. Please summarize the Request for Information ("RFI") the Company issued in connection with the Project?**

A. In February 2022, the Company issued an RFI to identify potentially qualified bidders and develop assumptions for the facility site assessment (e.g., area requirements, grade/slope conditions, distance to tree lines) and financial analysis (e.g., equipment and installation cost estimates, typical annual energy production to validate the Company's estimations, anticipated useful life of major components, and efficiency degradation factor of PV modules) needed to assess the viability of constructing a PV facility. In March 2022, the Company received responses from three PV project developers.

The RFI is attached as Exhibit JSD-2.

## III. PERMITTING, PROCUREMENT, AND PROJECT CONSTRUCTION APPROACH

**Q. How does the Company plan to obtain the necessary permitting for the Project?**

A. As discussed above, site permitting is part of the scope of work in the Site Assessment RFP that was awarded to TFM. Accordingly, TFM will be responsible for obtaining all the necessary permits for the site work component of project.

Any necessary permits required for the PV facility itself will be the responsibility of the vendor designing, procuring, and constructing the PV facility.

**Q. What permits does the Company anticipate it will need for the Kingston Solar Project?**

A. The Company anticipates that the following construction applications/permits will be required:

| | |
|---|---|
| **Town of Kingston** | • Zoning Board<br>  o Use Variance<br>• Planning Board<br>  o Site Plan Review<br>• Conservation Commission<br>  o Wetland Dredge and Fill Review<br>  o Wetland Buffer Impact Review |
| **State of New Hampshire** | • NH Natural Heritage Bureau (NHB)<br>  o NHB Data Check<br>• NH Fish & Game<br>  o Wildlife Assessment per Env-Wq 1503.19(h)<br>• NH Dep't of Environmental Services<br>  o Alteration of Terrain<br>  o Major Wetlands Dredge and Fill (incl. functional assessment)<br>• NH Division of Historical Resources<br>  o Request for Project Review |

| | |
|---|---|
| **Federal** | • US Army Corps of Engineers<br>  o NH Programmatic General Permit<br>• US Environment Protection Agency - NPDES<br>  o Construction Stormwater Discharge Notice of Intent |

**Q. What is the current status of permitting for the Project?**

A. The site survey and wetlands delineation is currently ongoing. Once complete, the site plan engineering and design will commence and is expected to be completed by the end of 2022. Permit application submittals are expected in late December of 2022 and early January of 2023.

**Q. How does the Company plan on designing, procuring, and constructing the Kingston Solar Project?**

A. As discussed in the testimony of Mr. Sprague, Fitchburg Gas and Electric Light Company ("FG&E") (UES's Massachusetts affiliate company) constructed a 1.3 MW solar facility in Massachusetts (the "Sawyer Passway Project"). For that facility, FG&E successfully employed a competitive RFP process to select a qualified contractor to build the Sawyer Passway Project. UES plans to leverage that experience for the Kingston Solar Project.

UES plans to use a three phase approach for the design, procurement, and construction of the Kingston Solar Project.

Phase 1 of this approach is site plan development, which is part of the on-going due diligence. TFM will be designing a "pad-ready" site that will include the specifications and construction requirements for tree clearing, access road construction, drainage facilities, and final site grading. This design will be used to develop an RFP for "Civil Construction Services" for the construction of the "pad-ready" site. To the extent practical, it is the Company's intent to include any below grade infrastructure required for the PV facility in the Civil Construction Services RFP.

Phase 2 is for the construction of the "pad-ready" site. UES intends to use local civil and land clearing contractors for this portion of the construction. TFM will provide construction oversight and permit compliance services.

Phase 3 includes the engineering/design, procurement, and construction of the PV facility. UES plans to rely on the experience of an outside contractor with proven expertise in the engineering, procurement, and construction of "turn-key" solar generation facilities, which will be installed on the "pad-ready" site constructed during Phase 2. UES expects the Project contractor will provide the necessary construction oversight services for this phase of the construction.

**Q. How does the Company define a "turn-key" solar generation facility?**

A. The Company defines a turn-key facility as a PV facility that will, upon completion of construction, generate AC electricity in a safe and reliable manner in accordance with all local, state, and federal laws and applicable codes and regulations.

**Q. Please elaborate on the Company's procurement process for a contractor to construct the "pad-ready" site.**

Consistent with the requirements of RSA 374-G:5, I(d)[4] and 374-G, II(g),[5] the Company will employ a competitive RFP process to select a contractor to construct a "pad-ready" site for the Kingston Solar Project.

The Company will issue the "Civil Construction RFP" to select local site construction contractors. The "Civil Construction RFP" will be developed with the assistance of TFM and will include all the necessary information for site construction. The Final "Civil Construction RFP" will not be awarded unless and until the Commission issues an order finding that the Project is in the public interest.

**Q. What criteria will the Company use for selecting the winning contractor for the "pad-ready" site?**

A. Each proposal will be evaluated and ranked on a quantitative and qualitative basis using criteria that will include but not be limited to:

- Overall company background, history, and key characteristics;
- Experience with similar sized projects;
- Ability to comply/meet the components of the RFP;

[4] RSA 374-G:5, I(d) requires a showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers.

[5] RSA 374-G, II(g) is one of the public interest factors that must be considered by the Commission and includes, among other thing, a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project.

- Ability to execute the work as evidenced by the project execution plan and schedule; and
- Overall pricing proposal.

**Q. When does the Company expect to select the contractor for construction of the "pad-ready" site?**

A. The Company expects to issue the RFP for the construction of the "pad-ready" site in the second calendar quarter of 2023. As noted above, the Company will award the contract only if the Commission issues an order finding that the Kingston Solar Project is in the public interest.

**Q. Please elaborate on the Company's procurement process for a contractor to design, procure, and construct the PV Facility for Kingston Solar Project.**

Consistent with the requirements of RSA 374-G:5, I(d)[6] and 374-G, II(g),[7] the Company is employing a two-stage, competitive RFP process to select an engineering, procurement, and construction ("EPC") contractor to design and build the PV facility.

In Stage 1 of the procurement process, the Company conducted a preliminary RFP to obtain detailed cost estimates for this filing (the "Preliminary EPC RFP"), which are reflected in the Benefit-Cost Analysis described in Exhibit FDGP-1 and

---

[6] RSA 374-G:5, I(d) requires a showing that the utility has used a competitive bidding process to reasonably minimize the costs of the project to its customers.

[7] RSA 374-G, II(g) is one of the public interest factors that must be considered by the Commission and includes, among other thing, a demonstration that the company has exercised competitive processes to reasonably minimize costs of the project to ratepayers and to maximize private investment in the project.

presented in Exhibit FDGP-2. The Company issued the Preliminary EPC RFP on September 12, 2022 to the three contractors that responded to the RFI described above. The Company required bidders to provide cost estimates for all components of the PV facility up to the Point of Interconnection ("POI"), including PV modules, inverters, step-up transformers, equipment racking and foundations, and fencing. Responses to the Preliminary EPC RFP were due on October 11, 2022. The Preliminary EPC RFP is attached as Exhibit JSD-6. The responses to the Preliminary EPC RFP were used to estimate the costs of the Project and the configuration presented in this filing.

In Stage 2 of the procurement process, the Company will issue a Final RFP (the "Final EPC RFP") to select the EPC contractor. The Company expects to issue the Final EPC RFP in the first calendar quarter of 2023.

**Q. What criteria will the Company use for selecting the winning EPC contractor for the PV Facility?**

A. Each proposal will be evaluated and ranked on a quantitative and qualitative basis by criteria that include but are 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.

**Q. When does the Company expect to select the EPC contractor?**

A. As stated above, the Company expects to issue the Final EPC RFP for the EPC contract in the first quarter of 2023. The Company will move forward with the EPC award only if the Commission issues an order in this proceeding finding that the proposed Kingston Solar Project is in the public interest.

**Q. What is the expected timeline for constructing the Kingston Solar Project?**

A. After the competitive bidding process has been completed, the Company will execute contracts with the winning contractors. A formal, detailed construction schedule will be established as part of the contracts with the selected contractors.

The Company estimates construction would take approximately 12 months from the time the Commission issues an order finding the Project is in the public interest.

## IV. EXPECTED PROJECT COSTS AND BENEFITS

**Q. What is the total expected cost to construct the Kingston Solar Project?**

A. As shown in Exhibit FDGP-2, Schedule 11, the overall cost of the Kingston Solar Project is comprised of the PV array installation cost (including the inverter, racking, and other components), electric system upgrades, site work, permitting, and land acquisition costs. The Company estimates the total cost to construct the Project will be $13.23 million (Exhibit FDGP-2, Schedule 3). These cost estimates were developed through a combination of information provided in response to the RFI and the Preliminary EPC RFP, assistance from TFM, and the experience of FG&E (the Company's Massachusetts affiliate) in constructing a 1.3 MW solar facility in Massachusetts (the Sawyer Passway Project).

**Q. What are the physical components of the PV array installation?**

A. At a high level, the PV array installation is comprised of four major categories of physical plant:

- <u>Modules</u> or PV panels;
- <u>Inverters</u> or the DC to AC conversion equipment;
- <u>Step-Up Transformer(s)</u>
- <u>Balance of Plant ("BOP")</u> which includes the racking components and electrical equipment such as conduit, wiring, combiner and electrical boxes.

**Q. Will the PV arrays be tracking or stationary?**

A. In response to the Company's Preliminary EPC RFP, the contractors provided cost and production information for both fixed-tilt and single-axis tracker technologies. Although single-axis tracker technology is typically more expensive than a fixed-tilt approach, single-axis trackers allow for greater energy production because the solar panels rotate from east to west on a fixed axis throughout the day to track the movement of the sun. Based on a review of the cost and performance tradeoffs of these two technologies, the Company determined that the single-axis tracker technology is a better approach because the increase in benefits exceeds the added cost.

**Q. What are the costs estimates for the major categories of investment identified above?**

A. The cost estimates for the four major categories identified above, as well as estimates for additional cost categories are provided in the table below:

| PROJECT CAPITAL COSTS | |
|---|---|
| **Cost Element** | **Estimated Cost** |
| **Inverter and Associated Material** | [redacted] |
| **PV Modules and Associated Material** | [redacted] |
| **Step-up Transformer and Associated Material** | [redacted] |
| **Balance of Plant (e.g., racking, etc.)** | [redacted] |
| Fencing | [redacted] |
| Project Management | [redacted] |
| Construction Field Representative | [redacted] |
| Spare Step-Up Transformer | [redacted] |
| Spare Inverter | [redacted] |
| Spare PV Modules (5) | [redacted] |
| Labor | [redacted] |
| **TOTAL** | [redacted] |

The cost estimates in the table above are based on pricing information provided in response to the Preliminary EPC RFP.

**Q. Does the Company anticipate any capital costs beyond the initial installed costs?**

A. Yes. Inverters typically have a lifespan of 10 to 20 years. Accordingly, the Company expects that it will need to replace the inverters once over the 30-year estimated life

**REDACTED**



of the facility. As shown in Exhibit FDGP-2, Schedule 3, the Company estimates the inverters will be replaced in Year 15, at a cost [redacted]—which is an inflation-adjusted figure.

**Q. Apart from the PV array installation costs, are there additional costs associated with constructing the facility?**

A. Yes, the Company estimates system upgrade costs of $600,000 to interconnect the facility to the electric distribution system, which I discuss in more detail in Section V below. There are also the costs for site work and permitting ([redacted]) and land acquisition ($857,938).

The breakdown of the site work and permitting costs is as follows:

| SITE WORK AND PERMITTNG | |
|---|---|
| **Cost Element** | **Estimated Cost** |
| Site Due Diligence, Design, and Permitting[8] | [redacted] |
| Site Work | $550,000 |
| **TOTAL** | [redacted] |

The breakdown of the land acquisition costs allocated to the Kingston Solar Project is as follows:

[8] *See* Exhibit JSD-4(b).

| LAND ACQUISITION COSTS | |
|---|---|
| **Cost Element** | **Estimated Cost** |
| Site Identification | $25,000 |
| Purchase Price[9] | [redacted] |
| Transfer Tax | [redacted] |
| Commission | [redacted] |
| Current Use Penalty | [redacted] |
| Title Search | $10,500 |
| Appraisal[10] | [redacted] |
| **TOTAL** | **$1,715,876** |
| **ALLOCATED COST (50%)** | **$857,938** |

**Q. What factors could change the estimated project costs?**

A. Several factors could contribute to actual project costs being different than estimated costs including material costs, labor market challenges, demand for solar components, which is expected to increase in the wake of the federal Inflation Reduction Act, and shipping and freight costs.

**Q. Will the Company be subject to property taxes for the Kingston Solar Project?**

A. Yes. The Company will pay property taxes to the Town of Kingston, New Hampshire for the facilities it constructs. As shown in Exhibit FDGP-2, Schedules 3 and 5, the Company estimates that it will pay $357,638 in the first year and a total of nearly $6.1 million over the projected 30 year life of the facility. Although property taxes are a cost to the Project, they are a significant economic benefit to the Town of Kingston.

---

[9] Exhibit JSD-5. The Company assumed for purposes of its Benefit-Cost Analysis (Exhibit FDGP-2) that only 50 percent of this cost is allocated to the Kingston Solar Project because it will be located on only a portion of the property.

[10] Exhibit JSD-7.

**Q. Please provide an overview of the expected benefits that will be generated by the Project.**

A. As discussed in the joint testimony of Messrs. Francoeur, Diggins, Goulding, and Pentz, and the joint testimony of Ms. Gilbert and Mr. Pierce, the Company expects the Kingston Solar Project will generate avoided energy costs, avoided capacity costs, local and regional transmission benefits, Renewable Energy Certificates, avoided CO2 and NOx costs, Demand Reduction Induced Price Effects, and economic development benefits.

**Q. How will the proposed Kingston Solar Project offset line losses consistent with the requirement of RSA 374-G:3, I?**

A. 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 UES from the transmission system, thus offsetting distribution system losses.[11]

Additionally, each component of the utility distribution system contributes to electricity losses and the amount of losses depends on the distance from the source to the load. Generally speaking, the longer the distance over which electricity is transmitted, the more electricity is lost. Output from the Kingston Solar Project will be injected directly into the electric distribution system and will offset the amount

---

[11] ISO-NE's Operating Procedure No. 14 allows any generating facility with a nameplate capacity between one to five megawatts to operate as a load reducer in the region as long as the facility does not participate in any ISO-NE. ISO new England Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources (Effective May 13, 2022).

of electricity that must be delivered to that point on the electric distribution system, marginally reducing distribution system losses.

**Q. The definition of DERs in RSA 374-G:2 includes, among other things, renewable generation that provides peak load shaving benefits as part of a strategy for minimizing transmission and distribution costs. Will the proposed Kingston Solar Project reduce peak demand?**

A. On days when output from the Project is available during peak hours (most likely during the summer months), the system can provide peak load shaving benefits. Since 2017, the ISO-NE and regional transmission annual peak hours have occurred during the summer months of June, July, and August from 16:00 to 18:00. Load reducers, like the Kingston Solar Project, decrease the capacity obligation for a utility by reducing the utility's load requirement at the time of the peak load for the ISO-NE system.

Based on information provided in response to the Preliminary EPC RFP, the Company has assumed the Project will generate approximately 37 percent of its nameplate capacity (1,850 kW) during the annual historical ISO-NE peak hour, thus reducing UES peak load by that amount. This capacity benefit is quantified in the testimony and accompanying exhibits of Messrs. Francoeur, Diggins, Goulding, and Pentz.

As a load reducer, the Kingston Solar Project also produces local and regional transmission benefits by reducing load, which are also captured in the Benefit-Cost

Analysis presented in the in the testimony and accompanying exhibits of Messrs. Francoeur, Diggins, Goulding, and Pentz. Based on information provided in response to the Preliminary EPC RFP, the Company has assumed the Project will generate approximately 12 percent of its nameplate capacity (600 kW) during the monthly historical ISO-NE peak hour, reducing UES peak load by that amount.

**Q. Will the project provide any advanced functionality such as voltage regulation or power factor management?**

A. The proposed facility will have the ability to provide advanced functionality such as voltage control and power factor management that the Company may elect to implement at a future time.

**Q. What are the expected environmental benefits associated with the Kingston Solar Project?**

A. $CO_2$ emissions make up the vast majority of New Hampshire's greenhouse gas emissions, most of which are generated by burning fossil fuels (e.g., oil, coal, gas) to produce heat and electricity, and to power vehicles.[12]

As noted above, UES estimates that the Kingston Solar Project annual generation will average 8,904 MWh and is expected to offset approximately 57,300 tons of $CO_2$ annually (*See* Exhibits GPP-1 and GPP-2). In addition to $CO_2$ reduction benefits,

[12] New Hampshire Department of Environmental Services, *Greenhouse Gas Emissions Inventory*, https://www.des nh.gov/climate-and-sustainability/climate-change/greenhouse-gas (*last visited* Sept. 9, 2022).

Daymark estimates the Project would reduce 0.15 tons of NOx (*See* Exhibits GPP-1 and GPP-2).

**V. PROJECT OPERATIONS**

**Q. What is the expected design life of the Kingston Solar Project?**

A. The Company has estimated a 30 year design life based on information provided by PV contractors in response to the RFI and the Preliminary EPC RFP.

**Q. Is the Kingston Solar Project below the statutory cap of 5MW on individual DER projects?**

A. Yes, as noted above the capacity of the Kingston Solar Project will be 4.99 MWac.

**Q. What is the expected Direct Current ("DC") capacity of the Kingston Solar Project?**

A. The Company plans to upsize the DC capacity of the Kingston Solar Project to 6 MWs or more to improve the capacity factor and output of the facility, including output at the traditional electric system annual peak hour. However, the inverters will be sized for 4.99 MWac, meaning the inverters will limit the facility's output to 4.99 MWac.

**Q. How will the Kingston Solar Project be dispatched?**

A. As discussed above, the Kingston Solar Project will operate as a load reducer and therefore it will not be "dispatched" like traditional fossil fuel generation resources. The Project will deliver electricity during the hours in which the facility is producing energy directly into the Company's electric distribution system. The amount of electricity produced by a generating unit is a function of (1) the project's capacity factor and (2) the degradation factor.

The capacity factor is the ratio of actual electrical energy output over a given period of time (typically the number of hours in a year—8,760) to the theoretical maximum electrical energy output over that same period. The actual energy output of a generating facility can vary greatly depending on a range of factors. With regard to solar, solar panels generally produce less energy during the winter months, due to less available sunlight, than during the summer. The Company has estimated an annual capacity factor of approximately 22 percent for the Kingston Solar Project. The Company's capacity factor estimate was developed based on information received in response to the Preliminary EPC RFP.

With regard to the degradation factor, all PV panels lose efficiency and production over time. Solar panel degradation is caused by a range of factors including temperature and humidity. The degradation factor accounts for the decrease in performance over time and the Company has assumed an annual degradation rate of 0.5 percent. This assumption is based on information received in response to the Preliminary EPC RFP.

**Q. Will the Company be able to monitor energy production at the Kingston Solar Project?**

A. Yes. The Company will have the ability to monitor energy production from the Project at three locations.

The first location, which will be the location of record for facility production, will be the revenue meter installed at the POI for the facility. This location will record a minimum of fifteen minute interval revenue metering data.

The second location will be instantaneous AC and DC data from the facility inverters. This information, along with other AC and DC telemetry, will be integrated with the Company's SCADA system.

The third location will be from the recloser installed at the POI. The recloser will provide instantaneous telemetry, including power, to the Company's SCADA system.

**Q. What process will UES follow to interconnect the Kingston Solar Project?**

A. The AC output of the Kingston Solar project will be interconnected to one of the existing 34.5kV lines running through the property or one of the 34.5kV distribution circuits in close proximity to the property. The 34.5kV lines and circuits that are being considered for interconnection are supplied from the existing 115kV to 34.5kV substation located adjacent to the facility. The combination of these factors results in a less expensive interconnection than otherwise would be necessary to modify the electric distribution system to accommodate a utility-scale solar facility. The Company will be responsible for the procurement, installation and commissioning of equipment required to interconnect the facility. As shown in Exhibit FDGP-2,Schedule 11, and summarized in the table below, the Company estimates a total interconnection cost of $600,000, which breaks down as follows:

| ELECTRIC SYSTEM UPGRADES | |
|---|---|
| **Category** | **Estimated Cost** |
| System Impact Study | $75,000 |
| POI Material and Installation | $350,000 |
| Tap 3345 Line with Gang Operated Air Break switch | $50,000 |
| Kingston Relaying Upgrades | $125,000 |
| **TOTAL** | **$600,000** |

**Q. Please further describe the cost elements that make up the total estimated interconnection cost.**

A. The infrastructure required to interconnect the facility is expected to consist of the POI, a three-phase 34.5 kV line extension from the interconnecting line/circuit to the step-up transformer and protection and relaying upgrades at the 115kV to 34.5kV substation. The POI is expected to consist of disconnect switches, a recloser and primary metering outfit.

**Q. One of the public interest factors listed under RSA 374-G:5 is the effect on the reliability, efficiency, and safety of electric service. Will the Kingston Solar Project have any impact on the reliability, efficiency, and safety of electric service?**

A. The Project is expected to have a positive effect on the efficiency of electric service by offsetting losses and slightly reducing losses by generating energy locally.

The Company will take all appropriate steps to ensure the Kingston Solar Project does not adversely impact the reliability, efficiency, and safety of electric service.

As a matter of course, the Company will install protective devices at the POI to disconnect the Project from the electric power system ("EPS") if a fault or abnormal operating condition occurs. In addition, as part of the interconnection process, the Company will conduct a System Impact Study. A System Impact Study examines the potential impacts on the operation, safety, and reliability of the EPS that may result due to the interconnection of the facility. To the extent that the System Impact Study identifies any additional upgrades necessary to ensure the continued safe and reliable operation of the Company's EPS, the Company will undertake those upgrades. Furthermore, the technical specification for the Kingston Solar Project will require that the system components are compliant with applicable codes and safety standards. For example, the system inverters will be UL 1741 compliant.[13]

**Q. How is the Kingston Solar Project part of the Company's strategy for minimizing transmission and distribution costs as required by RSA 374-G:2?**

A. Renewable electricity, such as that produced by the Project, is a cost-effective and environmentally-friendly means of generating electricity locally to reduce energy received from the local transmission system and offset distribution peak load.

**Q. Will the Kingston Solar Project require ongoing maintenance?**

A. Yes. The Company expects that there will be annual operation and maintenance ("O&M") to ensure that the system operates safely and generates at its maximum capacity over the projected 30-year design life. Categories of ongoing O&M include regular site inspections, vegetation management, fence maintenance, panel

[13] In response to the Preliminary EPC RFP, the EPC contractors submitted a listing of all applicable statutes, ordinances, codes, standards, and/or regulations the facility will be designed to comply with.

REDACTED



replacements, and inverter maintenance and/or replacements.

**Q. Who will be responsible for providing O&M services?**

A. Regular site inspections, vegetation management and fence maintenance will be performed by UES personnel or UES's maintenance contractors.

The Company will include ongoing O&M services as part of the Final PV Facility RFP and will evaluate the possibility of entering into an ongoing maintenance contract for PV facility specific items (inverter maintenance and/or panel and inverter replacement).

**Q. What is the annual estimated cost associated with O&M?**

A. As shown in Exhibit FDGP-2, Schedule3, the Company estimates an O&M cost of [redacted] in Year 1, and adjusts that estimate for inflation for the balance of the projected 30-year design life of the facility. The Company's estimated cost for O&M is based on responses to the Preliminary EPC RFP.

As noted above, due to an expected life of 15 years, the Benefit-Cost Analysis (Exhibit FDGP-2) assumes the replacement of the inverters in year 15 of the project life.

**Q. What warranty requirements is the Company placing on the developer?**

A. UES plants to request that all inverters be warrantied for a minimum of twelve years (with a preference for fifteen years) and all PV modules be warrantied for a minimum of twenty-five years (with a preference for thirty years) after energization.

All other equipment is expected to have a life expectancy and/or be corrosion resistant for a minimum of thirty years.

## VI. CONCLUSION

**Q. Does this conclude your testimony?**

A. Yes, it does.

# Unitil Energy Systems

## Utility Scale PV – Facility Design and Installation
## Request for Information

Issued February 11, 2022

TABLE OF CONTENTS

1 INFORMATION ABOUT UNITIL ....................1
2 PURPOSE/ QUESTIONS TO BIDDERS ....................1
2.1 Experience....................2
2.2 Services....................2
2.3 Site Requirements....................3
2.4 Project Responsibilities and Schedule....................3
2.5 Typical Costs....................3
2.6 Life Cycle and Maintenance....................4
2.7 References....................4
3 SCHEDULE....................4

## 1 INFORMATION ABOUT UNITIL

Unitil Corporation is a public utility holding company with electric and gas utility operations in New Hampshire, Massachusetts and Maine. Unitil Corporation is the parent company of three wholly-owned distribution utilities.

Unitil Energy Systems, Inc. provides electric service in the southeast seacoast and state capital regions of New Hampshire, including the capital city of Concord, New Hampshire.

Fitchburg Gas and Electric Light Company provides both electric and natural gas service in the greater Fitchburg area of north central Massachusetts; and,

Northern Utilities, Inc. provides natural gas service in southeastern New Hampshire, and parts of southern and central Maine, including the city of Portland, which is the largest city in Northern New England.

Together, these three distribution utilities serve approximately 102,700 electric customers and 77,900 natural gas customers in their service areas.

## 2 PURPOSE/ QUESTIONS TO BIDDERS

Unitil views renewable energy as a valuable resource that provides benefits to the grid and the environment. Unitil is exploring the possibility of constructing utility scale photovoltaic generating (PV) facilities within its electric service territory.

Unitil is in the process of developing a qualified bidders list for the installation of a PV facility on a ‘pad-ready site’.

The following questions will be evaluated by Unitil to create a qualified bidders list as well as to develop assumptions that will be used by Unitil in the site assessment and financial analysis to assess the viability of constructing a Unitil owned PV facility.  The answers to the pricing and land requirement questions below will only be used by Unitil to develop assumptions and not to determine the qualifications of the bidders.  However the bidder’s ability to answer these question may be used in the determination of their qualifications. Please feel free to provide any additional information you feel would assist Unitil in evaluating responses and developing a qualified bidders list.

2.1 Experience

- Describe at least five (5) examples of previous projects installing "utility scale" PV facilities ranging from 2 MW to 15MW in size. Your response should include your responsibilities as well as the responsibilities of others.
- Describe examples of previous projects that included the installation of Energy Storage Systems (ESS) in conjunction with PV infrastructure.
- Describe your experience installing facilities on remediated brownfield sites and/or capped landfills.
- Provide example one-lines and site layouts of PV only installations as well and combined PV/ESS installations.
- Provide an example layout, design and construction package for a 2MW or more facility installed on vacant land has had all site work (tree clearing, grading, drainage installation, etc.) complete.
- Please provide the number of facilities of the following size ranges that you have installed in the past five (5) years. Indicate the number of PV only and PV/ESS combined facilities in each range.
    - 0.5MW to 2.0MW
    - 2.1MW to 5MW
    - 5.1MW to 10MW
    - 10.1MW and above
- Please provide the ESS size that is typically paired with a 2MW, 5MW and 10MW PV facility.

2.2 Services

- Please describe all services your company offers in relation to the installation PV/ESS facilities, such as:
    - Site assessment (surveying, wetlands delineation, geotechnical evaluation, etc.)
    - Land acquisition
    - Site design and construction (grading, drainage, etc.)
    - Structural design of foundations and other support structures to support PV/ESS infrastructure
    - Construction permitting
    - Facility layout design

- Electrical design of PV/ESS facility up to the PCC including the step-up transformer, equipment/facility grounding, PV/ESS side SCADA integration, etc.
- Procurement and installation

-

2.3 Site Requirements

- Please provide the typical site requirements (cleared area, slope, compass facing direction, etc.) for 2MW, 5MW and 10MW PV facilities.
- Please provide the typical distance from the tree line to the first PV panel in each compass direction.
- Please provide additional site requirements for the incorporation of an ESS in conjunction with the PV.
- Please describe the site information required to complete the PV/ESS facility design.

2.4 Project Responsibilities and Schedule

- Based on your past experience is land assessment, site planning, construction permitting and site construction (tree clearing, grading, drainage installation, etc.) typically performed by others?
- Please provide a typical schedule including PV facility installation and commissioning assuming site work is complete and the site is ready for the installation of the PV infrastructure.
- Please describe what is required and who is typically responsible for the design and installation of structural foundations to support the PV/ESS infrastructure.

2.5 Typical Costs

- Assuming a cleared, graded and accessible site that has a slight grade please provide the typical cost (or cost range) for the design, procurement, installation and commissioning of a 2MW, 5MW and 10MW PV facility. A listing of the components and services included in each cost provided shall be included with your response.
- Please provide any additional costs and describe the necessary work to install a PV facility that is ESS ready, such that the installation is designed and constructed in a manner that energy storage can be easily added without the need to install additional infrastructure with the exception of the ESS (battery systems, connection to the DC system, etc.) specific equipment.

### 2.6 Life Cycle and Maintenance

- Provide the typical annual output per MW of a PV facility of 2MW or more located in Northern Massachusetts and Southern New Hampshire.
- Provide the anticipated useful life of components for a PV/ESS facility.
- Provide the annual efficiency degradation factor of the PV panels along with any other degradation factors associated with of the PV facility components.
- Provide typical ESS minimum acceptable depletion levels, ESS discharge efficiency factors and any other degradation factors associated with ESS components.
- Provide typical maintenance requirements of the facility components.
- Please provide a list of recommended spare components that should be kept on hand for both PV and ESS facilities.

### 2.7 References

- Provide a listing of at least five (5) clients that have engaged your organization in projects associated with the installation of PV facilities of 1MW or more 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.

## 3 SCHEDULE

The following lists the activities relevant to the RFI process. Unitil reserves the right to change these dates and will notify Vendors in such a case.

| Key Dates | | |
|---|---|---|
| **Release of RFI** | 3:00 PM | 02/11/2022 |
| **Deadline for Questions** | 5:00 PM | 02/21/2022 |
| **Responses to Questions** | 5:00 PM | 02/23/2022 |
| **Submission Due Date** | 5:00 PM | 03/04/2022 |

Submit questions in writing via the Bonfire portal no later than Monday, February 21st by 5PM EST. Bidders should refer to the specific RFI paragraph number and page and should quote the passage being questioned. Unitil will respond to questions as per the schedule above and will send answers to Bidders as a group.

Submissions are due Friday, March 4th via the Bonfire portal no later than 5:00 PM EST.

# Utility Scale PV
# Siting, Site Evaluation & Permitting

## Request for Proposal

Unitil
energy for life

| Unitil energy for life | Utility Scale PV<br>Siting, Site Evaluation & Permitting<br>Request for Proposal | RFP No. | UES12822 |
|---|---|---|---|
| | | Page No. | 1 |
| | | Date: | 1/28/2022 |

# Table of Contents

1 Project Description ... 3
2 Scope of Services ... 3
2.1 Land Search and Assessment ... 3
2.1.1 Unitil Owned Property ... 4
2.1.2 Private and Municipal Property Search ... 4
2.1.3 Property Ranking ... 4
2.1.4 Detail Assessment ... 5
2.2 Final Site Plan Development and Construction Permitting ... 5
2.2.1 Final Site Plans ... 6
2.2.2 Permit Applications ... 6
2.2.3 Meetings and Hearing ... 7
2.3 Realty Services ... 7
2.4 Project Management ... 7
2.4.1 Project Manager ... 7
2.4.2 Company Communication ... 8
2.5 Site Construction Oversite ... 8
2.5.1 Survey Services ... 8
2.5.2 Construction Field Representative ... 8
2.5.3 SWPPP ... 8
3 Project Schedule ... 9
4 Price Proposal ... 9
5 Questions to Bidders ... 10
5.1 Experience ... 10
5.1.1 PV Site Plan Development ... 10
5.1.2 Construction Permitting ... 10
5.1.3 Realty ... 10
5.2 Workforce Configuration ... 10
5.2.1 Internal Staffing ... 10
5.2.2 Use of Subcontractors ... 10
5.3 Communication with Company ... 10
5.4 Additional Information ... 10
5.5 Work Planning ... 11
6 Attachments ... 11
7 Administrative Information ... 11

7.1 RFP Schedule ....11
7.1.1 Questions ....11
7.1.2 Intent to Bid ....12
7.1.3 Submission of Proposals ....12
7.1.4 No Referrals ....12
7.1.5 Award Notification ....12
7.1.6 Rejection of Proposals ....12
7.1.7 Errors in Proposals ....13
7.1.8 Evaluation Criteria ....13
7.1.9 Contract Terms and Conditions ....13

# 1 Project Description

Unitil views renewable energy as a valuable resource that provides benefits to the grid and the environment. Unitil is exploring the possibility of constructing utility scale photovoltaic generating (PV) facilities within its electric service territory in New Hampshire.

To assist in this effort, Unitil is seeking a qualified firm to identify and assess potential locations to site PV facilities (and if necessary provide the realty service to acquire the desired parcel), develop the final site design and permitting package for the selected location(s) and to provide construction and permit compliance oversight of the site construction.

Each proposal should be prepared simply and economically, providing a straightforward, concise description of the Bidder's ability to meet the requirements of this RFP. Emphasis should be on completeness, clarity of content, responsiveness to the requirements, and an understanding of Unitil's needs.

By submitting a proposal, each Bidder certifies that it understands this RFP and has full knowledge of the scope, nature, quality, and quantity of the work to be performed, the detailed requirements of the services to be provided, and the conditions under which the services are to be performed. Each Bidder also certifies that it understands that all costs related to preparing and responding to this RFP, including but not limited to providing additional information or attending an interview will be the sole responsibility of the Bidder.

Should the Company find it necessary, modification to this RFP will be made by addenda.

# 2 Scope of Services

## 2.1 Land Search and Assessment

To accommodate the development/construction of a Unitil owned utility scale PV facility, the Company is looking to identify possible sites of 10 acres or more. The actual size of the lot required will depend on how much of the lot can be utilized to construct the facility. The ideal site should be located at or near our existing sub-transmission infrastructure and/or located on road frontage that has our existing 3-phase backbone infrastructure in place (3-phase power).

### 2.1.1 Unitil Owned Property

The following two Unitil owned parcels have been identified by the Company as possible sites for PV facilities. These parcels shall have feasibility assessments performed and preliminary layouts developed. These assessments and layouts shall be based on existing conditions plans and information provided by Unitil.

Broken Ground

The Broken Ground site is a 132 acre parcel located between Curtisville Road and Portsmouth Street in Concord, NH. This parcel was acquired by Unitil several years ago for the construction of Broken Ground substation.

In order to construct a PV facility on the Broken Ground parcel the City of Concord would need to modify conservation easements rights on the property.

Kensington DOC

The second location is the parcel (27 acres) of the old Seacoast DOC at 114 Drinkwater Road in Kensington.

### 2.1.2 Private and Municipal Property Search

The selected firm shall perform a review of private and municipally owned property within the Unitil NH electric service territory (see Exhibit A).

Unitil will provide a map and/or list from its GIS that highlights all parcels that are at least ten acres in size and are within one quarter mile of Unitil's sub transmission system and/or are at least 5 acres in size and within one hundred feet of a three-phase 34.5 kV distribution line to assist in identifying locations. (see Exhibits B&C)

Each proposal shall include the bidder's proposed process for identifying locations and determining if a parcel is a potential site.

Potential parcels shall be reviewed and ranked (2.1.3) to determine if detailed assessments should be performed and preliminary layouts developed (see section 2.1.4).

### 2.1.3 Property Ranking

All potential properties shall be ranked based on their ability to support a PV facility. This ranking shall include purchase price, cost to construct (site work – to be estimated by awarded firm and PV installation – to be estimated by Unitil), utility upgrade requirements (to be determined by Unitil) usable land size, constructability and permit ability.

The awarded bidder shall develop the ranking methodology with input from Unitil and will rank the properties per the finalized methodology.

The top parcel(s) shall have a detailed assessment performed and a preliminary layout developed (see section 2.1.4)

### 2.1.4 Detail Assessment

Upon Unitil's approval and authorization to move forward the top parcel(s) shall have a due-diligence detailed assessment performed to confirm site feasibility. For the purposes of this RFP, assume two (2) top parcels were identified, one 50 acres in size and the other 100 acres in size with both being located in the City of Concord.

This process may also include initial construction permitting discussions with local and state agencies to identify potential permitting challenges associated with each identified location.

A due-diligence detailed assessment shall include the following:

Title Commitment Policy to the extent required to identify items effecting the title that may limit the property for the proposed use.

ALTA Boundary, Topographic and Utility Survey – to the extent required to perform the tasks below and to assess the feasibility of siting a PV facility on the property. Existing plans and other records shall be used when possible to reduce the amount of survey work performed during this stage of the project. ALTA Boundary to be performed with information developed in the Title Commitment Policy.

Wetlands Delineation – to the extent required to perform the tasks below and to assess the feasibility of siting a PV facility on the property. Existing plans and other records shall be used when possible to reduce the amount of field work performed during this stage of the project.

Preliminary Site Layout – a preliminary site layout shall be developed indicating the proposed location of the PV facility. The plan shall be used to develop estimated site construction costs.

Site Construction Cost Estimate – an estimate for the cost to make the site "pad-ready" for the installation of the PV facility shall be developed. This cost estimate shall include all construction costs to make the site ready for the installation of the PV components including, but not limited to the construction of permanent site access, tree removal, grading and the installation of site drainage.

Phase 1A Archeological Sensitivity Assessment – shall be performed. This study shall follow guidelines established for archeological surveys by the NHDHR.

Phase 1 Environmental Site Assessment – shall be performed in accordance with latest ASTM requirements.

## 2.2 Final Site Plan Development and Construction Permitting

Once the final location for the PV facility have been selected and upon Unitil's direction to move forward the selected firm will develop final site plans, assist Unitil in the construction permitting process and provide site construction oversite. For the purpose of this RFP assume the final site is a 50 acre parcel located in the City of Concord in which the PV facility is place on a 15 acre portion of the lot.

### 2.2.1 Final Site Plans

The development of final site plans shall include the following:

Boundary, Topographic and Utility Survey and Wetland Delineation – Full site survey including wetlands delineation for the purposes of permitting and site plan development.

Site Plans

- Existing Conditions Plan
- Site Preparation Plan
- Site Layout Plan
- Grading and Drainage Plan
- Stormwater Management and Erosion Control Plan
- Utility Plan
- Landscaping Plan
- Site Work Detail Items Necessary for Construction

Site Specific Soil Mapping – a certified soil scientist shall perform soil mapping of the project area in accordance with the Alteration of Terrain program.

Test pits and infiltration testing shall be performed as required for the drainage system design.

A stormwater management report shall be provided that includes an analysis of the proposed stormwater management system and its effects on the surrounding area and existing drainage infrastructure in the area.

All necessary reports, mapping and other surveying to complete site designs and construction permitting efforts.

### 2.2.2 Permit Applications

The awarded bidder shall include the cost associated with preparing the necessary applications, plans, and applicable support materials for the following:

- Local Municipal Permits (assume City of Concord)
    - Planning Board
        - Site Plan Review
        - Conditional Use – Public Utility
        - Conditional Use – Wetland Buffer Impacts
    - Conservation Commission
        - Wetland Dredge and Fill Review

- Wetland Buffer Impact Review

- State of New Hampshire
  - NHB
    - Natural Heritage Bureau Data Check
  - NHDES
    - Alteration of Terrain
    - Major Wetlands Dredge and Fill
  - NHDHR
    - Request for Project Review
- US ACOE
  - NH Programmatic General Permit (PGP)
- US EPA
  - NPDES
    - Construction Storm Water Discharge Notice of Intent (NOI)
    - Disturbing Ground Within Wetlands

### 2.2.3 Meetings and Hearing

The awarded bidder shall attend meetings with the Client, Town/State Agencies and Boards for the processing of the permit applications. The awarded bidder shall include an allowance of sixty (60) hours for meetings and hearings.

## 2.3 Realty Services

It is Unitil's expectation that the awarded firm will utilize internal realtor services or partner with an external realtor(s) to assist in the land search efforts. It is Unitil's intent to only review parcels that are vacant lots owned by municipalities we serve or privately owned lots that a realtor feels could be acquired by either purchase or long-term lease agreement for a fair market value.

Additionally, Unitil plans to enlist such realtor(s) to assist in the acquisition of the desired parcel from a private land owner. In the event a Unitil owned parcel or municipal owned property is selected then the realty services for land acquisition may not be required.

## 2.4 Project Management

### 2.4.1 Project Manager

It is Unitil's desire to have one primary point of contact, Project Manager, with the Contractor 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 Firm's assigned Project Manager. This Project Manager

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-3
Page 9 of 17



should be experienced in Work of this nature and the importance of communicating with customers regarding the project's progress.

### 2.4.2 Company Communication

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 company and the hourly rate in which this will billed.

## 2.5 Site Construction Oversite

After permits are received and upon Unitil's authorization to move forward the selected firm will provide construction support services throughout the duration of the site work.

### 2.5.1 Survey Services

Provide field layout services of the limits of clearing, layout of erosion control measures and construction baselines. Assume three mobilizations.

### 2.5.2 Construction Field Representative

Provide a construction field representative that will serve as the Company's on-site representations throughout the duration of site work. 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 in understanding the intent of the construction documents, confirming the site is constructed as designed and submitting weekly progress reports to the company. For the purpose of this RFP, assume that site work construction will take approximately six months. 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.

### 2.5.3 SWPPP

The awarded bidder shall prepare a SWPPP and NOI for stormwater discharge associated with the construction and provide SWPPP and EMP inspection services. For the purposes of this RFP assume twenty-five (25 inspections).

# 3 Project Schedule

A preliminary project schedule is included below. These dates will be updated upon the award of the project and as the project progresses and information is obtained regarding land assessment and availability.

| Task | Anticipated Date |
|---|---|
| Project Awarded | 3/4/2022 |
| Feasibility Assessments and Preliminary Layouts Completed for the Broken Ground and Kensington DOC Properties | 4/8/2022 |
| Property Search and Ranking Complete | 6/3/2022 |
| Detailed Assessment(s) Complete | 8/12/2022 |
| Construction Site Selected | 8/26/2022 |
| Final Site Plans Complete and Permit Applications Submitted | Q1 2023 |
| Begin Site Construction | Q2 2023 |
| Site Construction Complete | Q3 2023 |

Each proposal shall include comments and any recommended changes to the schedule above, including the information required to be provided by Unitil and date of which the information is needed to meet the proposed milestones.

# 4 Price Proposal

Price proposals shall be based on and will be evaluated on the assumptions provided within this document.

Price proposals shall be broken down based on each subsection of section 2 (2.1.1 through 2.5.3 shall each have its own subtotal) and include descriptions of any assumptions used to developed the cost proposals.

Unitil will provide email authorization prior to commencing work on any of the tasks described in the RFP and prior to commencing with activities described in sections 2.1.4, 2.2 and 2.5. Unitil will request and approve the detailed pricing based on the selected site(s) prior to any work taking place under these sections.

At any point during this project Unitil at its sole discretion may decide to stop work at any time/stage of the project.

# 5 Questions to Bidders

Each bidder is required to provide complete and detailed responses to all information requested. Responses to the questions below will be used in the evaluation of proposals.

## 5.1 Experience

### 5.1.1 PV Site Plan Development

Briefly describe previous work experience developing "pad-ready" site designs for PV facilities.

### 5.1.2 Construction Permitting

Briefly describe previous work experience permitting construction projects within Unitil's electric service territory in NH. Please include any experience associated with the permitting of PV facilities in your response.

### 5.1.3 Realty

Briefly describe your previous experience working with realtors to evaluate and acquire properties such as what is described in the RFP.

## 5.2 Workforce Configuration

### 5.2.1 Internal Staffing

Briefly describe your staffing plan to provide the necessary workforce to complete the tasks described in the RFP.

### 5.2.2 Use of Subcontractors

Please indicate where you intend to make use of subcontractors throughout this project. Please identify the subcontractors and define what services these subcontractors will provide. Briefly describe your past experience utilizing each of the proposed subcontractors.

## 5.3 Communication with Company

Briefly describe the assigned project manager's work scope and communication plan with Unitil. Please indicate the number of additional projects the project manager will be supporting, or typically supports, outside of this project.

## 5.4 Additional Information

Based on your experience with work similar in scope to what is described in the RFP, please suggest supplemental or alternative tasks to be undertaken for this project to help Unitil achieve its objective. Your response may include omissions, additions or modifications to tasks outlined in the RFP.

Any omission, addition or modification to what is outlined in the RFP shall be clearly identified in your proposal, including a detailed explanation of the reason(s) for the proposed change.

### 5.5 Work Planning

Discuss your plan to deliver the work described in the RFP throughout completion. Your description should include details on how you plan to approach the tasks in section 2.1, including your proposed approach to the private and municipal land search, tasks/site information required to adequately develop the ranking of properties, and the work and tasks required to complete the detailed assessments.

## 6 Attachments

- NH Service Territories Map – NH electric territory is highlighted in orange or orange/red stripe. Red only shading indicates gas only territory.
- Solar Parcel Suitability Map – pdf of a GIS view that show's Unitil's subtransmission lines and three-phase 34.5 kV distribution lines. Areas highlighted in green are any parcel at least 10 acres in size that are within 0.25 miles of a subtransmission line and areas shaded in orange are any parcel 5 acres or more within 100' of a three-phase 34.5 kV distribution line.

## 7 Administrative Information

### 7.1 RFP Schedule

| Event | Time | Date |
|---|---|---|
| **RFP Released** | | 1/28/2022 |
| **Intent to Bid Deadline** | | 2/4/2022 |
| **RFP Questions Deadline** | 5:00 PM EST | 2/4/2022 |
| **RFP Responses to Questions** | 5:00 PM EST | 2/9/2022 |
| **Proposal Due** | 5:00 PM EST | 2/25/2022 |
| **Bid Awarded** | | 3/4/2022 |

#### 7.1.1 Questions

Submit questions and/or clarification needed via the Bonfire portal. No telephone questions will be accepted or considered. Bidders should refer to the specific RFP paragraph number and page and should quote the passage being questioned. Unitil will respond to questions as per the RFP schedule above and will send answers to Bidders as a group. Unitil will remove bidder names from the text of the questions and answers being sent. The deadline date for submission of questions is Friday, February 4th by 5:00PM EST.

### 7.1.2 Intent to Bid

All interested bidders must submit their 'Intent to Bid' through the Bonfire portal (in the Submissions section) no later than Friday, February 4th by 5 PM EST. Submission of this intent constitutes the Bidder's acceptance of the RFP schedule, procedures, evaluation criteria and other administrative requirements. Bidders who do NOT notify us of their intent to bid are automatically blocked from further participation in this RFP.

### 7.1.3 Submission of Proposals

Proposals are due Friday, February 25th, no later than 5:00 PM EST. Submission of bids via the Bonfire website is mandatory; no hard copies will be accepted. Bids MUST be received in Bonfire by the due date and time in order to be considered.

** Bonfire will automatically close the RFP at 5:00 PM EST on February 25th – we recommend NOT waiting to the last minute to upload your proposal and accompanying documents.

### 7.1.4 No Referrals

Bidders may not refer or pass on this RFP to another Bidder without prior approval from Unitil.

### 7.1.5 Award Notification

After the winning bid is selected, the awarded Bidder will be invited to negotiate a contract with Unitil. The remaining bidders will be notified of their selection status.

### 7.1.6 Rejection of Proposals

This RFP does not commit Unitil to select a Bidder or to award a contract to any Bidder. Unitil reserves the right to accept or reject, in whole or in part, any proposal it receives pursuant to this RFP.

### 7.1.7 Errors in Proposals

Unitil is not liable for errors in Bidder proposals. A Bidder may correct an error in their proposal with Unitil's approval. Changes after the submission date may be made only to correct an error in an existing part of the proposal. New material may not be submitted.

### 7.1.8 Evaluation Criteria

Bidders will be evaluated on their ability to help Unitil achieve its commitment through their price offering and particular focus will be paid to the following areas of consideration;

- Experience
- Workforce Configuration
- Communication
- Work Planning

Unitil is committed to reducing company-wide direct greenhouse gas emissions from 2019 levels by at least 50 percent by 2030 and to net-zero emissions by 2050. These goals are just part of Unitil's overall commitment to environmental stewardship, sustainability, diverse workforce and corporate responsibility. Our mission is to encourage all of our suppliers and service providers to join us in our efforts.

To that end, Unitil now includes in all procurement sourcing, a Sustainability and Diversity Questionnaire to be completed by each bidder. (See Exhibit E)

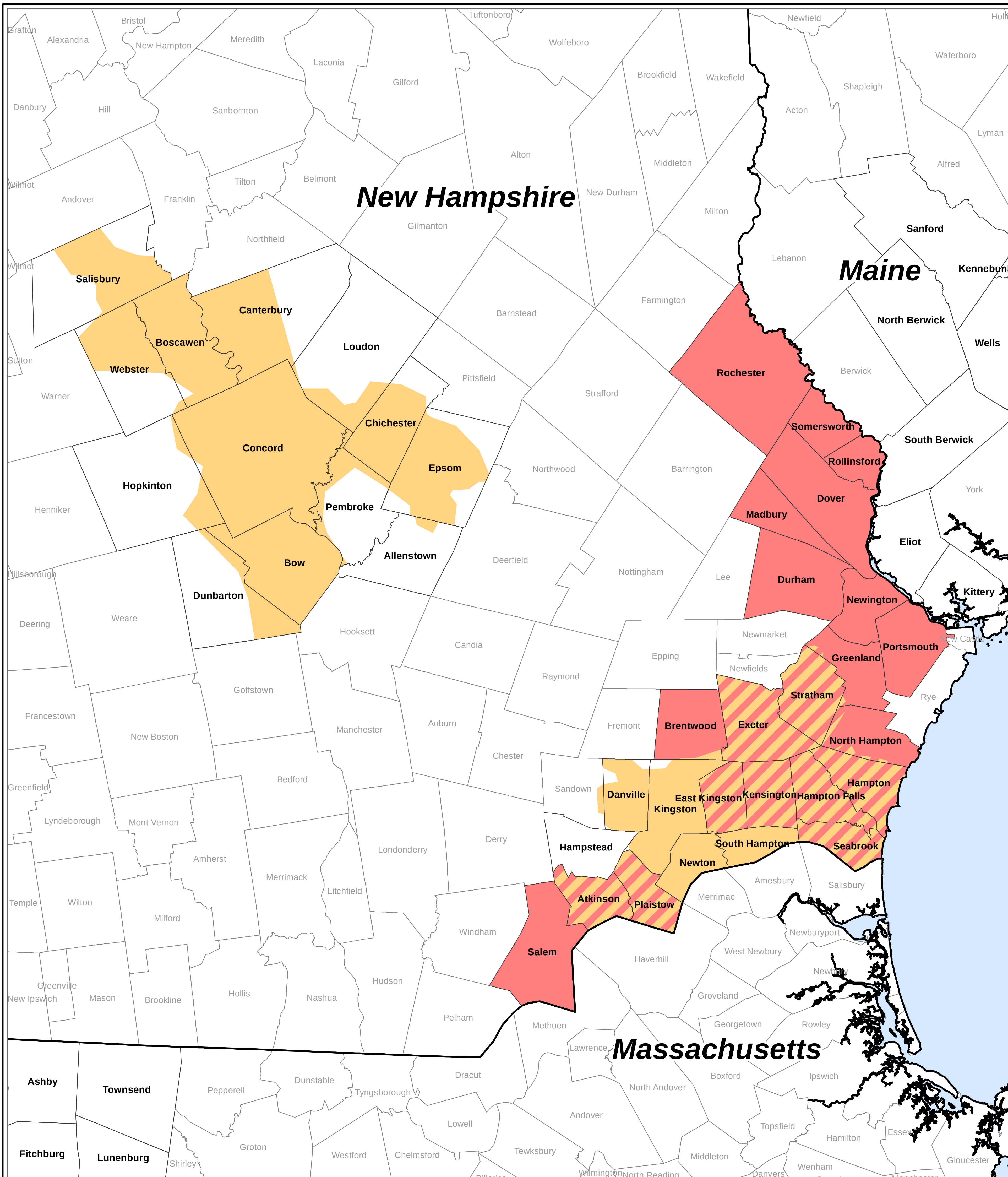
Unitil will utilize a proposal evaluation team for the evaluation of this RFP. The award(s) will be based on the proposals judged to be in the best interest of Unitil and the judgment in this regard shall be considered final.

Unitil reserves the right to invite the apparent top bidders to provide revised pricing which will be accepted and understood as a best and final offer.

### 7.1.9 Contract Terms and Conditions

Contractual terms and conditions will be negotiated with the selected Bidder after initial selection. Bidders should review terms and conditions of our Master Agreement attached as Exhibit D and identify to Unitil in their proposals, any exceptions that will be taken.

Other terms and conditions, may be included, as appropriate.




