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February 4, 2020

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Review of Proposed Power Purchase Agreements Pursuant to R.I. Gen. Laws § 39-26.1 Docket No._______

Dear Ms. Massaro:

Enclosed for filing with the Rhode Island Public Utilities Commission (Commission) is a 20-year Power Purchase Agreement (PPA) entered into by National Grid[1] with Gravel Pit Solar II, LLC (Gravel Pit) for review and approval under the Long-Term Contracting Standard for Renewable Energy, R.I. Gen. Laws § 39-26.1.1 et seq. (LTC Standard). The proposed PPA with Gravel Pit provides for National Grid to acquire 99% of the renewable energy output and renewable energy certificates (RECs) from Gravel Pit's proposed 50 MW solar facility over a term of 20 years (see initial filing at Bates NG000007).

Gravel Pit was selected by National Grid, in consultation with the Rhode Island Office of Energy Resources (OER) and the Rhode Island Division of Public Utilities and Carriers (Division), out of a total of 41 bids submitted in response to a competitive procurement issued by National Grid on September 12, 2018 (see initial filing at Bates NG000016; NG000021-22). National Grid, in consultation with the OER and Division, selected the Gravel Pit proposal to pursue a long-term power purchase agreement under the LTC Standard because analysis of Gravel Pit's proposal indicated that it had favorable, competitive pricing and significant net benefits for Rhode Island (id. at NG000021-22; NG000159).

Under the terms of the power purchase agreement with Gravel Pit, National Grid will purchase 99 percent of the energy and environmental attributes associated with the facility for a term of 20 years following the commercial operation date of the facility (see initial filing at Bates NG000023).[2] The fixed contract price for energy and RECs is $52.95/MWh over the entire 20-year term of the PPA (id.). The purchase price allocated to energy, in the event the RECs associated with the Facility fail to satisfy the Renewable Energy Standard as an Environmental Attribute is $46.95/MWh (id.).

1 The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

2 The targeted commercial operation date is March 31, 2023 (see initial filing at Bates NG000024; NG000055).

As explained in the enclosed Direct Testimony of Stephen A. McCauley and Katherine Wilson, the PPA is consistent with the purpose and requirements of the LTC Standard. The PPA costs for energy and RECs are projected to be $30.8 million (net present value in 2018 dollars) below the market forecast of energy and RECs over the term of the PPA (see initial filing at Bates NG000025). The PPA is expected to result in total net benefits of over $101 million over the life of the contract (id. at NG000034; NG000335).

This filing also includes a Motion for Protective Treatment in accordance with Rule 1.3(H)(2) of Commission's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company seeks protection from public disclosure of certain highly sensitive and proprietary analysis provided by the Company's third-party consultants. The Company is also requesting protective treatment of certain non-price contractual terms, identified by Gravel Pit as commercially sensitive, which have been redacted at Gravel Pit's request. The Company understands that Gravel Pit intends to move to intervene in this matter to protect its interests in the PPA and will provide a further motion for protective treatment further substantiating the basis of its request. The Company respectfully requests that the Commission preliminarily treat the redacted information in Schedule NG-1 as confidential, pending receipt and ruling on Gravel Pit's anticipated motions. Preliminary confidential treatment will preserve the interests of Gravel Pit until the Commission reaches a determination on the merits of Gravel Pit's legal arguments. Accordingly, the Company has provided the Commission with one (1) complete, unredacted copy of the confidential documents in a sealed envelope marked **"Contains Privileged Information – Do Not Release,"** and has included redacted copies of these materials for the public filing.

Please contact me at 617-951-1400 if you have any questions regarding this filing.

Sincerely,

John K. Habib

John K. Habib, Esq.
R.I. Bar # 7431

cc: Jonathan Schrag, Deputy Administrator, Division (Electronic Only)
Jon Hagopian, Esq. (Electronic Only)
Leo Wold, Esq. (Electronic Only)
Nicholas Ucci, Acting Energy Commissioner, Office of Energy Resources (Electronic Only)
Cynthia Wilson-Frias, Esq.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

Petition of Narragansett Electric Company d/b/a National Grid for Approval of Proposed Power Purchase Agreements Pursuant to R.I. Gen. Laws § 39-26.1	))))	Docket No.________

APPEARANCE OF COUNSEL

In the above-referenced proceeding, I hereby appear for and on behalf of The Narragansett Electric Company d/b/a National Grid.

John K. Habib

John K. Habib, Esq. (RI Bar #7431)
Keegan Werlin LLP
99 High Street, Suite 2900
Boston, Massachusetts 02110
(617) 951-1400

Dated: February 4, 2020

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

Petition of Narragansett Electric Company d/b/a National Grid for Approval of Proposed Power Purchase Agreements Pursuant to R.I. Gen. Laws § 39-26.1	))))	Docket No.________

NATIONAL GRID'S PETITION
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (Commission) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by Commission Rule 1.3(H) and R.I.G.L. § 38-2-1, *et seq.* National Grid requests that, pending entry of findings pursuant to these provisions, the Commission preliminarily grant National Grid's request for confidential treatment pursuant to Public Information, Commission Rule 1.3(H)(2).

I. BACKGROUND

On February 4, 2020, National Grid is filing with the Commission its request for approval of a 20-year Power Purchase Agreement entered into by National Grid for the purchase of energy and environmental attributes from Gravel Pit Solar II, LLC's 50 MW solar photovoltaic generating facility (the PPA), pursuant to a request for proposals for long-term contracts for renewable energy issued on September 12, 2018 (RFP). In support of its request for approval, National Grid is submitting initial testimony and supporting exhibits of Stephen A. McCauley and Katherine Wilson, including a copy of the PPA and certain analyses calculating the net

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1 The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

benefits of the project and that of other proposals submitted in response to the RFP, including proprietary modeling information and analysis provided by the Company's third-party consultants.

Specifically, the Company is seeking protective treatment for each of the following schedules submitted in support of its request for approval (together, the Confidential Information):

Schedule NG-1 [CONFIDENTIAL], the 20-year PPA executed by the Company; and

Schedule NG-3 [CONFIDENTIAL], the RFP Evaluation Report prepared by National Grid's consultant, Tabors Caramanis Rudkevich (TCR).

The Company is also submitting Company Work Papers (hereinafter WP Support) that contain the documentary support for the solicitation and subsequent bid evaluation process followed by the Company in this competitive procurement. Tabs B, C, D and E of the WP Support contains confidential, proprietary and competitively sensitive bid evaluation information for which the Company is seeking protective treatment.[2]

In this proceeding, the Company seeks protective treatment of its evaluation and bid information consistent with past practices in filings related to competitive procurements of long-term contracts. As the Commission is aware, market forecasting methods and evaluation protocols may be used by the Company in future or ongoing solicitations in Rhode Island or other jurisdictions. The protection of such information is vital to ensure the continued success of competitive solicitations to procure the best possible projects for customers.

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[2] The WP Support materials are being provided in electronic format only due to the size and nature of the files. Redacted copies of WP Support Tab D and E are being provided, but the Company requests confidential treatment of the entirety of the information contained in WP Support Tab B and C. The Company notes that public versions of initial bid packages are available on the Company's website for the RFP, https://RICleanEnergyRFP.com.

II. LEGAL STANDARD

The Commission's Rule 1.3(H) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I.G.L. §38-2-1 *et seq.*

Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the Commission falls within one of the designated exceptions to the public records law, the Commission has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure. In that regard, R.I.G.L. §38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The exception "protects persons who submit financial or commercial data to government agencies from the competitive disadvantages which would result from its publication." Critical Mass Energy Project v. Nuclear Regulatory Commission, 975 F.2d 871, 873 (D. D.C. Cir. 1992); see also Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001) (adopting Critical Mass). The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely to either: (1) impair the Government's ability to obtain necessary information in the future; or (2) cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal, 774 A.2d at 47 (emphasis added).

The second prong of the Providence Journal test has been interpreted to not require "a sophisticated economic analysis of the likely effects of disclosure." New Hampshire Right to

Life v. US Dept. of Health and Human Services, 778 F. 3d 43, 50 (1st. Cir. 2015) (quoting Pub. Citizen Health Research Grp., 704 F. 2d 1280, 1291 (1983)). The party opposing disclosure must establish "actual competition and a likelihood of substantial competitive injury" to bring the information under the confidential exemption. Id. In determining whether information is confidential the court should not limit its assessment of bidding information in a singular ad-hoc manner, but rather should acknowledge the likelihood of additional bids in the future. Id., at 51. As discussed further below, the Confidential Information here should be protected because it is commercial or financial information that, if disclosed, would be likely to cause substantial harm to the competitive position of the persons from whom the information was obtained.

III. BASIS FOR CONFIDENTIALITY

The information contained in the un-redacted versions of the Confidential Information contains confidential and proprietary bid information and bid-evaluation information. Specifically, the confidential information contains references to proprietary reports provided to the Company by consultants for evaluation of the bids and market forecasts of energy and renewable energy certificate (REC) prices prepared by the Company's consultant.

A. Proprietary Information Regarding Market Forecast Information And Bid Evaluation Should Be Protected From Public Disclosure.

With regard to Schedule NG-3, the release of the redacted, confidential material to the public would compromise the ability of the Company to negotiate future purchase-power contracts because that material contains proprietary and confidential information about the Company's market forecasts of energy and REC prices. The forecasts were used by the Company to evaluate the net benefits of the project and are considered proprietary by the consultants that produced them. More importantly, however, these projections must be protected from public disclosure because the Company has used this information to evaluate bids associated with the competitive procurements in the past, and may continue to use this forecast, or similar forecasts, to evaluate future bids for renewable generation services. If other parties gain access to the details of Schedule NG-3, and the assumptions regarding future energy and REC prices contained therein, the Company's ability to negotiate the best deals possible on behalf of customers would be compromised. Accordingly, the Commission should protect the confidential information in those documents from the public record.[3]

B. Commercially Sensitive Contract Terms Have Been Redacted At The Counterparty's Request.

The counterparty to the PPA, Gravel Pit Solar II, LLC (Gravel Pit), has identified certain terms or project information in the PPA, Schedule NG-1, which it considers competitively sensitive and which could cause it economic harm if publicly released. The Company understands that Gravel Pit intends to move to intervene in this matter to protect its interests in the PPA and will provide a further motion for protective treatment further substantiating the basis of its request. At this time, the Company respectfully requests that the Commission preliminarily treat the redacted information in Schedule NG-1 as confidential, pending receipt and ruling on Gravel Pit's anticipated motions. Preliminary confidential treatment will preserve the interests of Gravel Pit until the Commission reaches a determination on the merits of Gravel Pit's legal arguments.

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[3] The Commission has protected proprietary confidential evaluation material historically. See Docket No. 4764 November 20, 2017 Hearing on Motion for Protective Treatment.

B. Confidential Bid Information and Bid Evaluation Information In The Company's WP Support Material Should Be Protected From Public Disclosure.

Information contained in WP Support Tabs B, C, D and E includes confidential bid information submitted in response to the RFP, evaluation material derived from confidential bid information, and details of the Company's confidential bid evaluation protocol. This information should be protected from public disclosure to protect the interests of the bidders, consistent with the terms of the RFP, and to ensure that the Company can continue to conduct competitive solicitations in the future without revealing the details of its scoring methodology to prospective bidders.

The RFP permitted bidders to designate information in their bid as confidential, not to be disclosed to the public. The Company agreed to use commercially reasonable efforts to treat the non-public information received in response to the RFP in a confidential manner, and not to disclose such information to any third party other than the state agencies involved in the evaluation or review of proposals. See Schedule NG-2, at 24-25. The process was designed this way to encourage participation, promote competition in the bidding process, and maximize the value of the bids received. Any disclosure now could significantly damage the RFP process. Consistent with the commitments made in the RFP, the Company respectfully requests that confidential bid information contained in WP Support Tab B and C be protected from public disclosure.

Moreover, if the bid-related information or contract price terms are disclosed, the effectiveness and competitiveness of competitive solicitations for renewable generation will be harmed substantially. Indeed, if the confidential bid information is released, it may make bidders more reluctant to submit bids in future solicitations to the extent they wish to submit bids confidentially, or may inflate bids that might otherwise be submitted based on a respondent's review of the Company's bid information received to date. Thus, the release of the bid information at this time would potentially prejudice future RFPs for renewable generation and ultimately harm the Company's customers.

In addition, WP Support Tab D and E includes information about the Company's allocation of points assigned in the qualitative review of proposals. If other parties gain access to the details of these decisions, and the assumptions regarding evaluation of proposals contained therein, the Company's ability to negotiate the best deals possible on behalf of customers would be compromised. Accordingly, the Department should protect the information in WP Support Tabs D and E from the public record.

IV. CONCLUSION

Accordingly, the Company requests that the Commission grant protective treatment above-listed Confidential Information.

Respectfully submitted,

NATIONAL GRID

By its attorney,

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Dated: February 4, 2020

The Narragansett Electric Company
d/b/a National Grid

Review of Power Purchase Agreements Pursuant to R.I. Gen. Laws § 39-26.1

February 4, 2020

RIPUC Docket No. _____

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

DIRECT TESTIMONY

OF

STEPHEN A. MCCAULEY
AND
KATHERINE WILSON

Table of Contents

I. <u>Introduction</u>

Q. Mr. McCauley, please state your name and business address.

A. My name is Stephen A. McCauley. I work at National Grid USA Service Company, Inc. (National Grid), with a business address of 100 E. Old Country Road, Hicksville, New York 11801.

Q. Please describe your position and responsibilities at National Grid.

A. I am Director of Wholesale Electric Supply and Environmental Transactions in the Energy Procurement organization of National Grid. As Director, one of my responsibilities is to oversee the procurement of energy, capacity and ancillary services, and other energy supply-related activities for National Grid's operating companies, including The Narragansett Electric Company d/b/a National Grid (Narragansett or the Company). For Narragansett, these activities include the competitive solicitations for renewable energy projects, including negotiations for long-term contracts for renewable energy projects.

Q. Please describe your education and professional background.

A. I graduated from the United States Merchant Marine Academy in 1984 with a Bachelor of Science degree in Marine Engineering Systems. I joined National Grid in 1992 as an engineer for the gas peak-shaving plants and the gas-regulator and telemetering stations. In 1996, I joined the gas supply group as a trader responsible for purchasing the natural gas supply requirements for the firm gas customers and the Long Island Lighting Company generation facilities. In 1999, my responsibilities were changed to managing the emissions-allowance portfolio and the financial-hedging activities of the regulated utilities. In 2002, I was promoted to Director of Origination and Price Volatility Management. In 2017, I was promoted to my current position.

Q. Have you previously testified in proceedings before the Rhode Island Public Utilities Commission (PUC) or in other jurisdictions?

A. Yes, I have testified before the PUC on several occasions involving both gas and electric costs; Gas Procurement Incentive Plan (GPIP), Natural Gas Portfolio Management Plan (NGPMP), Standard Offer Service (SOS) Procurement Plan, Renewable Energy Standard (RES) Procurement Plan and the Solicitation of Long-Term Contracts for Renewable Energy and Renewable Energy Certificates. I have also testified before the Massachusetts Department of Public Utilities multiple times.

Q. Ms. Wilson, please state your name and business address.

A. My name is Katherine Wilson. My business address is National Grid, 40 Sylvan Road, Waltham, MA 02451.

Q. By whom are you employed and in what capacity?

A. I am a Lead Trader in the Environmental Transactions, Energy Procurement of National

Grid USA Service Company, Inc. (Service Company), which provides services to Narragansett Electric Company d/b/a National Grid (National Grid).

Q. Please describe your present responsibilities.

A. My responsibilities include managing the competitive solicitations for renewable energy projects, including negotiations for long-term contracts for renewable energy projects for National Grid's New England electric regulated operating companies in Massachusetts and Rhode Island.

Q. Please describe your education and professional background.

A. I received Bachelor and Master of Science degrees in Resource Economics from the University of Massachusetts Amherst. In July 2019, I joined National Grid. Prior to my current role, I was at Eversource Energy for approximately four years as a member of the Evaluation Team selecting clean energy and offshore wind projects in Massachusetts, and five years at Cambridge Energy Research Associates (CERA), which ultimately became IHS Markit after a series of acquisitions, researching the electric utility business in general and power markets in particular.

Q. Have you previously testified in proceedings before the Rhode Island Public Utilities Commission (PUC) or in other jurisdictions?

A. No, I have not.

Q. What is the Company requesting in this proceeding?

A. The Company is seeking PUC approval under the Long-Term Contracting Standard for Renewable Energy (LTCS or LTC Standard) of a power purchase agreement (PPA) for the purchase of energy and environmental attributes from an eligible renewable energy generation facility, pursuant to the Request For Proposals (the RFP) issued on September 12, 2018.

Pursuant to the RFP, the Company conducted a solicitation for eligible renewable energy resources, selected and negotiated a PPA with Gravel Pit Solar II, LLC (Gravel Pit) to acquire 99% of the renewable energy output and renewable energy certificates (RECs) of the proposed renewable energy project over a term of 20 years. Block Island Utility District and Pascoag Utility District will purchase the remaining 0.2% and 0.8% of the output of the facility, respectively, pursuant to power purchase agreements that are expected to be substantially the same as the PPA, other than certain provisions that are specific to their status as utility districts.

Q. What is the purpose of your testimony?

A. Our testimony will demonstrate that: (1) the Company's procurement of the PPA satisfies the requirements of the LTC Standard relating to the solicitation of long-term contracts from renewable energy developers, and that the Company followed the provisions of the RFP issued on September 12, 2018 and approved by the PUC in Docket No. 4822; (2) describe the competitive solicitation and the selection of the Gravel Pit Project; (3) explain the pricing and other key provisions of the PPA; and (4) address the applicable goals and principles from the PUC's Docket No. 4600A Order and Guidance Document.

Q. What schedules are you sponsoring in your testimony?

A. We are sponsoring five schedules, including:

- Schedule NG-1 [CONFIDENTIAL] is the 20-year PPA executed by the Company;
- Schedule NG-2 is a copy of the Request for Proposals (RFP) approved in Docket No. 4822;
- Schedule NG-3 [CONFIDENTIAL] is the RFP Evaluation Report prepared by Tabors Caramanis Rudkevich (TCR);
- Schedule NG-4 presents the Company's Docket No. 4600 analysis; and
- Schedule NG-5 provides a Comparison of Gravel Pit project's net benefits to other programs.

Also accompanying this filing are Company Work Papers (hereinafter WP Support) that contain the documentary support for the solicitation and subsequent bid evaluation process followed by the Company in this competitive procurement. The WP Support is provided in electronic format only and is arranged as follows:

- Tab A - List of entities sent the RFP;
- Tab B - [CONFIDENTIAL] initial bid package for bids received plus additional information received from the bidder used for the evaluation;
- Tab C - [CONFIDENTIAL] bidder communications;
- Tab D - [CONFIDENTIAL] Qualitative Bid Evaluation Protocol;
- Tab E - [CONFIDENTIAL] Qualitative summary scoring sheets for each proposal;

Q. Please describe how you have organized your testimony.

A. Section I of our testimony is an introduction. Section II of our testimony describes the RFP and provides an overview of the LTC Standard and the requirements set forth in the PUC's Rules and Regulations Governing Long-Term Contracting Standards for Renewable Energy (LTC Rules & Regulations) regarding the review and approval of executed PPAs under the LTC Standard. Section III of our testimony describes and discusses the solicitation process, including bid scoring and project selection. Section IV of our testimony describes the specifics of the PPA and discusses how it satisfies the requirements of the LTC Standard and the LTC Rules & Regulations. Section V of our testimony addresses the applicable goals and principles of the PUC's Docket No. 4600A Order and Guidelines.

II. Overview of the RFP and LTC Standard Requirements

Q. Please describe the process of formulating the RFP, as approved by the PUC.

A. The RFP, provided as Schedule NG-2, was developed by Narragansett and in consultation with the Rhode Island Office of Energy Resources (OER) and the Rhode Island Division of Public Utilities and Carriers (Division). The RFP development process involved careful consideration of the LTCS as well as a range of other issues involved in creating a standard method and timetable for bid solicitation and evaluation. The RFP was issued both to satisfy the Company's LTCS obligations and to further the renewable energy goals of Rhode Island in a cost-effective manner. Therefore, the Company was able, but not required, to select up to 400MW of renewable energy through the RFP.

The Company submitted the RFP to the PUC for approval in accordance with LTCS requirements. The RFP was reviewed and approved by the PUC in Docket No. 4822.

Q. Why is the Company seeking approval of the PPA under the LTC Standard?

A. National Grid's obligation to procure a minimum long-term contract capacity under the LTCS is 90 MW (or, the equivalent of 788,400 megawatt-hours (MWh) per year). R.I.G.L. § 39-26.1-2. The long-term contract capacity is determined by adjusting the nameplate capacity of a facility by the capacity factor of the renewable energy resource, as determined by the ISO-New England rules.

The 2014 amendments to the LTC Standard, R.I. Gen. Laws §§ 39-26.1-3(c)(2) and (f) required that the electric distribution company conduct solicitations at least once per year beginning in 2014 until 100% of the 90 MW requirement is met. In addition, Section 1.5C of the LTC Rules & Regulations provides that in the event a long-term contract is terminated, the Company "will not be found noncompliant . . . and it shall be required to make additional annual solicitation and to enter into additional Long-Term Contracts in order to replace the energy, capacity and/or NEPOOL GIS Certificates lost as a result of the termination."

On January 23, 2017 Champlain Wind, LLC (a/k/a, Bowers Wind) gave notice to Narragansett of Termination of the Power Purchase Agreement (PPA) dated as of August 2, 2013. With the termination of this PPA, the contract capacity of all LTCS PPAs dropped below the required 90 MW.

Therefore, at the time the RFP was issued, National Grid had executed contracts for approximately 87 percent of the minimum long-term contract capacity required by the LTCS. National Grid is required by Section 1.5C of the Regulations to solicit the remaining approximately 13 percent of its LTCS capacity, which is the equivalent of approximately 94,124 MWh or 10.74 MW. The Gravel Pit Solar Project will fulfill the Company's remaining LTCS obligation. The Gravel Pit Solar Project is a 50 MW solar electric generation facility, with a proposed 27 percent capacity factor.[1] With the PPA Buyer's Percentage Entitlement of 99%, the projected long-term contract capacity is equal to 13.36 MW.

Q. Please explain the requirements for solicitations under the LTC Standard.

A. Under R.I. Gen. Laws § 39-26.1-3, the Company was required to annually solicit proposals from renewable-energy developers for long-term contracts beginning on or before July 1, 2010. The solicitation process had to include an annual solicitation but could also include individual negotiations.

The solicitation process under R.I. Gen. Laws §§ 39-26.1-3(b) must permit a reasonable amount of negotiating discretion for the parties to engage in commercially reasonable, arms-length negotiations over final contract terms. In addition, Section 1.4B of the LTC Rules and Regulations require that the Company file its proposed timetable and method for solicitation with the PUC and explain: (1) the methods reviewed or selected; (2) the rationale for choosing the proposed method selected and for rejecting other methods; (3) set forth a clear timetable for each event that will occur prior to filing a contract for Commission review; (4) set forth the Company's intent for use of energy, capacity and

[1] Per the proposal, submitted by North Light Energy, the Gravel Pit Project will be using the latest inverter technology, tracking panel rack systems, bi-facial panels, and the newest engineering approaches to produce substantially more energy from a smaller footprint than similar solar projects, resulting in the 27 percent capacity factor.

other attributes procured; (5) set forth the criteria that will be used to evaluate responses to the solicitation, including the value of direct economic benefits to the State of Rhode Island when evaluating whether the pricing is consistent with what an experienced power market analyst would expect to see in transactions involving newly developed renewable energy resources; (6) address how the Company will seek to fulfill its annual obligation in the event the annual solicitation does not result in the execution of commercially reasonable contracts; and (7) address how the Company may, at its option, seek to execute long-term contracts in excess of the given year's annual obligation in the event the annual solicitation results in proposals that could reasonably result in the execution of commercially reasonable contracts in excess of the annual obligation.

Q. Does the RFP meet the requirements for a solicitation under the LTC Standard?

A. Yes. In the PUC's review of the RFP in Docket No. 4822, it found the Company's proposed solicitation process and timetable to be consistent with the LTCS. Moreover, the Commission found the solicitation will facilitate contracts that are consistent with the purposes of the Long-Term Contracting Act and that are consistent with the policy of the state.

Q. Please describe the eligibility criteria under the LTC Standard for renewable energy projects.

A. Pursuant to the LTC Standard, an "eligible renewable energy resource" means a resource as defined in § 39-26-5 and any references therein, including but not limited to wind, solar and small hydro facilities.

In addition, the LTC Standard requires that:

(1) the renewable energy resource is newly developed such that it has not begun operation, nor have the developers of the units implemented investment or lending agreements necessary to finance the construction of the unit;

(2) the contract must be commercially reasonable, with terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving newly developed renewable energy resources;

(3) pricing under the contracts must be below the forecasted market price of energy and renewable energy certificates over the term of the proposed contract, using industry standard forecasting methodologies as have been used to evaluate pricing in the past solicitation process reviewed by the PUC.

Q. Does the PPA executed pursuant to the RFP meet these requirements?

A. Yes. As described in Section IV, herein, the PPA meets each of the requirements of the LTC Standard. The selected project has not begun operation, nor, at the time of selection, had the developer implemented investments or lending agreements necessary to finance construction of the project.[2] The PPA is commercially reasonable, as required by Rhode Island law. Finally, pricing under the contract is forecasted to be below the forecasted

[2] The project development and financing status was confirmed by the bidder in Section 7.13 of its proposal.

market price of energy and renewable energy certificates over the term of the proposed contract, using industry standard forecasting methodologies as have been used to evaluate pricing in past solicitation processes reviewed by the PUC.

III. Solicitation for Long-Term Renewable Contract

Q. Please describe the solicitation process completed in accordance with the RFP.

A. The Company released the RFP to bidders on September 12, 2018. The RFP was distributed to approximately 600 individuals and entities with an interest in developing renewable energy projects. The list of entities to which the RFP was sent is provided in WP Support, Tab A.

The RFP sought proposals for the supply of energy and Renewable Energy Certificates and related attributes (RECs) from eligible renewable projects under one or more long-term power purchase agreement. Eligible bids included projects with a nameplate capacity of at least 20 MW each, not to exceed 200 MW each, with proposed PPAs with durations of 10 to 15 years, though long-term contracts exceeding 15 years could be submitted as subject to approval of the PUC under R.I. Gen. Laws § 39-26.1-3(a). National Grid was authorized, but not required, to select up to 400 MW of renewable energy projects through the RFP. The RFP also noted that the Pascoag Utility District and the Block Island Power Company may be invited to purchase a portion of the energy and RECs from any selected project(s).

A bidder conference was held on September 26, 2018. Prospective bidders had an opportunity to submit written questions to the Evaluation Team pertaining to the RFP before submitting bids. Approximately 11 questions (with subparts) were submitted, which the Evaluation Team responded to in writing. All questions and answers were posted on the public website for the RFP, https://RICleanEnergyRFP.com.

Q. How many bids were submitted in response to the RFP?

A. In response to the RFP, a total of 41 proposals were received. A copy of each bid package submitted to Narragansett in response to the RFP is included in WP Support Tab B [CONFIDENTIAL].

Q. Please describe the bid evaluation process, as outlined in the RFP.

A. The Company evaluated bids in consultation and coordination with the OER and the Division. The evaluation consisted of three stages of evaluation, as described in Section 2.1 of the RFP. The first stage (Stage One) consists of a review of whether the proposals satisfy specified eligibility and threshold requirements. Eligibility requirements are designed to ensure that the proposals under review offer the appropriate product and PPA tenor from qualifying newly developed renewable energy resources. Threshold requirements are designed to ensure that proposed projects satisfy statutory criteria under the LTCS and meet minimum standards for viability.

The second stage (Stage Two) evaluated bids in a technology-neutral manner based on specified price and non-price evaluation criteria. This portion of the evaluation is quantitative in nature (i.e., a quantitative scoring system was utilized). Proposals that pass the eligibility and threshold review and that score favorably in the Stage Two advance to the final stage of the evaluation process.

The final stage, Stage Three, involved further evaluation of the remaining bids on matters pertaining to project viability and the extent to which the bids, individually and as a portfolio, achieve a variety of objectives, including cost-effectiveness and diversity of resources.

Q. Did National Grid retain independent consultants to assist with the evaluation?

A. Yes. National Grid retained TCR to conduct an analysis to quantify the net costs and benefits under Stage Two, and to run any portfolio analysis required in Stage Three. This was a similar practice used in previous Rhode Island solicitations and used the best available information at the time of the evaluation.

Q. Can you please elaborate on the elements of the first stage evaluation?

A. Stage One of the evaluation involved reviewing bids to determine whether they complied with the eligibility, threshold, and other minimum requirements of Section 2.2 of the RFP. As set forth in the RFP, Section 2.2, Stage One criteria are designed to ensure that proposed projects comply with the requirements of the RFP, satisfy all relevant statutory criteria, and meet minimum standards demonstrating project viability. The criteria are specified in Sections 2.2.1 through 2.2.4 of the RFP.

Q. Were any of the bids received disqualified under Stage One of the evaluation?

A. None of the bids received were disqualified under Stage One of the evaluation. However, one bidder withdrew two bid proposals prior to the evaluation process. Therefore, 39 bid proposals passed the eligibility and threshold evaluation criteria and continued on to be evaluated under Stage Two.

Q. Please describe the evaluation of the bids under Stage Two.

A. As described in Section 2.3 of the RFP, for each submission that passed the eligibility and threshold evaluation criteria of Stage One, National Grid conducted an initial price and non-price analysis of the proposals. Price factors were weighted at eighty percent (80%) and non-price factors at twenty percent (20%) for the purpose of conducting the initial evaluation.

Q. Were all projects that passed Stage One evaluated on both price and non-price factors?

A. Yes, all projects that passed Stage One were evaluated on both quantitative and qualitative factors. However, prior to creating the final ranking of projects following the Stage Two evaluation of all bid proposals, nine proposals were withdrawn by the proposal sponsors. The initial Stage Two ranking therefore included 30 proposals, 19 of which met the LTCS requirement of being commercially reasonable in that they resulted in pricing below the forecasted market price of energy and renewable energy certificates over the term of the proposed contract.

Q. How were price-related factors evaluated in Stage Two?

A. The price evaluation is based on a comparison of (a) the total contract cost of the products bid, which must include energy and RECs, to (b) the estimated market value of these products, taking into consideration the production profile and location of the proposed project over the term of the proposed contract term and any locational marginal price benefits. National Grid used a price forecast that incorporated the effects of future federal or state regulation of carbon dioxide emissions on relevant energy prices. The metric used was net $/MWh cost or benefit. As part of the price evaluation, National Grid assessed the relative above-market or below-market costs on a present value basis in order to assess the relative front-loading or back-loading of the proposed bid. Proposals were ranked from highest to lowest present value of net benefit (or lowest to highest present value of net cost) on a dollars per MWh basis based on the result derived through the application of the methodology described above.

All projects, regardless of their location, were required to provide other direct economic benefits to the State of Rhode Island, such as job creation, increased property tax revenues, or other similar revenues, or pricing benefits, as determined by National Grid's analysis of the value of the respective direct economic benefits to the State of Rhode Island in relation to the cost under the contract. For projects that were not located in Rhode Island, the benefits of cost savings for Rhode Island customers resulting from competitive pricing were considered. The potential economic benefits of each project were evaluated in the non-price analysis of Stage Two, addressed below. The price-related evaluation process is outlined in Section 2.3.1 of the RFP.

Q. How were non-price-related factors evaluated in Stage Two?

A. The non-price evaluation consisted of: (1) siting, permitting, and environmental impacts; (2) project development status and operational viability; (3) experience and capabilities of bidder and the project development team; (4) interconnection; (5) financing; (6) contract risk; and (7) economic benefits to Rhode Island. Each of these categories is further broken down into more granular subcategories as described in Section 2.3.2.2 of the RFP. The weight assigned to each criterion was determined prior to evaluation of any bids received and was submitted to the PUC under seal in Docket 4822.[3] The non-price evaluation criteria, other than contract exceptions, are designed to assess the likelihood of a project

[3] The breakdown of points available within the category of Economic Impact was revised to allow for more granular point allocations due to the variation of commitments within the proposals. The total points allocated to the Economic Impact criterion and all other qualitative criteria remained unchanged from that submitted in Docket 4822.

coming to fruition based on various factors critical to successful project development.

Q. Please describe the evaluation of the bids under Stage Three of the evaluation.

A. In Stage Three, the Company considered and weighted the following factors: (1) ranking in Stage Two; (2) commercial reasonableness of the bid; (3) risk associated with project viability of the bid; (4) the extent to which the bid would create additional economic and environmental benefits within Rhode Island; and (5) portfolio effect: the overall impact of any combinations of proposals. The objective of Stage Three is to select the proposal(s) that provide the greatest value consistent with the stated objectives and requirements as set forth in the RFP.

During Stage Three, a portfolio was analyzed consisting of the three top-ranked proposals, which was a portfolio with a total nameplate capacity of 398 MW. The Stage Three ranking results consisted of 31 proposals, 20 of which met the LTCS requirement of being commercially reasonable in that they resulted in pricing below the forecasted market price of energy and renewable energy certificates over the term of the proposed contract.

Q. Which projects were selected for contract negotiation?

A. After completing all stages of the evaluation process, Gravel Pit Solar's project was the clear top-ranked bid. Final proposal evaluation scores and rankings are identified in Schedule NG-3. Based on the evaluation results, Gravel Pit Solar was selected for contract negotiation on July 25, 2019.