# Unitil Service Territory Overview Map - NH

## ELECTRIC

### UES Capital

| | |
|---|---|
| Allenstown | Dunbarton |
| Boscawen | Epsom |
| Bow | Hopkinton |
| Canterbury | Loudon |
| Chichester | Pembroke |
| Concord | Salisbury |
| | Webster |

### UES Seacoast

| | |
|---|---|
| Atkinson | Kensington |
| Danville | Kingston |
| East Kingston | Newton |
| Exeter | Plaistow |
| Hampstead | Seabrook |
| Hampton | South Hampton |
| Hampton Falls | Stratham |

## GAS

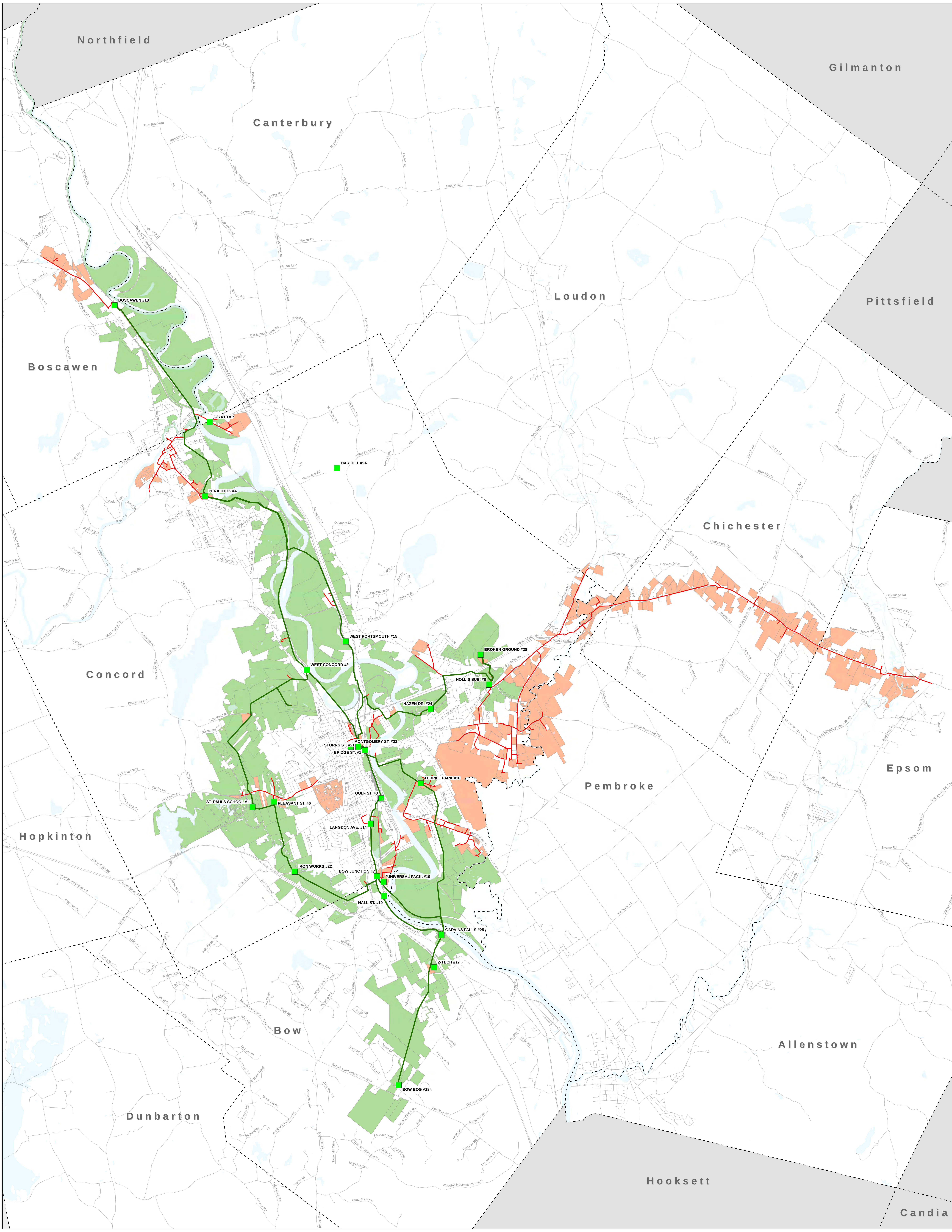
### Northern Utilities NH

| | | |
|---|---|---|
| Atkinson | Hampton | Portsmouth |
| Brentwood | Hampton Falls | Rochester |
| Dover | Kensington | Rollinsford |
| Durham | Madbury | Salem |
| East Kingston | Newington | Seabrook |
| Exeter | North Hampton | Somersworth |
| Greenland | Plaistow | Stratham |

Electric & Gas
Electric
Gas

0 0.5 1 2 3 4 5
Miles

Unitil




Subtransmission Conductor Lines

Distribution Primary OH Conductor Lines (34.5kV/3ph)

Subtransmission Parcels (0.25 mile/10 acres)

Distribution Parcels (100 feet/ 5 acres)

Substation

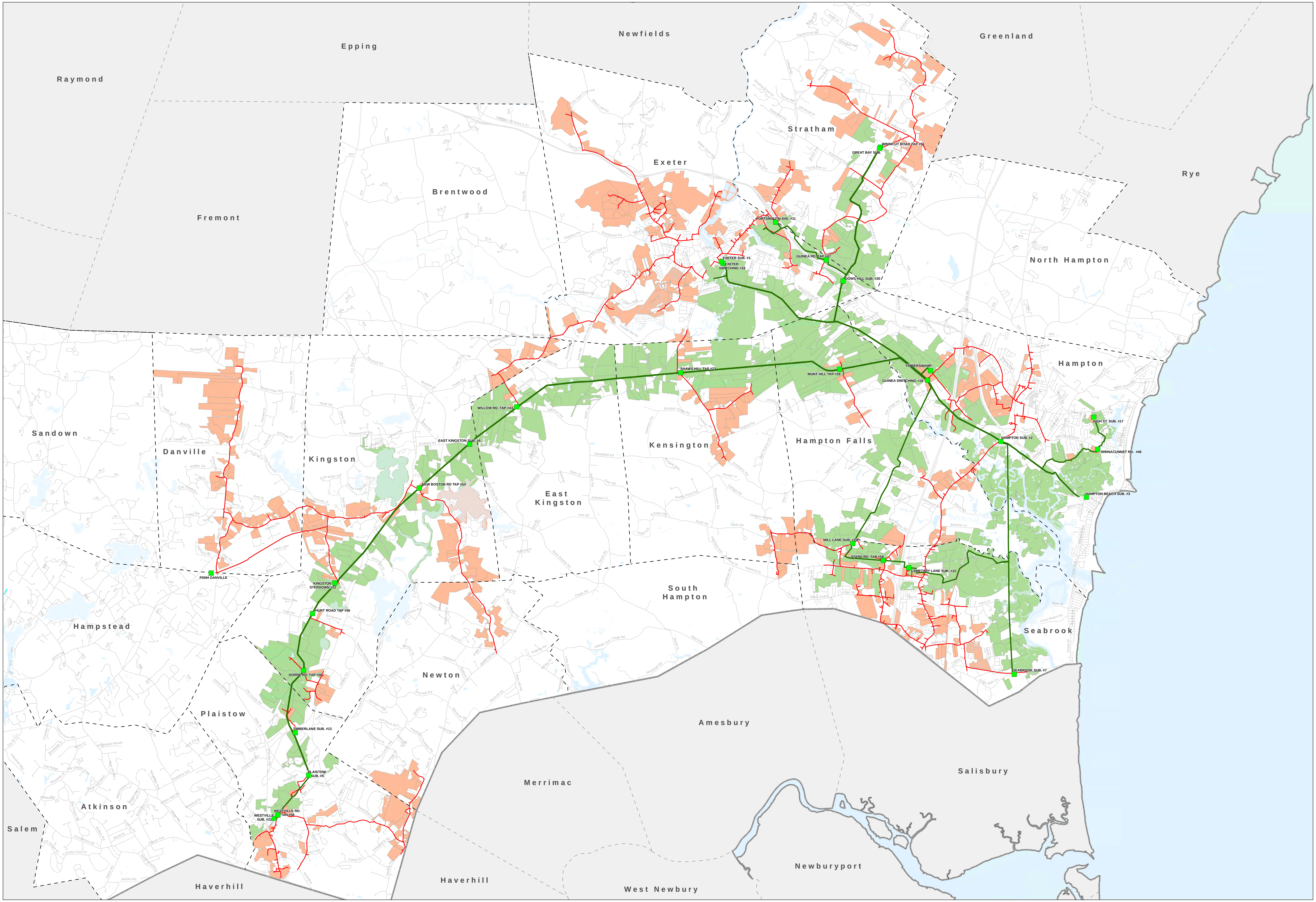
| | |
|---|---|
| Drawn | doreyk |
| Date | 1/17/2022 |
| Scale | 1 " = 2,500 ' |

N W E S

Unitil

Disclaimer:
Unitil has prepared these maps based on best available information. The information provided is not warranted for accuracy and may be incomplete. Field verification is advised for all information shown on the maps.

**Capital**
**Solar Parcel Suitability**




Subtransmission Conductor Lines
Distribution Primary OH Conductor Lines (34.5kV/3ph)
Subtransmission Parcels (0.25 mile/10 acres)
Distribution Parcels (100 feet/ 5 acres)
Substation

| | |
|---|---|
| Drawn doreyk | |
| Date 1/17/2022 | Disclaimer: Unitil has prepared these maps based on best available information. The information provided is not warranted for accuracy and may be incomplete. Field verification is advised for all information shown on the maps. |
| Scale 1 " = 2,750 ' | |

**Seacoast**
**Solar Parcel Suitability**

# Proposal:

# 2022 Utility Scale PV Siting, Site Evaluation & Permitting

*Prepared for*

Unitil
energy for life

February 25, 2022

TFM Since 1968
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**TFMoran Inc.** 48 Constitution Drive, Bedford, New Hampshire 03110 ~ Tel: (603) 472-4488

**www.tfmoran.com**

TFM®
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Table of Contents*

*Reply to Bidder Questions* ............................................................. 1

*Project Schedule* ........................................................................... 2

*Pricing Information*......................................................................... 3

*Project Manager Resume*.................................................................. 4

*Appendix A – TFM Relevant Project Experience in New Hampshire by Region*

*Appendix B – Additional Key Staff Resumes*

*Appendix C – Certificates of Insurance*

TFM®
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Section 1: Reply to Bidder Questions*

TFM Since 1968 Civil Engineers Structural Engineers Traffic Engineers Land Surveyors Landscape Architects Scientists



# 5. Questions to Bidders

## 5.1 Experience

### 5.1.1 PV Site Plan Development

TFMoran Inc. has had the opportunity to service the Utility industry for over 50 years, most recently having provided services to Unitil, Eversource Energy, New Hampshire Electric Cooperative and Liberty Utilities (formally National Grid). TFMoran has provided a complete relevant project experience list in Appendix A, with a sample of recent projects specific to the proposed RFP as following;

**Industrial Roofing Corporation (IRC), Yankee Solar Array, Dublin, NH**
Site Plan and permitting for a 125kW Ground Mounted Solar Array at the Yankee Publishing Facility. Tasks include layout and landscaping improvements. Permits include a NHDOT Driveway Permit and Town of Dublin Site Plan Review, Driveway and Building Permits.

**Unitil, Broken Ground Substation and Eversource Energy, Curtisville Substation, Concord, NH:**
Site plan and permitting to construct one (1) transmission and one (1) distribution substations, including structures to house electrical equipment, access, parking, and stormwater management areas. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NHDES AoT and Wetland Permits, Concord Subdivision, Site Plan, Conditional Use Permit, FAA Determination of No Hazard. Daily construction compliance monitoring inspections to ensure compliance with all local, state, and federal permitting associated with the project (City Site Plan, City CUP, City Subdivision, NHDES AoT, NHDES Dredge and Fill, FAA.

**Unitil, Gulf Street Substation Reconstruction, Concord, NH:**
Site plan and permitting to reconstruct the existing Unitil Gulf Street Substation and adjacent overhead electric lines. Tasks include layout and access design. Permits include City of Concord Planning Board Site Plan Approval and FAA Determination of No Hazard.

**Unitil, Kingston Distribution Substation, Kingston, NH:**
Site Plan and permitting for upgrades to existing distribution substation. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, and Municipal Planning Board, Conservation Commission permits. Boundary and Topographic Surveys. Construction Layout.

**Eversource Energy, Shattuck Laydown Area, Newington, NH:**
Site Plan and permitting for construction of a 10-acre gravel laydown and staging yard associated with the Eversource Seacoast Reliability Project. Tasks include layout, grading, access, parking, and stormwater management design. Permits include NHDES AoT and Wetland Permit, and Town of Newington Planning Board Site Plan Approval.

TFM Since 1968 Civil Engineers Structural Engineers Traffic Engineers Land Surveyors Landscape Architects Scientists

### 5.1.2 Construction Permitting

TFMoran has extensive experience completing site assessment and permit application projects in New Hampshire. Our successful experience with the various levels of permitting is highlighted in the TFM Experience List attached to this proposal. We have maintained key relationships with permitting authorities at the various national, state, and local levels that are necessary to follow through with the permitting process.

### 5.1.3 Realty

TFMoran regularly works with realty professionals to assist clients in evaluating and obtaining properties for the purposes of land development, including mitigation parcels due to unavoidable wetland impacts. For this project we are proposing to subcontract with a respected regional commercial realtor to assist Until in the land search efforts. Specific project examples can be provided if so requested.

## 5.2 Workforce Configuration

### 5.2.1 Internal Staffing

TFMoran incorporates a tiered workforce configuration to insure appropriate staffing for all of our projects. This system provides a principal to provide upper-level oversight of the project and to confirm appropriate quality control prior to issuance of plans and reports. Underneath the Principal is the Project Manager who is responsible for the day-to-day administration of the project. This individual is the primary point of contact with the Client and corresponds directly with subcontractors, permit agencies and the public in conveying the projects message and design specifications. The Project Manager also oversees the support staff and provides guidance on design related items, engaging in components of the design as warranted. The project support staff typically consists of one to two engineers and an environmental scientist who will prepare the project deliverables. These individuals are in turn assisted by administrative staff that provides clerical support and graphic technicians who provide AutoCAD based drafting or presentation support materials such as renderings or elevations. As part of this workforce configuration each tier is responsible for their component of the project but to also have an understanding of the responsibilities of the next tier. This provides for an appropriate amount of redundancy in staffing such that the project may move on multiple parallel paths while still maintaining the integrity and consistency required to generate a successful project.

TFM also has an experienced survey staff of licensed professionals and experienced field personnel available. We are experienced in all areas outlined, utilize up to date equipment encompassing Total Station, Robotic Total Station, and survey grade GPS technology. We are able to meet the technical specifications outlined in the RFP and are competent in the required deliverable formats.

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

### 5.2.2 Use of Subcontractors

TFMoran has formed a strategic partnership with several subcontractors in areas of expertise that TFM does not provide. Relative to the proposed project this would consist of a Realtor and Archaeologist. TFM proposes to team with NAI Norwood as our realtor subcontractor and Monadnock Archaeological Consulting, LLC as our Archaeological subcontractor. We have previously/presently teamed with both firms specifically on similar projects and the familiarity between our firms through past work will continue to generate successful projects.

## 5.3 Communication with Company

A successful project takes teamwork and effective communication. A successful project manager has a communication plan for each project component and communicates pertinent information about project deliverables to the client, project team and public while maintaining an understanding of their audience. At the onset of the project your assigned Project Manager, Nicholas (Nick) Golon, would work with Unitil to devise a communication plan that best fits Unitil's needs and implement this plan through the duration of the project. Likely communication methods would include weekly email updates on work completed to date, work in progress, and upcoming key milestones. These updates would be supplemented by phone calls on time sensitive issues and to confirm levels of responsibilities between TFM and Unitil. Prior to agency or public meetings, a strategy session via teleconference or in person would be held to confirm responsibilities and provide a consistent project message.

As Project Manager, Nick will be responsible for the day-to-day administration of the project and be your one primary point of contact. He will correspond directly with you the Client, subcontractors, permit agencies and the public in conveying the projects message and design specifications in addition to overseeing the support staff, providing guidance on design related items and engaging in components of the design as warranted. Outside of this project Nick oversees our Utility Division and corresponds regularly with numerous clients, agencies, subcontractors and project team members to effectively lead this component of our business.

## 5.4 Additional Information

TFM would suggest the following additional scope not specifically noted in the RFP, which we have included our proposal.

Site Plans:
This Plan Set will include;

- Cover Plan
- Driveway Plan & Profile
- Sight Distance Plan

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

- Lighting Plan

Traffic:
A Trip Generation Memo will be provided to address the anticipated traffic generated by the proposed facility.

Renderings:
Due to the visual nature of the proposed project, TFM will develop a 3D rendering of the subject development for use in conveying the project to the anticipated review agencies.

Agency Comment Allowance:
TFM has included an allowance of 10% of the estimated budget amount for the Site Plans to respond to review comments received by government agencies and their consultants.

Permit Applications

- **NH Fish & Game (NHFG)**
  - Wildlife Assessment per Env-Wq 1503.19(h)
- **Federal Aviation Administration (FAA)**
  - Form 7460-1 Notice of Proposed Construction or Alteration
  - Form 7460-2, Part 2

## 5.5 Work Planning

After consummation of a contract TFMoran would begin the project with a meeting with Unitil to discuss project deliverables, expectations, and responsibilities of each party and a communication plan for the project. With this meeting complete and with Unitil's authorization, TFM would concurrently initiate the Feasibility Assessment and Private and Municipal property search. AS stated in our proposal TFM will team with a respected regional commercial realtor to assist in the land search efforts. It is our understanding that the property search will be conducted based upon specific criteria identified in the Request for Proposal (RFP), supplemented with additional criteria TFM deems appropriate to accurately evaluate the subject parcels. The result of the property search will yield a ranking matrix evaluating pertinent property elements to be utilized in the property ranking. The matrix will be developed using a Microsoft Excel based spreadsheet with dynamic/sortable elements. Our process for identifying and evaluating suitable locations will include but not be limited to utilizing the following web-based services:

- Assessor Data including: Vision Appraisal, Avatar, Warren Group
- Municipal Geographic Information Systems (GIS)
- NH GRANITView (State GIS)
- US Fish & Wildlife Service IPaC
- NH Natural Heritage Bureau DataCheck Tool

TFM® Since 1968
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

- Natural Resources Conservation Services Web Soil Survey
- NH Department of Environmental Services - Aquatic Resource Mapper, Permit Planning Tool and Wildlife Action Plan
- NH Department of Transportation Project Viewer
- NH Division of Historical Resources Enhanced Mapping & Management Information Tool (EMMIT)
- USGS TopoViewer
- Federal Aviation Administration Notice Criteria Tool
- EPA RE-Powering Mapper
- Zillow, Trulia, LoopNet, NEREN (MLS), New England Commercial Property Exchange Assessor's Databases, and other public records

Using the matrix, TFM and our realtor will rank the subject properties based on the criteria listed in the RFP (purchase price, cost to construct, utility upgrade requirements, usable land size, constructability, and permit availability), with the acknowledgment that several elements of the above are to be determined by Unitil as stated in the RFP. Our expectation for each evaluated parcel will consist of a list of comparable properties and an associated narrative to assist in determining an anticipated market value of the property.

TFM and our commercial realtor will then work with Unitil to select the appropriate property to advance to the detailed assessment stage. Once the subject parcel(s) are selected, TFM would verify permit assumptions and advance our due-diligence, with the first items being the potential presence of endangered species or archaeological resources as these items can present long lead times to resolve, which would impact the overall project schedule. Based on the results of the detailed assessment TFM would offer recommendations as which parcels to proceed with.

Once the subject development site is selected TFM will initial boundary research and commencement of boundary and topographic survey's once the initial research and wetland delineation is complete Once the existing conditions for the site have been completed TFM would further our due-diligence with coordinating the siting of the Utility Scale PV with Unitil. This siting effort would account for the electrical configuration requirements of Unitil, and balancing potential environmental impacts with the construction of the Utility Scale PV. With a conceptual location for the Utility Scale PV and associated site features approved by Until, TFM would proceed through engineering design which would include site plan preparation and stormwater modeling for the intended improvements. The site design would then be refined through coordination with Unitil and varies permit agencies prior to permit submittal. TFM would attend meetings with Unitil for the processing of project permits, performing functions as requested by Unitil to provide a concise project message. With permits successfully obtained TFM would issue a final set of site plans for construction, prepare the Stormwater Pollution Prevention Plan, file the NPDES construction general permit and schedule survey crews to provide field layout of clearing limits and base lines. TFM can also provide construction administration services to Unitil to provide a smooth transition from the design/permit phase of the project into the construction phase of the project.

TFM®
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Section 2: Project Schedule*

TFM
Since 1968
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

February 25, 2022

**Unitil Utility Scale PV**
**Concord, NH**

Anticipated Permits:

- **City of Concord**
  - Conservation Commission
    - Wetland Dredge & Fill & Wetlands Buffer Impact Review
  - Planning Board
    - Site Plan Review
    - Conditional Use – Public Utility
    - Conditional Use – Wetlands Buffer Impacts
- **State of New Hampshire**
  - Department of Environmental Services
    - Alteration of Terrain (AoT)
    - Major Wetland Dredge & Fill
  - NH Natural Heritage Bureau
    - NHB Data-check
  - NH Division of Historical Resources
    - Request for Project Review
- **Federal**
  - US ACOE – Section 404
    - New Hampshire Programmatic General Permit (PGP)
  - US EPA
    - NPDES eNOI
  - Federal Aviation Administration
    - Form 7460-1 Notice of Proposed Construction or Alteration

Tentative Submittal/Meeting Schedule*:

| | |
|---|---|
| **3/4/22** | **Project Award** |
| **4/8/22** | **Feasibility Assessments and Preliminary Layouts Completed for the Broken Ground and Kensington DOC Properties** |
| **6/3/22** | **Property Search and Rankings Complete** |
| **8/12/22** | **Detailed Assessment(s) Complete** |
| **8/26/22** | **Construction Site Selected** |
| 9/2/23 - 10/3/23 | Conduct Survey and prepare Existing Conditions Plan |
| 10/3/23 - 11/16/22 | Site Plan Design & Application Development |
| 11/16/22 | City of Concord Conservation Commission Submittal |
| | City of Concord Planning Board Submittal |
| | NHDES Wetland Submittal |
| | NHDES AoT Submittal |
| | NHDHR Submittal |

| | |
|---|---|
| 12/14/22 | City of Concord Conservation Commission Meeting (7:00 pm) |
| 12/21/22 | City of Concord Planning Board Meeting (7:00 pm) |
| | Anticipated NHDHR Response |
| 1/14/23 | City of Concord Conservation Commission Meeting (7:00 pm) |
| 1/16/23 | Submit FAA Form 7460-1 |
| 1/18/23 | City of Concord Planning Board Meeting (7:00 pm) |
| 2/1/23 | Anticipated NHDES Wetland Approval |
| 3/1/23 | Anticipated US ACOE Approval |
| | Anticipated FAA Approval |
| 3/2/23 | Submit EPA eNOI |
| 3/16/23 | EPA eNOI Approval |
| **Q1 2023** | **Final Site Plans Complete and Permit Applications Approved** |
| **Q2 2023** | **Begin Site Construction** |
| **Q3 2023** | **Site Construction Complete** |

*Schedule subject to modification contingent on Town/State review timelines and agenda availability.

TFM®

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Section 3: Pricing Information*

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

February 25, 2022

Unitil Energy Systems
6 Liberty Lane West
Hampton, NH 03842

**RE: Proposal for Engineering & Survey Services**
**Utility Scale PV – Siting, Site Evaluation & Permitting**
**Location to be Determined (NH)**

TFMoran, Inc. (TFM) is pleased to provide this proposal to provide Engineering & Survey services for the Siting, Site Evaluation & Permitting for utility scale photovoltaic generating (PV) facilities within Unitil's electric service territory in New Hampshire. We understand our scope to include identifying and assessing potential locations to site PV facilities (and if necessary, provide the realty service to acquire the desired parcel), develop the final site design and permitting package for the selected location(s) and to provide construction and permit compliance oversight of the site construction. Our scope of work is as follows:

**Scope of Services:**

## 2.1 LAND SEARCH AND ASSESSMENT

### 2.1.1 Unitil Owned Property

TFM will prepare feasibility assessments evaluating the Broken Ground Substation site, located on Portsmouth Road in Concord, NH, and the Kensington DOC site, located on Drinkwater Road in Kensington, NH, for the proposed use as requested. The deliverable(s) for the feasibility assessments will be similar to the work previously prepared by TFM during evaluation of the original construction of the Unitil Broken Ground and Eversource Curtisville Substations. We anticipate the Feasibility Assessment will include the following;

- Zoning Due-Diligence to establish likely permitting requirements and limitations on the subject parcels;
- Schematic Site Layout/Site Prep Plan
- Schematic Grading & Drainage Plan
- Details for site work items suitable for construction
- Order of Magnitude Construction Cost Estimate based on Schematic Plans

### 2.1.2 Private and Municipal Property Search

TFM will subcontract with a respected regional commercial realtor to assist in the land search efforts. We will perform a review of private and municipally owned property within the Unitil NH electric service territories as identified on the Capitol Solar Parcel Suitability and Seacoast Solar Parcel Suitability exhibits provided. It is our understanding that the property search will be conducted based upon specific criteria identified in the Request for Proposal (RFP), supplemented with additional criteria TFM deems appropriate to accurately evaluate the subject parcels. The result of the property search will yield a ranking matrix evaluating pertinent property elements to be utilized in Section 2.13 below. The matrix will be developed using a Microsoft Excel based spreadsheet with dynamic/sortable elements. Our process for identifying

48 Constitution Drive
Bedford, NH 03110
Phone (603) 472-4488
Fax (603) 472-9747
www.tfmoran.com

and evaluating suitable locations will include but not be limited to utilizing the following web-based services:

- Assessor Data including: Vision Appraisal, Avatar, Warren Group
- Municipal Geographic Information Systems (GIS)
- NH GRANITView (State GIS)
- US Fish & Wildlife Service IPaC
- NH Natural Heritage Bureau DataCheck Tool
- Natural Resources Conservation Services Web Soil Survey
- NH Department of Environmental Services - Aquatic Resource Mapper, Permit Planning Tool and Wildlife Action Plan
- NH Department of Transportation Project Viewer
- NH Division of Historical Resources Enhanced Mapping & Management Information Tool (EMMIT)
- USGS TopoViewer
- Federal Aviation Administration Notice Criteria Tool
- EPA RE-Powering Mapper
- Zillow, Trulia, LoopNet, NEREN (MLS), New England Commercial Property Exchange Assessor's Databases, and other public records

### 2.1.3 Property Ranking

Using the matrix derived under Section 2.1.2, TFM and our commercial realtor will rank the subject properties based on the criteria listed in the RFP (purchase price, cost to construct, utility upgrade requirements, usable land size, constructability, and permit availability), with the acknowledgment that several elements of the above are to be determined by Unitil as stated in the RFP. Our expectation for each evaluated parcel will consist of a list of comparable properties and an associated narrative to assist in determining an anticipated market value of the property.

### 2.1.4 Detail Assessment

TFM will prepare a due-diligence detailed assessment of the two (2) highest-ranking parcels identified in the Property Ranking task 2.1.3 to evaluate site feasibility. As required by the RFP we have assumed the parcels will be a 50-acre parcel and 100-acre parcel, both being located in the City of Concord.

<u>Title Commitment Policy:</u>
TFM will review the Title Commitment to interpret potential development limitations associated with the proposed use. We have carried an allowance of (16) hours total for this task.

Estimate: [redacted]

<u>ALTA Boundary, Topographic and Utility Survey:</u>
TFM proposes use of existing plans of record and City GIS information to fulfill the requirements of this task. No site survey is anticipated to complete this task as described. Anticipated site survey costs, subject to final site selection, are addressed in section 2.2.1.

Estimate: [redacted]

<u>Wetland Delineation:</u>
TFM proposes use of the US Fish and Wildlife Service National Wetlands Inventory Mapper to complete this task as described. To verify the anticipated locations a TFM NH Certified Wetland Scientist will conduct a site-walk at the selected locations to confirm their approximate locations. We have carried an allowance of (24) hours total for a wetland scientist relating to this task.

Estimate: [redacted]

Preliminary Site Layout:
TFM will prepare a Preliminary Site Layout Plan showing the layout of the Project on the subject parcels with dimensional information and preliminary grading & drainage design. The plan shall be used to develop estimated site construction costs.

Estimate: [redacted]

Site Construction Cost Estimate:
TFM will prepare order of magnitude construction cost estimates based on the preliminary site layout plans prepared.

Estimate: [redacted]

Phase IA Archeological Sensitivity Assessment:
TFM will coordinate with an Archeological Consulting firm to provide a Phase IA Archeological Sensitivity Assessment for the subject properties. This study will follow guidelines established for archaeological surveys by the New Hampshire Division of Historic Resources (NHDHR).

Estimate: [redacted]

Phase 1 Environmental Site Assessment:
TFM or their subconsultant will provide a Phase 1 Environmental Site Assessment in accordance with ASTM E 1527-05 for the subject properties.

Estimate: [redacted]

## 2.2 FINAL SITE PLAN DEVELOPMENT AND CONSTRUCTION PERMITTING

### 2.2.1 Final Site Plans

As directed in the RFP TFM assumes the final site is a 50-acre parcel located in the City of Concord in which the PV facility is located on a 15-acre portion of the lot.

Boundary, Topographic and Utility Survey and Wetland Delineation:
TFM will conduct research at the Town/City and County Registry of Deeds. TFM will conduct an accurate instrument survey of the subject parcel. TFM will process the field survey data to confirm compliance with the NH Board of Land Surveyors Rules & Regulations. TFM will analyze the field and record boundary evidence and determine the parcel boundaries based on our analysis.

TFM will locate physical improvements on the subject tract and the adjacent roadway. TFM will locate the delineated wetlands as described below. TFM will locate the visible, above ground portions of utilities immediately adjacent to the subject tracts. TFM will show underground utilities based on maps provided by utility owners.
TFM will prepare an Existing Conditions Plan for use in Site Plan Engineering for the proposed development.

TFM assumes the parcel will be of average terrain and geometry with readily available access. This estimate is based on the average time and cost for such services and may vary upon the existing field conditions at the time of the field survey and the actual services performed.

Estimate: [redacted]

A TFM wetland scientist will flag the jurisdictional wetlands on the subject parcels within the area of anticipated work and provide field documentation of wetland boundaries using Corps of Engineers wetland data forms. We have carried an allowance of (3) days for this task.

Estimate: [redacted]

Site Plans:
TFM will prepare a Site Plan package showing the layout of the Project on the selected parcel with dimensional information, grading and drainage design (including oil containment), erosion control, utility service design, landscape design, lighting, and details of site work items suitable for construction, stamped by a licensed State of New Hampshire Professional Engineer. This Plan Set will include;

- Cover Plan
- Existing Conditions
- Site Preparation Plan
- Site Layout Plan
- Grading, Drainage & Utility Plan
- Stormwater Management/Erosion Control Plan
- Driveway Plan & Profile
- Sight Distance Plan
- Landscaping Plan
- Lighting Plan
- Details for site work items suitable for construction

Estimate: [redacted]

Site Soils Mapping:
Site-specific soils mapping is required per the NH Department of Environmental Services, Alteration of Terrain permitting program. As part of this proposal, TFM will have a NH Certified Soil Scientist map readily accessible and identifiable surficial soil types at the Project site.

Estimate: [redacted]

Stormwater Management Report:
A stormwater management report will be provided that includes an analysis of the proposed stormwater management system and its effect on the surrounding area and existing drainage infrastructure in accordance with City and State requirements. TFM will perform test pits and infiltration testing as required for the drainage systems (backhoe cost billed as a reimbursable expense).

Estimate: [redacted]

Traffic:
A Trip Generation Memo will be provided to address the anticipated traffic generated by the proposed facility.

Estimate: [redacted]

Renderings:
Due to the visual nature of the proposed project, TFM will develop a 3D rendering of the subject development for use in conveying the project to the anticipated review agencies.

Estimate: [redacted]

Agency Comment Allowance:
TFM has included an allowance of 10% of the estimated budget amount for the Site Plans to respond to review comments received by government agencies and their consultants.

Estimate: [redacted]

**2.2.2 Permit Applications**

TFM will prepare applications, plans, and applicable support materials for the following filings with the City, State and Federal Government.

- **City of Concord**
  - Planning Board
    - Site Plan Review
    - Conditional Use – Public Utility
    - Conditional Use – Wetland Buffer Impacts
  - Conservation Commission
    - Wetland Dredge and Fill Review
    - Wetland Buffer Impact Review
- **State of New Hampshire**
  - **NH Natural Heritage Bureau (NHB)**
    - NHB DataCheck
  - **NH Fish & Game (NHFG)**
    - Wildlife Assessment per Env-Wq 1503.19(h)
  - **NH Department of Environmental Service (NHDES)**
    - Alteration of Terrain (AoT)
    - Major Wetlands Dredge and Fill (including functional assessment)
  - **NH Division of Historical Resources (NHDHR)**
    - Request for Project Review (RPR)
- **Federal**
  - **US Army Corps of Engineers (ACOE)**
    - NH Programmatic General Permit (PGP)
  - **US Environmental Protection Agency (EPA)**
    - NPDES
      - Construction Stormwater Discharge Notice of Intent (NOI)
  - **Federal Aviation Administration (FAA)**
    - Form 7460-1 Notice of Proposed Construction or Alteration
    - Form 7460-2, Part 2

NH Fish & Game:
TFM will coordinate with NHFG to determine the need for endangered species studies. If studies beyond the wildlife assessment conducted under task 2.1.4. are required, they will be performed as an Additional Service at the Clients direction.

NH Division of Historical Resources:
It is assumed that a Phase 1A archaeological sensitivity assessment is performed under task 2.1.4.

### 2.2.3 Meetings & Hearings

TFM will attend meetings with the Client, City/State Agencies and Boards for the processing of the permit applications. TFM has included an allowance of (60) hours. If additional meetings are needed, they will be attended as directed by the Client and billed on a time and materials basis.

## 2.3 REALTY SERVICES

In the event that Realty (Brokerage) services are requested for the buyer side of any parcels, the commercial realtor could be contracted to represent in the negotiations of that project. The brokerage services fee would be 3% of the total transaction, paid only if the property transfers. In most cases of listed property this fee is paid by the seller and the broker will endeavor to do so. In the event that it is unlisted, the broker requests that the fee be paid at closing by the Buyer.

## 2.4 PROJECT MANAGEMENT

### 2.4.1 Project Manager

Unitil will have one primary point of contact, Nicholas (Nick) Golon, PE, who serves as a Principal in TFMoran's Corporate office located in Bedford, NH. Nick has served as Project Manager for approximately 25 Unitil projects covering approximately 10-years, dating back to the Kingston Distribution Substation in Kingston, NH (built) and most recently the Gulf Street Substation in Concord, NH (built) and the 3348/3350/3359 Line (permitted) in Hampton, Hampton Halls and Seabrook, NH.

### 2.4.2 Company Communication

TFM's Project Manager will participate in routine project meetings to review the status of the construction project. It is our understanding the frequency of such meetings will be dependent on the on-going tasks being performed, and that for convenience, remote meeting call-ins will be conducted. TFM has provided an allowance of (26) hours for this task, which assumes weekly status meetings, not to exceed an hour, over the anticipated 6-month duration of design and permitting of the project.

## 2.5 SITE CONSTRUCTION OVERSITE

### 2.5.1 Survey Services

TFM will provide field layout of the Clear Limits for the proposed PV facility, layout of Silt Fence and Erosion Control Measures, and layout of Construction Baseline including Vertical Control. Three mobilizations have been assumed for this work at a daily rate of [redacted], including office staff support time.

### 2.5.2 Construction Field Representation

TFM will provide a construction field representative to serve as the owner's on-site representation. This individual will have a good understanding of the various aspects of the project's permitting and construction and have a broad general understanding of current construction practices. TFM has assumed a construction schedule of six months, with the construction field representative onsite 5-days a week, with an 8-hour workday, at a rate of [redacted]/hour. This schedule may be modified by Unitil as necessary based on the needs of the project with appropriate notice.

Typical Responsibilities include;

- Develop a thorough familiarity with the purpose of the project, along with the owner's requirements, with the design, and with the contract documents.
- Develop a thorough understanding of the project budget.
- Maintain continuous communication with the owner and contractor.
- Observe the quality and progress of construction to determine, in general, that it is proceeding in accordance with the contract documents and schedule.
- Assist the contractor's superintendent in understanding the intent of the contract documents. In particular, be present and observe and inspect the following procedures to ensure compliance with contract specifications:
    - Shaping/grading and compaction of slopes;

- Installation of drainage and under-drain(s);
- Proper depth of pavements, gravel selects; and fills
- Installation of foundations;
- Witness field tests and review soil analysis, density, concrete, rebar, reports.

- Work with the owner and contractor to provide speedy resolution of field changes and/or site related items.
- Attend meetings as the owner's representative. Submit written meeting notes to the owner following each meeting.
- Create and submit to owner electronic summary report upon completion of on-site evaluations.
- Meet, verify identification, and accompany inspectors from local, state, and/or federal agencies having jurisdiction over the project. Immediately report the results of such inspections to the owner, construction manager or general contractor, and the engineer. Report on any corrective actions.
- Immediately notify the owner, construction manager or general contractor, of any work which, in the opinion of the evaluator is substandard or otherwise not in accordance with the contract documents.
- Evaluate, log, and make recommendations on requests for change orders.
- Maintain separate files of approved and disapproved change orders.
- Participate in final inspections and review as-built drawings for project turnover.

**2.5.3 SWPPP**

TFM will prepare a Stormwater Pollution Prevention Plan (SWPPP) and electronic Notice of Intent (eNOI) for stormwater discharges associated with construction activity under a NPDES Construction General Permit (CGP) to be filed with the Environmental Protection Agency (EPA).

Estimate: [redacted]

TFM will provide SWPPP and Environmental Monitor Report (EMR) inspection services for the subject property and coordinate necessary sediment and erosion control requirements with the Contractor and Owner. An EMR is required for projects requiring an NHDES AoT Permit whereby 5 or more acres will be disturbed. The inspection schedule is dependent on the duration of the project and the amount of precipitation received within a given timeframe (0.50 inch of rainfall) but as directed by the RFP, we have provided budget to cover (25) inspections, noting additional inspections may be required due to rainfall events in excess of (0.50) inches or fewer inspections due to frozen conditions during winter construction. We have assumed a rate of [redacted]/inspection.

Estimate: [redacted]

**Assumptions/Exclusions:**

This proposal is only for work outlined above and is subject to the regulations in place at the time of its preparation. TFM has assumed reasonable recovery and agreement between field monuments and plans and deeds of record with no disputed boundaries. Should we find a significant boundary dispute the Client will be contacted with anticipated costs. The following items have not been included in this proposal but can be performed by our office at the Client's request. TFM will provide a proposal for the Client's authorization prior to beginning such additional work if requested:

- Costs associated with task items 2.1.4, 2.2.1, 2.2.2, have been estimated based on prior project experience consisting of similar scope, and are subject to revision upon final site selection.
- The survey estimate is based on the average time and cost for such services and may vary upon the existing field conditions at the time of the field survey and the actual services performed.

- Significant revisions to the development components/layout requested by Client or Regulatory Agencies after commencement of site design will be additional services.
- TFM assumes no zoning relief is required for the project. We assume this will be evaluated during the detail assessment phase of the project.
- We have excluded Easement Plans, legal descriptions, etc.
- We assume that there is adequate capacity in the adjacent utilities to service this project, and that no offsite utility studies or designs will be required.
- We assume the existing adjacent roadways are adequate for access to this project without improvements, so we have not included a formal Traffic Impact and Access Study (TIAS) and we assume that no offsite roadway designs will be required.
- This proposal does not include structural design for any onsite retaining walls, nor any retaining walls or underpinning to support adjacent structures.
- We have not included Geotechnical Studies, Wetlands Studies (other than those identified), Hazardous Waste Studies Fiscal Impact Studies, Noise Studies, Air Quality Studies, Wildlife Studies (other than those identified), Phase 1B Archeological Studies or other technical studies and reports not included above.

**Compensation:**

TFM will complete this Scope of Services for the Estimated Sums shown below plus miscellaneous reimbursable expenses.

**Schedule of Fees:**

| | | |
|---|---|---|
| **2.1.1** | **Unitil Owned Property Search** | [redacted] |
| **2.1.2** | **Private and Municipal Property Search** | [redacted] |
| **2.1.3** | **Property Ranking** | [redacted] |
| **2.1.4** | **Detail Assessment** | [redacted] |
| ***Section 2.1 Subtotal*** | | [redacted] |
| **2.2.1** | **Final Site Plans** | [redacted] |
| **2.2.2** | **Permit Applications** | [redacted] |
| **2.2.3** | **Meetings & Hearings** | [redacted] |
| ***Section 2.2 Subtotal*** | | [redacted] |
| **2.4.1** | **Project Manager** | **NA** |
| **2.4.2** | **Company Communication** | [redacted] |
| ***Section 2.4 Subtotal*** | | [redacted] |
| **2.5.1** | **Survey Services** | [redacted] |
| **2.5.2** | **Construction Field Representative** | [redacted] |
| **2.5.3** | **SWPPP ($250 per inspection)** | [redacted] |
| ***Section 2.5 Subtotal*** | | [redacted] |
| **Total:** | | [redacted]* |

*Section 2.3 – no cost estimate provided as it is assumed Unitil, and the realtor will enter into a separate agreement should they be contracted for the land acquisition.

Fees that may be required by City, State, and Federal governments and/or other agencies shall be paid directly by the Client. In general, normal and typical reimbursable expenses for projects of this type and scope run approximately [redacted] of the estimated budget cost. TFM will bill Client monthly and the bill will reflect work completed at the time of the billing.

We appreciate this opportunity to provide you with a proposal for this project and are available to meet with you at any time to discuss this project, the scope of work or budget.

We look forward to working with you on another successful project!

Sincerely,
**TFMoran Inc.**

Nicholas Golon, P.E.
Principal

TFM Since 1968

Civil Engineers
Structural Enginee
Traffic Engineers
Land Surveyors
Landscape Archite
Scientists

# UNITIL UTILITY SCALE PV FEE SCHEDULE
**Applicable: March 2022 – December 2023**

| DEPARTMENT | CLASSIFICATION | RATE |
|---|---|---|
| **E – Engineering** | Expert Witness | [redacted] / Hour |
| | Chief Engineer | [redacted] / Hour |
| | Chief Structural Engineer | [redacted] / Hour |
| | Project Supervisor | [redacted] / Hour |
| | Senior Project Manager | [redacted] / Hour |
| | Senior Traffic Engineer | [redacted] / Hour |
| | Project Manager | [redacted] / Hour |
| | Traffic Engineer | [redacted] / Hour |
| | Senior Civil Engineer | [redacted] / Hour |
| | Structural Engineer | [redacted] / Hour |
| | Certified Professional in Erosion/Sediment Control | [redacted] / Hour |
| | Engineer | [redacted] / Hour |
| | Engineering Technician | [redacted] / Hour |
| | Construction Inspector | [redacted] / Hour |
| **S – Surveying** | Expert Witness | [redacted] / Hour |
| | Chief Surveyor | [redacted] / Hour |
| | Project Manager | [redacted] / Hour |
| | Surveyor | [redacted] / Hour |
| | Survey Technician | [redacted] / Hour |
| | Field Operations Manager | [redacted] / Hour |
| | Robotic Field Crew | [redacted] Hour |
| | Chief of Party | [redacted] / Hour |
| | Instrument Operator | [redacted] / Hour |
| | Field Technician | [redacted] / Hour |
| **W – Environmental** | Wetland Scientist | [redacted] / Hour |
| | Subsurface Designer | [redacted] / Hour |
| | Environmental Scientist | [redacted] / Hour |
| **D – CADD / GIS** | Senior CADD Designer | [redacted] / Hour |
| | CADD Technician | [redacted] / Hour |
| **P – Landscape Architecture** | Landscape Architect | [redacted] / Hour |
| | Land Planner / Designer | [redacted] / Hour |
| **A – Administration / Support** | Support | [redacted] / Hour |
| | Project Coordinator | [redacted] / Hour |

REDACTED


**TFMoran, Inc.** **SCHEDULE OF REIMBURSABLE EXPENSES***

| | | |
|---|---|---|
| **PRINTS** | In-House: | |
| | Xerox Plan Copier | [redacted] / Square Foot |
| | Mylar (Plotter) | [redacted] / Square Foot |
| | Bond (Plotter) | [redacted] / Square Foot |
| | Color Plot - Bond | [redacted] / Square Foot |
| | Color Plot - High Gloss Photo | [redacted] / Square Foot |
| | Color Print - 8.5 X 11 | [redacted] / Page |
| | Black and White – 8.5 X 11 | [redacted] / Page |
| | Color Print - 11 X 17 | [redacted] / Page |
| | Black and White – 11 X 17 | [redacted] / Page |
| | Framing | [redacted] / Print |
| **RENDERINGS** | Conceptual Color Presentation | [redacted] |
| | Detailed Colored Plan Presentation | [redacted] |
| | Perspective Rendering | [redacted] |
| **REPROGRAPHICS SERVICES** | Outside Service | [redacted] |
| **POSTAGE and HANDLING** | | [redacted] |
| **COURIER SERVICES** | | [redacted] |
| **APPLICATION / SUBMISSION FEES** | | [redacted] |
| **CONSULTANTS / SUBCONTRACTORS** | | [redacted] |
| **BACKHOE and OPERATOR** | | [redacted] |
| **TRAVEL / MILEAGE** | | [redacted] / Mile |
| **TRAFFIC COUNTERS** | | [redacted] |
| **FIELD MONUMENTATION** | Granite Bounds | [redacted] Per Bound |
| | Iron Pins | [redacted] Per Pin |
| | Wood Stakes | [redacted] Per Stake |
| **REGISTRY FEES** | | [redacted] |

* Reimbursable expenses include but are not limited to the above. Revised: 02/24/2022

TFM®
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Section 4: Project Manager Resume*

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**NICHOLAS C. GOLON, PE**
Senior Project Manager
Principal

**EXPERIENCE**

Mr. Golon serves as a Senior Project Manager and a Principal for TFMoran, Inc. He is responsible for the management, engineering design and permitting of land development projects. Mr. Golon has over 20 years of experience in site planning, drainage design, sewer design, and local, state and federal permitting for residential, commercial, industrial, municipal, and energy projects.

***Selected project experience includes:***

- **Industrial Roofing Corporation (IRC), Yankee Solar Array, Dublin, NH:** Project Manager for Site Plan and permitting for a 125kW Ground Mounted Solar Array at the Yankee Publishing Facility. Tasks include layout and landscaping improvements. Permits include a NHDOT Driveway Permit and Town of Dublin Site Plan Review, Driveway and Building Permits.
- **Unitil, Broken Ground Substation and Eversource Energy, Curtisville Substation, Concord, NH:** Project Manager for site plan and permitting of one (1) transmission and one (1) distribution substations, including structures to house electrical equipment, access, parking, and stormwater management areas. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NHDES AoT and Wetland Permits, Concord Subdivision, Site Plan, Conditional Use Permit, FAA Determination of No Hazard.
- **Unitil, Gulf Street Substation Reconstruction, Concord, NH:** Project Manager for Site plan and permitting to reconstruct the existing Unitil Gulf Street Substation and adjacent overhead electric lines. Tasks include layout and access design. Permits include City of Concord Planning Board Site Plan Approval and FAA Determination of No Hazard.
- **PSNH, Merrimack Station Clean Air Project, Bow, NH:** Project Manager for site design and state and local permitting for the Phase I, site preparation stage of this $400 million project to construct a flue gas desulfurization scrubber on this PSNH coal-fired power plant. Details of Phase I include access and security improvements, creation of parking and lay-down areas, stormwater management, grading design, septic design and creation of an integrated construction Storm Water Pollution Prevention Plan (SWPPP) prior to the Station upgrades proposed in Phase II of the project.
- **GE Aviation Plant Expansion, Hooksett, NH:** Project Manager for site plan and permitting of a 55,000sf plant expansion on Industrial Park Drive. The building expansion was sited over a portion of a Town-owned road, which was discontinued and re-aligned for local traffic.
- **PSNH, Farmwood Road Substation, Concord, NH:** Site Plan, Subdivision Plan and permitting for original construction and expansion of Farmwood Road Substation. Responsible for management and design in overseeing industrial land development project. Design tasks include grading, drainage, Storm Water Pollution Prevention Plan (SWPPP), and local, state and federal permitting.

**EDUCATION**

Wentworth Institute of Technology, BS Civil Engineering Technology

**REGISTRATIONS, CERTIFICATIONS and AFFILIATIONS**

Professional Engineer, NH and ME
American Society of Civil Engineers, Member
American Society of Civil Engineers – NH Section, Board of Directors
NHDOT Local Public Agency (LPA) Certification #1386

*Rev. 10/21*

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Appendix A – TFM Relevant Project Experience in NH by Region*

TFM Civil Engineers Structural Engineers Traffic Engineers Land Surveyors Landscape Architects Scientists

## RELEVANT PROJECT EXPERIENCE BY REGION
## (NH Southern/NH Lakes/NH Northern/NH Seacoast/NH Western, Massachusettes)

### NEW HAMPSHIRE – SOUTHERN REGION:

**PSNH, Pinardville Substation, Goffstown (Pinardville), NH:**

- Site Plan and permitting for replacement of existing Pinardville Distribution Substation. Tasks include grading, stormwater management design, landscape architecture, Municipal Planning Board, and ZBA permits. Construction monitoring provided.
- Boundary and Topographic Surveys, wetland mapping, and As-built surveys. Preparation of easement documents and construction layout.

**Eversource Energy, Rimmon Substation, Goffstown, NH:**

- Site plan and permitting to replace the existing Rimmon Distribution substation and construct a control house within the new substation yard. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES-AoT, and Goffstown Planning Board permits. Stormwater monitoring provided.

**PSNH, Malvern Street Substation, Manchester, NH:**

- Site Plan and permitting for expansion of existing Malvern Street Distribution Substation to convert the Manchester area 4.16 kV system to 12.47kV. Tasks include grading, stormwater management design, landscape architecture, and Municipal Planning Board and ZBA permits.
- Boundary and Topographic Surveys. Construction Layout.

**PSNH, 393 Line Project, Manchester, NH:**

- Site plans and permitting for 1.3-mile utility corridor, reliability improvement project. Tasks include NHDES Dredge and Fill Permit, NH Division of Historic Resources Section 106 review, US Army Corps of Engineers permit area determination, and Municipal Conservation Commission permits. Construction monitoring provided. Construction ongoing.
- Corridor Easement Control, Boundary, wetland location Surveys.

**PSNH Call Center, Manchester, NH:**

- Site Plan and permitting for the installation of the Call Center and parking garage facility. Permits included discontinuance of historic right-of-ways through the site and Planning Board.
- Boundary, topographic, utility, and layout survey to support site design for a 15,430 sf Call Center building with a 1-level parking garage.

**Eversource Energy, Blaine Street Substation, Manchester, NH:**

- Site Plan and permitting for expansion of existing Distribution Substation to convert the Manchester area 4.16 kV system to 12.47kV. Tasks include grading, stormwater management design, landscape architecture, and Municipal Planning Board and ZBA permits.
- Boundary, Topography, and Existing Conditions Plan.

**PSNH, Merrimack Station Clean Air Project, Bow, NH:**

- Site design and state and local permitting for the Phase I, site preparation stage of this $450 million project to construct a flue gas desulfurization scrubber on this PSNH coal-fired power plant.
- Design details of Phase I include access and security improvements, creation of parking and lay-down areas, stormwater management design, grading design and septic design.
- Obtained permits including Municipal Planning Board, Conservation Commission and ZBA, NHDES Alteration of Terrain, NHDES Shoreland, NHDES Dredge and Fill, US Army Corps of Engineers New Hampshire Programmatic General Permit (PGP), NPDES NOI, NHDES Subsurface Systems and FAA for notice of proposed construction or alteration including structures exceeding obstruction standards.
- TFM created both an integrated construction Storm Water Pollution Prevention Plan (SWPPP) prior to the Station upgrades proposed in Phase II as well as an operational SWPPP for the Station once construction is complete.
- TFM provided construction monitoring services for onsite septic installation on behalf of NHDES and serves on project SWPPP Management Team responsible for inspection and coordination of erosion and sedimentation controls for ongoing construction.
- Boundary, Topographic, Utility Surveys, Construction Layout and Supervision and As-built surveys.

**Eversource Energy, Merrimack Station Subdivision, Bow, NH:**

- Site plan and permitting of roadway and drainage associated with a two-lot subdivision, predicated by the required divestiture. Permits include Bow Planning Board Approval.

**PSNH, Mobile Substation Facility, Bow, NH:**

- Site Plan and permitting for proposed mobile substation warehouse buildings and associated site improvements. Tasks include grading, stormwater management, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, Municipal Planning Board and Conservation Commission permits and stormwater monitoring.
- Topographic Survey and Construction Layout.

**PSNH, Central Warehouse, Bow, NH:**

- Site Plan and permitting for the installation of the Central Warehouse facility. Permits included Town Planning Board, NHDES-AoT and NHDES-Septic.
- Boundary, Topographic and Utility Surveys and Construction Layout.

**PSNH, 32W4 Line Project, Londonderry-Derry, NH:**

- Site plans and permitting for 2.5-mile utility corridor, reliability improvement project. Tasks include preparation of NHDES Dredge and Fill Permit, NH Division of Historic Resources Section 106 review, and Municipal Conservation Commission permits.
- Corridor Easement Control, Boundary, wetland location Surveys, Easement Plans.

**PSNH, 32W5 Line Project, Derry, NH:**

- Site plans and permitting for 1.2-mile utility corridor, reliability improvement project. Tasks include preparation of Storm Water Pollution Prevention Plan (SWPPP), associated NPDES NOI, NHDES Dredge and Fill Permit and Municipal Conservation Commission permits. Construction monitoring provided.
- Corridor Easement Control, Boundary, wetland location Surveys, Easement Plans.

**Eversource Energy, Derry Area Work Center Expansion, Derry, NH:**

- Site plans for reconstruction of the paved storage yard at the Existing Derry Area Work Center. Tasks include construction specifications and stormwater management improvements.

**PSNH, Mammoth Road Substation, Londonderry, NH:**

- Site Plan and permitting for upgrades to Mammoth Road Substation. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI and Municipal Planning Board, Conservation Commission and ZBA permits. Construction monitoring provided.
- Boundary and Topographic Surveys, wetland mapping, and As-built surveys.

**PSNH, Scobie Pond Substation, Londonderry-Derry, NH:**

- Site Plan and permitting for Scobie Pond 345 kV Substation, 115kV substation and 12.47kV distribution substation. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Alteration of Terrain Permit, NHDES Dredge and Fill Permit, Municipal Planning Board and Conservation Commission permits and stormwater monitoring.
- Boundary, Topographic and Wetland Surveys for Substation expansions.

**PSNH, Construction Test & Maintenance Facility, Hooksett, NH:**

- Site design, permitting, structural engineering, traffic engineering, and landscape architecture for new one-story 67,000+sf office and warehouse building to provide a centralized location for PSNH's transmission resources in southern New Hampshire. Tasks include grading, stormwater management design, sewer design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Alteration of Terrain Permit, Municipal Planning Board and Conservation Commission permits. Stormwater monitoring provided.
- Boundary and Topographic Surveys, wetland mapping, and As-built surveys. Preparation of easement documents and construction layout.

**Eversource Energy, Legends Drive Pole School, Hooksett, NH:**

- Site plan and permitting of a pole school area to train new employees at the existing Legends Drive Facility. Permits include NHDES AoT Amendment.

**Eversource Energy, Legends Drive Parking Expansion, Hooksett, NH:**

- Design and permitting of a paved parking area expansion with associated stormwater management improvements. Permits include NHDES AoT Amendment.

**PSNH, Hooksett Warehouse, Hooksett, NH:**

- Site Plan and permitting for proposed warehouse building and associated site improvements. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, Municipal Planning Board and Conservation Commission permits and stormwater monitoring.
- Boundary, Topographic, and Utility Survey, Construction Layout and As-Built Survey, Lot Line Adjustment Plan.

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 30 of 50



**Eversource Energy, Legends Drive Pole Storage Facility, Hooksett, NH:**

- Site Plan and permitting to construct an 6-acre paved storage yard with associated access and stormwater management systems. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES-Wetlands Dredge and Fill, NHDES-AoT, Hooksett Planning Board and Conservation Commission permits. Stormwater monitoring provided.
- Boundary, Topographic, and Utility Survey, Construction Layout and As-Built Survey, Lot Line Adjustment Plan.

**PSNH, Bedford Substation, Bedford, NH:**

- Site Plan and permitting for the expansion of the Bedford substation. Permits included Historic Commission (archeological study) Bedford Board of Adjustment, Planning Board, Conservation Commission, NHDES-Wetlands Bureau, and NHDES-AoT.
- Boundary, topographic, wetland, and utility surveys to support site design for a substation and transmission lines.

**PSNH, Kundu Property, Bedford, NH:**

- ALTA survey and wetlands for substation mitigation.

**Eversource Energy, Bedford Area Work Center, Bedford, NH:**

- Site plan and permitting to construct a 5,000 square foot garage, paved storage yard and 1-acre gravel marshalling area, with associated access, parking, and site improvements. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES-AoT, and Bedford Planning Board permits. Stormwater monitoring provided.

**PSNH, Nowell Street Substation, Nashua, NH:**

- Site Plan and permitting for conversion of Nowell Street Substation to pad mount transformers. Tasks include grading, stormwater management design, NHDES Shoreland permit, and Municipal Planning Board, Conservation Commission and ZBA permits. Construction monitoring provided.
- Boundary and Topographic Surveys, wetland mapping.

**Eversource Energy, Front Street Substation, Nashua, NH:**

- Site plan and permitting to construct a substation yard expansion, replace existing electrical infrastructure and security fencing, and develop a comprehensive landscape plan in conjunction with the City of Nashua Riverwalk. Permits included City Administrative Approval.

**PSNH, New Boston Pad Mount Transformer, New Boston, NH:**

- Site Plan and permitting for New Boston pad mount transformer. Tasks include grading, stormwater management design. Construction monitoring provided.
- Boundary and Topographic Surveys, wetland mapping, easement plan preparation and Construction layout.

**PSNH, North Merrimack Switching Substation, Merrimack, NH:**

- Civil engineering and permitting services for a switching substation with a 61,800-sf yard area. TFM obtained a NHDES Alteration of Terrain permit and filed a USEPA Notice of Intent under the NPDES Stormwater CGP.
- Topographic and Utility survey.

**Granite Ridge Energy, Londonderry, NH:**

- Site Plan and permitting for the installation of the Granite Ridge Energy power plant. Permits included NHDES-Wetlands Bureau, NHDES-AoT, and Town informational hearings.
- ALTA, Boundary, ROW, Topographic, Utility surveys, Utility ROW staking for various consultants for development of the Granite Ridge Power Station and related transmission and utility lines.

**AES Power, Line ROW from Power Plan to Grid, Londonderry/Litchfield, NH:**

- Survey control and wetland location for Power Line Corridor. Preparation of Easement Plans. Construction Layout for Pole and Pole structure contractor.

**Keyspan, Pembroke, NH:**

- Route Survey/Gas line design/Permitting.

**Loudon Road, Concord, NH:**

- Engineering review and field survey services for 3,400 LF +/- of proposed gas main along Loudon Road for KeySpan Energy Delivery.

**Unitil, Broken Ground Substation and Eversource Energy, Curtisville Substation, Concord, NH:**

- Site plan and permitting to construct one (1) transmission and one (1) distribution substations, including structures to house electrical equipment, access, parking, and stormwater management areas. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NHDES AoT and Wetland Permits, Concord Subdivision, Site Plan, Conditional Use Permit, FAA Determination of No Hazard.
- **Unitil Energy, Broken Ground Substation and Eversource Energy, Curtisville Substation Compliance Monitoring, Concord, NH:** Weekly construction compliance monitoring inspections to ensure compliance with all local, state, and federal permitting associated with the project (City Site Plan, City CUP, City Subdivision, NHDES AoT, NHDES Dredge and Fill, FAA

**Eversource Energy, Farmwood Substation, Concord, NH**

- Site plan and permitting to construct a 40,000 square feet substation yard expansion, and a 6,800 square foot structure to house two synchronous condensers. Tasks include layout, grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES-AoT Amendment, and Concord Planning Board permits. Stormwater monitoring provided.

**City of Manchester, NH: Survey for Cohas Brook Interceptor Project for HTA Companies:**

- Survey of over 2 miles of control, cross country survey, and easement and construction stakeout for the Phase 2 Interceptor project.

**City of Manchester West Side CSO, Manchester, NH:**

- Topographic, route and existing conditions survey for CDM, Inc., HTA Companies, and M&E. Over 15 miles combined survey, control, and easement plan work.

**Eversource Energy, Eddy Street Substation, Manchester, NH:**

- Site plan and permitting to construct a substation yard expansion, replace existing electrical infrastructure and security fencing to meet current Eversource standards, and construct an approximately 600 square foot control house within the substation yard. Tasks include layout, grading, stormwater management design, NHDES-Shoreland and Manchester Planning Board permits and ZBA Special Exception. Construction monitoring provided.

**Eversource Energy, Merrimack Station Parking Expansion, Bow, NH:**

- Site plan and permitting to reconstruct a 37-space paved parking area with associated stormwater management improvements. Tasks include layout, grading, stormwater management design, and NHDES AoT Permit Amendment.

**Eversource Energy, Mobile Substation Facility, Bow, NH:**

- Site plan and permitting to construct a one (1) bay addition at the existing Eversource Facility. Tasks include layout, grading, access, parking, stormwater management improvements, and wastewater holding tank design, a Town of Bow Site Plan Amendment and Conditional Use Permit.

**Eversource Energy, Mobile Substation Facility, Bow, NH:**

- Site plan and permitting to construct a 2,400 square foot addition at the existing Eversource Facility. Tasks include layout, grading, access, parking, stormwater management improvements and a Town of Bow Site Plan Amendment.

**Eversource Energy, 1250 Hooksett Road Site Improvements, Hooksett, NH:**

- Site plan and permitting to construct a parking lot expansion at the existing Eversource 1250 Hooksett Road Facility. Tasks include layout, grading, access, parking, stormwater management improvements. Permits include a Town of Hooksett Site Plan Amendment.

**Eversource Energy, Construction, Test & Maintenance (CT&M) Parking, Hooksett, NH:**

- Site plan and permitting to construct a paved parking lot expansion with associated stormwater management improvements. Tasks include layout, grading, stormwater management design. Permits include a NHDES AoT Permit Amendment and Hooksett Site Plan Amendment.

**Eversource Energy, Greggs Substation, Goffstown, NH:**

- Site plan and permitting to construct a 750 square foot control building expansion at the existing Eversource Greggs Substation. Tasks include layout, grading, access, parking, and stormwater management improvements. Permits include a Town of Goffstown Site Plan Approval.

**Eversource Energy, Greggs Substation Rebuild, Goffstown, NH:**

- Site plan and permitting to reconstruct the existing Eversource Greggs Substation and adjacent overhead electric lines. Tasks include layout, grading, access, parking, and stormwater management design. Permits include NHDES AoT, Shoreland, Subsurface

Effluent Disposal Permits, NHDOT Driveway Amendment Permit, Town of Goffstown ZBA Variances and Special Exception, Planning Board Site Plan Approval and Conditional Use Permit, Grasmere Water Precinct Service Connection Permit and FAA Determination of No Hazard.

**Eversource Energy, Millyard Substation Relocation, Nashua, NH:**

- Site plan and permitting to relocate the existing Eversource Millyard Substation as part of a Land Swap with the City of Nashua. Tasks include layout, grading, access, parking, and stormwater management design. Permits include City of Nashua Planning Board Lot Line Adjustment (LLA) and Site Plan Approval, and FAA Determination of No Hazard.

**Eversource Energy, 3891 Line, Nashua, NH:**

- Permitting to replace the existing Eversource 3891 Line in association with the reconstruction of the Eversource Millyard Substation. Tasks include layout and permitting development for NHDES Shoreland and Wetland Permits, and Nashua ZBA Special Exception.

**Eversource Energy, W157 Line, Litchfield, NH:**

- Site plan and permitting to install electrical upgrades along the existing Eversource W157 Line. Tasks include layout, grading, and access design. Permits include NHDES Wetland Permit, NHDOT Temporary and Permanent Driveway Permits, Town of Litchfield ZBA Special Exception, and FAA Determination of No Hazard.

**Eversource Energy, Nashua Area Work Center, Nashua, NH:**

- Site Plan and permitting for construction of a 14,500 square foot garage and office addition at the existing Eversource Nashua Area Work Center (AWC). Tasks include layout, grading, access, parking, utilities, and stormwater management improvement design. Permits include a NHDES AoT Permit, City of Nashua Planning Board Site Plan Approval, and FAA Determination of No Hazard.

**Eversource Energy, Boulder Cove Wire Crossing, Atkinson, NH:**

- Surveying and permitting services to reconstruct the existing 3818 4.16 kV Line water crossing across Boulder Cove. Tasks included permitting development for a NH Public Utilities Commission (PUC) Line Crossing.

**Eversource Energy, Amherst Substation Expansion, Amherst, NH:**

- Site Plan and permitting for proposed electrical upgrades at the existing Eversource North Keene Substation including construction of a 3,080 square foot electrical enclosure to house proposed synchronous condensers. Tasks include layout, grading, stormwater management improvements and site access driveway design. Permits include a NHDES AoT Permit, Town of Amherst Planning Board Lot Line Adjustment (LLA), Site Plan Approval, and Stormwater Permit, and FAA Determination of No Hazard.

**Eversource Energy, 314 Line, Milford, NH:**

- Site plan and permitting to reconstruct the existing Eversource 314 Line. Tasks include layout and access design. Permits include a NHDES Wetland Permit.

**Unitil, Gulf Street Substation Reconstruction, Concord, NH:**

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 34 of 50


- Site plan and permitting to reconstruct the existing Unitil Gulf Street Substation and adjacent overhead electric lines. Tasks include layout and access design. Permits include City of Concord Planning Board Site Plan Approval and FAA Determination of No Hazard.

**Unitil, 374 Line, Concord, NH:**

- Site plan and permitting to reconstruct the existing Unitil 374 Line from Theater Street to Gulf Street in coordination with the Gulf Street Substation Reconstruction. Tasks include layout and access design. Permits include NHDES Wetland Permit, City of Concord Planning Board Conditional Use Permits, and FAA Determination of No Hazard.

**Unitil, 37 Line Rebuild, Concord, NH:**

- Site plan and permitting to reconstruct the existing Unitil 37 Line from MacCoy Street to Village Street. Tasks include layout and access design. Permits include NHDES Wetland Permit, City of Concord Planning Board Conditional Use Permits, and FAA Determination of No Hazard.

**Eversource Energy, Warner Line Crossing, Warner, NH:**

- Surveying and permitting services to reconstruct the existing 3410/317 Line water crossing across the Warner River. Tasks included permitting development for a NH Public Utilities Commission (PUC) Line Crossing.

**Unitil, 38 Line, Concord, NH:**

- Surveying services to reconstruct a portion of the existing Until 38 Line in Concord, NH.

*TFM also has extensive survey experience in the surrounding communities of Hooksett, Goffstown, Amherst, Milford, and Auburn.*

## NEW HAMPSHIRE - LAKES REGION:

**PSNH, 3166 Line Removal Project, Franklin, Hill & New Hampton, NH:**

- Site plans and permitting for 11-mile utility corridor, pole, and line removal project. Tasks include preparation of NHDES Dredge and Fill Permit, NH Division of Historic Resources Section 106 review, and Municipal Conservation Commission permits. Construction monitoring provided.
- Corridor Easement Control, Boundary, wetland location Surveys.

**PSNH, Eastman Falls Plant, Franklin, NH:**

- ALTA Survey/ Easement Plans for divestiture.

**PSNH, Messer Street/Former MGP Site, Laconia, NH:**

- Boundary survey and subsequent Topographic and Hydrographic Surveys for Haley & Aldrich Site Remediation Plan. Layout and volumetric surveys and As-builts for Maxymillian Company for the Site Restoration.

**Eversource Energy, Messer Street Substation, Laconia, NH:**

- Site plan and permitting to construct an 800 square foot control house, replace the existing transformers, electrical equipment and fencing to meet current Eversource standards. Tasks include layout, grading, stormwater management design, NHDES-Shoreland and Manchester Planning Board permits and ZBA Special Exception. Construction monitoring provided.

**New Hampshire Electric Cooperative, Moultonborough Neck Substation, Moultonborough, NH:**
- Construction Plans/Specifications for a new 34.5kV-12.47/7.2kV Substation. Permits included NPDES NOI and preparation of a Storm Water Pollution Prevention Plan (SWPPP).

**Keyspan Energy, Laconia, NH:**
- Easement Plan & Boundary Research Fairmont Street.

**Keyspan Energy, Tilton, NH:**
- Topographic and Route Surveys Rte 3, Rte 140, and East Main Street for utility expansion.

**Eversource Energy, Pemi Substation, New Hampton, NH:**
- Construction and permitting compliance monitoring for reconstruction of the existing Eversource Energy Pemi-Substation.

**Eversource Energy, Ossipee Line Crossing, Ossipee, NH:**
- Surveying and permitting services to reconstruct the existing 3116X Line water crossing across the Bearcamp and Lovell Rivers. Tasks included permitting development for a NH Public Utilities Commission (PUC) Line Crossings.

**Eversource Energy, Tilton Area Work Center, Tilton, NH:**
- Site Plan and permitting for a proposed 2,600 square foot prefabricated fleet vehicle storage enclosure at the existing Eversource Tilton AWC. Tasks include layout and City of Tilton Building Permit.

*TFM's experience also covers many other Lakes Region Communities.*

## NEW HAMPSHIRE – NORTHERN REGION:

**PSNH, Saco Valley Substation, Conway NH:**
- Site Plan and permitting for upgrades to Saco Valley Substation. Tasks include grading, stormwater management, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Dredge and Fill Permit, NH Division of Historic Resources Section 106 review and Municipal Planning Board and Conservation Commission permits.
- Boundary and Topographic Survey.

**New Hampshire Electric Cooperative Intervale Substation, Conway/Bartlett, NH:**
- Coordinate design work with Substation Design Firm. Coordinate geotechnical work.

**North Conway Water Precinct/CDM Inc., North Conway, NH:**
- Several miles of Street/Route Surveys for Water, Sewer, and Drainage Improvements.

**Windfarm Project, Groton, NH:**
- GPS Horizontal and Vertical Control for Project Aerial Mapping by Minuteman Mapping, project consultant.

**Eversource Energy, White Lake Substation, Tamworth, NH:**
- The existing White Lake Substation was subdivided, as part of the required divestiture, to provide clear separation between generation and transmission/distribution for the future owner of the generation assets. NHDES and local Subdivision approval were obtained as part of the project.

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 36 of 50


**Eversource Energy, Lancaster Area Work Center, Lancaster, NH:**

- Site plan and permitting of a 1,575 square foot garage addition and paved parking and drive improvements with associated stormwater management systems at the existing Eversource Energy Lancaster Area Work Center (AWC). Tasks include layout, grading, stormwater management improvements and NHDOT Driveway permit.

**Eversource Energy, Gorham Hydro Substation, Gorham, NH:**

- Site plan and permitting for the reconstruction of the existing Eversource Gorham Hydro Substation. Tasks include layout and access. Permits include NHDES Shoreland and Wetland Permits.

## NEW HAMPSHIRE - SEACOAST REGION:

**PSNH, Eastport Substation, Rochester, NH:**

- Site Plan and permitting for proposed Eastport Substation. Tasks include grading and stormwater management design, preparation of Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Alteration of Terrain Permit, NHDES Wetland Dredge and Fill Permit, NH Division of Historic Resources Section 106 review and Municipal Planning Board and Conservation Commission permits.
- Boundary and Topography Surveys, wetland location for substation expansion. Construction layout.

**Unitil, Kingston Distribution Substation, Kingston, NH:**

- Site Plan and permitting for upgrades to existing distribution substation. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, and Municipal Planning Board, Conservation Commission permits.
- Boundary and Topographic Surveys. Construction Layout.

**PSNH, Peaslee Transmission Substation, Kingston, NH:**

- Site Plan and permitting for proposed switching station. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Wetland Dredge and Fill Permit, NH Division of Historic Resources Section 106 review and Municipal Planning Board, Conservation Commission and ZBA permits.
- Boundary and Topographic Surveys. Construction Layout.

**Unitil, Circuit/Route 111, Kingston and Danville, NH:**

- Design and permitting for construction of the 5-mile distribution line along the 22X1 Circuit in the Towns of Kingston and Danville, NH. Permits include NHDES Wetland Minimum Impact, NHDOT TCP, Danville Planning Board permits.

**PSNH, 3111- & 3171-Line Project, Portsmouth/Greenland, NH:**

- Site plans and permitting for 1.2-mile utility corridor, reliability improvement project. Tasks include NHDES Dredge and Fill Permit, NH Division of Historic Resources Section 106 review, US Army Corps of Engineers approval, and Municipal Planning Board and Conservation Commission permits.
- Corridor Easement Control, Boundary, wetland location Surveys.

**PSNH, Brentwood Substation Site, Exeter, NH:**

- Boundary and Topography Surveys, Wetland location.

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 37 of 50


**Eversource Energy, Shattuck Laydown Area, Newington, NH:**

- Site Plan and permitting for construction of a 10-acre gravel laydown and staging yard associated with the Eversource Seacoast Reliability Project. Tasks include layout, grading, access, parking, and stormwater management design. Permits include NHDES AoT and Wetland Permit, and Town of Newington Planning Board Site Plan Approval.

**Unitil, 3348/3350 Line, Hampton/Seabrook/North Hampton, NH:**

- Permitting to inspect wood pole structures along the existing Unitil 3348/3350 from Hampton to Seabrook Substations. Permits include NHDES Wetland Permit.

**Unitil, 3346 Line, Hampton, NH:**

- Traffic Control Plan and permitting to reconstruct the existing Unitil 3346 Line crossing NH Route 101. Permits include a NHDOT Temporary Driveway Permit.

**Unitil, 3348/3350 Line Emergency Permitting, Hampton/Seabrook/North Hampton, NH:**

- Permitting to inspect approximately 110 wood pole structures along the existing Unitil 3348/3350 from Hampton to Seabrook Substations. Tasks include layout and access design. Permits include NHDES Wetland Emergency Authorization.

**Unitil, 3348/3350/3359 Line Rebuild, Hampton/Seabrook/North Hampton, NH:**

- Site plan and permitting to reconstruct 4.6-miles of the existing Unitil 3348/3350 Line, from Hampton to Seabrook Substations and 1.0-mile of the 3359 Line from the Seabrook Power Plant to the 3348/3350 Line. Tasks include layout and access design. Permits include NHDES Wetland and Shoreland Permits, NHDOT Temporary Driveway Permits, NH Department of Energy (DOE) Line Crossing Permits, Town of Hampton Wetlands Permit, and Town of Hampton Falls Special Use Permit.

**Eversource Energy, Rochester Area Work Center, Rochester, NH:**

- Site Plan and permitting for a proposed 2,600 square foot prefabricated fleet vehicle storage enclosure at the existing Eversource Rochester AWC. Tasks include layout and City of Rochester ZBA Variance, and Planning Board Site Plan Approval.

*TFM has also done extensive survey and civil engineering/permit design work in the communities of Dover, Barrington, and Newington.*

## NEW HAMPSHIRE – WESTERN REGION:

**Eversource Energy, Jackman Hydro Facility, Hillsborough, NH:**

- Site Plan and permitting for upgrades to Jackman Hydro Facility including construction of a 1,300 square foot control enclosure and 1,000 square foot substation yard expansion. Tasks include grading, stormwater management design, Storm Water Pollution Prevention Plan (SWPPP), NPDES NOI, NHDES Wetland Dredge and Fill Permit, NHDES Shoreland and Municipal Planning Board, Conservation Commission and ZBA permits.
- ALTA and easement surveys for PSNH at the hydro facility at the Jackman Station facility at the Gregg Lake Dam. Survey and Civil Site Design and Permitting- Hillsborough Substation.

**Eversource Energy, Hillsborough Pad Mount Transformer, Hillsborough, NH:**

- Site Plan and permitting for removal of existing distribution substation and installation of pad mount transformer. Tasks include grading, stormwater management design, NHDES

Dredge and Fill Permit, NH Division of Historic Resources Section 106 review and local approvals. Construction monitoring provided.
- Boundary and Topographic Surveys, wetland mapping, easement plan preparation and Construction layout.

**Eversource Energy, North Road Substation, Sunapee, NH:**
- Permitting associated with the installation of new utility poles and removal of existing utility poles. Permits include a NHDES Wetlands Minimum Impact Permit. Construction monitoring provided.

**PSNH, Emerald Street/MGP Facility, Keene, NH:**
- Boundary, Topographic, Hydrographic surveys for Weston & Sampson downstream remediation project.

**Windfarm Project, Lempster, NH:**
- GPS Horizontal and Vertical Control for Project Aerial Mapping by Minuteman Mapping, project consultant.

**Eversource Energy Newport Area of Work Center Expansion, Newport, NH**
- Site Plan and permitting for a 2,560 square foot garage addition at the existing Newport Area Work Center (AWC). Tasks include layout, grading, stormwater management improvements and sewer extension. Permits include NHDES Shoreland and Newport Planning Board permits.

**Industrial Roofing Corporation (IRC), Yankee Solar Array, Dublin, NH**
- Site Plan and permitting for a 125kW Ground Mounted Solar Array at the Yankee Publishing Facility. Tasks include layout and landscaping improvements. Permits include a NHDOT Driveway Permit and Town of Dublin Site Plan Review, Driveway and Building Permits.

**Eversource Energy, North Keene Substation, Keene, NH:**
- Site Plan and permitting for proposed electrical upgrades at the existing Eversource North Keene Substation including construction of a 3,080 square foot electrical enclosure to house proposed synchronous condensers. Tasks include layout, grading, stormwater management improvements and site access driveway design. Permits include a NHDES AoT Permit, NHDOT Temporary Driveway Permit, City of Keene Variances, Site Plan Approval, Conditional Use Permit and FAA Determination of No Hazard.

**Eversource Energy, Keene Area Work Center, Keene, NH:**
- Site Plan and permitting for a proposed 2,600 square foot prefabricated fleet vehicle storage enclosure at the existing Eversource Keene AWC. Tasks include layout and City of Keene Site Plan Approval.

**Eversource Energy, Lafayette Substation, Claremont, NH:**
- Site Plan and permitting for proposed electrical upgrades at the existing Eversource Lafayette Substation. Tasks include layout, grading, stormwater management improvements and site access driveway design. Permits include a NHDES Shoreland Permit, City of Claremont ZBA Variance and Special Exception, Site Plan Approval, and FAA Determination of No Hazard.

## NEW HAMPSHIRE – STATEWIDE:

**Eversource Energy, Long-term Maintenance Inspections, Various Sites in NH, and ME:**

- Bi-annual stormwater maintenance systems inspection and maintenance monitoring per approved permits (NHDES AoT). Locations include the Bedford Area Work Center (Bedford, NH), Curtisville Substation (Concord, NH), Daniel Substation (Franklin, NH), Eagle Substation (Merrimack, NH), Eastport Substation (Rochester, NH), Eliot Substation (Eliot, ME), Farmwood Substation (Concord, NH), Huckins Hill Substation (Holderness, NH), Legends Drive Facility (Hooksett, NH), North Keene Substation (Keene, NH), Peaslee Substation (Kingston, NH), Pulpit Rock Substation (Chester, NH), Rimmon Substation (Goffstown, NH), Saco Valley Substation (North Conway, NH), Scobie Pond Substation (Londonderry/Derry, NH), Tasker Farm Substation (Milton, NH). and Thorton Substation (Merrimack, NH).

## MASSACHUSETTS:

**National Grid Energy, Site Locations in Western and Central Massachusetts*:**

- Wire crossing permit surveys along highways and waterways utilizing GPS and Remote elevation/reflectorless total station surveying. TFM performed 113 crossing surveys at approximately 56 locations in 33 Cities/Towns in Massachusetts.

**National Grid Energy, Numerous Boundary, Right of Way, Utility and Construction Surveys*:**

- Survey of Substation Facilities, Transmission Corridors, Underground Conduits and Route Surveys and Related Utility Construction Layout within 18 cities/towns in Massachusetts, 5 cities/towns in New Hampshire and 4 cities/towns in Vermont.

*Due to confidentiality provisions with this client, more specific project information cannot be provided.

**Springfield Gas Works Facility, Springfield, MA:**

- Boundary, Topography, Monitor Well surveys for AMEC Inc.

**Unitil, Townsend Substation, Townsend, MA:**

- Site Plan and permitting for construction of an Energy Storage Unit (ESU) at the existing Unitil Townsend Substation. Tasks include layout, grading, stormwater management and site access improvements. Permits include a MassDOT Driveway Permit.

**Unitil, 1341 Line Rebuild, Fitchburg, MA:**

- Surveying and permitting services to reconstruct the existing 1341 Line. Tasks included layout and access. Permitting to be determined upon completion of existing conditions survey.

TFM®

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Appendix B – Additional Key Staff Resumes*

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 41 of 50

# TFMoran, Inc.
# 2022 Corporate Structure

48 Constitution Drive, Bedford, NH 03110 T: (603) 472-4488 www.tfmoran.com

TFM Since 1968
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**Robert Duval, PE, LEED AP**
*President / Chief Engineer*

**Corey Colwell, LLS**
*Principal / Senior VP*
*Division Manager*

**Jeffrey Kevan**
*Principal / Senior VP*
*Civil Project Supervisor*

**Paul Sbacchi, PE**
*Principal / Senior VP*
*Chief Structural Engineer*

**Dylan Cruess**
*Principal / Senior VP*
*Chief Operating Officer*

## PORTSMOUTH, NH DIVISION

**Christopher Rice, EIT** — *Principal, Sr. Project Manager*
**Brenda Kolbow, LLS, PLS** — *Survey Department Manager*
**Hannah Giovannucci, PE** — *Civil Project Manager*
**Jack McTigue, PE** — *Civil Project Manager*
**Justin Macek, EIT** — *Civil Project Engineer*
**Maurice Vander Pol, LLS** — *Survey Project Manager*
**Jason Aube, CWS** — *Environmental Permitting Specialist*
**Irina Donskaia** — *CADD Technician*
**Robert Hoover, PLA** — *Landscape Architect*
**Todd Emerson** — *Field Crew Chief*
**Jason Cook, EIT** — *Civil Project Engineer*
**Patrick Day** — *Survey Field Technician*
**Robert Bradshaw** — *Survey Technician*
**Martha Klein** — *Office Manager*
**Susan Ramsdell** — *Receptionist*

## LAND SURVEYING

**Michael Dahlberg, LLS, PLS** — *Survey Department Manager, Assistant Vice President*
**Hans Mertsch, LLS, PLS** — *Survey Project Manager*
**Stephen Bibeau, LLS** — *Field Operations Manager*
**Thomas Berube, LLS, PLS** — *Project Surveyor*
**Michael Burt** — *Surveyor*
**Thomas Wood** — *Surveyor*
**Richard Ward** — *Surveyor*
**Aaron Lamond** — *Survey Field Technician*
**Marty Gavin** — *Survey Field Technician*
**Philip Dahlberg** — *Survey Field Technician*
**Morgan Hershey** — *Survey Field Technician*
**Jonathan Rahilly** — *Survey Field Technician*

## WETLANDS SOILS AND MAPPING

**Paul O'Hanlon** — *Environmental Permitting Specialist*

## LANDSCAPE ARCHITECTURE

**Michael Krzeminski, PLA** — *Landscape Architect*
**Sophie Haddock** — *Assistant Land Planner, Landscape Designer*

## CIVIL / SITE ENGINEERING

**Nicholas Golon, PE** — *Principal, Sr. Project Manager*
**Thomas Burns, PE** — *Sr. Project Manager*
**Daniel Blais, CPESC** — *Sr. Project Manager*
**Jason Hill, PE** — *Project Manager*
**Matthew Routhier, PLA** — *Project Manager*
**Jennifer Porter, PE** — *Sr. Project Engineer, Civil/Traffic Engineer*
**Jeremy Belanger, PE** — *Sr. Project Engineer, Project Manager*
**Bryan Levesque, PE** — *Geotechnical Engineer*
**Scott Olsen, EIT, CPESC** — *Civil Project Engineer*
**Maureen Kelly, EIT** — *Civil Project Engineer*
**Phillip Houston** — *Civil Project Engineer*
**Christopher Chiaramonte** — *Civil Project Engineer*
**Alexander Croteau** — *Civil Project Engineer*
**Jonathan Devine, EIT** — *Civil Project Engineer*
**Stephen Perley** — *CADD Technician*
**Jeffrey Tate** — *CADD Technician*

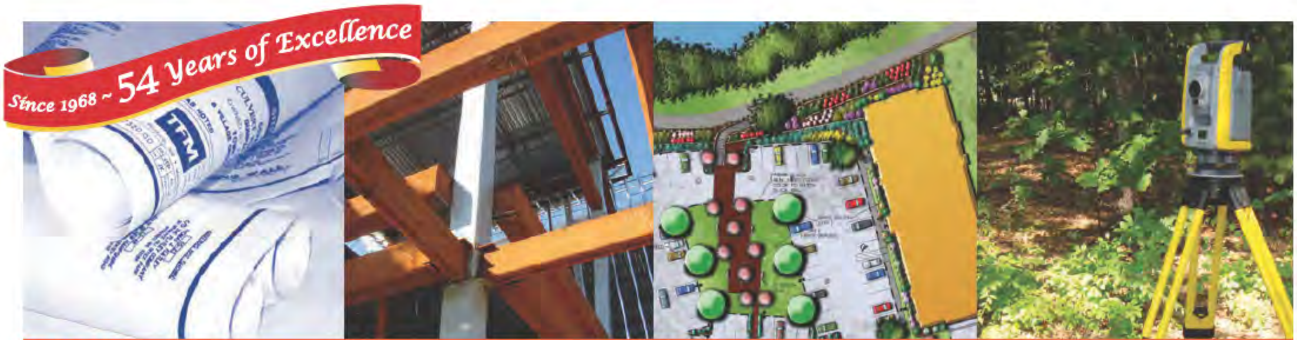
## STRUCTURAL ENGINEERING

**Thomas Lamb, PE** — *Principal, Sr. Structural Engineer*
**Kyle Roy, PE** — *Principal, Sr. Structural Engineer*
**Louis Cote** — *Structural Project Manager*
**Jacob Pouliot, PE** — *Structural Engineer*
**Jonathan Nadeau, EIT** — *Structural Engineer*
**Andrew Griffin, EIT** — *Structural Engineer*
**Ezequiel Galvan** — *Structural Engineer*
**Jacob Woodard** — *Structural Engineer*
**Aiden Behar, EIT** — *Structural Engineer Intern*

## OPERATIONS / ACCOUNTING

**Maryanne Murray** — *Controller*
**Cassi Beroney** — *Accounting Assistant*
**Julia Chartier** — *Marketing Coordinator*
**Haley James** — *Receptionist*

*Updated February 18, 2022*




2022

**TFM**

Civil Engineers
Traffic Engineers
Structural Engineers
Land Surveyors
Landscape Architects
Scientists

**(603) 472-4488**


Shopping Centers

Educational Institutions


Manufacturing/Industrial

D str b ti n C ter

## *TFMoran Company Profile*

**TFMoran, Inc. (TFM) is a regionally recognized civil, structural and traffic engineering, land surveying, and landscape architectural firm with over fifty years of continuous service to private and public clients. We are actively involved in many of the largest development initiatives now underway inside and outside of New Hampshire. The company has a staff of over 60 professionals, with office locations in Bedford and Portsmouth, New Hampshire.**

**LEED Accredited** TFMoran offers the first **LEED Accredited Professional structural and civil engineering staff** in the state of New Hampshire, and is committed to responsible, sustainable development. The Company is in the forefront of developing and introducing cost-effective low-impact development techniques into all of the professional services we offer.

**Certified Erosion Control Specialists** TFMoran professional staff includes Certified Professionals in Sediment and Erosion Control (CPESC) and Certified Erosion Sediment and Storm Water Inspectors (CESSWI). These certifications are required for many environmentally sensitive projects.

## *Professional Services*

**Civil, Structural & Traffic Engineering** TFMoran is a full-service engineering firm offering civil, structural and traffic engineering services. We handle all aspects of permitting, local through federal. Our engineers and CADD technicians utilize state-of-the-art industry software, including Autodesk, REVIT® Structure and ArcView™ GIS.

***Services Include:***

- Site Planning & Design
- Subdivision Design
- Structural Design
- Traffic Impact Analyses
- Septic System Design
- Drainage Analysis & Design
- Construction Administration
- Environmental Permitting
- Water Supply Systems
- SWPPP Reports
- Stormwater Inspections
- Marine Engineering

**Land Planning** TFMoran's Land Planning services include studies and analysis associated with developing the highest and best use of property under a variety of zoning and site development regulations.

***Services Include:***

- Site Analysis Plans
- Land Use Studies
- Zoning Analysis
- Conceptual Site Plans
- Conceptual Cost Estimates
- Fiscal Impact Studies
- Master Planning
- Graphic Representation

www.tfmoran.com

**Civil Engineers | Structural Engineers | Traffic Engineers | Land Surveyors | Landscape Architects | Scientists**

**Professional Services** *(continued)*


Supermarkets


Banks


Health Care Facilities


Multi-Family Residential


Municipal Facilities


Energy / Utilities


Roads / Construction Support

**Land Surveying** Our surveyors use the latest technology for field data collection including **Global Navigation Satellite System (GNSS)** which allows data to be collected in the field while being received in the office for greater quality control and a new level of productivity. **Robotic Total Station** has become an integral member of the team obtaining vital survey data more efficiently, saving the client time and money. We have now combined the two technologies with our purchase of a **Topcon Robotic Hybrid Positioning System** which utilizes the Robotic Total Station and allows for a swift transition to **GPS Hybrid Positioning**. This allows our team to be more efficient at every phase of a project.

***Services Include:***

- Site Analysis Plans
- ALTA Surveys
- Boundary Surveys
- Topographic Surveys
- HazMat Surveys
- Conceptual Site Plans
- Route Surveys
- Subdivisions
- Title Surveys
- Marine Surveys
- Master Planning
- Easements
- ROW Surveys
- Construction Layout
- Control Surveys

**Soils/Wetlands Mapping** TFMoran provides these services in accordance with local, state and federal regulatory agency requirements.

***Services Include:***

- High Intensity Soil Survey
- Percolation Tests
- Environmental Site Assessments
- Wetland Function & Value
- Test Pits
- Wetland Mapping

**Landscape Architecture** The role of the Landscape Architect is critical to the design of successful developments. Our experienced staff provides master plans and detailed designs for parks, campuses, mixed-use developments, downtown revitalization, and maintaining and improving the character of our communities.

***Services Include:***

- Walkable Communities
- Park Design
- Streetscape Improvements
- Planting Selection & Design
- Walks, Curbs & Pavements
- Athletic Fields/Complexes
- Exterior Lighting Design
- Campus Planning
- Signs & Fences

TFM® Since 1968

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

NEW HAMPSHIRE 200

BEST OF BUSINESS 2022 BOB AWARDS NH BUSINESS REVIEW

Voted BEST NH Engineering Firm 10 Years Running!

*LEED Accredited Professionals*

**TFMoran, Inc.**
48 Constitution Drive, Bedford, NH 03110 (603) 472-4488
170 Commerce Way, Suite 102, Portsmouth, NH 03801 (603) 421-2222
www.tfmoran.com

**Contact:**
**Robert Duval**, PE, LEED AP - *President*
**Dylan Cruess** - *Chief Operating Officer*
**Paul Sbacchi**, PE - *Chief Structural Engineer*
**Jeffrey Kevan** - *Civil Project Supervisor*
**Corey Colwell**, LLS - *Division Manager*
**Michael Krzeminski**, PLA - *Landscape Architect*
**Dan Blais**, CPESC, CESSWI - *Sr. Project Manager*
**Michael Dahlberg**, LLS, PLS - *Survey Dept. Manager*

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-4(a)
Page 44 of 50

TFM Since 1968 — Civil Engineers, Structural Engineers, Traffic Engineers, Land Surveyors, Landscape Architects, Scientists

**ROBERT E. DUVAL, PE, LEED AP**
President
Chief Engineer

## EXPERIENCE

Mr. Duval serves as President and Chief Engineer for TFMoran Inc. and is responsible for technical oversight of all TFMoran projects. Mr. Duval has over 30 years experience in the engineering and construction industry. His multi-disciplinary background enables him to handle complex projects including civil, structural, and traffic engineering challenges. His project experience includes civil and structural design of public buildings, public parks and athletic facilities, schools, courthouses, fire stations, and public utility structures; marine engineering projects, traffic engineering and design of local, state, and federal highway projects.

***Selected project experience includes:***

- **Army Aviation Support Facility, Bangor, ME:** Principal-in-charge of over 80,000sf of new structural design and renovations to the helicopter support and maintenance facilities for the Maine Army National Guard in Bangor. The project cost exceeded $20M in two phases, to allow ongoing Guard operation while providing new and completely renovated facilities over a three-year time frame.
- **NH Port Authority Port Expansion, Portsmouth, NH:** Project Manager for final design of this $30+M expansion to the NH State Pier along the Piscataqua River. The project included a $5M Barge Wharf and several hundred feet of new pier, hardstand, and containment structures for dredge spoils. Design of on-site truck circulation and material stockpiles were major project design considerations.
- **Tweed New Haven ARFF Fire/Rescue Facility, East New Haven, CT:** Principal-in-charge of structural design of a new Aircraft Rescue and Fire Fighting facility at the Tweed New Haven Airport. The facility was designed to FAA Index A standards.
- **Pierre Bouchard Public Works Facility, Dover, NH:** Principal-in-charge of civil and structural design of new $6M public works facility. Special environmental precautions were incorporated into the design because the site was located in an active gravel pit inside the wellhead protection zones of two Class AA drinking water supply wells. The project featured one of the first salt storage facilities in the state where all loading was performed indoors. The site also included several thousand feet of water and sewer main extensions, and master planning of the adjacent recycling and transfer station.
- **NHDOT New Public Works Maintenance Facility, Concord, NH:** Principal-in-charge of this new 30,000sf maintenance garage for the NHDOT Bureau of Public Works. This is the first public works maintenance facility to be delivered on a fast-track design-build basis. The facility provides for storage and maintenance of public works vehicles, hazardous materials, and incidental office uses.
- **Acton Public Safety Facility, Acton, ME:** Principal-in-charge for design of this new Public Safety Facility housing the town's Police and Fire Departments. The facility was designed on two levels to take advantage of the natural terrain in this steep, rocky, donated site. Although a completely modern facility, the building was designed to blend in with the agricultural landscape of this picturesque section of Maine.

## EDUCATION

McGill University, Montreal, Canada, BSc 1978 - Meteorology
University of New Orleans, Louisiana, Graduate Studies 1980-81 - Structural Engineering

## REGISTRATIONS, CERTIFICATIONS and AFFILIATIONS

Professional Engineer: (Structural, Civil, Highway) in NH, ME, MA, CT and VT
LEED (Leadership in Energy and Environmental Design) Accredited Professional
Charter Member, Steel Structures Painting Council
Member, Institute of Transportation Engineers (Pedestrian/Bicycle Council)
Member, National Fire Protection Association (Aviation Section)
Chair, New Hampshire DES Air Resources Council
Board of Directors, Greater Manchester Chamber of Commerce

TFM Since 1968

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**MICHAEL R. DAHLBERG, LLS, RPLS, PLS**
Assistant Vice President
Survey Department Manager

## EXPERIENCE

Mr. Dahlberg is a licensed land surveyor with nearly 40 years of experience in New Hampshire, Massachusetts, Maine, and Vermont. His passion is historical research, boundary determination and resolution. He has a wide variety of experience in ALTA Surveys, Utility and Roadway Route Surveys, Construction Layout, As-Built Surveys, Boundary Surveys, Conservation Easements, etc. He has been an Expert Witness for boundary and right-of-way disputes in Northern Middlesex County, MA, Hillsborough, Merrimack, and Belknap Counties in NH. Mr. Dahlberg is responsible for the daily survey operations for TFMoran's Bedford, New Hampshire office.

***Selected project experience includes:***

- **Liberty Utilities & Eversource, Golden Rock Substation, Methuen, MA & Salem, NH:** Lead Surveyor/Project Manager for the re-establishment of 2.2 miles of utility easement for future expansion of utility service for the Tuscan Village Development in Salem, NH. The project required detailed research and field survey of all encroachments within the corridor. Mr. Dahlberg was responsible for deeds and document research and survey calculations and determination of existing easement locations as well as the preparation of final plans for use by Liberty Utilities & Eversource.
- **Route 102 Natural Gas Line Upgrade, Liberty Utilities, Londonderry, NH:** Lead Surveyor and Project Manager for the survey of 3 miles of NH Route 102 in Londonderry for the expansion and extension of Natural Gas Service for the towns of Londonderry and Hudson, NH. The project required detailed research and field survey information for the establishment of the Route 102 right-of-way and survey location of existing improvements within and adjacent to the proposed gas line expansion. Mr. Dahlberg was responsible for deeds and document research and survey calculations and determination of existing right-of-way limits for use by Liberty Utilities in the design and construction of the proposed gas line expansion.
- **Route 3 Natural Gas Line Upgrade, Liberty Utilities, Tilton & Belmont, NH**: Lead Surveyor and Project Manager for the survey of 4.5 miles of NH Route 3 Tilton and Belmont for the expansion and extension of Natural Gas Service for the towns of Tilton, Belmont, Sanbornton and Laconia, NH. The project included the establishment of the Interstate 93 Right-Of-Way and a detailed survey of the Route 3 Overpass of Interstate 93 in Tilton, NH.
- **Souhegan River Crossing, Liberty Utilities, Merrimack, NH:** Lead Surveyor/Project Manager for the survey of .30 miles of U.S. Route 3 in Merrimack, NH and the village bridge over the Souhegan River for a gasline crossing under the Souhegan River. The project included extensive deeds research to establish the right-of-way limits of what is now U.S. Route 3, a pre-colonial era road circa 1640-1650.

## EDUCATION

New Hampshire Vocational Technical College, Berlin, New Hampshire, AS 1982 – Natural Resources Management with specialization in Surveying and Soils.

## REGISTRATIONS, CERTIFICATIONS and AFFILIATIONS

Licensed Land Surveyor in New Hampshire, Maine, Massachusetts, and Vermont
Member, State of New Hampshire Board of Licensure for Land Surveyors

*Rev. 08/21*

TFM® Since 1968

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**JASON "JAY" AUBE, CWS**
Environmental Permitting Specialist

## EXPERIENCE

Mr. Aube serves as an Environmental Permitting Specialist and a Certified Wetland Scientist (CWS) for TFMoran with over 20 years of experience. His responsibilities include performing wetland delineations, conducting assessments of wetland functions and values, and preparing wetland and shoreland permit applications for approval at the federal, state, and local levels.

Prior to joining TFMoran, Mr. Aube worked in the public sector for twelve years as an employee of the New Hampshire Department of Environmental Services (NHDES) where he was responsible for Shoreland Program and Wetlands Bureau outreach, wetlands and shoreland permitting, and compliance.

***Selected project experience includes:***

- **NHDES Wetlands and Shoreland Outreach:** Continually prepared and provided engaging presentations and annual updates to a diverse group of stakeholders relative to the periodic amendments to the NH Wetlands Law, the NH Shoreland Water Quality Protection Act (SWQPA) and the associated NHDES Administrative Rules.
- **NHDES Wetlands and Shoreland Permitting:** Reviewed Wetlands and Shoreland Permit Applications and determined if applicant's project proposals met the minimum standards of the relevant NHDES laws and Administrative Rules. Worked with applicants and provided guidance on how to best meet the standards of the applicable laws and rules.
- **NHDES Land Resources Management Compliance:** Triaged and responded to formal complaints alleging violations of NH Wetlands Law, the NH Shoreland Water Quality Protection Act (SWQPA) and NH Alteration of Terrain Law. Working collaboratively with all parties to find practicable solutions to complex sites that required wetlands and shoreland restoration. Reviewed and approved formal Wetlands and Shoreland Restoration plans. When required, provided testimony at legal hearings.
- **Wetlands Crossing, North Hampton, NH:** Prepared NHDES Wetlands Permit Application for a 50-foot wetland crossing to the buildable portions of a single residential lot. Performed wetlands delineation, conducted a functions and values assessment of the wetland, and developed a project proposal that clearly offered the least impacting alternative to wetland resources. Received approvals in a timely and efficient manner.
- **Wetlands Restoration, Rye, NH:** Prepared NHDES Wetlands Permit Application for the restoration of a Palustrine Forested Wetland that was impacted by unauthorized fill and overrun with invasive species. Generated a systematic construction sequence to ensure the fill was removed to original grade, all invasive species were removed, and the wetland's functions and values were returned by replanting with site specific native wetland vegetation. Received approvals in a timely and efficient manner.
- **Wetlands and Shoreland Permitting, Barrington, NH:** Prepared and submitted NHDES Wetlands and Shoreland Permit Applications for the development of a residential lot on a public waterbody. Proposed impacts were within the Protected Shoreland and the shoreline, an area jurisdictional under NH Wetlands Law. Received each approval in a timely and efficient manner.

## EDUCATION

Plymouth State University, Plymouth, NH, BS, Environmental Biology, Minor in Chemistry, 1999

## REGISTRATIONS, CERTIFICATIONS and AFFILIATIONS

Certified Wetland Scientist, New Hampshire CWS #00313
City of Dover Conservation Commission, Member
Cocheco River Local Advisory Committee, Vice Chair
New Hampshire Association of Natural Resources Scientists, Member
New Hampshire Beekeepers Association, Member

TFM Since 1968
Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

**JEREMY C. BELANGER, PE**
Senior Project Engineer

**EXPERIENCE**

Mr. Belanger serves as a Senior Project Engineer for TFMoran, Inc. and is responsible for the engineering design and permitting of land development projects. He has experience in site planning, drainage design, sewer design, and local, state and federal permitting for residential, commercial, industrial, municipal and energy projects.

***Selected project experience includes:***

- **Murphy's Taproom and Carriage House, Bedford, NH:** Site plan development and permitting associated with a 22,265sf restaurant and banquet facility, with associated access, parking and site improvements.
- **Chuckster's Mini-Golf Course, Hooksett, NH:** Site plan development and permitting associated with a 36-hole miniature-golf course and clubhouse.
- **Granite State Solar Warehouse Facility, Bow, NH:** Site plan development and permitting associated with a 9,000sf warehouse facility with associated access, parking, and site improvements.
- **Eversource Energy, Bedford Area Work Center, Bedford, NH:** A 5,000sf garage, paved storage yard and 1-acre gravel marshalling area, with associated access, parking and site improvements was constructed in at the Eversource Bedford Area Work Center (AWC).
- **Eversource Energy, Blaine Street Substation, Manchester, NH:** Design included grading and drainage design associated with the increase in impervious area and construction of the control enclosure.
- **Bow Auto Parts, Bow, NH:** Site design and permitting associated with a 4,000sf office, 10,000sf warehouse expansion with associated access, parking and site improvements.
- **Eversource Energy, Messer Street Substation, Laconia, NH:** Design included siting for the proposed reconstruction including layout, grading and drainage and temporary staging areas to be utilized during construction.
- **Eversource Energy, Eddy Street Substation, Manchester, NH:** Design included siting for the proposed substation upgrade including layout of proposed electrical components, fencing, grading and drainage.
- **Eversource Energy, Farmwood Substation, Concord, NH:** Design included siting for the proposed reconstruction including layout, grading and drainage and temporary staging areas to be utilized during construction.
- **Eversource Energy, Legends Drive Pole Storage Facility:** Design included siting for the proposed storage yard, fencing, grading and drainage and utilities.

**EDUCATION**

University of New Hampshire, BS Civil Engineering
University of New Hampshire, MS Civil Engineering

**REGISTRATIONS, CERTIFICATIONS AND AFFILIATIONS**

Professional Engineer, NH
Named New Hampshire Young Engineer of the Year, 2020
OSHA 10 Certified
NFPA 70E Certified
2020 Member, American Society of Civil Engineers
Member, Manchester Young Professionals Network
Volunteer, UpReach Therapeutic Equestrian Center, Inc.

*Revised 02/2020*

TFM Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

# *Appendix C – TFMoran Insurance Certificate*

THOMFMO-01 PSPENCER

ACORD

# CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY) 10/29/2021

**THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.**

**IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).**

PRODUCER License # AGR8150
Clark Insurance
One Sundial Ave Suite 302N
Manchester, NH 03103

CONTACT NAME:
PHONE (A/C, No, Ext): (603) 622-2855 FAX (A/C, No): (603) 622-2854
E-MAIL ADDRESS: info@clarkinsurance.com

| INSURER(S) AFFORDING COVERAGE | NAIC # |
|---|---|
| INSURER A: Acadia | 31325 |
| INSURER B: | |
| INSURER C: | |
| INSURER D: | |
| INSURER E: | |
| INSURER F: | |

INSURED
Thomas F Moran, Inc. dba TFMoran, Inc.
48 Constitution Drive
Bedford, NH 03110

COVERAGES CERTIFICATE NUMBER: REVISION NUMBER:

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

| INSR LTR | TYPE OF INSURANCE | ADDL INSD | SUBR WVD | POLICY NUMBER | POLICY EFF (MM/DD/YYYY) | POLICY EXP (MM/DD/YYYY) | LIMITS | |
|---|---|---|---|---|---|---|---|---|
| A | X COMMERCIAL GENERAL LIABILITY; CLAIMS-MADE; X OCCUR | X | | CPA5498924-10 | 10/31/2021 | 10/31/2022 | EACH OCCURRENCE | $ 1,000,000 |
| | | | | | | | DAMAGE TO RENTED PREMISES (Ea occurrence) | $ 500,000 |
| | | | | | | | MED EXP (Any one person) | $ 10,000 |
| | | | | | | | PERSONAL & ADV INJURY | $ 1,000,000 |
| | GEN'L AGGREGATE L MIT APPL ES PER: POLICY; X PRO-JECT; X LOC | | | | | | GENERAL AGGREGATE | $ 2,000,000 |
| | OTHER: | | | | | | PRODUCTS - COMP/OP AGG | $ 2,000,000 |
| | | | | | | | | $ |
| A | AUTOMOBILE LIABILITY; X ANY AUTO; OWNED AUTOS ONLY; SCHEDULED AUTOS; HIRED AUTOS ONLY; NON-OWNED AUTOS ONLY | | | CAA5498925-10 | 10/31/2021 | 10/31/2022 | COMBINED SINGLE LIMIT (Ea accident) | $ 1,000,000 |
| | | | | | | | BODILY INJURY (Per person) | $ |
| | | | | | | | BODILY INJURY (Per accident) | $ |
| | | | | | | | PROPERTY DAMAGE (Per accident) | $ |
| | | | | | | | | $ |
| A | X UMBRELLA LIAB; X OCCUR; EXCESS LIAB; CLAIMS-MADE; DED; RETENTION $ | | | CUA5498926-10 | 10/31/2021 | 10/31/2022 | EACH OCCURRENCE | $ 5,000,000 |
| | | | | | | | AGGREGATE | $ 5,000,000 |
| | | | | | | | | $ |
| A | WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y/N; ANY PROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? (Mandatory in NH) N; If yes, describe under DESCR PTION OF OPERATIONS below | N / A | | WCA5498927-10 | 10/31/2021 | 10/31/2022 | X PER STATUTE; OTH-ER | |
| | | | | | | | E.L. EACH ACC DENT | $ 1,000,000 |
| | | | | | | | E.L. DISEASE - EA EMPLOYEE | $ 1,000,000 |
| | | | | | | | E.L. DISEASE - POLICY LIMIT | $ 1,000,000 |

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)
Unitil Corporation and its subsidiaries are each designated as additional insureds as respect to the general liability coverage when required by written contract with the named insured.

CERTIFICATE HOLDER
Unitil Corporation and its subsidiaries
6 Liberty Lane West
Hampton, NH 03842

CANCELLATION
SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.

AUTHORIZED REPRESENTATIVE
Sean Parnell

ACORD

MORAN-1 | OP ID: BC

# CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY) 02/24/2022

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

| | |
|---|---|
| PRODUCER 781-245-5400<br>Poole Professional B&B of MA<br>107 Audubon Rd, #2, Ste 305<br>Wakefield, MA 01880<br>Thomas J. Mullen | CONTACT NAME: Thomas J. Mullen<br>PHONE (A/C, No, Ext): 781-245-5400 FAX (A/C, No): 781-245-5463<br>E-MAIL ADDRESS: |

| INSURER(S) AFFORDING COVERAGE | NAIC # |
|---|---|
| INSURER A: XL Specialty Insurance Company | 37885 |
| INSURER B: | |
| INSURER C: | |
| INSURER D: | |
| INSURER E: | |
| INSURER F: | |

INSURED
TFMORAN, INC.
48 Constitution Drive
Bedford, NH 03110

COVERAGES CERTIFICATE NUMBER: REVISION NUMBER:

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

| INSR LTR | TYPE OF INSURANCE | ADDL INSD | SUBR WVD | POLICY NUMBER | POLICY EFF (MM/DD/YYYY) | POLICY EXP (MM/DD/YYYY) | LIMITS | |
|---|---|---|---|---|---|---|---|---|
| | COMMERCIAL GENERAL LIABILITY<br>CLAIMS-MADE / OCCUR<br>GEN'L AGGREGATE LIMIT APPLIES PER: POLICY / PRO-JECT / LOC<br>OTHER: | | | | | | EACH OCCURRENCE | $ |
| | | | | | | | DAMAGE TO RENTED PREMISES (Ea occurrence) | $ |
| | | | | | | | MED EXP (Any one person) | $ |
| | | | | | | | PERSONAL & ADV INJURY | $ |
| | | | | | | | GENERAL AGGREGATE | $ |
| | | | | | | | PRODUCTS - COMP/OP AGG | $ |
| | | | | | | | | $ |
| | AUTOMOBILE LIABILITY<br>ANY AUTO<br>OWNED AUTOS ONLY / SCHEDULED AUTOS<br>HIRED AUTOS ONLY / NON-OWNED AUTOS ONLY | | | | | | COMBINED SINGLE LIMIT (Ea accident) | $ |
| | | | | | | | BODILY INJURY (Per person) | $ |
| | | | | | | | BODILY INJURY (Per accident) | $ |
| | | | | | | | PROPERTY DAMAGE (Per accident) | $ |
| | | | | | | | | $ |
| | UMBRELLA LIAB / OCCUR<br>EXCESS LIAB / CLAIMS-MADE<br>DED / RETENTION $ | | | | | | EACH OCCURRENCE | $ |
| | | | | | | | AGGREGATE | $ |
| | | | | | | | | $ |
| | WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y / N<br>ANY PROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? (Mandatory in NH)<br>If yes, describe under DESCRIPTION OF OPERATIONS below | N / A | | | | | PER STATUTE / OTH-ER | |
| | | | | | | | E.L. EACH ACCIDENT | $ |
| | | | | | | | E.L. DISEASE - EA EMPLOYEE | $ |
| | | | | | | | E.L. DISEASE - POLICY LIMIT | $ |
| A | Arch/Engrs Prof Liability | | | DPR9985962 | 11/10/2021 | 11/10/2022 | Per Claim | 5,000,000 |
| | | | | | | | Aggregate | 5,000,000 |

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)

| CERTIFICATE HOLDER | CANCELLATION |
|---|---|
| UNITI74<br>Unitil Corporation<br>& its Subsidiaries<br>6 Liberty Lane West<br>Hampton, NH 03842-1720 | SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.<br>AUTHORIZED REPRESENTATIVE |

ACORD 25 (2016/03)

TFM Since 1968

Civil Engineers
Structural Engineers
Traffic Engineers
Land Surveyors
Landscape Architects
Scientists

August 24, 2022

Mr. Jacob Dusling, P.E.
Unitil
30 Energy Way
Exeter, NH 03833

**RE: Proposal for Engineering & Survey Services**
**Proposed Kingston Utility Scale PV Facility**
**2 Mill Road and 24 Towle Road**
**Lot R11-9 and R12-26**

Dear Jake:

TFMoran, Inc. (TFM) is pleased to provide this proposal to provide Engineering & Survey services for the Siting, Site Evaluation & Permitting for a proposed utility scale photovoltaic generating (PV) facilities to be located at the above noted properties. We understand the below scope of work is to support the construction of a 5 MW facility as well as provide a conceptual master plan for the siting of a future 5 MW facility on adjacent land. Our scope of work is as follows:

**Scope of Work:**

**Task 1 Wetland Delineation**

TFM will delineate wetlands on lot R-11 and R12-26, comprised of approximately 96-acres. Wetland flags will be located during the wetlands survey defined in task 2. We have carried an allowance of (6) days for this task.

**Task 2 Survey Services**

*Boundary & Topographic Survey*

TFM will conduct research at the Town of Kingston, the Rockingham County Registry of Deeds and the State of New Hampshire Archives. TFM will conduct an accurate instrument of the subject parcels. TFM will process the field survey data to confirm compliance with the NH Board of Land Surveyors Rules & Regulations. TFM will locate physical improvements on the subject tract and the adjacent roadway. TFM will locate the visible, above ground portions of utilities immediately adjacent to the subject tracts. TFM will obtain LIDAR data from NHGRANIT and perform a ground verification. TFM will survey the location of the delineated wetlands. TFM will analyze the field and record evidence. TFM will determine the parcel boundaries based on our analysis. TFM will prepare an Existing Conditions Plan that demonstrates the results of our survey efforts.

*ALTA Survey*

TFM will prepare a 2021 ALTA/NSPS Land Title Survey, including ALTA Table "A" items 1 (State Requirement), 2, 3, 4, 6(b), 7(a), 7(b1), 7(c), 8, 9, 13 and 14. Client will provide a current Title Commitment and exception documents. Final product will be a 2021 ALTA/NSPS Land Title Survey certified to parties, as specified by the Client.

48 Constitution Drive
Bedford, NH 03110
Phone (603) 472-4488
Fax (603) 472-9747
www.tfmoran.com

*Monuments*

Missing corners can be installed at the completion of the survey for [redacted] per monument. We have carried an allowance of (25) monuments.

**Task 3** **Site Plan Package**

TFM will prepare a Site Plan package showing the layout of the Project on the selected parcel with dimensional information, grading and drainage design (including oil containment), erosion control, utility service design, landscape design, lighting, and details of site work items suitable for construction, stamped by a licensed State of New Hampshire Professional Engineer. This Plan Set will include;

- Cover Plan
- Existing Conditions (see task 2)
- Conceptual Master Plan (future 5 MW facility to be shown)
- Lot Line Adjustment Plan
- Site Preparation Plan
- Site Layout Plan
- Grading, Drainage & Utility Plan
- Stormwater Management/Erosion Control Plan
- Driveway Plan & Profile
- Sight Distance Plan & Profile
- Landscaping Plan
- Lighting Plan
- Details for site work items suitable for construction

Preliminary Site Layout:

TFM will prepare a Preliminary Site Layout Plan showing the layout of the Project on the subject parcels with dimensional information and preliminary grading & drainage design. The plan shall be used to develop estimated site construction costs.

Site Construction Cost Estimate:

TFM will prepare order of magnitude construction cost estimates based on the preliminary site layout plans prepared.

Site Soils Mapping:

Site-specific soils mapping is required per the NH Department of Environmental Services, Alteration of Terrain permitting program. As part of this proposal, TFM will have a NH Certified Soil Scientist map readily accessible and identifiable surficial soil types at the Project site.

Stormwater Management Report:

A stormwater management report will be provided that includes an analysis of the proposed stormwater management system and its effect on the surrounding area and existing drainage infrastructure in accordance with City and State requirements. TFM will perform test pits and infiltration testing as required for the drainage systems (backhoe cost billed as a reimbursable expense).

Traffic:

A Trip Generation Memo will be provided to address the anticipated traffic generated by the proposed facility.

Renderings:

Due to the visual nature of the proposed project, TFM will develop a 3D rendering of the subject development for use in conveying the project to the anticipated review agencies.

Agency Comment Allowance:

TFM has included an allowance of [redacted] of the estimated budget amount for the Site Plans to respond to review comments received by government agencies and their consultants.

**Task 4** **Preparing Applications**

TFM will prepare applications, plans, and applicable support materials for the following filings with the City, State and Federal Government.

- **Town of Kingston**
  - Zoning Board
    - Use Variance
  - Planning Board
    - Site Plan Review
  - Conservation Commission
    - Wetland Dredge and Fill Review
    - Wetland Buffer Impact Review
- **State of New Hampshire**
  - **NH Natural Heritage Bureau (NHB)**
    - NHB DataCheck
  - **NH Fish & Game (NHFG)**
    - Wildlife Assessment per Env-Wq 1503.19(h)
  - **NH Department of Environmental Service (NHDES)**
    - Alteration of Terrain (AoT)
    - Major Wetlands Dredge and Fill (including functional assessment)
  - **NH Division of Historical Resources (NHDHR)**
    - Request for Project Review (RPR)
- **Federal**
  - **US Army Corps of Engineers (ACOE)**
    - NH Programmatic General Permit (PGP)
  - **US Environmental Protection Agency (EPA)**
    - NPDES
      - Construction Stormwater Discharge Notice of Intent (NOI)

Phase IA Archeological Sensitivity Assessment:

TFM will coordinate with an Archeological Consulting firm to provide a Phase IA Archeological Sensitivity Assessment for the subject properties. This study will follow guidelines established for archaeological surveys by the New Hampshire Division of Historic Resources (NHDHR).

Phase 1 Environmental Site Assessment:

TFM or their subconsultant will provide a Phase 1 Environmental Site Assessment in accordance with ASTM E 1527-05 for the subject properties.

NH Fish & Game:

TFM will coordinate with NHFG to determine the need for endangered species studies. TFM has included an allowance of (12) hours. If studies beyond the wildlife habitat assessment are required, they will be performed as an Additional Service at the Clients direction.

**Task 5 Meetings & Coordination**

TFM will attend meetings with the Client, Town Agencies and Boards for the processing of the permit applications and for coordination of the project's activities including but not limited to scheduling and project status reports. TFM has included an allowance of (60) hours. If additional meetings are needed, they will be attended as directed by the Client and billed on a time and materials basis.