Q. Why did the Company only select 50 MW when the RFP allowed for selection of up to 400 MW?

A. The Company needed approximately 50 MW nameplate capacity to fulfill its remaining requirement under the Long-Term Contracting Standard. To help meet Governor Gina M. Raimondo's goal of increasing Rhode Island's clean energy portfolio ten-fold by 2020, the Company issued an RFP that would allow, and considered procuring up to 400 MW nameplate capacity of renewable energy instead of just the 50 MW needed to meet the LTCS requirement. Prior to making the final selection in this RFP, the Company voluntarily selected, negotiated, filed and received approval of the Revolution Wind 400 MW offshore wind PPA in accordance with the Affordable Clean Energy Security Act, R.I. Gen. Laws Chapter 39-31. With the selection of the 400 MW Revolution Wind project, the Company was forecasted to meet the 1,000 MW goal by the end of 2020 and therefore only needed to satisfy the LTCS requirement in this RFP. The selection of the 50 MW Gravel Pit project fulfilled the remaining LTCS requirement.

IV. <u>Description of the Contract and Consistency with the LTC Standard and the PUC's Regulations</u>

Q. Please provide an overview of the PPA proposed for approval.

A. As a result of the contract negotiations, the Company executed a PPA with Gravel Pit for the purchase of energy and environmental attributes from a 50 MW solar electric generation facility located in East Windsor, Connecticut. The PPA is conditioned upon obtaining regulatory approval from the PUC. Under the terms of the PPA, if the PPA does not receive final unappealable approval of the project within 270 days after the date the PPA is filed with the PUC, either party can terminate the PPA. The PPAs include terms for the purchase of energy and RECs, as described below.

Q. Please describe the particulars of the PPA executed by the Company.

A. The PPA is for the purchase of 49.5 MW of the solar generating facility, due to the Buyer's Percentage Entitlement of 99%. The remaining 1%, or 0.5 MW, is being purchased by Block Island Utility District and Pascoag Utility District. The PPA has a twenty-year term for the purchase of energy and RECs.

Q. Please describe the pricing in the PPA.

A. The PPA provides a fixed contract price of $52.95/MWh for the energy and RECs over the entire 20-year term of the PPA. However, as described below, if the Gravel Pit project fails to qualify as an eligible renewable energy resource due to a change in law and notwithstanding Gravel pit's commercially reasonable efforts, the Company must continue purchasing energy at the Adjusted Price for energy only of $46.95/MWh.

Q. Does the PPA include each of the provisions and terms required under Section 1.5 of the LTC Rules & Regulations?

A. Yes, the PPA includes commercially reasonable terms covering all 14 items identified under Section 1.5 of the LTC Rules and Regulations.

Q. Do the RECs generated by the project and included in the PPA qualify under the Renewable Energy Standard (RES) program?

A. The Gravel Pit project qualifies as an "eligible renewable energy resource", as defined pursuant to the RES statute, R.I. Gen. Laws § 39-26-5 and the regulations promulgated thereunder.[4] If, solely as a result of change in law, the energy provided no longer meets the requirements for eligibility, Gravel Pit Solar must use commercially reasonable efforts to ensure qualification.

Q. What is the Commercial Operation Date associated with the project?

A. The Commercial Operation Date for the Gravel Pit Project is March 31, 2023. The Company considers this date reasonable based on certain critical milestones for the construction and achievement of commercial operation as more particularly set forth in Section 3.1(a) of the PPA, and based on the duration between contract execution and commercial operation in other contracts for similar facilities executed by the Company.

[4] See Section 1.5 Rules and Regulations Governing the Implementation of a Renewable Energy Standard.

Q. Please describe how the Company determined that the proposed price is commercially reasonable over the term of the contract.

A. The proposed price in the PPA was solicited through an open, robust competitive bid process. The RFP was widely distributed to a list of approximately 600 entities active in the renewable generation market in the Northeast and nationally. It was also posted on a public website maintained by National Grid. The RFP process addressed each of the requirements under Section 1.4 of the LTC Rules & Regulations. The RFP process was fairly administered, and the results were evaluated against a model derived market price forecast provided by TCR.

Q. How does the cost for energy and RECs under the PPA compare with the forecasted market price for energy and RECs?

A. Based on the analysis conducted at the time of the proposal evaluation, the aggregate cost for energy and RECs under the PPA is less than the forecasted market price for energy and RECs over the 20-year term of the contract. Overall, based on an analysis of the bid data, the cost of energy and RECs under the PPA, based on commercial operation dates as reflected in the bid, is less than the forecasted market prices by a total of $30.8 million (Net Present Value in 2018 dollars) over the life of the PPA.

Q. How were the below-market costs derived?

A. Below-market costs were calculated by taking the sum of the Direct Costs and Direct

Benefits.[5] The method of calculating the Direct Costs and Direct Benefits is described fully in the TCR report.

Q. If the Gravel Pit Project fails to qualify as an eligible renewable energy resource are the Company's customers still obligated to pay for the RECs?

A. If the failure to qualify is solely as a result of change in law and notwithstanding Gravel Pit's commercially reasonable efforts, the Company must continue to purchase the energy under the Adjusted Price. See § 4.7(b). However, the Company is not obligated to pay for any REC which fails to satisfy or maintain its eligibility for the RES. See § 4.1(b).

Q. What are the forecasted regional greenhouse gas benefits of the Project?

A. The annual reduction in societal greenhouse gas emission reductions is projected to be approximately 41,000 tons CO2/year.

Q. How does the approval of the PPA facilitate the financing of renewable energy generation?

A. The PPA requires that the facility meet the definition of a Newly Developed Renewable Energy Resource under R.I. Gen. Laws § 39-26.1-2(6). See §3.5(g). In addition, Gravel Pit confirmed in its proposal that obtaining a long-term contract is the most critical element of

5 Direct Costs and Direct Benefits described in TCR Report section 2.1.1.

securing financing for the project because the resulting cost of financing is a function of the certainty of revenues.

Q. Does the PPA provide economic benefit to Rhode Island?

A. Yes. The PPA is forecasted over the term to result in the Company's customers paying less than the market price for energy and RECs, based on the quantitative model developed by TCR and discussed in detail in Schedule NG-3. Accordingly, the PPA will result in economic benefits by providing cost savings to Rhode Island customers. In addition, as part of the Gravel Pit Project bid, Gravel Pit committed to investing at least $300,000 into training Rhode Island's new energy workforce.

Q. Were other commercially reasonable proposals also submitted in response to the RFP?

A. Yes. Of the 30 bid proposals analyzed in Stage Two, 19 other bid proposals were commercially reasonable in that they resulted in pricing below the forecasted market price of energy and renewable energy certificates over the term of the proposed contract.

Q. Did any of those proposals include facilities that would be located within the state of Rhode Island?

A. No. The 19 proposals mentioned above all consisted of project sites and delivery points outside of Rhode Island.

Q. How did the Company determine that the Gravel Pit Project produced favorable economic benefits to Rhode Island as compared to other commercially reasonable proposals?

A. The Company determined that the Gravel Pit Solar Project was favorable to all other commercially reasonable proposals based on the final results and rankings of the quantitative and qualitative evaluation, which resulted in Gravel Pit Solar being the top-ranked project.

Q. Why does the Company support PUC approval of the PPA under the LTC Standard?

A. The PPA will benefit customers and the State of Rhode Island for the following reasons: (1) the PPA pricing is favorable relative to all of the bids received and evaluated in the robust, competitive solicitation process, and relative to the market forecast at the time of bid evaluation, as discussed above; (2) the project selected is, in total, sized to meet the Company's remaining obligation under the LTC Standard; and (3) the PPA otherwise satisfies the requirements of the LTC Standard, as discussed above.

V. Analysis of Docket No. 4600 Benefit-Cost Framework

Q. Please summarize the purpose of the PUC's Docket No. 4600 Benefit-Cost Framework.

A. In Docket No. 4600, Investigation into the Changing Electric Distribution System, the PUC determined that, due to the changing and modernizing electric distribution system, it was necessary to develop an improved understanding and consistent accounting of the costs and benefits caused by various activities on the system.[6] The PUC sought to answer the following questions:

> (1) What are the costs and benefits that can be applied across any and/or all programs, identifying each and whether each is aligned with state policy?
>
> (2) At what level should these costs and benefits be quantified – where physically on the system and where in cost-allocation and rates? and
>
> (3) How can we best measure these costs and benefits at these levels – what level of visibility is required on the system and how is that visibility accomplished?[7]

After a thorough stakeholder process, the PUC accepted the Stakeholder Report and adopted the goals, principles and new Rhode Island Benefit-Cost Framework (Framework). The Framework includes thirty-four categories of costs and benefits and the PUC also issued a Guidance Document further discussing the goals, principles and values to be considered in connection with the Framework.[8] The Framework identified several methodologies that could be used to quantify costs and benefits, but also recognized that the Framework is meant to be refined or modified over time as the PUC and parties to dockets gain more experience applying the Framework.

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[6] Docket No. 4600, Report and Order at 4-5 (May 4, 2017).

[7] Id. at 5.

[8] Id. at 8.

In adopting the Framework, the PUC held the following:

> The PUC holds that the Framework should be relied upon, but also that it should not be the exclusive measure of whether a specific proposal should be approved. Rather, the Framework should serve as a starting point in making a business case for a proposal. For example, there may be outside factors that need to be considered by the PUC regardless of whether a specific proposal is determined to be cost-effective or not. This may include statutory mandates or qualitative considerations. Such application is consistent with the PUC's broad regulatory authority in setting just and reasonable rates.[9]

Q. Does the PUC's Guidance on "Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid" (Guidance Document) provide further detail about how the Framework should be applied in this case?

A. Yes. The Guidance Document provides that a proponent of any proposal affecting the Company's electric rates should provide evidence demonstrating how the proposal advances, detracts from, or is neutral to each of the stated goals of the electric system. Additionally, specific to the Framework, the Guidance Document provides that "any rate design proposal should, at the very least, reference each category within the first two columns of the Report: Mixed Cost-Benefit, Cost, or Benefit Category and System Attribute Benefit/Cost Driver (Categories and Drivers, respectively)."[10] The Guidance Document states that each Categories and Drivers should be discussed and where costs and benefits can be quantified, the proponent should provide the basis for the quantification

[9] Id. at 23.

[10] Guidance Document, at 6.

reached. Where quantification is not possible or practical, the proponent should explain.[11] While the Company's request for approval of the PPA under LTCS is not a rate design proposal, the Company has followed the directives of the Guidance Document as closely as possible.

Q. How has the Company applied the Framework to the review of the PPA?

A. To support this filing, the Company conducted its own analysis to demonstrate that the PPA will result in net benefits and is consistent with state energy policies. Based on additional guidance from the PUC,[12] the Company applied the Framework and related business case to the PPA.

To apply the Framework, the Company first reviewed each category of costs and benefits identified in the Framework to determine which categories are applicable to the PUC's review of the PPA. The analysis attached as Schedule NG-4 indicates the Framework category in the column on the left, and the column on the right indicates whether the criteria is applicable, and if so, how it has been addressed through the project analysis.

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[11] Guidance Document, at 6.

[12] The PUC provided additional guidance on the appropriate application of the Framework in an Open Meeting held on August 29, 2018 in docket No. 4822 and at a technical session held in docket No. 4600 on November 1, 2018.

Q. Did the Company determine that any of the costs and benefits within the Power System Level category are not applicable to the review of this PPA?

A. Yes. The PPA is a long-term wholesale power contract for the purchase of energy and RECs, to be delivered at the transmission level. Therefore, there are no costs or benefits to be quantified at the distribution level. Similarly, the PPA is not related to energy demand reduction and therefore has no energy demand reduction induced price effect; although the project's indirect benefit impact on market LMP price change[13] and REC price change has been quantified. In addition, the PPA does not include the purchase of capacity, and as a result, there are no direct capacity costs or benefits associated with PPA. Modeling indirect costs or benefits associated with capacity is beyond the accuracy of the modeling employed by the Company and TCR. Accordingly, capacity value and ancillary services values have been identified as applicable, but not quantifiable. Finally, all interconnection and transmission upgrade costs are included in the fixed purchase price of energy and RECs, and therefore all electric transmission infrastructure costs have been accounted for in the PPA cost of energy and RECs.

Q. Are any of the Customer Level costs and benefits applicable to the PPA?

A. No, the Customer Level costs and benefits are not applicable to the PPA. The costs and

[13] The indirect energy price change benefit, attributed to the proposal, was positive but had little to no measurable impact. Per the TCR Report, Appendix C.2 this proposal did not meet the criteria for having a significant LMP impact so the indirect energy price impact was nullified.

benefits in the Customer Level category are intended to measure direct participant costs and benefits of retail customer program participation, such as energy efficiency or distributed energy resource programs. The PPA is not a retail customer program. Rather, all distribution customers will pay for the cost of the PPA through distribution rates such that costs and benefits of the PPA are distributed equitably to all customers. While the Company does not consider the Customer Level costs and benefits applicable to the review of the PPA, the Company has separately provided the above-and below-market cost projections for each year of the PPA along with the estimated utilized amount per kWh across all distribution customers.

Q. Are any costs or benefits in the Societal Level category not applicable?

A. The Societal Low-Income Impact category is intended to measure attributes such as poverty alleviation, reduced energy burden, reduced involuntary disconnections from service and other reductions in the costs of social services. The PPA at issue is not intended to address these issues, and therefore the category is not applicable. To the extent this category is intended to measure local economic benefits, those values have been captured in the economic development category.

Q. Are there any costs or benefits that the Company determined are applicable, but that cannot be quantified?

A. Yes, the Company has noted those categories in Schedule NG-4.

Q. For those categories that were quantified, what method did the Company use to quantify the benefits and costs?

A. The Company relied upon the analysis prepared by TCR to quantify the project net benefits, as discussed further in Section III of the testimony, above, and in Schedule NG-3. The Company also relied upon the economic benefit analysis and workforce investment commitments reported by the bidder in its proposal to determine the value of Non-energy costs/benefits: Economic Development.

Q. What is the net result of the benefit-cost analysis completed under the Framework?

A. The project is estimated to provide $101,283,156 in total net benefits over the life of the contract, demonstrating that the benefits exceed the costs of the project and furthers the objectives of the LTC Standard.

Q. How do the costs and benefits of this project compare to the costs and benefits of other programs?

A. The Company has prepared a comparison of the project's Benefit/Cost Test as compared to the Energy Efficiency program for the 2019 and 2020 program year, as well as a comparison of the project's levelized cost as compared to other renewable energy programs in Rhode Island and the recent contract with Revolution Wind for 400 MW of offshore wind energy generation. The analysis is provided as Schedule NG-5.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>Schedules of Stephen A. McCauley and Katherine Wilson</u>

Schedule NG-1 [CONFIDENTIAL] is the 20-year PPA executed by the Company;

Schedule NG-2 is a copy of the Request for Proposals (RFP) approved in Docket No. 4822;

Schedule NG-3 [CONFIDENTIAL] is the RFP Evaluation Report prepared by Tabors Caramanis Rudkevich (TCR);

Schedule NG-4 presents the Company's Docket No. 4600 analysis; and

Schedule NG-5 provides a Comparison of Gravel Pit project's net benefits to other programs.

REDACTED

POWER PURCHASE AGREEMENT

BETWEEN

THE NARRAGANSETT ELECTRIC COMPANY, D/B/A NATIONAL GRID,

AS BUYER

AND

GRAVEL PIT SOLAR II, LLC,

AS SELLER

As of December 20, 2019

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<u>Exhibits</u>

POWER PURCHASE AGREEMENT

This **POWER PURCHASE AGREEMENT** (as amended from time to time in accordance with the terms hereof, this "**Agreement**") is entered into as of December 20, 2019 (the "**Effective Date**"), by and between The Narragansett Electric Company, d/b/a National Grid, a Rhode Island corporation ("**Buyer**"), and Gravel Pit Solar II, LLC, a Delaware limited liability company ("**Seller**"). Buyer and Seller are individually referred to herein as a "**Party**" and are collectively referred to herein as the "**Parties**".

WHEREAS, Seller is developing the 50 MW solar electric generation facility to be located in East Windsor, Connecticut, which is more fully described in Exhibit A hereto (the "**Facility**"), from which the Buyer's Percentage Entitlement of the Products (as defined below) is to be delivered to Buyer pursuant to the terms of this Agreement; and

WHEREAS, the Facility is, and shall qualify as a Newly Developed Renewable Energy Resource in the state of Rhode Island, which is expected to be in commercial operation by January 15, 2023; and

WHEREAS, pursuant to R.I.G.L. § 39-26.1 and the regulations thereunder, Buyer is authorized to enter into certain long-term contracts for the purchase of energy or energy and renewable energy certificates from renewable generators meeting the requirements of R.I.G.L. § 39-26-5; and

WHEREAS, Buyer and Seller desire to enter into this Agreement whereby Buyer shall purchase from Seller certain Energy and RECs (each as defined herein) generated by or associated with the Facility;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. DEFINITIONS

In addition to terms defined in the recitals hereto, the following terms shall have the meanings set forth below. Any capitalized terms used in this Agreement and not defined herein shall have the same meaning as ascribed to such terms under the ISO-NE Practices and ISO-NE Rules.

"**Actual Facility Size**" shall mean the actual nameplate capacity of the Facility, as built, and as certified by an Independent Engineer, as provided in Section 3.4(b)(xi)(A).

"**Adjusted Price**" shall mean the purchase price(s) for Energy referenced in Section 5.1 if the RECs fail to satisfy the Renewable Energy Standard as an Environmental Attribute associated with the specified MWh of generation from a Newly Developed Renewable Energy Resource and Buyer does not purchase the RECs pursuant to Section 4.1(b) hereof.

"**Adverse Determination**" shall have the meaning set forth in Section 19.7.

"**Affiliate**" shall mean, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries Controls, is Controlled by, or is under common Control with, such first Person.

"**Agreement**" shall have the meaning set forth in the first paragraph of this Agreement.

"**Alternative Compliance Payment Rate**" shall mean the rate per MWh paid by electricity suppliers under applicable Law for failure to supply RECs in accordance with the Renewable Energy Standard.

"Bid" shall mean the proposal submitted by Seller for the Facility for a 20-year Services Term in response to Buyer's 2018 Request for Proposals for Long-Term Contracts for Renewable Energy.

"Biennial Average Real-Time High Operating Limit" shall have the meaning set forth in Section 4.9 hereof.

"**Business Day**" shall mean a day on which Federal Reserve member banks in New York, New York are open for business; and a Business Day shall start at 8:00 a.m. and end at 5:00 p.m. Eastern Prevailing Time.

"**Buyer's Percentage Entitlement**" shall mean Buyer's rights to ninety-nine percent (99%) of the Products. Buyer's Percentage Entitlement may be adjusted in accordance with Section 3.3(c).

"**Buyer's Taxes**" shall have the meaning set forth in Section 5.4(a) hereof.

"**Capacity Deficiency**" shall mean, at the Commercial Operation Date, the amount (expressed in MW), if any, by which the Actual Facility Size is less than 50 MW.

"**Cash**" shall mean U.S. dollars held by or on behalf of a Party as Posted Collateral hereunder.

"**Certificate**" shall mean an electronic certificate created pursuant to the GIS Operating Rules or any successor thereto to represent certain Environmental Attributes of each MWh of Energy generated within the ISO-NE control area and the generation attributes of certain Energy imported into the ISO-NE control area.

"**CFTC rules**" shall have the meaning set forth in Section 19.6 hereof.

"**Collateral Account**" shall have the meaning specified in Section 6.5(a)(iii)(B) hereof.

"**Collateral Interest Rate**" shall mean the rate published in The Wall Street Journal as the "Prime Rate" from time to time (or, if more than one such rate is published, the arithmetic mean of such rates), or, if such rate is no longer published, a successor rate agreed to by Buyer and Seller, in each case determined as of the date the obligation to pay interest arises, but in no event more than the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties.

"**Collateral Requirement**" shall mean at any time the amount of Development Period Security or Operating Period Security required under this Agreement at such time.

"**Commercial Operation Date**" shall mean the date on which the conditions set forth in Section 3.4(b) have been satisfied, as set out in a written notice from Seller to Buyer.

"**Contract Maximum Amount**" shall mean 49.5 MWh per hour of Energy and a corresponding portion of all other Products, as may be adjusted in accordance with Section 3.3(b).

"**Contract Year**" shall mean the twelve (12) consecutive calendar months starting on the first day of the calendar month following the Commercial Operation Date and each subsequent twelve (12) consecutive calendar month period; provided that the first Contract Year shall include the days in the prior month in which the Commercial Operation Date occurred.

"**Control**" shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise.

"**Cover Damages**" shall mean, with respect to any Delivery Failure, an amount equal to (a) the positive net amount, if, any, by which the Replacement Price exceeds the Price or Adjusted Price, as applicable, that would have been paid for the Products pursuant to Section 5.1 hereof, multiplied by the quantity of that Delivery Failure, plus (b) any other costs incurred by Buyer in purchasing Replacement Energy and/or Replacement RECs due to that Delivery Failure, plus (c) any applicable penalties and other costs assessed by ISO-NE or any other Person against Buyer as a result of that Delivery Failure, plus (d) any other costs and losses incurred by Buyer as a result of that Delivery Failure, in each case to the extent not already accounted for in the calculation of any Replacement Price; provided, that there shall be no duplication of amounts related to the subsections (a) through (d) of this definition in the calculation of Cover Damages. Buyer shall provide a statement for the applicable period explaining in reasonable detail the calculation of any Cover Damages.

"**Credit Support**" shall have the meaning specified in Section 6.2(d) hereof.

"**Credit Support Delivery Amount**" shall have the meaning specified in Section 6.3 hereof.

"**Credit Support Return Amount**" shall have the meaning specified in Section 6.4 hereof.

"**Critical Milestones**" shall have the meaning set forth in Section 3.1(a) hereof.

"**Custodian**" shall have the meaning specified in Section 6.5(a)(i) hereof.

"**Day Ahead Energy Market**" shall have the meaning set forth in the ISO-NE Rules.

"**Default**" shall mean any event or condition which, with the giving of notice or passage of time or both, could become an Event of Default.

"**Defaulting Party**" shall mean the Party with respect to which a Default or Event of Default has occurred.

"**Delay Damages**" shall mean the damages assessed pursuant to Section 3.2(a) hereof.

"**Deliver**" or "**Delivery**" shall mean with respect to (i) Energy, to supply Energy into Buyer's ISO-NE account at the Delivery Point in accordance with the terms of this Agreement and the ISO-NE Rules, and (ii) RECs, to supply RECs in accordance with Section 4.7(e).

"**Delivery Failure**" shall have the meaning set forth in Section 4.3 hereof.

"**Delivery Point**" shall mean the specific location on the Pool Transmission Facilities where Seller shall Deliver its Energy to Buyer, as set forth in Exhibit A hereto.

"**Development Period Security**" shall have the meaning set forth in Section 6.2(a) hereof.

"**Dispute**" shall have the meaning set forth in Section 11.1 hereof.

"**Disputing Party**" shall have the meaning set forth in Section 6.6(a) hereof.

"**Eastern Prevailing Time**" shall mean either Eastern Standard Time or Eastern Daylight Time, as in effect from time to time.

"**Effective Date**" shall have the meaning set forth in the first paragraph hereof.

"**Eligible Renewable Energy Resource**" shall mean an eligible renewable energy resource as defined in R.I.G.L. § 39-26-5.

"**Energy**" shall mean electric "energy," as such term is defined in the ISO-NE Tariff, generated by the Facility as measured in MWh in Eastern Prevailing Time, less such Facility's station service use, generator lead losses and transformer losses and energy not otherwise delivered to the Delivery Point, which quantity for purposes of this Agreement will never be less than zero.

"**Environmental Attributes**" shall mean any and all generation attributes under the Renewable Energy Standard and under any and all other international, federal, regional, state or other law, rule, regulation, bylaw, treaty or other intergovernmental compact, decision, administrative decision, program (including any voluntary compliance or membership program), competitive market or business method (including all credits, certificates, benefits, and emission measurements, reductions, offsets and allowances related thereto) that are attributable, now or in the future, to Buyer's Percentage Entitlement to the favorable generation or environmental attributes of the Facility or the Products produced by the Facility, up to and including the Contract Maximum Amount, during the Services Term including Buyer's Percentage Entitlement to: (a) any such credits, certificates, benefits, offsets and allowances computed on the basis of the Facility's generation using renewable technology or displacement of fossil-fuel derived or other conventional energy generation; (b) any Certificates issued pursuant to the GIS in connection with Energy generated by the Facility; and (c) any voluntary emission reduction credits obtained or obtainable by Seller in connection with the generation of Energy by the Facility; provided, however, that Environmental Attributes shall not include: (i) any state or federal production tax credits; (ii) any state or federal investment tax credits or other tax credits associated with the construction or ownership of the Facility; (iii) any state or federal tax credit introduced after the date of this Agreement supplementing, replacing or enhancing the tax credits described in the foregoing clauses (i) or (ii); (iv) any depreciation deductions permitted under the Internal Revenue Code with respect to the Facility (including any bonus or accelerated depreciation); or (v) any state, federal or private grants, Financing, guarantees or other credit support relating to the construction or ownership, operation or maintenance of the Facility or the output thereof.

"**Event of Default**" shall have the meaning set forth in Section 9.1 hereof and shall include the events and conditions described in Section 9.1 and Section 9.2 hereof.

"**EWG**" shall mean an exempt wholesale generator under 42 U.S.C. §§ 16451-16463, as amended from time to time, and FERC's implementing regulations thereunder.

"**Extended Group**" shall have the meaning set forth in Section 25 hereof.

"**Facility**" shall have the meaning set forth in the Recitals.

"**FCA**" shall have the same meaning set forth in Section 3.7 hereof.

"**FCAQ**" shall have the same meaning set forth in Section 3.7 hereof.

"**FERC**" shall mean the United States Federal Energy Regulatory Commission, and shall include its successors.

"**Financial Closing Date**" shall mean the date of the closing of the initial agreements for any Financing of the Facility and of an initial disbursement of funds under such agreements.

"**Financing**" shall mean indebtedness or equity financing, whether secured or unsecured, loans, guarantees, notes, convertible debt, and/or bond issuances for the construction of the Facility, provided by a Lender to Seller and/or one or more Affiliates of Seller, including pursuant to one or more lease transactions related to the Facility (including but not limited to, sale-leaseback transactions or other tax equity transactions, synthetic leases or other lease transactions for Financing purposes), and any refinancing of the foregoing.

"**Force Majeure**" shall have the meaning set forth in Section 10.1(a) hereof.

"**Forced Outage**" shall mean the removal from service of the Facility for emergency reasons or any condition in which the Facility is unavailable due to an unanticipated failure, including NERC Event Types U1, U2 and U3.

"**GIS**" shall mean the NEPOOL Generation Information System or any successor thereto, which includes a generation information database and certificate system, operated by NEPOOL, its designee or successor entity, that accounts for generation attributes of electricity generated or consumed within New England.

"**GIS Operating Rules**" shall mean the NEPOOL Generation Information System Operating Rules effective as of the Effective Date, as amended, superseded, or restated from time to time.

"**Good Utility Practice**" shall mean compliance with all applicable laws, codes, rules and regulations, all ISO-NE Rules and ISO-NE Practices, and any practices, methods and acts engaged in or approved by a significant portion of the electric industry in New England during the relevant time period, taking into account the technology of the equipment, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather is intended to include acceptable practices, methods and acts generally accepted in the electric industry in New England.

"**Governmental Entity**" shall mean any federal, state or local governmental agency, authority, department, instrumentality or regulatory body, and any court or tribunal, with jurisdiction over Seller, Buyer or the Facility, but does not include an RTO.

"**Guaranteed Commercial Operation Date**" shall have the meaning set forth in Section 3.1(a)(iv) hereof.

"**I.3.9 Confirmation**" refers to the ISO-NE Tariff Section I.3.9 pertaining to ISO-NE's approval of proposed plans as specified therein.

"**Independent Engineer**" shall mean a licensed Professional Engineer with expertise in the development of renewable energy projects using the same renewable energy technology as the Facility, reasonably selected by and retained by Seller in order to determine the as-built nameplate capacity of the Facility as provided in Section 3.4(b)(xi)(A) hereof.

"**Interconnecting Utility**" shall mean the utility (which may or may not be Buyer or an Affiliate of Buyer) providing interconnection service for the Facility to the Transmission System of that utility.

"**Interconnection Agreement**" shall mean an agreement between Seller and the Interconnecting Utility and ISO-NE, as applicable, regarding the interconnection of the

Facility to the Transmission System of the Interconnecting Utility, as the same may be amended from time to time.

"**Interconnection Point**" shall have the meaning set forth in the Interconnection Agreement.

"**Interest Amount**" shall mean with respect to a Party and an Interest Period, the sum of the daily interest amounts for all days in such Interest Period; each daily interest amount to be determined by such Party as follows: (a) the amount of Cash held by such Party on that day (but excluding any interest previously earned on such Cash); multiplied by (b) the Collateral Interest Rate for that day; divided by (c) 360.

"**Interest Period**" shall mean the period from (and including) the last Business Day on which an Interest Amount was Transferred by Buyer (or if no Interest Amount has yet been Transferred by Buyer, the Business Day on which Cash was Transferred to Seller) to (but excluding) the Business Day on which the current Interest Amount is to be Transferred.

"**Internal Bilateral Transaction**" shall mean an "Internal Bilateral for Market for Energy" as defined in the ISO-NE Tariff.

"**ISO**" or "**ISO-NE**" shall mean ISO New England Inc., the independent system operator established in accordance with the RTO arrangements for New England, or its successor.

"**ISO-NE Practices**" shall mean the ISO-NE practices and procedures for delivery and transmission of energy in effect from time to time and shall include, without limitation, applicable requirements of the NEPOOL Agreement, and any applicable successor practices and procedures.

"**ISO-NE Rules**" shall mean all rules and procedures adopted by NEPOOL, ISO-NE, or the RTO, and governing wholesale power markets and transmission in New England, as such rules may be amended from time to time, including but not limited to, the ISO-NE Tariff, the ISO-NE Operating Procedures (as defined in the ISO-NE Tariff), the ISO-NE Planning Procedures (as defined in the ISO-NE Tariff), the Transmission Operating Agreement (as defined in the ISO-NE Tariff), the ISO-NE Participants Agreement, the manuals, procedures and business process documents published by ISO-NE via its web site and/or by its e-mail distribution to appropriate NEPOOL participants and/or NEPOOL committees, as amended, superseded or restated from time to time.

"**ISO-NE Tariff**" shall mean ISO-NE's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, as amended, superseded or restated from time to time.

"**ISO Settlement Market System**" shall have the meaning set forth in the ISO-NE Tariff.

"**Late Payment Rate**" shall have the meaning set forth in Section 5.3 hereof.

"**Law**" shall mean all federal, state and local statutes, regulations, rules, orders, executive orders, decrees, policies, judicial decisions and notifications.

"**Lender**" shall mean a party providing Financing for the development and construction of the Facility, or any refinancing of that Financing, including any Person receiving a security interest in the Facility, and shall include hedge providers and any assignee or transferee of such a party and any trustee, collateral agent or similar entity acting on behalf of such a party and any party to a sale-leaseback transaction or other tax equity transaction.

"**Letter of Credit**" shall mean an irrevocable, non-transferable, standby letter of credit, issued by a Qualified Institution utilizing a form acceptable to the Party in whose favor such letter of credit is issued that automatically renews annually unless either (a) the beneficiary thereof is notified at least thirty (30) days in advance of its expiration or termination, or (b) the final expiration date of such letter of credit occurs. All costs relating to any Letter of Credit shall be for the account of the Party providing that Letter of Credit.

"**Letter of Credit Default**" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events (a) the issuer of such Letter of Credit shall fail to be a Qualified Institution; (b) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (c) the issuer of the Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; or (d) the Letter of Credit shall expire or terminate or have a Value of $0 at any time the Party on whose account that Letter of Credit is issued is required to provide Credit Support hereunder and that Party has not Transferred replacement Credit Support meeting the requirements of this Agreement; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be cancelled or returned in accordance with the terms of this Agreement.

"**Locational Marginal Price**" or "**LMP**" shall have the meaning set forth in the ISO-NE Rules.

"**Maintenance Outage**" shall mean NERC Event Types MO and ME, and specifically excludes any Forced Outage or Planned Outage.

"**Marginal Loss Revenue Fund**" shall have the meaning set forth in the ISO-NE Rules.

"**Meters**" shall have the meaning set forth in Section 4.6(a) hereof.

"**Moody's**" shall mean Moody's Investors Service, Inc., and any successor thereto.

"**MW**" shall mean a megawatt AC.

"**MWh**" shall mean a megawatt-hour (one MWh shall equal 1,000 kWh).

"**NEPOOL**" shall mean the New England Power Pool and any successor organization.

"**NERC**" shall mean the North American Electric Reliability Corporation and shall include any successor thereto.

"**Network Upgrades**" shall mean upgrades to the Pool Transmission Facilities and the Transmission Provider's transmission and distribution systems, as determined and identified in the interconnection study approved in connection with construction of the Facility or in the Interconnection Agreement, necessary for Delivery of the Energy to the Delivery Point, including those that are necessary for the Seller's satisfaction of the obligations under Section 3.7 of this Agreement.

"**Newly Developed Renewable Energy Resource**" shall mean, pursuant to R.I.G.L. § 39-26.1-2(6), an electrical generation unit that uses exclusively an Eligible Renewable Energy Resource (as defined in R.I.G.L. § 39-26-5), and has not begun operation, nor have the developers of the unit implemented investment or lending agreements necessary to finance the construction of the unit.

"**Non-Defaulting Party**" shall mean the Party with respect to which a Default or Event of Default has not occurred.

"**Obligations**" shall have the meaning specified in Section 6.1 hereof.

"**Operating Period Security**" shall have the meaning set forth in Section 6.2(b) hereof.

"**Party**" and "**Parties**" shall have the meaning set forth in the first paragraph hereof.

"**Permits**" shall mean any permit, authorization, license, order, consent, waiver, exception, exemption, variance or other approval by or from, and any filing, report, certification, declaration, notice or submission to or with, any Governmental Entity required to authorize action, including any of the foregoing relating to the ownership, siting, construction, operation, use or maintenance of the Facility under any applicable Law and the Delivery of the Products in accordance with this Agreement.