**Task 6 Geotechnical Services**

*Typical Subsurface Investigation, Geotechnical Report & Sampling*

TFM will subcontract with a geotechnical/boring company to perform test pits appropriately spaced for the anticipated development area, assumed to be 25 to 35-acres for the proposed 5MW facility.

**Task 7 Permit Fees**

TFM has estimated this value based on similar project experience. Permit fees will be confirmed once applications have been prepared. This estimate does not include fees associated with mitigation for wetland impacts.

**Task 8 Reimbursable Expenses**

TFM has estimated this value based on similar project experience which assumes [redacted] of the budget cost.

**Assumptions/Exclusions:**

This proposal is only for the services outlined above and is applicable the regulations in place at the time of this proposal. TFM has assumed reasonable recovery and agreement between field monuments and plans and deeds of record with no disputed boundaries. Should we find a significant boundary dispute the Client will be contacted with anticipated costs. The following items have not been included in this proposal but can be performed by our office at the Client's request. TFM will provide an estimate for the Client's authorization prior to beginning such additional work if requested:

- Unitil or their vendor will provide the General Arrangement for the PV facility including accessory outbuildings. TFM will work with Unitil and their vendor on the siting of these elements on the subject parcels.
- Significant revisions to the development components/layout requested by Client or Regulatory Agencies after commencement of site design will be additional services.
- We have excluded Easement Plans, legal descriptions, etc.
- We assume the existing adjacent roadways are adequate for access to this project without improvements, so we have not included a formal Traffic Impact and Access Study (TIAS) and we assume that no offsite roadway design will be required.
- We assume that there is adequate capacity in the adjacent utilities to service this project, and that no offsite utility studies or designs will be required.
- Significant revisions to the development components/layout requested by Client or Regulatory Agencies after commencement of site design will be additional services.
- This proposal does not include structural design for any onsite retaining walls over four feet.

- We have not included, Wetlands Studies (other than delineation), Hazardous Waste Studies, Fiscal Impact Studies, Noise Studies, Air Quality Studies (including generators), Wildlife Studies (other than those identified), Phase 1B Archeological Studies or other technical studies and reports not included above.

**Compensation:**

TFM will complete this Scope of Services for the Estimated Sums shown below plus miscellaneous reimbursable expenses.

**Schedule of Fees:**

| | | |
|---|---|---|
| **Task 1:** | **Wetland Delineation** | [redacted] |
| **Task 2:** | **Survey Services** | [redacted] |
| **Task 3:** | **Site Plan Package** | [redacted] |
| **Task 4:** | **Preparing Applications** | [redacted] |
| **Task 5:** | **Meetings & Coordination** | [redacted] |
| **Task 6:** | **Geotechnical Services** | [redacted] |
| **Task 7:** | **Permit Fees** | [redacted] **(assumed)** |
| **Task 8:** | **Reimbursable Expenses** | [redacted] **(8% of budget)** |
| **Total:** | | [redacted] |

Fees that may be required by the City, State or Federal government and/or other agencies, have been estimated and will be confirmed prior to permit submittal. Fees will be paid by TFM and billed to the client under the specified task. Typical reimbursable expenses run approximately [redacted] to [redacted] of the budget cost and have been estimated at [redacted] for this project. TFM will bill on a monthly basis and the bill will reflect work completed to date.

We appreciate this opportunity to provide you with a proposal for this project and are available to meet with you at any time to discuss this project, the scope of work or budget.

We look forward to working with you on another successful project!

Sincerely,
**TFMoran Inc.**

Nicholas Golon, PE
Principal

# PURCHASE AND SALES AGREEMENT
## New Hampshire Association of REALTORS® Standard Form

08/25/2022 , ______ ("EFFECTIVE DATE")
EFFECTIVE DATE is defined in Section 21 of this Agreement.

1. **THIS AGREEMENT** made this ______ day of ______, ______ between Two Mill Road Realty Trust and 24 Towle Road Realty Trust ("SELLER") of 18 Old Mill Road, City/Town Kingston, State NH Zip 03848 and Unitil Realty Corp. ("BUYER") of 6 Liberty Lane West, City/Town Hampton, State NH Zip 03842.

2. **WITNESSETH:** That SELLER agrees to sell and convey, and BUYER agrees to buy certain real estate situated in City/Town of Kingston located at Two vacant land parcels: 2 Mill Rd (63 Acres) Bk/pg 2893/2178 and 24 Towle Rd (33 Acres) Bk/pg 2893/2190 County Rockingham Book see above Page see above Date 08/03/1991 ("PROPERTY").

3. The **SELLING PRICE** is [redacted] Dollars [redacted].
A DEPOSIT in the form of Check, is to be held in an escrow account by Keller Williams Coastal and Lakes & Mountains ("ESCROW AGENT"). BUYER ☐ has delivered, or ☒ will deliver to the ESCROW AGENT's FIRM within 10 days of the EFFECTIVE DATE, a deposit of earnest money in the amount of [redacted].
~~BUYER agrees that an additional deposit of earnest money in the amount of $______ will be delivered on or before~~ ______. If BUYER fails to deliver the initial or additional deposit in compliance with the above terms, SELLER may terminate this Agreement. The remainder of the purchase price shall be paid by wire, certified, cashier's or trust account check, in the amount of [redacted].

4. **DEED:** Marketable title shall be conveyed by a Warranty deed, and shall be free and clear of all encumbrances except usual public utilities serving the PROPERTY.

5. **TRANSFER OF TITLE:** On or before *See Section 19 at Mutually accepted location or some other place of mutual consent as agreed to in writing.

6. **POSSESSION:** Full possession and occupancy of the premises ~~with all keys~~ shall be given upon the transfer of title free of all tenants and occupant's personal property and encumbrances except as herein stated. Said premises to be then in the same condition in which they now are, ~~reasonable wear and tear excepted. SELLER agrees that the premises will be delivered to BUYER free of all debris and in "broom clean" condition.~~ Exceptions: None

Buyer reserves the right to conduct a walk through inspection upon reasonable notice to SELLER's real estate FIRM within 96 hours prior to time of closing to ensure compliance with the terms of this Agreement.

7. **REPRESENTATION:** The undersigned SELLER(S) and BUYER(S) acknowledge the roles of the agents as follows:
Chantal O'Hara of Keller Williams Coastal and Lakes & Mountains
is a ☒ seller agent ☐ buyer agent ☐ facilitator ☐ disclosed dual agent*
Mark Dickey / Chris Norwood of NAI Norwood Group
is a ☐ seller agent ☒ buyer agent ☐ facilitator ☐ disclosed dual agent*
~~*If agent(s) are acting as disclosed dual agents, SELLER and BUYER acknowledge prior receipt and signing of a Dual Agency Informed Consent Agreement.~~
☐ ~~NOTICE OF DESIGNATED AGENCY: If checked, notice is hereby given that BUYER is represented by a designated buyer's agent and SELLER is represented by a designated seller's agent in the same firm.~~

8. **INSURANCE:** ~~The buildings on said premises shall, until full performance of this Agreement, be kept insured against fire, and other extended casualty risk by SELLER. In case of loss, all sums recoverable from said insurance shall be paid or assigned, on transfer of title, to BUYER, unless the premises shall previously have been restored to their former condition by SELLER; or, at the option of BUYER, this Agreement may be rescinded and the DEPOSIT refunded if any such loss exceeds~~ $______.

SELLER(S) INITIALS PFP 08/25/22 10:05 AM EDT dotloop verified / LDT 08/25/22 9:31 AM EDT dotloop verified BUYER(S) INITIALS RBH / ______

## PURCHASE AND SALES AGREEMENT
### New Hampshire Association of REALTORS® Standard Form

9. **TITLE:** If upon examination of title it is found that the title is not marketable, SELLER shall have a reasonable time, not to exceed thirty (30) days from the date of notification of defect (unless otherwise agreed to in writing), to remedy such defect. Should SELLER be unable to provide marketable title within said thirty (30) days, BUYER may rescind this Agreement at BUYER'S sole option, with full deposit being refunded to BUYER and all parties being released from any further obligations hereunder. SELLER hereby agrees to make a good faith effort to correct the title defect within the thirty (30) day period above prescribed once notification of such defect is received. The cost of examination of the title shall be borne by BUYER.

10. **PRORATIONS:** Taxes, ~~condo fees~~, special assessments, ~~rents, water and sewage~~ bills shall be prorated as of time and date of closing. ~~Buyer shall pay for all fuel remaining in tank(s) calculated as of the closing date or such earlier date as required to comply with lender requirements, if any. The amount owed shall be determined using the most recently available cash price of the company that last delivered the fuel.~~

11. **PROPERTY INCLUDED:** ~~All Fixtures~~ Vacant Land

12. In compliance with the requirements of RSA 477:4-a, the following information is provided to BUYER relative to Radon Gas, Arsenic and Lead Paint:

**RADON**: Radon, the product of decay of radioactive materials in rock may be found in some areas of New Hampshire. Radon gas may pass into a structure through the ground or through water from a deep well. Testing of the air by a professional certified in radon testing and testing of the water by an accredited laboratory can establish radon's presence and equipment is available to remove it from the air or water.

**Arsenic:** Arsenic is a common groundwater contaminant in New Hampshire that occurs at unhealthy levels in well water in many areas of the state. Tests are available to determine whether arsenic is present at unsafe levels, and equipment is available to remove it from water. The buyer is encouraged to consult the New Hampshire department of environmental services private well testing recommendations (www.des.nh.gov) to ensure a safe water supply if the subject property is served by a private well.

**LEAD:** Before 1978, paint containing lead may have been used in structures. Exposure to lead from the presence of flaking, chalking, chipping lead paint or lead paint dust from friction surfaces, or from the disturbance of intact surfaces containing lead paint through unsafe renovation, repair or painting practices, or from soils in close proximity to the building, can present a serious health hazard, especially to young children and pregnant women. Lead may also be present in drinking water as a result of lead in service lines, plumbing and fixtures. Tests are available to determine whether lead is present in paint or drinking water.

Disclosure Required ☐ YES ☒ NO

13. **BUYER ACKNOWLEDGES PRIOR RECEIPT OF SELLER'S PROPERTY DISCLOSURE FORM AND SIGNIFIES BY INITIALING HERE:** LBA ____ / ____

14. **INSPECTIONS:** The BUYER is encouraged to seek information from licensed home inspectors and other professionals normally engaged in the business regarding any specific issue of concern. SELLER'S real estate FIRM makes no warranties or representations regarding the condition, permitted use or value of the SELLER'S real or personal property. This Agreement is contingent upon the following inspections, with results being satisfactory to the BUYER:

| TYPE OF INSPECTION: | YES | NO | RESULTS TO SELLER | TYPE OF INSPECTION: | YES | NO | RESULTS TO SELLER |
|---|---|---|---|---|---|---|---|
| a. General Building | ☐ | ☒ | within ____ days | f. Lead Paint | ☐ | ☒ | within ____ days |
| b. Sewage Disposal | ☐ | ☒ | within ____ days | g. Pests | ☐ | ☒ | within ____ days |
| c. Water Quality | ☐ | ☒ | within ____ days | h. Hazardous Waste | ☐ | ☐ | within ____ days |
| d. Radon Air Quality | ☐ | ☒ | within ____ days | i. See Item #19 | ☒ | ☐ | within ____ days |
| e. Radon Water Quality | ☐ | ☒ | within ____ days | j. ____ | ☐ | ☐ | within ____ days |

**The use of days is intended to mean calendar days from the effective date of this Agreement. TIME IS OF THE ESSENCE** in the observance of all deadlines set forth within this Paragraph 14. All inspections will be done by licensed home inspectors or other professionals normally engaged in the business, to be chosen and paid for by BUYER. If BUYER does not notify SELLER in writing that the results of an inspection are unsatisfactory within the time period set forth above, the contingency is waived by BUYER. **If the results of any inspection specified herein reveal significant issues or defects, which were not previously disclosed to BUYER then:**

(a) BUYER shall have the option at BUYER'S sole discretion to terminate this Agreement and all deposits shall be returned to BUYER in accordance with NH RSA 331-A:13; or

(b) If BUYER elects to notify SELLER in writing of the unsatisfactory condition(s) then:

1) SELLER and BUYER can reach agreement in writing on the method of repair or remedy of the unsatisfactory condition(s); or

SELLER(S) INITIALS PPP 08/25/22 10:05 AM EDT dotloop verified / LDT 08/25/22 9:31 AM EDT dotloop verified BUYER(S) INITIALS LBA / ____

**PURCHASE AND SALES AGREEMENT**
**New Hampshire Association of REALTORS® Standard Form**

2) If SELLER elects not to repair or remedy the unsatisfactory conditions(s) the BUYER may release the home inspection contingency and accept the property as is; or

3) If SELLER and BUYER cannot reach agreement in writing with respect to the method of repair and remedy of the unsatisfactory condition(s), then this Agreement is terminated and all deposits shall be returned to BUYER in accordance with NH RSA 331-A:13.

Notification in writing of SELLER'S intent to repair or remedy or not to repair or remedy pursuant to Section (b) above, shall be delivered to BUYER or their licensee within five (5) days of receipt by SELLER of notification of unsatisfactory condition(s). BUYER shall respond in writing to SELLER'S notification within five (5) days. If BUYER does not respond within five (5) days, SELLER may elect to terminate this Agreement and all deposits shall be returned to BUYER in accordance with NH RSA 331-A:13.

In the absence of inspection mentioned above, BUYER is relying upon BUYER'S own opinion as to the condition of the PROPERTY.
**BUYER HEREBY ELECTS TO *WAIVE THE RIGHT* TO ALL INSPECTIONS AND SIGNIFIES BY INITIALING HERE:** _______ _______

**15. DUE DILIGENCE:** This Agreement is contingent upon BUYER'S satisfactory review of the following:

| | YES | NO | | YES | NO |
|---|---|---|---|---|---|
| a. Restrictive Covenants of Record | [X] | [ ] | d. Condominium documentation per N.H. RSA 356-B:58 | [ ] | [X] |
| b. Easements of Record/Deed | [X] | [ ] | e. Co-op/PUD/Association Documents | [ ] | [X] |
| c. Park Rules and Regulations | [X] | [ ] | f. Availability of Property/Casualty Insurance | [ ] | [X] |
| | | | g. Availability and cost of Flood Insurance | [ ] | [X] |

If such review is unsatisfactory, BUYER must notify SELLER in writing within __90__ days from the effective date of the Agreement failing which such contingency shall lapse. If BUYER so notifies SELLER, then all deposits shall be returned to BUYER in accordance with NH RSA 331-A:13.

**16. LIQUIDATED DAMAGES:** If BUYER shall default in the performance of their obligation under this Agreement, the amount of the deposit may, at the option of SELLER, become the property of SELLER as reasonable liquidated damages. In the event of any dispute relative to the deposit monies held in escrow, the **ESCROW AGENT** may, in its sole discretion, pay said deposit monies into the Clerk of Court of proper jurisdiction in an Action of Interpleader, providing each party with notice thereof at the address recited herein, and thereupon the **ESCROW AGENT** shall be discharged from its obligations as recited therein and each party to this Agreement shall thereafter hold the **ESCROW AGENT** harmless in such capacity. Both parties hereto agree that the **ESCROW AGENT** may deduct the cost of bringing such Interpleader action from the deposit monies held in escrow prior to the forwarding of same to the Clerk of such court.

**17. PRIOR STATEMENTS**: Any verbal representation, statements and agreements are not valid unless contained herein. This Agreement completely expresses the obligations of the parties.

**18. FINANCING:** This Agreement ( [ ] is) ( [X] is not) contingent upon BUYER obtaining financing under the following terms:

AMOUNT ______________ TERM/YEARS _______ RATE _________ MORTGAGE TYPE ______________

~~For the purposes of this Agreement, financing is to be demonstrated by a conditional loan commitment letter, which states that BUYER is creditworthy, has been approved and that the lender shall make the loan in a timely manner at the Closing on specified customary conditions for a loan of the type specified above. BUYER is responsible to resolve all conditions included in the loan commitment by the Closing date.~~

SELLER(S) INITIALS PPP 08/25/22 10:05 AM EDT dotloop verified / LDT 08/25/22 9:31 AM EDT dotloop verified BUYER(S) INITIALS LBK / ______

**PURCHASE AND SALES AGREEMENT**
**New Hampshire Association of REALTORS® Standard Form**

~~The existence of conditions in the loan commitment will not extend either the Financing Deadline described below or the closing date.~~

~~BUYER hereby authorizes, directs and instructs its lender to communicate the status of BUYER'S financing and the satisfaction of lender's specified conditions to SELLER and SELLER'S/BUYER'S real estate FIRM.~~

~~TIME IS OF THE ESSENCE in the observance of all deadlines set forth within this financing contingency.~~

~~BUYER agrees to act diligently and in good faith in obtaining such financing and shall, within ______________ calendar days from the effective date, submit a complete and accurate application for mortgage financing to at least one financial institution currently providing such loans, requesting financing in the amount and on the terms provided in this Agreement.~~

~~If BUYER provides written evidence of inability to obtain financing to SELLER by ______________________ ("Financing Deadline"), then:~~

- ~~(a) This Agreement shall be null and void; and~~
- ~~(b) All deposits will be returned to BUYER in accordance with the procedures required by the New Hampshire Real Estate Practice Act (N.H. RSA 331-A:13) ("the Deposit Procedures"); and~~
- ~~(c) The premises may be returned to the market.~~

~~BUYER may choose to waive this financing contingency by notifying SELLER in writing by the Financing Deadline and this Agreement shall no longer be subject to financing.~~

~~If, however:~~

- ~~(a) BUYER does not make application within the number of days specified above; or~~
- ~~(b) BUYER fails to provide written financing commitment or written evidence of inability to obtain financing to SELLER by the Financing Deadline,~~

~~Then SELLER shall have the option of either:~~

- ~~(a) Declaring BUYER in default of this Agreement; or~~
- ~~(b) Treating the financing contingency as having been waived by BUYER.~~

~~If SELLER declares BUYER in default, in addition to the other remedies afforded under this Agreement:~~

- ~~(a) SELLER will be entitled to all deposits in accordance with the Deposit Procedures; and~~
- ~~(b) This Agreement will be terminated; and~~
- ~~(c) The premises may be returned to the market for sale.~~

~~If SELLER opts to treat the financing contingency as waived or relies on a conditional loan commitment and BUYER subsequently does not close in a timely manner, SELLER can then declare BUYER in default. SELLER then, in addition to the other remedies afforded under this Agreement:~~

- ~~(a) Will be entitled to all deposits in accordance with the Deposit Procedures; and~~
- ~~(b) This Agreement will be terminated; and~~
- ~~(c) The premises may be returned to the market for sale.~~

~~BUYER shall be solely responsible to provide SELLER in a timely manner with written evidence of financing or lack of financing as described above.~~

**WIRE FRAUD ALERT.** Sophisticated criminals are targeting the email accounts of real estate agents, title companies, settlement attorneys and others to generate fake wire transfer instructions designed to divert closing funds to the criminals. The emails are professionally created and look real. Buyer and Seller should not send personal information such as social security numbers, bank account numbers or credit card numbers except through secure email or personal delivery of the information. **Buyer and Seller are advised not to wire any funds without pers[onally sp]eaking wit[h the inte]nded recipient of the wire to confirm the routing number and the account number.** Seller PPP 08/25/22 10:05 AM dotloop LDT 08/25/22 9:31 AM EDT dotloop verified Buyer ____________ ____________

SELLER(S) INITIALS PPP 08/25/22 10:05 AM EDT dotloop verified / LDT 08/25/22 dotloop verified BUYER(S) INITIALS LBH / ____________

dotloop signature verification: dtlp.us/qIAT-7wBv-auub

## PURCHASE AND SALES AGREEMENT
New Hampshire Association of REALTORS® Standard Form

**19. ADDITIONAL PROVISIONS:**
1) Seller shall have no tree or mineral harvesting, as property seen today (effective date).
2) Added to the Inspection Period of this agreement will be inserted into Section 14(i) will be 180 days for each of the following to the Buyer's sole and absolute discretion and satisfaction:
a) Subject to the buyer obtaining an appraisal with a value of the offer price or greater.
b) The Buyer obtaining all State and Town required approvals.
c) Environmental and Geotechnical review.
3) Buyer shall have the right to extend the Inspection Period outlined in Section 14 for an additional 60 days by
Continued... See Addendum Additional Provisions 1

**20. ADDENDA ATTACHED:** [X] Yes [ ] No Addendum

**21. EFFECTIVE DATE/NOTICE:** Any notice, communication or document delivery requirements in this agreement may be satisfied by providing the required notice, communication or documentation to the party or their licensee. All notices and communications must be in writing to be binding except for withdrawals of offers or counteroffers. This Agreement is a binding contract when signed and all changes initialed by both BUYER and SELLER and when that fact has been communicated in writing which shall be the EFFECTIVE DATE. Licensee is authorized to fill in the EFFECTIVE DATE on Page 1 hereof. The use of days is intended to mean calendar days from the EFFECTIVE DATE of this Agreement. Deadlines in this Agreement, including all addenda, expressed as "within x days" shall be counted from the EFFECTIVE DATE, unless another starting date is expressly set forth, beginning with the first day after the EFFECTIVE DATE, or such other established starting date, and ending at 12:00 midnight Eastern Time on the last day counted. Unless expressly stated to the contrary, deadlines in this Agreement, including all addenda, expressed as a specific date shall end at 12:00 midnight Eastern Time on such date.

Each party is to receive a fully executed copy of this Agreement. This Agreement shall be binding upon the heirs, executors, administrators and assigns of both parties.

PRIOR TO EXECUTION, IF NOT FULLY UNDERSTOOD, PARTIES ARE ADVISED TO CONTACT AN ATTORNEY.

| | |
|---|---|
| Robert B. [signature] 8/23/22 / | / |
| BUYER DATE/TIME | BUYER DATE/TIME |
| Unitil and/or assigns | |
| 6 Liberty Lane West | |
| MAILING ADDRESS | MAILING ADDRESS |
| Hampton NH 03842 | |
| CITY STATE ZIP | CITY STATE ZIP |

SELLER accepts the offer and agrees to deliver the above-described PROPERTY at the price and upon the terms and conditions set forth.

| | |
|---|---|
| Philip Farrar POA (dotloop verified 08/25/22 10:05 AM EDT JQQI-R18C-NDXK-9US9) / | Lynda Devost, Trustee (dotloop verified 08/25/22 9:31 AM EDT ZYNX-IJST-VB0T-KHWB) / |
| SELLER DATE/TIME | SELLER DATE/TIME |
| Two Mill Road Realty Trust and 24 Towle Road Realty Trust | |
| 18 Old Mill Road | |
| MAILING ADDRESS | MAILING ADDRESS |
| Kingston NH 03848 | |
| CITY STATE ZIP | CITY STATE ZIP |

# ADDENDUM

PROPERTY: **Two vacant land parcels: 2 Mill Rd (63 Acres) Bk/pg 2893/2178, Kingston,**

**1) Additional Provisions**
**providing written notice to Seller no later than 90 days after the effective date of this agreement.**
**4) Seller will provide all relevant reports, data and testing results pertinent to both sites.**
**5)Transfer of Title to take place on or before 30 days after the Inspection Period or any extension thereof as outlined Section 14.**

Date: 8/23/22
Robert B[illegible]
Signature

Date:
Signature

Date:
Philip Farrar POA
dotloop verified
08/25/22 10:05 AM EDT
PSOX-ZFDS-JN53-RXP8
Signature

Date:
Lynda Dewost, Trustee
dotloop verified
08/25/22 9:31 AM EDT
GGSO-9HCF-PCUW-UVFE
Signature

# Utility Scale PV – Facility Design, Procurement and Installation
# 2 Mill Road, Kingston
# Preliminary Request for Proposal – Scope of Services

September 12, 2022

## 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 property of 2 Mill Road in Kingston, NH and is currently performing due diligence exploration on the parcel. 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 "Preliminary" Request for Proposal (P-RFP) for the design, procurement and construction of the PV facility. The purpose of this P-RFP is to obtain detailed pricing information for various facility options that will be utilized by Unitil in regulatory filings and for the development of a "Final" RFP for the project.

All references to professional engineering review and final designs in this P-RFP are to inform the vendors of the level of final design that is expected when the project is awarded after the "Final" RFP process is complete. Unitil is not intending for any Vendors to complete final stamped designs as part of this P-RFP process. It is the Company's expectation that preliminary designs, layouts, equipment specifications, schedules and costs be included in response to this P-RFP.

## 2 Property Description

Mill Road, Kingston, NH is a 63 acre vacant parcel that has two 34.5kV "subtransmission" lines running through it and is adjacent to a Unitil 115kV to 34.5kV substation.

Information of record reviews indicate that the parcel is relatively flat with limited wetlands. Unitil's subcontractor is in the process of surveying the parcel, formally identifying wetlands and performing other due diligence activities.

It is Unitil's intent to perform all construction permitting and "pad-ready" construction (access road, drainage facilities, and final site grading) utilizing its typical, local site engineering firms and construction contractors. The scope of this work is outside the scope of this P-RFP. However, Unitil will coordinate with the site construction contractor to have below grade conduit, cable trench, transformer pads and inverter pads installed as part of the site construction. The specification, procurement and cost of this equipment shall be included in the proposals to the P-RFP.

For the purposes of the P-RFP assume the "pad-ready" site will have a 5% north-to-south slope.

## 3 Design Requirements

All components of the PV Facility up to the Point of Interconnection (POI), including PV modules, inverters, step-up transformers, equipment racking and foundations, facility fence, etc., shall be considered in scope and included in responses to this P-RFP.

For the purposes of this P-RFP the POI shall be considered the utility side of the step-up transformer(s).

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-6
Page 2 of 19

# Utility Scale PV – Facility Design, Procurement and Installation
# 2 Mill Road, Kingston
# Preliminary Request for Proposal – Scope of Services

September 12, 2022

## 3.1 Ratings:

| | |
|---|---|
| Nameplate Capacity: | 4.9MW AC (facility AC rating shall be less than 5MW) |
| Utility System Voltage at POI: | 34,500GRD Y/19,920 V |
| Utility System Insulation Level at POI: | 200kV BIL |

## 3.2 General Design Requirements

- The facility and all its components shall be designed and installed in accordance with the latest versions of the 2023 National Electric Safety Code (NESC), 2023 National Electric Code (NEC), UL-1741, IEEE 1547, and all other applicable local and state codes and standards.
- The selected vendor shall have a professional engineering firm that is licensed to practice engineering in the state of New Hampshire sign off on the final design and must certify that the system is designed and built in accordance with the NESC, NEC, and all local, state and federal codes.

## 3.3 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.

## 3.4 Electrical Design Requirements

- Electrical engineering and design shall meet industry standards such as the NESC, NEC, UL-1741, IEEE 1547, and all other applicable local and state codes and standards.
- All equipment and enclosures, including but not limited to, disconnects and combiners shall String combiner boxes must 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 affectively grounded.
- A convenience outlet at 120v/20 amp to provide power for test equipment and other diagnostic equipment shall be installed within fifteen feet of each inverter.

## 3.5 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 110MPH 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.
- All fasteners and hardware throughout the system shall be stainless steel or materials of equivalent corrosion resistance
- All non-metallic exposed materials shall be sunlight and UV resistant (30 year life expectancy)

## 3.6 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 P-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, 7' in width.
- Fabric shall be attached to posts and rails by means of #9 gauge galvanized steel 'Easy Twist Ties'.
- All corner posts and gate posts shall be 4" allied tube SS40 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" allied tube SS40 pipe and shall be installed in 8" diameter sonotubes to a depth of 5'-0" (minimum) below finished grade.
- Rivets shall be stainless steel.
- All other steel parts shall be hot-dipped galvanized after fabrication with the exception of the fence fabric which shall be aluminized.
- 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.

**Utility Scale PV – Facility Design, Procurement and Installation**
**2 Mill Road, Kingston**
**Preliminary Request for Proposal – Scope of Services**
September 12, 2022

- 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.
- Top of fence shall be a minimum of 7' above final grade.
- Gaps of no more than 2" between the bottom rail and final grade shall be allowed.

### 3.7 Other Design Requirements

- All fasteners and hardware throughout the system shall be stainless steel or materials of equivalent corrosion resistance
- All non-metallic exposed materials shall be sunlight and UV resistant (30 year life expectancy)

## 4 Equipment Requirements

The Company prefers equipment from PV module and inverter manufacturers as well as transformer manufacturers that are located in the United States and have at least ten (10) years of experience manufacturing the selected components of the type and size proposed, for this applications.

All solar PV system equipment shall be newly manufactured (not refurbished or reconditioned) from a reputable manufacturer, experienced in providing equipment for the application and site conditions.

### 4.1 Inverters

- Inverters shall be compliant with current versions of UL 1741, IEEE 1547 and all other applicable codes and standards.
- Inverters must carry a UL 1741 or equivalent certification.
- It is Unitil's intent to integrate the inverters 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.).
- On-site commissioning of the inverters as well as their SCADA functionality shall be included in the proposals.
- The inverter units should have built-in tolerance to variation in grid voltages. The inverter shall be capable of riding through voltage sags. Tolerance set points should be configurable to +/- 10% minimum.
- The three phase output voltages and currents shall be sinusoidal with low total harmonic distortion (THD) to meet IEEE 519 harmonic requirements. Harmonic filters shall be provided if required.
- The proposed systems it will have a CEC weighted efficiency of 97.5 % or higher.

**Utility Scale PV – Facility Design, Procurement and Installation**
**2 Mill Road, Kingston**
**Preliminary Request for Proposal – Scope of Services**
September 12, 2022

- All inverters shall be warrantied for a minimum of twelve (12) years, fifteen (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 5MW.
  - 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.

## 4.2 Solar Modules/Panels

- Modules should be compliant with current versions of UL 1703, ISO9001, IEC 61215, IEC 61730 and all other applicable codes and standards.
- 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 twenty-five (25) years, thirty (30) years or more is preferred, after energization.

## 4.3 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 throughout the thirty (30) year project life taking into consideration the 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.

**Utility Scale PV – Facility Design, Procurement and Installation**
**2 Mill Road, Kingston**
**Preliminary Request for Proposal – Scope of Services**
September 12, 2022

- All final structural drawings associated with the project must be stamped by a Professional Structural Engineer registered within the State of New Hampshire.

## 4.4 Step-Up Transformer

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

- Rating Information:

| | |
|---|---|
| High-Voltage: | 34.5/19.92 kV |
| High-Voltage BIL: | 200kV (deadfront 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 Scale PV – Facility Design, Procurement and Installation
# 2 Mill Road, Kingston
# Preliminary Request for Proposal – Scope of Services

September 12, 2022

| 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

## 5 Facility Options

Unitil is interested in exploring alternates to optimize/improve "generation factor" to increase energy export, especially during peak load hours. The following options are being considered by Unitil and this P-RFP process will assist the Company in determining the requirements of a future "Final" RFP.

For all options below include alternatives for both fixed PV modules and multi-axis tracking modules.

The various alternatives will be evaluated by Unitil to determine the most cost effective option.

### 5.1 AC and DC "Matched" Capacity

PV facility in which the estimated DC peak capacity is matched to the 4.9MW AC capacity of the invertors. This is the base option in which the other options described below will be compared to.

### 5.2 Larger DC Capacity

PV facility in which the DC capacity is greater than the AC capacity to improve "generation factor" during off-peak generation times. It is understood that during peak generation times of year, inverter clipping will occur reducing AC output to the rating of the invertors.

Vendors shall propose a reasonable DC rating based on their past experience.

### 5.3 Paired Energy Storage System

Energy Storage System (ESS) installed in conjunction with the PV system on the DC side of the facility. The ESS shall only be capable of being charged from the solar modules/DC side of the PV facility. In this option the purpose of the ESS is to improve "generation factor" during the following between the hours of 15:00-20:00.

Vendors shall propose a reasonable ESS size and charge/discharge schedule rating based on their past experiences for both the AC and DC "Match" Capacity PV Facility (5.1 above) and the Larger DC Capacity PV Facility (5.2 above).

## 6 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 P-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.

# 7 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.

# 8 Proposal Requirements

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

## 8.1 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

## 8.2 Construction, Commissioning and Maintenance

- For each of the options described in section 5.
  - 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.

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-6
Page 9 of 19



- List and location of below-grade equipment proposed to be installed by Unitil's site contractor.
- Environmental loading facility is designed for.
- Description of below grade equipment to be installed by Unitil's site contractor.
- 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.
- Estimated annual energy production and method utilized to perform the calculation for each year of the next 30 years.
- Estimated hourly energy production and method utilized to perform the calculation for each month of the year for the following hours:
  15:00-16:00
  16:00-17:00
  17:00-18:00
  18:00-19:00
  19:00-20:00
- List of recommended spare equipment.
- Recommended annual maintenance requirements.

o Sample testing and commissioning plan
o Country of manufacture of all major equipment (e.g., inverters, modules, transformer, etc.)
o Detailed schedule for engineering, procurement and construction
o Describe capability to provide 5 years of PV and ESS system operation and maintenance
o Listing of all applicable statutes, ordinances, codes, standards, and/or regulations facility is designed to comply with.

## 8.3 Pricing Proposals

Price proposals shall be based on and will be evaluated on the assumptions provided within this document. All pricing proposals shall be completed in the excel document entitled "2020 PV Facility Design and Installation P-RPP – Pricing Response".

## 8.4 Lead Time

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

# Utility Scale PV – Facility Design, Procurement and Installation
# 2 Mill Road, Kingston
# Preliminary Request for Proposal – Scope of Services

September 12, 2022

## 8.5 Exceptions

Any and all exceptions to this specification shall be clearly noted, including the reasoning for the exception.

Please indicate any requirements of this specification that are atypical for a facility of this type and size and indicate the typical alternative.

## 8.6 Questions to Vendors

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

### 8.6.1 Inverter Type

Briefly describe the advantages and disadvantages of a central inverter design and a string inverter design for a facility such as this.

### 8.6.2 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.

### 8.6.3 Geotechnical Information

Describe what geotechnical information is require to complete the detailed PV facility design.

### 8.6.4 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.

Provide any additional details regarding the grounding of equipment and fencing to comply with the NESC.

### 8.6.5 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.

### 8.6.6 Investment Tax Credit

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

# Utility Scale PV – Facility Design, Procurement and Installation
# 2 Mill Road, Kingston
# Preliminary Request for Proposal – Scope of Services

September 12, 2022

### 8.6.7 Other Benefits of PV/ESS

Briefly describe any quantitative (other than reduction of load and renewable energy credits) and qualitative benefits of PV and ESS. For any quantitative benefits please provide the benefit the proposed facility is expected to provide and the method in which the benefit was calculated.

### 8.6.8 Additional Information

Based on your experience with work similar in scope to what is described in the P-RFP, please suggest supplemental or alternative tasks to be undertaken for this project to help Unitil achieve its objective. Your response may include omissions, additions or modifications to tasks outlined in the P-RFP.

Any omission, addition or modification to what is outlined in the P-RFP shall be clearly identified in your proposal, including a detailed explanation of the reason(s) for the proposed change.

### 8.6.9 Work Planning

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

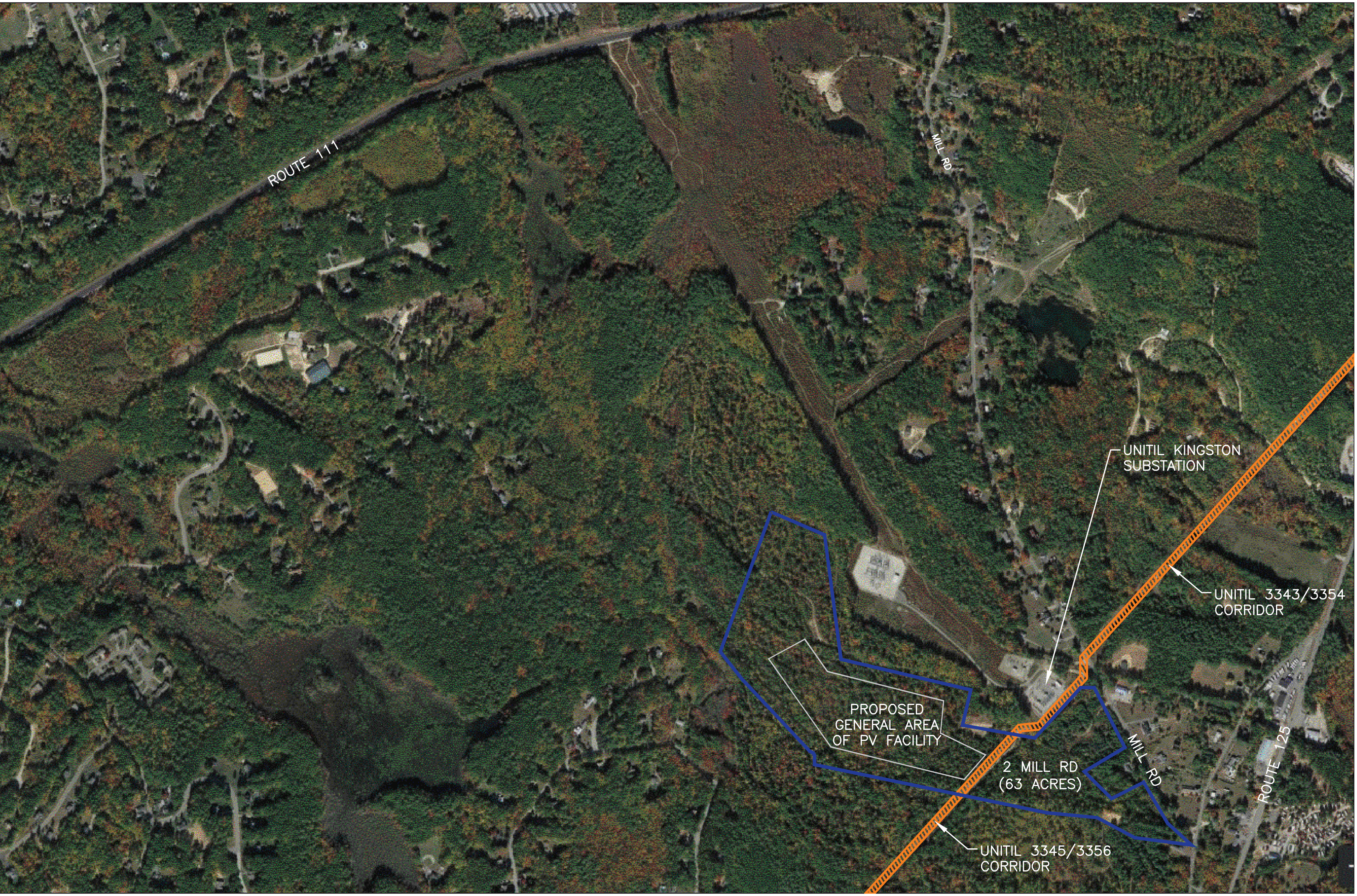
### 8.6.10 "Final" RFP

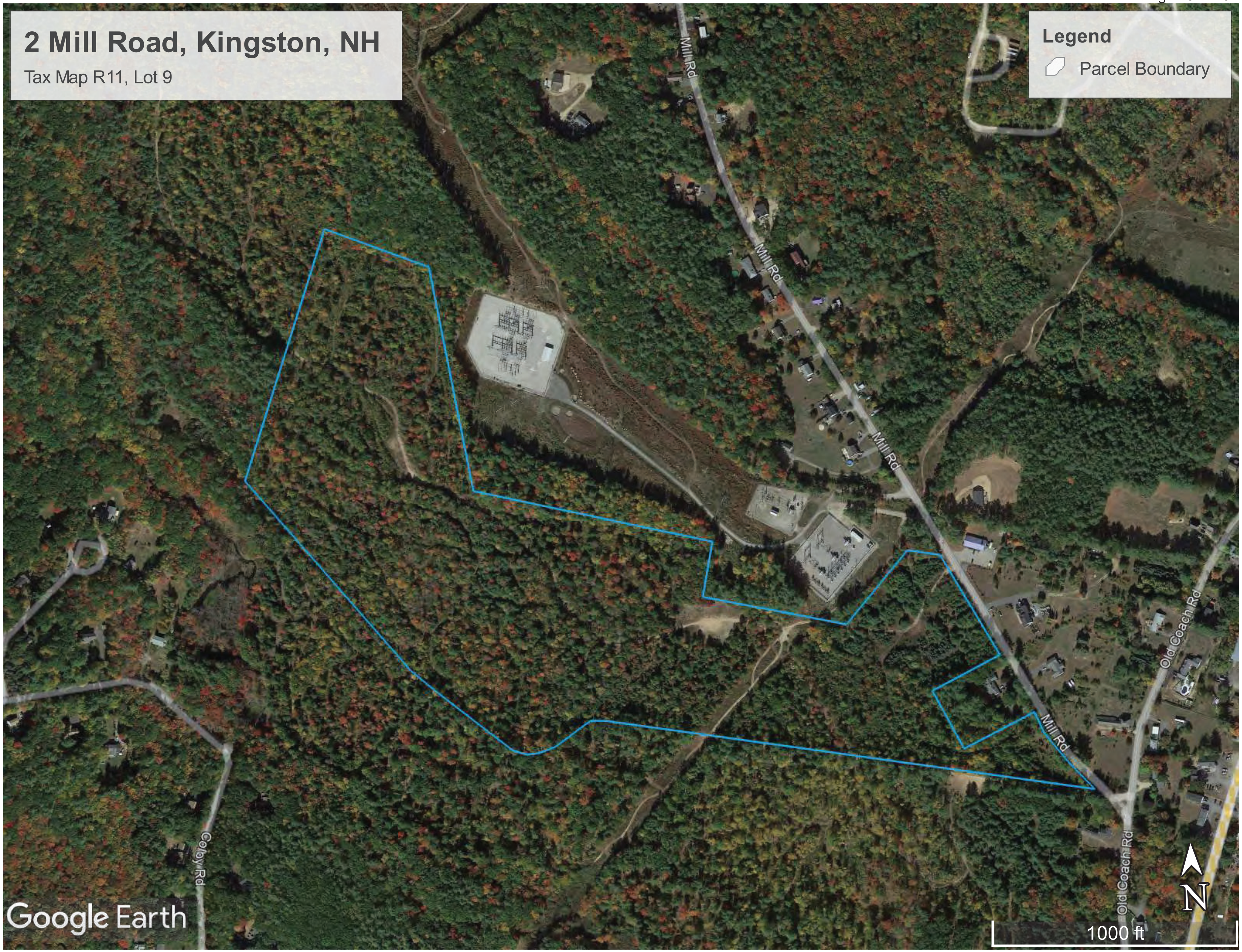
Provide a list of additional information that you would like to have included in a future "Final" RFP to assist you in providing a final proposal.

Indicate the typical validity period of final proposal.

## 9 Attachments

- <u>2 Mill Road Overview</u> – Overview of 2 Mill Road with surrounding electric infrastructure highlighted. The proposed general area of the PV facility shown on this print may change as more information becomes available through the site due diligence process. This document is not to scale.
- <u>2 Mill Rd Aerial</u> – Overview of 2 Mill Road without surrounding electric infrastructure highlighted. This document is to scale.
- <u>2020 PV Facility Design and Installation P-RPP – Pricing Response</u> – pricing response spreadsheet that shall be completed by all participating vendors. If electing to not quote specific options please provide an explanation in the spreadsheet.


ROUTE 111
MILL RD
UNITIL KINGSTON SUBSTATION
UNITIL 3343/3354 CORRIDOR
PROPOSED GENERAL AREA OF PV FACILITY
2 MILL RD (63 ACRES)
MILL RD
ROUTE 125
UNITIL 3345/3356 CORRIDOR


2 Mill Road, Kingston, NH
Tax Map R11, Lot 9
Legend
Parcel Boundary
Mill Rd
Old Coach Rd
Colby Rd
N
1000 ft
Google Earth

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-6
Page 14 of 19

**Option 5.3B - Paired ESS - Multi-Axis Track Panel Design**

General Information

| | | | | |
|---|---|---|---|---|
| AC Nameplate Capacity | | kWh | | |
| Total Nameplate Capacity of PV Modules | | kWh | | |
| Nameplate Capacity of ESS | | kWh | | kW |
| Estimated Required Clear Space | | Acres | | |

Estimated Energy Production

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

Pricing Information:

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding ESS and fence) | |
| Labor to Install Facility (excluding ESS and fence) | |
| ESS Material | |
| Labor to Install ESS | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

Proposed Charge Schedule of ESS

| | kWh | Charge/ Discharge | | kWh | Charge/ Discharge |
|---|---|---|---|---|---|
| 00:00-1:00 | | | 12:00-13:00 | | |
| 1:00-2:00 | | | 13:00-14:00 | | |
| 2:00-3:00 | | | 14:00-15:00 | | |
| 3:00-4:00 | | | 15:00-16:00 | | |
| 4:00-5:00 | | | 16:00-17:00 | | |
| 5:00-6:00 | | | 17:00-18:00 | | |
| 6:00-7:00 | | | 18:00-19:00 | | |
| 7:00-8:00 | | | 19:00-20:00 | | |
| 8:00-9:00 | | | 20:00-21:00 | | |
| 9:00-10:00 | | | 21:00-22:00 | | |
| 10:00-11:00 | | | 22:00-23:00 | | |
| 11:00-12:00 | | | 23:00-00:00 | | |

Notes and Comments

**Option 5.1A - AC and DC "Matched" Capacity - Fixed Panel Design**

General Information

| | | |
|---|---|---|
| AC Nameplate Capacity | | kWh |
| Total Nameplate Capacity of PV Modules | | kWh |
| Estimated Required Clear Space | | Acres |

Estimated Energy Production

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

Pricing Information:

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding fence) | |
| Labor to Install Facility (excluding fence) | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

Notes and Comments

**Option 5.1B - AC and DC "Matched" Capacity - Multi-Axis Track Panel Design**

General Information

| | | |
|---|---|---|
| AC Nameplate Capacity | | kWh |
| Total Nameplate Capacity of PV Modules | | kWh |
| Estimated Required Clear Space | | Acres |

Estimated Energy Production

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

Pricing Information:

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding fence) | |
| Labor to Install Facility (excluding fence) | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

Notes and Comments

**Option 5.2A - Larger DC Capacity - Fixed Panel Design**

General Information

| | | |
|---|---|---|
| AC Nameplate Capacity | | kWh |
| Total Nameplate Capacity of PV Modules | | kWh |
| Estimated Required Clear Space | | Acres |

Estimated Energy Production

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

Pricing Information:

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding fence) | |
| Labor to Install Facility (excluding fence) | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

Notes and Comments

Unitil Energy Systems, Inc. d/b/a Unitil
Docket No. DE 22-_____
Exhibit JSD-6
Page 18 of 19

**<u>Option 5.2B - Larger DC Capacity - Multi-Axis Track Panel Design</u>**

<u>General Information</u>

| | | |
|---|---|---|
| AC Nameplate Capacity | | kWh |
| Total Nameplate Capacity of PV Modules | | kWh |
| Estimated Required Clear Space | | Acres |

<u>Estimated Energy Production</u>

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

<u>Pricing Information:</u>

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding fence) | |
| Labor to Install Facility (excluding fence) | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

<u>Notes and Comments</u>

**Option 5.3A - Paired ESS - Fixed Panel Design**

General Information

| | | | | |
|---|---|---|---|---|
| AC Nameplate Capacity | | kWh | | |
| Total Nameplate Capacity of PV Modules | | kWh | | |
| Nameplate Capacity of ESS | | kWh | | kW |
| Estimated Required Clear Space | | Acres | | |

Estimated Energy Production

| | | |
|---|---|---|
| Estimated Annual Energy Generated - Year 1 | | kWh |
| % Reduction from Year 1 to Year 2 | | % |
| Annual % Reduction Year 2 to the End of Life of the Facility | | % |

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

Pricing Information:

| | $ |
|---|---|
| Inverters and Associated Material | |
| PV Modules and Associated Material | |
| Step-up Transformer and Associated Material | |
| All Other Material (excluding ESS and fence) | |
| Labor to Install Facility (excluding ESS and fence) | |
| ESS Material | |
| Labor to Install ESS | |
| Fence Material | |
| Labor to Install Fence | |
| 5 Year Maintenance Plan | |

| | Hours | $/hr |
|---|---|---|
| Project Management | | |
| Construction Field Representative | | |

| | |
|---|---|
| One (1) Spare Step-Up Transformer | |
| One (1) Spare Inverter | |
| Five (5) Spare PV Modules | |
| Other Recommended Spare Equipment | |

Proposed Charge Schedule of ESS

| | kWh | Charge/ Discharge | | kWh | Charge/ Discharge |
|---|---|---|---|---|---|
| 00:00-1:00 | | | 12:00-13:00 | | |
| 1:00-2:00 | | | 13:00-14:00 | | |
| 2:00-3:00 | | | 14:00-15:00 | | |
| 3:00-4:00 | | | 15:00-16:00 | | |
| 4:00-5:00 | | | 16:00-17:00 | | |
| 5:00-6:00 | | | 17:00-18:00 | | |
| 6:00-7:00 | | | 18:00-19:00 | | |
| 7:00-8:00 | | | 19:00-20:00 | | |
| 8:00-9:00 | | | 20:00-21:00 | | |
| 9:00-10:00 | | | 21:00-22:00 | | |
| 10:00-11:00 | | | 22:00-23:00 | | |
| 11:00-12:00 | | | 23:00-00:00 | | |

Notes and Comments

**Capital Appraisal Associates, Inc.** *Real Estate Appraisers and Consultants*
128 South Fruit Street, Concord, New Hampshire 03301-4845
(603) 228-9040 FAX (603) 228-2072

**Job #:** ______

## AGREEMENT FOR APPRAISAL SERVICES

This Agreement made on the **24th** day of **August, 2022** by and between

**Jacob Dusling**
**Unitil**
**30 Energy Way, Exeter, NH 03833**

hereinafter called the "Client", and Capital Appraisal Associates, Inc. of Concord, NH, a New Hampshire Business, hereinafter called the "Appraiser".

Whereas, the Client desires to employ the Appraiser to furnish appraising services to establish market value for negotiating purposes in connection with properties owned by Richard W. Senter Trust and located as follows:

**(1) 2 Mill Road, Kingston, NH - Land - 63.0 Acres . . . . . . . . . . . . . .** [redacted]
**(2) 24 Towle Road, Kingston, NH - Land - 33.0 Acres. . . . . . . . . . . . .**
**Total Fee:. . . .**

Therefore, it is hereby agreed that the Appraiser shall furnish the requisite Appraisal Services based on our Professional Services Fee (and direct costs, if applicable) of [redacted] The Client shall make payment for the Services as follows: total fee due at time of delivery of the reports. The appraisal reports are to be delivered no later than November 30, 2022. No work by the Appraiser shall commence without a signed contract. The Client may interrupt or terminate the services with two (2) days notice, in writing, compensating the Appraiser for all costs incurred to expiration of the notice period.

It is further agreed that the maximum liability of the Appraiser for services performed under this Agreement shall be limited to the total fee paid to the Appraiser under this Agreement.

Client agrees to pay all reasonable costs of collection, and all interest charges at the rate of [redacted] per month of the unpaid balance after 15 days.

In Witness Whereof, the parties hereunto have caused these presents to be executed the day and year first above written.

Attest:

Aug. 30, 2022
Date

Capital Appraisal Associates, Inc.

August 29, 2022
Date

Jacob Dusling

REDACTED

**UNITIL ENERGY SYSTEMS, INC.**

**JOINT DIRECT TESTIMONY**

**OF**

**ANDRE J. FRANCOEUR**

**TODD R. DIGGINS**

**CHRISTOPHER J. GOULDING**

**AND**

**JEFFREY M. PENTZ**

**EXHIBIT FDGP-1**

**New Hampshire Public Utilities Commission**

**Docket No. DE 22-_____**

## Table of Contents

I. INTRODUCTION ........................................................................................ 1
II. OVERVIEW OF BENEFIT-COST ANALYSIS ........................................................ 6
III. KINGSTON SOLAR PROJECT COST ESTIMATES ........................................... 12
IV. KINGSTON SOLAR PROJECT BENEFITS ........................................................ 17
V. DISCUSSION OF BENEFIT-COST ANALYSIS RESULTS ................................ 24
VI. COST RECOVERY AND BILL IMPACTS ......................................................... 26
VII. CONCLUSION ........................................................................................ 32

**Exhibits**

Exhibit FDGP-2: Benefit-Cost Analysis [CONFIDENTIAL]

Exhibit FDGP-3: Bill Impact Analysis

## I. INTRODUCTION

**Q. Mr. Francoeur, would you please state your name and business address?**

A. My name is Andre J. Francoeur. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

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

A. I am the Financial Planning and Analysis Manager for Unitil Service Corp. ("Unitil Service"), which provides services to Unitil Energy Systems, Inc. ("UES" or the "Company"). My responsibilities are primarily in the areas of strategic planning and budgeting, supporting investor relations, and assisting with various regulatory and treasury projects.

**Q. Please describe your business and educational background.**

A. I have approximately 7 years of professional experience within the finance and accounting areas. I began working for Unitil Service in 2017 as a Financial Analyst, was promoted to Senior Financial Analyst in 2020, and promoted to my current role in 2021. I graduated with honors from the State University of New York at Plattsburgh with a Bachelor of Science degree. I am currently pursuing a Master's degree in Business Administration from the University of New Hampshire.

**Q. Mr. Francoeur, do you hold any professional certifications?**

A. Yes, I am a Certified Management Accountant.

**Q. Have you previously testified before the Commission, or other regulatory agencies?**

A. Yes, I recently testified before the New Hampshire Public Utilities Commission (the "Commission") in DG 21-104, Northern Utilities' most recent base distribution rate case.

**Q. Mr. Diggins, please state your name and business address.**

A. My name is Todd R. Diggins. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

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

A. I am the Treasurer and Director of Finance for Unitil Service, a subsidiary of Unitil Corporation that provides managerial, financial, accounting, regulatory, engineering and information technology services to Unitil Corporation's subsidiaries. I am also the Treasurer of UES and Unitil Corporation's other utility subsidiaries. My responsibilities are primarily in the areas of financial planning and analyses, regulatory projects, treasury operations, investor relations, and insurance and loss control programs.

**Q. Mr. Diggins, please describe your business and educational background.**

A. I have over 20 years of professional experience in the utility industry focused within the finance, accounting, and regulatory areas. I joined Unitil Service in 1998 as a Systems Financial Analyst. In 2004, I accepted a position within the Accounting

Department as a General Accountant and was promoted to Corporate Accounting Manager in 2009. In 2018, I was promoted to Director of Finance and in 2020 became Treasurer and Director of Finance. I hold a Bachelor of Science degree from the University of New Hampshire, a Master's Degree of Science in Finance from Southern New Hampshire University, and a Masters of Global Business Administration from Southern New Hampshire University.

**Q. Do you hold any professional licenses?**

A. Yes, I am a Certified Public Accountant in the State of New Hampshire.

**Q. Have you previously testified before the Commission, or other regulatory agencies?**

A. Yes, I recently testified before the Commission in DE 21-030, UES's most recent base distribution rate case.

**Q. Mr. Goulding, please state your name and business addresses.**

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

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

A. I am the Director of Rates and Revenue Requirements for Unitil Service, a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's utility subsidiaries including UES. My responsibilities include all rate and regulatory filings related to the financial requirements of UES and its affiliates.

**Q. Please describe your business and educational background.**

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

**Q. Mr. Goulding, have you previously testified before the Department or other regulatory agencies?**

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

**Q. Mr. Pentz, would you please state your name and business address?**

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

**Q. What is your position?**

A. I am employed by Unitil Service as a Senior Energy Analyst.

**Q. Please describe your business and educational background.**

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

**Q. Have you previously testified before the Commission?**

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

**Q. What is the purpose of your testimony and how is it organized?**

A. As discussed in the testimonies of Messrs. Sprague and Dusling, the Company is proposing to construct, own, and operate a 4.99 megawatt ("MW") alternating current ("AC" or "ac") utility-scale solar generating facility in Kingston, New Hampshire pursuant to New Hampshire Revised Statutes Annotated ("RSA") 374-G (the "Kingston Solar Project" or the "Project"). Among other things, RSA 374-G requires electric utilities to provide an analysis of the benefits and costs ("Benefit-Cost") of proposed Distributed Energy Resource ("DER") projects, and the associated rate implications. The purpose of our testimony is to present the Company's Benefit-Cost Analysis and the estimated bill impacts associated with the Kingston Solar Project.

Section II provides an overview of the Company's methodological approach to the Benefit-Cost Analysis. Section III provides a detailed discussion of the estimated costs for the Project. Section IV provides a detailed discussion of the estimated benefits of the Kingston Solar Project. Section V discusses the results of the Benefit-Cost analysis. Section VI presents the Company's cost recovery proposal and the estimated bill impacts for the Project. Lastly, Section VII is the conclusion.

## II. OVERVIEW OF BENEFIT-COST ANALYSIS

**Q. Please provide an overview of the methodology the Company employed in its Benefit-Cost Analysis.**

A. Whether it be explicit or implicit, investment decisions generally involve a comparison of benefits and costs. A Benefit-Cost Analysis is a systematic approach for calculating and comparing the estimated benefits and costs of a project to determine the extent of net benefits (the excess of benefits over costs). In many cases, project benefits accrue over many years while capital costs, which often represent a significant portion of total costs, are incurred primarily in the initial years. Therefore, the benefits and costs estimated over an analysis period are discounted to calculate the net present value ("NPV") of benefits and costs so they may be compared. The present value of the benefits and costs can be compared to calculate a benefit-cost ratio and if this ratio is greater than 1.00, it generally indicates the proposed investment is worth undertaking. The Company applied this methodological approach in the Benefit-Cost Analysis discussed below. The benefits and costs included in this analysis were viewed from the vantage point of the Company's customers.

**Q. Does RSA 374-G require a Benefit-Cost Analysis?**

A. As part of the minimum filing requirements for a DER investment, RSA 374-G:5, I(b) requires a discussion of the costs, benefits, and risks of the proposal, with specific reference to the public interest factors (set forth in RSA 374-G:5, II) that must be considered by the Commission. This discussion should include an analysis of the costs and benefits of the project to participating customers, the utility's default service customers, and its distribution customers. The public interest factors that must be considered by the Commission include a quantitative analysis of the benefits and costs to the utility's customers (RSA 374-G:5, II(g)), whether the expected economic benefits outweigh the economic costs (RSA 374-G:5, II(h)), and the costs and benefits to any participating customers (RSA 374-G:5, II(i)).

**Q. Please briefly explain the benefits and costs included in the Benefit-Cost Analysis.**

A. In brief, the benefits included in the economic analysis are direct benefits that will accrue to all customers. The costs included in the model (Exhibit FDGP-2) reflect the revenue requirement associated with owning and operating the Project. Partially offsetting the revenue requirement is the benefit of the Investment Tax Credit ("ITC"), which is discussed in further detail later in this testimony.

**Q. Please describe the classification of benefits reflected in the Company's filing.**

A. For purposes of analysis and discussion, the Company has divided the Project's expected benefits into two categories: (1) "direct benefits" and (2) "indirect benefits." Direct benefits are readily quantifiable because there are well-established markets or indices with accessible data and/or prices that can be relied upon to monetize benefits that will accrue directly to customers. Indirect benefits, on the other hand, seek to quantify benefits that flow to society more broadly. Although indirect benefits may be more complicated to quantify, they are as real and valid as those that are readily quantifiable.

**Q. What is the analysis period over which the Company discounted the estimated costs and benefits of the Project?**

A. The Company assumed a 30-year life, based on input from the contractors who responded to the Company's Request for Information ("RFI") and the preliminary engineering, procurement, and construction Request for Proposals ("Preliminary EPC RFP"), which are discussed in the testimony of Mr. Dusling.

**Q. What discount rate was used in the Benefit-Cost Analysis?**

A. The Company used its weighted average after tax cost of capital of 6.71 percent as the discount rate for the estimated costs and the direct benefits of the Project. The weighted average after tax cost of capital of 6.71 percent incorporates the most recently approved capital structure and cost of capital by the Commission as part of a settlement agreement in the Company's most recent base distribution rate case.[1] The Company's consultant, Daymark Energy Advisors ("Daymark"), presents the quantification of indirect benefits in Exhibits GPP-1 and GPP-2, as well as the discount rates applied in those calculations.

**Q. Has the Commission provided any guidance with respect to the discount rate that should be used in the Benefit-Cost Analysis?**

A. Yes, the Commission has. In DE 09-137, the Commission held that, as a general

[1] *See*, *Unitil Energy Systems Inc.*, DE 21-030, Order No. 26,623, at 32-33 (May 3, 2022); Settlement Agreement Attachment, Schedule RevReq-5; Schedule RevReq-3-21, page 1 of 4.

matter, the same discount rate should be used to calculate the present value of both costs and benefits.[2] The Commission further held that, for consistency, it is appropriate to use the after tax cost of capital as the discount rate.[3]

In DE 09-137, the Commission further held that there may be times when it is appropriate to use other discount rates as part of a secondary analysis provided the petition provides justification for such alternative discount rate analyses.[4] As Daymark explains, that is the case in calculating the present value of indirect benefits.

**Q. Has the Commission provided any guidance with respect to the incorporation of indirect benefits into a Benefit-Cost Analysis?**

A. Yes. 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.[5]

The indirect benefits associated with the Project are discussed in detail in the joint testimony of Ms. Gilbert and Mr. Pierce. As discussed below, the Project's Benefit-

---

[2] Order No. 25,111, at 33.
[3] Order No. 25,111, at 33.
[4] Order No. 25,111, at 33.
[5] Order No. 25,111, at 35.

Cost ratio exceeds 1.00 without considering indirect benefits—therefore, those (indirect) benefits serve to further increase the Project's already positive benefits and reinforce a finding that the Project is in the public interest.

**Q. Is the Company's Benefit-Cost Analysis approach consistent with past practice before the Commission?**

A. Yes. In the context of the DE 09-137 proceeding, the Company and Commission Staff agreed that an accurate estimate of project economics would be achieved by comparing lifetime benefits to lifetime revenue requirements.[6] The Company employed the same approach in this filing.

**Q. Do the benefits of the Project outweigh the costs?**

A. Yes, the direct benefits outweigh the costs over the Project's 30-year investment horizon.[7] As explained in greater detail in Section V of this testimony, the Project yields a positive NPV of approximately $1.4 million and a Benefit-Cost Ratio of greater than 1.0.[8]

---

[6] *Unitil Energy Systems Inc.*, Order No. 25,111, at 10, 20, 33 (June 11, 2010).
[7] As discussed below, the Project's useful life may exceed 30 years.
[8] Here, the positive Net Present Value may be seen as a positive Present Value of net benefits.

## III. KINGSTON SOLAR PROJECT COST ESTIMATES

**Q. How is the Company calculating the total costs of the Kingston Solar Project in the context of its Benefit-Cost Analysis?**

A. The cost included in the analysis is the 30-year revenue requirement associated with owning and operating the PV facility.

As shown in Exhibit FDGP-2, Schedule 1, UES has calculated a Year 1 revenue requirement of $1.82 million which declines over the life of the Project to a cost of $0.55 million in Year 30. The annual revenue requirement steadily declines due to ongoing depreciation, which has the effect of reducing Rate Base.

**Q. Does RSA 374-G provide direction regarding the project-related costs that may be recovered?**

A. Yes. RSA 374-G:5, III provides that recovery for authorized and prudently incurred costs shall include recovery of depreciation, a return on investment, taxes, and operating and maintenance ("O&M") expenses directly associated with the investment, net of any offsetting revenues directly attributable to the investment.

RSA 374-G:5 further provides that the Commission may add an incentive to the return on investment component as it deems appropriate to encourage investments in DERs.

**Q. What cost elements are included in the Company's revenue requirement?**

A. The revenue requirement consists of the pre-tax return on Rate Base, O&M expense, Depreciation expense, Property Tax expense, and activity associated with crediting the benefit of the ITC to customers. The cost components of the revenue requirement are summarized on Exhibit FDGP-2, Schedule 3.

**Q. Has the Company requested an incentive return?**

A. No, it has not.

**Q. Please provide an overview of the Project's Rate Base.**

A. The determination of Rate Base for the Project begins with gross plant, which consists of the estimated capital spending explained below. Net plant is then calculated as gross plant less accumulated depreciation. Lastly, rate base is calculated by reducing net plant by accumulated deferred income taxes.

**Q. Please explain the capital costs included in the Benefit-Cost Analysis.**

A. The capital costs included in the analysis are discussed in detail in the testimony of Mr. Dusling. For economic modeling purposes, the Project's capital costs are categorized as follows: PV Facility Installation, Solar Inverter 1, Solar Inverter 2, Electric System Upgrades, Land Improvements, and Land Acquisition costs.

| **KINGSTON SOLAR PROJECT CAPITAL COST CATEGORIES** |
|---|
| • PV Facility Installation |
| • Solar Inverter 1 |
| • Solar Inverter 2 |
| • Electric System Upgrades |
| • Land Improvements |
| • Land Acquisition |

Unlike the other PV Facility Installation costs, the Solar Inverters have an assumed 15-year life and as such must be modeled differently than the other Facility Installation costs which have a 30-year life. Solar Inverter 2 represents the replacement cost of Solar Inverter 1 at the end of its useful life in Year 15. The economic modeling also assumes that 50 percent of the Land Acquisition costs will be transferred to UES for the Project, which is explained in the testimony of Mr. Dusling. The total capital costs included in the Benefit-Cost Analysis in Year 1 are $13.2 million and are detailed in Exhibit FDGP-2, Schedule 11. As noted above, this capital spending serves as the basis for gross plant in the rate base calculation.

**Q. Please explain the calculation for Return and Taxes on Rate Base.**

A. We calculate the Return and Taxes on Rate Base by applying a pre-tax rate of return of 9.18 percent to the average Rate Base balance. Average rate base is the simple average of current and prior year balances. The pre-tax rate of return represents the Company's most recently approved capital structure and cost of capital in DE 21-030. Income tax expense is included in this calculation by grossing up the cost of equity by a factor of 1.3685 to account for the effective tax rate of 26.93 percent associated with both state and Federal taxes (*See* Exhibit FDGP-2, Schedule 12).

**Q. Please explain the Operating Expenses included in the Revenue Requirement in the Benefit-Cost Analysis.**

**<u>O&M Expense</u>**

Based on information provided in response to the Preliminary EPC RFP, the

REDACTED



Company estimates Year 1 O&M expense at [redacted] escalated at 2.5 percent annually (*See* Exhibit FDGP-2, Schedule 4).

**Depreciation Expense**

Book depreciation expense is calculated using the straight-line depreciation method. As noted above, the PV facility and system upgrades are assumed to be 30-year property and the inverters are assumed to be 15-year property. The forecasted capital spending in each respective 30-year and 15-year asset category is multiplied by the annual depreciation rate, 3.33 percent in the case of the 30-year property and 6.66 percent for the 15-year property. In Year 16, depreciation expense increases slightly to account for the cost of the replacement inverter (Solar Inverter 2).

The Land Improvements and Land Acquisition costs are non-depreciable plant additions. As noted above, Accumulated Depreciation is derived by the calculation of Depreciation expense and is included in the calculation of Net Plant and Rate Base. Exhibit FDGP-2, Schedule 7.

**Property Tax Expense**

The Property Tax expense included in the model is a function of Net Plant multiplied by an assumed Property Tax Rate of $27.88 (per $1,000 of value).

The assumed tax rate is the sum of the current property tax rate in Kingston of $21.28 and the current State Rate of $6.60 (*See* Exhibit FDGP-2, Schedule 5).

**Q. Please discuss the Investment Tax Credit and how it is reflected in the Revenue Requirement.**

A. The Company expects the Project, under current guidance, to qualify for a 30 percent federal ITC for certain eligible facilities. The Inflation Reduction Act ("IRA"), signed into law on August 16, 2022, extended the energy ITC for solar electricity production facilities beginning construction before January 1, 2025. The ITC begins at 30 percent and steps down to 26 percent in 2033 and 22 percent in 2034.

Based on the current capital cost estimates, the Company expects the Project will generate ITCs totaling approximately $3.5 million. For purposes of the Benefit-Cost model, the Company reduces the Revenue Requirement by amortizing the ITC over the life of the facilities that generated the credits. There is also a tax Gross Up associated with the amortization of the ITC. In Year 1, the ITC Amortization and Gross Up reduces the Revenue Requirement by approximately $160,000. Also included in the Revenue Requirement is the ITC Tax Effect and associated tax Gross Up. The ITC Tax Effect is included to recover the tax impact of the permanent book-tax difference that arises due to the ITC. The federal investment tax basis is reduced by 50 percent of the ITC resulting in lower book depreciation expense than federal tax depreciation. In Year 1, the ITC Tax Effect and Gross Up increases the Revenue Requirement by approximately $17,000.

This approach is consistent with the methodology for flowing back the ITC to customers pursuant to Generally Accepted Accounting Principles and prevailing tax laws. The Company also is exploring options to further maximize the value of the ITC for customers. Specifically, the IRA authorizes taxpayers to transfer the ITC to other taxpayers in exchange for cash. In addition, if components of a qualified facility are deemed to have been produced in the United States, the ITC can be increased above 30 percent. These potential structures could reduce the amount of capital that UES would otherwise include in rate base, which in turn would reduce the Project's overall revenue requirement and increase its Benefit-Cost ratio.

## IV. KINGSTON SOLAR PROJECT BENEFITS

**Q. How is the Company measuring the total benefits of the Kingston Solar Project in the context of its Benefit-Cost Analysis?**

A. The Company is including direct benefits (summarized in the table below) that will accrue to customers over the course of the 30-year Project. In Year 1, the Company estimates customers will realize direct benefits of approximately $1.5 million.

| KINGSTON SOLAR PROJECT BENEFITS |
|---|
| **Direct Benefits** |
| • Avoided Energy Costs |
| • Avoided Capacity Costs |
| • Local Transmission Benefits |
| • Regional Transmission Benefits |
| • Renewable Energy Certificate ("REC") Savings |

**Q. Please discuss each direct benefit the Company has included in the Benefit-Cost Analysis.**

A. <u>Avoided Energy Costs</u>

As discussed in the testimony of Mr. Dusling, the Company's estimate of the annual electricity production from the Kingston Solar Project is shaped by two factors: (1) the capacity factor and (2) the degradation factor.

The capacity factor is the ratio of actual electricity produced to the electricity that could have been produced at continuous full power operation during the same period. For purposes of the Benefit-Cost Analysis, the Company assumed the Project will operate at an approximately 22 percent capacity factor.

The degradation factor represents the percentage by which the energy production of the solar panels is expected to decrease over time. For purposes of the Benefit-Cost Analysis, the Company assumed an annual degradation factor of 0.5 percent.

As shown in Exhibit FDGP-2, Schedule 2, by applying those capacity and degradation factors to the Project, the Company has calculated energy output of 9,600,000 kWh in Year 1 declining to 8,208,000 kWh by Year 30.

As Mr. Dusling explains, the Kingston Solar Project will operate as a load reducer, meaning the facility will not participate in wholesale markets. Rather, the electricity output will offset energy that otherwise would be received by UES from the transmission system. The avoided energy costs represent the avoided cost of purchasing power from the market to meet the needs of customers that now would be generated by the Project.

The Company calculated this benefit as the product of the annual electricity production and an annual estimate of the price of electricity. As shown in Exhibit FDGP-2, Schedule 2, the Company used the "ISO New England MASS HUB 5 MW LMP Futures" to extrapolate electricity prices for the first four years of the Project. For the balance of the project life, the Company escalated the ISO New England ("ISO-NE") futures prices beginning in Year 5 by 2 percent, which is the long-run annual growth rate included in Energy Information Administration's 2022 Annual Energy Outlook for end-use prices ("Escalation Rate"). This escalation also is consistent with the Federal Reserve's target inflation rate. As shown in Exhibit FDGP-2, Schedule 2, the avoided energy costs are the most significant quantitative benefit generated by the Kingston Solar Project.

**Avoided Capacity Costs**

As a load reducer, the Kingston Solar Project will reduce capacity from the perspective of the ISO-NE market. Based on information provided in response to the Preliminary EPC RFP, the Company estimated that the generating capacity of the Project would be 1,850 kW (i.e., approximately 37 percent of nameplate capacity) during the annual historical ISO-NE peak hour. As shown on Exhibit-FDGP-2, Schedule 2, the Company calculated the avoided capacity costs as the product of the generation output at the peak hour and the estimated capacity clearing price. The Company's estimated capacity clearing prices for years 1 through 12 are the levelized rate from the 2021 Avoided Energy Supply Components in New England Report (the "AESC Report").[9]

As shown in Exhibit FDGP-2, Schedule 2, from Year 13 through Year 30, the Company escalated the levelized capacity value from the AESC Report using the previously described Escalation Rate.

**Local Transmission Benefits**

Based on information provided in response to the Preliminary EPC RFP, the Company estimated the Kingston Solar Project's generation output during the monthly peak hour to be approximately 600 kW (i.e., approximately 12 percent of nameplate capacity). As shown on Exhibit FDGP-2, Schedule 2, the Company calculated the Year 1 local transmission benefits as the total of: (1) the product of the generation output at the monthly peak hour and the annualized transmission rate ($/MWh) and (2) the product of the generation output at the monthly peak hour and the annualized ancillary services rate ($/MWh). The Company escalated the

[9] AESC Report, at 13, *available at* https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc. The AESC Report calculated four "counterfactuals", each of which represents a hypothetical future that lacks some amount of anticipated demand-side measures. AESC Report, at 1. For purposes of the capacity value assumption, the Company utilized the AESC's Counterfactual #1 prices. Counterfactual #1 represents a future in which program administrators install no new energy efficiency, building electrification, or active demand management (demand response and energy storage) resources in 2021 or later years. Id. For the current program year (and upcoming Program Year), the New Hampshire Energy Efficiency programs are using the 2021 AESC Counterfactual #1 for the avoided capacity costs.

transmission and ancillary services rates for the remaining 29 years of the projected life of the facility by the previously described Escalation Rate.

The transmission and ancillary service rates are based on the most recent bill from Eversource to UES setting forth the local service rate for Schedule 21-ES (Part A) Tariff Service. Eversource is the transmission provider to UES for the Kingston, New Hampshire service area.

**Regional Transmission Benefits**

To quantify regional transmission benefits, the Company used the same production assumptions described above for local transmission – that is, it – assumed production of 600 kW during the monthly system peak hour. As shown on Exhibit FDGP-2, Schedule 2, the Company calculated the Year 1 regional transmission benefits as the total of: (1) the product of the generation output at the monthly peak hour and the Open Access Transmission Tariff ("OATT") Schedule 1 Regional Network Service Rate; (2) the product of the generation output at the monthly peak hour and the OATT Schedule 5 Regional Network Service Rate; (3) the product of the generation output at the monthly peak hour and the ISO Schedule 1 Regional Network Service ("RNS") Rate; and (4) the OATT Schedule 9 Rate. The Company escalated the ISO-NE transmission rates for the remaining 29 years of the facility using the previously described Escalation Rate.

**Renewable Energy Certificates**

The New Hampshire Renewable Portfolio Standard ("RPS") was created to stimulate investment in low-emission, renewable energy generation, like the Kingston Solar Project. The RPS requires retail electricity suppliers, including UES with respect to providing Default Service, to purchase a certain percentage of the electricity they supply from renewable energy sources every year. A REC represents one megawatt hour of energy generated by an eligible renewable source. Providers of electricity may acquire RECs either by generating energy from a qualified renewable generation unit or by purchasing RECs in the market. Alternative Compliance Payments can be made to satisfy RPS obligations in the absence of RECs being generated or procured.

The Kingston Solar Project will generate RECs that will be retained to either meet UES's Default Service RPS obligations or sold into the market and credited back to customers. The Company will first apply any RECs produced by the Project to the Company's RPS obligations associated with its default service load. Applying the RECs produced by the facility to RPS obligations results in administrative savings by reducing the management and transaction fees that would result if the Company were to sell the RECs produced by the Kingston Solar Project into the market and separately purchase comparable RECs from the market. Any RECs produced by the facility in excess of Default Service RPS requirements would be sold into the market. In any case, as explained later in our testimony, the revenue received from the sale of RECs generated by the Project will be credited to all UES customers, regardless of whether they purchase delivery service supply from UES or competitive supply from a Competitive Electric Power Supplier.

New Hampshire's RPS statute divides renewable energy sources into four separate classes with solar generation like the Kingston Solar Project, falling into the Class II category. The Company estimated REC revenues as the product of the facility's electricity (MWh) output and the estimated value of RECs. The Company estimated the REC value at [redacted], which is based on a recent quote from a REC broker. The Company assumed the [redacted] REC value remains fixed over the Project's 30 year life.

**Q. Does the Company's filing also contain a discussion of indirect benefits?**

A. Yes. As noted above, the joint testimony of Ms. Gilbert and Mr. Pierce provides a discussion of the methods used to quantify the indirect benefits.

**Q. Please briefly summarize the Indirect Customer benefits.**

A. As discussed in Exhibits GPP-1 and GPP-2, Daymark has quantified three indirect benefits: economic benefits, emissions reduction benefits, and Demand Reduction Induced Price Effects ("DRIPE") benefits. Daymark estimates the Project will generate $11.2 million dollars of direct, indirect, and induced economic benefits, on an NPV basis. For $CO_2$ and NOx benefits, Daymark estimates a total benefit of $1.8 million on an NPV basis. Lastly, Daymark's DRIPE analysis shows the aggregate benefits to New Hampshire load would be $566,963 on an NPV basis. These indirect benefits reinforce the viability of the Kingston Solar Project.

## V. DISCUSSION OF BENEFIT-COST ANALYSIS RESULTS

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

A. As shown in Exhibit FDGP-2, Schedule 1, the present value of the Project's benefits is approximately $17.7 million and the present value of the costs is approximately $16.3 million. This produces a Benefit-Cost ratio of 1.09. The Project has a strong Internal Rate of Return of 11.15 percent, indicating a positive NPV.

**Q. Earlier you mentioned that the IRA may provide the ability to transfer the Project's ITCs to a third party. How might such a transaction affect the Benefit-Cost Analysis and the results?**

A. Tax normalization rules from the IRS have limited the ability of utilities to maximize the ITC benefit for their customers. Normalization requires the utility to pass the value of the ITC back over the life of the asset that generated the credit rather than immediately realizing the benefit. Without normalization, customers could receive immediate economic value as initial Rate Base would be lowered by the ITC. For illustrative purposes, if the Company were able to reduce Rate Base by the expected ITC at the outset of the Project, the NPV would increase by approximately $2.8 million, the Benefit-Cost ratio would increase to approximately 1.3, and the discounted payback period would significantly shorten. As mentioned earlier, the IRA will allow companies to transfer the ITC to other tax payers in exchange for cash. Because the IRA was only recently passed, it is unclear whether transferring the ITC will allow utilities to avoid IRS normalization rules. The Company will continue to investigate this potential pathway to ensure ratepayers receive the maximum economic value.

**Q. Is it reasonable that the PV facility could continue to provide customer benefits after Year 30?**

A. Yes. Based on conversations with PV contractors it is reasonable to assume a useful life greater than thirty years. Thirty years represents the length of solar module warranties, not necessarily when they become obsolete. System efficiency is modeled to be reduced to 85.5 percent in Year 30 and still producing customer benefits in excess of $1.6 million. It is likely that the Project will continue to provide benefits to customers even past its warranty period, further supporting the Project's value proposition.

**Q. In addition to the direct and indirect benefits discussed above, is there any other value this Project could provide to customers?**

A. Yes. If the Project is deemed to be in the public interest, the Company will investigate pairing it with an Energy Storage System. Energy storage could positively augment the economic value of the Project by shifting the Project's output closer to the peak periods, further lowering supply and transmission charges.

## VI. COST RECOVERY AND BILL IMPACTS

**Q. Does RSA 374-G specify how the costs of DER investments made pursuant to the statute should be recovered?**

A. Yes. RSA 374-G, III provides that authorized and prudently incurred investments shall be recovered in a utility's base distribution rates as a component of rate base.

**Q. What is the Company's proposal with regard to recovering the costs of the Kingston Solar Project?**

A. As discussed in the testimony of Mr. Sprague, the Company is seeking the Commission's approval of a two-step regulatory review process. In this filing (Stage One), the Company is requesting that the Commission find that the Kingston Solar Project is in the public interest. In Stage Two, the Company will seek recovery of the Project's costs. The Company plans to request rate recovery in the context of its next base distribution rate case or a subsequent step adjustment.

**Q. Does RSA 374-G require project proponents to calculate estimated bill impacts?**

A. Yes. RSA 374-G:5, I (b) requires electric utilities to include an analysis of rate implications to participating customers, the company's default customers, and the utility's distribution customers for all proposed projects. In DE 09-137, the Commission reinforced the importance of this minimum filing requirement and stated that all future filings must include the estimated rate impacts required by RSA 374-G:5, I (b).[10]

**Q. Have you provided the bill impacts associated with the Kingston Solar Project as required by the statute?**

A. Yes, bill impacts by rate class associated with the Kingston Solar Project have been provided as Exhibit FDGP-3.

**Q. Please summarize the bill impacts provided in Exhibit FDGP-3.**

A. Page 1 of Exhibit FDGP-3 provides the bill impacts for an average customer within each rate class. Bill impacts will vary based on usage above or the below the average usage.

As shown on line 7, in Year 1 an average Residential customer would see an increase in their monthly bill of $0.18 per month after accounting for the cost and the direct benefits of the project. In Year 30, an average Residential customer would see a decrease in their monthly bill of $0.59 per month.

As shown on line 14, in Year 1 an average Regular General Service G2 kWh meter customer would see an increase in their monthly bill of $0.03 per month after accounting for the cost and direct benefits of the project. In Year 30, an average Regular General Service G2 kWh meter customer would see a decrease in their

[10] DE 09-137, Order No. 25,111, at 29.

monthly bill of $0.09 per month.

As shown on line 21, in Year 1 an average Uncontrolled (Quick Recovery) Water Heating customer would see an increase in their monthly bill of $0.41 per month after accounting for the cost and direct benefits of the project. In Year 30, an average Uncontrolled (Quick Recovery) Water Heating customer would see a decrease in their monthly bill of $1.35 per month.

As shown on line 30, in Year 1 an average Regular General Service G2 customer would see an increase in their monthly bill of $0.69 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Regular General Service G2 customer would see a decrease in their monthly bill of $2.29 per month.

As shown on line 39, in Year 1 an average Large General Service G1 customer would see an increase in their monthly bill of $44.58 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Large General Service G1 customer would see a decrease in their monthly bill of $147.94 per month.

As shown on line 46, in Year 1 an average Outdoor Lighting customer would see an increase in their monthly bill of $0.02 per month after accounting for the cost and direct benefits of the project. In Year 30 an average Outdoor Lighting customer would see a decrease in their monthly bill of $0.07 per month.

**Q. Please explain the calculation detail that has been provided on page 2 of Exhibit FDGP-2.**

A. Page 2 provides the calculation detail that converts the Project's direct benefits into the rate impacts those benefits would produce.

Current transmission costs are collected in Schedule External Delivery Charge ("EDC") as a per kWh charge, so the direct benefit associated with a reduction in allocated transmission costs from Eversource would flow through the EDC by reducing the EDC rate.

To ensure that all customers receive the benefit from the sale of the RECs, the Company proposes that all REC revenue be included in the EDC. As shown on line 5, the impact to the EDC to capture these benefits would be a reduction of $0.00039 per kWh over the project life

The direct benefit associated with the reduction in capacity and energy cost would accrue to customers as lower energy service rates. As mentioned above, the benefits would be realized by all customers whether they are on default service or purchasing their energy service from a competitive supplier. To reflect that all customers would receive these benefits, the total cost reduction was divided by the total kWh sales of the Company. As shown on line 9, the impact on the energy service rate would be a reduction of $0.00090 per kWh in Year 1 with an average reduction over the life of the project of $0.00085 per kWh.

**Q. Please further explain how the Company will account for the value of the RECs to ensure that all customers receive the benefit.**

A. Earlier it was discussed how RECs would be used to either satisfy the RPS requirements associated with default service or sold into the market. If the RECs are used the satisfy the RPS requirements associated with default service, a transfer price will be established and charged to default service 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. This will ensure that the benefit of the RECs generated by the Project would go to all customers whether they are sold into the market or are used to satisfy the RPS requirements of customers taking default service from the Company.

**Q. Please explain the calculations provided on page 3 of Exhibit FDGP-3.**

A. The calculations on page 3 adjust currently approved distribution energy rates to account for the revenue requirement associated with the Project. Since customers would realize direct benefits as a reduction to kWh charges, the revenue requirement was first allocated to each rate class based on the share of total company kWh sales. After the rate class allocated revenue requirement amount is determined, currently effective kWh and demand rates for each class were adjusted to recover the rate class share of the revenue requirement. The Company did not adjust the currently effective customer charges for any rate class.

As shown on line 14, in Year 1 the residential rate's allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.04511 per kWh to $0.04668 per kWh.

As shown on line 22, in Year 1 the Regular General Service G2 kWh meter rate's allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.02933 per kWh to $0.03090 per kWh.

As shown on line 30, in Year 1 the Uncontrolled (Quick Recovery) Water Heating rate's allocated portion of the revenue requirement would increase the distribution kWh charge from the currently effective charge of $0.03599 per kWh to $0.03756 per kWh.

As shown on line 39, in Year 1 the Regular General Service G2 rate's allocated portion of the revenue requirement would increase the distribution kW demand charge from the currently effective demand charge of $11.91 per kW to $12.31 per kW. The rate currently has no distribution revenue collected through a kWh charge.

As shown on line 53, in Year 1 the Large General Service G1 rate's allocated portion of the revenue requirement would increase the distribution kVA demand charge from the currently effective demand charge of $8.40 per kVA to $8.90 per kVA. The rate currently has no distribution revenue collected through a kWh charge.

As shown on line 65, in Year 1 the Outdoor Lighting rate's allocated portion of the revenue requirement would increase the current average fixture charge of $16.71 to

$16.82. The rate currently has no distribution revenue collected through a kWh charge.

## VII. CONCLUSION

**Q. Does this conclude your testimony?**

A. Yes, it does.

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**

## Table of Contents


| | Exhibit & Schedule # |
|---|---|
| Summary | Exhibit FDGP-2, Schedule 1 |
| Direct Customer Benefits | Exhibit FDGP-2, Schedule 2 |
| Rate Base & Revenue Requirement | Exhibit FDGP-2, Schedule 3 |
| O&M Expense | Exhibit FDGP-2, Schedule 4 |
| Property Tax Expense | Exhibit FDGP-2, Schedule 5 |
| Deferred Tax Calculation | Exhibit FDGP-2, Schedule 6 |
| Book Depreciation Schedule | Exhibit FDGP-2, Schedule 7 |
| Tax Depreciation Schedule | Exhibit FDGP-2, Schedule 8 |
| Investment Tax Credit Amortization | Exhibit FDGP-2, Schedule 9 |
| Investment Tax Credit Tax Effect | Exhibit FDGP-2, Schedule 10 |
| Capital Costs | Exhibit FDGP-2, Schedule 11 |
| Cost of Capital | Exhibit FDGP-2, Schedule 12 |
| MACRS Half-Year Depreciation Rate Table | Exhibit FDGP-2, Schedule 13 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, 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 11 | $ 968,235 | $ 809,903 | $ 776,620 | $ 747,078 | $ 758,152 | $ 769,369 | $ 780,732 | $ 792,242 | $ 803,900 | $ 815,707 |
| 3 | Avoided Capacity Costs | Direct Customer Benefits, Line 18 | 77,922 | 77,532 | 77,143 | 76,753 | 76,363 | 75,974 | 75,584 | 75,195 | 74,805 | 74,415 |
| 4 | Local Transmission Benefits | Direct Customer Benefits, Line 26 | 11,797 | 11,973 | 12,151 | 12,331 | 12,514 | 12,699 | 12,887 | 13,077 | 13,269 | 13,464 |
| 5 | Regional Transmission Benefits | Direct Customer Benefits, Line 36 | 87,050 | 88,347 | 89,662 | 90,993 | 92,342 | 93,708 | 95,092 | 96,494 | 97,914 | 99,352 |
| 6 | Renewable Energy Credit Savings | Direct Customer Benefits, Line 41 | 352,800 | 351,036 | 349,272 | 347,508 | 345,744 | 343,980 | 342,216 | 340,452 | 338,688 | 336,924 |
| 7 | Total Direct Customer Benefits | Sum Lines 2 through 6 | $ 1,497,804 | $ 1,338,792 | $ 1,304,847 | $ 1,274,663 | $ 1,285,115 | $ 1,295,730 | $ 1,306,511 | $ 1,317,459 | $ 1,328,576 | $ 1,339,862 |
| 8 | | | | | | | | | | | | |
| 9 | Costs | | | | | | | | | | | |
| 10 | Revenue Requirement | Rate Base & Revenue Requirement, Line 26 | $ 1,822,979 | $ 1,718,730 | $ 1,615,519 | $ 1,538,322 | $ 1,470,895 | $ 1,410,804 | $ 1,365,357 | $ 1,327,246 | $ 1,289,162 | $ 1,251,106 |
| 11 | Total Costs | Line 10 | $ 1,822,979 | $ 1,718,730 | $ 1,615,519 | $ 1,538,322 | $ 1,470,895 | $ 1,410,804 | $ 1,365,357 | $ 1,327,246 | $ 1,289,162 | $ 1,251,106 |
| 12 | | | | | | | | | | | | |
| 13 | Net Benefit (Cost) to Customers | Line 7 - Line 11 | $ (325,175) | $ (379,938) | $ (310,672) | $ (263,658) | $ (185,781) | $ (115,074) | $ (58,846) | $ (9,787) | $ 39,413 | $ 88,756 |
| 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 | $ 17,728,936 | | | | | | | | | |
| 19 | PV of Costs | PV of Line 11 | 16,305,176 | | | | | | | | | |
| 20 | Net Present Value | Line 18 - Line 19 | $ 1,423,760 | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | Internal Rate of Return | Internal Rate of Return of Line 13 | 11.15% | | | | | | | | | |
| 23 | | | | | | | | | | | | |
| 24 | Benefit-Cost Ratio (BCR) | Line 18 ÷ Line 19 | 1.09 | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, 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 11 | $ 827,665 | $ 839,775 | $ 852,039 | $ 864,457 | $ 877,031 | $ 889,762 | $ 902,651 | $ 915,700 | $ 928,910 | $ 942,283 |
| 3 | Avoided Capacity Costs | Direct Customer Benefits, Line 18 | 74,026 | 73,636 | 74,712 | 75,800 | 76,903 | 78,019 | 79,150 | 80,294 | 81,452 | 82,625 |
| 4 | Local Transmission Benefits | Direct Customer Benefits, Line 26 | 13,661 | 13,861 | 14,064 | 14,269 | 14,476 | 14,686 | 14,899 | 15,114 | 15,332 | 15,553 |
| 5 | Regional Transmission Benefits | Direct Customer Benefits, Line 36 | 100,808 | 102,283 | 103,777 | 105,289 | 106,821 | 108,371 | 109,941 | 111,531 | 113,140 | 114,768 |
| 6 | Renewable Energy Credit Savings | Direct Customer Benefits, Line 41 | 335,160 | 333,396 | 331,632 | 329,868 | 328,104 | 326,340 | 324,576 | 322,812 | 321,048 | 319,284 |
| 7 | Total Direct Customer Benefits | Sum Lines 2 through 6 | $ 1,351,321 | $ 1,362,952 | $ 1,376,223 | $ 1,389,683 | $ 1,403,334 | $ 1,417,179 | $ 1,431,217 | $ 1,445,451 | $ 1,459,883 | $ 1,474,513 |
| 8 | | | | | | | | | | | | |
| 9 | Costs | | | | | | | | | | | |
| 10 | Revenue Requirement | Rate Base & Revenue Requirement, Line 26 | $ 1,213,077 | $ 1,175,078 | $ 1,137,107 | $ 1,099,168 | $ 1,099,324 | $ 1,101,577 | $ 1,059,651 | $ 1,017,809 | $ 977,308 | $ 937,331 |
| 11 | Total Costs | Line 10 | $ 1,213,077 | $ 1,175,078 | $ 1,137,107 | $ 1,099,168 | $ 1,099,324 | $ 1,101,577 | $ 1,059,651 | $ 1,017,809 | $ 977,308 | $ 937,331 |
| 12 | | | | | | | | | | | | |
| 13 | Net Benefit (Cost) to Customers | Line 7 - Line 11 | $ 138,243 | $ 187,874 | $ 239,115 | $ 290,515 | $ 304,010 | $ 315,602 | $ 371,566 | $ 427,642 | $ 482,575 | $ 537,182 |
| 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 FDGP-2, 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 11 | $ 955,818 | $ 969,518 | $ 983,384 | $ 997,417 | $ 1,011,617 | $ 1,025,987 | $ 1,040,526 | $ 1,055,237 | $ 1,070,120 | $ 1,085,177 |
| 3 | Avoided Capacity Costs | Direct Customer Benefits, Line 18 | 83,811 | 85,013 | 86,229 | 87,459 | 88,704 | 89,964 | 91,239 | 92,529 | 93,834 | 95,154 |
| 4 | Local Transmission Benefits | Direct Customer Benefits, Line 26 | 15,777 | 16,003 | 16,232 | 16,463 | 16,698 | 16,935 | 17,175 | 17,418 | 17,663 | 17,912 |
| 5 | Regional Transmission Benefits | Direct Customer Benefits, Line 36 | 116,417 | 118,086 | 119,774 | 121,484 | 123,213 | 124,963 | 126,734 | 128,526 | 130,339 | 132,173 |
| 6 | Renewable Energy Credit Savings | Direct Customer Benefits, Line 41 | 317,520 | 315,756 | 313,992 | 312,228 | 310,464 | 308,700 | 306,936 | 305,172 | 303,408 | 301,644 |
| 7 | Total Direct Customer Benefits | Sum Lines 2 through 6 | $ 1,489,343 | $ 1,504,375 | $ 1,519,611 | $ 1,535,050 | $ 1,550,696 | $ 1,566,549 | $ 1,582,611 | $ 1,598,882 | $ 1,615,365 | $ 1,632,059 |
| 8 | | | | | | | | | | | | |
| 9 | Costs | | | | | | | | | | | |
| 10 | Revenue Requirement | Rate Base & Revenue Requirement, Line 26 | $ 897,758 | $ 858,956 | $ 820,560 | $ 782,202 | $ 743,884 | $ 705,606 | $ 667,370 | $ 629,177 | $ 591,028 | $ 552,924 |
| 11 | Total Costs | Line 10 | $ 897,758 | $ 858,956 | $ 820,560 | $ 782,202 | $ 743,884 | $ 705,606 | $ 667,370 | $ 629,177 | $ 591,028 | $ 552,924 |
| 12 | | | | | | | | | | | | |
| 13 | Net Benefit (Cost) to Customers | Line 7 - Line 11 | $ 591,585 | $ 645,419 | $ 699,051 | $ 752,849 | $ 806,813 | $ 860,943 | $ 915,240 | $ 969,705 | $ 1,024,337 | $ 1,079,136 |
| 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 FDGP-2, 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 JSD-1 | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW |
| 2 | Efficiency Rate | Decrease 0.5% annually, Exhibit JSD-1 | 100.00% | 99.50% | 99.00% | 98.50% | 98.00% | 97.50% | 97.00% | 96.50% | 96.00% | 95.50% |
| 3 | Capacity - Adjusted for Efficiency Rate | Line 1 x Line 2 | 4.99 MW | 4.97 MW | 4.94 MW | 4.92 MW | 4.89 MW | 4.87 MW | 4.84 MW | 4.82 MW | 4.79 MW | 4.77 MW |
| 4 | | | | | | | | | | | | |
| 5 | 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% |
| 6 | | | | | | | | | | | | |
| 7 | Avoided Energy Costs | | | | | | | | | | | |
| 8 | Annual Capacity Factor | Exhibit JSD-1 | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% |
| 9 | Annual Production (kWh) | Line 3 x Line 8 x 1000 x 365 x 24 | 9,600,000 | 9,552,000 | 9,504,000 | 9,456,000 | 9,408,000 | 9,360,000 | 9,312,000 | 9,264,000 | 9,216,000 | 9,168,000 |
| 10 | Energy Rate ($ Per kWh) (2) | See Footnote | $ 0.1009 | $ 0.0848 | $ 0.0817 | $ 0.0790 | $ 0.0806 | $ 0.0822 | $ 0.0838 | $ 0.0855 | $ 0.0872 | $ 0.0890 |
| 11 | Annual Avoided Energy Costs | Line 9 x Line 10 | $ 968,235 | $ 809,903 | $ 776,620 | $ 747,078 | $ 758,152 | $ 769,369 | $ 780,732 | $ 792,242 | $ 803,900 | $ 815,707 |
| 12 | | | | | | | | | | | | |
| 13 | Avoided Capacity Costs | | | | | | | | | | | |
| 14 | PV Capacity at Annual Peak | Exhibit JSD-1 | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% |
| 15 | Capacity at Peak Hour (kW) | Line 3 x Line 14 x 1000 | 1,850 | 1,841 | 1,831 | 1,822 | 1,813 | 1,804 | 1,794 | 1,785 | 1,776 | 1,767 |
| 16 | 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 |
| 17 | Monthly Avoided Capacity Costs | Line 15 x Line 16 | $ 6,493 | $ 6,461 | $ 6,429 | $ 6,396 | $ 6,364 | $ 6,331 | $ 6,299 | $ 6,266 | $ 6,234 | $ 6,201 |
| 18 | Annual Avoided Capacity Costs | Line 17 x 12 | $ 77,922 | $ 77,532 | $ 77,143 | $ 76,753 | $ 76,363 | $ 75,974 | $ 75,584 | $ 75,195 | $ 74,805 | $ 74,415 |
| 19 | | | | | | | | | | | | |
| 20 | Local Transmission Benefits | | | | | | | | | | | |
| 21 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 22 | Capacity at Peak Hour (MW-Month) | Line 3 x Line 21 | 0.60 | 0.60 | 0.59 | 0.59 | 0.59 | 0.58 | 0.58 | 0.58 | 0.58 | 0.57 |
| 23 | 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 |
| 24 | 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 |
| 25 | Monthly Local Transmission Benefits | Line 22 x (Line 23 + Line 24) | $ 983 | $ 998 | $ 1,013 | $ 1,028 | $ 1,043 | $ 1,058 | $ 1,074 | $ 1,090 | $ 1,106 | $ 1,122 |
| 26 | Annual Local Transmission Benefits | Line 25 x 12 | $ 11,797 | $ 11,973 | $ 12,151 | $ 12,331 | $ 12,514 | $ 12,699 | $ 12,887 | $ 13,077 | $ 13,269 | $ 13,464 |
| 27 | | | | | | | | | | | | |
| 28 | Regional Transmission Benefits | | | | | | | | | | | |
| 29 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 30 | Capacity at Peak Hour (kW-Month) | Line 3 x Line 29 x 1000 | 600 | 597 | 594 | 591 | 588 | 585 | 582 | 579 | 576 | 573 |
| 31 | ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) (5) | Annual Escalation, Line 5 | $ 0.1918 | $ 0.1956 | $ 0.1995 | $ 0.2035 | $ 0.2076 | $ 0.2117 | $ 0.2159 | $ 0.2203 | $ 0.2247 | $ 0.2292 |
| 32 | ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) (6) | Annual Escalation, Line 5 | $ 0.0074 | $ 0.0075 | $ 0.0077 | $ 0.0078 | $ 0.0080 | $ 0.0081 | $ 0.0083 | $ 0.0085 | $ 0.0086 | $ 0.0088 |
| 33 | 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 |
| 34 | 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 |
| 35 | Monthly Regional Transmission Benefits | Line 30 x (Sum Lines 31 through 34) | $ 7,254 | $ 7,362 | $ 7,472 | $ 7,583 | $ 7,695 | $ 7,809 | $ 7,924 | $ 8,041 | $ 8,159 | $ 8,279 |
| 36 | Annual Regional Transmission Benefits | Line 35 x 12 | $ 87,050 | $ 88,347 | $ 89,662 | $ 90,993 | $ 92,342 | $ 93,708 | $ 95,092 | $ 96,494 | $ 97,914 | $ 99,352 |
| 37 | | | | | | | | | | | | |
| 38 | Renewable Energy Credits (REC) Savings | | | | | | | | | | | |
| 39 | Annual Production (MWh) | Line 9 ÷ 1000 | 9,600 | 9,552 | 9,504 | 9,456 | 9,408 | 9,360 | 9,312 | 9,264 | 9,216 | 9,168 |
| 40 | REC II Rate ($ Per MWh) (9) | New England Power Pool | [redacted] | | | | | | | | | |
| 41 | Annual REC Savings | Line 39 x Line 40 | | | | | | | | | | |
| 42 | | | | | | | | | | | | |
| 43 | Total Direct Customer Benefits | Line 11 + Line 18 + Line 26 + Line 36 + Line 41 | $ 1,497,804 | $ 1,338,792 | $ 1,304,847 | $ 1,274,663 | $ 1,285,115 | $ 1,295,730 | $ 1,306,511 | $ 1,317,459 | $ 1,328,576 | $ 1,339,862 |

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, 2022
(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, 2022
(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2022
(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 FDGP-2, Benefit-Cost Analysis**
**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 JSD-1 | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW |
| 2 | Efficiency Rate | Decrease 0.5% annually, Exhibit JSD-1 | 95.00% | 94.50% | 94.00% | 93.50% | 93.00% | 92.50% | 92.00% | 91.50% | 91.00% | 90.50% |
| 3 | Capacity - Adjusted for Efficiency Rate | Line 1 x Line 2 | 4.74 MW | 4.72 MW | 4.69 MW | 4.67 MW | 4.64 MW | 4.62 MW | 4.59 MW | 4.57 MW | 4.54 MW | 4.52 MW |
| 4 | | | | | | | | | | | | |
| 5 | 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% |
| 6 | | | | | | | | | | | | |
| 7 | <u>Avoided Energy Costs</u> | | | | | | | | | | | |
| 8 | Annual Capacity Factor | Exhibit JSD-1 | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% |
| 9 | Annual Production (kWh) | Line 3 x Line 8 x 1000 x 365 x 24 | 9,120,000 | 9,072,000 | 9,024,000 | 8,976,000 | 8,928,000 | 8,880,000 | 8,832,000 | 8,784,000 | 8,736,000 | 8,688,000 |
| 10 | Energy Rate ($ Per kWh) (2) | See Footnote | $ 0.0908 | $ 0.0926 | $ 0.0944 | $ 0.0963 | $ 0.0982 | $ 0.1002 | $ 0.1022 | $ 0.1042 | $ 0.1063 | $ 0.1085 |
| 11 | Annual Avoided Energy Costs | Line 9 x Line 10 | $ 827,665 | $ 839,775 | $ 852,039 | $ 864,457 | $ 877,031 | $ 889,762 | $ 902,651 | $ 915,700 | $ 928,910 | $ 942,283 |
| 12 | | | | | | | | | | | | |
| 13 | <u>Avoided Capacity Costs</u> | | | | | | | | | | | |
| 14 | PV Capacity at Annual Peak | Exhibit JSD-1 | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% |
| 15 | Capacity at Peak Hour (kW) | Line 3 x Line 14 x 1000 | 1,757 | 1,748 | 1,739 | 1,730 | 1,720 | 1,711 | 1,702 | 1,693 | 1,683 | 1,674 |
| 16 | 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 |
| 17 | Monthly Avoided Capacity Costs | Line 15 x Line 16 | $ 6,169 | $ 6,136 | $ 6,226 | $ 6,317 | $ 6,409 | $ 6,502 | $ 6,596 | $ 6,691 | $ 6,788 | $ 6,885 |
| 18 | Annual Avoided Capacity Costs | Line 17 x 12 | $ 74,026 | $ 73,636 | $ 74,712 | $ 75,800 | $ 76,903 | $ 78,019 | $ 79,150 | $ 80,294 | $ 81,452 | $ 82,625 |
| 19 | | | | | | | | | | | | |
| 20 | <u>Local Transmission Benefits</u> | | | | | | | | | | | |
| 21 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 22 | Capacity at Peak Hour (MW-Month) | Line 3 x Line 21 | 0.57 | 0.57 | 0.56 | 0.56 | 0.56 | 0.55 | 0.55 | 0.55 | 0.55 | 0.54 |
| 23 | 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 |
| 24 | 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 |
| 25 | Monthly Local Transmission Benefits | Line 22 x (Line 23 + Line 24) | $ 1,138 | $ 1,155 | $ 1,172 | $ 1,189 | $ 1,206 | $ 1,224 | $ 1,242 | $ 1,260 | $ 1,278 | $ 1,296 |
| 26 | Annual Local Transmission Benefits | Line 25 x 12 | $ 13,661 | $ 13,861 | $ 14,064 | $ 14,269 | $ 14,476 | $ 14,686 | $ 14,899 | $ 15,114 | $ 15,332 | $ 15,553 |
| 27 | | | | | | | | | | | | |
| 28 | <u>Regional Transmission Benefits</u> | | | | | | | | | | | |
| 29 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 30 | Capacity at Peak Hour (kW-Month) | Line 3 x Line 29 x 1000 | 570 | 567 | 564 | 561 | 558 | 555 | 552 | 549 | 546 | 543 |
| 31 | ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) (5) | Annual Escalation, Line 5 | $ 0.2337 | $ 0.2384 | $ 0.2432 | $ 0.2480 | $ 0.2530 | $ 0.2581 | $ 0.2632 | $ 0.2685 | $ 0.2739 | $ 0.2793 |
| 32 | ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) (6) | Annual Escalation, Line 5 | $ 0.0090 | $ 0.0092 | $ 0.0093 | $ 0.0095 | $ 0.0097 | $ 0.0099 | $ 0.0101 | $ 0.0103 | $ 0.0105 | $ 0.0107 |
| 33 | 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 |
| 34 | 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 |
| 35 | Monthly Regional Transmission Benefits | Line 30 x (Sum Lines 31 through 34) | $ 8,401 | $ 8,524 | $ 8,648 | $ 8,774 | $ 8,902 | $ 9,031 | $ 9,162 | $ 9,294 | $ 9,428 | $ 9,564 |
| 36 | Annual Regional Transmission Benefits | Line 35 x 12 | $ 100,808 | $ 102,283 | $ 103,777 | $ 105,289 | $ 106,821 | $ 108,371 | $ 109,941 | $ 111,531 | $ 113,140 | $ 114,768 |
| 37 | | | | | | | | | | | | |
| 38 | <u>Renewable Energy Credits (REC) Savings</u> | | | | | | | | | | | |
| 39 | Annual Production (MWh) | Line 9 ÷ 1000 | 9,120 | 9,072 | 9,024 | 8,976 | 8,928 | 8,880 | 8,832 | 8,784 | 8,736 | 8,688 |
| 40 | REC II Rate ($ Per MWh) (9) | New England Power Pool | [redacted] | | | | | | | | | |
| 41 | Annual REC Savings | Line 39 x Line 40 | [redacted] | | | | | | | | | |
| 42 | | | | | | | | | | | | |
| 43 | Total Direct Customer Benefits | Line 11 + Line 18 + Line 26 + Line 36 + Line 41 | $ 1,351,321 | $ 1,362,952 | $ 1,376,223 | $ 1,389,683 | $ 1,403,334 | $ 1,417,179 | $ 1,431,217 | $ 1,445,451 | $ 1,459,883 | $ 1,474,513 |

**<u>Notes</u>**
(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, 2022
(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, 2022
(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2022
(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 FDGP-2, 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 JSD-1 | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW | 4.99 MW |
| 2 | Efficiency Rate | Decrease 0.5% annually, Exhibit JSD-1 | 90.00% | 89.50% | 89.00% | 88.50% | 88.00% | 87.50% | 87.00% | 86.50% | 86.00% | 85.50% |
| 3 | Capacity - Adjusted for Efficiency Rate | Line 1 x Line 2 | 4.49 MW | 4.47 MW | 4.44 MW | 4.42 MW | 4.39 MW | 4.37 MW | 4.34 MW | 4.32 MW | 4.29 MW | 4.27 MW |
| 4 | | | | | | | | | | | | |
| 5 | 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% |
| 6 | | | | | | | | | | | | |
| 7 | Avoided Energy Costs | | | | | | | | | | | |
| 8 | Annual Capacity Factor | Exhibit JSD-1 | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% | 21.96% |
| 9 | Annual Production (kWh) | Line 3 x Line 8 x 1000 x 365 x 24 | 8,640,000 | 8,592,000 | 8,544,000 | 8,496,000 | 8,448,000 | 8,400,000 | 8,352,000 | 8,304,000 | 8,256,000 | 8,208,000 |
| 10 | Energy Rate ($ Per kWh) (2) | See Footnote | $ 0.1106 | $ 0.1128 | $ 0.1151 | $ 0.1174 | $ 0.1197 | $ 0.1221 | $ 0.1246 | $ 0.1271 | $ 0.1296 | $ 0.1322 |
| 11 | Annual Avoided Energy Costs | Line 9 x Line 10 | $ 955,818 | $ 969,518 | $ 983,384 | $ 997,417 | $ 1,011,617 | $ 1,025,987 | $ 1,040,526 | $ 1,055,237 | $ 1,070,120 | $ 1,085,177 |
| 12 | | | | | | | | | | | | |
| 13 | Avoided Capacity Costs | | | | | | | | | | | |
| 14 | PV Capacity at Annual Peak | Exhibit JSD-1 | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% | 37.1% |
| 15 | Capacity at Peak Hour (kW) | Line 3 x Line 14 x 1000 | 1,665 | 1,656 | 1,646 | 1,637 | 1,628 | 1,619 | 1,609 | 1,600 | 1,591 | 1,582 |
| 16 | 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 |
| 17 | Monthly Avoided Capacity Costs | Line 15 x Line 16 | $ 6,984 | $ 7,084 | $ 7,186 | $ 7,288 | $ 7,392 | $ 7,497 | $ 7,603 | $ 7,711 | $ 7,820 | $ 7,930 |
| 18 | Annual Avoided Capacity Costs | Line 17 x 12 | $ 83,811 | $ 85,013 | $ 86,229 | $ 87,459 | $ 88,704 | $ 89,964 | $ 91,239 | $ 92,529 | $ 93,834 | $ 95,154 |
| 19 | | | | | | | | | | | | |
| 20 | Local Transmission Benefits | | | | | | | | | | | |
| 21 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 22 | Capacity at Peak Hour (MW-Month) | Line 3 x Line 21 | 0.54 | 0.54 | 0.53 | 0.53 | 0.53 | 0.52 | 0.52 | 0.52 | 0.52 | 0.51 |
| 23 | 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 |
| 24 | 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 |
| 25 | Monthly Local Transmission Benefits | Line 22 x (Line 23 + Line 24) | $ 1,315 | $ 1,334 | $ 1,353 | $ 1,372 | $ 1,391 | $ 1,411 | $ 1,431 | $ 1,451 | $ 1,472 | $ 1,493 |
| 26 | Annual Local Transmission Benefits | Line 25 x 12 | $ 15,777 | $ 16,003 | $ 16,232 | $ 16,463 | $ 16,698 | $ 16,935 | $ 17,175 | $ 17,418 | $ 17,663 | $ 17,912 |
| 27 | | | | | | | | | | | | |
| 28 | Regional Transmission Benefits | | | | | | | | | | | |
| 29 | PV Capacity at Monthly Peak | Exhibit JSD-1 | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% | 12.0% |
| 30 | Capacity at Peak Hour (kW-Month) | Line 3 x Line 29 x 1000 | 540 | 537 | 534 | 531 | 528 | 525 | 522 | 519 | 516 | 513 |
| 31 | ISO NE Section 4A, Schedule 1 Rate ($ kW-Month) (5) | Annual Escalation, Line 5 | $ 0.2849 | $ 0.2906 | $ 0.2964 | $ 0.3024 | $ 0.3084 | $ 0.3146 | $ 0.3209 | $ 0.3273 | $ 0.3338 | $ 0.3405 |
| 32 | ISO NE Section 4A, Schedule 5 Rate ($ kW-Month) (6) | Annual Escalation, Line 5 | $ 0.0109 | $ 0.0112 | $ 0.0114 | $ 0.0116 | $ 0.0118 | $ 0.0121 | $ 0.0123 | $ 0.0126 | $ 0.0128 | $ 0.0131 |
| 33 | 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 |
| 34 | 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 |
| 35 | Monthly Regional Transmission Benefits | Line 30 x (Sum Lines 31 through 34) | $ 9,701 | $ 9,840 | $ 9,981 | $ 10,124 | $ 10,268 | $ 10,414 | $ 10,561 | $ 10,711 | $ 10,862 | $ 11,014 |
| 36 | Annual Regional Transmission Benefits | Line 35 x 12 | $ 116,417 | $ 118,086 | $ 119,774 | $ 121,484 | $ 123,213 | $ 124,963 | $ 126,734 | $ 128,526 | $ 130,339 | $ 132,173 |
| 37 | | | | | | | | | | | | |
| 38 | Renewable Energy Credits (REC) Savings | | | | | | | | | | | |
| 39 | Annual Production (MWh) | Line 9 ÷ 1000 | 8,640 | 8,592 | 8,544 | 8,496 | 8,448 | 8,400 | 8,352 | 8,304 | 8,256 | 8,208 |
| 40 | REC II Rate ($ Per MWh) (9) | New England Power Pool | [redacted] | | | | | | | | | |
| 41 | Annual REC Savings | Line 39 x Line 40 | | | | | | | | | | |
| 42 | | | | | | | | | | | | |
| 43 | Total Direct Customer Benefits | Line 11 + Line 18 + Line 26 + Line 36 + Line 41 | $ 1,489,343 | $ 1,504,375 | $ 1,519,611 | $ 1,535,050 | $ 1,550,696 | $ 1,566,549 | $ 1,582,611 | $ 1,598,882 | $ 1,615,365 | $ 1,632,059 |