"**Person**" shall mean an individual, partnership, corporation, limited liability company, limited liability partnership, limited partnership, association, trust, unincorporated organization, or a government authority or agency or political subdivision thereof.

"**Planned Outage**" shall mean planned and scheduled maintenance of the Facility including NERC Event Types PO and PE, and specifically excludes any Maintenance Outage or Forced Outage.

"**Pool Transmission Facilities**" shall have the meaning set forth in the ISO-NE Rules.

"**Posted Collateral**" shall mean all Credit Support and all proceeds thereof that have been Transferred to or received by a Party under this Agreement and not Transferred to the Party providing the Credit Support or released by the Party holding the Credit

Support. Any Interest Amount or portion thereof not Transferred will constitute Posted Collateral in the form of Cash.

"**Price**" shall mean the purchase price(s) for Products referenced in Section 5.1 hereof and set forth on Exhibit D.

"**Products**" shall mean Energy and RECs; provided, however, that Energy and RECs generated by or associated with the Facility during the Test Period or in excess of the Contract Maximum Amount and RECs not purchased by Buyer under Section 4.1(b) shall not be deemed Products.

"**PUC**" shall mean the Rhode Island Public Utilities Commission and shall include its successors.

"**QF**" shall mean a cogeneration or small power production facility which meets the criteria as defined by FERC in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207, as amended from time to time.

"**Qualified Institution**" shall mean a major U.S. commercial bank or trust company, the U.S. branch office of a foreign bank, or another financial institution, in any case, organized under the laws of the United States or a political subdivision thereof having assets of at least $10 billion and a credit rating of at least (A) "A3" from Moody's or "A-" from S&P, if such entity is rated by both S&P and Moody's or (B) "A-" by S&P or "A3" by Moody's, if such entity is rated by either S&P or Moody's but not both.

"**Qualified Person**" shall mean a Person who, (i) together with any parent guarantor of such Person, has a net worth of at least $100,000,000 and (ii) has at least three (3) years' experience and capability involving the ownership and operation of solar generating facilities of a similar size to the Facility; provided that this clause (ii) may be satisfied by a Person who retains or contracts, on terms that are customary for such an agreement for a solar generating facility similar to the Facility or that are otherwise reasonably satisfactory to Buyer, with a Person satisfying the criteria set forth in this clause (ii) to act as the operator of the entire Facility.

"**Real Time Energy Market**" shall have the meaning set forth in the ISO-NE Rules.

"**RECs**" shall mean all of the Certificates and any and all other Environmental Attributes associated with the Energy or otherwise produced by the Facility, including, without limitation, all Certificates and any and all other Environmental Attributes, in each case which satisfy the Renewable Energy Standard for a Newly Developed Renewable Energy Resource, and shall represent title to and claim over all Environmental Attributes associated with the specified MWh of Energy Delivered from such Newly Developed Renewable Energy Resource.

"**Reference Market-Maker**" shall mean a leading dealer in the relevant market that is selected in a commercially reasonable manner and is not an Affiliate of either Party.

"**Regulatory Approval**" shall mean the PUC's approval of this Agreement without material modification or conditions pursuant to R.I.G.L. §§ 39-26.1-3 through 39-26.1-5 and the regulations promulgated thereunder, including recovery by Buyer of its costs incurred under this Agreement and remuneration equal to two and three-quarters percent (2.75%) of Buyer's actual annual payments under this Agreement pursuant to R.I.G.L. § 39-26.1-4, which approval shall be final and not subject to appeal or rehearing and shall be acceptable to Buyer in its sole discretion.

"**Rejected Purchase**" shall have the meaning set forth in Section 4.4 hereof.

"**Reliability Curtailment**" shall mean any curtailment of Delivery of Energy resulting from (i) an emergency condition as defined in the Interconnection Agreement or the ISO-NE Tariff, or (ii) any other order or directive of the Interconnecting Utility or the Transmission Provider pursuant to an Interconnection Agreement or tariff.

"**Renewable Energy Standard**" shall mean the requirements established pursuant to R.I.G.L. § 39-26-1 et seq. and the regulations promulgated thereunder that require all obligated entities in Rhode Island to provide a minimum percentage of electricity from Newly Developed Renewable Energy Resources, and such successor laws and regulations as may be in effect from time to time.

"**Replacement Energy**" shall mean energy purchased by Buyer as replacement for any Delivery Failure relating to the Energy to be provided hereunder.

"**Replacement Price**" shall mean (A) the price at which Buyer, acting in a commercially reasonable manner purchases Replacement Energy and Replacement RECs; provided, however, that in no event shall Buyer be required to utilize or change its utilization of its owned or controlled assets, contracts or market positions to minimize Seller's liability, or (B) if the Buyer elects in its sole discretion not to purchase Replacement Energy and/or Replacement RECs, the market value of energy and the Alternative Compliance Payment Rate as of the date and the time of the Delivery Failure.

"**Replacement RECs**" shall mean any generation or environmental attributes, including any Certificates or other certificates or credits related thereto reflecting generation by a Newly Developed Renewable Energy Resource that are purchased by Buyer as replacement for any RECs not Delivered as required hereunder during the Services Term.

"Reporting Party" shall have the meaning set forth in Section 19.6 hereof.

"**Request Date**" shall have the meaning set forth in Section 6.6(a) hereof.

"**Requesting Party**" shall have the meaning set forth in Section 6.6(a) hereof.

"**Resale Damages**" shall mean, with respect to any Rejected Purchase, an amount equal to (a) the positive net amount, if any, by which the Price or Adjusted Price, as applicable, that would have been paid pursuant to Section 5.1 hereof for such Rejected Purchase, had it been accepted, exceeds the Resale Price multiplied by the quantity of that Rejected

Purchase (in MWh and/or RECs, as applicable), plus (b) any applicable penalties assessed by ISO-NE or any other Person against Seller as a result of Buyer's failure to accept such Products in accordance with the terms of this Agreement, plus (c) transaction and other out-of-pocket costs reasonably incurred by Seller in re-selling such Rejected Purchase that Seller would not have incurred but for the Rejected Purchase; provided, that there shall be no duplication of amounts related to the subsections (a) through (c) of this definition in the calculation of Resale Damages. Seller shall provide a written statement for the applicable period explaining in reasonable detail the calculation of any Resale Damages.

"**Resale Price**" shall mean the price at which Seller, acting in a commercially reasonable manner, sells or is paid for a Rejected Purchase; provided, however, that in no event shall Seller be required to utilize or change its utilization of the Facility or its other assets, contracts or market positions in order to minimize Buyer's liability for such Rejected Purchase.

"**Rounding Amount**" shall have the meaning specified in Section 6.2(c) hereof.

"**RTO**" shall mean ISO-NE and any successor organization or entity to ISO-NE, as authorized by FERC to exercise the functions pursuant to FERC's Order No. 2000 and FERC's corresponding regulations, or any successor organization, or any other entity authorized to exercise comparable functions in subsequent orders or regulations of FERC.

"**S&P**" shall mean Standard & Poor's Financial Services LLC, and any successor thereto.

"**Schedule**" or "**Scheduling**" shall mean the actions of Seller and/or its designated representatives pursuant to Section 4.2, of notifying, requesting and confirming to ISO-NE the quantity of Energy to be delivered on any given day or days (or in any given hour or hours) during the Services Term at the Delivery Point.

"**Seller's Taxes**" shall have the meaning set forth in Section 5.4(a) hereof.

"**Services Term**" shall have the meaning set forth in Section 2.2(b) hereof.

"**Substitute Credit Support**" shall have the meaning assigned in Section 6.5(e) hereof.

"**Term**" shall have the meaning set forth in Section 2.2(a) hereof.

"**Termination Payment**" shall have the meaning set forth in Section 9.3(b) hereof.

"**Test Energy**" shall have the meaning set forth in Section 4.8 hereof.

"**Test Period**" shall have the meaning set forth in Section 3.4(a) hereof.

"**Transfer**" shall mean, with respect to any Posted Collateral or Interest Amount, and in accordance with the instructions of the Party entitled thereto:

(a) in the case of Cash, payment or transfer by wire transfer into one or more bank accounts specified by the Party to whom such Cash is being delivered; and

(b) in the case of Letters of Credit, delivery of the Letter of Credit or an amendment thereto to the Party to whom such Letter of Credit is being delivered.

"**Transmission Provider**" shall mean (a) ISO-NE, its respective successor or Affiliates; (b) Buyer; and/or (c) such other third parties from whom transmission services are necessary for Seller to fulfill its performance obligations to Buyer hereunder, as the context requires.

"**Transmission System**" shall mean the transmission facilities operated by a Transmission Provider, now or hereafter in existence, which provide energy transmission service for the Energy to or from the Delivery Point.

"Unacceptable PUC Order" shall mean a final written order of the PUC regarding this Agreement that does not satisfy all of the requirements of the Regulatory Approval (except that the final written order may remain subject to appeal or rehearing).

"**Unit Contingent**" shall mean that the Products are to be supplied only from the Facility and only to the extent that the Facility is generating Energy.

"**Valuation Agent**" shall mean Buyer; provided, however, that in all cases, if an Event of Default has occurred and is continuing with respect to the Buyer, then in such case, for so long as the Event of Default continues, the Seller shall be the Valuation Agent.

"**Valuation Date**" shall mean each Business Day.

"**Valuation Percentage**" shall have the meaning specified in Section 6.2(d) hereof.

"**Valuation Time**" shall mean the close of business on the Business Day before the Valuation Date or date of calculation, as applicable.

"**Value**" shall mean, with respect to Posted Collateral or Credit Support, the Valuation Percentage multiplied by the amount then available under the Letter of Credit to be unconditionally drawn by Buyer.

2. EFFECTIVE DATE; TERM

2.1 Effective Date. Subject in all respects to Article 8, this Agreement is effective as of the Effective Date.

2.2 Term.

(a) The "**Term**" of this Agreement is the period beginning on the Effective Date and ending upon the final settlement of all obligations hereunder after the expiration of the Services Term or the earlier termination of this Agreement in accordance with its terms.

(b) The "**Services Term**" is the period during which Buyer is obligated to purchase Products Delivered to Buyer by Seller (which shall not include Energy and RECs Delivered during the Test Period under Section 4.8) commencing on the Commercial Operation Date and continuing for a period of 20 years from the Commercial Operation Date, unless this Agreement is earlier terminated in accordance with the provisions hereof.

(c) At the expiration of the Term or earlier termination of this Agreement pursuant to the terms hereof, the Parties shall no longer be bound by the terms and provisions hereof, except (i) to the extent necessary to make payments of any amounts owed to the other Party arising prior to or resulting from termination of, or on account of a breach of, this Agreement, (ii) to the extent necessary to enforce the rights and the obligations of the Parties arising under this Agreement before such expiration or termination, and (iii) the obligations of the Parties hereunder with respect to confidentiality and indemnification shall survive the expiration or termination of this Agreement.

3. FACILITY DEVELOPMENT AND OPERATION

3.1 Critical Milestones.

(a) Subject to the provisions of Section 3.1(d), commencing on the Effective Date, Seller shall develop the Facility in order to achieve the following milestones ("**Critical Milestones**") on or before the dates set forth in this Section 3.1(a):

(i) receipt of all Permits necessary to construct the Facility, (A) as set forth in Exhibit B, Part 1, in final form, by [redacted], and (B) as set forth in Exhibit B, Part 2, in final form, by [redacted];

(ii) acquisition of all required real property rights necessary for construction and operation of the Facility and the interconnection of the Facility to the Interconnecting Utility and the construction of Network Upgrades in full and final form with all options and/or contingencies having been exercised demonstrating complete site control, (A) as set forth in Exhibit B, Part 3, by [redacted], and (B) as set forth in Exhibit B, Part 4, by [redacted]

(iii) closing of the Financing or other demonstration to Buyer's satisfaction of the financial capability to construct the Facility, including, as applicable, Seller's financial obligations with respect to interconnection of the Facility to the Interconnecting Utility and construction of the Network Upgrades by [redacted]; and

(iv) achievement of the Commercial Operation Date by March 31, 2023 ("**Guaranteed Commercial Operation Date**").

(b) Seller shall provide Buyer with written notice of the achievement of each Critical Milestone within seven (7) days after that achievement, which notice shall include information demonstrating with reasonable specificity that such Critical Milestone has been achieved. Seller acknowledges that Buyer will receive such notice solely to monitor progress toward the Commercial Operation Date, and Buyer shall have no responsibility or liability for the development, construction, operation or maintenance of the Facility.

(c) In addition to any extension to a date for a Critical Milestone as a result of Force Majeure under Section 10.1, Seller may elect to extend all of the dates for the Critical Milestones not yet achieved by up to three six-month periods from the applicable dates set forth in Section 3.1(a) by posting additional Development Period Security in an amount equal to $247,500.00 ($5,000 per MWh per hour of the Contract Maximum Amount) for each such six-month period. Any such election shall be made in a written notice delivered to Buyer on or prior to the first date for a Critical Milestone that has not yet been achieved (as such date may have previously been extended).

(d) To the extent a Force Majeure event pursuant to Section 10.1 has occurred that prevents the Seller from achieving the Critical Milestone date for acquisition of real property rights and interconnection (Section 3.1(a)(ii)) or the Commercial Operation Date (Section 3.1(a)(iv)) by the applicable date, the Critical Milestone Date(s) impacted by such Force Majeure event shall be extended for the duration of the Force Majeure event, but under no circumstances shall extensions of those Critical Milestone dates due to Force Majeure events exceed twelve (12) months beyond the applicable date, and further provided, that the Seller shall not have the right to declare a Force Majeure event related to the Permits Critical Milestone (Section 3.1(a)(i)) or the Financing Critical Milestone (Section 3.1(a)(iii)).

(e) The Parties agree that time is of the essence with respect to the Critical Milestones and is part of the consideration to Buyer in entering into this Agreement.

3.2 Delay Damages.

(a) If the Commercial Operation Date is not achieved by the Guaranteed Commercial Operation Date (as extended pursuant to Sections 3.1(c) and 10.1), Seller shall pay to Buyer damages for each day from and after such date in an amount equal to $4,950.00 ($100.00 per MWh per hour of Contract Maximum Amount), commencing on the Guaranteed Commercial Operation Date (as extended pursuant to Sections 3.1(c) and 10.1) and ending on the earlier of (i) the Commercial Operation Date, (ii) the date that Buyer exercises its right to terminate this Agreement under Section 9.3, or (iii) the date that is twelve (12) months after the Guaranteed Commercial Operation Date ("**Delay Damages**"). Delay Damages shall be due under this Section 3.2(a) without regard to whether Buyer exercises its right to terminate this Agreement pursuant to Section 9.3; provided, however, that if Buyer exercises its right to terminate this Agreement under Section 9.3, Delay Damages shall be due and owing to the extent that such Delay Damages were due and owing at the date of such termination.

(b) Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to Seller's delay in achieving the Commercial Operation Date by the Guaranteed Commercial Operation Date would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties and set forth herein are a fair and reasonable calculation of such damages.

(c) By the fifteenth (15th) day following the end of the calendar month in which Delay Damages first become due and continuing and by the fifteenth (15th) day of each subsequent calendar month during the period in which Delay Damages accrue (and the following months if applicable), Buyer shall deliver to Seller an invoice showing Buyer's computation of such damages and any amount due Buyer in respect thereof for the preceding calendar month. No later than fifteen (15) days after receiving such an invoice, Seller shall pay to Buyer, by wire transfer of immediately available funds to an account specified in writing by Buyer or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice. If Seller fails to pay such amounts when due, Buyer may draw upon the Development Period Security for payment of such Delay Damages, and Buyer may exercise any other remedies available for Seller's default hereunder.

(d) Notwithstanding the foregoing, nothing set forth in this Section 3.2 shall limit the amount of damages payable to Buyer if this Agreement is terminated as a result of Seller's failure to achieve the Commercial Operation Date. Any such termination damages shall be determined in accordance with Article 9.

3.3 <u>Construction and Changes in Capacity</u>.

(a) <u>Construction of Facility</u>. Seller shall construct the Facility as described in Exhibit A, in accordance with Good Utility Practice, the manufacturer's guidelines for all material components of the Facility and all requirements of the ISO-NE Rules and ISO-NE Practices for the delivery of the Products to Buyer. Seller shall bear all costs related thereto. Seller may contract with other Persons to provide construction functions, so long as Seller maintains overall control over the construction of the Facility through the Term.

(b) <u>Capacity Deficiency</u>. To the extent that Seller has constructed the Facility in accordance with Good Utility Practice and met all other requirements for the Commercial Operation Date under Section 3.4(b) of this Agreement, but a Capacity Deficiency exists on the Commercial Operation Date as permitted by Section 3.4(b), then on the Commercial Operation Date, the Contract Maximum Amount, the Delivery Schedule, and the Collateral Requirement shall be automatically and permanently reduced commensurate with the Capacity Deficiency, which reduced Contract Maximum Amount shall be stated in a notice from Buyer to Seller, which notice shall be binding absent manifest error.

(c) <u>Increase in Facility Size</u>. To the extent that Seller has constructed the Facility in accordance with Good Utility Practice and met all requirements under Section 3.4(b) of this Agreement, if the Independent Engineer's certification provides that the Actual Facility Size exceeds 50 MW, the Buyer's Percentage Entitlement will be recalculated and replaced by the percentage derived by dividing 50 MW by the Actual Facility Size.

(d) Progress Reports. Within ten (10) days of the end of each calendar quarter after the Effective Date and until the Commercial Operation Date, Seller shall provide Buyer with a progress report regarding Critical Milestones not yet achieved, including projected time to completion of the Facility, in accordance with the form attached hereto as Exhibit C, and shall provide supporting documents and detail regarding the same upon Buyer's request. Seller shall permit Buyer and its advisors and consultants to review and discuss with Seller and its advisors and consultants such progress reports during business hours and upon reasonable notice to Seller.

(e) Site Access. Buyer and its representatives shall have the right but not the obligation, during business hours on weekdays and upon no less than twenty-four (24) hours' advance notice to Seller, to inspect the Facility site and view the construction of the Facility; provided that Buyer and its representatives shall observe all applicable Facility safety and access rules while at the Facility Site and Seller may remove Buyer or any such representatives if they have violated any of the Facility safety and access rules.

3.4 Commercial Operation.

(a) Seller's obligation to Deliver the Products and Buyer's obligation to pay Seller for such Products commences on the Commercial Operation Date; provided, that any Energy and RECs generated by the Facility prior to the Commercial Operation Date (the "**Test Period**") shall not be deemed Products.

(b) The Commercial Operation Date shall occur on the date on which the Facility as described in Exhibit A is completed (subject, if applicable, to a Capacity Deficiency so long as the Actual Facility Size on the Commercial Operation Date is at least 45 MW) and capable of regular commercial operation in accordance with Good Utility Practice, the manufacturer's guidelines for all material components of the Facility, all requirements of the ISO-NE Rules and ISO-NE Practices for the delivery of the Products to the Buyer have been satisfied, and all performance testing for the Facility has been successfully completed, provided Seller has also satisfied the following conditions precedent as of such date:

(i) completion of all transmission and interconnection facilities and any Network Upgrades, including final acceptance and authorization to interconnect the Facility from ISO-NE or the Interconnecting Utility in accordance with the fully executed Interconnection Agreement and as required to interconnect the Facility at the Interconnection Point at a level that is capable of satisfying the Network Capability Interconnection Standard and that is equivalent to the Capacity Capability Interconnection Standard under the ISO-NE Rules;

(ii) Seller has obtained and demonstrated possession of all Permits required for the lawful construction and operation of the Facility, for the interconnection of the Facility to the Interconnecting Utility (including any Network Upgrades) and for Seller to perform its obligations under this Agreement, including but not limited to

Permits related to environmental matters, all as set forth on Exhibit B;

(iii) Seller has (i) obtained qualification by the applicable regulatory authority for the state of Rhode Island qualifying the Facility as an Eligible Renewable Energy Resource; and (ii) satisfied all of the requirements (other than achieving the Commercial Operation Date) for, and applied to the applicable regulatory authority for, qualification under the renewable portfolio standard or similar law of Connecticut, Maine, Massachusetts, New Hampshire, New York and Vermont and/or any federal renewable energy standard, to the extent required under Section 4.7(c);

(iv) Seller has acquired all real property rights needed to construct and operate the Facility, to interconnect the Facility to the Interconnecting Utility, to construct the Network Upgrades (to the extent that it is Seller's responsibility to do so) and to perform Seller's obligations under this Agreement;

(v) Seller (or the party with whom Seller contracts pursuant to Section 3.5(e)) has established all requisite ISO-NE-related accounts and entered into all requisite ISO-NE-related agreements required for the performance of Seller's obligations in connection with the Facility and this Agreement, which agreements shall be in full force and effect, including the registration of the Facility in the GIS;

(vi) Seller has provided to Buyer I.3.9 Confirmation from ISO-NE regarding approval of generation entry, has submitted the Asset Registration Form (as defined in ISO-NE Practices) for the Facility to ISO-NE and has taken such other actions as are necessary to effect the Delivery of the Energy to Buyer in the ISO Settlement Market System;

(vii) Seller has successfully completed all pre-operational testing and commissioning in accordance with manufacturer guidelines;

(viii) Seller has satisfied all Critical Milestones that precede the Commercial Operation Date in Section 3.1;

(ix) no Default or Event of Default by Seller shall have occurred and remain uncured;

(x) the Facility is owned or leased by, and under the care, custody and control of, Seller;

(xi) Seller has delivered to Buyer:

(A) an Independent Engineer's certification stating (i) that the Facility has been completed in all material respects (excepting punchlist items that do not materially and adversely affect the ability of the Facility to operate as intended hereunder) in accordance with this Agreement, and (ii) the Actual Facility Size; and

(B) certificates of insurance evidencing the coverages required under Section 3.5(i);

(xii) Seller has demonstrated that it can reliably transmit real time data and measurements to ISO-NE; and

(xiii) Seller has updated Exhibit A to include the model number and number of the Facility's individual panels and inverters planned for the Facility, which Exhibit A will be further updated within 60 days after the Commercial Operation Date to include the actual model number and number of the Facility's individual panels and the serial number and number of inverters for the Facility as it was constructed on the Commercial Operation Date.

3.5 Operation of the Facility.

(a) Compliance With Utility Requirements. At all times during the Services Term, Seller shall comply with, and shall cause the Facility to comply with: (i) Good Utility Practice; and (ii) all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by ISO-NE, any Transmission Provider, any Interconnecting Utility, NERC and/or any regional reliability entity, including, in each case, all practices, requirements, rules, procedures and standards related to Seller's ownership, operation and maintenance of the Facility and its performance of its obligations under this Agreement (including obligations related to the generation, Scheduling, interconnection, and transmission of Energy, and the transfer of RECs), whether such requirements were imposed prior to or after the Effective Date. Seller shall be solely responsible for registering as the "Generator Owner and Generator Operator" of the Facility with NERC and any applicable regional reliability entities, as applicable.

(b) Permits. At all times during the Services Term, Seller shall maintain or cause to be maintained in full force and effect all Permits necessary for it to perform its obligations under this Agreement, including all Permits necessary to construct, operate and maintain the Facility.

(c) Maintenance and Operation of Facility. Seller shall, at all times during the Services Term, maintain and operate the Facility in accordance with Good Utility Practice and in accordance with Exhibit A to this Agreement. Seller shall bear all costs related thereto. Seller may contract with other Persons to provide operation and maintenance functions, so long as Seller maintains overall control over the operation and maintenance of the Facility throughout the Term.

(d) Interconnection Agreement. Seller shall comply with the terms and conditions of the Interconnection Agreement and shall be responsible for obtaining interconnection of the Facility at the Interconnection Point at a level that is capable of satisfying both the Network Capability Interconnection Standard and the equivalent of the Capacity Capability Interconnection Standard under the ISO-NE Rules.

(e) ISO-NE Status. Seller shall, at all times during the Services Term, either: (i) be an ISO-NE "Market Participant" pursuant to the ISO-NE Rules; or (ii) have entered into an agreement with a Market Participant that shall perform all of Seller's ISO-NE-related obligations in connection with the Facility and this Agreement.

(f) Forecasts. Upon Buyer's request, commencing at least thirty (30) days prior to the anticipated Commercial Operation Date and continuing throughout the Services Term, Seller shall update and deliver to Buyer on an annual basis and in a form reasonably acceptable to Buyer, twelve (12) month rolling forecasts of Energy production by the Facility, which forecasts shall be prepared in good faith and in accordance with Good Utility Practice based on historical performance, maintenance schedules, Seller's generation projections and other relevant data and considerations. Any notable changes from prior forecasts or historical energy delivery shall be noted and an explanation provided. The provisions of this section are in addition to Seller's requirements under ISO-NE Rules and ISO-NE Practices, including ISO-NE Operating Procedure No. 5.

(g) Newly Developed Renewable Energy Resource. Subject to Section 4.7(b), Seller shall be solely responsible at Seller's cost for qualifying the Facility as a Newly Developed Renewable Energy Resource and maintaining such qualification and status as an Eligible Renewable Energy Resource throughout the Services Term. Seller shall take all actions necessary to register for and maintain participation in the GIS to register, monitor, track, and transfer RECs. Seller shall provide such additional information as Buyer may request relating to such qualification and participation and the registration, monitoring, tracking and transfer of RECs.

(h) Compliance Reporting. Upon Buyer's request, within thirty (30) days following the end of each calendar quarter, Seller shall provide Buyer information pertaining to fuel types, labor information and any other information to the extent required by Buyer to comply with the disclosure requirements contained under applicable Law and any other such disclosure regulations which may be imposed upon Buyer during the Term, which information requirements will be provided to Seller by Buyer at least fifteen (15) days before the beginning of the calendar quarter for which the information is required. To the extent Buyer is subject to any other certification or compliance reporting requirement with respect to the Products produced by Seller and delivered to Buyer hereunder, Seller shall provide any information in its possession (or, if not in Seller's possession, available to it and not reasonably available to Buyer) requested by Buyer to permit Buyer to comply with any such reporting requirement.

(i) Insurance. Throughout the Term, and without limiting any liabilities or any other obligations of Seller hereunder, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "A-" by the A.M. Best Company (or any successor thereto) the insurance coverage (including without limitation any limits or sub-limits) and with the deductibles that are customary for a generating facility of the type and size of the Facility and as otherwise legally required. Upon the execution of this Agreement, and at each subsequent policy renewal date thereafter, Seller shall provide Buyer with a standard ACORD form certificate of insurance which (i) shall include Buyer as an additional insured on each policy, in accordance with standard industry practice, (ii) shall include policy endorsements which evidence of the additional insured in accordance with standard industry practice, (iii) shall evidence a firm obligation of the insurer to provide Buyer with thirty (30) days' (ten (10) days for non-payment of premium) prior written notice of coverage cancellation or nonrenewal, and (iv) shall be endorsed by a Person who has authority to issue the certificate. If any coverage is written on a "claims-made" basis, the certification accompanying the policy shall conspicuously state that the policy is "claims made."

(j) Contacts. Each Party shall identify a principal contact or contacts, which contact(s) shall have adequate authority and expertise to make day-to-day decisions with respect to the administration of this Agreement.

(k) Compliance with Law. Without limiting the generality of any other provision of this Agreement, Seller shall be responsible for complying with all applicable requirements of Law, including all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by FERC and any other Governmental Entity, whether imposed pursuant to existing Law or procedures or pursuant to changes enacted or implemented during the Term, including all risks of operational and environmental matters relating to the Facility or the Facility site. Seller shall indemnify Buyer against any and all claims arising out of or related to such environmental matters and against any costs imposed on Buyer as a result of Seller's violation of any applicable Law, or ISO-NE or NERC requirements. For the avoidance of doubt, Seller shall be responsible for procuring, at its expense, all Permits and governmental approvals required for the construction and operation of the Facility in compliance with applicable requirements of Law.

(l) FERC Status. Seller shall be responsible for ensuring that it is in compliance with all FERC directives and requirements necessary for Seller to fulfill its obligations under this Agreement. As part of Seller's satisfaction of this responsibility, it shall maintain the Facility's status as a QF or EWG (to the extent Seller meets the criteria for such status) at all times on and after the Commercial Operation Date and shall obtain and maintain any requisite authority to sell the output of the Facility at market-based rates, including market-based rate authority to the extent applicable. If Seller certifies the Facility as a QF, for so long as this Agreement is in effect, Seller waives, and agrees not to assert, any rights Seller may have to require Buyer to purchase or transmit electric power or to pay a specified price for electric power by virtue of the status of the Facility as a QF.

(m) Maintenance. No later than (a) the Commercial Operation Date and (b) two months prior to the end of each calendar year thereafter during the Term, Seller shall submit to Buyer a schedule of Planned Outages and scheduled Maintenance Outages for the following calendar year for the Facility. Throughout the Term, Seller shall coordinate all Planned Outages and scheduled Maintenance Outages with ISO-NE, consistent with ISO-NE Rules, and shall promptly provide applicable information concerning scheduled outages, as determined by ISO-NE, to Buyer. To maximize the value of the Products, to the extent possible and consistent with

ISO-NE Rules, Seller shall not schedule Planned Outages and scheduled Maintenance Outages of the Facility during the months of December, January and February or June through September, and shall operate the Facility so as to maximize energy production during the hours of anticipated peak load and Energy prices in New England; provided, however, that Planned Outages and scheduled Maintenance Outages may be scheduled during such period to the extent the failure to perform such maintenance or work is contrary to operation of the Facility in accordance with Good Utility Practice. Seller shall take commercially reasonable steps to operate the Facility so as to minimize any unplanned outages during the hours of anticipated peak load and Energy prices in New England.

3.6 Interconnection and Delivery Services.

(a) Seller shall be responsible for all costs associated with Network Upgrades, including, but not limited to, interconnection of the Facility at the Interconnection Point at a level that is capable of satisfying both the Network Capability Interconnection Standard and the equivalent of the Capacity Capability Interconnection Standard under the ISO-NE Rules (including the construction of those facilities), consistent with all standards and requirements set forth by the FERC, ISO-NE, any other applicable Governmental Entity and the Interconnecting Utility. Seller shall be responsible for procuring delivery service to the Delivery Point and all costs associated with it.

(b) Seller shall defend, indemnify and hold Buyer harmless against any and all liabilities, fees, costs and expenses, including but not limited to reasonable attorneys' fees arising due to Seller's performance or failure to perform under the Interconnection Agreement or any agreement for delivery service associated with Seller's performance of its obligations under this Agreement.

3.7 Forward Capacity Market Participation. Seller shall participate in the ISO-NE's Forward Capacity Auction Qualification ("**FCAQ**") process for, and take all other necessary and appropriate actions to qualify for, the Forward Capacity Auction ("**FCA**") for the first full Capacity Commitment Period during the Services Term with a summer Seasonal Claimed Capability and, if applicable, a winter Seasonal Claimed Capability in each case not less than the respective maximum Seasonal Claimed Capabilities as determined by ISO-NE for Seller's project as described in the Bid, including qualifying the Capabilities described in the Bid for Capacity Capability Interconnection Standard-level interconnection. Notwithstanding the above, actual Seller participation in any FCA or obtaining a Capacity Supply Obligation shall not be required, but may be pursued at the option of Seller. Seller will provide Buyer with (i) copies of all material technical reports and studies provided to and/or by ISO-NE as part of the FCAQ process for the Facility, as described in this Section 3.7, at the same time when those materials are provided to and/or by ISO-NE, (ii) a list of all non-material technical reports and studies provided to and/or by ISO-NE as part of the FCAQ process for the Facility at the same time when those materials are provided to and/or by ISO-NE, and (iii) copies of any such non-material technical reports and studies that are requested by Buyer. Seller shall use commercially reasonable efforts, consistent with Good Utility Practice, to maximize the summer and, if applicable, winter Seasonal Claimed Capabilities for the Facility consistent with the technical reports and studies provided to and/or by ISO-NE and with the Bid. Seller will provide Buyer with written notice of the summer and, if applicable, winter Seasonal Claimed Capabilities for the Facility and the Network Upgrades required to satisfy both the Network Capability Interconnection Standard and the equivalent of the Capacity Capability Interconnection Standard at the Interconnection Point at those Seasonal Claimed Capabilities within fifteen (15) days after the determination thereof by ISO-NE.

4. DELIVERY OF PRODUCTS

4.1 Obligation to Sell and Purchase Products.

(a) Beginning on the Commercial Operation Date and subject to Section 4.1(b), Seller shall sell and Deliver, and Buyer shall purchase and receive all right, title and interest in and to, Buyer's Percentage Entitlement of the Products in accordance with the terms and conditions of this Agreement, but in no event exceeding the Contract Maximum Amount in any hour, in accordance with the terms and conditions of this Agreement. The aforementioned obligations for Seller to sell and Deliver the Products and for Buyer to purchase and receive the same are Unit Contingent and shall be subject to the operation of the Facility. Seller agrees that Seller will not curtail or otherwise reduce deliveries of the Products in order to sell such Products to other purchasers.

(b) Buyer shall not be obligated to accept or pay for any REC or comparable certificate, credit, attribute or other similar product produced by or associated with the Facility which fails to satisfy or maintain its eligibility for the Renewable Energy Standard as an Environmental Attribute associated with the specified MWh of generation from a Newly Developed Renewable Energy Resource, and, to the extent that Buyer does not purchase any such REC or comparable certificate, credit, attribute or other similar product associated with the Facility, Seller may, in its sole discretion, sell, transfer or otherwise dispose of that REC or comparable certificate, credit, attribute or other similar product. In the event that the Buyer notifies Seller that it will not purchase any REC or comparable certificate, credit, attribute or other similar product produced by the Facility which fails to satisfy the Renewable Energy Standard as an Environmental Attribute associated with the specified MWh of generation from a Newly Developed Renewable Energy Resource, then Buyer may resume purchasing such RECs or comparable certificates, credits, attributes or other similar products produced by the Facility upon thirty (30) days' prior written notice to Seller, unless otherwise agreed by Buyer and Seller.