**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, 2022
(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, 2022
(6) ISO New England Tariff Rates, Section 4A. Recovery of ISO Administrative Expenses, Schedule 3. Reliability Administration Service, Rates effective January 1, 2022
(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 FDGP-2, 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 Facility Installation | Capital Costs, Line 43 | $ [redacted] | | | | | | | | | | |
| 3 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | | |
| 4 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | | |
| 5 | Electric System Upgrades | Capital Costs, Line 46 | 600,000 | | | | | | | | | | |
| 6 | Land Improvements | Capital Costs, Line 50 | [redacted] | | | | | | | | | | |
| 7 | Land Acquisition | Capital Costs, Line 51 | 857,938 | | | | | | | | | | |
| 8 | Total Investments | Sum Lines 2 through 7 | $ 13,228,105 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | | | | | | | | | | | | | |
| 10 | Rate Base Calculation | | | | | | | | | | | | |
| 11 | Gross Plant (1) | CY Line 8 + PY Line 11 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 |
| 12 | Accumulated Depreciation (1) | Book Depreciation Schedule, Line 30 | | (400,337) | (800,673) | (1,201,010) | (1,601,347) | (2,001,684) | (2,402,020) | (2,802,357) | (3,202,694) | (3,603,030) | (4,003,367) |
| 13 | Net Plant | Line 11 + Line 12 | 13,228,105 | 12,827,768 | 12,427,432 | 12,027,095 | 11,626,758 | 11,226,421 | 10,826,085 | 10,425,748 | 10,025,411 | 9,625,075 | 9,224,738 |
| 14 | Deferred Income Tax | Deferred Tax Calculation, Line - 27 | | (457,674) | (1,247,061) | (1,682,622) | (1,905,886) | (2,129,150) | (2,193,192) | (2,098,012) | (2,002,832) | (1,907,652) | (1,812,472) |
| 15 | Year-End Rate Base | Line 13 + Line 14 | $ 13,228,105 | $ 12,370,094 | $ 11,180,370 | $ 10,344,473 | $ 9,720,872 | $ 9,097,272 | $ 8,632,893 | $ 8,327,736 | $ 8,022,580 | $ 7,717,423 | $ 7,412,266 |
| 16 | | | | | | | | | | | | | |
| 17 | Revenue Requirement | | | | | | | | | | | | |
| 18 | Average Rate Base | (CY Line 15 + PY Line 15) ÷ 2 | | $ 12,799,099 | $ 11,775,232 | $ 10,762,422 | $ 10,032,673 | $ 9,409,072 | $ 8,865,082 | $ 8,480,315 | $ 8,175,158 | $ 7,870,001 | $ 7,564,845 |
| 19 | 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% |
| 20 | Return and Taxes | Line 18 x Line 19 | | $ 1,175,200 | $ 1,081,190 | $ 988,195 | $ 921,190 | $ 863,931 | $ 813,983 | $ 778,654 | $ 750,635 | $ 722,616 | $ 694,596 |
| 21 | Operations & Maintenance | O&M Expense, Line 1 | | [redacted] | | | | | | | | | |
| 22 | Book Depreciation | Book Depreciation Schedule, Line 29 | | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 |
| 23 | Property Taxes | Property Tax Expense, Line 4 | | 357,638 | 346,477 | 335,315 | 324,154 | 312,993 | 301,831 | 290,670 | 279,508 | 268,347 | 257,186 |
| 24 | ITC Tax Effect & Gross Up | ITC Tax Effect, Line 41 | | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 25 | ITC Amortization & Gross Up | - (ITC Amortization, Line 37 + ITC Amortization, Line 40) | | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) |
| 26 | Annual Revenue Requirement | Sum Lines 20 through 25 | | $ 1,822,979 | $ 1,718,730 | $ 1,615,519 | $ 1,538,322 | $ 1,470,895 | $ 1,410,804 | $ 1,365,357 | $ 1,327,246 | $ 1,289,162 | $ 1,251,106 |

**Notes**
(1) Beginning in Year 15 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**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 Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | [redacted] | | | | | |
| 4 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 5 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 6 | Land Improvements | Capital Costs, Line 50 | | | | | | | | | | |
| 7 | Land Acquisition | Capital Costs, Line 51 | | | | | | | | | | |
| 8 | Total Investments | Sum Lines 2 through 7 | $ - | $ - | $ - | $ - | $ [redacted] | $ - | $ - | $ - | $ - | $ - |
| 9 | | | | | | | | | | | | |
| 10 | Rate Base Calculation | | | | | | | | | | | |
| 11 | Gross Plant (1) | CY Line 8 + PY Line 11 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,228,105 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 |
| 12 | Accumulated Depreciation (1) | Book Depreciation Schedule, Line 30 | (4,403,704) | (4,804,041) | (5,204,377) | (5,604,714) | (5,621,751) | (6,030,926) | (6,440,101) | (6,849,276) | (7,258,450) | (7,667,625) |
| 13 | Net Plant | Line 11 + Line 12 | 8,824,401 | 8,424,064 | 8,023,728 | 7,623,391 | 7,738,925 | 7,329,750 | 6,920,575 | 6,511,400 | 6,102,226 | 5,693,051 |
| 14 | Deferred Income Tax | Deferred Tax Calculation, Line - 27 | (1,717,292) | (1,622,112) | (1,526,931) | (1,431,751) | (1,336,571) | (1,265,986) | (1,212,069) | (1,140,373) | (1,058,009) | (975,646) |
| 15 | Year-End Rate Base | Line 13 + Line 14 | $ 7,107,110 | $ 6,801,953 | $ 6,496,796 | $ 6,191,640 | $ 6,402,353 | $ 6,063,764 | $ 5,708,506 | $ 5,371,027 | $ 5,044,216 | $ 4,717,405 |
| 16 | | | | | | | | | | | | |
| 17 | Revenue Requirement | | | | | | | | | | | |
| 18 | Average Rate Base | (CY Line 15 + PY Line 15) ÷ 2 | $ 7,259,688 | $ 6,954,531 | $ 6,649,375 | $ 6,344,218 | $ 6,296,997 | $ 6,233,059 | $ 5,886,135 | $ 5,539,767 | $ 5,207,622 | $ 4,880,811 |
| 19 | 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% |
| 20 | Return and Taxes | Line 18 x Line 19 | $ [redacted] | | | | | | | | | |
| 21 | Operations & Maintenance | O&M Expense, Line 1 | | | | | | | | | | |
| 22 | Book Depreciation | Book Depreciation Schedule, Line 29 | 400,337 | 400,337 | 400,337 | 400,337 | 400,337 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 |
| 23 | Property Taxes | Property Tax Expense, Line 4 | 246,024 | 234,863 | 223,702 | 212,540 | 215,761 | 204,353 | 192,946 | 181,538 | 170,130 | 158,722 |
| 24 | ITC Tax Effect & Gross Up | ITC Tax Effect, Line 41 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 25 | ITC Amortization & Gross Up | - (ITC Amortization, Line 37 + ITC Amortization, Line 40) | (164,353) | (164,353) | (164,353) | (164,353) | (164,353) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) |
| 26 | Annual Revenue Requirement | Sum Lines 20 through 25 | $ 1,213,077 | $ 1,175,078 | $ 1,137,107 | $ 1,099,168 | $ 1,099,324 | $ 1,101,577 | $ 1,059,651 | $ 1,017,809 | $ 977,308 | $ 937,331 |

Notes
(1) Beginning in Year 15 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**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 Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 4 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 5 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 6 | Land Improvements | Capital Costs, Line 50 | | | | | | | | | | |
| 7 | Land Acquisition | Capital Costs, Line 51 | | | | | | | | | | |
| 8 | Total Investments | Sum Lines 2 through 7 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | | | | | | | | | | | | |
| 10 | Rate Base Calculation | | | | | | | | | | | |
| 11 | Gross Plant (1) | CY Line 8 + PY Line 11 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 | $ 13,360,676 |
| 12 | Accumulated Depreciation (1) | Book Depreciation Schedule, Line 30 | (8,076,800) | (8,485,975) | (8,895,150) | (9,304,324) | (9,713,499) | (10,122,674) | (10,531,849) | (10,941,024) | (11,350,198) | (11,759,373) |
| 13 | Net Plant | Line 11 + Line 12 | 5,283,876 | 4,874,701 | 4,465,526 | 4,056,352 | 3,647,177 | 3,238,002 | 2,828,827 | 2,419,653 | 2,010,478 | 1,601,303 |
| 14 | Deferred Income Tax | Deferred Tax Calculation, Line - 27 | (885,282) | (786,917) | (688,552) | (590,188) | (491,823) | (393,459) | (295,094) | (196,729) | (98,365) | - |
| 15 | Year-End Rate Base | Line 13 + Line 14 | $ 4,398,594 | $ 4,087,784 | $ 3,776,974 | $ 3,466,164 | $ 3,155,354 | $ 2,844,544 | $ 2,533,733 | $ 2,222,923 | $ 1,912,113 | $ 1,601,303 |
| 16 | | | | | | | | | | | | |
| 17 | Revenue Requirement | | | | | | | | | | | |
| 18 | Average Rate Base | (CY Line 15 + PY Line 15) ÷ 2 | $ 4,558,000 | $ 4,243,189 | $ 3,932,379 | $ 3,621,569 | $ 3,310,759 | $ 2,999,949 | $ 2,689,139 | $ 2,378,328 | $ 2,067,518 | $ 1,756,708 |
| 19 | 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% |
| 20 | Return and Taxes | Line 18 x Line 19 | $ 418,511 | $ 389,605 | $ 361,067 | $ 332,529 | $ 303,991 | $ 275,452 | $ 246,914 | $ 218,376 | $ 189,837 | $ 161,299 |
| 21 | Operations & Maintenance | O&M Expense, Line 1 | [redacted] | | | | | | | | | |
| 22 | Book Depreciation | Book Depreciation Schedule, Line 29 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 | 409,175 |
| 23 | Property Taxes | Property Tax Expense, Line 4 | 147,314 | 135,907 | 124,499 | 113,091 | 101,683 | 90,275 | 78,868 | 67,460 | 56,052 | 44,644 |
| 24 | ITC Tax Effect & Gross Up | ITC Tax Effect, Line 41 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 25 | ITC Amortization & Gross Up | - (ITC Amortization, Line 37 + ITC Amortization, Line 40) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) | (153,863) |
| 26 | Annual Revenue Requirement | Sum Lines 20 through 25 | $ 897,758 | $ 858,956 | $ 820,560 | $ 782,202 | $ 743,884 | $ 705,606 | $ 667,370 | $ 629,177 | $ 591,028 | $ 552,924 |

**Notes**
(1) Beginning in Year 15 Gross Plant and Accumulated Depreciation are reduced by the retirement of Solar Inverter 1

REDACTED


**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 4**
**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 | O&M Expense [1] | 2.50% Annual Escalation | $ [redacted] | | | | | | | | | |

**Notes**
(1) Preliminary RFP Response: assumes 6.15 (MW) DC size x [redacted] per kW DC annual maintenance in Year 1

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 4**
**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 | O&M Expense [(1)] | 2.50% Annual Escalation | $ [redacted] | | | | | | | | | |

**Notes**
**(1) Preliminary RFP Response: assumes 6.15 (MW) DC size x [redacted] per kW DC annual maintenance in Year 1**

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 4**
**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 | O&M Expense [1] | 2.50% Annual Escalation | $ [redacted] | | | | | | | | | |

**Notes**
(1) Preliminary RFP Response: assumes 6.15 (MW) DC size x [redacted] per kW DC annual maintenance in Year 1

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 5**
**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 13 | $ 12,827,768 | $ 12,427,432 | $ 12,027,095 | $ 11,626,758 | $ 11,226,421 | $ 10,826,085 | $ 10,425,748 | $ 10,025,411 | $ 9,625,075 | $ 9,224,738 |
| 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) | $ 357,638 | $ 346,477 | $ 335,315 | $ 324,154 | $ 312,993 | $ 301,831 | $ 290,670 | $ 279,508 | $ 268,347 | $ 257,186 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 5**
**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 13 | $ 8,824,401 | $ 8,424,064 | $ 8,023,728 | $ 7,623,391 | $ 7,738,925 | $ 7,329,750 | $ 6,920,575 | $ 6,511,400 | $ 6,102,226 | $ 5,693,051 |
| 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) | $ 246,024 | $ 234,863 | $ 223,702 | $ 212,540 | $ 215,761 | $ 204,353 | $ 192,946 | $ 181,538 | $ 170,130 | $ 158,722 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 5**
**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 13 | $ 5,283,876 | $ 4,874,701 | $ 4,465,526 | $ 4,056,352 | $ 3,647,177 | $ 3,238,002 | $ 2,828,827 | $ 2,419,653 | $ 2,010,478 | $ 1,601,303 |
| 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) | $ 147,314 | $ 135,907 | $ 124,499 | $ 113,091 | $ 101,683 | $ 90,275 | $ 78,868 | $ 67,460 | $ 56,052 | $ 44,644 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 6**
**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, Line 77 | $ [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | - | $ - | $ - | $ - |
| 3 | ITC Tax Effect Flowthrough | ITC Tax Effect, Line 37 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 4 | Total Annual Federal Tax Depreciation | Line 2 + Line 3 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 5 | Cumulative Federal Tax Depreciation | CY Line 4 + PY Line 5 | $ [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | | | | | | | | | | | | |
| 7 | Total Annual State Tax Depreciation | Tax Depreciation, Line 79 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 8 | Cumulative State Tax Depreciation | CY Line 7 + PY Line 8 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 9 | | | | | | | | | | | | |
| 10 | Book Depreciation: PV Facility Installation | Book Depreciation Schedule, Line 5 | $ [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 11 | Book Depreciation: Electric System Upgrades | Book Depreciation Schedule, Line 12 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 12 | Book Depreciation: Solar Inverter 1 | Book Depreciation Schedule, Line 19 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 13 | Book Depreciation: Solar Inverter 2 | Book Depreciation Schedule, Line 26 | - | - | - | - | - | - | - | - | - | - |
| 14 | Total Book Depreciation | Sum Lines 10 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 5 - Line 15 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 18 | Federal Tax Rate | Cost of Capital, Line 14 | 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 8 - Line 15 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 24 | State Tax Rate | Cost of Capital, Line 12 | 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 | $ 457,674 | $ 1,247,061 | $ 1,682,622 | $ 1,905,886 | $ 2,129,150 | $ 2,193,192 | $ 2,098,012 | $ 2,002,832 | $ 1,907,652 | $ 1,812,472 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 6**
**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, Line 77 | $ - | $ - | $ - | $ - | $ - | [redacted] | | | | |
| 3 | ITC Tax Effect Flowthrough | ITC Tax Effect, Line 37 | | | | | | | | | | |
| 4 | Total Annual Federal Tax Depreciation | Line 2 + Line 3 | | | | | | | | | | |
| 5 | Cumulative Federal Tax Depreciation | CY Line 4 + PY Line 5 | | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | Total Annual State Tax Depreciation | Tax Depreciation, Line 79 | $ - | $ - | $ - | $ - | $ - | [redacted] | | | | |
| 8 | Cumulative State Tax Depreciation | CY Line 7 + PY Line 8 | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | Book Depreciation: PV Facility Installation | Book Depreciation Schedule, Line 5 | $ [redacted] | | | | | | | | | |
| 11 | Book Depreciation: Electric System Upgrades | Book Depreciation Schedule, Line 12 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| 12 | Book Depreciation: Solar Inverter 1 | Book Depreciation Schedule, Line 19 | [redacted] | | | | | | | | | |
| 13 | Book Depreciation: Solar Inverter 2 | Book Depreciation Schedule, Line 26 | - | - | - | - | - | [redacted] | | | | |
| 14 | Total Book Depreciation | Sum Lines 10 through 13 | | | | | | | | | | |
| 15 | Cumulative Book Depreciation | CY Line 14 + PY Line 15 | | | | | | | | | | |
| 16 | | | | | | | | | | | | |
| 17 | Cumulative Book / Tax Timer | Line 5 - Line 15 | $ [redacted] | | | | | | | | | |
| 18 | Federal Tax Rate | Cost of Capital, Line 14 | 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] | | | | | | | | | |
| 20 | Less: Federal Deduction for Deferred State Taxes | Line 18 x - Line 25 | | | | | | | | | | |
| 21 | Net Deferred Federal Tax Reserve | Line 19 + Line 20 | | | | | | | | | | |
| 22 | | | | | | | | | | | | |
| 23 | Cumulative Book / Tax Timer | Line 8 - Line 15 | $ [redacted] | | | | | | | | | |
| 24 | State Tax Rate | Cost of Capital, Line 12 | 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] | | | | | | | | | |
| 26 | | | | | | | | | | | | |
| 27 | Total Deferred Taxes | Line 21 + Line 25 | $ 1,717,292 | $ 1,622,112 | $ 1,526,931 | $ 1,431,751 | $ 1,336,571 | $ 1,265,986 | $ 1,212,069 | $ 1,140,373 | $ 1,058,009 | $ 975,646 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 6**
**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 | Deferred Tax Calculation | | | | | | | | | | | |
| 2 | Annual Federal Tax Depreciation | Tax Depreciation Schedule, Line 77 | $ [redacted] | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 3 | ITC Tax Effect Flowthrough | ITC Tax Effect, Line 37 | [redacted] | | | | | | | | | |
| 4 | Total Annual Federal Tax Depreciation | Line 2 + Line 3 | | | | | | | | | | |
| 5 | Cumulative Federal Tax Depreciation | CY Line 4 + PY Line 5 | $ | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | Total Annual State Tax Depreciation | Tax Depreciation, Line 79 | $ [redacted] | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Cumulative State Tax Depreciation | CY Line 7 + PY Line 8 | $ [redacted] | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | Book Depreciation: PV Facility Installation | Book Depreciation Schedule, Line 5 | $ [redacted] | | | | | | | | | |
| 11 | Book Depreciation: Electric System Upgrades | Book Depreciation Schedule, Line 12 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| 12 | Book Depreciation: Solar Inverter 1 | Book Depreciation Schedule, Line 19 | - | - | - | - | - | - | - | - | - | - |
| 13 | Book Depreciation: Solar Inverter 2 | Book Depreciation Schedule, Line 26 | [redacted] | | | | | | | | | |
| 14 | Total Book Depreciation | Sum Lines 10 through 13 | | | | | | | | | | |
| 15 | Cumulative Book Depreciation | CY Line 14 + PY Line 15 | $ | | | | | | | | | |
| 16 | | | | | | | | | | | | |
| 17 | Cumulative Book / Tax Timer | Line 5 - Line 15 | [redacted] | | | | | | | | | $ - |
| 18 | Federal Tax Rate | Cost of Capital, Line 14 | 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] | | | | | | | | | - |
| 20 | Less: Federal Deduction for Deferred State Taxes | Line 18 x - Line 25 | (58,001) | (51,556) | (45,112) | (38,667) | (32,223) | (25,778) | (19,334) | (12,889) | (6,445) | - |
| 21 | Net Deferred Federal Tax Reserve | Line 19 + Line 20 | [redacted] | | | | | | | | | $ - |
| 22 | | | | | | | | | | | | |
| 23 | Cumulative Book / Tax Timer | Line 8 - Line 15 | [redacted] | | | | | | | | | - |
| 24 | State Tax Rate | Cost of Capital, Line 12 | 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] | | | | | | | | | $ - |
| 26 | | | | | | | | | | | | |
| 27 | Total Deferred Taxes | Line 21 + Line 25 | $ 885,282 | $ 786,917 | $ 688,552 | $ 590,188 | $ 491,823 | $ 393,459 | $ 295,094 | $ 196,729 | $ 98,365 | $ - |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 7**
**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 | Year 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 30 Year Property | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Capital Investment | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 5 | Annual Book Depreciation | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | Cumulative Book Depreciation | CY Line 5 + PY Line 6 | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | 30 Year Property | | | | | | | | | | | |
| 9 | Electric System Upgrades | Capital Costs, Line 46 | $ 600,000 | | | | | | | | | |
| 10 | Cumulative Capital Investment | CY Line 9 + PY Line 10 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 11 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 12 | Annual Book Depreciation | Line 10 x Line 11 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| 13 | Cumulative Book Depreciation | CY Line 12 + PY Line 13 | $ 20,000 | $ 40,000 | $ 60,000 | $ 80,000 | $ 100,000 | $ 120,000 | $ 140,000 | $ 160,000 | $ 180,000 | $ 200,000 |
| 14 | | | | | | | | | | | | |
| 15 | 15 Year Property | | | | | | | | | | | |
| 16 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 17 | Cumulative Capital Investment | CY Line 16 + PY Line 17 | | | | | | | | | | |
| 18 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 19 | Annual Book Depreciation | Line 17 x Line 18 | [redacted] | | | | | | | | | |
| 20 | Cumulative Book Depreciation | CY Line 19 + PY Line 20 | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | 15 Year Property | | | | | | | | | | | |
| 23 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 24 | Cumulative Capital Investment | CY Line 23 + PY Line 24 | | | | | | | | | | |
| 25 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | | | | | | | | | | |
| 26 | Annual Book Depreciation | Line 24 x Line 25 | | | | | | | | | | |
| 27 | Cumulative Book Depreciation | CY Line 26 + PY Line 27 | | | | | | | | | | |
| 28 | | | | | | | | | | | | |
| 29 | Total Annual Book Depreciation | Line 5 + Line 12 + Line 19 + Line 26 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 |
| 30 | Total Cumulative Book Depreciation | CY Line 29 + PY Line 30 | $ 400,337 | $ 800,673 | $ 1,201,010 | $ 1,601,347 | $ 2,001,684 | $ 2,402,020 | $ 2,802,357 | $ 3,202,694 | $ 3,603,030 | $ 4,003,367 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 7**
**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 | Year 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 30 Year Property | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Capital Investment | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 5 | Annual Book Depreciation | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | Cumulative Book Depreciation | CY Line 5 + PY Line 6 | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | 30 Year Property | | | | | | | | | | | |
| 9 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 10 | Cumulative Capital Investment | CY Line 9 + PY Line 10 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 11 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 12 | Annual Book Depreciation | Line 10 x Line 11 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| 13 | Cumulative Book Depreciation | CY Line 12 + PY Line 13 | $ 220,000 | $ 240,000 | $ 260,000 | $ 280,000 | $ 300,000 | $ 320,000 | $ 340,000 | $ 360,000 | $ 380,000 | $ 400,000 |
| 14 | | | | | | | | | | | | |
| 15 | 15 Year Property | | | | | | | | | | | |
| 16 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 17 | Cumulative Capital Investment | CY Line 16 + PY Line 17 | | | | | | | | | | |
| 18 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | | | | | |
| 19 | Annual Book Depreciation | Line 17 x Line 18 | [redacted] | | | | | | | | | |
| 20 | Cumulative Book Depreciation | CY Line 19 + PY Line 20 | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | 15 Year Property | | | | | | | | | | | |
| 23 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | [redacted] | | | | |
| 24 | Cumulative Capital Investment | CY Line 23 + PY Line 24 | | | | | | | | | | |
| 25 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | | | | | | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 26 | Annual Book Depreciation | Line 24 x Line 25 | | | | | | [redacted] | | | | |
| 27 | Cumulative Book Depreciation | CY Line 26 + PY Line 27 | | | | | | | | | | |
| 28 | | | | | | | | | | | | |
| 29 | Total Annual Book Depreciation | Line 5 + Line 12 + Line 19 + Line 26 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 400,337 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 |
| 30 | Total Cumulative Book Depreciation | CY Line 29 + PY Line 30 | $ 4,403,704 | $ 4,804,041 | $ 5,204,377 | $ 5,604,714 | $ 6,005,051 | $ 6,414,225 | $ 6,823,400 | $ 7,232,575 | $ 7,641,750 | $ 8,050,925 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 7**
**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 | Year 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 30 Year Property | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Capital Investment | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 5 | Annual Book Depreciation | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | Cumulative Book Depreciation | CY Line 5 + PY Line 6 | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | 30 Year Property | | | | | | | | | | | |
| 9 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 10 | Cumulative Capital Investment | CY Line 9 + PY Line 10 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 11 | Annual Depreciation Rate | Annual Depreciation Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 12 | Annual Book Depreciation | Line 10 x Line 11 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 | 20,000 |
| 13 | Cumulative Book Depreciation | CY Line 12 + PY Line 13 | $ 420,000 | $ 440,000 | $ 460,000 | $ 480,000 | $ 500,000 | $ 520,000 | $ 540,000 | $ 560,000 | $ 580,000 | $ 600,000 |
| 14 | | | | | | | | | | | | |
| 15 | 15 Year Property | | | | | | | | | | | |
| 16 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 17 | Cumulative Capital Investment | CY Line 16 + PY Line 17 | | | | | | | | | | |
| 18 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | | | | | | | | | | |
| 19 | Annual Book Depreciation | Line 17 x Line 18 | | | | | | | | | | |
| 20 | Cumulative Book Depreciation | CY Line 19 + PY Line 20 | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | 15 Year Property | | | | | | | | | | | |
| 23 | Solar Inverter 2 | Capital Costs, Line 45 | [redacted] | | | | | | | | | |
| 24 | Cumulative Capital Investment | CY Line 23 + PY Line 24 | | | | | | | | | | |
| 25 | Annual Depreciation Rate | Annual Depreciation Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 26 | Annual Book Depreciation | Line 24 x Line 25 | [redacted] | | | | | | | | | |
| 27 | Cumulative Book Depreciation | CY Line 26 + PY Line 27 | | | | | | | | | | |
| 28 | | | | | | | | | | | | |
| 29 | Total Annual Book Depreciation | Line 5 + Line 12 + Line 19 + Line 26 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 | $ 409,175 |
| 30 | Total Cumulative Book Depreciation | CY Line 29 + PY Line 30 | $ 8,460,099 | $ 8,869,274 | $ 9,278,449 | $ 9,687,624 | $ 10,096,799 | $ 10,505,973 | $ 10,915,148 | $ 11,324,323 | $ 11,733,498 | $ 12,142,672 |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 8**
**Tax Depreciation Schedule**

| 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 | Federal Tax Depreciation | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | | | | |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | Tax Depreciation Reduction at 50% of ITC | Line 5 x 50% | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | Investment Tax Basis | Line 3 | [redacted] | | | | | | | | | |
| 9 | ITC Tax Depreciation Reduction | - Line 6 | | | | | | | | | | |
| 10 | Net Tax Basis | Line 8 + Line 9 | | | | | | | | | | |
| 11 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 12 | Federal Tax Depreciation | Line 10 x Line 11 | [redacted] | | | | | | | | | |
| 13 | | | | | | | | | | | | |
| 14 | State Tax Depreciation | | | | | | | | | | | |
| 15 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 16 | Cumulative Investment Tax Basis | CY Line 15 + PY Line 16 | | | | | | | | | | |
| 17 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 18 | State Tax Depreciation | Line 16 x Line 17 | [redacted] | | | | | | | | | |
| 19 | | | | | | | | | | | | |
| 20 | Federal Tax Depreciation | | | | | | | | | | | |
| 21 | Electric System Upgrades | Capital Costs, Line 46 | $ 600,000 | | | | | | | | | |
| 22 | Cumulative Investment Tax Basis | CY Line 21 + PY Line 22 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | | | | |
| 23 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | | | | |
| 24 | Investment Tax Credit | Line 22 x Line 23 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | | | | |
| 25 | Tax Depreciation Reduction at 50% of ITC | Line 24 x 50% | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | | | | |
| 26 | | | | | | | | | | | | |
| 27 | Investment Tax Basis | Line 22 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | | | | |
| 28 | ITC Tax Depreciation Reduction | - Line 25 | (90,000) | (90,000) | (90,000) | (90,000) | (90,000) | (90,000) | | | | |
| 29 | Net Tax Basis | Line 27 + Line 28 | 510,000 | 510,000 | 510,000 | 510,000 | 510,000 | 510,000 | | | | |
| 30 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 31 | Federal Tax Depreciation | Line 29 x Line 30 | $ 102,000 | $ 163,200 | $ 97,920 | $ 58,752 | $ 58,752 | $ 29,376 | | | | |
| 32 | | | | | | | | | | | | |
| 33 | State Tax Depreciation | | | | | | | | | | | |
| 34 | Electric System Upgrades | Capital Costs, Line 46 | $ 600,000 | | | | | | | | | |
| 35 | Cumulative Investment Tax Basis | CY Line 34 + PY Line 35 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | | | | |
| 36 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 37 | State Tax Depreciation | Line 35 x Line 36 | $ 120,000 | $ 192,000 | $ 115,200 | $ 69,120 | $ 69,120 | $ 34,560 | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Federal Tax Depreciation | | | | | | | | | | | |
| 40 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 41 | Cumulative Investment Tax Basis | CY Line 40 + PY Line 41 | | | | | | | | | | |
| 42 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | | | | |
| 43 | Investment Tax Credit | Line 41 x Line 42 | [redacted] | | | | | | | | | |
| 44 | Tax Depreciation Reduction at 50% of ITC | Line 43 x 50% | | | | | | | | | | |
| 45 | | | | | | | | | | | | |
| 46 | Investment Tax Basis | Line 41 | [redacted] | | | | | | | | | |
| 47 | ITC Tax Depreciation Reduction | - Line 44 | | | | | | | | | | |
| 48 | Net Tax Basis | Line 46 + Line 47 | | | | | | | | | | |
| 49 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 50 | Federal Tax Depreciation | Line 48 x Line 49 | [redacted] | | | | | | | | | |
| 51 | | | | | | | | | | | | |
| 52 | State Tax Depreciation | | | | | | | | | | | |
| 53 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 54 | Cumulative Investment Tax Basis | CY Line 53 + PY Line 54 | | | | | | | | | | |
| 55 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | |
| 56 | State Tax Depreciation | Line 54 x Line 55 | [redacted] | | | | | | | | | |
| 57 | | | | | | | | | | | | |
| 58 | Federal Tax Depreciation | | | | | | | | | | | |
| 59 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 60 | Cumulative Investment Tax Basis | CY Line 59 + PY Line 60 | | | | | | | | | | |
| 61 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 62 | Investment Tax Credit | Line 60 x Line 61 | | | | | | | | | | |
| 63 | Tax Depreciation Reduction at 50% of ITC | | | | | | | | | | | |
| 64 | | | | | | | | | | | | |
| 65 | Investment Tax Basis | Line 60 | | | | | | | | | | |
| 66 | ITC Tax Depreciation Reduction | - Line 63 | | | | | | | | | | |
| 67 | Net Tax Basis | Line 65 + Line 66 | | | | | | | | | | |
| 68 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 69 | Federal Tax Depreciation | Line 67 x Line 68 | | | | | | | | | | |
| 70 | | | | | | | | | | | | |
| 71 | State Tax Depreciation | | | | | | | | | | | |
| 72 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 73 | Cumulative Investment Tax Basis | CY Line 72 + PY Line 73 | | | | | | | | | | |
| 74 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 75 | State Tax Depreciation | Line 73 x Line 74 | | | | | | | | | | |
| 76 | | | | | | | | | | | | |
| 77 | Total Federal Tax Depreciation | Line 12 + Line 31 + Line 50 + Line 69 | [redacted] | | | | | | $ - | $ - | $ - | $ - |
| 78 | | | | | | | | | | | | |
| 79 | Total State Tax Depreciation | Line 18 + Line 37 + Line 56 + Line 75 | | | | | | | $ - | $ - | $ - | $ - |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 8**
**Tax Depreciation Schedule**

| 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 | Federal Tax Depreciation | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 5 | Investment Tax Credit | Line 3 x Line 4 | | | | | | | | | | |
| 6 | Tax Depreciation Reduction at 50% of ITC | Line 5 x 50% | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | Investment Tax Basis | Line 3 | | | | | | | | | | |
| 9 | ITC Tax Depreciation Reduction | - Line 6 | | | | | | | | | | |
| 10 | Net Tax Basis | Line 8 + Line 9 | | | | | | | | | | |
| 11 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 12 | Federal Tax Depreciation | Line 10 x Line 11 | | | | | | | | | | |
| 13 | | | | | | | | | | | | |
| 14 | State Tax Depreciation | | | | | | | | | | | |
| 15 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 16 | Cumulative Investment Tax Basis | CY Line 15 + PY Line 16 | | | | | | | | | | |
| 17 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 18 | State Tax Depreciation | Line 16 x Line 17 | | | | | | | | | | |
| 19 | | | | | | | | | | | | |
| 20 | Federal Tax Depreciation | | | | | | | | | | | |
| 21 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 22 | Cumulative Investment Tax Basis | CY Line 21 + PY Line 22 | | | | | | | | | | |
| 23 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 24 | Investment Tax Credit | Line 22 x Line 23 | | | | | | | | | | |
| 25 | Tax Depreciation Reduction at 50% of ITC | Line 24 x 50% | | | | | | | | | | |
| 26 | | | | | | | | | | | | |
| 27 | Investment Tax Basis | Line 22 | | | | | | | | | | |
| 28 | ITC Tax Depreciation Reduction | - Line 25 | | | | | | | | | | |
| 29 | Net Tax Basis | Line 27 + Line 28 | | | | | | | | | | |
| 30 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 31 | Federal Tax Depreciation | Line 29 x Line 30 | | | | | | | | | | |
| 32 | | | | | | | | | | | | |
| 33 | State Tax Depreciation | | | | | | | | | | | |
| 34 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 35 | Cumulative Investment Tax Basis | CY Line 34 + PY Line 35 | | | | | | | | | | |
| 36 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 37 | State Tax Depreciation | Line 35 x Line 36 | | | | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Federal Tax Depreciation | | | | | | | | | | | |
| 40 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 41 | Cumulative Investment Tax Basis | CY Line 40 + PY Line 41 | | | | | | | | | | |
| 42 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 43 | Investment Tax Credit | Line 41 x Line 42 | | | | | | | | | | |
| 44 | Tax Depreciation Reduction at 50% of ITC | Line 43 x 50% | | | | | | | | | | |
| 45 | | | | | | | | | | | | |
| 46 | Investment Tax Basis | Line 41 | | | | | | | | | | |
| 47 | ITC Tax Depreciation Reduction | - Line 44 | | | | | | | | | | |
| 48 | Net Tax Basis | Line 46 + Line 47 | | | | | | | | | | |
| 49 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 50 | Federal Tax Depreciation | Line 48 x Line 49 | | | | | | | | | | |
| 51 | | | | | | | | | | | | |
| 52 | State Tax Depreciation | | | | | | | | | | | |
| 53 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 54 | Cumulative Investment Tax Basis | CY Line 53 + PY Line 54 | | | | | | | | | | |
| 55 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 56 | State Tax Depreciation | Line 54 x Line 55 | | | | | | | | | | |
| 57 | | | | | | | | | | | | |
| 58 | Federal Tax Depreciation | | | | | | | [redacted] | | | | |
| 59 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 60 | Cumulative Investment Tax Basis | CY Line 59 + PY Line 60 | | | | | | | | | | |
| 61 | Investment Tax Credit Rate | Expected Rate | | | | | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 62 | Investment Tax Credit | Line 60 x Line 61 | | | | | | - | - | - | - | - |
| 63 | Tax Depreciation Reduction at 50% of ITC | | | | | | | - | - | - | - | - |
| 64 | | | | | | | | | | | | |
| 65 | Investment Tax Basis | Line 60 | | | | | | [redacted] | | | | |
| 66 | ITC Tax Depreciation Reduction | - Line 63 | | | | | | | | | | |
| 67 | Net Tax Basis | Line 65 + Line 66 | | | | | | [redacted] | | | | |
| 68 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% |
| 69 | Federal Tax Depreciation | Line 67 x Line 68 | | | | | | [redacted] | | | | |
| 70 | | | | | | | | | | | | |
| 71 | State Tax Depreciation | | | | | | | | | | | |
| 72 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | [redacted] | | | | |
| 73 | Cumulative Investment Tax Basis | CY Line 72 + PY Line 73 | | | | | | | | | | |
| 74 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | [redacted] | | | | |
| 75 | State Tax Depreciation | Line 73 x Line 74 | | | | | | | | | | |
| 76 | | | | | | | | | | | | |
| 77 | Total Federal Tax Depreciation | Line 12 + Line 31 + Line 50 + Line 69 | $ - | $ - | $ - | $ - | $ | | | | | |
| 78 | | | | | | | | | | | | |
| 79 | Total State Tax Depreciation | Line 18 + Line 37 + Line 56 + Line 75 | $ - | $ - | $ - | $ - | $ | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 8**
**Tax Depreciation Schedule**

| 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 | Federal Tax Depreciation | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 5 | Investment Tax Credit | Line 3 x Line 4 | | | | | | | | | | |
| 6 | Tax Depreciation Reduction at 50% of ITC | Line 5 x 50% | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | Investment Tax Basis | Line 3 | | | | | | | | | | |
| 9 | ITC Tax Depreciation Reduction | - Line 6 | | | | | | | | | | |
| 10 | Net Tax Basis | Line 8 + Line 9 | | | | | | | | | | |
| 11 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 12 | Federal Tax Depreciation | Line 10 x Line 11 | | | | | | | | | | |
| 13 | | | | | | | | | | | | |
| 14 | State Tax Depreciation | | | | | | | | | | | |
| 15 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 16 | Cumulative Investment Tax Basis | CY Line 15 + PY Line 16 | | | | | | | | | | |
| 17 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 18 | State Tax Depreciation | Line 16 x Line 17 | | | | | | | | | | |
| 19 | | | | | | | | | | | | |
| 20 | Federal Tax Depreciation | | | | | | | | | | | |
| 21 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 22 | Cumulative Investment Tax Basis | CY Line 21 + PY Line 22 | | | | | | | | | | |
| 23 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 24 | Investment Tax Credit | Line 22 x Line 23 | | | | | | | | | | |
| 25 | Tax Depreciation Reduction at 50% of ITC | Line 24 x 50% | | | | | | | | | | |
| 26 | | | | | | | | | | | | |
| 27 | Investment Tax Basis | Line 22 | | | | | | | | | | |
| 28 | ITC Tax Depreciation Reduction | - Line 25 | | | | | | | | | | |
| 29 | Net Tax Basis | Line 27 + Line 28 | | | | | | | | | | |
| 30 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 31 | Federal Tax Depreciation | Line 29 x Line 30 | | | | | | | | | | |
| 32 | | | | | | | | | | | | |
| 33 | State Tax Depreciation | | | | | | | | | | | |
| 34 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 35 | Cumulative Investment Tax Basis | CY Line 34 + PY Line 35 | | | | | | | | | | |
| 36 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 37 | State Tax Depreciation | Line 35 x Line 36 | | | | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Federal Tax Depreciation | | | | | | | | | | | |
| 40 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 41 | Cumulative Investment Tax Basis | CY Line 40 + PY Line 41 | | | | | | | | | | |
| 42 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 43 | Investment Tax Credit | Line 41 x Line 42 | | | | | | | | | | |
| 44 | Tax Depreciation Reduction at 50% of ITC | Line 43 x 50% | | | | | | | | | | |
| 45 | | | | | | | | | | | | |
| 46 | Investment Tax Basis | Line 41 | | | | | | | | | | |
| 47 | ITC Tax Depreciation Reduction | - Line 44 | | | | | | | | | | |
| 48 | Net Tax Basis | Line 46 + Line 47 | | | | | | | | | | |
| 49 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 50 | Federal Tax Depreciation | Line 48 x Line 49 | | | | | | | | | | |
| 51 | | | | | | | | | | | | |
| 52 | State Tax Depreciation | | | | | | | | | | | |
| 53 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 54 | Cumulative Investment Tax Basis | CY Line 53 + PY Line 54 | | | | | | | | | | |
| 55 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | | | | | | | | | | |
| 56 | State Tax Depreciation | Line 54 x Line 55 | | | | | | | | | | |
| 57 | | | | | | | | | | | | |
| 58 | Federal Tax Depreciation | | | | | | | | | | | |
| 59 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 60 | Cumulative Investment Tax Basis | CY Line 59 + PY Line 60 | [redacted] | | | | | | | | | |
| 61 | Investment Tax Credit Rate | Expected Rate | 0.00% | | | | | | | | | |
| 62 | Investment Tax Credit | Line 60 x Line 61 | - | | | | | | | | | |
| 63 | Tax Depreciation Reduction at 50% of ITC | | - | | | | | | | | | |
| 64 | | | | | | | | | | | | |
| 65 | Investment Tax Basis | Line 60 | [redacted] | | | | | | | | | |
| 66 | ITC Tax Depreciation Reduction | - Line 63 | - | | | | | | | | | |
| 67 | Net Tax Basis | Line 65 + Line 66 | [redacted] | | | | | | | | | |
| 68 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 5.76% | | | | | | | | | |
| 69 | Federal Tax Depreciation | Line 67 x Line 68 | $ [redacted] | | | | | | | | | |
| 70 | | | | | | | | | | | | |
| 71 | State Tax Depreciation | | | | | | | | | | | |
| 72 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 73 | Cumulative Investment Tax Basis | CY Line 72 + PY Line 73 | [redacted] | | | | | | | | | |
| 74 | Annual 5 Year MACRS | MACRS Rate Table, Line 2 | 5.76% | | | | | | | | | |
| 75 | State Tax Depreciation | Line 73 x Line 74 | $ [redacted] | | | | | | | | | |
| 76 | | | | | | | | | | | | |
| 77 | Total Federal Tax Depreciation | Line 12 + Line 31 + Line 50 + Line 69 | $ [redacted] | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 78 | | | | | | | | | | | | |
| 79 | Total State Tax Depreciation | Line 18 + Line 37 + Line 56 + Line 75 | $ [redacted] | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 9**
**Investment Tax Credit Amortization**

| 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 | 30 Year Property | | [redacted] | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 7 | Annual ITC Amortization | Line 5 x Line 6 | [redacted] | | | | | | | | | |
| 8 | Cumulative ITC Amortization | CY Line 7 + PY Line 8 | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | 30 Year Property | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | $ 600,000 | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 16 | Annual ITC Amortization | Line 14 x Line 15 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 |
| 17 | Cumulative ITC Amortization | CY Line 16 + PY Line 17 | $ 6,000 | $ 12,000 | $ 18,000 | $ 24,000 | $ 30,000 | $ 36,000 | $ 42,000 | $ 48,000 | $ 54,000 | $ 60,000 |
| 18 | | | | | | | | | | | | |
| 19 | 15 Year Property | | [redacted] | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | | | | | | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 23 | Investment Tax Credit | Line 21 x Line 22 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 24 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 25 | Annual ITC Amortization | Line 23 x Line 24 | [redacted] | | | | | | | | | |
| 26 | Cumulative ITC Amortization | CY Line 25 + PY Line 26 | | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | 15 Year Property | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | | | | | | | | | | |
| 31 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 32 | Investment Tax Credit | Line 30 x Line 31 | | | | | | | | | | |
| 33 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | | | | | |
| 34 | Annual ITC Amortization | Line 32 x Line 33 | | | | | | | | | | |
| 35 | Cumulative ITC Amortization | CY Line 34 + PY Line 35 | | | | | | | | | | |
| 36 | | | | | | | | | | | | |
| 37 | Total Annual ITC Amortization | Line 7 + Line 16 + Line 25 + Line 34 | [redacted] | | | | | | | | | |
| 38 | Total Cumulative ITC Amortization | CY Line 37 + PY Line 38 | | | | | | | | | | |
| 39 | | | | | | | | | | | | |
| 40 | Tax Gross-Up | Line 37 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total Cumulative Tax Gross-Up | CY Line 40 + PY Line 41 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 9**
**Investment Tax Credit Amortization**

| 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 | <u>30 Year Property</u> | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 7 | Annual ITC Amortization | Line 5 x Line 6 | [redacted] | | | | | | | | | |
| 8 | Cumulative ITC Amortization | CY Line 7 + PY Line 8 | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | <u>30 Year Property</u> | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 16 | Annual ITC Amortization | Line 14 x Line 15 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 |
| 17 | Cumulative ITC Amortization | CY Line 16 + PY Line 17 | $ 66,000 | $ 72,000 | $ 78,000 | $ 84,000 | $ 90,000 | $ 96,000 | $ 102,000 | $ 108,000 | $ 114,000 | $ 120,000 |
| 18 | | | | | | | | | | | | |
| 19 | <u>15 Year Property</u> | | | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | | | | | |
| 23 | Investment Tax Credit | Line 21 x Line 22 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | | | | | |
| 24 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | | | | | |
| 25 | Annual ITC Amortization | Line 23 x Line 24 | [redacted] | | | | | | | | | |
| 26 | Cumulative ITC Amortization | CY Line 25 + PY Line 26 | | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | <u>15 Year Property</u> | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | [redacted] | | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | | | | | | | | | | |
| 31 | Investment Tax Credit Rate | Expected Rate | | | | | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 32 | Investment Tax Credit | Line 30 x Line 31 | | | | | | - | - | - | - | - |
| 33 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 34 | Annual ITC Amortization | Line 32 x Line 33 | | | | | | - | - | - | - | - |
| 35 | Cumulative ITC Amortization | CY Line 34 + PY Line 35 | | | | | | $ - | $ - | $ - | $ - | $ - |
| 36 | | | | | | | | | | | | |
| 37 | Total Annual ITC Amortization | Line 7 + Line 16 + Line 25 + Line 34 | [redacted] | | | | | | | | | |
| 38 | Total Cumulative ITC Amortization | CY Line 37 + PY Line 38 | | | | | | | | | | |
| 39 | | | | | | | | | | | | |
| 40 | Tax Gross-Up | Line 37 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total Cumulative Tax Gross-Up | CY Line 40 + PY Line 41 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 9**
**Investment Tax Credit Amortization**

| 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>30 Year Property</u> | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 6 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 7 | Annual ITC Amortization | Line 5 x Line 6 | [redacted] | | | | | | | | | |
| 8 | Cumulative ITC Amortization | CY Line 7 + PY Line 8 | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | <u>30 Year Property</u> | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 | 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 16 | Annual ITC Amortization | Line 14 x Line 15 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 | 6,000 |
| 17 | Cumulative ITC Amortization | CY Line 16 + PY Line 17 | $ 126,000 | $ 132,000 | $ 138,000 | $ 144,000 | $ 150,000 | $ 156,000 | $ 162,000 | $ 168,000 | $ 174,000 | $ 180,000 |
| 18 | | | | | | | | | | | | |
| 19 | <u>15 Year Property</u> | | | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | | | | | | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 23 | Investment Tax Credit | Line 21 x Line 22 | | | | | | | | | | |
| 24 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | | | | | |
| 25 | Annual ITC Amortization | Line 23 x Line 24 | | | | | | | | | | |
| 26 | Cumulative ITC Amortization | CY Line 25 + PY Line 26 | | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | <u>15 Year Property</u> | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| 31 | Investment Tax Credit Rate | Expected Rate | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| 32 | Investment Tax Credit | Line 30 x Line 31 | - | - | - | - | - | - | - | - | - | - |
| 33 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 34 | Annual ITC Amortization | Line 32 x Line 33 | - | - | - | - | - | - | - | - | - | - |
| 35 | Cumulative ITC Amortization | CY Line 34 + PY Line 35 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | | | | | | | | | | | | |
| 37 | Total Annual ITC Amortization | Line 7 + Line 16 + Line 25 + Line 34 | [redacted] | | | | | | | | | |
| 38 | Total Cumulative ITC Amortization | CY Line 37 + PY Line 38 | | | | | | | | | | |
| 39 | | | | | | | | | | | | |
| 40 | Tax Gross-Up | Line 37 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total Cumulative Tax Gross-Up | CY Line 40 + PY Line 41 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 10**
**Investment Tax Credit Tax Effect**

| 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 | <u>30 Year Property</u> | | [redacted] | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 5 x 50% | | | | | | | | | | |
| 7 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 8 | Book Depreciation on ITC Basis Reduction | Line 6 x Line 7 | [redacted] | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | <u>30 Year Property</u> | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | $ 600,000 | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 14 x 50% | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 |
| 16 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 17 | Book Depreciation on ITC Basis Reduction | Line 15 x Line 16 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 |
| 18 | | | | | | | | | | | | |
| 19 | <u>15 Year Property</u> | | | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | | | | | | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 23 | Investment Tax Credit | Line 21 x Line 22 | [redacted] | | | | | | | | | |
| 24 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 23 x 50% | | | | | | | | | | |
| 25 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 26 | Book Depreciation on ITC Basis Reduction | Line 24 x Line 25 | [redacted] | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | <u>15 Year Property</u> | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | | | | | | | | | | |
| 31 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 32 | Investment Tax Credit | Line 30 x Line 31 | | | | | | | | | | |
| 33 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 32 x 50% | | | | | | | | | | |
| 34 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | | | | | |
| 35 | Book Depreciation on ITC Basis Reduction | Line 33 x Line 34 | | | | | | | | | | |
| 36 | | | | | | | | | | | | |
| 37 | Flowthrough Items | Line 8 + Line 17 + Line 26 + Line 35 | [redacted] | | | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Tax Impact of Flowthrough Item | Line 37 x 21% Federal Tax Rate | | | | | | | | | | |
| 40 | Tax Gross Up | Line 39 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total ITC Tax Effect | Line 39 + Line 40 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 10**
**Investment Tax Credit Tax Effect**

| 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 | 30 Year Property | | | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | [redacted] | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 5 x 50% | | | | | | | | | | |
| 7 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 8 | Book Depreciation on ITC Basis Reduction | Line 6 x Line 7 | [redacted] | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | 30 Year Property | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 14 x 50% | 90,000 | 90,000 | 90,000 | 90,000 | 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 |
| 16 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 17 | Book Depreciation on ITC Basis Reduction | Line 15 x Line 16 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 |
| 18 | | | | | | | | | | | | |
| 19 | 15 Year Property | | | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | [redacted] | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | | | | | | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | | | | | |
| 23 | Investment Tax Credit | Line 21 x Line 22 | [redacted] | | | | | | | | | |
| 24 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 23 x 50% | | | | | | | | | | |
| 25 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | | | | | |
| 26 | Book Depreciation on ITC Basis Reduction | Line 24 x Line 25 | [redacted] | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | 15 Year Property | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | | | | | | [redacted] | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | | | | | | | | | | |
| 31 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 32 | Investment Tax Credit | Line 30 x Line 31 | | | | | | - | - | - | - | - |
| 33 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 32 x 50% | | | | | | $ - | $ - | $ - | $ - | $ - |
| 34 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 35 | Book Depreciation on ITC Basis Reduction | Line 33 x Line 34 | | | | | | $ - | $ - | $ - | $ - | $ - |
| 36 | | | | | | | | | | | | |
| 37 | Flowthrough Items | Line 8 + Line 17 + Line 26 + Line 35 | [redacted] | | | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Tax Impact of Flowthrough Item | Line 37 x 21% Federal Tax Rate | | | | | | | | | | |
| 40 | Tax Gross Up | Line 39 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total ITC Tax Effect | Line 39 + Line 40 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 10**
**Investment Tax Credit Tax Effect**

| 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>30 Year Property</u> | | [redacted] | | | | | | | | | |
| 2 | PV Facility Installation | Capital Costs, Line 43 | | | | | | | | | | |
| 3 | Cumulative Investment Tax Basis | CY Line 2 + PY Line 3 | | | | | | | | | | |
| 4 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 5 | Investment Tax Credit | Line 3 x Line 4 | [redacted] | | | | | | | | | |
| 6 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 5 x 50% | | | | | | | | | | |
| 7 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 8 | Book Depreciation on ITC Basis Reduction | Line 6 x Line 7 | [redacted] | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | <u>30 Year Property</u> | | | | | | | | | | | |
| 11 | Electric System Upgrades | Capital Costs, Line 46 | | | | | | | | | | |
| 12 | Cumulative Investment Tax Basis | CY Line 11 + PY Line 12 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 | $ 600,000 |
| 13 | Investment Tax Credit Rate | Expected Rate | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% | 30.00% |
| 14 | Investment Tax Credit | Line 12 x Line 13 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 | 180,000 |
| 15 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 14 x 50% | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 | $ 90,000 |
| 16 | Annual ITC Amortization Rate | Annual Amortization Rate @ 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% | 3.33% |
| 17 | Book Depreciation on ITC Basis Reduction | Line 15 x Line 16 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 | $ 3,000 |
| 18 | | | | | | | | | | | | |
| 19 | <u>15 Year Property</u> | | | | | | | | | | | |
| 20 | Solar Inverter 1 | Capital Costs, Line 44 | | | | | | | | | | |
| 21 | Cumulative Investment Tax Basis | CY Line 20 + PY Line 21 | | | | | | | | | | |
| 22 | Investment Tax Credit Rate | Expected Rate | | | | | | | | | | |
| 23 | Investment Tax Credit | Line 21 x Line 22 | | | | | | | | | | |
| 24 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 23 x 50% | | | | | | | | | | |
| 25 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | | | | | | | | | | |
| 26 | Book Depreciation on ITC Basis Reduction | Line 24 x Line 25 | | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | <u>15 Year Property</u> | | | | | | | | | | | |
| 29 | Solar Inverter 2 | Capital Costs, Line 45 | [redacted] | | | | | | | | | |
| 30 | Cumulative Investment Tax Basis | CY Line 29 + PY Line 30 | | | | | | | | | | |
| 31 | Investment Tax Credit Rate | Expected Rate | - | - | - | - | - | - | - | - | - | - |
| 32 | Investment Tax Credit | Line 30 x Line 31 | - | - | - | - | - | - | - | - | - | - |
| 33 | ITC Tax Depreciation Reduction at 50% ITC Rate | Line 32 x 50% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 34 | Annual ITC Amortization Rate | Annual Amortization Rate @ 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% | 6.67% |
| 35 | Book Depreciation on ITC Basis Reduction | Line 33 x Line 34 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | | | | | | | | | | | | |
| 37 | Flowthrough Items | Line 8 + Line 17 + Line 26 + Line 35 | [redacted] | | | | | | | | | |
| 38 | | | | | | | | | | | | |
| 39 | Tax Impact of Flowthrough Item | Line 37 x 21% Federal Tax Rate | | | | | | | | | | |
| 40 | Tax Gross Up | Line 39 x (Cost of Capital, Line 20 - 1) | | | | | | | | | | |
| 41 | Total ITC Tax Effect | Line 39 + Line 40 | | | | | | | | | | |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 11**
**Capital Cost Estimate Schedule**

| Line No. | Description | Reference | (a) | (b) | (c) |
|---|---|---|---|---|---|
| 1 | Detailed Capital Cost Estimates | | | | |
| 2 | | | | | |
| 3 | Facility Installation Costs | | Cost | Labor Adjustment | Labor Adjusted [1] |
| 4 | Solar Inverter 1 and Associated Material | Exhibit JSD-1 | $ [redacted] | [redacted] | $ [redacted] |
| 5 | PV Modules and Associated Material | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 6 | Step-up Transformer and Associated Material | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 7 | Fencing | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 8 | All Other Material | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 9 | Project Management | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 10 | Construction Field Representative | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 11 | Spare Step-Up Transformer | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 12 | Spare Inverter | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 13 | Spare PV Modules (5) | Exhibit JSD-1 | [redacted] | [redacted] | [redacted] |
| 14 | Labor | Exhibit JSD-1 | [redacted] | | [redacted] |
| 15 | Total Facility Installation Costs | Sum Lines 4 through 14 | $ [redacted] | 100.0% | $ [redacted] |
| 16 | | | | | [redacted] |
| 17 | Electric System Upgrades | | Cost | | |
| 18 | System Impact Study | Exhibit JSD-1 | $ 75,000 | | |
| 19 | POI Material & Installation | Exhibit JSD-1 | 350,000 | | |
| 20 | Tap 3345 Line with GOAB | Exhibit JSD-1 | 50,000 | | |
| 21 | Kingston Relaying Upgrades | Exhibit JSD-1 | 125,000 | | |
| 22 | Total Electric System Upgrades | Sum Lines 18 through 21 | $ 600,000 | | |
| 23 | | | | | |
| 24 | Land Improvements | | Cost | | |
| 25 | Site Due Diligence, Design and Permitting | Exhibit JSD-1 | $ [redacted] | | |
| 26 | Site Work | Exhibit JSD-1 | 550,000 | | |
| 27 | Total Land Improvements | Sum Lines 25 through 26 | $ [redacted] | | |
| 28 | | | | | |
| 29 | Land Acquisition Costs | | Cost | | |
| 30 | Site Identification | Exhibit JSD-1 | $ 25,000 | | |
| 31 | Purchase Price | Exhibit JSD-1 | [redacted] | | |
| 32 | Transfer Tax | Exhibit JSD-1 | [redacted] | | |
| 33 | Commission covered by Unitil | Exhibit JSD-1 | [redacted] | | |
| 34 | CU Penalty | Exhibit JSD-1 | [redacted] | | |
| 35 | Title Search | Exhibit JSD-1 | 10,500 | | |
| 36 | Appraisal | Exhibit JSD-1 | [redacted] | | |
| 37 | Total Land Acquisitions Costs | Sum Lines 30 through 36 | $ 1,715,876 | | |
| 38 | | | | | |
| 39 | Total Capital Costs | Line 15 + Line 22 + Line 27 + Line 37 | $ 14,086,043 | | |

| Line No. | Description | Reference | (a) |
|---|---|---|---|
| 40 | Summarized Capital Cost Estimates | | |
| 41 | | | |
| 42 | Depreciable Plant Additions | | Cost |
| 43 | PV Facility Installation | Sum Column (c) Lines 5 through 14 | $ [redacted] |
| 44 | Solar Inverter 1 | Column (c), Line 4 | [redacted] |
| 45 | Solar Inverter 2 (Year 15) [2] | Future Value of Solar Inverter 1 | [redacted] |
| 46 | Electric System Upgrades | Line 22 | 600,000 |
| 47 | Total | Sum Lines 43 through 46 | $ 12,142,672 |
| 48 | | | |
| 49 | Non-Depreciable Plant Additions [3] | | Cost |
| 50 | Land Improvements | Line 27 | $ [redacted] |
| 51 | Land Acquisition Costs | Line 37 x 50% | 857,938 |
| 52 | Total | Line 50 + Line 51 | $ [redacted] |

**Notes**
(1) Labor allocated based on proportional cost of line item
(2) Assumes a 15-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 FDGP-2, Benefit-Cost Analysis**
**Schedule 12**
**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

NH Docket No. DE 22-___


**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 13**
**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 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3-Year | 33.33% | 44.45% | 14.81% | 7.41% | | | | | | | |
| 2 | 5-Year | 20.00% | 32.00% | 19.20% | 11.52% | 11.52% | 5.76% | | | | | |
| 3 | 7-Year | 14.29% | 24.49% | 17.49% | 12.49% | 8.93% | 8.92% | 8.93% | 4.46% | | | |
| 4 | 10-Year | 10.00% | 18.00% | 14.40% | 11.52% | 9.22% | 7.37% | 6.55% | 6.55% | 6.56% | 6.55% | 3.28% |
| 5 | 15-Year | 5.00% | 9.50% | 8.55% | 7.70% | 6.93% | 6.23% | 5.90% | 5.90% | 5.91% | 5.90% | 5.91% |
| 6 | 20-Year | 3.75% | 7.22% | 6.68% | 6.18% | 5.71% | 5.29% | 4.89% | 4.52% | 4.46% | 4.46% | 4.46% |

**Unitil Energy Systems d/b/a Unitil**
**Exhibit FDGP-2, Benefit-Cost Analysis**
**Schedule 13**
**IRS Publication 946 Table A-1**
**MACRS Half-Year Depreciation Rates**

| Line No. | Recovery Year | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3-Year | | | | | | | | | | |
| 2 | 5-Year | | | | | | | | | | |
| 3 | 7-Year | | | | | | | | | | |
| 4 | 10-Year | | | | | | | | | | |
| 5 | 15-Year | 5.90% | 5.91% | 5.90% | 5.91% | 2.95% | | | | | |
| 6 | 20-Year | 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 30**

| 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 | Year 15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (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 | $ 0.00157 | $ 0.00148 | $ 0.00139 | $ 0.00133 | $ 0.00127 | $ 0.00122 | $ 0.00118 | $ 0.00114 | $ 0.00111 | $ 0.00108 | $ 0.00105 | $ 0.00101 | $ 0.00098 | $ 0.00095 | $ 0.00095 |
| 4 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 5 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 6 | Average Usage kWh | Page 3, Line 16 / Line 15 | 633 | 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** | **$ 0.18** | **$ 0.21** | **$ 0.17** | **$ 0.14** | **$ 0.10** | **$ 0.06** | **$ 0.03** | **$ 0.01** | **$ (0.02)** | **$ (0.05)** | **$ (0.08)** | **$ (0.10)** | **$ (0.13)** | **$ (0.16)** | **$ (0.17)** |
| 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 | $ 0.00157 | $ 0.00148 | $ 0.00139 | $ 0.00133 | $ 0.00127 | $ 0.00122 | $ 0.00118 | $ 0.00114 | $ 0.00111 | $ 0.00108 | $ 0.00105 | $ 0.00101 | $ 0.00098 | $ 0.00095 | $ 0.00095 |
| 11 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 12 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 13 | Average Usage kWh | Page 3, Line 24 / Line 23 | 97 | 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** | **$ 0.03** | **$ 0.03** | **$ 0.03** | **$ 0.02** | **$ 0.02** | **$ 0.01** | **$ 0.00** | **$ 0.00** | **$ (0.00)** | **$ (0.01)** | **$ (0.01)** | **$ (0.02)** | **$ (0.02)** | **$ (0.02)** | **$ (0.03)** |
| 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 | $ 0.00157 | $ 0.00148 | $ 0.00139 | $ 0.00133 | $ 0.00127 | $ 0.00122 | $ 0.00118 | $ 0.00114 | $ 0.00111 | $ 0.00108 | $ 0.00105 | $ 0.00101 | $ 0.00098 | $ 0.00095 | $ 0.00095 |
| 18 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 19 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 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 | 1,451 |
| **21** | **Average Regular General (G2 QR WH/SH) Monthly Bill Impact** | **(Line 17 + Line 18 + Line 19) * Line 20** | **$ 0.41** | **$ 0.48** | **$ 0.39** | **$ 0.33** | **$ 0.23** | **$ 0.14** | **$ 0.07** | **$ 0.01** | **$ (0.05)** | **$ (0.11)** | **$ (0.17)** | **$ (0.23)** | **$ (0.30)** | **$ (0.36)** | **$ (0.38)** |
| 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 | $ 0.39720 | $ 0.37448 | $ 0.35200 | $ 0.33518 | $ 0.32048 | $ 0.30739 | $ 0.29749 | $ 0.28919 | $ 0.28089 | $ 0.27260 | $ 0.26431 | $ 0.25603 | $ 0.24776 | $ 0.23949 | $ 0.23952 |
| 26 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 27 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 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 | 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 | 10 |
| **30** | **Average Regular General (G2 Demand) Monthly Bill Impact** | **(Line 26 + Line 27) * Line 28 + Line 25 * Line 29** | **$ 0.69** | **$ 0.81** | **$ 0.66** | **$ 0.56** | **$ 0.39** | **$ 0.24** | **$ 0.12** | **$ 0.02** | **$ (0.08)** | **$ (0.19)** | **$ (0.29)** | **$ (0.40)** | **$ (0.51)** | **$ (0.62)** | **$ (0.65)** |
| 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 | $ 0.50220 | $ 0.47348 | $ 0.44505 | $ 0.42378 | $ 0.40521 | $ 0.38865 | $ 0.37613 | $ 0.36564 | $ 0.35514 | $ 0.34466 | $ 0.33418 | $ 0.32372 | $ 0.31326 | $ 0.30280 | $ 0.30285 |
| 35 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 36 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 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 | 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 | 498 |
| **39** | **Average Large General (G1 Demand) Monthly Bill Impact** | **(Line 35 + Line 36) * Line 37 + Line 34 * Line 54** | **$ 44.58** | **$ 52.09** | **$ 42.59** | **$ 36.15** | **$ 25.47** | **$ 15.78** | **$ 8.07** | **$ 1.34** | **$ (5.40)** | **$ (12.17)** | **$ (18.95)** | **$ (25.76)** | **$ (32.78)** | **$ (39.83)** | **$ (41.68)** |
| 40 | Outdoor Lighting (OL): | | | | | | | | | | | | | | | | |
| 41 | Average Luminaire Charge | Page 3, Line 65 Change over Current Rates | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.09 | $ 0.09 | $ 0.09 | $ 0.08 | $ 0.08 | $ 0.08 | $ 0.08 | $ 0.07 | $ 0.07 | $ 0.07 | $ 0.07 | $ 0.07 |
| 42 | Distribution kWh Charge ($/kWh) | Page 3, Line 66 Change over Current Rates | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 43 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 44 | Default Service | Page 2, Line 8 | $ (0.00090) | $ (0.00076) | $ (0.00074) | $ (0.00071) | $ (0.00072) | $ (0.00073) | $ (0.00074) | $ (0.00075) | $ (0.00076) | $ (0.00077) | $ (0.00078) | $ (0.00079) | $ (0.00080) | $ (0.00081) | $ (0.00082) |
| 45 | Average Usage kWh | Page 3, Line 68 / Line 67 | 70 | 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** | **$ 0.02** | **$ 0.02** | **$ 0.02** | **$ 0.02** | **$ 0.01** | **$ 0.01** | **$ 0.00** | **$ 0.00** | **$ (0.00)** | **$ (0.01)** | **$ (0.01)** | **$ (0.01)** | **$ (0.01)** | **$ (0.02)** | **$ (0.02)** |

**UNITIL ENERGY SYSTEMS, INC. D/B/A UNITIL**
**BILL IMPACT ANALYSIS**
**YEAR 1 THROUGH YEAR 30**

| Line # | Rate Class | Source | 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 | Year 29 | Year 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | | (q) | (r) | (s) | (t) | (u) | (v) | (w) | (x) | (y) | (z) | (aa) | (ab) | (ac) | (ad) | (ae) |
| 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 | $ 0.00095 | $ 0.00091 | $ 0.00088 | $ 0.00084 | $ 0.00081 | $ 0.00077 | $ 0.00074 | $ 0.00071 | $ 0.00067 | $ 0.00064 | $ 0.00061 | $ 0.00058 | $ 0.00054 | $ 0.00051 | $ 0.00048 |
| 4 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 5 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 6 | Average Usage kWh | Page 3, Line 16 / Line 15 | 633 | 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** | **$ (0.17)** | **$ (0.20)** | **$ (0.23)** | **$ (0.26)** | **$ (0.29)** | **$ (0.32)** | **$ (0.35)** | **$ (0.38)** | **$ (0.41)** | **$ (0.44)** | **$ (0.47)** | **$ (0.50)** | **$ (0.53)** | **$ (0.56)** | **$ (0.59)** |
| 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 | $ 0.00095 | $ 0.00091 | $ 0.00088 | $ 0.00084 | $ 0.00081 | $ 0.00077 | $ 0.00074 | $ 0.00071 | $ 0.00067 | $ 0.00064 | $ 0.00061 | $ 0.00058 | $ 0.00054 | $ 0.00051 | $ 0.00048 |
| 11 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 12 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 13 | Average Usage kWh | Page 3, Line 24 / Line 23 | 97 | 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** | **$ (0.03)** | **$ (0.03)** | **$ (0.04)** | **$ (0.04)** | **$ (0.04)** | **$ (0.05)** | **$ (0.05)** | **$ (0.06)** | **$ (0.06)** | **$ (0.07)** | **$ (0.07)** | **$ (0.08)** | **$ (0.08)** | **$ (0.09)** | **$ (0.09)** |
| 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 | $ 0.00095 | $ 0.00091 | $ 0.00088 | $ 0.00084 | $ 0.00081 | $ 0.00077 | $ 0.00074 | $ 0.00071 | $ 0.00067 | $ 0.00064 | $ 0.00061 | $ 0.00058 | $ 0.00054 | $ 0.00051 | $ 0.00048 |
| 18 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 19 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 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 | 1,451 |
| **21** | **Average Regular General (G2 QR WH/SH) Monthly Bill Impact** | **(Line 17 + Line 18 + Line 19) * Line 20** | **$ (0.39)** | **$ (0.46)** | **$ (0.53)** | **$ (0.60)** | **$ (0.67)** | **$ (0.74)** | **$ (0.81)** | **$ (0.87)** | **$ (0.94)** | **$ (1.01)** | **$ (1.08)** | **$ (1.14)** | **$ (1.21)** | **$ (1.28)** | **$ (1.35)** |
| 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 | $ 0.24002 | $ 0.23088 | $ 0.22176 | $ 0.21294 | $ 0.20423 | $ 0.19561 | $ 0.18715 | $ 0.17879 | $ 0.17043 | $ 0.16208 | $ 0.15374 | $ 0.14541 | $ 0.13709 | $ 0.12878 | $ 0.12047 |
| 26 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 27 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 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 | 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 | 10 |
| **30** | **Average Regular General (G2 Demand) Monthly Bill Impact** | **(Line 26 + Line 27) * Line 28 + Line 25 * Line 29** | **$ (0.67)** | **$ (0.79)** | **$ (0.91)** | **$ (1.02)** | **$ (1.14)** | **$ (1.26)** | **$ (1.37)** | **$ (1.48)** | **$ (1.60)** | **$ (1.71)** | **$ (1.83)** | **$ (1.94)** | **$ (2.06)** | **$ (2.17)** | **$ (2.29)** |
| 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 | $ 0.30347 | $ 0.29192 | $ 0.28039 | $ 0.26923 | $ 0.25822 | $ 0.24732 | $ 0.23663 | $ 0.22605 | $ 0.21548 | $ 0.20493 | $ 0.19438 | $ 0.18385 | $ 0.17333 | $ 0.16282 | $ 0.15232 |
| 35 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 36 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 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 | 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 | 498 |
| **39** | **Average Large General (G1 Demand) Monthly Bill Impact** | **(Line 35 + Line 36) * Line 37 + Line 34 * Line 54** | **$ (43.27)** | **$ (50.94)** | **$ (58.63)** | **$ (66.16)** | **$ (73.65)** | **$ (81.10)** | **$ (88.48)** | **$ (95.84)** | **$ (103.21)** | **$ (110.61)** | **$ (118.03)** | **$ (125.48)** | **$ (132.94)** | **$ (140.43)** | **$ (147.94)** |
| 40 | Outdoor Lighting (OL): | | | | | | | | | | | | | | | | |
| 41 | Average Luminaire Charge | Page 3, Line 65 Change over Current Rates | $ 0.07 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.03 |
| 42 | Distribution kWh Charge ($/kWh) | Page 3, Line 66 Change over Current Rates | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 43 | External Delivery Charge | Page 2, Line 5 | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) | $ (0.00039) |
| 44 | Default Service | Page 2, Line 8 | $ (0.00083) | $ (0.00085) | $ (0.00086) | $ (0.00087) | $ (0.00088) | $ (0.00090) | $ (0.00091) | $ (0.00092) | $ (0.00093) | $ (0.00095) | $ (0.00096) | $ (0.00098) | $ (0.00099) | $ (0.00100) | $ (0.00102) |
| 45 | Average Usage kWh | Page 3, Line 68 / Line 67 | 70 | 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** | **$ (0.02)** | **$ (0.02)** | **$ (0.03)** | **$ (0.03)** | **$ (0.03)** | **$ (0.04)** | **$ (0.04)** | **$ (0.04)** | **$ (0.05)** | **$ (0.05)** | **$ (0.05)** | **$ (0.06)** | **$ (0.06)** | **$ (0.06)** | **$ (0.07)** |

**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 |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1 | Reduction in Allocated LNS Cost | | $ 11,797 | $ 11,973 | $ 12,151 | $ 12,331 | $ 12,514 | $ 12,699 | $ 12,887 | $ 13,077 |
| 2 | Reduction in Allocated RNS Cost | | 87,050 | 88,347 | 89,662 | 90,993 | 92,342 | 93,708 | 95,092 | 96,494 |
| 3 | Total Transmission Cost Savings(1) | External Delivery Charge ("EDC") | $ 98,847 | $ 100,320 | $ 101,812 | $ 103,324 | $ 104,856 | $ 106,407 | $ 107,978 | $ 109,570 |
| 4 | REC Revenues(2) | External Delivery Charge ("EDC") | 352,800 | 351,036 | 349,272 | 347,508 | 345,744 | 343,980 | 342,216 | 340,452 |
| 5 | **External Delivery Charge Impact $/kWh** | | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** |
| 6 | Reduction in Energy Cost | | $ 968,235 | $ 809,903 | $ 776,620 | $ 747,078 | $ 758,152 | $ 769,369 | $ 780,732 | $ 792,242 |
| 7 | Reduction in Capacity Cost | | 77,922 | 77,532 | 77,143 | 76,753 | 76,363 | 75,974 | 75,584 | 75,195 |
| 8 | Total Avoided Cost of Energy/Capacity | Energy Service for All Customers | $ 1,046,157 | $ 887,436 | $ 853,762 | $ 823,831 | $ 834,515 | $ 845,343 | $ 856,317 | $ 867,437 |
| 9 | **Average Energy Service Impact $/kWh** | | **$ (0.00090)** | **$ (0.00076)** | **$ (0.00074)** | **$ (0.00071)** | **$ (0.00072)** | **$ (0.00073)** | **$ (0.00074)** | **$ (0.00075)** |
| 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 |
| 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 |
| 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 |
| 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 |
| 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 |

| Line # | Customer Benefits | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 |
|---|---|---|---|---|---|---|---|---|
| | (a) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| 1 | Reduction in Allocated LNS Cost | $ 13,269 | $ 13,464 | $ 13,661 | $ 13,861 | $ 14,064 | $ 14,269 | $ 14,476 |
| 2 | Reduction in Allocated RNS Cost | 97,914 | 99,352 | 100,808 | 102,283 | 103,777 | 105,289 | 106,821 |
| 3 | Total Transmission Cost Savings(1) | $ 111,183 | $ 112,816 | $ 114,470 | $ 116,144 | $ 117,840 | $ 119,558 | $ 121,297 |
| 4 | REC Revenues(2) | 338,688 | 336,924 | 335,160 | 333,396 | 331,632 | 329,868 | 328,104 |
| 5 | **External Delivery Charge Impact $/kWh** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** |
| 6 | Reduction in Energy Cost | $ 803,900 | $ 815,707 | $ 827,665 | $ 839,775 | $ 852,039 | $ 864,457 | $ 877,031 |
| 7 | Reduction in Capacity Cost | 74,805 | 74,415 | 74,026 | 73,636 | 74,712 | 75,800 | 76,903 |
| 8 | Total Avoided Cost of Energy/Capacity | $ 878,705 | $ 890,123 | $ 901,691 | $ 913,411 | $ 926,750 | $ 940,257 | $ 953,934 |
| 9 | **Average Energy Service Impact $/kWh** | **$ (0.00076)** | **$ (0.00077)** | **$ (0.00078)** | **$ (0.00079)** | **$ (0.00080)** | **$ (0.00081)** | **$ (0.00082)** |
| 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 |
| 12 | Regular General | 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 |
| 14 | Outdoor Lighting | 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) Lower Allocated Costs based on lower peak load
(2) Lower wholesale supplier costs
(3) No impact to Default b/c transferring at market

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

| Line # | Customer Benefits | Recovery Mechanism | 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 | Year 29 | Year 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (r) | (s) | (t) | (u) | (v) | (w) | (x) | (y) | (z) | (aa) | (ab) | (ac) | (ad) | (ae) | (af) |
| 1 | Reduction in Allocated LNS Cost | | $ 14,686 | $ 14,899 | $ 15,114 | $ 15,332 | $ 15,553 | $ 15,777 | $ 16,003 | $ 16,232 | $ 16,463 | $ 16,698 | $ 16,935 | $ 17,175 | $ 17,418 | $ 17,663 | $ 17,912 |
| 2 | Reduction in Allocated RNS Cost | | 108,371 | 109,941 | 111,531 | 113,140 | 114,768 | 116,417 | 118,086 | 119,774 | 121,484 | 123,213 | 124,963 | 126,734 | 128,526 | 130,339 | 132,173 |
| 3 | Total Transmission Cost Savings[(1)] | External Delivery Charge ("EDC") | $ 123,058 | $ 124,840 | $ 126,645 | $ 128,472 | $ 130,322 | $ 132,194 | $ 134,088 | $ 136,006 | $ 137,947 | $ 139,911 | $ 141,898 | $ 143,909 | $ 145,944 | $ 148,002 | $ 150,084 |
| 4 | REC Revenues[(2)] | External Delivery Charge ("EDC") | 326,340 | 324,576 | 322,812 | 321,048 | 319,284 | 317,520 | 315,756 | 313,992 | 312,228 | 310,464 | 308,700 | 306,936 | 305,172 | 303,408 | 301,644 |
| 5 | **External Delivery Charge Impact $/kWh** | | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** | **$ (0.00039)** |
| 6 | Reduction in Energy Cost | | $ 889,762 | $ 902,651 | $ 915,700 | $ 928,910 | $ 942,283 | $ 955,818 | $ 969,518 | $ 983,384 | $ 997,417 | $ 1,011,617 | $ 1,025,987 | $ 1,040,526 | $ 1,055,237 | $ 1,070,120 | $ 1,085,177 |
| 7 | Reduction in Capacity Cost | | 78,019 | 79,150 | 80,294 | 81,452 | 82,625 | 83,811 | 85,013 | 86,229 | 87,459 | 88,704 | 89,964 | 91,239 | 92,529 | 93,834 | 95,154 |
| 8 | Total Avoided Cost of Energy/Capacity | Energy Service for All Customers | $ 967,781 | $ 981,801 | $ 995,994 | $ 1,010,363 | $ 1,024,907 | $ 1,039,630 | $ 1,054,531 | $ 1,069,613 | $ 1,084,876 | $ 1,100,321 | $ 1,115,951 | $ 1,131,766 | $ 1,147,766 | $ 1,163,955 | $ 1,180,331 |
| 9 | **Average Energy Service Impact $/kWh** | | **$ (0.00083)** | **$ (0.00085)** | **$ (0.00086)** | **$ (0.00087)** | **$ (0.00088)** | **$ (0.00090)** | **$ (0.00091)** | **$ (0.00092)** | **$ (0.00093)** | **$ (0.00095)** | **$ (0.00096)** | **$ (0.00098)** | **$ (0.00099)** | **$ (0.00100)** | **$ (0.00102)** |
| 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 | 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 | 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 | 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 | 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 | 1,160,418,601 | 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

**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 | Year 13 | Year 14 | Year 15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) |
| 1 | Annual Revenue Requirement | | $ 1,822,979 | $ 1,718,730 | $ 1,615,519 | $ 1,538,322 | $ 1,470,895 | $ 1,410,804 | $ 1,365,357 | $ 1,327,246 | $ 1,289,162 | $ 1,251,106 | $ 1,213,077 | $ 1,175,078 | $ 1,137,107 | $ 1,099,168 | $ 1,099,324 |
| 2 | Revenue Requirement Change | | $ 1,822,979 | $ (104,249) | $ (103,211) | $ (77,197) | $ (67,426) | $ (60,092) | $ (45,447) | $ (38,111) | $ (38,084) | $ (38,057) | $ (38,028) | $ (38,000) | $ (37,970) | $ (37,940) | $ 157 |
| | | | | | | | | | | | | | | | | | |
| 3 | **Allocation based on 2020 TY kWh:** | | | | | | | | | | | | | | | | |
| 4 | Residential (Rate D) | | $ 810,570 | $ (46,353) | $ (45,892) | $ (34,325) | $ (29,980) | $ (26,719) | $ (20,207) | $ (16,946) | $ (16,934) | $ (16,921) | $ (16,909) | $ (16,896) | $ (16,883) | $ (16,870) | $ 70 |
| 5 | Regular General (Rate G2-kWh) | | 689 | (39) | (39) | (29) | (25) | (23) | (17) | (14) | (14) | (14) | (14) | (14) | (14) | (14) | 0 |
| 6 | Regular General (Rate G2 - QR WH/SH) | | 7,044 | (403) | (399) | (298) | (261) | (232) | (176) | (147) | (147) | (147) | (147) | (147) | (147) | (147) | 1 |
| 7 | Regular General (Rate G2) | | 490,353 | (28,041) | (27,762) | (20,765) | (18,137) | (16,164) | (12,224) | (10,251) | (10,244) | (10,237) | (10,229) | (10,221) | (10,213) | (10,205) | 42 |
| 8 | Large General (Rate G1) | | 502,344 | (28,727) | (28,441) | (21,273) | (18,580) | (16,559) | (12,523) | (10,502) | (10,495) | (10,487) | (10,479) | (10,471) | (10,463) | (10,455) | 43 |
| 9 | Outdoor Lighting (Rate OL) | | 11,980 | (685) | (678) | (507) | (443) | (395) | (299) | (250) | (250) | (250) | (250) | (250) | (250) | (249) | 1 |
| 10 | **Total** | | $ 1,822,979 | $ (104,249) | $ (103,211) | $ (77,197) | $ (67,426) | $ (60,092) | $ (45,447) | $ (38,111) | $ (38,084) | $ (38,057) | $ (38,028) | $ (38,000) | $ (37,970) | $ (37,940) | $ 157 |
| | | | | | | | | | | | | | | | | | |
| 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 | $ 16.22 | $ 16.22 |
| 14 | Distribution kWh Charge ($/kWh) | $ 0.04511 | $ 0.04668 | $ 0.04659 | $ 0.04650 | $ 0.04644 | $ 0.04638 | $ 0.04633 | $ 0.04629 | $ 0.04625 | $ 0.04622 | $ 0.04619 | $ 0.04616 | $ 0.04612 | $ 0.04609 | $ 0.04606 | $ 0.04606 |
| 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 | 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 | 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 | $ 13,223,834 | $ 13,223,834 |
| 18 | Distribution kWh Charge Revenues | 23,275,483 | 24,086,052 | 24,039,699 | 23,993,807 | 23,959,482 | 23,929,502 | 23,902,782 | 23,882,575 | 23,865,629 | 23,848,696 | 23,831,774 | 23,814,865 | 23,797,969 | 23,781,086 | 23,764,216 | 23,764,286 |
| 19 | Total Rate D Revenues | $ 36,499,316 | $ 37,309,886 | $ 37,263,532 | $ 37,217,641 | $ 37,183,316 | $ 37,153,335 | $ 37,126,616 | $ 37,106,409 | $ 37,089,463 | $ 37,072,529 | $ 37,055,608 | $ 37,038,699 | $ 37,021,803 | $ 37,004,920 | $ 36,988,050 | $ 36,988,120 |
| | | | | | | | | | | | | | | | | | |
| 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 | $ 18.38 | $ 18.38 |
| 22 | Distribution kWh Charge ($/kWh) | $ 0.02933 | $ 0.03090 | $ 0.03081 | $ 0.03072 | $ 0.03066 | $ 0.03060 | $ 0.03055 | $ 0.03051 | $ 0.03047 | $ 0.03044 | $ 0.03041 | $ 0.03038 | $ 0.03034 | $ 0.03031 | $ 0.03028 | $ 0.03028 |
| 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 | 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 | 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 | $ 83,500 | $ 83,500 |
| 26 | Distribution kWh Charge Revenues | 12,868 | 13,558 | 13,518 | 13,479 | 13,450 | 13,425 | 13,402 | 13,385 | 13,370 | 13,356 | 13,341 | 13,327 | 13,313 | 13,298 | 13,284 | 13,284 |
| 27 | Total Rate G2-kWh Revenues | $ 96,369 | $ 97,058 | $ 97,019 | $ 96,980 | $ 96,950 | $ 96,925 | $ 96,902 | $ 96,885 | $ 96,871 | $ 96,856 | $ 96,842 | $ 96,827 | $ 96,813 | $ 96,799 | $ 96,784 | $ 96,784 |
| | | | | | | | | | | | | | | | | | |
| 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 | $ 9.73 | $ 9.73 |
| 30 | Distribution kWh Charge ($/kWh) | $ 0.03599 | $ 0.03756 | $ 0.03747 | $ 0.03738 | $ 0.03731 | $ 0.03725 | $ 0.03720 | $ 0.03716 | $ 0.03713 | $ 0.03710 | $ 0.03706 | $ 0.03703 | $ 0.03700 | $ 0.03697 | $ 0.03693 | $ 0.03693 |
| 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 | 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 | 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 | $ 30,056 | $ 30,056 |
| 34 | Distribution kWh Charge Revenues | 161,350 | 168,393 | 167,990 | 167,592 | 167,293 | 167,033 | 166,801 | 166,625 | 166,478 | 166,331 | 166,184 | 166,037 | 165,890 | 165,743 | 165,597 | 165,597 |
| 35 | Total Rate G2 Qr W/H Revenues | $ 191,406 | $ 198,449 | $ 198,046 | $ 197,648 | $ 197,349 | $ 197,089 | $ 196,857 | $ 196,681 | $ 196,534 | $ 196,387 | $ 196,240 | $ 196,093 | $ 195,946 | $ 195,799 | $ 195,653 | $ 195,653 |
| | | | | | | | | | | | | | | | | | |
| 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 | $ 29.19 | $ 29.19 |
| 38 | Distribution kWh Charge ($/kWh) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 39 | Distribution kW Charge ($/kW) | $ 11.91 | $ 12.31 | $ 12.29 | $ 12.26 | $ 12.25 | $ 12.23 | $ 12.22 | $ 12.21 | $ 12.20 | $ 12.19 | $ 12.18 | $ 12.18 | $ 12.17 | $ 12.16 | $ 12.15 | $ 12.15 |
| 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) | $ (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 | 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 | 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 | 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 | 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 | $ 3,698,724 | $ 3,698,724 |
| 46 | Distribution kWh Charge Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 47 | Distribution Demand Revenues | 14,704,548 | 15,194,901 | 15,166,859 | 15,139,097 | 15,118,332 | 15,100,196 | 15,084,032 | 15,071,808 | 15,061,556 | 15,051,312 | 15,041,076 | 15,030,847 | 15,020,625 | 15,010,412 | 15,000,207 | 15,000,249 |
| 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) | (18,421) | (18,421) |
| 49 | Total Rate G2 Demand Revenues | $ 18,384,850 | $ 18,875,203 | $ 18,847,162 | $ 18,819,400 | $ 18,798,635 | $ 18,780,498 | $ 18,764,334 | $ 18,752,110 | $ 18,741,859 | $ 18,731,615 | $ 18,721,378 | $ 18,711,149 | $ 18,700,928 | $ 18,690,714 | $ 18,680,509 | $ 18,680,551 |
| | | | | | | | | | | | | | | | | | |
| 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 | $ 147.31 | $ 147.31 |
| 52 | Distribution kWh Charge ($/kWh) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 53 | Distribution kVA Charge ($/kVA) | $ 8.40 | $ 8.90 | $ 8.88 | $ 8.85 | $ 8.83 | $ 8.81 | $ 8.79 | $ 8.78 | $ 8.77 | $ 8.76 | $ 8.75 | $ 8.74 | $ 8.73 | $ 8.72 | $ 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) | $ (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 | 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 | 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 | 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 | 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 | $ 296,084 | $ 296,084 |
| 60 | Distribution kWh Charge Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 61 | Distribution Demand Revenues | 8,404,156 | 8,906,500 | 8,877,773 | 8,849,332 | 8,828,059 | 8,809,479 | 8,792,920 | 8,780,396 | 8,769,895 | 8,759,400 | 8,748,913 | 8,738,434 | 8,727,963 | 8,717,499 | 8,707,045 | 8,707,088 |
| 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) | (161,824) | (161,824) |
| 63 | Total Rate G1 Demand Revenues | $ 8,538,416 | $ 9,040,760 | $ 9,012,033 | $ 8,983,592 | $ 8,962,320 | $ 8,943,739 | $ 8,927,180 | $ 8,914,657 | $ 8,904,155 | $ 8,893,661 | $ 8,883,174 | $ 8,872,694 | $ 8,862,223 | $ 8,851,760 | $ 8,841,305 | $ 8,841,349 |
| | | | | | | | | | | | | | | | | | |
| 64 | **Outdoor Lighting (Rate OL)** | | | | | | | | | | | | | | | | |
| 65 | Average Luminaire Charge | $ 16.71 | $ 16.82 | $ 16.82 | $ 16.81 | $ 16.81 | $ 16.80 | $ 16.80 | $ 16.80 | $ 16.79 | $ 16.79 | $ 16.79 | $ 16.79 | $ 16.79 | $ 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 | 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 | 7,625,729 | 7,625,729 |
| | | | | | | | | | | | | | | | | | |
| 69 | Luminaire Charge Revenues | $ 1,815,201 | $ 1,827,180 | $ 1,826,495 | $ 1,825,817 | $ 1,825,310 | $ 1,824,867 | $ 1,824,472 | $ 1,824,173 | $ 1,823,923 | $ 1,823,672 | $ 1,823,422 | $ 1,823,172 | $ 1,822,923 | $ 1,822,673 | $ 1,822,424 | $ 1,822,425 |
| 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 | 8,639 | 8,639 |
| 72 | Total Rate OL Revenues | $ 1,823,840 | $ 1,835,820 | $ 1,835,135 | $ 1,834,456 | $ 1,833,949 | $ 1,833,506 | $ 1,833,111 | $ 1,832,812 | $ 1,832,562 | $ 1,832,312 | $ 1,832,062 | $ 1,831,812 | $ 1,831,562 | $ 1,831,312 | $ 1,831,063 | $ 1,831,064 |

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

| Line # | Customer Benefits | 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 | Year 29 | Year 30 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (r) | (s) | (t) | (u) | (v) | (w) | (x) | (y) | (z) | (aa) | (ab) | (ac) | (ad) | (ae) | (af) |
| 1 | Annual Revenue Requirement | $ 1,101,577 | $ 1,059,651 | $ 1,017,809 | $ 977,308 | $ 937,331 | $ 897,758 | $ 858,956 | $ 820,560 | $ 782,202 | $ 743,884 | $ 705,606 | $ 667,370 | $ 629,177 | $ 591,028 | $ 552,924 |
| 2 | Revenue Requirement Change | $ 2,252 | $ (41,926) | $ (41,842) | $ (40,501) | $ (39,976) | $ (39,573) | $ (38,802) | $ (38,397) | $ (38,358) | $ (38,318) | $ (38,278) | $ (38,236) | $ (38,193) | $ (38,149) | $ (38,104) |
| 3 | **Allocation based on 2020 TY kWh:** | | | | | | | | | | | | | | | |
| 4 | Residential (Rate D) | $ 1,001 | $ (18,642) | $ (18,604) | $ (18,009) | $ (17,775) | $ (17,596) | $ (17,253) | $ (17,073) | $ (17,055) | $ (17,038) | $ (17,020) | $ (17,001) | $ (16,982) | $ (16,963) | $ (16,943) |
| 5 | Regular General (Rate G2-kWh) | 1 | (16) | (16) | (15) | (15) | (15) | (15) | (15) | (15) | (14) | (14) | (14) | (14) | (14) | (14) |
| 6 | Regular General (Rate G2 - QR WH/SH) | 9 | (162) | (162) | (156) | (154) | (153) | (150) | (148) | (148) | (148) | (148) | (148) | (148) | (147) | (147) |
| 7 | Regular General (Rate G2) | 606 | (11,277) | (11,255) | (10,894) | (10,753) | (10,645) | (10,437) | (10,328) | (10,318) | (10,307) | (10,296) | (10,285) | (10,273) | (10,262) | (10,249) |
| 8 | Large General (Rate G1) | 621 | (11,553) | (11,530) | (11,161) | (11,016) | (10,905) | (10,692) | (10,581) | (10,570) | (10,559) | (10,548) | (10,536) | (10,525) | (10,512) | (10,500) |
| 9 | Outdoor Lighting (Rate OL) | 15 | (276) | (275) | (266) | (263) | (260) | (255) | (252) | (252) | (252) | (252) | (251) | (251) | (251) | (250) |
| 10 | **Total** | $ 2,252 | $ (41,926) | $ (41,842) | $ (40,501) | $ (39,976) | $ (39,573) | $ (38,802) | $ (38,397) | $ (38,358) | $ (38,318) | $ (38,278) | $ (38,236) | $ (38,193) | $ (38,149) | $ (38,104) |
| 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 | $ 16.22 |
| 14 | Distribution kWh Charge ($/kWh) | $ 0.04606 | $ 0.04602 | $ 0.04599 | $ 0.04595 | $ 0.04592 | $ 0.04588 | $ 0.04585 | $ 0.04582 | $ 0.04578 | $ 0.04575 | $ 0.04572 | $ 0.04569 | $ 0.04565 | $ 0.04562 | $ 0.04559 |
| 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 | 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 | 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 | $ 13,223,834 |
| 18 | Distribution kWh Charge Revenues | 23,765,288 | 23,746,646 | 23,728,041 | 23,710,033 | 23,692,258 | 23,674,662 | 23,657,409 | 23,640,336 | 23,623,281 | 23,606,243 | 23,589,223 | 23,572,222 | 23,555,240 | 23,538,277 | 23,521,335 |
| 19 | Total Rate D Revenues | $ 36,989,121 | $ 36,970,479 | $ 36,951,875 | $ 36,933,866 | $ 36,916,091 | $ 36,898,495 | $ 36,881,243 | $ 36,864,170 | $ 36,847,114 | $ 36,830,077 | $ 36,813,057 | $ 36,796,056 | $ 36,779,074 | $ 36,762,111 | $ 36,745,168 |
| 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 | $ 18.38 |
| 22 | Distribution kWh Charge ($/kWh) | $ 0.03028 | $ 0.03024 | $ 0.03021 | $ 0.03017 | $ 0.03014 | $ 0.03010 | $ 0.03007 | $ 0.03004 | $ 0.03000 | $ 0.02997 | $ 0.02994 | $ 0.02991 | $ 0.02987 | $ 0.02984 | $ 0.02981 |
| 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 | 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 | 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 | $ 83,500 |
| 26 | Distribution kWh Charge Revenues | 13,285 | 13,269 | 13,253 | 13,238 | 13,223 | 13,208 | 13,193 | 13,179 | 13,164 | 13,150 | 13,135 | 13,121 | 13,106 | 13,092 | 13,077 |
| 27 | Total Rate G2-kWh Revenues | $ 96,785 | $ 96,769 | $ 96,754 | $ 96,738 | $ 96,723 | $ 96,708 | $ 96,693 | $ 96,679 | $ 96,664 | $ 96,650 | $ 96,636 | $ 96,621 | $ 96,607 | $ 96,592 | $ 96,578 |
| 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 | $ 9.73 |
| 30 | Distribution kWh Charge ($/kWh) | $ 0.03694 | $ 0.03690 | $ 0.03686 | $ 0.03683 | $ 0.03679 | $ 0.03676 | $ 0.03673 | $ 0.03669 | $ 0.03666 | $ 0.03663 | $ 0.03659 | $ 0.03656 | $ 0.03653 | $ 0.03650 | $ 0.03646 |
| 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 | 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 | 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 | $ 30,056 |
| 34 | Distribution kWh Charge Revenues | 165,606 | 165,444 | 165,282 | 165,126 | 164,971 | 164,818 | 164,668 | 164,520 | 164,372 | 164,224 | 164,076 | 163,928 | 163,781 | 163,633 | 163,486 |
| 35 | Total Rate G2 Qr W/H Revenues | $ 195,662 | $ 195,500 | $ 195,338 | $ 195,182 | $ 195,027 | $ 194,874 | $ 194,724 | $ 194,576 | $ 194,428 | $ 194,280 | $ 194,132 | $ 193,984 | $ 193,837 | $ 193,689 | $ 193,542 |
| 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 | $ 29.19 |
| 38 | Distribution kWh Charge ($/kWh) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 39 | Distribution kW Charge ($/kW) | $ 12.15 | $ 12.14 | $ 12.13 | $ 12.12 | $ 12.12 | $ 12.11 | $ 12.10 | $ 12.09 | $ 12.08 | $ 12.07 | $ 12.06 | $ 12.06 | $ 12.05 | $ 12.04 | $ 12.03 |
| 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) | $ (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 | 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 | 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 | 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 | 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 | $ 3,698,724 |
| 46 | Distribution kWh Charge Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 47 | Distribution Demand Revenues | 15,000,855 | 14,989,577 | 14,978,323 | 14,967,428 | 14,956,675 | 14,946,031 | 14,935,594 | 14,925,266 | 14,914,948 | 14,904,641 | 14,894,345 | 14,884,060 | 14,873,787 | 14,863,525 | 14,853,276 |
| 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) | (18,421) |
| 49 | Total Rate G2 Demand Revenues | $ 18,681,157 | $ 18,669,880 | $ 18,658,625 | $ 18,647,731 | $ 18,636,978 | $ 18,626,333 | $ 18,615,896 | $ 18,605,568 | $ 18,595,250 | $ 18,584,943 | $ 18,574,647 | $ 18,564,362 | $ 18,554,089 | $ 18,543,828 | $ 18,533,578 |
| 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 | $ 147.31 |
| 52 | Distribution kWh Charge ($/kWh) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 53 | Distribution kVA Charge ($/kVA) | $ 8.71 | $ 8.69 | $ 8.68 | $ 8.67 | $ 8.66 | $ 8.65 | $ 8.64 | $ 8.63 | $ 8.62 | $ 8.61 | $ 8.60 | $ 8.59 | $ 8.58 | $ 8.56 | $ 8.55 |
| 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) | $ (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 | 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 | 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 | 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 | 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 | $ 296,084 |
| 60 | Distribution kWh Charge Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 61 | Distribution Demand Revenues | 8,707,708 | 8,696,155 | 8,684,625 | 8,673,465 | 8,662,449 | 8,651,544 | 8,640,852 | 8,630,271 | 8,619,701 | 8,609,142 | 8,598,594 | 8,588,058 | 8,577,533 | 8,567,021 | 8,556,521 |
| 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) | (161,824) |
| 63 | Total Rate G1 Demand Revenues | $ 8,841,969 | $ 8,830,416 | $ 8,818,886 | $ 8,807,725 | $ 8,796,709 | $ 8,785,804 | $ 8,775,112 | $ 8,764,531 | $ 8,753,962 | $ 8,743,402 | $ 8,732,855 | $ 8,722,318 | $ 8,711,794 | $ 8,701,281 | $ 8,690,781 |
| 64 | **Outdoor Lighting (Rate OL)** | | | | | | | | | | | | | | | |
| 65 | Average Luminaire Charge | $ 16.78 | $ 16.78 | $ 16.78 | $ 16.77 | $ 16.77 | $ 16.77 | $ 16.77 | $ 16.76 | $ 16.76 | $ 16.76 | $ 16.76 | $ 16.75 | $ 16.75 | $ 16.75 | $ 16.75 |
| 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 | 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 | 7,625,729 |
| 69 | Luminaire Charge Revenues | $ 1,822,440 | $ 1,822,164 | $ 1,821,889 | $ 1,821,623 | $ 1,821,360 | $ 1,821,100 | $ 1,820,845 | $ 1,820,593 | $ 1,820,341 | $ 1,820,089 | $ 1,819,838 | $ 1,819,586 | $ 1,819,335 | $ 1,819,085 | $ 1,818,834 |
| 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 | 8,639 |
| 72 | Total Rate OL Revenues | $ 1,831,079 | $ 1,830,803 | $ 1,830,528 | $ 1,830,262 | $ 1,830,000 | $ 1,829,740 | $ 1,829,485 | $ 1,829,232 | $ 1,828,980 | $ 1,828,728 | $ 1,828,477 | $ 1,828,226 | $ 1,827,975 | $ 1,827,724 | $ 1,827,473 |

**UNITIL ENERGY SYSTEMS, INC.**

**DIRECT TESTIMONY**

**OF**

**CARRIE GILBERT AND KEVIN PIERCE**

**EXHIBIT GPP-1**

**New Hampshire Public Utilities Commission**

**Docket No. DE 22-_____**

## Table of Contents

I. INTRODUCTION ........ 1
II. ECONOMIC BENEFITS ........ 3
III. AVOIDED EMISSIONS BENEFITS ........ 4
IV. DEMAND REDUCTION INDUCED PRICE EFFECTS ("DRIPE") BENEFITS ........ 6

Exhibits

Exhibit GPP-2: Indirect Benefits of Kingston Solar Project Report

Exhibit GPP-3: Resume of Carolyn C. Gilbert

Exhibit GPP-4: Resume of Kevin R. Pierce

## I. INTRODUCTION

**Q. Ms. Gilbert, would you please state your name, position, and business address?**

A. My name is Carolyn C. Gilbert and I work as a Managing Consultant for Daymark Energy Advisors ("Daymark"), 370 Main Street, Suite 325, Worcester, MA 01608.

**Q. Please summarize your professional experience and qualifications.**

A. I have been with Daymark since 2007. I am an expert in state and regional renewable resource development, economics, and policy. My work focuses on renewable project development and economics, value of distributed energy resources, asset valuation, and competitive resource procurement. Exhibit GPP-3 provides my professional resume.

**Q. Have you previously testified before the Commission?**

A. No, I have not testified before the New Hampshire Public Utilities Commission (the "Commission"). I have testified before the Utilities Commissions in Arkansas, North Carolina, Georgia, Maryland, Rhode Island, and FERC. My appearances are included in Exhibit GPP-3.

**Q. Mr. Pierce, would you please state your name, position, and business address?**

A. My name is Kevin R. Pierce and I work as a Senior Consultant for Daymark Energy Advisors. My business address is 370 Main Street Suite 325, Worcester, Massachusetts, 01608

**Q. Please summarize your professional experience and qualifications.**

A. I have a B.A. in Political Science from the University of Maine as well as an M.A. in Law and Diplomacy from the Fletcher School at Tufts University. After graduating from the Fletcher School, I joined Daymark Energy Advisors in 2019 as an Analyst. At Daymark, I work on both electric and natural gas projects, including providing regulatory support and regulatory review for a number of clients. In my work, I have supported a variety of analyses for various renewable energy projects, including several economic benefits reports. I have also worked with members of the Daymark team to evaluate long-term power supply agreements, including solar PPAs for three electric cooperatives. Additionally, I have worked to assist New Jersey's Board of Public Utilities in developing and designing their competitive solar procurement process and criteria. Exhibit GPP-4 provides my professional resume.

**Q. Have you previously testified before the Commission?**

A. No.

**Q. Please summarize Daymark and its business.**

A. Daymark provides integrated policy, planning, and strategic decision support services to the North American electricity and natural gas industries.[1] Daymark serves a diverse clientele from our offices in Worcester, Massachusetts by providing

[1] Daymark Energy Advisors is the new name of the firm previously known as La Capra Associates. The name change occurred on November 9, 2015.

consulting services to organizations involved with energy markets, including renewable energy producers, private and public utilities, transmission owners, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include cost allocation, rates and pricing, power market forecasting models and methods, economics, management, planning, energy procurement, contracting and portfolio management, and reliability assessments. Our experience includes detailed analyses of energy and environmental performance of electric systems, economic planning for transmission and distribution, and market analytics.

**Q. What is the purpose of your testimony and how is it organized?**

A. The purpose of our testimony is to discuss and quantify the indirect benefits provided by the Kingston Solar project. We discuss the results of three different analyses, quantifying economic benefits, emissions reduction benefits, and Demand Reduction Induced Price Effects ("DRIPE") benefits. We summarize our analysis and findings in the following sections. A detailed description of our analysis and results is attached as Exhibit GPP-2.

## II. ECONOMIC BENEFITS

**Q. How was the economic benefits analysis performed?**

A. Daymark performed its economic benefits analysis using the IMPLAN input-output model to estimate the direct, indirect, and induced economic impacts to a region resulting from the development, construction, and operation of a project.

**Q. What inputs were used in the IMPLAN model?**

A. Daymark was provided with the total cost of the Kingston Solar project by Unitil, broken into spending categories. Within certain categories, Daymark and Unitil discussed the breakdown of costs into labor and materials, to determine what could be reasonably sourced from within New Hampshire. For example, it is unlikely the solar panels or inverters will be manufactured in New Hampshire, therefore the investment in these materials was not considered in the analysis. On the other hand, construction supervision and labor could reasonably be sourced from New Hampshire firms, and was included in the analysis.

**Q. What were the results of the analysis?**

A. As shown in greater detail in the attached report, the IMPLAN analysis estimates approximately $11.2 million dollars of direct, indirect, and induced impacts to New Hampshire. This value is a present value figure in 2023 USD. Additionally, the project can be expected to support approximately 87 direct, indirect, and induced jobs in the state through the 30-year operational life.

## III. AVOIDED EMISSIONS BENEFITS

**Q. What are the avoided emissions benefits?**

A. Adding a solar project to the New Hampshire electric grid has the effect of displacing emitting generation resources. This results in reduced $CO_2$ and $NO_x$ emissions. The reduction in emission results in societal benefits in the form of health benefits, reductions in impacts of climate change, and reduced environmental impacts.

**Q. Can you describe the avoided emissions analysis?**

A. We have largely followed the methodology used in the 2021 Avoided Energy Supply Components in New England Report (the "AESC Report"). This report was developed to help energy efficiency program administrators in New England understand the benefits of their initiatives and is a respected publicly available source on this topic.

There are two steps to calculating the emissions reduction benefit of the project. The first step is calculating the amount of emissions that will be avoided by the project and the second step is calculating the value of the avoided emissions. The 2021 AESC Report combines these steps and calculates a per kWh benefit for each unit of energy that was utilized in the calculation. From there, we multiplied the $/kWh value of the avoided emissions by the expected generation of the project in summer on- and off-peak, as well as winter on- and off-peak.

**Q. What was the value of avoided $CO_2$ that you used in your analysis?**

A. We utilized the social cost of carbon ("SCC") as the value of avoided $CO_2$ in our analysis. The SCC is an estimate of the cost of the damage that is avoided by reducing carbon emissions. The federal government has developed an estimate of the SCC and has selected a value to use in agency decision making. We have utilized the same SCC as currently used by the Biden administration in its decision making. The history of the SCC is discussed in more detail in Exhibit GPP-2.

**Q. What were the results of the analysis?**

A. The results of our emissions analysis are shown below in Table 1. This shows a total societal benefit of over $1.8 Million when $CO_2$ and $NO_x$ benefits are combined over the operating life of the project.

**Table 1: Emissions Benefit Summary**

| | Total Emissions Savings (tons) | NPV Emissions Savings ($) |
|---|---|---|
| $CO_2$ | 57,300 | $1,775,800 |
| $NO_x$ | 0.15 | $ 44,100 |

## IV. DEMAND REDUCTION INDUCED PRICE EFFECTS ("DRIPE") BENEFITS

**Q. How was the DRIPE benefit analysis performed?**

A. The DRIPE analysis was performed by adjusting the 2021 AESC Report DRIPE figures to appropriately fit them to a solar project. Three primary adjustments were made to the 2021 AESC DRIPE analysis: an adjustment to capture the impact of the difference in energy, peak demand, and capacity characteristics of a solar project verses energy efficiency, adjusting the figures to account for a 2024 start year, and updating the DRIPE findings to account for changes in the pricing of energy and capacity.

**Q. What were the inputs used in the analysis?**

A. The inputs used in the analysis were the 2021 AESC Report, the 2021 AESC appendices, ISO-New England ("ISO-NE") market futures, ISO-NE Capacity clearing prices, and the ISO-NE 2022 CELT report.

**Q. What were the results of the analysis?**

A. The DRIPE analysis for the solar project concluded that the aggregate benefits to New Hampshire load would be around $566,963 Net Present Value ("NPV") as shown on the table below. If the benefit is allocated across New Hampshire load it would result in approximately a $0.0067/MWh reduction in LMP pricing in New Hampshire.

| Intrastate DRIPE Benefits | | | |
|---|---|---|---|
| | Unitil Solar Project Output (MWh) | DRIPE Benefit ($/MWh) | Benefits to NH Load (Nominal; $) |
| 2024 | 9,617 | 15.56 | 149,675 |
| 2025 | 9,569 | 12.68 | 121,316 |
| 2026 | 9,521 | 10.83 | 103,155 |
| 2027 | 9,472 | 11.04 | 104,591 |
| 2028 | 9,424 | 7.56 | 71,220 |
| 2029 | 9,376 | 7.47 | 70,081 |
| 2030 | 9,328 | 6.47 | 60,395 |
| 2031 | 9,280 | 3.14 | 29,145 |
| 2032 | 9,232 | - | - |
| 2033 | 9,184 | - | - |
| 2034 | 9,136 | - | - |
| 2035 | 9,088 | - | - |
| 2036 | 9,040 | - | - |
| 2037 | 8,992 | - | - |
| 2038 | 8,944 | - | - |
| 2039 | 8,895 | - | - |
| 2040 | 8,847 | - | - |
| 2041 | 8,799 | - | - |
| 2042 | 8,751 | - | - |
| 2043 | 8,703 | - | - |
| 2044 | 8,655 | - | - |
| 2045 | 8,607 | - | - |
| 2046 | 8,559 | - | - |
| 2047 | 8,511 | - | - |
| ***Total:*** | | | ***709,578*** |
| ***NPV:*** | | | ***566,963*** |

## V. CONCLUSION

**Q. Does this conclude your testimony?**

A. Yes, it does.

# INDIRECT BENEFITS OF KINGSTON SOLAR

## EXHIBIT GPP-2

## OCTOBER 31, 2022

**PREPARED FOR**

Unitil Energy Systems, Inc.

**PREPARED BY**

Daymark Energy Advisors, Inc.

DAYMARK ENERGY ADVISORS
370 MAIN STREET, SUITE 325 | WORCESTER, MA 01608
TEL: (617) 778-5515 | DAYMARKEA.COM

DAYMARK ENERGY ADVISORS



# TABLE OF CONTENTS

**I. Executive Summary ....................................................5**
A. Project Description .................................................... 5
B. Economic Benefits Summary .................................................... 5
C. Emissions Benefit Summary .................................................... 7
D. Demand Reduction Induce Price Effect ("DRIPE") Summary .................................................... 8
**II. IntroDuction ....................................................8**
**III. Project Description ....................................................9**
**IV. Economic BeneFits ....................................................9**
A. Analysis Method .................................................... 9
B. Economic Impact .................................................... 13
**V. Environmental Benefits ....................................................15**
A. Avoided Emissions .................................................... 16
B. Avoided $CO_2$ Emissions Benefit .................................................... 17
C. Avoided $NO_x$ Emissions Reduction Benefit .................................................... 19
D. Total Avoided Emissions Benefit .................................................... 20
**VI. Demand reduction induced price effect ("DRIPE") benefits ....................................................22**
A. Introduction .................................................... 22
B. Capturing Impacts of Energy, Peak Demand, and Capacity for Solar .................................................... 23
C. Include Effects of Installation in 2024 .................................................... 23
D. Update Energy and Capacity Outlook .................................................... 24
E. Results of DRIPE Analysis .................................................... 24

# APPENDICES

**Appendix A:** Detailed Results

# TABLE OF FIGURES

Figure 1. Components of output for a given industry........10
Figure 2: Annual Emissions Benefit ($)........22

# TABLE OF TABLES

Table 1 - Total Expenditure of Kingston Solar (2023$)........ **Error! Bookmark not defined.**
Table 2 – Total Economic Benefits of Kingston Solar (2023$ PV) ........6
Table 3 – Total Tax Benefit of Kingston Solar (2023$ PV) ........7
Table 4 - Emissions Benefit Summary ........8
Table 5 – Total Economic Impact of Kingston Solar (2023$ PV) ........14
Table 6 - Total Tax Benefits of Kingston Solar (2023$ PV) ........15
Table 7 - Marginal Emissions (lbs./MWh) ........17
Table 8 - Non-Embedded $CO_2$ Benefit ........19
Table 9 - Avoided Emissions Benefits ($/kWh) ........21
Table 10 - Intrastate DRIPE Benefits of Kingston Solar ........25

# LIST OF ACRONYMS

| | |
|---|---|
| **CapEx** | capital expenditures |
| **COD** | commercial operation date |
| **FTE** | full-time equivalent |
| **FTE-year** | full-time equivalent job year |
| **MRIO** | Multi-Regional Input-Output |
| **NAICS** | North American Industry Classification System |
| **OpEx** | operating and maintenance expenses |
| **PV** | present value |
| **RFP** | request for proposals |

# DISCLAIMER

The analyses supporting the results presented here involve the use of assumptions and projections with respect to conditions that may exist or events that may occur in the future. Although Daymark Energy Advisors has applied assumptions and projections that are believed to be reasonable, they are subjective and may differ from those that might be used by other economic or industry experts to perform similar analysis. In addition, actual future outcomes are dependent upon future events that are outside Daymark Energy Advisors' control. Daymark Energy Advisors cannot, and does not, accept liability under any theory for losses suffered, whether direct or consequential, arising from any reliance on this presentation, and cannot be held responsible if any conclusions drawn from this presentation should prove to be inaccurate.

# I. EXECUTIVE SUMMARY

Daymark was retained by Unitil Energy Systems, Inc. ("Unitil") to quantify the indirect benefits of the proposed Kingston Solar facility (the "Kingston Solar Project" or the "Project"). This study is meant to complement a separate analysis conducted by Unitil of the Project's direct benefits. The direct benefits are the benefits that will accrue directly to Unitil's customers, such as avoided energy and capacity costs. The indirect benefits, which are the focus of this report, are benefits that flow to society more broadly including the larger body of electricity customers in New Hampshire and New Hampshire residents.

Our analysis focuses on three categories of indirect benefits: economic benefits, environmental benefits, and demand reduction induced price effects ("DRIPE"). This report quantifies the indirect Project benefits during the presumed 30-year operating life in addition to the development and construction activities.

## A. Project Description

The proposed Project is a 4.99 MWac utility-scale solar generating facility that will be located in Kingston, New Hampshire. Unitil plans to deploy single axis tracking technology and the Project will be operated as a "load reducer," meaning the energy produced by the facility will offset energy that would otherwise be received by Unitil from the transmission system.

## B. Economic Benefits Summary

### Project Expenditures

Table 1below lists the breakdown of total project expenditure assumptions provided by Unitil for Daymark's efforts. Efforts were made to make accurate and reasonable assumptions on the percentage of local content and sourcing for each budgeted item, with Daymark only analyzing impacts on the New Hampshire economy.

**Table 1 - Total Expenditure of Kingston Solar (2023$)**

| | Total Expenditure | Assumed Local Content |
|---|---|---|
| Development and Construction | $14,336,043 | $4,671,897 |
| Operation and Maintenance | $2,213,280 | $1,715,465 |
| **Total** | **$16,549,323** | **$6,387,362** |

## Economic Benefits Results Summary

The economic benefits of the Project are summarized in Table 2 below. The annual totals for each benefit category are provided in Appendix A.

**Table 2 – Total Economic Benefits of Kingston Solar (2023$ PV)**

| Description | | | Total |
|---|---|---|---|
| *Direct Impact* | | | |
| | Employment (Job Years) | | 54 |
| | Labor Income, PV $ | $ | 4,901,038 |
| | Output, PV $ | $ | 5,774,872 |
| *Indirect Impact* | | | |
| | Employment (Job Years) | | 10 |
| | Labor Income, PV $ | $ | 748,405 |
| | Output, PV $ | $ | 1,943,423 |
| *Induced Impacts* | | | |
| | Employment (Job Years) | | 23 |
| | Labor Income, PV $ | $ | 1,232,450 |
| | Output, PV $ | $ | 3,478,635 |
| *Total Direct, Indirect, and Induced Impacts* | | | |
| | Employment (Job Years) | | 87 |
| | Labor Income, PV $ | $ | 6,881,893 |
| | Output, PV $ | $ | 11,196,930 |

The economic benefits estimated in this report are gross benefits, not net benefits. The results show total benefits in terms of economic output and employment resulting from the proposed investments. Most of the estimated gross benefits and employment numbers are most properly interpreted as "*supported*" impacts rather than "*created*," as detailed further in Section IIIA.