(c) Seller shall Deliver Buyer's Percentage Entitlement of the Products produced by or associated with the Facility, up to and including the Contract Maximum Amount, exclusively to Buyer, and Seller shall not sell, divert, grant, transfer or assign such Products or any right, claim, certificate or other attribute associated with such Products to any Person other than Buyer during the Term. Seller shall not enter into any agreement or arrangement under which such Products can be claimed by any Person other than Buyer. Buyer shall have the exclusive right to resell or convey the Products in its sole discretion.

(d) Without limiting Seller's rights to all Products to be purchased under this Agreement, to the extent that Seller receives any payment or other consideration for any Environmental Attributes to be purchased under this Agreement directly from any other Person, Seller shall hold such payment or other consideration in trust for the benefit of Buyer and shall promptly remit such payment or other consideration to Buyer in the form so received, or if not transferrable in such form, in the cash equivalent of such form.

4.2 Scheduling and Delivery.

(a) During the Services Term and in accordance with Section 4.1, Seller shall Schedule and Deliver Energy hereunder with ISO-NE in accordance with this Agreement and all ISO-NE Practices and ISO-NE Rules. Seller shall transfer the Energy to Buyer in the Day Ahead Energy Market, Real Time Energy Market or another ISO-NE energy market to the extent that such other market provides Buyer with additional value for the Energy being purchased hereunder, as reasonably agreed from time to time by Buyer and Seller and consistent with prevailing electric industry practices at the time, in each case in such a manner that Buyer may resell such Energy in the Day Ahead Energy Market, Real Time Energy Market, and/or such other ISO-NE energy market, as applicable. Buyer shall have no obligation to pay for any Energy not transferred to Buyer in the Day Ahead Energy Market, Real Time Energy Market or such other ISO-NE energy market or for which Buyer is not credited in the ISO-NE Settlement Market System (including, without limitation, as a result of an outage on any electric transmission system) in accordance with the foregoing sentence. As of the Effective Date, the Parties contemplate that initial Deliveries of Energy shall be effected through transfers in the Real Time Energy Market through Buyer being registered as the Asset Owner for the Facility in such ISO-NE Settlement Market System, and Seller will take all actions reasonably requested by Buyer in order to register Buyer at the Asset Owner for the Facility in the ISO-NE Settlement Market System. Buyer and Seller may agree from time to time, in accordance with this Section 4.2(a) and in conformity with ISO-NE Rules and ISO-NE Practices, that Seller shall (i) Schedule Delivery of the Energy in the Day Ahead Energy Market or in another ISO-NE energy market, and/or (ii) Deliver the Energy to Buyer or at Buyer's direction through Internal Bilateral Transactions executed through ISO-NE and settled at the Delivery Point. Any such Internal Bilateral Transactions will specify the actual metered hourly delivery of Energy and will be entered into daily, with any necessary adjustments being made pursuant to ISO-NE settlement protocols, and Seller will not receive any payment associated with a Marginal Loss Revenue Fund allocation in connection with any such Internal Bilateral Transactions. Under no circumstances shall the Seller enter estimated generation values into an Internal Bilateral Transaction. Notwithstanding any other provision of this Agreement, if during the Term of this Agreement the LMP at the Delivery Point is negative, or, in the reasonable opinion of Seller, is likely to become negative, then Seller may deliver to Buyer a written notice stating that such condition has occurred or is likely to occur and the period during which such condition has occurred or is likely to occur. Buyer and Seller hereby agree that in such event Seller shall be under no obligation to schedule or Deliver Products to the Delivery Point during such negative LMP period.

(b) The Parties agree to use commercially reasonable efforts to comply with all applicable ISO-NE Rules and ISO-NE Practices in connection with the Scheduling and Delivery of Energy hereunder. Penalties or similar charges assessed by a Transmission Provider and caused by Seller's noncompliance with the Scheduling obligations set forth in this Section 4.2 shall be the responsibility of Seller.

(c) Without limiting the generality of this Section 4.2, Seller or the party with whom Seller contracts pursuant to Section 3.5(e) shall at all times during the Services Term be designated with ISO-NE as the "Lead Market Participant" (or any successor designation) for the Facility and shall be solely responsible for any obligations and liabilities imposed by ISO-NE or under the ISO-NE Rules and ISO-NE Practices with respect to the Facility, including all charges, penalties, financial assurance obligations, losses, transmission charges, ancillary service charges, line losses, congestion charges and other ISO-NE or applicable system costs or charges associated with transmission. To the extent Buyer incurs such costs, charges, penalties or losses which are the responsibility of Seller, (including amounts not credited to Buyer as described in Section 4.2(a)), Seller shall reimburse Buyer for the same.

4.3 Failure of Seller to Deliver Products. Subject to the Unit Contingent nature of the Products, in the event that Seller fails to satisfy any of its obligations to Deliver any of the Products or any portion of the Products hereunder in accordance with Section 4.1, Section 4.2 and Section 4.7, and such failure is not excused under the express terms of this Agreement (a "**Delivery Failure**"), (and without limiting Buyer's rights under Section 9.2(h) and Section 9.3), Seller shall pay Buyer an amount for such Delivery Failure (measured in MWh and/or RECs) equal to the Cover Damages for such Delivery Failure. Such payment shall be due no later than the date for Buyer's payment for the applicable month as set forth in Section 5.2 hereof. Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to a Delivery Failure would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Cover Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.4 Failure by Buyer to Accept Delivery of Products. If Buyer fails to accept all or part of any of the Products to be purchased by Buyer hereunder during the Services Term, and such failure to accept (a) is not the result of Reliability Curtailment or (b) is not otherwise excused under the terms of this Agreement (a "**Rejected Purchase**"), then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred, an amount for such Rejected Purchase equal to the Resale Damages. Each Party agrees and acknowledges that (i) the damages that Seller would incur due to a Rejected Purchase would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Resale Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.5 Delivery Point.

(a) All Energy that is a Product shall be Delivered hereunder by Seller to Buyer at the Delivery Point. Seller shall be responsible for the costs of delivering such Energy to the Delivery Point consistent with all standards and requirements set forth by the FERC, ISO-NE and any other applicable Governmental Entity or applicable tariff.

(b) Seller shall be responsible for all applicable charges associated with transmission and interconnection service and delivery charges, including all related ISO-NE administrative fees, uplift, socialized charges, all costs for Network Upgrades (to the extent Seller is responsible for the cost of those Network Upgrades under the Interconnection

Agreement or under this Agreement) , and all other charges in connection with the satisfaction of Seller's obligations hereunder, including without limitation the Delivery of Energy to and at the Delivery Point and any Capacity Supply Obligation assumed by the Seller. Seller shall indemnify and hold harmless Buyer for any such charges, fees, costs or expenses imposed upon Buyer by operation of ISO-NE Rules or otherwise in connection with Seller's performance of its obligations hereunder.

(c) Buyer shall be responsible for all applicable charges associated with transmission and delivery of the Energy from and after the Delivery Point, provided that Buyer shall have no responsibility or liability for any Network Upgrade or the cost of constructing or upgrading any other transmission or distribution facilities.

4.6 Metering.

(a) Metering. All electric metering associated with the Facility, including the Facility meter and any other real-time meters, billing meters and back-up meters (collectively, the "**Meters**"), shall be installed, operated, maintained and tested at Seller's expense in accordance with Good Utility Practice and any applicable requirements and standards issued by NERC, the Interconnecting Utility and ISO-NE; provided that each Meter shall be tested at Seller's expense once each Contract Year. All Meters used to provide data for the computation of payments shall be sealed and Seller shall break the seal only when such Meters are to be inspected and tested (or adjusted) in accordance with this Section 4.6. Seller shall provide Buyer with a copy of all metering and calibration information and documents regarding the Meters promptly following receipt thereof by Seller.

(b) Measurements. Readings of the Meters at the Delivery Point by the Interconnecting Utility in whose territory the Delivery Point is located (or an independent Person mutually acceptable to the Parties) shall be conclusive as to the amount of Energy generated by the Facility; provided however, that Seller, upon request of Buyer and at Buyer's expense (if more frequently than annually as provided for in Section 4.6(a)), shall cause the Meters to be tested by the Interconnecting Utility in whose territory the Delivery Point is located, and if any Meter is out of service or is determined to be registering inaccurately by more than two percent (2%), (i) the measurement of Energy produced by the Facility shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, in accordance with the filed tariff of such Interconnecting Utility or the ISO-NE Tariff, whichever is applicable, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder and (ii) Seller shall reimburse Buyer for the cost of such test of the Meters. Meter readings shall be adjusted to take into account the losses to Deliver the Energy to the Delivery Point. Seller shall make recorded meter data available monthly to the Buyer at no cost.

(c) Inspection, Testing and Calibration. Buyer shall have the right to inspect and test (at its own expense) any of the Meters at or prior to the Delivery Point, as well as any other measurements relayed by the Facility's SCADA system at reasonable times and upon reasonable notice from Buyer to Seller. Buyer shall have the right to have a representative present during any testing or calibration of such Meters by Seller. Seller shall provide Buyer with timely notice of any such testing or calibration.

(d) Audit of Meters. Following reasonable notice to Seller, Buyer shall have access to the Meters and the right to audit all information and test data related to such Meters.

(e) Notice of Malfunction. Seller shall provide Buyer with prompt notice of any malfunction or other failure of the Meters or other telemetry equipment necessary to accurately report the quantity of Energy being produced by the Facility. If any Meter is found to be inaccurate by more than two percent (2%), the meter readings shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder.

(f) Telemetry. The Meters shall be capable of sending meter telemetry data, and Seller shall provide Buyer with simultaneous access to such data at no additional cost to Buyer. This provision is in addition to Seller's requirements under ISO-NE Rules and Practices, including ISO-NE Operating Procedure No. 18.

4.7 RECs.

(a) Seller shall transfer to Buyer all of the right, title and interest in and to Buyer's Percentage Entitlement of the Environmental Attributes, including any and all RECs, generated by, or associated with, the Facility during the Services Term in accordance with the terms of this Section 4.7.

(b) Regarding the Renewable Energy Standard:

(i) Except as provided in subsection (ii) of this Section 4.7(b), all Energy provided by Seller to Buyer from the Facility under this Agreement shall meet the requirements for eligibility pursuant to the Renewable Energy Standard, and Seller's failure to satisfy such requirements shall constitute an Event of Default pursuant to Section 9.2(j) of this Agreement except as provided in Section 4.7(b)(ii), below; and

(ii) It shall not be an Event of Default under Article 9 if, solely as a result of change in Law, Energy provided by Seller to Buyer from the Facility under this Agreement no longer meets the requirements for eligibility pursuant to the Renewable Energy Standard, provided Seller promptly uses commercially reasonable efforts to ensure that qualification will continue after the change in Law. If, notwithstanding such commercially reasonable efforts and solely as a result of change in Law, the Facility does not qualify as a Newly Developed Renewable Energy Resource, then (A) Seller shall continue to sell, and Buyer shall continue to purchase Energy under this Agreement at the Adjusted Price in accordance with Section 5.1 and (B) any purchases and sales of RECs shall be in accordance with Section 4.1(b).

(c) At Seller's sole cost, Seller shall also obtain within ninety (90) days after the Commercial Operation Date and shall maintain throughout the Services Term qualification by the applicable regulatory authority under the renewable portfolio standard or similar law of Connecticut, Maine, Massachusetts, New Hampshire, New York and Vermont and/or any federal renewable energy standard, to the extent the renewable energy technology used in the Facility is eligible under such renewable portfolio standard, renewable energy standard or similar law, and Seller shall use commercially reasonable efforts, consistent with Good Utility Practice, to maintain such qualifications at all times during the Services Term unless otherwise agreed by Buyer. Seller shall provide evidence of such qualification in each such jurisdiction within ninety (90) days after the Commercial Operation Date and, if reasonably requested by Buyer, at any time thereafter during the Services Term. Seller shall also submit to Buyer or as directed by Buyer any information required by any state or federal agency with regard to administration of its rules regarding Environmental Attributes or its renewable energy standard or renewable portfolio standard or Seller's qualification under the foregoing.

(d) Seller shall comply with all GIS Operating Rules, including without limitation such Rules relating to the creation, tracking, recording and transfer of all RECs to be purchased by Buyer under this Agreement. In addition, at Buyer's request, Seller shall register with and comply with the rules and requirements of any other tracking system or program that tracks, monetizes or otherwise creates or enhances value for Environmental Attributes, which compliance shall be at Seller's sole cost if such registration and compliance is requested in connection with Section 4.7(c) above and shall be at Buyer's sole cost in other instances.

(e) Prior to the delivery of any Energy hereunder, either (i) Seller shall cause Buyer to be registered in the GIS as the initial owner of all Certificates to be Delivered hereunder to Buyer or (ii) Seller and Buyer shall effect an irrevocable Forward Certificate Transfer (as defined in the GIS Operating Rules) of the Certificates to be Delivered hereunder to Buyer in the GIS for the Services Term; provided, however, that no payment shall be due to Seller for any RECs until either (x) the Certificates are actually deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing, or (y) (i) Buyer and Seller enter such an irrevocable Forward Certificate Transfer of the Certificates to be Delivered to Buyer in the GIS, which Forward Certificate Transfer shall be denoted in the GIS as not being capable of rescission by Seller, and (ii) the Energy with which such RECs are associated has been Delivered to Buyer.

(f) The Parties intend for the transactions entered into hereunder to be physically settled, meaning that the RECs are intended to be Delivered in the GIS account of Buyer or its designee as set forth in this Section 4.7.

(g) For the avoidance of doubt, the Parties intend that Seller shall Deliver to Buyer or otherwise cause Buyer to receive the maximum value of any Environmental Attributes. Promptly following a request by Buyer, Seller shall execute, deliver, register, qualify, file, and take any other action that may be necessary or desirable for Seller to Deliver the Environmental Attributes to Buyer or to enable Buyer to receive and use the maximum value of the Environmental Attributes. Without limiting the rights of Buyer under the remainder of this Section 4.7, Seller shall be responsible for the costs incurred pursuant to this Section 4.7(g) up to and including $5,000 in out-of-pocket costs, and Buyer shall be responsible for all such out-of-pocket costs that exceed such amount.

4.8 Production During Test Period. During the Test Period, Seller shall sell and Deliver, and Buyer shall purchase and receive Buyer's Percentage Entitlement of any Energy ("**Test Energy**") and associated RECs produced by or associated with the Facility. Notwithstanding the provisions of Section 5.1, payment for Test Energy Delivered during the Test Period and RECs associated with such Test Energy shall be equal to Buyer's Percentage Entitlement of (x) the Test Energy Delivered (in MWh) and (y) the Real Time LMP at the Delivery Point, with no additional amount paid for the RECs associated with that Test Energy. In no event shall the portion of the Test Period during which Buyer purchases Energy or RECs extend beyond six (6) months, except due to Force Majeure.

4.9 Real-Time High Operating Limit. Not later than 10 days after the end of each Contract Year beginning with the second Contract Year, Seller shall provide Buyer with a certificate of an officer of Seller setting forth the average hourly Real-Time High Operating Limit (as defined in the ISO-NE Rules) of the Facility for such Contract Year and the immediately preceding Contract Year (the **"Biennial Average Real-Time High Operating Limit"**), each as reported to ISO-NE from time-to-time in accordance with the ISO-NE Rules, which certificate shall include information demonstrating with reasonable specificity the calculations made by Seller to determine such average hourly Real-Time High Operating Limit. To the extent that during any period, the Real-Time High Operating Limit of the Facility is reduced due to a Force Majeure, Forced Outage or Reliability Curtailment, the amount of the Real-Time High Operating Limit reduced as a result such Force Majeure, Forced Outage or Reliability Curtailment will be included in calculating the Biennial Average Real-Time High Operating Limit for such period.

5. PRICE AND PAYMENTS FOR PRODUCTS

5.1 Price for Products. All Products Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Price specified in Exhibit D; provided, however, that if the RECs fail to satisfy the Renewable Energy Standard as an Environmental Attribute associated with the specified MWh of generation from a Newly Developed Renewable Energy Resource and Buyer does not purchase the RECs pursuant to Section 4.1(b), then all Energy Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Adjusted Price specified in Exhibit D. Other than the (i) payment for the Products under this Section 5.1, (ii) payments related to Meter testing under Section 4.6(b), (iii) payments related to Meter malfunctions under Section 4.6(e), (iv) payment for Energy and RECs during the Test Period in accordance with Section 4.8, (v) payment of any Resale Damages under Section 4.4, (vi) payment of interest on late payments under Section 5.3, (vii) payments for reimbursement of Buyer's Taxes under Section 5.4(a), (viii) return of any Credit Support under Section 6.7, and (ix) payment of any Termination Payment due from Buyer under Section 9.3, Buyer shall not be required to make any other payments to Seller under this Agreement, and Seller shall be solely responsible for all costs and losses incurred by it in connection with the performance of its obligations under this Agreement. If the Seller has not voluntarily curtailed deliveries in accordance with Section 4.2(a) and in the event that the LMP for the Energy at the Delivery Point is less than $0.00 per MWh in any hour, Seller shall credit to Buyer, on the appropriate monthly invoice, an amount equal to the product of (i) such Energy delivered in such hour and (ii) the absolute value of the hourly LMP at the Delivery Point.

5.2 Payment and Netting.

(a) Billing Period. The calendar month shall be the standard period for all charges and payments under this Agreement. On or before the fifteenth (15th) day following the end of each month, Seller shall render to Buyer an invoice for the payment obligations incurred hereunder during the preceding month, based on the Energy Delivered in the preceding month, and any RECs deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing in the preceding month. Such invoice shall contain supporting detail for all charges reflected on the invoice, and Seller shall provide Buyer with additional supporting documentation and information as Buyer may request.

(b) Timeliness of Payment. All undisputed charges shall be due and payable in accordance with each Party's invoice instructions on or before the later of (x) fifteen (15) days from receipt of the applicable invoice or (y) the last day of the calendar month in which the applicable invoice was received (or in either event the next Business Day if such day is not a Business Day). Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any undisputed amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Late Payment Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

(c) Disputes and Adjustments of Invoices.

(i) All invoices rendered under this Agreement shall be subject to adjustment after the end of each month in order to true-up charges based on changes resulting from ISO-NE billing statements or revisions, if any, to previous ISO-NE billing statements. If ISO-NE resettles any invoice which relates to the Products sold under this Agreement and (a) any charges thereunder are the responsibility of the other Party under this Agreement or (b) any credits issued thereunder would be due to the other Party under this Agreement, then the Party receiving the invoice from ISO-NE shall in the case of (a) above invoice the other Party or in the case of (b) above pay the amount due to the other Party. Any invoices issued or amounts due pursuant to this Section shall be invoiced or paid as provided in this Section 5.2.

(ii) Within twelve (12) months of the issuance of an invoice the Seller shall adjust any invoice for any arithmetic or computational error and shall provide documentation and information supporting such adjustment to Buyer. Within twelve (12) months of the receipt of an invoice (or an adjusted invoice), the Buyer may dispute any charges on that invoice. In the event of such a dispute, the Buyer shall give notice to the Seller and shall state the basis for the dispute. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment or refund shall be made within ten (10) days of such resolution along with interest accrued at the Late Payment Rate from and including the due date (or in the case of a refund, the payment date) but excluding the date paid. Any claim for additional payment is waived unless the Seller issues an adjusted invoice within twelve (12) months of issuance of the original invoice. Any dispute of charges is waived unless the Buyer provides notice of the dispute to the Seller within twelve (12) months of receipt of the invoice (or adjusted invoice) including such charges.

(d) Netting of Payments. The Parties hereby agree that they may discharge mutual debts and payment obligations due and owing to each other under this Agreement on the same date through netting of such monetary obligations, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Agreement, including any related damages calculated pursuant to this Agreement, interest, and payments or credits, may be netted so that only the excess amount remaining due shall be paid by the Party who owes it. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, such Party shall pay such sum in full when due. The Parties agree to provide each other with reasonable detail of such net payment or net payment request.

5.3 Interest on Late Payment or Refund. A late payment charge shall accrue on any late payment or refund as specified above at the lesser of (a) the prime rate specified in the "Money & Investing" section of The Wall Street Journal (or, if such rate is not published therein, in a successor index mutually selected by the Parties) plus one percent (1%), and (b) the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties (the "**Late Payment Rate**").

5.4 Taxes, Fees and Levies.

(a) Seller shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with the Facility or delivery or sale of the Products ("**Seller's Taxes**"). Buyer shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with such Products after Delivery of such Products to Buyer, or imposed on or associated with the purchase of such Products by Buyer (other than ad valorem, franchise or income taxes which are related to the sale of the Products and are, therefore, the responsibility of Seller) ("**Buyer's Taxes**"). In the event Seller shall be required by law or regulation to remit or pay any Buyer's Taxes, Buyer shall reimburse Seller for such payment. In the event Buyer shall be required by law or regulation to remit or pay any Seller's Taxes, Seller shall reimburse Buyer for such payment, and Buyer may also elect to deduct any of the amount of any such Seller's Taxes from the amount due to Seller under Section 5.2. Buyer shall have the right to all credits, deductions and other benefits associated with taxes paid by Buyer or reimbursed to Seller by Buyer as described herein. Nothing shall obligate or cause a Party to pay or be liable to pay any taxes, fees and levies for which it is exempt under law.

(b) Seller shall bear all risks, financial and otherwise, throughout the Term, associated with Seller's or the Facility's eligibility to receive any federal or state tax credits, to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes, or to receive any other favorable tax or accounting right or benefit, or any grant or subsidy from a Governmental Entity or other Person. Seller's obligations under this Agreement shall be effective regardless of whether the Facility is eligible for or receives, or the transactions contemplated under this Agreement are eligible for or receives, any federal or state tax credits, grants or other subsidies or any particular accounting, reporting or tax treatment.

6. SECURITY FOR PERFORMANCE

6.1 Grant of Security Interest. Subject to the terms and conditions of this Agreement, Seller hereby pledges to Buyer as security for all outstanding obligations under this Agreement (other than indemnification obligations surviving the expiration of the Term) and any other documents, instruments or agreements executed in connection therewith (collectively, the "**Obligations**"), and grants to Buyer a first priority continuing security interest, lien on, and right of set-off against all Posted Collateral delivered to or received by Buyer hereunder. Upon the return by Buyer to Seller of any Posted Collateral, the security interest and lien granted hereunder on that Posted Collateral will be released immediately and, to the extent possible, without further action by either Party.

6.2 Seller's Support.

(a) Seller shall be required to post Credit Support with a Value of $990,000.00 ($20,000.00 per MWh per hour of Contract Maximum Amount), as adjusted in accordance with Section 3.1(c), to secure Seller's Obligations until the Commercial Operation Date ("**Development Period Security**"). $495,000.00 (fifty percent (50%) of the Development Period Security) shall be provided to Buyer on the Effective Date, and the remaining $495,000.00 (fifty percent (50%) of the Development Period Security) shall be provided to Buyer within fifteen (15) days after the receipt of the Regulatory Approval. Buyer shall return any undrawn amount of the Development Period Security to Seller within thirty (30) days after the later of (x) Buyer's receipt of an undisputed notice from Seller that the Commercial Operation Date has occurred or (y) Buyer's receipt of the full amount of the Operating Period Security.

(b) Beginning not later than three (3) days following the Commercial Operation Date, Seller shall provide Buyer with Credit Support to secure Seller's Obligations after the Commercial Operation Date through and including the date that all of Seller's Obligations are satisfied ("**Operating Period Security**"). The Operating Period Security shall have a Value of $990,000.00 ($20,000.00 per MWh per hour of Contract Maximum Amount), as adjusted in accordance with Section 3.3(b).

(c) The Credit Support Delivery Amount, as defined below, will be rounded up, and the Return Amount, as defined below, will be rounded down, in each case to the nearest integral multiple of $10,000 ("**Rounding Amount**").

(d) The following items will qualify as "**Credit Support**" hereunder in the amount noted under "Valuation Percentage":

		“**Valuation Percentage**”
(A)	Cash	100%
(B)	Letters of Credit	100% unless either (i) a Letter of Credit Default shall have occurred and be continuing with respect to such Letter of Credit, or (ii) twenty (20) or fewer Business Days remain prior to the expiration of such Letter of Credit, in which cases the Valuation Percentage shall be 0%.

(e) All calculations with respect to Credit Support shall be made by the Valuation Agent as of the Valuation Time on the Valuation Date.

6.3 Delivery of Credit Support.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Buyer, and (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Buyer for which there exist any unsatisfied payment obligations with respect to Buyer, then Buyer may request, by written notice, that Seller Transfer to Buyer, or cause to be Transferred to Buyer, Credit Support for the benefit of Buyer, having a Value of at least the Collateral Requirement (“**Credit Support Delivery Amount**”). Such Credit Support shall be delivered to Buyer on the next Business Day if the request is received by the Notification Time; otherwise Credit Support is due by the close of business on the second Business Day after the request is received.

6.4 Reduction and Substitution of Posted Collateral.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Seller, (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Seller for which there exist any unsatisfied payment Obligations, and (c) the Posted Collateral posted by Seller exceeds the required Operating Period Security (rounding downwards for any fractional amount to the next interval of the Rounding Amount), then Seller may, at its sole cost, request that Buyer return Operating Period Security in the amount of such difference (“**Credit Support Return Amount**”) and Buyer shall be obligated to do so. Such Posted Collateral shall be returned to Seller by the close of business on the second Business Day after Buyer’s receipt of such request. The Parties agree that if Seller has posted more than one type of Credit Support to Buyer, Seller can, in its sole discretion, select the type of Credit Support for Buyer to return; provided, however, that Buyer shall not be required to return the specified Credit Support if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Operating Period Security.

6.5 Administration of Posted Collateral.

(a) Cash. Posted Collateral provided in the form of Cash to Buyer hereunder shall be subject to the following provisions:

(i) So long as no Event of Default has occurred and is continuing with respect to Buyer, Buyer will be entitled to either hold Cash or to appoint an agent which is a Qualified Institution (a "**Custodian**") to hold Cash for Buyer. In the event that an Event of Default has occurred and is continuing with respect to Buyer, then the provisions of Section 6.5(a)(ii) shall not apply with respect to Buyer and Cash shall be held in a Qualified Institution in accordance with the provisions of Section 6.5(a)(iii)(B). Upon notice by Buyer to Seller of the appointment of a Custodian, Seller's Obligations to make any Transfer will be discharged by making the Transfer to that Custodian. The holding of Cash by a Custodian will be deemed to be the holding of Cash by Buyer for which the Custodian is acting. If Buyer or its Custodian fails to satisfy any conditions for holding Cash as set forth above, or if Buyer is not entitled to hold Cash at any time, then Buyer will Transfer, or cause its Custodian to Transfer, the Cash to a Qualified Institution and the Cash shall be maintained in accordance with Section 6.5(a)(iii)(B). Except as set forth in Section 6.5(b), Buyer will be liable for the acts or omissions of the Custodian to the same extent that Buyer would be held liable for its own acts or omissions.

(ii) Notwithstanding the provisions of applicable Law, if no Event of Default has occurred and is continuing with respect to Buyer and no termination date has occurred or been designated as a result of an Event of Default with respect to Buyer for which there exists any unsatisfied payment obligations with respect to Buyer, then Buyer shall have the right to sell, pledge, rehypothecate, assign, invest, use, comingle or otherwise use in its business any Cash that it holds as Posted Collateral hereunder, free from any claim or right of any nature whatsoever of Seller, including any equity or right of redemption by Seller.

(iii) Notwithstanding Section 6.5(a)(ii), if neither Buyer nor the Custodian is eligible to hold Cash pursuant to Section 6.5(a)(i) then:

(A) the provisions of Section 6.5(a)(ii) will not apply with respect to Buyer; and

(B) Buyer shall be required to Transfer (or cause to be Transferred) not later than the close of business within five

(5) Business Days following the beginning of such ineligibility all Cash in its possession or held on its behalf to a Qualified Institution to be held in a segregated, safekeeping or custody account (the "**Collateral Account**") within such Qualified Institution with the title of the account indicating that the property contained therein is being held as Cash for Buyer. The Qualified Institution shall serve as Custodian with respect to the Cash in the Collateral Account, and shall hold such Cash in accordance with the terms of this Article 6 and for the security interest of Buyer and execute such account control agreements as are necessary or applicable to perfect the security interest of Seller therein pursuant to Section 9-314 of the Uniform Commercial Code or otherwise, and subject to such security interest, for the ownership and benefit of Seller. The Qualified Institution holding the Cash will invest and reinvest or procure the investment and reinvestment of the Cash in accordance with the written instructions of Buyer, subject to the approval of such instructions by Seller (which approval shall not be unreasonably withheld). Buyer shall have no responsibility for any losses resulting from any investment or reinvestment effected in accordance with Seller's approval.

(iv) So long as no Event of Default with respect to Seller has occurred and is continuing, and no termination date has occurred or been designated for which any unsatisfied payment obligations of Seller exist as the result of an Event of Default with respect to Seller, in the event that Buyer or its Custodian is holding Cash, Buyer will Transfer (or cause to be Transferred) to Seller, in lieu of any interest or other amounts paid or deemed to have been paid with respect to such Cash (all of which shall be retained by Buyer), the Interest Amount. Interest on Cash shall accrue at the Collateral Interest Rate. Interest accrued during the previous month shall be paid by Buyer to Seller on the 3rd Business Day of each calendar month and on any Business Day that posted Credit Support in the form of Cash is returned to Seller, but solely to the extent that, after making such payment, the amount of the Posted Collateral will be at least equal to the required Development Period Security or Operating Period Security, as applicable. On or after the occurrence of an Event of Default with respect to Seller or a termination date as a result of an Event of Default with respect to Seller, Buyer or its Custodian shall retain any such Interest Amount as additional Posted Collateral hereunder until the Obligations of Seller under the Agreement have been satisfied in the case of a termination date or for so long as such Event of Default is continuing in the case of an Event of Default.

(b) Buyer's Rights and Remedies. If at any time an Event of Default with respect to Seller has occurred and is continuing, then, unless Seller has paid in full all of its Obligations that are then due, including those under Section 9.3(b) of this Agreement, Buyer may exercise one or more of the following rights and remedies: (i) all rights and remedies available to a secured party under applicable Law with respect to Posted Collateral held by Buyer, (ii) the right to set-off any amounts payable by Seller with respect to any Obligations against any Posted Collateral or the cash equivalent of any Posted Collateral held by Buyer, or (iii) the right to liquidate any Posted Collateral held by Buyer and to apply the proceeds of such liquidation of the Posted Collateral to any amounts payable to Buyer with respect to the Obligations in such order as Buyer may elect. For purposes of this Section 6.5, Buyer may draw on the undrawn portion of any Letter of Credit from time to time up to the amount of the Obligations that are due at the time of such drawing. Cash proceeds that are not applied to the Obligations shall be maintained in accordance with the terms of this Article 6. Seller shall remain liable for amounts due and owing to Buyer that remain unpaid after the application of Posted Collateral, pursuant to this Section 6.5.

(c) Letters of Credit. Credit Support provided in the form of a Letter of Credit shall be subject to the following provisions.

(i) As one method of providing increased Credit Support, Seller may increase the amount of an outstanding Letter of Credit or establish one or more additional Letters of Credit.

(ii) Upon the occurrence of a Letter of Credit Default, Seller agrees to Transfer to Buyer either a substitute Letter of Credit or Cash, in each case on or before the first (1st) Business Day after the occurrence thereof (or the third (3rd) Business Day after the occurrence thereof if only clause (a) under the definition of Letter of Credit Default applies).

(iii) Notwithstanding Section 6.4, (1) Buyer need not return a Letter of Credit unless the entire principal amount is required to be returned, (2) Buyer shall consent to a reduction of the principal amount of a Letter of Credit to the extent that a Credit Support Delivery Amount would not be created thereby (as of the time of the request or as of the last time the Credit Support Delivery Amount was determined), and (3) if there is more than one form of Posted Collateral when a Credit Support Return Amount is to be Transferred, the Secured Party may elect which to Transfer.

(d) Care of Posted Collateral. Buyer shall exercise reasonable care to assure the safe custody of all Posted Collateral to the extent required by applicable Law, and in any event Buyer will be deemed to have exercised reasonable care if it exercises at least the same degree of care as it would exercise with respect to its own property. Except as specified in the preceding sentence, Buyer will have no duty with respect to the Posted Collateral, including without limitation, any duty to enforce or preserve any rights thereto.

(e) Substitutions. Unless otherwise prohibited herein, upon notice to Buyer specifying the items of Posted Collateral to be exchanged, Seller may, on any Business Day, deliver to Buyer other Credit Support ("**Substitute Credit Support**"). On the Business Day following the day on which the Substitute Credit Support is delivered to Buyer, Buyer shall return to Seller the items of Credit Support specified in Seller's notice; provided, however, that Buyer shall not be required to return the specified Posted Collateral if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Development Period Security or Operating Period Security set forth in Sections 6.2(a) and 6.2(b), respectively.

6.6 Exercise of Rights Against Posted Collateral.

(a) Disputes Regarding Amount of Credit Support. If either Party disputes the amount of Credit Support to be provided or returned (such Party the "**Disputing Party**"), then the Disputing Party shall (a) deliver the undisputed amount of Credit Support to the other Party (such Party, the "**Requesting Party**") and (b) notify the Requesting Party of the existence and nature of the dispute no later than 5:00 p.m. Eastern Prevailing Time on the Business Day that the request for Credit Support was made (the "**Request Date**"). On the Business Day following the Request Date, the Parties shall consult with each other in order to reconcile the two conflicting amounts. If the Parties are not able to resolve their dispute, the Credit Support shall be recalculated, on the Business Day following the Request Date, by each Party requesting quotations from two (2) Reference Market-Makers for a total of four (4) quotations. The highest and lowest of the four (4) quotations shall be discarded and the arithmetic average shall be taken of the remaining two (2), which shall be used in order to determine the amount of Credit Support required. On the same day the Credit Support amount is recalculated, the Disputing Party shall deliver any additional Credit Support required pursuant to the recalculation or the Requesting Party shall return any excess Credit Support that is no longer required pursuant to the recalculation.

(b) Further Assurances. Promptly following a request by a Party, the other Party shall use commercially reasonable efforts to execute, deliver, file, and/or record any financing statement, specific assignment, or other document and take any other action that may be necessary or desirable to create, perfect, or validate any Posted Collateral or other security interest or lien, to enable the requesting party to exercise or enforce its rights or remedies under this Agreement, or with respect to Posted Collateral, or accrued interest.

(c) Further Protection. Seller will promptly give notice to Buyer of, and defend against, any suit, action, proceeding, or lien (other than a banker's lien in favor of the Custodian appointed by Buyer so long as no amount owing from Seller to such Custodian is overdue) that involves the Posted Collateral delivered to Buyer by Seller or that could adversely affect any security interest or lien granted pursuant to this Agreement.

6.7 Return of Credit Support. Any unused Credit Support provided under this Agreement shall be returned to Seller only after any such Credit Support has been either replaced by Seller or used to satisfy any outstanding obligations of Seller in existence at the time of the expiration or termination of this Agreement. Provided such obligations have been satisfied, such Credit Support shall be returned to Seller within thirty (30) days after the earlier of (a) the expiration of the Term or (b) termination of this Agreement.

7. REPRESENTATIONS, WARRANTIES, COVENANTS AND ACKNOWLEDGEMENTS

7.1 Representations and Warranties of Buyer. Buyer hereby represents and warrants to Seller as follows:

(a) Organization and Good Standing; Power and Authority. Buyer is a corporation duly incorporated, validly existing and in good standing under the laws of the state of Rhode Island. Subject to the receipt of the Regulatory Approval, Buyer has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Due Authorization; No Conflicts. The execution and delivery by Buyer of this Agreement, and the performance by Buyer of its obligations hereunder, have been duly authorized by all necessary actions on the part of Buyer and do not and, under existing facts and Law, shall not: (i) contravene its certificate of incorporation or any other governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) subject to receipt of the Regulatory Approval, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing.

(c) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Buyer and, assuming the due execution hereof and performance hereunder by Seller and receipt of the Regulatory Approval, constitutes a legal, valid and binding obligation of Buyer, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(d) No Proceedings. As of the Effective Date, except to the extent relating to the Regulatory Approval, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Buyer or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Buyer reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Buyer's ability to perform its obligations under this Agreement.

(e) Consents and Approvals. Except to the extent associated with the Regulatory Approval, the execution, delivery and performance by Buyer of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken or that shall be duly obtained, made or taken on or prior to the date required, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable as required under applicable Law.

(f) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Buyer and equal bargaining power of the Parties. No principle of law or equity regarding construing ambiguities in this Agreement against the drafting Party shall apply.

(g) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Buyer, or, to Buyer's knowledge, threatened against it.

(h) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Buyer of its obligations under this Agreement.

7.2 Representations and Warranties of Seller. Seller hereby represents and warrants to Buyer as of the Effective Date as follows:

(a) Organization and Good Standing; Power and Authority. Seller is a limited liability company, duly formed, validly existing and in good standing under the laws of Delaware. Subject to the receipt of the Permits listed in Exhibit B, Seller has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Authority. Seller (i) has the power and authority to own and operate its businesses and properties, to own or lease the property it occupies and to conduct the business in which it is currently engaged; (ii) is duly qualified and in good standing under the laws of each jurisdiction where its ownership, lease or operation of property or the conduct of its business requires such qualification; and (iii) shall hold on or before the time required all rights and entitlements necessary to construct, own and operate the Facility and to deliver the Products to the Buyer in accordance with this Agreement.

(c) Due Authorization; No Conflicts. The execution and delivery by Seller of this Agreement, and the performance by Seller of its obligations hereunder, have been duly authorized by all necessary actions on the part of Seller and do not and, under existing facts and Law, shall not: (i) contravene any of its governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) assuming receipt of the Permits listed on Exhibit B, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing. As of the Commercial Operation Date and at all times thereafter, Seller is qualified to perform as a Market Participant under the ISO-NE Tariff, or is qualified to transact through another Market Participant under the ISO-NE Tariff. Seller will not be disqualified from or be materially adversely affected in the performance of any of its obligations under this Agreement by reason of market power or affiliate transaction issues under federal or state regulatory requirements.

(d) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Seller and, assuming the due execution hereof and performance hereunder by Buyer and receipt of the Permits listed on Exhibit B, constitutes a legal, valid and binding obligation of Seller, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(e) No Proceedings. Except to the extent associated with the Permits listed on Exhibit B, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Seller or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Seller reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Seller's ability to perform its obligations under this Agreement.

(f) Consents and Approvals. Subject to the receipt of the Permits listed on Exhibit B on or prior to the date such Permits are required under applicable Law, the execution, delivery and performance by Seller of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable. To Seller's knowledge, Seller shall be able to receive the Permits listed in Exhibit B in due course and as required under applicable Law to the extent that those Permits have not previously been received.

(g) Newly Developed Renewable Energy Resource. As of the Commercial Operation Date and at all times thereafter, the Facility is a Newly Developed Renewable Energy Resource, qualified by the applicable regulatory authority for the state of Rhode Island as eligible to participate in the Renewable Energy Standard program, under R.I.G.L. § 39-26-1 et seq. (subject to Section 4.7(b) in the event of a change in Law affecting such qualification as a Newly Developed Renewable Energy Resource) and shall have a Commercial Operation Date, as verified by the Buyer.

(h) Title to Products. Seller has and shall have good and marketable title to all Products sold and Delivered to Buyer under this Agreement, free and clear of all liens, charges and encumbrances. Seller has not sold and shall not sell any such Products to any other Person, and no Person other than Seller can claim an interest in any Product to be sold to Buyer under this Agreement.

(i) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Seller and equal bargaining power of the Parties. No principle of law or equity regarding construing ambiguities in this Agreement against the drafting Party shall apply.

(j) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Seller, or, to Seller's knowledge, threatened against it.

(k) No Misrepresentations. The reports and other submittals by Seller to Buyer under this Agreement are not false or misleading in any material respect as of the date made.

(l) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Seller of its obligations under this Agreement.

(m) Site Control. As of the Effective Date, Seller either (i) has acquired all real property rights to construct and operate the Facility and to perform Seller's obligations under this Agreement, or (ii) has an irrevocable option requiring only the payment of a commercially reasonable amount to acquire such real property rights through the end of the Services Term; provided, however, that with respect to the real property rights to interconnect the Facility to the Interconnecting Utility and to construct the Network Upgrades (to the extent it is Seller's responsibility to do so), Seller shall have acquired all such rights as of the date of the applicable Critical Milestone in Section 3.1(a). As of the Commercial Operation Date and at all times thereafter, Seller has all real property rights to construct and operate the Facility, to interconnect the Facility to the Interconnecting Utility, to construct the Network Upgrades (to the extent it is Seller's responsibility to do so) and to perform Seller's obligations under this Agreement.

7.3 Continuing Nature of Representations and Warranties. The representations and warranties set forth in this Section are made as of the Effective Date and deemed made continually throughout the Term, subject to the removal of the references to the Regulatory Approval and Permits as and when the Regulatory Approval and Permits are obtained. If at any time during the Term, a Party has knowledge of any event or information which causes any of the representations and warranties in this Article 7 to be untrue or misleading, such Party shall provide the other Party with prompt written notice of the event or information, the representations and warranties affected, and the corrective action such Party shall take. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

8. REGULATORY APPROVAL

8.1 Receipt of Regulatory Approval. The obligations of the Parties to perform this Agreement, other than the Parties' obligations under Section 3.3(d), Section 3.7, Section 6.1, Section 6.2, and Section 12, are conditioned upon and shall not become effective or binding until the receipt of the Regulatory Approval. Buyer shall notify Seller within thirty (30) days after receipt of the Regulatory Approval or receipt of an Unacceptable PUC Order. This Agreement may be terminated (a) by Buyer within thirty (30) days after its receipt of any Unacceptable PUC Order or (b) by either Buyer or Seller in the event that Regulatory Approval is not received within 270 days after filing. Any termination of this Agreement pursuant to this Section 8.1 shall be without liability to either Buyer or Seller as a result of such termination, subject to the return of Credit Support as provided in Section 6.7.

9. BREACHES; REMEDIES

9.1 Events of Default by Either Party. The following shall constitute an event of default ("**Event of Default**") by either Party hereunder:

(a) Representation or Warranty. Any breach of any representation or warranty of such Party set forth herein, or in filings or reports made pursuant to this Agreement occurs, where such breach is not fully cured and corrected within thirty (30) days after the Non-Defaulting Party has provided written notice to the Defaulting Party; provided, however, such period shall be extended for an additional period of up to sixty (60) days if, despite using commercially reasonable efforts, the Defaulting Party is unable to cure within the initial thirty (30) day period, so long as such cure is diligently pursued by the Defaulting Party until such Default had been corrected, but in any event shall be cured within ninety (90) days of the notice from the Non-Defaulting Party; or

(b) Payment Obligations. Any undisputed payment due and payable hereunder is not made on the date due, and such failure continues for more than ten (10) Business Days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; or

(c) Other Covenants. Other than:

(i) failure of the Facility to achieve the Commercial Operation Date by the Guaranteed Commercial Operation Date,

(ii) a failure to maintain the Renewable Energy Standard eligibility requirements set forth in Section 4.7(b) due solely to a change in Law,

(iii) a Rejected Purchase (the sole remedy for which shall be the payment of Resale Damages under Section 4.4), or

(iv) an Event of Default described in Section 9.1(a), 9.1(b), 9.1(d), 9.1(e) or 9.2

such Party fails to perform, observe or otherwise to comply with any obligation hereunder and such failure continues for more than thirty (30) days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; provided, however, such period shall be extended for an additional period of up to thirty (30) days if, despite using commercially reasonable efforts, the Defaulting Party is unable to cure within the initial thirty (30) day period so long as such cure is diligently pursued by the Defaulting Party until such Default had been corrected, but in any event shall be cured within sixty (60) days of the notice from the Non-Defaulting Party; or

(d) Bankruptcy. Such Party (i) is adjudged bankrupt or files a petition in voluntary bankruptcy under any provision of any bankruptcy law or consents to the filing of any bankruptcy or reorganization petition against such Party under any such law, or (without limiting the generality of the foregoing) files a petition to reorganize pursuant to 11 U.S.C. § 101 or any similar statute applicable to such Party, as now or hereinafter in effect, (ii) makes an assignment for the benefit of creditors, or admits in writing an inability to pay its debts generally as they become due, or consents to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of such Party, or (iii) is subject to an order of a court of competent jurisdiction appointing a receiver or liquidator or custodian or trustee of such Party or of a major part of such Party's property, which is not dismissed within sixty (60) days; or

(e) Permit Compliance. Such Party fails to obtain and maintain or cause to be obtained and maintained in full force and effect any Permit (other than the Regulatory Approval) necessary for such Party to perform its obligations under this Agreement and such failure continues for more than thirty (30) days after notice thereof is given by the Non-Defaulting Party; provided, however, such period shall be extended for an additional period of up to sixty (60) days if, despite using commercially reasonable efforts, the Defaulting Party is unable to cure within the initial thirty (30) day period so long as such cure is diligently pursued by the Defaulting Party until such Default had been corrected, but in any event shall be cured within ninety (90) days of the notice from the Non-Defaulting Party.

9.2 Events of Default by Seller. In addition to the Events of Default described in Section 9.1, each of the following shall constitute an Event of Default by Seller hereunder:

(a) Taking of Facility Assets. Except pursuant to security arrangements between Seller and any Lender, any asset of Seller that is material to the construction, operation or maintenance of the Facility or the performance of its obligations hereunder is taken upon execution or by other process of law directed against Seller, or any such asset is taken upon or subject to any attachment by any creditor of or claimant against Seller and such attachment is not disposed of within sixty (60) days after such attachment is levied; or

(b) Failure to Maintain Credit Support. The failure of Seller to provide, maintain and/or replenish the Development Period Security or the Operating Period Security as required pursuant to Article 6 of this Agreement, and such failure continues for more than five (5) Business Days after Buyer has provided written notice thereof to Seller (which five (5) Business Days period shall run concurrently with any applicable cure period in the definition of Letter of Credit Default); or

(c) Energy Output. The failure of the Facility to produce Energy for twelve (12) consecutive months during the Services Term; or

(d) Failure to Satisfy ISO-NE Obligations. The failure of Seller to satisfy, or cause to be satisfied (other than by Buyer), any material obligation under the ISO-NE Rules or ISO-NE Practices or any other obligation with respect to ISO-NE and such failure has an adverse effect on the Facility or Seller's ability to perform its obligations under this Agreement or on Buyer or Buyer's rights or ability to receive the benefits under this Agreement; provided, however, if Seller's failure to satisfy any material obligation under the ISO-NE Rules or ISO-NE Practices does not have an adverse effect on Buyer or Buyer's ability to receive the benefits under this Agreement, Seller shall have the opportunity to cure such failure within thirty (30) days of its occurrence; or

(e) Failure to Meet Critical Milestones. The failure of Seller to satisfy any Critical Milestone by the date set forth therefor in Section 3.1(a), as the same may be extended in accordance with Section 3.1(c) and Section 3.1(d); or

(f) Abandonment. On or after the Commercial Operation Date, the permanent relinquishment by Seller of all of its possession and control of the Facility, other than a transfer permitted under this Agreement; or

(g) Assignment. The assignment of this Agreement by Seller, or Seller's sale or transfer of its interest (or any part thereof) in the Facility, except as permitted in accordance with Article 14; or

(h) Recurring Delivery Failure. A Delivery Failure on ten (10) or more calendar days during the Services Term (unless such Delivery Failure remains subject to a good faith dispute pursuant to Article 11 of this Agreement); or

(i) Failure to Provide Status Reports. A failure to provide timely, accurate and complete status reports in accordance with this Agreement, and such failure continues for more than five (5) Business Days after notice thereof is given by the Buyer; or

(j) Failure to Maintain Renewable Energy Standard Eligibility. A failure to maintain Renewable Energy Standard eligibility as set forth in Section 4.7(b); or

(k) Biennial Average Real-Time High Operating Limit Deficiency. A failure of the Biennial Average Real-Time High Operating Limit for any two consecutive Contract Years to be at least fifty percent (50%) of the Actual Facility Size.

9.3 Remedies.

(a) Suspension of Performance and Remedies at Law. Upon the occurrence and during the continuance of an Event of Default, the Non-Defaulting Party shall have the right, but not the obligation, to (i) withhold any payments due the Defaulting Party under this Agreement, (ii) suspend its performance hereunder, and (iii) exercise such other remedies as provided for in this Agreement including, without limitation, the termination right set forth in Section 9.3(b), and, to the extent not inconsistent with the terms of this Agreement, such remedies available at law and in equity. In addition to the foregoing, except for breaches for which an express remedy or measure of damages is provided herein, the Non-Defaulting Party shall retain its right of specific performance to enforce the Defaulting Party's obligations under this Agreement.

(b) Termination and Termination Payment. Upon the occurrence of an Event of Default, a Non-Defaulting Party may terminate this Agreement at its sole discretion by providing written notice of such termination to the Defaulting Party. If the Non-Defaulting Party terminates this Agreement, it shall be entitled to calculate and receive as its sole remedy for such Event of Default a "**Termination Payment**" as follows:

(i) *Termination by Buyer Prior to Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring prior to the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the sum of (x) all Delay Damages due and owing by Seller through the date of such termination plus (y) the full amount of the Development Period Security required to be provided to Buyer by Seller.

(ii) *Termination by Seller Prior to Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer prior to the Commercial Operation Date, Seller shall only receive a Termination Payment if the Commercial Operation Date either occurs on or before the Guaranteed Commercial Operation Date or would have occurred by such date but for the Event of Default by Buyer giving rise to the termination of this Agreement. In such case, (x) if Seller terminates this Agreement because of an Event of Default by Buyer prior to the Financial Closing Date, the Termination Payment due to Seller shall be equal to the lesser of: (i) Buyer's Percentage Entitlement to Seller's out-of-pocket expenses incurred in connection with the development and construction of the Facility prior to such termination and for which Seller has provided adequate documentation to enable Buyer to verify the expense claimed, or (ii) the Termination Payment due to Seller as calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller; and (y) if Seller terminates this Agreement because of an Event of Default by Buyer on or after the Financial Closing Date, the Termination Payment due to Seller shall be calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller.

All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Buyer shall provide Seller with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(ii).

(iii) *Termination by Buyer On or After Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring on or after the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the greater of: (i) the security required to be provided in accordance with Article 6, or (ii) the amount, if positive, calculated according to the following formula: (x) the present value, discounted at a rate equal to the prime rate specified in the "Money & Investing" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (A) the amount, if, any, by which the forward market price of energy and renewable energy credits (as applicable), as determined by the average of the quotes of at least two nationally recognized energy consulting firms or brokers chosen by Buyer, for Replacement Energy and Replacement RECs (as applicable), exceeds the Price or Adjusted Price, as applicable, that would have been paid pursuant to Exhibit D of this Agreement, multiplied by (B) Buyer's Percentage Entitlement of the projected Energy output of the Facility as determined by a recognized third party expert selected by Buyer, using a probability of exceedance basis of 50%; plus, (y) any costs and losses incurred by Buyer as a result of the Event of Default and termination of the Agreement.

All such amounts shall be determined by Buyer in good faith and in a commercially reasonable manner, and Buyer shall provide Seller with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iii).

(iv) *Termination by Seller On or After Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer occurring on or after the Commercial Operation Date, the Termination Payment due to Seller shall be equal to the amount, if positive, calculated according to the following formula: (x) the present value, discounted at a rate equal to the prime rate specified in the "Money & Investing" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (i) the amount, if, any, by which the Price or Adjusted Price, as applicable, that would have been paid pursuant to Exhibit D of this Agreement, exceeds the forward market price of energy and renewable energy credits (as applicable) as determined by the average of the quotes of at least two nationally recognized energy consulting firms or brokers chosen by Seller, for Replacement Energy and Replacement RECs (as applicable), multiplied by (ii) Buyer's Percentage Entitlement to the projected Energy output of the Facility as determined by a recognized third party expert selected by Seller using a probability of exceedance basis of 50%; plus, (y) any costs and losses incurred by Seller as a result of the Event of Default and termination of the Agreement.

All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Seller shall provide Buyer with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iv).

(v) *Acceptability of Liquidated Damages*. Each Party agrees and acknowledges that (i) the damages and losses (including without limitation the loss of environmental, reliability and economic benefits contemplated under this Agreement) that the Parties would incur due to an Event of Default would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Termination Payment as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

(vi) *Payment of Termination Payment*. The Defaulting Party shall make the Termination Payment within ten (10) Business Days after such notice is effective, regardless whether the Termination Payment calculation is disputed. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall within ten (10) Business Days of receipt of the calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute. If the Parties are unable to resolve the dispute within thirty (30) days, Article 11 shall apply.

(c) Set-off. The Non-Defaulting Party shall be entitled, at its option and in its discretion, to withhold and set off any amounts owed by the Non-Defaulting Party to the Defaulting Party against any payments and any other amounts owed by the Defaulting Party to the Non-Defaulting Party, including any Termination Payment payable as a result of any early termination of this Agreement.

(d) Notice to Lenders. Seller shall provide Buyer with a notice identifying a single Lender (if any) to whom notices of Events of Default are to be issued. Buyer shall provide a copy of the notice of any Event of Default of Seller under this Article 9 to that Lender, and Buyer shall afford such Lender the same opportunities to cure Defaults and Events of Default under this Agreement as are provided to Seller hereunder.

(e) Limitation of Remedies, Liability and Damages. EXCEPT AS EXPRESSLY SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE

THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

10. FORCE MAJEURE

10.1 Force Majeure.

(a) The term "**Force Majeure**" means an unusual, unexpected or significant event: (i) that was not within the control of the Party claiming its occurrence; (ii) that could not have been prevented or avoided by such Party through the exercise of reasonable diligence; and (iii) that directly prohibits or prevents such Party from performing its obligations under this Agreement. Under no circumstances shall Force Majeure include (v) any full or partial curtailment in the electric output of the Facility that is caused by or arises from a mechanical or equipment breakdown or other mishap or events or conditions attributable to normal wear and tear or flaws, unless such curtailment or mishap is caused by Force Majeure, (w) any occurrence or event that merely increases the costs or causes an economic hardship to a Party, (x) any occurrence or event that was caused by or contributed to by the Party claiming the Force Majeure, (y) Seller's ability to sell the Products at a price greater than that set out in this Agreement, or (z) Buyer's ability to procure comparable products at a price lower than that set out in this Agreement. In addition, a delay or inability to perform attributable to a Party's lack of preparation, a Party's failure to timely obtain and maintain all necessary Permits (excepting the Regulatory Approval) or qualifications, any delay or failure in satisfying the Critical Milestone obligations specified in Section 3.1(a)(i) (Permits) or Section 3.1(a)(iii) (Financing), a failure to satisfy contractual conditions or commitments, or lack of or deficiency in funding or other resources shall each not constitute a Force Majeure or be the basis for a claim of Force Majeure. Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Products to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined herein has occurred.

(b) Subject to Section 3.1(d), if either Party is unable, wholly or in part, by Force Majeure to perform obligations under this Agreement, such performance shall be excused and suspended so long as the circumstances that give rise to such inability exist or would exist if the Party claiming the Force Majeure used commercially reasonable efforts to cure such circumstances, but for no longer period. The Party whose performance is affected shall give prompt notice thereof; such notice may be given orally or in writing but, if given orally, it shall be promptly confirmed in writing, providing details regarding the nature, extent and expected duration of the Force Majeure, its anticipated effect on the ability of such Party to perform obligations under this Agreement, and the estimated duration of any interruption in service or other adverse effects resulting from such Force Majeure, and shall be updated or supplemented to keep the other Party advised of the effect and remedial measures being undertaken to overcome the Force Majeure. Such inability shall be promptly corrected to the extent it may be corrected through the exercise of due diligence. Neither Party shall be liable for any losses or damages arising out of a suspension of performance that occurs because of Force Majeure.

(c) Notwithstanding the foregoing, if the Force Majeure prevents full or partial performance under this Agreement for a period of twelve (12) months or more, the Party whose performance is not prevented by Force Majeure shall have the right to terminate this Agreement upon written notice to the other Party and without further recourse. In no event will any delay or failure of performance caused by any conditions or events of Force Majeure extend this Agreement beyond its stated Term. Notwithstanding anything to the contrary herein, during any period of Force Majeure where Buyer is the party whose performance is affected, Seller shall be permitted to sell the Products to any third party in its sole discretion.

11. DISPUTE RESOLUTION

11.1 Dispute Resolution. In the event of any dispute, controversy or claim between the Parties arising out of or relating to this Agreement (collectively, a "**Dispute**"), in addition to any other remedies provided hereunder, the Parties shall attempt to resolve such Dispute through consultations between the Parties. If the Dispute has not been resolved within fifteen (15) Business Days after such consultations between the Parties, then either Party may seek to resolve such Dispute in the courts of the state of Rhode Island; provided, however, if the Dispute is subject to FERC's jurisdiction over wholesale power contracts, then either Party may elect to either (i) file a complaint with FERC seeking resolution of the dispute, or (ii) proceed with the mediation through FERC's Dispute Resolution Service; provided, however, that if one Party fails to participate in the negotiations as provided in this Section 11.1, the other Party can initiate mediation prior to the expiration of the thirty (30) Business Days. Unless otherwise agreed, the Parties will select a mediator from the FERC panel. The Parties may, by written agreement signed by both Parties, alter any time deadline, location(s) for meeting(s), or procedure outlined herein or in FERC's rules for mediation. The procedure specified herein shall be the sole and exclusive procedure for the resolution of Disputes. To the fullest extent permitted by law, any mediation proceeding and any settlement shall be maintained in confidence by the Parties.

11.2 Allocation of Dispute Costs. The fees and expenses associated with mediation shall be divided equally between the Parties, and each Party shall be responsible for its own legal fees, including but not limited to attorney fees, associated with any Dispute.

11.3 Consent to Jurisdiction. Subject to Section 11.1, the Parties agree to the exclusive jurisdiction of the state and federal courts located in the state of Rhode Island for any legal proceedings that may be brought by a Party arising out of or in connection with any Dispute that is not subject to the primary jurisdiction of FERC.

11.4 Waiver of Jury Trial and Inconvenient Forum Claim. EACH PARTY HEREBY WAIVES TO THE FULLEST EXTENT PERMITTED BY LAW ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR PROCEEDING ARISING OUT OF, RESULTING FROM OR IN ANY WAY RELATING TO THIS AGREEMENT. BOTH PARTIES IRREVOCABLY WAIVE, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY OBJECTION THAT THEY MAY NOW OR HEREAFTER HAVE TO THE LAYING OF VENUE AS SET FORTH IN THIS ARTICLE 11 AND ANY CLAIM THAT ANY SUCH PROCEEDING HAS BEEN BROUGHT IN ANY INCONVENIENT FORUM.

12. CONFIDENTIALITY

12.1 Nondisclosure. Buyer and Seller each agrees not to disclose to any Person and to keep confidential, and to cause and instruct its Affiliates, officers, directors, employees, partners and representatives not to disclose to any Person and to keep confidential, any non-public information relating to the terms and provisions of this Agreement, and any information relating to the Products to be supplied by Seller hereunder, and such other non-public information that is designated as "Confidential." Notwithstanding the foregoing, any such information may be disclosed:

(a) to the extent Buyer determines it is appropriate in connection with efforts to obtain or maintain the Regulatory Approval or to seek rate recovery for amounts associated with this Agreement, or to the extent Seller determines it is appropriate in connection with Seller's efforts to obtain or maintain the Permits, or in connection with any Financing of the Facility;

(b) as required by applicable Law or by any subpoena or similar legal process of any Governmental Entity so long as the disclosing Party gives the non-disclosing Party written notice at least three (3) Business Days prior to such disclosure, if practicable;

(c) to the Affiliates of either Party and to the consultants, contractors, suppliers, service providers, attorneys, auditors, financial advisors, lenders or potential lenders, investors or potential investors, and their advisors of either Party or their Affiliates, but solely to the extent they have a need to know that information;

(d) in order to comply with any rule or regulation of ISO-NE, other system operators, any stock exchange or similar Person or for financial disclosure purposes;

(e) to the extent the non-disclosing Party shall have consented in writing prior to any such disclosure; and

(f) to the extent that the information was previously made publicly available other than as a result of a breach of this Section 12.1;

provided, however, in each case, that the Party seeking such disclosure shall, to the extent practicable, use commercially reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce or seek relief in connection with this Section 12.1.

12.2 Public Statements. No public statement, press release or other voluntary publication regarding this Agreement or the transactions to be made hereunder shall be made or issued without the prior consent of the other Party.

13. INDEMNIFICATION

13.1 Indemnification Obligations. Seller shall indemnify, defend and hold Buyer and its partners, shareholders, directors, officers, employees and agents (including, but not limited to, Affiliates and contractors and their employees), harmless from and against all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever arising from or related to Seller's execution, delivery or performance of this Agreement, or Seller's negligence, gross negligence, or willful misconduct, or Seller's failure to satisfy any obligation or liability under this Agreement, or Seller's failure to satisfy any regulatory requirement or commitment associated with this Agreement.

13.2 Failure to Defend. If Seller fails to assume the defense of a claim meriting indemnification, Buyer may at the expense of Seller contest, settle or pay such claim, and shall promptly reimburse Buyer for all costs incurred by Buyer associated therewith.

14. ASSIGNMENT AND CHANGE OF CONTROL

14.1 Prohibition on Assignments. Except as permitted under this Article 14, this Agreement (and any portion thereof) may not be assigned by either Party without the prior written consent of the other Party, which consent may not be unreasonably withheld, conditioned or delayed. The Party requesting the other Party's consent to an assignment of this Agreement will reimburse such other Party for all "out of pocket" costs and expenses such other Party incurs in connection with that consent, without regard to whether such consent is provided. When assignable, this Agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assignees of the Parties, except that no assignment, pledge or other transfer of this Agreement by either Party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement (and shall not impair any Credit Support given by Seller hereunder) unless the other Party (or its successors or assigns) consents in writing to the assignment, pledge or other transfer and expressly releases the assignor, pledgor, or transferor from its obligations thereunder. This Section shall not apply to (a) the sale of the Facility (including Seller or any Affiliate of Seller) to an owner/lessor in connection with a sale-leaseback or tax equity Financing of the Facility in which Seller continues to control the Facility; or (b) the sale of the Facility in connection with the exercise of foreclosure rights by a Lender.

14.2 Permitted Assignment by Seller. Buyer's consent shall not be required for Seller to (i) assign this Agreement to an Affiliate of Seller that assumes all obligations to perform this Agreement; or (ii) pledge or assign the Facility, this Agreement or the revenues under this Agreement to any Lender as security for or in connection with any Financing of the Facility; provided, however, if Seller requests Buyer's consent to such an assignment or requests an estoppel in connection with any Financing, (y) Buyer shall provide that consent subject to Buyer's execution of a consent to assignment or estoppel, as the case may be, in a form acceptable to Buyer and Seller, and (z) Seller will reimburse Buyer for all "out of pocket" costs and expenses Buyer incurs in connection with that consent or estoppel, as the case may be, without regarding to whether such consent or estoppel is provided. The issuance or assignment of membership interests in connection with a tax equity transaction shall not be deemed an assignment by Seller for purposes of this Section 14.2.

14.3 Change in Control over Seller. Buyer's consent shall be required for any change in Control over Seller, which consent shall not be unreasonably withheld, conditioned or delayed and shall be provided if (i) Buyer reasonably determines that such change in Control does not have a material adverse effect on Seller's creditworthiness or Seller's ability to perform its obligations under this Agreement or (ii) after giving effect to any change of Control over Seller, Seller is Controlled by a Qualified Person; provided, however, that (a) following the Commercial Operation Date, a change of Control of the indirect parent entity of Seller, DESRI Holdings, L.P. (or its successor), (b) a tax equity transaction that does not otherwise result in a Person acquiring Control over Seller, and (c) an internal reorganization of the Persons Controlled by DESRI Holdings, L.P. that does not result in DESRI Holdings , L.P. losing Control over Seller shall not require the consent of Buyer.

14.4 Permitted Assignment by Buyer. Buyer shall have the right to assign this Agreement without consent of Seller (a) in connection with any merger or consolidation of the Buyer with or into another Person or any exchange of all of the common stock or other equity interests of Buyer or Buyer's parent for cash, securities or other property or any acquisition, reorganization, or other similar corporate transaction involving all or substantially all of the common stock or other equity interests in, or assets of, Buyer, or (b) to any substitute purchaser of the Products so long as in the case of either clause (a) or clause (b) of this Section 14.4, either (1) the proposed assignee's credit rating is at least either BBB- from S&P or Baa3 from Moody's or (2) the proposed assignee's credit rating is equal to or better than that of Buyer at the time of the proposed assignment, or (3) such assignment, or in the case of clause (a) above the transaction associated with such assignment, has been approved by the PUC or the appropriate Government Entity.

14.5 Prohibited Assignments. Any purported assignment of this Agreement not in compliance with the provisions of this Article 14 shall be null and void.

15. TITLE; RISK OF LOSS

Title to and risk of loss related to Buyer's Percentage Entitlement of the Energy shall transfer from Seller to Buyer at the Delivery Point. Title and risk of loss related to Buyer's Percentage Entitlement of the RECs shall transfer to Buyer when the same are credited to Buyer's GIS account(s) or the GIS account(s) designated by Buyer to Seller in writing. Seller warrants that it shall deliver to Buyer the Products free and clear of all liens and claims therein or thereto by any Person.

16. AUDIT

16.1 Audit. Each Party shall have the right, upon reasonable advance notice, and at its sole expense (unless the other Party has defaulted under this Agreement, in which case the Defaulting Party shall bear the expense) and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party additional information documenting the quantities of Products delivered or provided hereunder. If any such examination reveals any overcharge, the necessary adjustments in such statement and the payments thereof shall be made promptly and shall include interest at the Late Payment Rate from the date the overpayment was made until credited or paid.

16.2 Access to Financial Information. Seller shall provide to Buyer within fifteen (15) days of receipt of Buyer's written request financial information and statements applicable to Seller as well as access to financial personnel, so that Buyer may address any inquiries relating to Seller's financial resources available to satisfy Seller's obligations under this Agreement.

17. NOTICES

Any notice or communication given pursuant hereto shall be in writing and delivered by electronic mail (such notices shall be deemed given upon confirmation of delivery); followed by a hard copy of such notice (1) delivered personally (personally delivered notices shall be deemed given upon written acknowledgment of receipt after delivery to the address specified or upon refusal of receipt); or (2) mailed by registered or certified mail, postage prepaid (mailed notices shall be deemed given on the actual date of delivery, as set forth in the return receipt, or upon refusal of receipt); or (3) delivered by reputable overnight courier; in each case addressed as follows or to such other addresses as may hereafter be designated by either Party to the other in writing:

If to Buyer: Attn: Renewable Contract Manager, Environmental Transactions
National Grid
100 East Old Country Road, Second Floor
Hicksville, NY 11801-4218
Email: RenewableContracts@nationalgrid.com
With a copy to: ElectricSupply@nationalgrid.com

With a copy to:
Legal Department
Attn: Tonya Murphy, Esq.
Senior Counsel
National Grid
40 Sylvan Road
Waltham, MA 02451-1120
Email: tonya.murphy@nationalgrid.com

With a copy to:
Commercial Legal Department
Attn: Renewables
National Grid
40 Sylvan Road
Waltham, MA 02451-1120

If to Seller: Gravel Pit Solar II, LLC
c/o D. E. Shaw Renewable Investments, L.L.C.
1166 Avenue of the Americas, Third Floor
New York, NY 10036
Email: hy.martin@deshaw.com; DESRI-Notices@deshaw.com

18. WAIVER AND MODIFICATION

This Agreement may be amended and its provisions and the effects thereof waived only by a writing executed by the Parties, and no subsequent conduct of any Party or course of dealings between the Parties shall effect or be deemed to effect any such amendment or waiver. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided. The failure of either Party to enforce any provision of this Agreement shall not be construed as a waiver of or acquiescence in or to such provision. Buyer shall determine in its sole discretion whether any amendment or waiver of the provisions of this Agreement shall require Regulatory Approval or PUC filing and/or approval. If Buyer determines that any such approval or filing is required, then such amendment or waiver shall not become effective unless and until Regulatory Approval or such other approval is received, or such PUC filing is made and any requested PUC approval is received.