As depicted in Table 2, the Kingston Solar Project is expected to generate approximately $5.8 million in direct benefits, approximately $1.9 million in indirect benefits, and approximately $3.5 million in induced benefits. The economic impact is expressed in 2023$ present value ("PV"). The Project is expected to support around 54 job-years directly, with 10 indirect job-years supported and 23 induced job-years of employment.

Daymark separately used the IMPLAN model to estimate the potential state, county, and municipal tax benefits of the Project's development, construction, and assumed 30-year operations phases. Tax results include a myriad of taxes including sales, property, excise, personal income, corporate profits, and other special taxes.[1] Tax benefits are embedded in the overall economic benefits listed in Table 2 and are separately presented below in Table 3.

**Table 3 – Total Tax Benefit of Kingston Solar (2023$ PV)**

| | Description | Total |
|---|---|---|
| *Direct Impact* | | |
| | State Tax | -$19,812 |
| | County Tax | $3,255 |
| | Municipal Tax | $64,573 |
| | *Sub-Total* | $48,017 |
| *Indirect Impact* | | |
| | State Tax | $40,452 |
| | County Tax | $2,895 |
| | Municipal Tax | $56,954 |
| | *Sub-Total* | $100,300 |
| *Induced Impact* | | |
| | State Tax | $79,760 |
| | County Tax | $6,081 |
| | Municipal Tax | $106,643 |
| | *Sub-Total* | $192,484 |
| | **Total, PV $** | $340,801 |

## C. Emissions Benefit Summary

Adding solar generation to the New Hampshire electric grid will displace emitting resources on the grid. Displacing emitting resources results in reduced emissions and benefits to New Hampshire residents. We have calculated the benefit of emissions reductions for both $CO_2$ and NOx emissions. We have largely followed the methodology used in the 2021 Avoided Energy Supply Components in New England Report (the "AESC Report").

The results of this analysis showing both total emissions reductions and the Net Present Value of these reductions are shown in Table 4 below.

[1] The tax portion of the IMPLAN output is discussed here in more detail: https://support.implan.com/hc/en-us/articles/360041584233-Taxes-Where-s-the-Tax.

**Table 4 - Emissions Benefit Summary**

| | Total Emissions Savings (tons) | Net Present Value ("NPV") Emissions Savings ($) |
|---|---|---|
| $CO_2$ | 57,300 | $1,775,800 |
| $NO_x$ | 0.15 | $ 44,100 |

### D. Demand Reduction Induce Price Effect ("DRIPE") Summary

Operating the Kingston Solar Project as a load reducer will bring benefits to the ISO-NE system as a reduction in market demand inherently reduces market prices, all other variables being equal. The DRIPE calculations include price reduction induced effects for both energy and capacity. Daymark's analysis relied on the 2021 AESC Report, ISO-NE market futures, ISO-NE capacity clearing prices, and the ISO-NE 2022 CELT report.

Daymark's DRIPE analysis shows an estimated aggregate benefit to New Hampshire load of approximately $566,963 on a net present value basis. When allocated across New Hampshire load, this equates to a $0.0067/MWh reduction in locational marginal pricing ("LMP") pricing in New Hampshire.

## II. INTRODUCTION

Daymark was engaged to study the indirect benefits of the proposed Kingston Solar Project. This study is meant to complement a separate analysis conducted by Unitil of the Project's direct benefits. The direct benefits are the benefits that will accrue directly to Unitil's customers, such as avoided energy and capacity costs, which are discussed in Exhibit FDGP-1. The indirect benefits, which are the focus of this report, are benefits that flow to society more broadly including the larger body of electricity customers in New Hampshire and New Hampshire residents.

We calculated three categories of indirect benefits:

- **Economic impact benefits.** The economic impact benefits of the Project are the value to New Hampshire of the economic activity associated with building and operating the Project.

- **Environmental benefits.** The environmental benefits are related to the emissions reductions that occur when emitting resources are displaced by the addition of the Project. These are quantified in both tons of emissions avoided and the value to society of avoiding those emissions.
- **Demand Reduction Induced Price Effects (DRIPE).** DRIPE is the amount of price reduction in the wholesale capacity and energy market resulting from either reduced load or new capacity added.

This report quantifies the Kingston Solar Project benefits during the presumed 30-year operating life in addition to the development and construction activities.

# III. PROJECT DESCRIPTION

The proposed Project is a 4.99 MWac utility-scale solar generating facility that will be located in Kingston, New Hampshire. Unitil plans to deploy single axis tracking technology and the Project will be operated as a "load reducer," meaning the energy produced by the facility will offset energy that would otherwise be received by Unitil from the transmission system.

# IV. ECONOMIC BENEFITS

## A. Analysis Method

### IMPLAN

Daymark used the IMPLAN model,[2] an input/output model developed by the IMPLAN Group to estimate the direct and indirect economic impacts to New Hampshire resulting from the development, construction, and operation of the Kingston Solar Project.

Impacts from the analysis are broken into three categories: (1) direct benefits, (2) indirect benefits, and (3) induced benefits. This nomenclature should not be confused with direct benefits as described by Unitil in Exhibit FDGP-1. These three subtypes are all indirect benefits and are not easily ascribed only to Unitil's customers but rather to the state. Direct economic benefits are realized directly from Unitil's investment in New Hampshire-based businesses to complete the solar facility and maintain the site. Indirect economic benefits arise from the business-to-business

[2] IMPLAN, "*What is IMPLAN?,*" August 13, 2018, accessed October, 2022, available at: https://blog.implan.com/what-is-implan#:~:text=IMPLAN%20is%20a%20platform%20that,system%20that%20is%20fully%20customizable.

transactions that are inherent within an industry's supply chain (for example, should a developer hire a contractor, and the contractor in turn leases a crane, that lease would be considered an indirect benefit). IMPLAN also reports induced economic benefits, which are driven by household spending resulting from the direct investment in labor and wages. Categories of spending supported by induced benefits include consumer goods such as groceries and clothing or services such as childcare and healthcare. While induced benefits are included in this report, they are harder to track, measure, and verify, and they should therefore be viewed as less precise estimates than direct or indirect benefits. This does not diminish their importance or real-life impact.

All benefit types from IMPLAN are further broken down as shown in Figure 1. Intermediate Inputs are defined by IMPLAN as "purchases of non-durable goods and services such as energy, materials, and purchased services that are used for the production of other goods and services, rather than for final consumption."[3] Daymark primarily reports Output and Labor Income in this report, as well as the job-years associated with the Project.

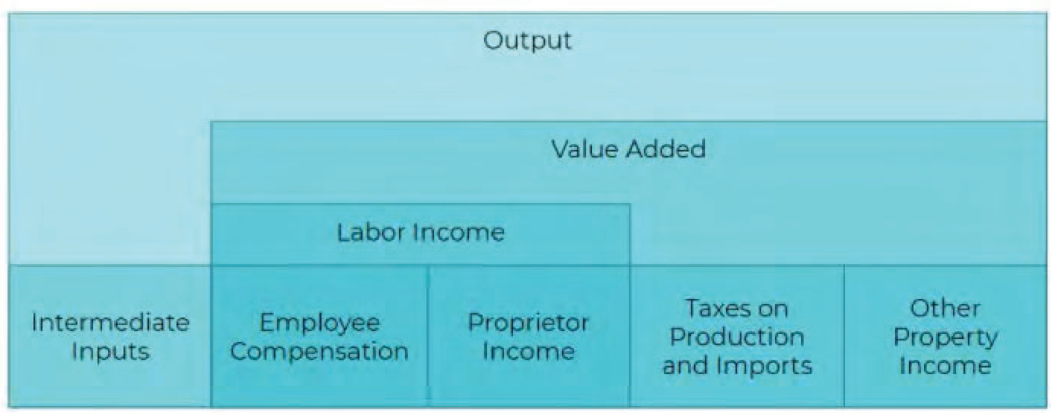



**Figure 1. Components of output for a given industry[4]**

The IMPLAN model reports employment output in two ways: "job years" and "employment compensation." If a worker is employed by a company in one position for 12 months, that is considered one job-year. If the same employee holds the same position for 24 months, that is considered two job-years. Additionally, if one employee

[3] IMPLAN, "*Understanding Intermediate Inputs (II)*," February 26, 2020, accessed October 2022, available at: https://support.implan.com/hc/en-us/articles/360044176233-Understanding-Intermediate-Inputs-II.

[4] IMPLAN, "*Understanding Output*," accessed October 2022, available at: https://implanhelp.zendesk.com/hc/en-us/articles/360035998833-Understanding-Output.

holds two positions for the same 12 months, that is considered two job-years. IMPLAN provides ratios to determine full-time equivalents ("FTEs") based on these job-years. The use of FTEs makes understanding employment figures easier – a person working one year for 35 hours a week, or more, is considered one FTE, while a second individual working half-time for the same year would be considered 0.5 FTEs. Employment compensation is simpler to understand, as it is the dollar value of the labor supported by the investment in a project. Unitil did not provide Daymark with FTE estimates, the employment figures reported here are generated from the IMPLAN model.

IMPLAN, like any input/output model, considers gross benefits only, not net benefits. It is difficult to determine exactly how much of the gross results are "new" jobs for example, and how much the Project can be supported by any existing margins or "slack" in the industry. This holds truer for indirect and induced benefits and employment, where the jobs and industries impacted are best described as "supported" rather than "created."[5] In other words, the results estimate the jobs and output necessary to complete the project and does not attribute their creation or current existence.

For this analysis, results generated by IMPLAN are reported in 2023 dollars. To estimate present value, Daymark discounted future years at a real discount rate of 2.39%, which is the current yield of a 20-year, investment-class New Hampshire General Obligation bond issued in 2022.[6] Daymark has chosen the New Hampshire state bond as Daymark believes it best approximates the social discount rate for the state.

## Multi-Regional Input-Output ("MRIO")

Using IMPLAN, Daymark performed a Multi-Regional Input-Output (MRIO)[7] analysis to estimate economic impact at the county-level and to capture any incremental economic activities occurring within New Hampshire. Due to regional business-to-business trade and worker commuting, the significant investment considered by the Project will impact not only the county where the activities occur, but also the neighboring counties in New Hampshire. Neighboring states, including Massachusetts, Maine, and the broader New England region, will also see some economic benefits from the Project due to the geographic proximity, but are not studied in this scope.

[5] IMPLAN, "*Employment Data Details*," accessed October 2022 available at: https://implanhelp.zendesk.com/hc/en-us/articles/115009510967-Employment-Data-Details.

[6] Electronic Municipal Market Access (EMMA) website, available at: https://emma.msrb.org/IssueView/Details/P2414760.

[7] IMPLAN, "*MRIO: Introduction to Multi-Regional Input-Output Analysis*," accessed October 2022, available at: https://implanhelp.zendesk.com/hc/en-us/articles/115009713448-Introduction-to-MRIO.

When assigning costs to specific regions for the MRIO analysis, Daymark was specific to allocate investments to Rockingham County where the Project will be located. The economic analysis considered all capital and operational expenses in this county. To track all relevant supply chain impacts and minimize leakage[8] (via indirect benefits), Daymark grouped the remaining New Hampshire counties into a study sub-region. While other states will likely receive some spill-over benefits, they are small and not within scope of the study.

The resulting regions (Rockingham County and Rest-of-NH) balance precision and accuracy in the MRIO analysis without overwhelming the model by inputting each county individually.

## Mapping to industry categories

Unitil provided Daymark with expected New Hampshire-specific spending by year and by category. The analysis requires defining how payments would be made, to whom they would go, and a breakdown of services, labor, and materials. Certain categories of spending such as direct reimbursement payments or real estate costs are not included in the analysis because they provide no economic benefit, despite providing a financial benefit.[9]

After receiving an understanding of planned direct investment in New Hampshire, Daymark mapped each investment to a North American Industry Classification System ("NAICS") code. NAICS codes are detailed industry standard categories commonly understood across the fields of public policy and economics.

Daymark used the IMPLAN model for the analysis. IMPLAN has its own industry categorization system. IMPLAN produces a "bridge" document that links NAICS industries directly to the appropriate IMPLAN category, as determined by IMPLAN's in-house economists.

[8] A leakage is indirect or induced economic activity that occurs outside of the study region. For example, if an employee living in New Hampshire earns income via the Project, but their closest grocery store is in Massachusetts, their grocery spending is an induced benefits leakage that will not be captured in the current model due to the omission of Massachusetts.

[9] Direct payments are transfers of funds from one entity to another that add no value to the economy because no products are created, and no services are provided. Real estate is best described as an asset swap, with no production related to the value of the land itself being transacted.

## B. Economic Impact

Daymark considered direct, indirect, and induced benefits estimated via IMPLAN in this economic impact analysis. Daymark presents economic impacts, both output and employment benefits, at the overall investment levels.

As discussed earlier in this report, the economic benefits estimated in this analysis are gross impacts. The results show overall benefits – both in terms of output and employment – to the economy as a result of the proposed investments. For example, the job numbers estimated in this analysis are labor necessary to complete various activities planned in each investment category. The analysis does not quantify net gain in economic impacts, rather, these estimates should be interpreted as supported impacts and not necessarily created impacts.

The Kingston Solar Project is expected to generate approximately $5.8 million in direct benefits, approximately $1.9 million in indirect benefits, and approximately $3.5 million in induced benefits in New Hampshire over the development, construction, and 30-year operational phase assumed in this study. The economic impact is expressed in 2023$ NPV.

The Project is also estimated to support a total of 87 job-years of employment, with 54 of these being direct job-year benefits, 10 indirect job-years, and 23 job-years of induced benefits. Again, these figures assume a 30-year operational period.

**Table 5 – Total Economic Impact of Kingston Solar (2023$ PV)**

| Description | | | Total |
|---|---|---|---|
| *Direct Impact* | | | |
| | Employment (Job Years) | | 54 |
| | Labor Income, PV $ | $ | 4,901,038 |
| | Output, PV $ | $ | 5,774,872 |
| *Indirect Impact* | | | |
| | Employment (Job Years) | | 10 |
| | Labor Income, PV $ | $ | 748,405 |
| | Output, PV $ | $ | 1,943,423 |
| *Induced Impacts* | | | |
| | Employment (Job Years) | | 23 |
| | Labor Income, PV $ | $ | 1,232,450 |
| | Output, PV $ | $ | 3,478,635 |
| *Total Direct, Indirect, and Induced Impacts* | | | |
| | Employment (Job Years) | | 87 |
| | Labor Income, PV $ | $ | 6,881,893 |
| | Output, PV $ | $ | 11,196,930 |

## Tax benefits

The Project will provide tax revenue benefits to local municipalities, counties, and to the State of New Hampshire. The IMPLAN model reports tax benefits accruing to various taxing authorities and jurisdictions based on historical relationships between the impacted industries and tax revenue in the assigned locations. Table 6 breaks down the tax impact to the State of New Hampshire, county governments, and various municipalities from the Kingston Solar Project.

It is important to note a couple of items. First, municipal tax benefits have been combined with sub-municipal and special tax districts, such as school districts. Second, negative state tax arising from direct investment occurs because of historical data. In this example, the IMPLAN results report negative Other Property Income in the base data year for certain industries utilized in the analysis (2019), and therefore do not owe corporate profit taxes to the state, a major source of state taxes. IMPLAN runs impacts based on the base year relationships between industries – this does not mean that corporate profits in the region will not improve and generate additional corporate profit tax in future years.

DAYMARK ENERGY ADVISORS



**Table 6 - Total Tax Benefits of Kingston Solar (2023$ PV)**

| | Description | Total |
|---|---|---|
| *Direct Impact* | | |
| | State Tax | -$19,812 |
| | County Tax | $3,255 |
| | Municipal Tax | $64,573 |
| | *Sub-Total* | $48,017 |
| *Indirect Impact* | | |
| | State Tax | $40,452 |
| | County Tax | $2,895 |
| | Municipal Tax | $56,954 |
| | *Sub-Total* | $100,300 |
| *Induced Impact* | | |
| | State Tax | $79,760 |
| | County Tax | $6,081 |
| | Municipal Tax | $106,643 |
| | *Sub-Total* | $192,484 |
| | **Total, PV $** | $340,801 |

### Impacted industries

The IMPLAN model also provides as output impacted industries in terms of both Output and Employment figures, for direct, indirect, and induced benefits. It is perhaps unsurprising that IMPLAN reports the largest direct impact on output and employment to industries such as Construction of New Power Structures, Industrial Machinery Repair, Construction of New Nonresidential Structures, and Architectural, Engineering, and Related Services.

Indirect impacts arise from business-to-business spending stemming from direct impacts. Industries at the top of the indirect output benefits are Architectural, engineering, and related services, Other Real Estate, industrial machinery repair, and wholesale durable goods.

Induced impacts arise from labor incomes and the choices employees make as a result of the direct spending. We see this reflected in the industries receiving the most induced output benefits, such as Owner-occupied dwellings, Hospitals, Other Real Estate, and Offices of Physicians.

## V. ENVIRONMENTAL BENEFITS

Adding solar generation to the New Hampshire electric grid has the impact of displacing emitting resources on the grid. Displacing emitting resources results in reduced emissions and benefits to New Hampshire residents. We have calculated the benefit of emission reductions for both $CO_2$ and NOx emission. We have largely followed the methodology used in the 2021 AESC Report. This report was developed to help energy efficiency program administrators in New England understand the benefits of their initiatives and is a respected publicly available source on this topic.

There are two steps to calculating the emissions benefit of the Project. The first step is calculating the amount of emissions that will be avoided by the Project and the second step is calculating the value of the avoided emissions. The AESC Report combines these steps and calculates a per kWh benefit for each unit of energy. We have calculated both the amount of emissions expected to be avoided by the Project and the dollar benefit.

## A. Avoided Emissions

The supporting spreadsheets to the AESC Report include an estimate of the marginal emissions savings for years 2021-2035 for both $CO_2$ and $NO_x$ emissions. These are shown below in Table 7 for the years 2024-2035. We assumed the avoided emissions in years 2036+ would be the average per MWh avoided emissions over the years 2031-2035.

**Table 7 - Marginal Emissions (lbs./MWh)**

| | $CO_2$ | | | | $NO_X$ | | | |
|---|---|---|---|---|---|---|---|---|
| | WINTER | | SUMMER | | WINTER | | SUMMER | |
| | ON PEAK | OFF PEAK | ON PEAK | OFF PEAK | OFF PEAK | OFF PEAK | ON PEAK | OFF PEAK |
| **2024** | 785 | 863 | 761 | 960 | 0.10 | 0.08 | 0.12 | 0.10 |
| **2025** | 791 | 875 | 807 | 959 | 0.07 | 0.07 | 0.12 | 0.10 |
| **2026** | 751 | 872 | 767 | 932 | 0.07 | 0.07 | 0.11 | 0.09 |
| **2027** | 677 | 819 | 755 | 923 | 0.06 | 0.08 | 0.11 | 0.09 |
| **2028** | 681 | 729 | 759 | 816 | 0.07 | 0.07 | 0.12 | 0.09 |
| **2029** | 697 | 713 | 747 | 788 | 0.08 | 0.07 | 0.11 | 0.08 |
| **2030** | 632 | 664 | 727 | 754 | 0.06 | 0.06 | 0.09 | 0.07 |
| **2031** | 643 | 688 | 718 | 763 | 0.06 | 0.06 | 0.09 | 0.07 |
| **2032** | 640 | 715 | 681 | 769 | 0.06 | 0.06 | 0.09 | 0.07 |
| **2033** | 648 | 697 | 732 | 783 | 0.06 | 0.06 | 0.08 | 0.07 |
| **2034** | 673 | 688 | 746 | 764 | 0.06 | 0.06 | 0.08 | 0.07 |
| **2035** | 686 | 685 | 755 | 787 | 0.06 | 0.05 | 0.07 | 0.06 |
| **2036+** | 658 | 695 | 727 | 773 | 0.06 | 0.06 | 0.08 | 0.07 |

Using the figures in Table 7, we determined that the Project would avoid about 57,000 tons of $CO_2$ and about .15 tons of $NO_x$ over its 30-year life.

## B. Avoided $CO_2$ Emissions Benefit

The AESC Report discussed several methods of valuing the benefits of avoiding carbon emissions:

- **Damage cost.** A damage cost is based on the damage that carbon emissions cause or the marginal abatement cost. This would be approximated by the social cost of carbon ("SCC"). The Biden administration is currently utilizing a SCC methodology in its analysis.
- **Global marginal abatement cost.** This would be the cost to abate carbon on a global scale. The AESC Report equates this to the cost of large-scale carbon capture and storage and estimates the cost at about $92/short ton of carbon equivalent.
- **Electric sector New England marginal abatement costs.** The AESC Report equates this to be equivalent to the cost of offshore wind and estimates this at about $125 per short ton of carbon equivalent.

- **Multi-sector New England marginal abatement costs.** This method assumes a cost of abating carbon in multiple sectors and is based on the future cost trajectory of RNG derived from power to gas technology. The AESC Report gives a value of $493 per short ton of carbon equivalent for this methodology.[10]

Based on our review of these methodologies we determined that a methodology based on the SCC was most applicable to New Hampshire. This decision was primarily based on the fact that the Biden Administration is currently using this methodology.

The federal government first opined on the SCC during the Obama administration. That administration established an Inter-agency Working Group ("IWG") to develop a recommended SCC for the purpose of evaluating benefits and costs of proposed regulatory actions. The IWG issued a technical support document dated August 2016.[11] The report monetized damages associated with $CO_2$ emissions, including (but not limited to):

- Changes in net agricultural productivity.
- Human health.
- Property damages from increased flood risk.
- Value of ecosystem services due to climate change.[12]

The 2016 IWG report presented a distribution of cost estimates based on a variety of quantified sources of uncertainty, including discount rate. The IWG recommended the central value, or the best point estimate, to be the average of estimates using a 3% discount rate. This average estimate was equivalent to $49 per short ton (2021$) of $CO_2$ in 2021.

During the Trump administration, the federal IWG was disbanded and the SCC was reduced to $1. In February 2021, the Biden Administration reverted to the Obama era SCC of $49 per short ton in 2021, reconvened the IWG, and began a process to update the SCC by 2022.[13] At this point, the update has not yet been released.

[10] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf. Page 172

[11] Interagency Working Group on Social Cost of Greenhouse Gases. August 2016. Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

[12] Ibid.

[13] https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf page 3-4.

Some portion of the social benefit of carbon reduction is already captured in Unitil's avoided energy direct benefit calculation. This is because wholesale energy prices in ISO NE include the cost of Regional Greenhouse Gas Initiative ("RGGI") Allowances. The value of these allowances is subtracted from the SCC to determine the non-embedded $CO_2$ benefit.

**Table 8 - Non-Embedded $CO_2$ Benefit**[14]

| | SCC | RGGI COMPLIANCE COST | NON-EMBEDDED BENEFIT |
|---|---|---|---|
| **2024** | $51.22 | $6.93 | $44.30 |
| **2025** | $52.21 | $7.26 | $44.95 |
| **2026** | $53.20 | $7.62 | $45.58 |
| **2027** | $54.19 | $7.99 | $46.20 |
| **2028** | $55.18 | $8.38 | $46.79 |
| **2029** | $56.16 | $8.79 | $47.37 |
| **2030** | $57.15 | $9.22 | $47.93 |
| **2031** | $58.21 | $9.67 | $48.54 |
| **2032** | $59.27 | $10.15 | $49.12 |
| **2033** | $60.33 | $10.64 | $49.68 |
| **2034** | $61.39 | $11.16 | $50.22 |
| **2035** | $62.44 | $11.71 | $50.73 |

The AESC report provides a spreadsheet that allows the user to select location, $CO_2$ price assumption preference, etc. The spreadsheet incorporates the marginal emissions rate and non-embedded $CO_2$ benefit shown in Table 7 and Table 8, respectively. We used this spreadsheet to calculate the $CO_2$ benefit per kWh over the life of the Project and multiplied this benefit by the expected generation of the Project to calculate the total benefit.

## C. Avoided $NO_x$ Emissions Reduction Benefit

We have utilized the $NO_x$ emission benefit as calculated in the 2021 AESC Report. That benefit was $14,700/ton.[15] Similar to the $CO_2$ benefit, we used the same AESC

[14] AESC User Interface – All-in climate policy, sheet "NonEmbedded_Calcs" 3% SCC case selected. Downloaded here: https://synapseenergyeconomics.app.box.com/s/xl54ic73lox3i6w4g11ygoax2gomdp8g

[15] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf, pp. 186-187.

spreadsheet to calculate the $NO_x$ benefit per kWh benefit and multiplied that by the expected project generation.

## D. Total Avoided Emissions Benefit

The per-kWh avoided emissions benefit of both $CO_2$ and $NO_x$ is shown below in Table 9.

DAYMARK ENERGY ADVISORS

OCTOBER 31, 2022

**Table 9 - Avoided Emissions Benefits ($/kWh)**

| | Non-Embedded $CO_2$ | | | | | Non-Embedded NOx | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Annual Average | Winter On-Peak | Winter Off-Peak | Summer On-Peak | Summer Off-Peak | Annual Average | Winter On-Peak | Winter Off-Peak | Summer On-Peak | Summer Off-Peak |
| **2024** | 0.01963 | 0.01846 | 0.02028 | 0.01789 | 0.02256 | 0.00076 | 0.00078 | 0.00066 | 0.00094 | 0.00074 |
| **2025** | 0.02066 | 0.01923 | 0.02129 | 0.01962 | 0.02333 | 0.00068 | 0.00059 | 0.00058 | 0.00093 | 0.00077 |
| **2026** | 0.02072 | 0.01890 | 0.02194 | 0.01929 | 0.02346 | 0.00066 | 0.00055 | 0.00060 | 0.00089 | 0.00075 |
| **2027** | 0.02025 | 0.01762 | 0.02129 | 0.01963 | 0.02401 | 0.00068 | 0.00054 | 0.00062 | 0.00092 | 0.00078 |
| **2028** | 0.01973 | 0.01831 | 0.01960 | 0.02040 | 0.02194 | 0.00070 | 0.00063 | 0.00056 | 0.00099 | 0.00075 |
| **2029** | 0.02017 | 0.01933 | 0.01979 | 0.02074 | 0.02188 | 0.00069 | 0.00066 | 0.00056 | 0.00094 | 0.00072 |
| **2030** | 0.01949 | 0.01809 | 0.01902 | 0.02081 | 0.02161 | 0.00058 | 0.00053 | 0.00050 | 0.00075 | 0.00062 |
| **2031** | 0.02046 | 0.01903 | 0.02034 | 0.02124 | 0.02256 | 0.00060 | 0.00056 | 0.00053 | 0.00077 | 0.00064 |
| **2032** | 0.02117 | 0.01953 | 0.02182 | 0.02081 | 0.02348 | 0.00063 | 0.00057 | 0.00058 | 0.00078 | 0.00067 |
| **2033** | 0.02211 | 0.02040 | 0.02196 | 0.02307 | 0.02466 | 0.00060 | 0.00056 | 0.00054 | 0.00074 | 0.00063 |
| **2034** | 0.02296 | 0.02187 | 0.02235 | 0.02424 | 0.02483 | 0.00062 | 0.00060 | 0.00054 | 0.00079 | 0.00064 |
| **2035** | 0.02396 | 0.02297 | 0.02294 | 0.02529 | 0.02635 | 0.00058 | 0.00055 | 0.00052 | 0.00071 | 0.00062 |
| **2036** | 0.02495 | 0.02409 | 0.02375 | 0.02639 | 0.02737 | 0.00058 | 0.00056 | 0.00053 | 0.00071 | 0.00062 |
| **2037** | 0.02599 | 0.02527 | 0.02458 | 0.02754 | 0.02843 | 0.00059 | 0.00056 | 0.00053 | 0.00071 | 0.00061 |
| **2038** | 0.02707 | 0.02651 | 0.02544 | 0.02874 | 0.02954 | 0.00059 | 0.00057 | 0.00053 | 0.00070 | 0.00061 |
| **2039** | 0.02819 | 0.02780 | 0.02634 | 0.03000 | 0.03068 | 0.00059 | 0.00058 | 0.00053 | 0.00070 | 0.00061 |
| **2040** | 0.02937 | 0.02916 | 0.02726 | 0.03131 | 0.03187 | 0.00059 | 0.00058 | 0.00054 | 0.00069 | 0.00061 |
| **2041** | 0.03058 | 0.03059 | 0.02822 | 0.03267 | 0.03310 | 0.00059 | 0.00059 | 0.00054 | 0.00069 | 0.00061 |
| **2042** | 0.03186 | 0.03208 | 0.02921 | 0.03410 | 0.03438 | 0.00059 | 0.00059 | 0.00054 | 0.00069 | 0.00061 |
| **2043** | 0.03318 | 0.03365 | 0.03023 | 0.03559 | 0.03571 | 0.00060 | 0.00060 | 0.00054 | 0.00068 | 0.00060 |
| **2044** | 0.03456 | 0.03530 | 0.03129 | 0.03714 | 0.03710 | 0.00060 | 0.00061 | 0.00055 | 0.00068 | 0.00060 |
| **2045** | 0.03599 | 0.03702 | 0.03239 | 0.03876 | 0.03853 | 0.00060 | 0.00062 | 0.00055 | 0.00067 | 0.00060 |
| **2046** | 0.03749 | 0.03883 | 0.03353 | 0.04045 | 0.04003 | 0.00060 | 0.00062 | 0.00055 | 0.00067 | 0.00060 |
| **2047** | 0.03905 | 0.04073 | 0.03471 | 0.04222 | 0.04158 | 0.00060 | 0.00063 | 0.00055 | 0.00067 | 0.00060 |
| **2048** | 0.04067 | 0.04273 | 0.03592 | 0.04406 | 0.04319 | 0.00060 | 0.00064 | 0.00056 | 0.00066 | 0.00060 |
| **2049** | 0.04236 | 0.04482 | 0.03718 | 0.04598 | 0.04486 | 0.00061 | 0.00064 | 0.00056 | 0.00066 | 0.00060 |
| **2050** | 0.04412 | 0.04701 | 0.03849 | 0.04799 | 0.04660 | 0.00061 | 0.00065 | 0.00056 | 0.00065 | 0.00059 |
| **2051** | 0.04595 | 0.04931 | 0.03984 | 0.05008 | 0.04840 | 0.00061 | 0.00066 | 0.00057 | 0.00065 | 0.00059 |
| **2052** | 0.04786 | 0.05172 | 0.04124 | 0.05227 | 0.05028 | 0.00061 | 0.00067 | 0.00057 | 0.00065 | 0.00059 |
| **2053** | 0.04985 | 0.05425 | 0.04268 | 0.05455 | 0.05222 | 0.00061 | 0.00067 | 0.00057 | 0.00064 | 0.00059 |
| **2054** | 0.05192 | 0.05690 | 0.04418 | 0.05693 | 0.05424 | 0.00062 | 0.00068 | 0.00057 | 0.00064 | 0.00059 |
| **2055** | 0.05407 | 0.05968 | 0.04573 | 0.05941 | 0.05635 | 0.00062 | 0.00069 | 0.00058 | 0.00063 | 0.00059 |

Multiplying these benefits by the expected output of the Kingston Solar Project yields annual benefits of approximately $112,000 and $4,500 for $CO_2$ and $NO_x$, respectively, in 2024. The annual benefits over the life of the Project are shown below in Figure 2.

Discounting these benefits over the life of the project at the Company's WACC yields a NPV of approximately $1.8 Million.

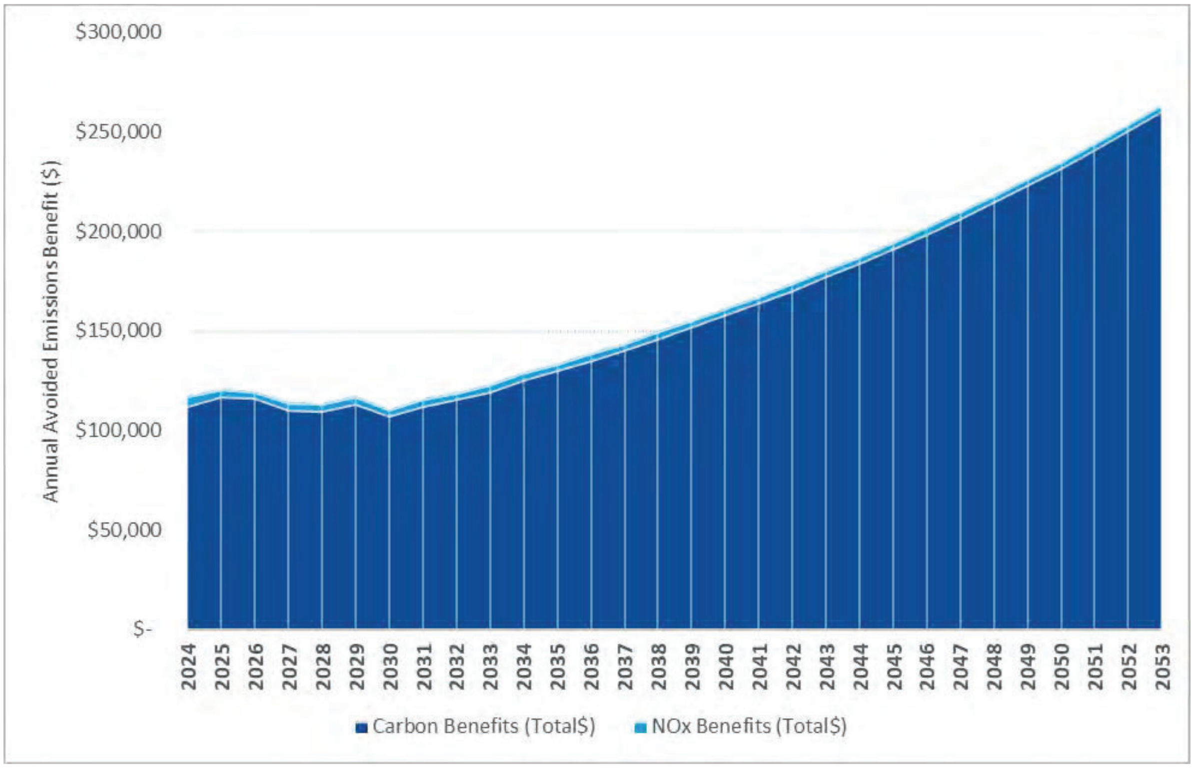



**Figure 2: Annual Emissions Benefit ($)**

# VI. DEMAND REDUCTION INDUCED PRICE EFFECT ("DRIPE") BENEFITS

## A. Introduction

Demand Reduction Induced Price Effects, or DRIPE, is the amount of price reduction in the wholesale capacity and energy market resulting from either reduced load or new capacity added. The AESC Report compiled by Synapse every three years estimates DRIPE resulting from energy efficiency measures. The analysis of DRIPE is a very detailed statistical exercise examining the hourly energy market and yearly capacity market supply curves either with actual market data or in hourly energy market simulations. Daymark's DRIPE analysis builds off the AESC DRIPE results for energy efficiency and makes several adjustments for solar. Two aspects of the AESC methodology that were preserved in the Daymark study are that the AESC methodology accounts for the temporal effects of the market price suppression and the estimates for the portion of load in New Hampshire and ISO-NE whose prices do not vary directly with changes in ISO-NE market clearing prices. There were three primary adjustments required to build off the 2021 AESC DRIPE analysis.

1. Capture the impact of the difference in energy, peak demand, and capacity characteristics from operating a load reducer as compared to energy efficiency,
2. Extend the analysis reflecting installations of solar facilities in 2024 rather than two years of energy efficiency which was the focus of the 2021 AESC Report, and
3. Update the DRIPE findings to account for the more current outlooks Daymark developed for the ISO-NE energy and capacity markets.

## B. Capturing Impacts of Energy, Peak Demand, and Capacity for Solar

Since solar is an intermittent resource, unlike energy efficiency, several additional factors were accounted for. These included a New Hampshire solar capacity factor, the number of months that solar is allowed in the Forward Capacity Market ("FCM"), and the seasonal ratio of solar generation in the winter versus summer. For the solar capacity factor, the Project-specific solar capacity factor, as provided by Unitil based on vendor response to a preliminary Request for Proposals, was used. This capacity factor was used to discount the capacity DRIPE, since solar is only awarded capacity revenues based on their actual generation, not nameplate (unlike energy efficiency).

We also discounted capacity DRIPE by the number of months that solar typically clears the capacity market. Typically, solar only clears for the designated summer months, which is 4 months total.

For our energy DRIPE calculation, we only included DRIPE from winter and summer peak hours, not off-peak. Since solar does not generate energy overnight, we decided it was more accurate to leave out off-peak effects. We further multiplied the summer and winter peak DRIPE by the ratio of how much solar is produced during winter peak versus summer peak, to account for the fact that the majority of solar output occurs during summer peak hours.

## C. Include Effects of Installation in 2024

The AESC report only analyzes the effect of energy efficiency installed for two years. For the purposes of analyzing the effect of the New Hampshire solar project beginning in

2024, the 2024 DRIPE benefits were utilized. As the AESC analysis showed, installing energy efficiency (or in our case, solar) in a single year has price effects that cascade for several years afterwards. The AESC provides more detail on these cascading effects but basically, prices decrease due to a decrease in load. Eventually, both the market and consumer behavior adjust to these lowered prices and the DRIPE effects decay. For the purposes of our analysis, Daymark assumed that the Project will be placed into service in 2024, and used the figures from that year to quantify the DRIPE benefit.

## D. Update Energy and Capacity Outlook

The most recent AESC Report was produced in 2021 and utilized pricing for energy that is not reflective of recent market developments, which have led to increased price volatility and overall energy costs. In order to reflect these changes, Daymark updated both the energy and capacity price outlooks using more recent data. This was done by creating a ratio of the prices used in the 2021 AESC Report compared to the current forward pricing. The same methodology was used with the 2021 AESC capacity pricing and the current forward clearing pricing. We substituted these prices into our analysis.

## E. Results of DRIPE Analysis

Looking at the benefits of the Project over the lifetime of the project, the overall DRIPE benefit to New Hampshire load is approximately $700,000 nominal or $566,963 NPV as shown on the table below. The DRIPE effect falls off after 8 years due to the above-mentioned cascading effects of DRIPE. If this $700,000 benefit is allocated based on the Project's contribution to New Hampshire forecast load as laid out in the 2022 CELT Report, the Project would account for a $0.0067/MWh reduction in LMP pricing in New Hampshire.

**Table 10 - Intrastate DRIPE Benefits of Kingston Solar**

| Intrastate DRIPE Benefits | | | |
|---|---|---|---|
| | Unitil Solar Project Output (MWh) | DRIPE Benefit ($/MWh) | Benefits to NH Load (Nominal; $) |
| 2024 | 9,617 | 15.56 | 149,675 |
| 2025 | 9,569 | 12.68 | 121,316 |
| 2026 | 9,521 | 10.83 | 103,155 |
| 2027 | 9,472 | 11.04 | 104,591 |
| 2028 | 9,424 | 7.56 | 71,220 |
| 2029 | 9,376 | 7.47 | 70,081 |
| 2030 | 9,328 | 6.47 | 60,395 |
| 2031 | 9,280 | 3.14 | 29,145 |
| 2032 | 9,232 | - | - |
| 2033 | 9,184 | - | - |
| 2034 | 9,136 | - | - |
| 2035 | 9,088 | - | - |
| 2036 | 9,040 | - | - |
| 2037 | 8,992 | - | - |
| 2038 | 8,944 | - | - |
| 2039 | 8,895 | - | - |
| 2040 | 8,847 | - | - |
| 2041 | 8,799 | - | - |
| 2042 | 8,751 | - | - |
| 2043 | 8,703 | - | - |
| 2044 | 8,655 | - | - |
| 2045 | 8,607 | - | - |
| 2046 | 8,559 | - | - |
| 2047 | 8,511 | - | - |
| ***Total:*** | | | ***709,578*** |
| ***NPV:*** | | | ***566,963*** |

# APPENDIX A: DETAILED ECONOMIC BENEFIT RESULTS

## Annual Results (2023$ PV)

| Description | | Total | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Direct Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 54 | 1 | 20 | 20 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 4,901,038 | $ 66,049 | $2,058,137 | $1,822,571 | $ 30,964 | $ 30,997 | $ 31,031 | $ 31,064 | $ 31,097 | $ 31,131 |
| | Output, PV $ | $ 5,774,872 | $ 127,988 | $2,493,778 | $2,041,234 | $ 36,077 | $ 36,116 | $ 36,155 | $ 36,194 | $ 36,233 | $ 36,272 |
| *Indirect Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 10 | 0 | 4 | 4 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 748,405 | $ 20,872 | $ 348,008 | $ 290,022 | $ 2,905 | $ 2,908 | $ 2,911 | $ 2,914 | $ 2,917 | $ 2,920 |
| | Output, PV $ | $ 1,943,423 | $ 47,355 | $ 904,593 | $ 756,352 | $ 7,631 | $ 7,639 | $ 7,647 | $ 7,655 | $ 7,663 | $ 7,672 |
| *Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 23 | 0 | 9 | 8 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 1,232,450 | $ 18,584 | $ 517,694 | $ 463,497 | $ 7,551 | $ 7,559 | $ 7,567 | $ 7,575 | $ 7,583 | $ 7,591 |
| | Output, PV $ | $ 3,478,635 | $ 52,673 | $1,460,514 | $1,307,557 | $ 21,350 | $ 21,372 | $ 21,395 | $ 21,418 | $ 21,441 | $ 21,464 |
| *Total Direct, Indirect, and Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 87 | 1 | 34 | 31 | 0 | 0 | 0 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 6,881,893 | $ 105,505 | $2,923,839 | $2,576,090 | $ 41,419 | $ 41,464 | $ 41,508 | $ 41,553 | $ 41,597 | $ 41,642 |
| | Output, PV $ | $ 11,196,930 | $ 228,015 | $4,858,885 | $4,105,142 | $ 65,058 | $ 65,127 | $ 65,197 | $ 65,267 | $ 65,338 | $ 65,408 |

DAYMARK ENERGY ADVISORS

OCTOBER 31, 2022

| Description | | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Direct Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 31,164 | $ 31,198 | $ 31,231 | $ 31,265 | $ 31,298 | $ 31,332 | $ 31,365 | $ 36,836 | $ 36,743 | $ 31,467 |
| | Output, PV $ | $ 36,311 | $ 36,350 | $ 36,389 | $ 36,428 | $ 36,467 | $ 36,506 | $ 36,545 | $ 42,919 | $ 42,810 | $ 36,663 |
| *Indirect Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 2,923 | $ 2,926 | $ 2,930 | $ 2,933 | $ 2,936 | $ 2,939 | $ 2,942 | $ 3,448 | $ 3,440 | $ 2,952 |
| | Output, PV $ | $ 7,680 | $ 7,688 | $ 7,696 | $ 7,705 | $ 7,713 | $ 7,721 | $ 7,730 | $ 9,055 | $ 9,032 | $ 7,755 |
| *Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 7,599 | $ 7,608 | $ 7,616 | $ 7,624 | $ 7,632 | $ 7,640 | $ 7,649 | $ 8,968 | $ 8,946 | $ 7,673 |
| | Output, PV $ | $ 21,488 | $ 21,511 | $ 21,534 | $ 21,557 | $ 21,580 | $ 21,603 | $ 21,626 | $ 25,356 | $ 25,293 | $ 21,696 |
| *Total Direct, Indirect, and Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 41,687 | $ 41,732 | $ 41,777 | $ 41,821 | $ 41,866 | $ 41,911 | $ 41,956 | $ 49,252 | $ 49,128 | $ 42,092 |
| | Output, PV $ | $ 65,478 | $ 65,548 | $ 65,619 | $ 65,689 | $ 65,760 | $ 65,831 | $ 65,901 | $ 77,329 | $ 77,135 | $ 66,114 |

| Description | | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Direct Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 31,500 | $ 31,534 | $ 31,568 | $ 31,602 | $ 31,636 | $ 31,670 | $ 31,704 | $ 31,738 | $ 31,772 | $ 31,806 |
| | Output, PV $ | $ 36,703 | $ 36,742 | $ 36,781 | $ 36,821 | $ 36,861 | $ 36,900 | $ 36,940 | $ 36,979 | $ 37,019 | $ 37,059 |
| *Indirect Impact* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 2,955 | $ 2,958 | $ 2,961 | $ 2,964 | $ 2,968 | $ 2,971 | $ 2,974 | $ 2,977 | $ 2,980 | $ 2,984 |
| | Output, PV $ | $ 7,763 | $ 7,771 | $ 7,780 | $ 7,788 | $ 7,796 | $ 7,805 | $ 7,813 | $ 7,821 | $ 7,830 | $ 7,838 |
| *Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 7,682 | $ 7,690 | $ 7,698 | $ 7,706 | $ 7,715 | $ 7,723 | $ 7,731 | $ 7,739 | $ 7,748 | $ 7,756 |
| | Output, PV $ | $ 21,720 | $ 21,743 | $ 21,766 | $ 21,790 | $ 21,813 | $ 21,836 | $ 21,860 | $ 21,883 | $ 21,907 | $ 21,930 |
| *Total Direct, Indirect, and Induced Impacts* | | | | | | | | | | | |
| | Employment (Job Years) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 42,137 | $ 42,182 | $ 42,227 | $ 42,273 | $ 42,318 | $ 42,364 | $ 42,409 | $ 42,455 | $ 42,500 | $ 42,546 |
| | Output, PV $ | $ 66,185 | $ 66,256 | $ 66,327 | $ 66,398 | $ 66,470 | $ 66,541 | $ 66,613 | $ 66,684 | $ 66,756 | $ 66,828 |

DAYMARK ENERGY ADVISORS

OCTOBER 31, 2022

| Description | | 2051 | 2052 | 2053 | 2054 |
|---|---|---|---|---|---|
| *Direct Impact* | | | | | |
| | Employment (Job Years) | 1 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 31,841 | $ 31,875 | $ 31,909 | $ 31,943 |
| | Output, PV $ | $ 37,099 | $ 37,139 | $ 37,179 | $ 37,218 |
| *Indirect Impact* | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 2,987 | $ 2,990 | $ 2,993 | $ 2,996 |
| | Output, PV $ | $ 7,847 | $ 7,855 | $ 7,864 | $ 7,872 |
| *Induced Impacts* | | | | | |
| | Employment (Job Years) | 0 | 0 | 0 | 0 |
| | Labor Income, PV $ | $ 7,764 | $ 7,773 | $ 7,781 | $ 7,789 |
| | Output, PV $ | $ 21,954 | $ 21,978 | $ 22,001 | $ 22,025 |
| *Total Direct, Indirect, and Induced Impacts* | | | | | |
| | Employment (Job Years) | 1 | 1 | 1 | 1 |
| | Labor Income, PV $ | $ 42,592 | $ 42,638 | $ 42,683 | $ 42,729 |
| | Output, PV $ | $ 66,899 | $ 66,971 | $ 67,043 | $ 67,115 |

DAYMARK
ENERGY ADVISORS

# Carolyn Gilbert

Managing Consultant

Carrie works closely with policymakers, regulators, renewable energy developers, and large C&I customers engaged in renewable energy markets. She is an expert on state and regional renewable energy policy and economics, and she provides strategic and technical advice to clients pursuing decarbonization and sustainability goals. Carrie has appeared as an expert before regulatory agencies in Arkansas, Maryland, Georgia, North Carolina, and Rhode Island.

## INDUSTRY EXPERIENCE

**Daymark Energy Advisors** | Portland, ME

*Daymark Energy Advisors is a consultancy that bring deep knowledge of energy infrastructure, regulation, and markets to help our clients make well-informed business, capital investment, and policy decisions in the face of uncertainty.*

Managing Consultant | 2021–Present
Senior Consultant | 2014–2021
Consultant | 2008–2014
Specialist | 2007–2008

*Consulting practice includes:*

- Distributed energy resources valuation
- Energy infrastructure and asset valuation
- Renewable energy policy and market forecasting
- Renewable energy contracting, and competitive solicitation processes
- Integrated resource planning
- Cost-benefit analysis, economic evaluations, and investment decision support

**Independent Consultant** | Boston, MA

Consultant | 2006–2007

*Consulting practice included:*

- Strategy consulting to Emerging Energy Research, Keystone Strategy, and Esty Environmental Partners

**Camp Dresser and McKee, Inc.** | Cambridge, MA

Environmental Engineer | 2000–2004

**Tellus Institute** | Boston, MA

Research Analyst | 1998–2000

## TESTIMONY, PRESENTATIONS & PUBLICATIONS

### *Expert Testimony*

| FORUM | ON BEHALF OF | MATTER |
|---|---|---|
| Arkansas Public Service Commission | Commission General Staff | Reviewed utility power purchase agreement. Docket 22-003-U. Ongoing. |
| Arkansas Public Service Commission | Commission General Staff | Reviewed utility acquisition of Build Own Transfer Solar Facility Docket 22-013-U. 2022. |
| Arkansas Public Service Commission | Commission General Staff | Reviewed Green Tariff Proposal Docket 21-054-TF. 2022. |
| Arkansas Public Service Commission | Commission General Staff | Reviewed utility acquisition of Build Own Transfer Solar Facility Docket 20-067-U. July 2021. |
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Review of Purchase of Receivables Program Docket 5073. 2021 |
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Retail Rate Filing Dockets 5005, 5127, and 5234. 2020 -2022 |
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Renewable Energy Standard Charge and Reconciliation Filing Dockets 4935, 5096, and 5190. 2020 - 2022. |
| Federal Energy Regulatory Commission | New England Power Pool | NEPOOL's proposed Offer Review Trigger Prices and Related Tariff Provisions Docket ER21-1637-000. April 2021. |
| Arkansas Public Service Commission | Commission General Staff | Reviewed utility acquisition of Build Own Transfer Solar Facility Docket 20-052-U. April 2021. |
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Ceiling prices for the Renewable Energy Growth program. Dockets 4983, 4774, 4672, 4589-B, 4536-B, and 4983. 2015-2018, 2020. |
| Arkansas Public Service Commission | Commission General Staff | Reviewed utility acquisition of Build Own Transfer Solar Facility Docket 19-019-U. |
| Maryland Public Service Commission | Commission Staff | Transforming Maryland's Electric Grid; prepared report *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland* and presented in a public hearing session. Docket PC44. April 2019. |
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Proposed wind power purchase agreement between National Grid and Copenhagen Wind, LLC. Docket 4574. September, October 2015. |
| Georgia Public Service Commission | Commission Staff | Georgia Power Company's application for the certification of power purchase agreements for wind resources from Blue Canyon II and Blue Canyon VI wind farms. Docket No. 37854. March 2014. |

| FORUM | ON BEHALF OF | MATTER |
|---|---|---|
| Rhode Island Public Utilities Commission | Rhode Island Division of Public Utilities and Carriers | Proposed wind power purchase agreement between National Grid and Champlain Wind, LLC for the Bowers wind project.<br>Docket 4437. October 2013. |
| North Carolina Utilities Commission | Southern Environmental Law Center and Environmental Defense Fund | Review and analysis of the proposed registration of Buck and Lee Steam Stations as Renewable Energy Facilities<br>Docket Nos. E-7, sub 939, and E-7, sub 940. June 2010. |

## *Industry Leadership*

**Maine Climate Council** | climatecouncil.maine.gov

*On June 26, 2019, the Governor and Legislature created the Maine Climate Council, an assembly of scientists, industry leaders, bipartisan local and state officials, and engaged citizens to develop a four-year plan to put Maine on a trajectory to reduce emissions by 45% by 2030 and at least 80% by 2050. By Executive Order of Gov. Mills, the state must also achieve carbon neutrality by 2045.*

**Member, Energy Working Group** | 2019–Present

*The Energy Working Group will evaluate and recommend short- and long-term mitigation strategies to reduce gross and net annual greenhouse gas emissions from Maine's energy sector, as well as evaluate and recommend short- and long-term strategies and actions for adaptation and resiliency to climate change.*

## *Invited Speaker & Conference Presentations*

- *Blueprint for a Zero Carbon Economy: Achieving Maine's Climate Goals,* panel moderator for virtual event hosted by the Environmental and Energy Technology Council of Maine (E2Tech), June 2020.
- *Energy Storage: Lessons Learned & Opportunities Ahead,* moderated panel at Renewable Energy Vermont, October 2018.
- *Generation Drivers in New England,* presented at the American Wind Energy Association's (AWEA) Wind Energy Regional Conference 2018 – Northeast, June 2018.
- *The Role of Large-Scale Renewables in Meeting the Region's Carbon Reduction Targets,* presented at the Northeast Energy and Commerce Association's Renewable Energy Conference, February 2018.
- *Financing Infrastructure in New England: Can it be done?,* moderated panel at the Northeast Energy and Commerce Association and the Connecticut Power and Energy Society's 22nd Annual New England Energy Conference and Exposition, May 2015.
- *Incorporating Wind Power in Portfolio Planning*, presented at Renewable Energy Vermont, October 2012.
- *New England Renewable Outlook: 2012 at the Crossroads,* presented at the Northeast Energy and Commerce Association's Renewable Energy Conference, February 2012.

### Publications

- *Costs and Benefits of Maine's Net Energy Billing Program,* report prepared for the Coalition for Community Solar Access. March 11, 2021. Lead Author.
- *Alternative Energy Portfolio Standard Review,* report prepared for the Massachusetts Department of Energy Resources. October 30, 2020. Lead Author.
- *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland,* report prepared for the Maryland Public Service Commission regarding an independent analysis of the benefits and costs of solar within each investor owned utility's service territory. November 2, 2018. Lead author.
- *Value of Solar Report*, report prepared for the Maryland Public Service Commission regarding an independent assessment of the value of distributed solar in the service territories of the two largest Maryland electric cooperatives, and developing rate design options that facilitate solar development with minimum impact to non-participating ratepayers. February 24, 2017. Lead author.
- *The Economic, Utility Portfolio, and Rate Impact of Clean Energy Development in North Carolina,* report prepared for the North Carolina Sustainable Energy Association. February 15, 2013. Contributing author.
- *NYSERDA's Renewable Portfolio Standard 2013 Program Review Main Tier Evaluation,* prepared for the New York State Energy Research and Development Authority. September 2013. Contributing author.
- *New York solar study: An analysis of the benefits and costs of increasing generation from photovoltaic devices in New York,* prepared for the New York State Energy Research and Development Authority. January 2012. Contributing author.

## EDUCATION

**M.B.A.** | University of Michigan, Ann Arbor, MI | 2006

**B.E. Engineering** | Dartmouth College, Thayer School of Engineering, Hanover, NH | 1998

**B.A. Engineering Sciences, Environmental Earth Sciences** | Dartmouth College, Hanover, NH | 1997

DAYMARK
ENERGY ADVISORS

# Kevin Pierce

## Senior Consultant

Kevin works with project developers, utilities, and regulators. He helps clients navigate interconnection processes, facilitates competitive procurement of energy, capacity, and renewable attributes, and supports long-term planning, load forecasting, production cost modeling, and economic impact analysis.

### SELECTED EXPERIENCE

- Evaluated the cost effectiveness and deliverability of Efficiency Manitoba's initial 3-year plan as part of the Independent Expert Consultant team.
- Developed a supply and demand model to forecast the price of Connecticut Class II Renewable Energy Credits for the Materials Innovation and Recycling Authority's trash-to-energy generation in order to value their output.
- Previously engaged in an independent corporate separation audit of First Energy's affiliated electric distribution companies operating in Ohio on behalf of the Public Utilities Commission of Ohio (PUCO); initial results include recommendations to both the regulatory commission and First Energy designed to improve reporting and enhance transparency.
- Drafted and filed seasonal cost of gas documentation for Blackstone Gas Company with the Massachusetts Department of Public Utilities as well as preparing monthly compliance filings.
- Analyzed load patterns and authored a load research report as part of a team developing allocated cost of service rate structures for Kaua'i Island Utility Cooperative.
- Operated PCI GenTrader modelling software for Kaua'i Island Utility Cooperative to determine optimal dispatch and fuel costs in support of annual regulatory filings with the Hawaii PUC.
- Developed regression models to perform load forecast modeling for Southern Louisiana Electric Membership Corporation for use in evaluating resource supply options as part of the development of a power supply RFP.
- Assisted the Massachusetts Department of Energy Resources in developing renewable thermal technology models and adoption rate forecasts as part of our assessment of the long-term efficacy of the Massachusetts Alternative Portfolio Standard; as part of this effort, researched the costs of a variety of alternative equipment for thermal heating in order to support the financial model development that assesses the relative benefits of many thermal heating systems.

### AREAS OF EXPERTISE

Regulatory advisory services

Financial evaluation of energy assets

Rate design

Economic analysis, particularly in the area of cost-benefit and cost-effectiveness testing

Clean energy strategy and policy

### BACKGROUND

Daymark Energy Advisors
2019 - Present

Maine International Trade Center
2018

### EDUCATION

M.A., Law and Diplomacy
The Fletcher School at Tufts University

B.A., Political Science
University of Maine