19. INTERPRETATION

19.1 Choice of Law. Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the state of Rhode Island (without regard to its principles of conflicts of law).

19.2 Headings. Article and Section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and exhibits are, unless the context otherwise requires, references to articles, sections and exhibits of this Agreement. The words "hereof" and "hereunder" shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

19.3 Forward Contract. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereunder are a "forward contract" within the meaning of the United States Bankruptcy Code.

19.4 Standard of Review.

(a) The Parties acknowledge and agree that the standard of review for any avoidance, breach, rejection, termination or other cessation of performance of or changes to any portion of this integrated, non-severable Agreement (as described in Section 22) over which FERC has jurisdiction, whether proposed by Seller, by Buyer, by a non-party of, by FERC acting *sua sponte* shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Serv. Co., 350 U.S. 332 (1956) and Federal Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348 (1956). Each Party agrees that if it seeks to amend any applicable power sales tariff during the Term, such amendment shall not in any way materially and adversely affect this Agreement without the prior written consent of the other Party. Each Party further agrees that it shall not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement.

(b) To the fullest extent permitted by applicable law, each Party, for itself and its successors and assigns, hereby expressly and irrevocably waives any rights it can or may have, now or in the future, whether under §§ 205 and/or 206 of the Federal Power Act or otherwise, to seek to obtain from FERC by any means, directly or indirectly (through complaint, investigation or otherwise), and each hereby covenants and agrees not at any time to seek to so obtain, an order from FERC changing any section of this Agreement specifying the rate, charge, classification, or other term or condition agreed to by the Parties, it being the express intent of the Parties that, to the fullest extent permitted by applicable law, neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Agreement, notwithstanding any subsequent changes in applicable law or market conditions that may occur. In the event it were to be determined that applicable law precludes the Parties from waiving their rights to seek changes from FERC to their market-based power sales contracts (including entering into covenants not to do so) then this subsection (b) shall not apply, provided that, consistent with the foregoing subsection (a), neither Party shall seek any such changes except solely under the "public interest" application of the "just and reasonable" standard of review and otherwise as set forth in this Section 19.4.

19.5 Change in ISO-NE Rules and Practices. This Agreement is subject to the ISO-NE Rules and ISO-NE Practices. If, during the Term of this Agreement, any ISO-NE Rule or ISO-NE Practice is terminated, modified or amended or is otherwise no longer applicable, resulting in a material alteration of a material right or obligation of a Party hereunder, the Parties agree to negotiate in good faith in an attempt to amend or clarify this Agreement to embody the Parties' original intent regarding their respective rights and obligations under this Agreement, provided that neither Party shall have any obligation to agree to any particular amendment or clarification of this Agreement. The intent of the Parties is that any such amendment or clarification reflect, as closely as possible, the intent, substance and effect of the ISO-NE Rule or ISO-NE Practice being replaced, modified, amended or made inapplicable as such ISO-NE Rule or ISO-NE Practice was in effect prior to such termination, modification, amendment, or inapplicability, provided that such amendment or clarification shall not in any event alter (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

19.6 Dodd Frank Act Representations. The Parties agree that this Agreement (including all transactions reflected herein) is not a "swap" within the meaning of the Commodity Exchange Act and the rules, interpretations and other guidance of the Commodity Futures Trading Commission ("**CFTC rules**"), and that the primary intent of this Agreement is physical settlement (i.e., actual transfer of ownership) of the nonfinancial commodity and not solely to transfer price risk. In reliance upon such agreement, each Party represents to the other that:

(a) With respect to the commodity to be purchased and sold hereunder, it is a commercial market participant, a commercial entity and a commercial party, as such terms are used in the CFTC rules, and it is a producer, processor, or commercial user of, or a merchant handling, the commodity and it is entering into this Agreement for purposes related to its business as such;

(b) It is not registered or required to be registered under the CFTC rules as a swap dealer or a major swap participant;

(c) It has entered into this Agreement in connection with the conduct of its regular business and it has the capacity or ability to regularly make or take delivery of the commodity to be purchased and sold hereunder;

(d) With respect to the commodity to be purchased and sold hereunder, it intends to make or take physical delivery of the commodity;

(e) At the time that the Parties enter into this Agreement, any embedded volumetric optionality in this Agreement is primarily intended by the holder of such option or optionality to address physical factors or regulatory requirements that reasonably influence demand for, or supply of, the commodity to be purchased and sold hereunder;

(f) With respect to any embedded commodity option in this Agreement, such option is intended to be physically settled so that, if exercised, the option would result in the sale of the commodity to be purchased or sold hereunder for immediate or deferred shipment or delivery; and

(g) The commodity to be purchased and sold hereunder is a nonfinancial commodity, and is also an exempt commodity or an agricultural commodity, as such terms are defined and interpreted in the CFTC rules.

To the extent that reporting of any transactions related to this Agreement is required by the CFTC rules, the Parties agree that Seller shall be responsible for such reporting (the **"Reporting Party"**). The Reporting Party's reporting obligations shall continue until the reporting obligation has expired or has been terminated in accordance with CFTC rules. The Buyer, as the Party that is not undertaking the reporting obligations shall timely provide the Reporting Party all necessary information requested by the Reporting Party for it to comply with CFTC rules.

19.7 Change in Law or Buyer's Accounting Treatment, Subsequent Judicial or Regulatory Action.

(a) If, during the Term of this Agreement, there is a change in Law or accounting standards or rules or a change in the interpretation or applicability thereof that would result in adverse balance sheet or creditworthiness impacts on Buyer associated with this Agreement or the amounts paid for Products purchased hereunder, the Buyer shall prepare an amendment to this Agreement to avoid or mitigate such impacts. Buyer shall use commercially reasonable efforts to prepare such amendment in a manner that mitigates any material adverse effect(s) on Seller (as identified by Seller, acting reasonably) that could reasonably be expected to result from such amendment, but only to the extent that such mitigation can be accomplished in a manner that is consistent with the purpose of such amendment. Seller agrees to execute such amendment provided that such amendment does not (unless the Seller otherwise agrees) alter: (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

(b) Upon a determination by a court or regulatory body having jurisdiction over this Agreement or any of the Parties hereto, or over the establishment and enforcement of any of the statutes or regulations or orders or actions of regulatory agencies (including the PUC) supporting this Agreement or the rights or obligations of the Parties hereunder that any of the statutes or regulations supporting this Agreement or the rights or obligations of the Parties hereunder, or orders of or actions of regulatory agencies (including the PUC) implementing such statutes or regulations, or this Agreement on its face or as applied, in the reasonable determination by a Party, violates any Law (including the State or Federal Constitution) (an "**Adverse Determination**"), each Party shall have the right to suspend performance under this Agreement without liability. Seller may deliver and sell Products to a third party during any period of time for which Buyer suspends payments or purchases under this Section 19.7(b). Upon an Adverse Determination becoming final and non-appealable, this Agreement shall be rendered null and void.

20. COUNTERPARTS; FACSIMILE SIGNATURES

Any number of counterparts of this Agreement may be executed, and each shall have the same force and effect as an original. Facsimile signatures hereon or on any notice or other instrument delivered under this Agreement shall have the same force and effect as original signatures.

21. NO DUTY TO THIRD PARTIES

Except as provided in any consent to assignment of this Agreement, nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a Party to this Agreement.

22. SEVERABILITY

If any term or provision of this Agreement or the interpretation or application of any term or provision to any prior circumstance is held to be unenforceable, illegal or invalid by a court or agency of competent jurisdiction, the remainder of this Agreement and the interpretation or application of all other terms or provisions to Persons or circumstances other than those which are unenforceable, illegal or invalid shall not be affected thereby, and each term and provision shall be valid and be enforced to the fullest extent permitted by law so long as all essential terms and conditions of this Agreement for both Parties remain valid, binding and enforceable and have not been declared to be unenforceable, illegal or invalid by a Governmental Entity of competent jurisdiction. The Parties acknowledge and agree that essential terms and conditions of this Agreement for each Party include, without limitation, all pricing and payment terms and conditions of this Agreement, and that the essential terms and conditions of this Agreement for Buyer also include, without limitation, the terms and conditions of Section 19.7 of this Agreement.

23. INDEPENDENT CONTRACTOR

Nothing in this Agreement shall be construed as creating any relationship between Buyer and Seller other than that of Seller as independent contractor for the sale of Products, and Buyer as principal and purchaser of the same. Neither Party shall be deemed to be the agent of the other Party for any purpose by reason of this Agreement, and no partnership or joint venture or fiduciary relationship between the Parties is intended to be created hereby. Nothing in this Agreement shall be construed as creating any relationship between Buyer and the Interconnecting Utility.

24. ENTIRE AGREEMENT

This Agreement shall constitute the entire agreement and understanding between the Parties hereto and shall supersede all prior agreements and communications.

25. NON-RECOURSE

The Parties agree that their obligations arising under (or relating to) this Agreement shall be without recourse to any member, unitholder, shareholder or partner of either Party, any controlling Person thereof, or any successor of any such member, unitholder, shareholder, partner or controlling Person (each a member of the "**Extended Group**"); and no member of the Extended Group shall have any liability in such capacity for the obligations of either Party. The Parties reserve the right to modify or terminate this Agreement without the consent of any member of the Extended Group.

[Signature page follows]

REDACTED

IN WITNESS WHEREOF, each of Buyer and Seller has caused this Agreement to be duly executed on its behalf as of the date first above written.

THE NARRAGANSETT ELECTRIC COMPANY, D/B/A NATIONAL GRID, as Buyer

By:_______________________________ FKM JAM

Name: John V Vaughn

Title: Authorized Signatory

GRAVEL PIT SOLAR II, LLC, as Seller

By:_______________________________

Name:

Title:

Signature Page to
Power Purchase Agreement

REDACTED

IN WITNESS WHEREOF, each of Buyer and Seller has caused this Agreement to be duly executed on its behalf as of the date first above written.

THE NARRAGANSETT ELECTRIC COMPANY, D/B/A NATIONAL GRID, as Buyer

By:_________________________________
Name:
Title:

GRAVEL PIT SOLAR II, LLC, as Seller

By:_________________________________
Name: David Zwillinger
Title: Authorized Signatory

EXHIBIT A

DESCRIPTION OF FACILITY

Facility: Those certain panels and inverters, owned or controlled by Seller at [redacted], Connecticut to be included in the Facility (the aggregate nameplate capacity of which will be 50 MW (AC)), and related equipment necessary to deliver the Product to the Delivery Point.

Panel Model	Total Number of Panels

Inverter	Serial Number

Seller will update this Exhibit A to include the model number and number of the Facility's individual panels and inverters planned for the Facility on or before the Commercial Operation Date and further update this Exhibit A within 60 days after the Commercial Operation Date to include the actual model number and number of the Facility's individual panels and the serial number and number of inverters for the Facility as it was constructed on the Commercial Operation Date

Delivery Point:

Settlement in the ISO-NE energy market system will occur when Energy is supplied into Buyer's ISO-NE settlement account at the ISO-NE pricing node ("pnode") for the Facility established in accordance with ISO-NE Rules. The Delivery Point will be the pnode established for the Facility by ISO-NE in the vicinity of the interconnection of the Facility to Pool Transmission Facilities ("PTF") at a new substation to be built delivering to the [redacted] substation. Without limiting any other provision of this Agreement, Seller shall be responsible for all charges, fees and losses required for Delivery of Energy from the Facility to the Delivery Point, including but not limited to all (1) non-PTF and/or distribution system losses, (2) all transmission and/or distribution interconnection charges associated with the Facility, and (3) the cost of Delivery of the Products to the Delivery Point, including all related administration fees and non-PTF and/or distribution wheeling charges. In addition Seller shall be responsible to apply for and schedule all such service. Buyer shall be responsible for any charges, fees and losses from and after the Delivery Point.

Facility Size: 50 MW (AC)

Site Plan including panel location: APPENDIX A-1

REDACTED

APPENDIX A-1

SITE PLAN

[redacted]

EXHIBIT B

SELLER'S CRITICAL MILESTONES

Permits

Part 1 - To be obtained by [redacted]

Connecticut Siting Council Certificate of Environmental Compatibility and Public Need, or, Declaratory Ruling that no Certificate of Environmental Compatibility and Public Need is required

Part 2 - To be obtained by [redacted]

Connecticut DOT Encroachment Permit
Connecticut General Permit for the Discharge of Stormwater and Dewatering Wastewaters from Construction Activities

Real Property

Part 3 - To be obtained by [redacted]

Real property rights to the Facility panel and inverter array area.

Part 4 - To be obtained by [redacted]

Real property rights to the Facility substation that is the Interconnection Point and point of change of ownership under the Interconnection Agreement adjacent to the Interconnection Point.

REDACTED

EXHIBIT C

FORM OF PROGRESS REPORT

For the Quarter Ending:__________________

Milestones Achieved:

Milestones Pending:

Status of Progress toward achievement of Critical Milestones during the quarter:

Status of permitting and Permits obtained during the quarter:

Status of Financing for Facility:

Current projection for Financial Closing Date:

Events expected to result in delays in achievement of any Critical Milestones:

Critical Milestones not yet achieved and projected date for achievement:

Current projection for Commercial Operation Date:

[*Attach Documentation supporting any claim that a Critical Milestone has been achieved*]

EXHIBIT D

PRODUCTS AND PRICING

1. Price for Buyer's Percentage Entitlement of Products up to the Contract Maximum Amount. The Price for the Buyer's Percentage Entitlement of Delivered Products up to the Contract Maximum Amount in nominal dollars shall be as follow:

(a) Product Price - Commencing on the Commercial Operation Date, the Price per MWh for the Products shall be equal to $52.95 per MWh. The Price per MWh for each billing period shall be allocated between Energy and RECs as follows:

(i) Energy = The $/MWh price of Energy for the applicable month shall be equal to the weighted average of the Real-Time or Day Ahead Locational Marginal Price (as applicable consistent with Section 4.2(a)) in that month (also on a $/MWh basis) for the pnode on the Pool Transmission Facilities that is associated with the Delivery Point.

(ii) RECs = The Price less the Energy allocation determined above for the applicable billing period, expressed in $/MWh.

(b) Adjusted Price - The Adjusted Price for Energy shall be equal to $46.95 per MWh.

(c) Negative Pricing - If the market price at the Delivery Point in the Real-Time or Day-Ahead markets, as applicable, for Energy Delivered by Seller is negative in any hour, the payment to Seller for deliveries of Energy shall be reduced by the difference between the absolute value of the hourly LMP at the Delivery Point and $0.00 per MWh for that Energy for each such hour. Each monthly invoice shall reflect a reduction for all hours in the applicable month in which the LMP for the Energy at the Delivery Point is less than $0.00 per MWh.

Examples. If delivered Energy equals 1 MWh and Price equals $50.00/MWh:

LMP at the Delivery Point equals (or is greater than) $0.00/MWh
Buyer payment of Price to Seller $50.00
Seller credit/reimbursement for negative LMP to Buyer $0.00
Net Result: Buyer pays Seller $50 for that hour

LMP at the Delivery Point equals -$150.00/MWh
Buyer payment of Price to Seller $50.00
Seller credit/reimbursement for negative LMP to Buyer $150.00
Net Result: Seller credits or reimburses Buyer $100/MWh for that hour

(d) Price for Products Delivered in Excess of Contract Maximum Amount. Any Products Delivered in excess of the Contract Maximum Amount in any hour shall be purchased by Buyer at a Price equal to the product of (x) the MWhs of Energy in excess of the Contract Maximum Amount Delivered to the Delivery Point and (y) the lesser of (i) ninety percent (90%) of the Real Time LMP at such Delivery Point, or (ii) the Price determined in accordance with

REDACTED

Section 1(a) or the Adjusted Price determined in accordance with Section 1(b) of this Exhibit D (as applicable) for each hour of the month during which such Products in excess of the Contract Maximum Amount is Delivered to Buyer, subject to adjustment as provided in Section 1(c) of this Exhibit D.

REQUEST FOR PROPOSALS

FOR

LONG-TERM CONTRACTS FOR RENEWABLE ENERGY

Issuance Date:

September 12, 2018

The Narragansett Electric Company d/b/a National Grid

nationalgrid

Table of Contents

I. Introduction and Overview

1.1 Purpose of the Request for Proposals ("RFP")

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company"), an investor-owned electric distribution company serving customers in Rhode Island, seeks proposals for the supply of energy as well as Renewable Energy Certificates and related attributes[1] (collectively, "RECs") from eligible renewable energy projects under one or more long-term power purchase agreements ("PPAs"). This RFP is being issued pursuant to the Long-Term Contracting Standard for Renewable Energy (the "LTCS") and in accordance with the "Rules and Regulations Governing Long-Term Contracting Standards for Renewable Energy," promulgated by the Rhode Island Public Utilities Commission ("PUC").[2] The LTCS and the Regulations are included as Appendix C to this RFP.

In addition to satisfying its obligations under the LTCS, National Grid is issuing this competitive RFP to support Governor Gina M. Raimondo's goal of increasing Rhode Island's clean energy portfolio ten-fold by 2020 by procuring up to an additional 400 megawatts ("MW") nameplate capacity of renewable energy.[3] Accordingly, National Grid may, but is not required to, select up to 400 MW of renewable energy projects through this RFP if they meet the requirements of the LTCS, subject to PUC approval. See R.I. Gen. Laws §§ 39-26.1-3(a) and (c)(1). Also, in furtherance of Governor Raimondo's goal to include other Rhode Island utilities in this solicitation, the Pascoag Utility District ("PUD") and the Block Island Power Company ("BIPCo") may be invited by National Grid to purchase a portion of the energy and RECs from any selected project(s).[4]

In this RFP, National Grid is soliciting energy and RECs from renewable energy resources with a nameplate capacity of at least 20 MW each that do not exceed 200 MW each, pursuant to executed PPAs with durations of 10 to 15 years.[5] As explained in Section 1.2, the LTCS requires National Grid to solicit long-term contracts for a minimum amount of long-term contract capacity, and National Grid may enter into long-term contracts for more capacity, voluntarily, as long as such contracts also meet the LTCS requirements. Specifically, to be selected, bids must be "Commercially Reasonable," and pricing under such contract(s) must be below the forecasted market price of energy

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1 Such RECs include Certificates issued in the New England Power Pool Generation Information System.

2 The LTCS and the PUC's authority to promulgate the Regulations can be found in R.I. Gen. Laws § 39-26.1-5(e) (the "Regulations"). The Regulations became effective January 28, 2010.

3 See Governor Gina M. Raimondo Press Release of February 5, 2018, "Raimondo Touts Goal to Make Energy System 10 Times Cleaner: Directs State Energy Team to Work with Utilities to Procure 400MW of Affordable, Clean Energy," available at: http://www.ri.gov/press/view/32439.

4 After any project(s) have been selected by National Grid for PPAs, PUD and BIPCo may be allocated a portion of the energy and REC purchases based on their relative load shares, provided that such purchases are specifically authorized by PUD and BIPCo as being in the best interest of their ratepayers, and that such purchases are projected to reduce or have no effect on the cost to National Grid's customers.

5 Long-term contract durations may exceed 15 years, upon approval of the PUC. R.I. Gen. Laws § 39-26.1-3(a). For more details, please refer to Section 2.2.2.4, "Allowable Contract Term."

and RECs over the term of the proposed contract. More information and details about the LTCS obligation and its requirements are described in Section 1.2, below.

This RFP includes draft contracts for Clean Energy Generation ("Draft Contracts") as Appendix D, and the terms of any PPAs will be finalized between National Grid and successful bidders based on the proposals submitted and selected in accordance with the process set forth in this RFP.

This RFP outlines the process that National Grid plans to follow, sets forth timetables regarding the solicitation process, provides information and instructions to prospective bidders, and describes the evaluation process that will be followed once proposals are received.

1.2 Statutory and Regulatory Framework of the LTCS

All PPAs approved under the LTCS must be commercially reasonable long-term contracts[6] between electric distribution companies and developers or sponsors of newly developed renewable energy resources, and are ultimately subject to PUC approval. R.I. Gen. Laws § 39-26.1-1. Under the LTCS, PPAs must also meet "the goals of stabilizing long-term energy prices, enhancing environmental quality, creating jobs in Rhode Island in the renewable energy sector, and facilitating the financing of renewable energy generation within the jurisdictional boundaries of the state or adjacent state or federal waters or providing direct economic benefit to the state." R.I. Gen. Laws § 39-26.1-1. However, no PPAs shall be awarded unless the pricing under such contract(s) is below the forecasted market price of energy and RECs over the term of the proposed contract. R.I. Gen. Laws § 39-26.1-3(f).

The LTCS requires that, at least once per year, an electric distribution company shall conduct solicitations until the minimum long-term contract capacity is met.[7] R.I. Gen. Laws §§ 39-26.1-2(7) and 39-26.1-3(a). For that reason, and in order to attract and compare offers, the Company has decided to conduct this public solicitation instead of conducting individual negotiations. R.I. Gen. Laws § 39-26.1-3(b); Regulations Section 4.2(a).2. In addition, National Grid may, in its sole discretion, procure additional commercially reasonable contracts for newly developed renewable energy resources on an earlier timetable or above the minimum long-term contract capacity, subject

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6 As defined in R.I. Gen. Laws § 39-26.1-2(1) and Section 3.1 of the Regulations, "commercially reasonable" means terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving newly developed renewable energy resources. Commercially reasonable shall include having a credible project operation date, as determined by the PUC, but a project need not have completed the requisite permitting process to be considered commercially reasonable. If there is a dispute about whether any terms or pricing are commercially reasonable, the PUC shall make the final determination after evidentiary hearings.

7 National Grid's obligation to procure a minimum long-term contract capacity under the LTCS is 90 MW (or, the equivalent of 788,400 megawatt-hours ("MWh") per year). See R.I.G.L. § 39-26.2. (To determine long-term contract capacity, nameplate capacity is typically adjusted by the capacity factor -- as determined by ISO-New England Inc. ("ISO-NE") -- of each renewable energy resource.) As of December 30, 2017, National Grid had executed contracts for approximately 87 percent of the minimum long-term contract capacity required by the LTCS. National Grid is required by Section 5.3 of the Regulations to solicit the remaining approximately 13 percent of its LTCS capacity resulting from a terminated long-term contract, which is the equivalent of approximately 94,124 MWh or 10.74 MW.

to PUC approval. R.I. Gen. Laws § 39-26.1-3(c)(1). The amount of energy and RECs procured in this solicitation will depend entirely on National Grid's evaluation of the proposals submitted and National Grid's judgment as to whether there is value in selecting additional projects for the benefit of customers. See Section 5.4 of the Regulations. In addition, in its review of the discretionary procurements, the Commission will consider the LTCS statute, the least cost procurement statute, and the policy of just and reasonable rates. The Commission will also consider its guidance documents from RIPUC Docket No. 4600 on goals for the energy system and "Benefit-Cost Framework", as well as the rate design principles to the extent applicable. Using these tools, the Company must present a quantitative and qualitative business case that describes why the proposed investments are preferred over alternatives for advancing the goals for the energy system.[8] See RIPUC Docket No. 4600 for more information.[9] The Company encourages bidders to furnish any information that they believe would support the business case for long-term contract capacity in excess of the LTCS minimum amount of long-term contract capacity, and the Company's development of this business case may necessitate future requests to bidders for additional information. As explained in detail in note 7, above, National Grid is not legally obligated to execute PPAs for more than its minimum long-term contract capacity, but may do so voluntarily. In the event that the Company does not receive "Commercially Reasonable" bids in response to this solicitation, the Company will review its options again in 2019. See Section 4.2(a).6 of the Regulations.

To be eligible under this RFP, a generator must be a "newly developed renewable energy resource." Specifically, a "newly developed renewable resource" is defined by the LTCS and the Regulations as an electric generation unit that uses exclusively an eligible renewable energy resource to generate electricity, and that has neither begun operation, nor have the developers of the units implemented investment or lending arrangements necessary to finance the construction of the unit. R.I. Gen. Laws § 39-26.1-2(6); Section 3.16 of the Regulations. For more details on the eligibility of a facility under this RFP, please refer to Section 2.2.2.2, below.

All approved projects, regardless of their location, must "provide other direct economic benefits to Rhode Island, such as job creation, increased property tax revenues, or other similar revenues, deemed substantial" by the PUC, as determined on a case-by-case basis. R.I. Gen. Laws § 39-26.1-5(e); Section 5.2 of the Regulations.

In sum, a PPA must meet the following LTCS requirements for approval by the PUC:

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8 The business case should include at a minimum: (a) an explanation for the timing of the proposed procurement; (b) an explanation for the size of the proposed procurement; (c) consideration and comparison of alternatives to meeting the goals for the energy system, the Governor's clean energy goals, and clean energy jobs goals. Alternatives considered should include, but not be limited to, purchase of RECs from existing facilities, energy efficiency, Renewable Energy Growth, and net metering resources; and (d) the business case should be as transparent, complete, documented, and explained as possible. See RIPUC Docket No. 4822 for more information.

9 For more details on the standard of review for discretionary procurements and the requirements of the business case to support them, please consult RIPUC docket No. 4822 and the PUC directives issued at an Open Meeting on August 27, 2018. Webcast available at: https://www.ustream.tv/channel/WqQyXw296dg.

(a) the project must be qualified as a "newly developed renewable energy resource" (per R.I. Gen. Laws § 39-26.1-1 and Section 4.1 of the Regulations);

(b) the PPA must be commercially reasonable, and pricing under such contract(s) must be below the forecasted market price of energy and RECs over the term of the proposed contract (per R.I. Gen. Laws §§ 39-26.1-1 and 39-26.1-3(f); Section 4.1 of the Regulations); and

(c) regardless of whether it is located in Rhode Island or not, the project must provide substantial direct economic benefits to Rhode Island, such as job creation or property tax revenues, as determined by National Grid's analysis of the value of the respective direct economic benefits to the State of Rhode Island in relation to the cost under the contract (per R.I. Gen. Laws § 39-26.1-5(e); Section 5.2 of the Regulations).

1.3 Procurement Process and Evaluation Approach

The timeline following the issuance of this RFP for evaluation and selection, as well as the schedule for other steps in the process including approval by the PUC, is set forth below in Section 3.1. The procurement process is designed to have three stages of evaluation, as described in Section 2.1 of the RFP.

The evaluation of bids will be conducted by National Grid, in consultation with OER and the Division. See Chart 1, below. In Stage One, proposals will be evaluated on the basis of whether eligibility and threshold requirements are satisfied. Eligibility requirements are designed to ensure that the proposals under review offer the appropriate product and PPA tenor from qualifying newly developed renewable energy resources. Threshold requirements are designed to ensure that proposed projects satisfy statutory criteria under the LTCS and meet minimum standards for viability. National Grid reserves the right to conduct further evaluation of a proposal, at its discretion, before the Stage One evaluation is complete.

In Stage Two, bids will be evaluated in a technology-neutral manner based on specified price and non-price evaluation criteria. This portion of the evaluation will be quantitative in nature (i.e., a quantitative scoring system will be utilized). Proposals that pass the eligibility and threshold review and that score favorably in the Stage Two will advance to the final stage of the evaluation process.

In Stage Three, further evaluation of the remaining bids will be conducted on matters pertaining to project viability and the extent to which the bids, individually and as a portfolio, achieve a variety of objectives, including cost-effectiveness and diversity of resources. National Grid will select proposals for PPA consideration and negotiation from this pool. All three stages of the evaluation process, including the pertinent criteria, are described in Section II of this RFP.

1.4 Communications between National Grid and Bidders

With the exception of the bidders' conference (see Section 3.1, below), all pre-bid contact with prospective bidders and other interested parties will be via email and the National Grid energy procurement website provided in Section 3.5, below. Bidders should submit all questions by email, and National Grid will post responses to the website. Copies of proposals must be submitted to National Grid in the manner and at the mailing/delivery address set forth in Section 3.5 of this RFP.

Following the submission of a proposal, it is the bidder's responsibility to keep National Grid informed of any changes in the status of their proposals and/or projects for the next 270 days that its bid must remain open. National Grid retains the right to seek additional information from any bidder, and the right to negotiate modified pricing, until a final contract is developed.

II. Bid Evaluation and Selection Criteria and Process

2.1 Overview of Bid Evaluation and Selection Process

Proposals received by National Grid will be subjected to a consistent and defined review, evaluation, and selection process, as described in the following sections. Based on the results of the evaluation, National Grid will select proposals for contract negotiations, and will file any and all executed contracts for review and approval by the PUC.

2.2 Eligibility, Threshold and Other Minimum Requirements — Stage One

2.2.1 Introduction

In order to qualify for detailed evaluation, a proposal must be timely submitted[10] and satisfy certain minimum requirements, which are: (1) eligibility requirements; (2) a variety of threshold requirements; and (3) other requirements pertaining to participation in this RFP, including bidder certifications and allowable pricing. If a proposal does not satisfy all of these Stage One requirements, it may be disqualified from further review and evaluation.[11] See Sections 2.2.2 through 2.2.4, below.

2.2.2 Eligibility Requirements

All proposals must meet the following eligibility requirements set forth below. Specifically, proposals will be considered from an "Eligible Bidder" with respect to "Eligible Products" generated from an "Eligible Facility." The Eligible Products must be offered for the "Allowable Contract Term" in quantities that are equal or greater than the "Minimum Contract Size." Failure to meet any of these requirements will lead to disqualification of the proposal from further review and evaluation.

2.2.2.1 Eligible Bidder

An Eligible Bidder is the owner of an Eligible Facility or of the development rights to an Eligible Facility, i.e., the developer of the Eligible Facility.

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[10] For it to be eligible, National Grid must receive a bid by 12:00 p.m. (i.e., noon), Eastern Prevailing Time on the due date for proposals, as set forth in Section 3.1, below.

[11] National Grid reserves the right to conduct further evaluation of a proposal, at its discretion, before the Stage One evaluation is complete.

2.2.2.2 Eligible Facility

An Eligible Facility must be an electric generation facility that satisfies each of the following standards:

a. The electric generation facility must qualify as an eligible renewable energy resource as defined R.I. Gen. Laws § 39-26.1-2(4), § 39-26-5 and Section 3.16 of the Regulations; and

b. The facility must qualify as a "newly developed renewable energy resource," as defined in R.I. Gen. Laws § 39-26.1-2(6). As of the date of contract signing, the generation unit(s) must not have begun operation, and the developers must not have implemented investment or lending arrangements to finance construction.

Note: A generation unit is not eligible under this RFP if it is net-metered or behind a retail meter.

2.2.2.3 Eligible Products

An Eligible Bidder must propose to sell energy and RECs from an Eligible Facility under a PPA.[12] The structure of the contract must be both unit-specific and unit-contingent (i.e., if seller's specific unit produces energy and RECs, then seller must deliver that unit's energy and RECs to buyer) and the delivery point under the contract must be located within ISO-NE. The pricing for eligible products under such contract(s) must be below the forecasted market price of energy and RECs over the term of the proposed contract. R.I. Gen. Laws § 39-26.1-3(f). The Company intends to sell all energy and RECs immediately into the wholesale spot market and REC market. See R.I. Gen Laws § 39-26.1-5(b); Regulations Section 4.2(a).4.

For this RFP, the PPA capacity is the projected annual net (alternating current) electric output of the facility, divided by the product of the maximum net hourly output of the facility and 8,760 hours/year. For projects not located in ISO-NE, this annual amount shall be adjusted to the amount of renewable energy expected to be delivered under the long term contract to the delivery point within ISO-NE, as proposed by bidder. R.I. Gen. Laws § 39-26.1-2(7); Section 3.10 of the Regulations.

It is the bidder's responsibility to satisfy the delivery requirement. The delivery point must be located so that National Grid is not responsible for wheeling charges to move energy to the ISO-NE pool transmission facility ("PTF"). National Grid will not be responsible for any costs associated with delivery other than the payment of the contract prices. Similarly, National Grid will not be responsible for any scheduling associated with delivery.

2.2.2.4 Allowable Contract Term

An Eligible Bidder must submit a proposal for the sale of Eligible Products from an Eligible Facility for a term of 10 to 15 years. R.I. Gen. Laws §§ 39-26.1-2 and 39-26.1-3(a). Contract terms may be

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12 While R.I. Gen. Laws § 39-26.1-3(a) authorizes National Grid to purchase capacity, energy, and attributes from newly developed, renewable-energy resources, in this RFP, National Grid seeks only bids for energy and RECs.

greater than 15 years, upon approval of the PUC. R.I. Gen. Laws § 39-26.1-3(a). However, bidders seeking contract terms longer than 15 years must demonstrate that the longer contract term is a contract cost savings, and must submit pricing schedules for: (1) a contract of 10 to 15 years; and (2) for the longer contract term and the required bid fee. The two pricing schedules will be used to evaluate any economic justification for the longer term.

2.2.2.5 Minimum/Maximum Contract Size and Allowable Alternative Bids

The Minimum/Maximum Contract Size is the proposed sale of Eligible Products from all or a portion of the net generating capability of an Eligible Facility at a specific site that is, at a minimum, 20 MW and, at a maximum, 200 MW.[13] However, while each eligible bidder is required to submit at least one proposal that is at least 20 MW and no more than 200 MW, an eligible bidder may also submit alternative proposals with a nameplate capacity of more than 200 MW but no more than 400 MW. A bidder may bid the entire production of Eligible Products from its proposed Eligible Facility, or any portion of the production for its proposed Eligible Facility, provided that if a bidder only proposes a portion of the production from its proposed Eligible Facility, the pro rata portion of that production must be equivalent to at least 20 MW (e.g., if a bidder proposes one-half of the production from its Eligible Facility, then the generating capability of that Eligible Facility must be at least 40 MW) and must not exceed 200 MW, for the conforming bid. A bidder offering alternative proposal(s) with a nameplate capacity of more than 200 MW may present the same terms, schedule and pricing of the required proposal, with additional capacity, or may present entirely new terms for either portions of the proposal(s) or for the aggregate total capacity.

2.2.3 Threshold Requirements

2.2.3.1 Introduction

Proposals that meet all the Eligibility Requirements will be evaluated to determine compliance with threshold requirements, which have been designed to screen out proposals that are: insufficiently mature from a project development perspective; lack technical viability; impose unacceptable financial accounting consequences for National Grid; are not in compliance with RFP requirements pertaining to credit support, or fail to satisfy minimum standards for bidder experience and ability to finance the proposed project. The threshold requirements for this RFP are set forth below.

2.2.3.2 Reasonable Project Schedule

National Grid is interested in projects that can demonstrate the ability to develop, permit, finance, and construct the proposed Eligible Facility within a reasonably proximate time. To that end,

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[13] The Minimum Project Size as defined here is the maximum net output (alternating current) in MWh per hour. Note that this rating differs from the definition of "minimum long-term contract capacity" within R.I. Gen. Laws § 39-26.1-2(7) and Section 3.10 of the Regulations.

Eligible Bidders must provide a reasonable schedule[14] that provides deadlines for *both* of the following events, after the contract execution date:

a. Closing of construction financing and commencement of construction; and
b. Commercial Operation Date.

Section 3.3 of the Regulations specifically defines the term "credible operation date" as more likely than not that the project will come on line within ninety (90) days of the date that is projected within the proposal, as evidenced by documents filed by a bidder showing, at a minimum, the following:

- commencement of permitting processes;
- a plan for completing all permitting processes;
- viable resource assessment or fuel supply plans and agreements;
- viable financing plans;
- viable installation and electrical interconnect plans;
- material progress toward acquisition of real property rights; and
- evidence of material vendor activity.

Other considerations for establishing a credible operation date that are noted in the Regulations include:

- developer experience in completing similar projects by proposed dates;
- track record and state of development of the particular technology being proposed;
- assignment of an ISO-NE interconnection queue position; and
- developer's ability to secure financing necessary to complete the project by the proposed date.

A proposal that does not have a reasonable schedule that provides sufficient time for the application for, and receipt of, necessary permits and approvals may be determined not to have satisfied this threshold requirement. In addition, a proposal that is determined to have a "fatal flaw" such that it will be unable to obtain permits or property rights necessary to finance and construct the proposed project may be determined not to have satisfied this threshold requirement.

2.2.3.3 Site Control

General Requirements

With the exception of a bidder proposing an offshore wind energy project (see below for special requirements), the bidder must demonstrate that it has control, or an irrevocable option (conditioned only upon the payment of a reasonable amount) to acquire control, over the site for its proposed generation project, including any rights necessary to access the project site and any rights to the

[14] For example, reasonable deadlines may be no more than two years for the closing of construction financing and the commencement of construction from the date of contract execution, and no more than five years to become commercially operational from the date of contract execution, unless the bidder otherwise explains in its proposal that its schedule is reasonable, based on its technology and/or project size.

generator lead to the Delivery Point under the PPA (or, if the project is not within ISO-NE, to the point of interconnection for the project) Control or rights to acquire control must be documented by the bidder completing the form in Appendix B in its entirety and also by complying with all of the following additional requirements in their entirety:

i. Provide a site plan including a map of the site that clearly identifies the location of the generation unit site, the assumed right-of-way for any generator lead, the total acreage for the generation unit, the anticipated interconnection point, and the relationship of the site to other local infrastructure, including transmission facilities, roadways, and water resources. In addition to providing the required map, provide a site layout plan which illustrates the location of all major equipment and facilities on the site;

ii. Provide a certification of the bidder's rights to use the generation unit site and/or generator lead route for the entire proposed term of the PPA (e.g., by virtue of ownership or land development rights obtained from the owner or a lease or easement with a term that is at least as long at the proposed term of the PPA). Identify the individual deeds, leases, easements and other documents creating the right to use the generation unit site and any rights of way needed for interconnection. The bidder may be asked to provide copies of some or all of those documents within 5 days after the request for those documents is made. Under no circumstances will a bidder be selected to proceed to PPA negotiation without having secured and demonstrated full documentation of all property rights required for the project;

iii. Provide evidence that the generation unit site and/or generator lead route is properly zoned or permitted. If the generation unit site and/or generator lead route is not currently zoned or permitted properly, identify present and required zoning and/or land use designations and permits and provide a permitting plan and timeline to secure the necessary approvals;

iv. Provide a description of the area surrounding the generation unit site and/or generator lead route, including a description of the local zoning, flood plain information, existing land and/or waterway use and setting (woodlands, grassland, agriculture, marine environment, other); and

v. Provide a map of the proposed interconnection that includes the path from the generation site to the New England Power Pool (NEPOOL) Transmission Facilities.

Alternative Requirements for Offshore Wind Energy

A bidder proposing an offshore wind energy project must demonstrate that it has a federal lease issued on a competitive basis after January 1, 2012 for an Offshore Wind Energy Generation site that is located on the Outer Continental Shelf and for which no turbine is located within 10 miles of any inhabited area. Further, the bidder must demonstrate that it has a valid lease, or option to lease, for marine terminal facilities necessary for staging and deployment of major project components to the project site. The bidder must also detail the proposed interconnection site, describe what rights the bidder has to the interconnection site, and provide a detailed plan and timeline for the acquisition of any additional necessary rights. The bidder must: (i) specifically describe the portions of the route for which the bidder has acquired sufficient rights to locate its Offshore Delivery Facilities proposed,[15] those transmission facilities, and (ii) provide a reasonable and achievable detailed plan (with a timeline) to acquire sufficient rights to the remainder of the necessary Offshore Delivery Facilities locations. The required information and documentation shall include the following:

i. Plans, including a map of the Offshore Wind Energy Generation site, a map showing the location of the marine terminal facility, the proposed water routes to the project site, a map of the proposed interconnection that includes the path from the Offshore Wind Energy Generation site to the interconnection location, and, to the extent a bid includes associated Offshore Delivery Facilities or Project Specific Generator Lead Line proposed under section 2.2.1.3.1 (1), above, a map that shows those facilities' location(s);

ii. A description of all government – issued permits, approvals, and authorizations that have been obtained or need to be obtained for the use and operation of the Offshore Wind Energy Generation site, the proposed interconnection location, and, to the extent a bid includes associated Offshore Delivery Facilities or Project Specific Generator Lead Line proposed under section 2.2.1.3.1, above, the location(s) of such facilities. Provide copies of any permits, approvals, and authorizations obtained, and a detailed plan and timeline to secure the remaining permits, approvals, and authorizations;

iii. A copy of each of the leases, agreements, easements, and related documents granting the right to use the Offshore Wind Energy Generation site, the marine terminal for deployment of major project components, and, if available, the interconnection location;

iv. A copy of each of the related leases, agreements, easements, and related documents that have been obtained for the route of the Offshore Delivery Facilities or Project Specific Generator Lead Line proposed under section 2.2.1.3. above; and,

v. Provide a description of the area surrounding any land-based project area, including the marine terminal for deployment of major project components and all transmission and interconnection facility locations.

2.2.3.4 Interconnection and Delivery Requirements

The delivery of Eligible Products from an Eligible Facility must occur throughout the term of the contract. Substitution of non-Eligible Products is not allowed for delivery. The delivery point must be located so that National Grid is not responsible for wheeling charges to move energy to the ISO-NE delivery point. National Grid will not be responsible for any costs associated with delivery other than the payment of the contract prices. Similarly, National Grid will not be responsible for any

[15] Site control information as described above must be provided for all Offshore Delivery Facilities associated with the bid, whether or not they are proposed in a separate bid component from the Offshore Wind Energy Generation component of the bid.

scheduling associated with delivery. At no time will National Grid assume the responsibility of Lead Market Participant, as defined by ISO-NE.

The bidder will be responsible for all costs associated with and/or arising from interconnecting its project to the PTF. Delivery must occur in ISO-NE's settlement system at the delivery point. The Company is seeking projects from which energy can be delivered without material constraint or curtailment (i.e., the project can be fully dispatched) and the bidder is obligated to demonstrate how the Capacity Capability Interconnection Standard (CCIS) as defined by ISO-NE is to be satisfied. Consequently, bidders must demonstrate that their proposed point of delivery into ISO-NE, along with their proposed interconnection and transmission upgrades, is sufficient to ensure full dispatch of the proposal's generation profile. Proposals must include all interconnection and transmission or distribution system upgrade costs required to ensure full dispatch, including upgrades that may need to occur beyond the point of interconnection. Proposals that fail to provide sufficient supporting documentation or information necessary to reasonably ensure full delivery under a range of assumptions may be eliminated from further evaluation.

The generation unit shall comply with all ISO-NE and FERC interconnection requirements for generation facilities and interregional ties, as applicable. The RECs and environmental attributes must be delivered into National Grid's NEPOOL GIS accounts.

The bidder must detail the status (and conclusions, as available) of interconnection applications and studies, as further described in Section 6 of Appendix B to this RFP.

All projects submitted by bidders must have filed an interconnection request with ISO-NE, seeking service at the CCIS. Projects that have received their I.3.9 approval from ISO-NE must identify that approval and include such documentation in their proposal. Proposals that do not have I.3.9 approval from ISO-NE must include technical reports or system impact studies that approximate the ISO-NE interconnection process including the Overlapping System Impact Study required for qualification in the Forward Capacity Market (FCM). These studies and reports must include clear documentation of study technical and cost assumptions, reasoning, and justification of such assumptions. All studies must use the current ISO-NE interconnection process (including network impact scenarios from multiple projects interconnecting), and must also detail any assumptions with respect to projects that are ahead of the proposed project in the ISO-NE interconnection queue and any assumptions as to changes to the transmission system that differ from the current ISO-NE Regional System Plan. Proposals are strongly encouraged to include a scenario analysis in their studies that shows how changes in the project interconnection queue could impact their interconnection costs using the current ISO-NE interconnection rules.

To the extent that ISO-NE is considering changes to the current interconnection rules, bidders may also submit studies using the new ISO-NE proposed process. Any such studies must be accompanied with clear documentation of study technical and cost assumptions, reasoning, and justification of such assumptions. National Grid may consider such additional studies during the evaluation process if applicable, but will not consider submissions based on interconnection processes or rules that have not been proposed by ISO-NE.

The requirement to qualify for CCIS is strictly to assure deliverability, and bidders are not required to participate in the FCM. National Grid will not purchase capacity if the project clears in the Forward Capacity Auction (FCA), and any capacity revenues will accrue to the Lead Market Participant.

2.2.3.4 Technical Viability; Ability to Finance the Proposed Project

The bidder must demonstrate that the technology it proposes to use is technically viable and that the bidder has the ability to finance the proposed project. Technical viability may be demonstrated by showing that the technology is commercially available and has been used successfully. If a bidder plans to use technology that is not commercially proven, it must provide evidence of technical viability and a credible plan to finance the project in light of the state of development of the technology. All bidders must provide a reasonable plan for financing the proposed project, including the funding of development costs and the required development period security and the ability to acquire the required equipment in the time frame proposed.

2.2.3.5 Experience

The bidder must demonstrate that it has a sufficient amount of relevant experience to successfully develop, finance, construct and operate its proposed project. This demonstration can be made by showing that the bidder (or a substantial member of the bidder's development team) has:

a. Successfully developed a similar type of project by a proposed commercial operation date; OR
b. Successfully developed one or more projects of different technologies but of similar size or complexity or requiring similar skill sets by a proposed commercial operation date; AND
c. Experience in financing power generation projects.

2.2.3.6 Security Requirements

Bidders will be required to post Development Period Security and Operating Period Security. The required level of Development Period Security is $20,000 multiplied by the Contract Maximum Amount (as defined in the Draft Contracts, Appendix D). Fifty percent (50%) of the Development Period Security must be provided upon execution of the PPA. The remaining fifty percent (50%) of the Development Period Security must be provided upon PUC approval of the PPA. Any posted Development Period Security will be promptly returned if the PUC does not approve the PPA. Once a project achieves Commercial Operation, the amount of required security (Operating Period Security) will be the same as the required amount of Development Period Security.

The required security must be in the form of a cash deposit or a letter of credit, as required in the Draft Contracts.

2.2.3.7 Commercially Reasonable Standard

Under the LTCS, National Grid is not obligated to enter into long-term contracts for renewable energy resources on terms which National Grid believes to be commercially unreasonable. R.I. Gen. Laws § 39-26.1-3(c)(1). National Grid will consider both the pricing schedule and non-price terms and conditions in an initial assessment of whether a proposal is commercially reasonable, which is defined as having "terms and pricing that are reasonably consistent with what an experienced power market analyst would expect to see in transactions involving new developed renewable energy resources." R.I. Gen. Laws § 39-26.1-2.

2.2.3.8 Timeliness

The bid submitted must be timely submitted, in accordance with Sections 3.1 and 3.5, below.

2.2.4 Other Minimum Requirements

Other RFP requirements pertain to bid certification, allowable pricing and bid completeness, as described in this section.

2.2.4.1 Proposal Certification

Bidders are required to provide firm pricing for 270 days from the date of bid submission. The bidder must also sign the certification form in Appendix B verifying that the prices, terms and conditions of the proposal are valid for at least 270 days. An officer or duly authorized representative of the bidder is required to sign the Proposal Certification Form.

2.2.4.2 Pricing

2.2.4.2.1 Allowable Forms of Pricing:

All bidders should provide separate prices for energy and RECs, in accordance with pricing options (a) through (c), below:

(a) a fixed price with separate pricing for energy ($/MWh) and RECs ($/REC) for the term of the contract;

(b) prices for energy and RECs (in $/MWh and $/REC, respectively) that change by a fixed rate for the term of the contract (e.g., a 2% increase per year); or by different fixed rates for various periods of the contract (e.g., a 3% increase per year for the first 5 years, and then a 2% increase per year for the next 5 years, etc.); or

(c) an indexed price for energy and RECs (in $/MWh, and $/REC, respectively); indexed at or below the ISO-NE Day Ahead or Real-Time LMP as applicable, for a defined pricing node on the ISO-NE Pool Transmission Facility (“PTF”).

Regardless of the pricing option utilized, pricing for energy and RECs must align with the relative market value of those products. In order to assess whether the proposed REC prices meet this requirement, National Grid will determine a default REC price at the time this RFP is issued based on the most recent “Base Case, Class 1 Market Price for Rhode Island,” prepared by Sustainable Energy Advantage.

2.2.4.2.2 Pricing must conform to the following conditions:

Regardless of whether a bidder proposes pricing option (a), (b), or (c) listed in Section 2.2.4.2.1, above, any pricing option must also conform to the following pricing conditions:

(a) Proposed prices may not be conditioned upon, nor subject to adjustment, based upon the availability of the Federal Production Tax Credit or the Federal Investment Tax Credit, or the availability or receipt of any other government grant or subsidy;

(b) pricing must incorporate a price adjustment if the generation ceases to conform to R.I.G.L. § 39-26-5, National Grid will thereafter only purchase the electric energy under that PPA, and the Seller will be permitted to sell those non-conforming RECs to a third party; and

(c) pricing must adjust payment to compensate National Grid for any energy delivered at negative market clearing prices at the delivery node. In the event that the Locational Marginal Price ("LMP") for the Energy at the Delivery Point is less than $0.00 per MWh in any hour, the PPA price for Energy purchased during that hour will be reduced by the amount by which that LMP is below $0.00/MWh.

Examples:

<u>If Delivered Energy equals 1 MWh and Contract Price equals $50.00/MWh:</u>

<u>Hourly LMP at the Delivery Point equals (or is greater than) $0.00/MWh:</u>
Buyer payment of Price to Seller = $50/MWh
Seller credit/reimbursement for negative LMP to Buyer = $0.00
Net Result: Buyer pays Seller $50/MWh for that hour

<u>Hourly LMP at the Delivery Point equals -$150.00/MWh:</u>
Buyer payment of Price to Seller = $50.00
Seller credit/reimbursement for negative LMP to Buyer = $150/MWh
Net Result: Seller credits or reimburses Buyer: $150/MWh - $50/MWh = $100/MWh for that hour

These forms of pricing are conforming under this RFP. National Grid may consider other forms of pricing as an alternative, as long as the bidder submits a proposal for the project with conforming pricing and required bid fee. Alternative (<u>i.e.</u>, non-conforming) pricing may be considered subject to the following conditions:

- Any pricing formula must be symmetrical. In other words, if an index is used, prices must be allowed to increase or decrease in a symmetrical manner relative to a base price; and
- There must be a price cap for each year under the proposed contract.

National Grid is under no obligation to accept a proposal with any form of alternative (i.e., non-conforming) pricing.

The Delivery Point for electric energy must be at an ISO-NE PTF node. For projects not located in Rhode Island, National Grid may also require pricing based on the Rhode Island zone. For projects not located in within ISO-NE, National Grid still requires pricing based on delivery to an ISO-NE PTF node.

With respect to any pricing proposal, payments will only be made for Eligible Products delivered to National Grid's ISO-NE and NEPOOL accounts. For a project that is not located within the ISO-NE control area, National Grid will require the minimum delivery of the project's production profile to be delivered to the ISO-NE delivery point.

2.2.4.3 Bid Completeness: Bidder Response Forms

Bidders must use the forms provided in Appendix B and provide complete responses in each section. Appendix B contains the Bidder Response Forms which outline the information required from each bidder. If any of the information requested is inconsistent with the type of technology or product proposed, the Bidder should include "N/A" and describe the basis for this designation. If a bidder does not have the information requested in the bid forms and cannot obtain access to that information prior to the bid submittal due date, the bidder should provide an appropriate explanation.

Appendix D to this RFP is the form of the Draft Contracts being used in this solicitation: one contract is for projects within the ISO-NE control area, and one contract is for projects outside the ISO-NE control area. A bidder must include a marked version showing any proposed changes to the Draft Contract with its proposal. National Grid will presume that bidders are willing to execute the marked-up contracts included in their proposals. If a Bidder fails to include a marked version of one of the Draft Contracts, National Grid will presume that bidder is willing to execute the Draft Contract that applies to its project. Any exceptions taken to threshold and/or eligibility requirements may result in a proposal being rejected. Bidders are discouraged from proposing material changes to the Draft Contracts.

2.2.4.4 Non-Refundable Bid Fees

Each proposal must be accompanied by a non-refundable bid fee, which will be used to offset the cost of the evaluation of proposals. The minimum bid fee will be $25,000 for a project with a minimum nameplate capacity of 20 MW, and bid fees will increase by $1,000 for each MW above 20 MW to a maximum bid fee of $100,000. If there are changes to any physical aspect of a project, including but not limited to project size, technology type(s), production/delivery profile, in-service date, or delivery location, then another bid fee will be required. Each additional pricing offer for the same project, including those with alternate contract term lengths, will cost an additional fixed fee of $25,000.

Bid fees must be sent to National Grid. Instructions will be sent in response to a notice of intent to bid, and/or upon request. Bid fees must be received by National Grid no later than the final date for the submission of proposals. Proposals that are submitted without a bid fee will not be considered or reviewed. Before submitting proposals and bid fees, bidders are strongly encouraged to verify that the proposal and documentation meets all requirements of this RFP. Submission of a bid fee does not obligate National Grid to select a project.

2.3 Stage Two – Price and Non-Price Analysis

Stage Two of the evaluation involves an initial price and non-price analysis of proposals. The results of the price and non-price analysis will be a relative ranking and scoring of proposals. National Grid plans to weight price factors at eighty percent (80%) and non-price factors at twenty percent (20%) for purposes of conducting the initial evaluation. The Company will submit the specific scoring and weighting of each factor included within the price and non-price analysis to the PUC, under seal, prior to the bid submission deadline stated in Section 3.1, below.

2.3.1 Initial Evaluation Using Price-Related Evaluation Criteria

The price evaluation will be based on a comparison of (a) the total contract cost of the products bid, which must include energy and RECs, to (b) the estimated market value of these products, taking into consideration the production profile and location of the proposed project over the term of the proposed contract term and any locational marginal price benefits. National Grid plans to use a price forecast that will incorporate the effects of future federal or state regulation of carbon dioxide emissions on relevant energy prices. The metric used will be net $/MWh cost or benefit. Each bidder will be responsible for all costs associated with interconnecting its project to the transmission grid or, if applicable, local distribution facilities. Each bidder will identify in its bid(s) its proposed point(s) of delivery within ISO-NE.

As part of the price evaluation, National Grid will assess the relative above-market or below-market costs on a present value basis in order to assess the relative front-loading or back-loading of the proposed bid. The discount rate to be used in the evaluation will be 7%. All other things being held equal, bids that have more front-loaded above-market costs will not be evaluated as favorably as other bids.

Proposals will be ranked from highest to lowest present value of net benefit (or lowest to highest present value of net cost) on a dollars per MWh basis based on the result derived through the application of the methodology described above.

All projects, regardless of their location, shall provide other direct economic benefits to the State of Rhode Island. The projected change a project may produce in locational marginal prices and REC market prices will be evaluated in the price analysis of Stage Two. Economic benefits such as employment effects and increased revenues a project may provide will be evaluated in the non-price analysis of Stage Two.

2.3.2 Initial Non-Price Evaluation

The non-price evaluation will consist of: (1) siting, permitting, and environmental impacts; (2) project development status and operational viability; (3) experience and capabilities of bidder and the project development team; (4) interconnection; (5) financing; (6) contract risk; and (7) economic benefits to Rhode Island. Within each category are a number of related criteria that will be considered in the evaluation. This section of the RFP will identify and describe in more detail the individual criteria within each primary category. The relative importance of each of the criteria in terms of the scoring of the bids will be developed prior to receipt of bids and will be utilized during the bid evaluation process.

2.3.2.1 Purpose of Non-Price Evaluation Criteria

The non-price evaluation criteria other than contract exceptions are designed to assess the likelihood of a project coming to fruition based on various factors critical to successful project development. The objectives of the criteria are to provide an indication of the feasibility and viability of each project and the likelihood of meeting the proposed commercial operation date. Proposals are preferred that can demonstrate, based on the current status of project development and past experience, that the project will likely be successfully developed and operated as proposed.

2.3.2.2 Factors to be Assessed in Non-Price Evaluation

Within each of the non-price evaluation factors, a variety of project and proposal-related factors will be assessed. They are summarized as follows:

- Siting and permitting
  - Extent to which site control has been achieved, including acquisition of necessary easements or rights-of-way
  - Identification of required permits and approvals
  - Status of efforts and credibility of plan to obtain permits and approvals
  - Community relations plan
  - Environmental Impact
- Project development status and operational viability
  - Completeness and credibility of detailed critical path schedule; ability to meet scheduled construction start date and commercial operation date
  - Credibility of fuel supply plans or energy resource assessments
  - Reliability and state of development of proposed technology
  - Commercial access to proposed technology
  - Progress in interconnection process
- Experience and capabilities of bidder and project development team
  - Project development
  - Project financing
  - Operations and maintenance
  - Experience in the ISO-NE market
- Interconnection and Deliverability
  - Status of interconnection and system impact studies
  - Likelihood that interconnection process will be completed in accordance with schedule for project development
- Financing
  - Credibility of financing plan
  - Financial strength of bidder
- Contract Risk
  - Extent to which the bidder accepts provisions of the Draft Contract that applies to its project or shifts risk to buyer and customers
- Economic Benefits to Rhode Island

2.4 Stage Three -- Portfolio Analysis

Stage Three involves a further review[16] of the bids.[17] In Stage Three, National Grid will consider and weight at its discretion the following factors:

- Ranking in Stage Two;
- Commercial reasonableness of the bid;
- Risk associated with project viability of the bid;
- The extent to which the bid would create additional economic and environmental benefits within Rhode Island; and
- Portfolio effect: the overall impact of any combinations of proposals.

Stage Three uses Stage Two as a guide and provides for a reasonable degree of considered judgment based on criteria specified in this RFP, which will provide greater assurance that the RFP will lead to successful results.

The objective of Stage Three is to select the proposal(s) that provide the greatest value consistent with the stated objectives and requirements as set forth in the RFP. Generally, National Grid prefers viable projects that provide low cost renewable energy with limited risk and some degree of resource diversity. However, it is recognized that any particular project may not be ranked highly with respect to all of these considerations and the extent to which the stated RFP objectives will be satisfied will depend, in large part, on the particulars of the proposals that are submitted. Based on the results of Stage Three, one or more projects will be conditionally selected for contract negotiations, if appropriate.

2.5 Contract Negotiation Process

Any bidders selected for negotiations by National Grid will be required to indicate in writing whether they intend to proceed with their proposals within five business days of being notified. Bidders must be able to begin negotiations immediately upon that notification, including the resolution of any conflicts that their selected counsel may have with National Grid. If negotiations are not successful within a reasonable period of time, National Grid may terminate a project's conditional selection.

2.6 Regulatory Approval

If National Grid executes any PPA as a result of this RFP process, such PPA(s) will be filed with the PUC for review and approval within sixty (60) days of the execution date. After National Grid files

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[16] In connection with this review, and in evaluation of the pricing, a bidder may be asked to provide *pro forma* income and cash flow statements for the term of the proposed PPA (including revenue and cost data by major categories, debt service, depreciation expense and other relevant information).

[17] National Grid is under no obligation to proceed beyond Stage Two if bids do not meet the LTCS requirements.

the PPA(s), the PUC will hold public hearings within approximately forty-five (45) days of the filing, and issue a written order approving or rejecting the PPA within approximately sixty (60) days of the filing.[18] The PUC will approve the PPA(s) if it determines that:

(1) the PPA(s) is/are commercially reasonable,

(2) the requirements for the annual solicitation have been met; and

(3) the PPA(s) is/are consistent with the purposes of the LTCS and the Regulations.[19]

Pursuant to Section 5.3 of the Regulations, each PPA shall contain provisions that allow National Grid to terminate the PPA, without penalty, after three (3) years of execution should National Grid or the PUC determine that material progress on the project is not being made, as determined by evaluating the success in meeting PPA milestones.

National Grid is not obligated to execute any PPA on terms which it reasonably believes to be commercially unreasonable; provided that if there is a dispute about whether these terms are commercially unreasonable, the PUC shall make the final determination after an evidentiary hearing. R.I. Gen. Laws § 39-26.1-3(c)(1). Each long-term contract shall contain a condition that it shall not be effective without PUC review and approval. R.I. Gen. Laws § 39-26.1-3(b).

III. Instructions to Bidders

3.1 Schedule for the Bidding Process

The proposed schedule for the bidding process is set forth in Chart 1. National Grid reserves the right to revise the schedule as necessary. Any changes to the schedule will be posted on the website for this RFP.

Chart 1
RFP Schedule

Event	Anticipated Dates
Issue RFP	September 12, 2018
Bidders Conference	September 26, 2018
Submit Notice of Intent to Bid	September 28, 2018
Deadline for Submission of Questions	September 28, 2018
Due Date for Submission of Proposals	October 29, 2018 by 12:00 p.m. (noon) EPT
Review of Bids with the Rhode Island Office of Energy Resources ("OER") and the Rhode Island	November 5, 2018

[18] See R.I. Gen. Laws § 39-26.1-3(b). If the PUC rejects a contract, it may advise the parties of the reason for the contract being rejected and direct the parties to attempt to address the reasons for rejection in a revised contract within a specified period not to exceed ninety (90) days. R.I. Gen. Laws § 39-26.1-3(b).

[19] R.I. Gen. Laws § 39-26.1-3(b).

Division of Public Utilities and Carriers ("Division")	
Conditional selection of Bidder(s) for negotiation	May 2, 2019
Negotiate and Execute Contracts	July 29, 2019
Submit Contracts for PUC Approval	August 30, 2019

3.2 Bidders' Conference; Bidder Questions; Notice of Intent to Bid

A Bidders' Conference will be held for interested persons approximately three (3) weeks from the date of this RFP, and notice will be posted on the RFP website. The purpose of the Bidders' Conference is to provide the opportunity to clarify any aspects of the RFP. Prospective bidders may submit questions about the RFP prior to the Bidders' Conference. National Grid will attempt to answer questions submitted prior to and during the Bidders' Conference. Although National Grid may respond orally to questions posed at the Bidders' Conference, only written answers that are provided in response to written questions will be official responses.

National Grid will also accept written questions pertaining to the RFP following the Bidders' Conference up to the date provided in Chart 1. Both the questions and the written responses will be posted on the National Grid website (without identifying the person that asked the question).

Prospective bidders are also encouraged to submit a Notice of Intent to Bid form by the date provided in Chart 1. The Notice of Intent to Bid form is attached as Appendix A to the RFP. National Grid will provide any necessary updates by email regarding the RFP to prospective bidders who submit a Notice of Intent to Bid. Persons that submit a Notice of Intent to Bid are not obligated to submit a proposal, and persons who do not submit a Notice of Intent to Bid are not prohibited from submitting a bid.

3.3 Preparation of Proposals

Each bidder shall have sole responsibility for carefully reviewing the RFP and all attachments and for thoroughly investigating and informing itself with respect to all matters pertinent to this RFP and its proposal, including pertinent ISO-NE tariffs and documents. Bidders should rely only on information provided in the RFP and any associated written updates when preparing their proposal. Each bidder shall be solely responsible for and shall bear all of its costs incurred in the preparation of its proposal and/or its participation in this RFP.

3.4 Submission of Proposals; Confidentiality

If information contained in the proposal is confidential, bidders must submit a total of six (6) USB flash drives – three (3) with the public version of the proposal and three (3) with the confidential version of the proposal -- to the Official Contact listed in Section 3.5, below. **For it to be eligible, National Grid must receive a bid by 12:00 p.m. (i.e., noon), Eastern Prevailing Time on the due date for proposals set forth in Section 3.1, above.** Fax or email submissions will not be accepted. National Grid will reject any proposals that it receives after the deadline. Each proposal shall contain the full name and business address of the bidder and bidder's contact person and shall be signed by an authorized officer of the bidder.

The public version of the bid will be posted to the RFP website that is provided in Section 3.5, below. Each proposal must contain the full name and business address of the bidder, and the bidder's contact person, and the bid must be signed by an authorized officer or duly authorized representative of the bidder. Bidders must sign the original proposal and include copies of the signature page with the proposal. The full name and business address of the bidder must be included in the public version of the proposal(s). The public version of the bid should include the words "Public Version" to alert the recipients that the version may be publicly posted. The public proposals must be complete in all respects other than the redaction of confidential information.

With regard to completeness, "complete" proposals must include a properly completed Certification, Project and Pricing Data ("CPPD") Form, although at the bidder's option the CPPD submitted as part of the public version may be a PDF instead of a working Excel file so long as the bidder submits the un-redacted CPPD form as a working Excel file with the confidential version of the proposal. If there is conflicting information between the information in the CPPD form and information in other forms, then the information in the CPPD will be used in the evaluation of the bid. Information elsewhere in the bid cannot be used by the bidder to modify or qualify any information in the CPPD.

In addition, a bidder may redact the public version of the proposal to remove information that qualifies for confidential treatment pursuant to Rhode Island's requirements. The recipients will not redact the public versions of proposals for the bidder. Anything submitted within the public version will be made AVAILABLE TO THE PUBLIC. If the bidder wishes to redact any information from the public version of the bid, the bidder must submit three (3) confidential versions of the proposal (also on USB flash drives) that will not be publicly posted on the RFP website. It is solely bidder's responsibility to redact any portion of their bid that they wish to remain confidential in the public version of their proposal. For example, if the bidder considers the CPPD form to be confidential, it must redact the form from the public version of the proposal but include the CPPD form in the confidential version as a working Excel file, with all required information included. The confidential version of the proposal will be treated as confidential and sensitive information by the recipients, subject to the treatment of confidential information. Bidders should take care to designate as confidential only those portions of their proposals that genuinely warrant confidential treatment. The practice of marking each and every page of a proposal as "confidential" is discouraged.

National Grid agrees to use commercially reasonable efforts to treat the non-public information it receives from bidders in a confidential manner. National Grid will not, except as required by law or in a regulatory proceeding, disclose such information to any third party other than OER, and the Division and their respective agents and/or consultants (i.e., these state agencies will be independently reviewing the evaluation process), or use such information for any purpose other than in connection with this RFP, and it may use a non-disclosure agreement with these agencies and individuals; provided that, in any future regulatory, administrative or jurisdictional proceeding in which confidential information is sought, National Grid shall take reasonable steps to limit disclosure and use of said confidential information through the use of non-disclosure agreements or orders seeking protective treatment, and shall inform bidders that their confidential information has been sought in such proceeding.

Notwithstanding the foregoing, in any regulatory proceeding in which such confidential information is sought and a request for confidential treatment is made to the PUC, National Grid shall not be responsible in the event that its request for treating information in a confidential manner is not approved, and the information is shared with other parties or made public. Also, the bidder shall be responsible for filing, submitting, and/or providing to National Grid for such filing or submission, any motions or other pleadings (including associated affidavits, etc.) for protective orders or other relief to justify withholding the confidential information. Similarly, the bidders shall be required to use commercially reasonable efforts to treat all information received from National Grid in a confidential manner and will not, except as required by law or in a regulatory proceeding, disclose such information to any third party; provided, however that if such confidential information is sought in any regulatory or judicial proceeding, the bidders shall take reasonable steps to limit disclosure and use of said confidential information through the use of non-disclosure agreements or requests for orders seeking protective treatment, and shall inform National Grid that the confidential information is being sought.

Bidders also should be aware that National Grid is required pursuant to Section 5.5 of the Regulations to disclose in its entirety each executed PPA submitted to the PUC, and the entire PPA shall be a public document. Finally, any Rhode Island state agency may be required to disclose confidential information in response to a public records request, in accordance with the "Access to Public Records Act," R.I. Gen. Laws § 38-2-1 et seq.

In the event that a bidder's confidential information is not afforded confidential treatment by a governmental agency or other entity exercising proper authority, the entities and individuals involved in the evaluation of bids shall not be held responsible, and their employees, agents, and consultants, shall be held harmless for any release of confidential information as long as reasonable efforts to protect the information have been followed. In any event, each entity and individual involved in the evaluation of bids, as well as their employees, agents, and consultants, shall be held harmless for any release of confidential information made available through any public source by any other party.

During the evaluation of bids, ISO-NE will, and other authorities may, be requested to provide information to National Grid, OER, and the Division concerning proposals as part of the proposal evaluation process. Information classified as Critical Energy Infrastructure Information ("CEII") will only be shared with National Grid, OER, and the Division who are cleared to receive CEII by ISO-NE or any applicable other authorities. By participating in this RFP, bidders agree that ISO-NE and the other authorities may release information related to the projects which may otherwise be considered confidential under the relevant rules or policies of such organizations, to the entities and individuals involved in the evaluation of bids.

The bidder shall provide written confirmation of its consent for the sharing of this information as part of the bidder certification form, and, if requested by National Grid, the bidder shall specifically request that ISO-NE and/or any of the other authorities provide this information to the entities and individuals involved in the evaluation of bids and shall pay any costs imposed by ISO-NE or any of the other authorities associated with providing that information. Failure to comply with this request will result in disqualification of the bid. The entities and individuals involved in the evaluation of bids will treat the information provided as confidential, as described above, in accordance with the policies and practices described within this RFP.

3.5 Official Website and Contacts for the RFP

The official RFP website is: https://RICleanEnergyRFP.com. All updates and notifications will be posted to the website.

Each bid must be submitted as three public versions and three confidential versions, and should be delivered marked as such on separate USB flash drives. All copies should be submitted to the attention of the Official Contact for National Grid at the address listed below:

Clean Energy RFP Manager
Energy Procurement, 2nd Floor
National Grid
100 East Old Country Road
Hicksville, NY 11801

Any questions or correspondence regarding the RFP should be sent to the Official Contact at following email address: CleanEnergyRFP@nationalgrid.com. However, only bidders may send questions and correspondence to the Official Contact for this RFP. Any comments, questions, or information sent to the Official Contact by non-bidders will not be considered by National Grid. Members of the media should direct their communications to an official National Grid spokesperson.

Also, bidders should copy the following recipients on any questions or correspondence:

Thomas Kender: Thomas.Kender@nationalgrid.com
Omar Muneeruddin: Omar.Muneeruddin2@nationalgrid.com

3.6 Organization of the Proposal

Bidders are required to organize their proposal consistent with the contents of the Response Package in Appendix B. The organization and contents of the proposal should be organized as follows:

1. Proposal Certification Form
2. Proposal Summary/Contact Information
3. Executive Summary
4. Pricing Information and Schedules
5. Project Operational Parameters
6. Energy Resource Plan
7. Financial/Legal
8. Siting and Interconnection
9. Environmental Assessment and Permit Acquisition Plan
10. Engineering and Technology
11. Operations and Maintenance
12. Project Schedule
13. Project Management/Experience
14. Alternatives
15. Economic and Environmental Benefits to Rhode Island

3.7 Modification or Cancellation of the RFP and Solicitation Process

Following the submission of proposals, National Grid may request additional information from bidders at any time during the process. Bidders that are not responsive to such information requests may be eliminated from further consideration. Unless otherwise prohibited, National Grid may, at any time up to final award: postpone, withdraw and/or cancel this RFP; alter, extend or cancel any due date; and/or, alter, amend, withdraw and/or cancel any requirement, term or condition of this RFP, any and all of which shall be without any liability to National Grid.

By submitting a proposal, a bidder agrees that the sole recourse that it may have with respect to the conduct of this RFP is by submission of a complaint or similar filing to the PUC in a relevant docket pertaining to this RFP.

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Final Report

Rhode Island Long-Term Contracts for Renewable Energy

Quantitative Evaluation Report

Prepared for:

Narragansett Electric Company d/b/a National Grid

February 3, 2020

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DISCLAIMER

Rhode Island Long-Term Contracts for Renewable Energy Quantitative Evaluation Report has been prepared by Tabors Caramanis Rudkevich, INC ("TCR") for National Grid for the sole purpose of providing the quantitative analyses to allow them to evaluate the proposals that they receive in response to the Rhode Island Long Term Contracting Standards ("LTCS") RFPs. The information provided herein deals with the analysis, methodology and results of the proposal quantitative evaluations. Any other use of the materials without the explicit permission of the National Grid is strictly prohibited.

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Section 1. Summary and Overview

Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Company"), in consultation with the Rhode Island Office of Energy Resources ("OER") and the Rhode Island Division of Public Utilities and Carriers ("Division"), solicited proposals for long-term contracts of up to 400 MW of renewable energy from Newly Developed Renewable Energy Resources[1] ("Proposals") through its RFP for Long-Term Contracts for Renewable Energy issued September 12, 2018 ("2018 RI RFP"). Narragansett is seeking these proposals to satisfy its minimum obligation under the Long-Term Contracting Standard for Renewable Energy (the "LTCS") as well as to support the state of Rhode Island's clean energy portfolio goals. The minimum solicitation, under the LTCS, is for 10.74 MW of contract capacity. In total, National Grid could, but was not required to, select up to 400 MW nameplate capacity, of renewable energy projects, if they meet the requirements of the LTCS and additional factors the Rhode Island Public Utilities Commission ("Commission") might have considered in its review of discretionary procurements. Narragansett selected Tabors Caramanis Rudkevich ("TCR") as Narragansett's quantitative team ("NG Evaluation Team") Consultant to help them evaluate the quantitative costs and benefits[2] of the proposals received in response to the RFP. This report summarizes the analyses TCR undertook.

The NG Evaluation Team reviewed and evaluated the Proposals using a process described in the 2018 RI RFP. This process involved the evaluation of Proposals in the following three stages:

- **Stage One:** Proposals were required to meet specific eligibility and threshold requirements as set in the 2018 RI RFP, including the requirement that the Proposal PPAs must be commercially reasonable[3] ("LTCS threshold")
- **Stage Two:** Proposals meeting the stage one requirements were evaluated in a technology-neutral manner based on price ("Quantitative") and non-price ("Qualitative") criteria. Narragansett filed the protocols describing the criteria for quantitative ("Quantitative Protocol") and qualitative ("Qualitative Protocol") evaluation with the RI PUC on October 26, 2018, prior to opening of Bids.[4]
- **Stage Three:** Proposals that ranked favorably in stage two were evaluated as Portfolios of Proposals ("Portfolio") using the price and non-price evaluation criteria used in stage two as well as other pertinent criteria described in the 2018 RI RFP.

As part of this process, TCR performed the Stage Two Price Analysis ("Stage Two Quantitative Analysis") of each Proposal and the Stage Three Price Analysis ("Stage Three Quantitative Analysis") of

1 "Newly Developed Renewable Energy Resource" as defined in R.I.G.L. § 39-26.1-2(6).

2 The costs and benefits TCR analyzed were a subset of the overall costs and benefits associated with the 2018 RI RFP bids. Costs and benefits considered less amenable to quantification of the type performed by TCR were analyzed in other portions of the evaluation process, such as the Qualitative Analysis. In this report, we use "costs and benefits" and similar terms to refer to the subset of costs and benefits TCR quantified using its tools and methods.

3 Bid pricing must be below the forecasted market price of energy and RECs over the term of the proposed contract (per R.I. Gen. Laws §§ 39-26.1-1 and 39-26.1-3(f); Section 4.1 of the Regulations). TCR ran Stage Two Price Analysis for all proposals meeting the non-LTCS threshold requirements to establish forecasted market prices of energy and RECs.

4 Docket No. 4822 http://www.ripuc.org/eventsactions/docket/4822-NGrid-Compliance-EvalPlanFiling-Rev(10-29-18).pdf

each Portfolio of Proposals, as well as certain discrete analyses requested by the NG Evaluation Team at various points in the evaluation. TCR performed these analyses by creating a scenario or "case" for each Proposal ("Proposal Case") and Portfolio of Proposals ("Portfolio Case"). TCR evaluated the costs and benefits of each Proposal Case and Portfolio Case using inputs from their bids and results from modeling the operation of the New England and New York energy market assuming the specific Proposal or Portfolio being modeled is chosen. TCR also developed a Base Case ("2018 RI RFP Base Case") which represents a counterfactual projection of market parameters for a scenario in which Narragansett does not procure clean energy through the 2018 RI RFP. TCR used the results from the 2018 RI RFP Base Case in evaluating the costs and benefits of the Proposal/Portfolio Cases.

Appendix A summarizes the results of TCR's Stage Two Quantitative Analyses of each Proposal Case, the quantitative scores based on those results, the Stage Two non-price analysis ("Stage Two Qualitative Analysis") score for proposals developed by Narragansett, and ranking of each Proposal based on the total of the quantitative and qualitative scores. Appendix B provides the results of TCR's Stage Three Quantitative Analyses of each Portfolio Case, the quantitative scores based on those results, the calculated qualitative scores and ranking of each Portfolio Case based on the total of the quantitative and qualitative scores. It also includes the corresponding data for Proposal Cases from Stage Two.

The TCR Quantitative Analyses used metrics for three categories of costs and benefits associated with each Proposal and Portfolio case per the Quantitative Protocol, i.e. the cost of energy and RECs compared to the market value of those attributes ("Direct Costs and Benefits"), relative impact on the market prices of energy and RECs ("Indirect Costs and Benefits") and additional supporting metrics developed for the Docket 4600 Benefit-Cost Framework ("Additional Costs and Benefits"). Section 2 of this Report describes those metrics.

TCR developed values for each of these metrics in 2018 constant dollars (2018$) for each Proposal / Portfolio by year over a forecast evaluation period of 2019 to 2045 ("evaluation period" or "valuation horizon"). TCR developed values for the Direct Cost and Benefit metrics of each Proposal / Portfolio using data from the bids submitted for each Proposal, from the outputs of its simulation modeling of each Proposal Case and Portfolio Case.

TCR developed values for the Indirect and Additional Cost and Benefit metrics of each Proposal / Portfolio by comparing outputs of its simulation modeling of each Proposal Case and Portfolio Case to the outputs of its simulation modeling of the 2018 RI RFP Base Case for each Proposal Case.

Section 3 describes TCR's simulation of the 2018 RI RFP Base Case as well as the Proposal Cases and Portfolio Cases. Appendix D provides 2018 RI RFP Base Case results in detail. Appendix E provides detailed descriptions of the assumptions TCR used to model the RI 2018 RFP Base Case and the Proposal / Portfolio Cases, as well as the ENELYTIX platform used to do that simulation modeling. Section 4 describes the Quantitative Workbook for each Proposal Case and Portfolio Case.

As the Narragansett testimony describes, bid scoring was based on a 100-point scale under which a Proposal / Portfolio Case could receive a maximum of 80 points based upon the results of its Quantitative Analysis performed by TCR and a maximum of 20 points based upon the results of a separate Qualitative Analysis performed by Narragansett. TCR developed the Quantitative Analysis scores assigned to each Proposal / Portfolio Case based upon the results of the analyses described in this Report. TCR added these Quantitative Analysis scores to the Qualitative Analysis scores provided

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to it by Narragansett to calculate the total score of each Proposal / Portfolio Case. TCR then ranked each Proposal / Portfolio Case from high to low according to the total scores. TCR excluded Proposals / Portfolio Cases that did not meet the LTCS threshold as well as Proposals that were withdrawn by the bidders over the course of the evaluation. Section 5 of this report describes this scoring and ranking.

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Section 2.
Evaluation Costs and Benefits

This section summarizes the analytical approach and metrics TCR used to measure each category of costs and benefits and to develop values for each of those metrics.

The 2018 RI RFP process specified the price analysis include *"(a) the total contract cost of the products bid, which must include energy and RECs, (b) the estimated market value of these products, taking into consideration the production profile and location of the proposed project over the term of the proposed contract term and any locational marginal price benefits."* Which are quantified as the direct costs and benefits ("Direct Costs and Benefits"). The RFP also specifies *"The projected change a project may produce in locational marginal prices and REC market prices will be evaluated in the price analysis of Stage Two"* which are quantified as other costs and benefits to retail consumers ("Indirect Costs and Benefits"). The RFP also references the RI PUC Docket No. 4600 Benefit-Cost Framework which required the development of additional metrics addressing the costs and benefits under other categories such as regional emissions ("Additional Costs and Benefits"). Prior to opening the 2018 RI RFP bids, The NG Evaluation Team developed a Protocol for Quantitative Evaluation/Price Analysis ("2018 RI RFP Quantitative Protocol" or "Quantitative Protocol"). The Quantitative Protocol, provided in Appendix C, specifies the analytical approach and metrics to be used for the quantitative evaluation of those costs and benefits. TCR evaluated the costs and benefits of each Proposal and Portfolio according to the Quantitative Protocol. Appendix A reports the Stage Two results, i.e., Proposals. Appendix B reports Stage Three results for Portfolios and Proposals.

2.1: Metrics Used in Quantitative Evaluation of Proposal and Portfolio Cases

The Quantitative Protocol specifies that *"The quantitative evaluation measure will be the Total Net Direct Unit Benefit of the proposal expressed as a levelized amount per megawatt-hour ("MWh") in 2018 dollars ($2018)".* TCR developed the value for each quantitative metric described in this section for each Proposal / Portfolio Case, by year, over the evaluation period in 2018 constant dollars ("2018$"). It then calculated the present value for each metric using a nominal discount rate of 6.97%, which translates to 4.87% in 2018$. Finally, it calculated a levelized unit value ($/MWh) for each metric as the present value divided by the present value of the annual energy from the Proposal / Portfolio Case.

2.1.1: Direct Costs and Benefits

TCR measured the Direct Costs and Benefits of each Proposal and Portfolio Case by calculating the values of each of the following metrics:

i. Total Direct Costs include the Direct Cost of Energy and the Direct Cost of Renewable Energy Standard ("RES") Class 1 eligible Renewable Energy Certificates ("RECs"). The Direct Cost of Energy was calculated from the Proposal / Portfolio price for energy multiplied by the annual quantity of delivered energy for each year over the proposed contract term. The Direct Cost of New RECs was calculated from the Proposal price for RECs multiplied by the annual quantity of RECs for each year over the proposed contract term.

ii. Total Direct Benefits include the Direct Benefit of Energy and the Direct Benefit of RECs. The Direct Energy Benefit is the market value of the energy deliveries from the Proposal over the proposed contract term, based upon the forecast market energy prices at the delivery point with the Proposal / Portfolio Case in service. The Direct Benefit of RECs is the avoided cost of using these products from the Proposal / Portfolio Case to meet RES requirements, valued at the Base Case market price of RECs, plus the market value of RECs delivered by the Proposal / Portfolio surplus to RES requirements, if any.

The resulting Net Direct Unit Benefit (Cost) is the sum of the above Direct Costs and Direct Benefits. The levelized unit values of the Net Direct Unit Benefit (Cost) are reported in Column I of Appendix A for the Proposals and of Appendix B for the Portfolios. The levelized unit value of this metric is used to determine whether the Proposals meet the LTCS threshold. Proposals having negative Net Direct Unit Benefit (Cost) values do not meet the Stage One threshold requirements, and are not considered in the Stage Two evaluation and ranking.

2.1.2: Indirect Costs and Benefits

TCR measured the Indirect Benefits of each Proposal and Portfolio Case by calculating the values of each of the metrics described below.

i. Indirect Energy Price Benefits are the savings over the evaluation period from changes to wholesale energy market costs paid by Narragansett's distribution service retail load in Rhode Island ("NG Load"), i.e. from changes to Locational Marginal Prices ("LMP") in Rhode Island in the Proposal Case / Portfolio Case relative to energy market costs paid by NG Load without the Proposal / Portfolio in service, i.e. the 2018 RI RFP Base Case[5].

ii. Indirect REC Price Benefits are the savings over the evaluation period from changes to the costs paid by Rhode Island EDCs for Class 1 RECs based on expected market prices in the Proposal Case / Portfolio Case relative to the 2018 RI RFP Base Case. This metric applies to the residual RECs obtained by Narragansett meet the Rhode Island RES requirements that are incremental to the RECs delivered by the Proposal / Portfolio as well as those RECs under existing long-term contracts.

The resulting Total Indirect Benefit is the sum of the above Indirect Benefits. The levelized unit values of the Total Indirect Benefit for each Proposal and Portfolio are reported in Column J of Appendix A. for the Proposals and of Appendix B for the Portfolios

2.1.3: Net Benefit (Cost)

TCR calculated the Net Benefit (Cost) of each Proposal and Portfolio. The levelized unit value of this metric is the core measure for comparison under the Quantitative Protocol. Appendix A Column K reports this value, in $/MWh, for the Proposal Cases.; Appendix B Column K reports this value for the Portfolio Cases and Proposal Cases.

For further consideration, TCR also calculated the Net Benefit (Cost) in absolute terms ($). This value equals the present value of the Total Direct Benefits and Total Indirect Benefits less the present value

5 A statistical approach was developed to determine whether the change in energy prices for the Proposal / Portfolio cases were significantly different compared to the Base Case. Proposals whose impacts were determined to be significant used the resulting values from the metric calculations. All other proposals were assigned a zero value to this metric. Additional details are provided in Appendix C.

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of the Total Direct Costs. Appendix A Column L reports this metric. for the Proposal Cases.; Appendix B Column L reports this value for the Portfolio Cases and Proposal Cases.

2.1.4: Calculation of Additional Supporting Metrics

TCR measured the Additional Costs and Benefits of each Proposal and Portfolio Case by calculating the values of each of the metrics described below.

i. Value of proposal contribution toward reducing regional greenhouse gas ("GHG") emissions. Calculates the reduction in GHG emissions attributable to Rhode Island and ISO-NE neighboring states in the Proposal Case / Portfolio Case relative to the 2018 RI RFP Base Case. The annual non-embedded value of GHG reduction is calculated by multiplying the annual reductions with the non-embedded value of CO_2 per ton, which is calculated as the difference between the cost of carbon established in the 2018 Avoided Energy Supply Costs in New England 2018 Report ("AESC 2018") and the Regional Greenhouse Gas Initiative ("RGGI") allowance price projections.

ii. Value of proposal contribution toward reducing NO_x emissions. Calculates the reduction in NO_x emissions attributable to Rhode Island and ISO-NE neighboring states in the Proposal Case / Portfolio Case relative to the 2018 RI RFP Base Case. The annual non-embedded value of GHG reduction is calculated by multiplying the annual reductions with the non-embedded value of NO_x established in AESC 2018.

The levelized unit values of the additional supporting metrics for each Proposal and Portfolio are reported in Columns M and N of Appendix A. for the Proposals and of Appendix B for the Portfolios

2.1.5: Quantitative Workbooks

TCR developed the values of these metrics in a Quantitative Workbook for each Proposal Case and Portfolio Case.

- TCR developed values for the Direct Cost and Benefit metrics of each Proposal Case / Portfolio Case from the bids submitted for each Proposal, from the outputs of its simulation modeling of each Proposal Case / Portfolio Case, outputs from the 2018 RI RFP Base Case[6], and from its quantitative evaluation workbook for each Proposal Case and Portfolio Case.
- TCR developed values for the Indirect and Additional Cost and Benefit metrics of each Proposal Case / Portfolio Case by comparing outputs of its simulation modeling of each Proposal Case and Portfolio Case to the outputs of its simulation modeling of the 2018 RI RFP Base Case, as well as from its quantitative evaluation workbook for each Proposal Case and Portfolio Case.

Section 3 describes TCR's simulation of the 2018 RI RFP Base Case as well as the Proposal Cases and Portfolio Cases. Section 4 describes TCR's quantitative evaluation workbook for each Proposal Case and Portfolio Case.

6 The calculations for the direct benefit of RECs are calculated using the REC prices from the 2018 RI RFP Base Case

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Section 3. Market Simulations – 2018 RI RFP Base Case and Proposal / Portfolio Cases

TCR developed values for many of the metrics used in the calculations of Direct Costs and Benefits as well as Indirect and Other Costs and Benefits from the outputs of its simulation modeling of the 2018 RI RFP Base Case and each Proposal Case and Portfolio Case. This section describes the basic differences between the 2018 RI RFP Base Case and the Proposal Case / Portfolio Case. It then describes the ENELYTIX platform TCR used to model each of those Cases and the major input assumptions TCR used in that modeling.

3.1: 2018 RI RFP Base Case and Proposal Cases

The 2018 RI RFP Base Case provides a "but for" or "counterfactual" projection of carbon emissions as well as energy costs associated with Rhode Island electricity consumption under a future in which Narragansett does not acquire additional energy and RECs under long-term contracts from any of the Proposals received in response to the 2018 RI RFP.[7]

Each Proposal Case and Portfolio Case provides a projection of carbon emissions and costs associated with New England electricity consumption under a future in which Narragansett acquires the energy bid by that Proposal or Portfolio under a long-term contract. TCR used the results from each Proposal Case and Portfolio Case as well as certain inputs from the 2018 RI RFP Base Case to measure the Direct Costs and Benefits of that Proposal or Portfolio described in Section 2, i.e., these Cases provide the projections of carbon emissions and costs with the Proposal / Portfolio in service.

TCR reflected the difference between the 2018 RI RFP Base Case and each Proposal / Portfolio Case in its modeling by using different input assumptions for generation capacity additions and for transmission system upgrades/changes where these were affected by such generation capacity additions. Subsection 3.3: summarizes each major category of input assumptions TCR used in its modeling and describes the differences in input assumptions between the 2018 RI RFP Base Case and each Proposal / Portfolio Case. Appendix E provides detailed descriptions of the assumptions TCR used to model the 2018 RI RFP Base Case and the Proposal / Portfolio Cases, as well as of the ENELYTIX platform TCR used for its simulation modeling.

The differences in these input assumptions lead to differences in results between the Base Case and each Proposal/Portfolio Case. Appendix D provides key results from the ENELYTIX modeling of the 2018 RI RFP Base Case.

7 The 2018 RI RFP Base Case is not a plan for the Rhode Island electric sector and should not be viewed as such. TCR used the results from the 2018 RI RFP Base Case as a common reference point against which to measure the Indirect Costs and Benefits of each Proposal and Portfolio described in Section 2, i.e., the 2018 RI RFP Base Case provides the projections of carbon emissions and costs without any of the Proposals / Portfolios in service.

3.2: ENELYTIX Simulation Model

TCR used the ENELYTIX computer simulation software tool to simulate the operation of the New England wholesale markets for energy and ancillary services ("E&AS"), and RECs under the 2018 RI RFP Base Case and for each Proposal / Portfolio Case. ENELYTIX develops internally consistent, detailed projections of prices in each of those markets as well as of the key physical parameters underlying those prices such as capacity additions and retirements, energy generation by source, carbon emissions and natural gas burn. TCR conducted a separate ENELYTIX computer run for the Base Case and for each Proposal / Portfolio Case being analyzed.

TCR used the ENELYTIX system to develop its quantitative projections of metrics through the interaction of two model components, the Capacity Expansion module and the E&AS module.

The Capacity Expansion module determines an optimal electric system expansion in New England over a long-term planning horizon. Its objective function is to minimize the net present value of the total cost, i.e., capital, fuel and operating, of the generation fleet serving the wholesale market within the ISO-NE electrical footprint subject to resource adequacy, operational and environmental constraints. Resource adequacy constraints are specified in terms of installed capacity requirements ("ICR") for the ISO-NE system as whole and for reliability zones within ISO-NE. Environmental constraints include requirements for state-by-state procurement of electric energy generated by renewable resources, as well as state and regional emissions limits. The module represents each state's year-by-year Class 1 RPS requirements, Massachusetts CES requirements, state specific RPS resource eligibility, limitations on REC banking and borrowing, and alternative compliance payment ("ACP") prices.

The E&AS module simulates the Day-Ahead and Real-Time market operations within the footprint of the ISO-NE and New York Independent System Operator ("NYISO") power systems and markets. This module implements chronological simulations of the Security Constrained Unit Commitment ("SCUC") and Economic Dispatch ("SCED") processes, as well as the structure of the ancillary services markets in ISO-NE and NYISO.

The two ENELYTIX modules use the Power System Optimizer ("PSO") market simulator developed by Polaris Systems Optimization, Inc.[8] In addition the two modules rely on data obtained from ISO-NE, including the economic and operational characteristics of ISO-NE's existing generating units, representation of the electric transmission system, and projection of future electricity demand.

3.3: Major Input Assumptions Used to Model 2018 RI RFP Base and Proposal / Portfolio Cases

TCR used ten major categories of input assumptions[9] to model the 2018 RI RFP Base Case and each of the Proposal / Portfolio Cases in ENELYTIX. They were Generating Unit Capacity Additions, Transmission, Load Forecast, Installed Capacity Requirements, RPS Requirements, Massachusetts CES and cap on Carbon Emissions, Emission Allowance Prices, Generating Unit Retirements, Generating Unit Operational Characteristics and Fuel Prices. Of those, the only three categories in which there were a

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8 www.psopt.com.

9 TCR uses the term 'Assumptions' to refer to inputs to the modeling process that are exogenous to the model, and often calculated from data available from sources such as ISO-NE, EIA's Annual Energy Outlook or other proprietary datasets such as S&P Market Intelligence Platform.

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few input assumption differences between the 2018 RI RFP Base Case and each Proposal / Portfolio Case were Generating Unit Capacity Additions, Generating Unit Retirements, and Transmission.

This subsection summarizes each of the major categories of input assumptions TCR used in modeling ISO-NE and describes the differences in those input assumptions between the 2018 RI RFP Base Case and each Proposal / Portfolio Case. TCR used the input assumptions in the remaining eight categories to model both the 2018 RI RFP Base Case and each of the Proposal / Portfolio Cases. Appendix E provides detailed descriptions of the assumptions for ISO-NE and for the NYISO that TCR used to model the 2018 RI RFP Base Case and the Proposal / Portfolio Cases.

3.3.1: Modeling Input Assumption Categories with differences between the 2018 RI RFP Base Case and each Proposal / Portfolio Case

Three categories of modeling input assumptions that were different between the 2018 RI RFP Base Case and each Proposal / Portfolio Case were Generating Unit Capacity Additions, Generating Unit Retirements, and Transmission.

Generating Unit Capacity Additions (Existing / Scheduled and Optional). This category consists of two groups of assumptions. Existing / Scheduled resources are the generating resources input to ENELYTIX as being in-service during the evaluation period based on external source materials. Optional resources are categories of generic generating resources ENELYTIX has the option to choose to add during the study horizon, as determined by its internal calculations, to meet resource adequacy, energy and environmental constraints existing within the simulation model at various times at least cost.

The only existing / scheduled generating unit capacity addition assumptions that differed between the 2018 RI RFP Base Case and each Proposal / Portfolio Case were the generating capacity resource(s) from the particular Proposal or Portfolio Case. The remaining existing / scheduled generating unit capacity addition assumptions were common to the 2018 RI RFP Base Case and each Proposal / Portfolio Case over the evaluation horizon. Those assumptions include:

- 400 MW of offshore wind resource procured by Rhode Island under ACES
- 800 MW of generic offshore resources for Tranches 3 and 4 assumed to be procured through a future Massachusetts 83C RFP;
- The New England Clean Energy Connect ("NECEC") Hydro project selected through the 83D RFP process;
- Existing generating units listed in the 2018 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT Report");
- Projects that had cleared the latest Forward Capacity Auction as of October 15, 2018;
- Distributed photovoltaic (PV) capacity at levels in the ISO-NE's Final 2018 PV Forecast through 2027 and thereafter at levels extrapolated from the ISO-NE PV Forecast[10];
- Renewable generation projects selected under other recent clean energy procurements in Connecticut and New England; and

10 ISO New England Final 2018 PV Forecast, March 19, 2018.

- Imports of Class 1 eligible REC into ISO-NE from neighboring control areas at their 2015 levels (the most recent year such data are available);

For the 2018 RI RFP Base Case and the Project / Portfolio Cases ENELYTIX had the option of choosing to simulate additions of generating capacity from other (i.e., non-RI RFP) renewable resources and fossil fuel resources in order to satisfy resource adequacy, energy and environmental constraints assumed to be in effect over the evaluation period. ENELYTIX evaluated the economics of each of these possible resources with the assumption that they would be developed and financed on a merchant basis, i.e. without long-term purchase power agreements. Even if these resources were assumed to have long-term power sales agreements, the expectation is that the pricing terms of such agreements would reflect similar future economic fundamentals.

Generating Unit Retirements. This category, like generating unit additions, consists of two groups of assumptions. First, there are the specific generating capacity units input to ENELYTIX as retiring prior to, or during, the evaluation period. These are the actual generating units that have retired prior to the beginning of the evaluation period (January 2021) plus the ISO-NE approved scheduled retirements as of October 2018. Second, there are the economic assumptions ENELYTIX uses to determine whether to simulate retirement of an existing generating unit during the evaluation period. ENELYTIX determines within the simulation whether it is cost efficient to keep the existing unit online or retire and replace it with more efficient generator or with the resource needed to meet environmental constraints. All model selected retirements for the 2018 RI RFP Base Case are assumed to be carried forward to the Proposal / Portfolio Cases.

Transmission. ENELYTIX provides a detailed representation of the transmission topology and electric characteristics of transmission facilities within ISO-NE and the NYISO. The NG Evaluation Team and TCR worked together to ensure that the ENELYTIX model correctly reflected the transmission upgrades associated with each Proposal and Portfolio that were not required for the 2018 RI RFP Base Case. These included transmission topology and contingency sets for additional contingency constraints that might be affected by power injections from Proposals and Portfolios.

Aside from those differences, the remaining transmission input assumptions were common to the 2018 RI RFP Base Case and each Proposal / Portfolio Case over the evaluation horizon. ENELYTIX modeled the ISO-NE transmission system based on the 2020 SUMMER Peak case and the NYISO system based on the 2017 Market Monitoring Working Group power flow case. For the 2018 RI RFP Base Case, and each Proposal/Portfolio Case, TCR worked with the NG Evaluation Team to identify the relevant transmission constraints to assume and monitor. These included all major ISO-NE interfaces and frequently binding constraints assembled by the NG Evaluation Team using historical data from 2012 through October 15, 2018, transmission changes associated with large clean energy projects procured through recent RFP processes, and contingency analyses performed by the NG Evaluation Team and TCR.

3.3.2: Modeling Input Assumption Categories with no differences between the 2018 RI RFP Base Case and each Proposal / Portfolio Case

The remaining seven categories of modeling input assumptions with no differences between the Base case and each Proposal / Portfolio Case were Load Forecast, Installed Capacity Requirements, RPS Requirements, Massachusetts CES and cap on Carbon Emissions, Emission Allowance Prices, Generating Unit Operational Characteristics and Fuel Prices.

Load Forecasts. The load forecast inputs to ENELYTIX are annual energy and peak load before ("Gross") and after the impacts of reductions due to passive demand response ("PDR"), i.e. "Gross-PDR". TCR drew these forecasts through 2027 from the CELT Report. It developed the forecasts for 2029 through 2045 through separate extrapolations of the Gross and PDR components. TCR also developed a forecast of energy requirements net of the impacts of reductions from behind the meter PV (BTM PV or BMPV). This forecast, which corresponds to the obligation for retail metered load, is referred to by ISO-NE as Net Energy Load ("NEL") and as '"Gross-PV-PDR.'" TCR used this forecast to estimate annual state RPS obligations and MA CES obligations, both of which are inputs to ENELYTIX. In order to simulate the ISO-NE market on an hourly basis, TCR developed hourly load forecasts for each ISO-NE zone. It developed these based upon its forecasts of annual energy and summer/winter peaks and on 2012 historical load shapes to be consistent with calendar 2012 NREL wind generation profiles, the most recent detailed data available from NREL for New England.

Installed Capacity Requirements. ICR forecast inputs to ENELYTIX include the system-wide requirement as well as local sourcing requirements (LSR) for import constrained zones. TCR developed its forecasts of these requirements based on its analyses of ISO-NE studies. The forecast of system-wide ICR assumes that import capacity under the existing supply agreement with Hydro Quebec will remain at the 2021/22 level of 958 MW estimated by ISO-NE[11], that external control areas and Active Demand Response (ADR) within New England will provide an additional 1,768 MW.

RPS Requirements. ENELYTIX models the Class 1 RPS requirements of each New England state except Vermont, which does not have an equivalent Class 1 RPS requirement.[12] The RPS requirement input to ENELYTIX for each state equals the forecast load of Load Serving Entities (LSEs) obligated to comply with that state's RPS multiplied by that state's annual Class 1 RPS percentage target. The forecast load of LSEs is the forecast Gross-PV-PDR load for each state reduced by the load exempt from the RPS in that state. Additional RPS inputs to ENELYTIX are state-specific resource eligibility, limitations on certificate banking and borrowing, and ACP prices.

Massachusetts CES and Cap on Carbon Emissions. Although external to the Rhode Island footprint, TCR also models the Massachusetts regulations due to their interaction and impact on the New England Region as a whole. ENELYTIX models regulation 310 CMR 7.74, a cap on carbon emissions from electric generating units (EGU) located in Massachusetts and regulation 310 CMR 7.75, the CES. The CES requirement input to ENELYTIX equals the forecast load of LSEs obligated to comply with the CES multiplied by the Massachusetts annual CES percentage target. The CES ACP for 2018-2020 is 75% of the Massachusetts RPS ACP, and 50% of the RPS ACP thereafter.

Emission Allowance Prices. TCR developed its CO_2 allowance price assumptions based upon a review of Regional Greenhouse Gas Initiative (RGGI) projections from its 2016 Program Review and of assumptions in ISO New England's 2016 Economic Study and 2017 Economic Study. The allowance prices assumed for CO_2 emissions follow a trajectory starting in 2017 at the allowance price of RGGI's "No NP PS#2" scenario, rising smoothly to reach the level of RGGI's "MRPS, NP High " scenario by 2031, and continuing along the same curve to 2045. TCR developed its NO_x and SO_2 allowance price

11 These estimates do not reflect the incremental HQ capacity brought to ISO-NE through the NECEC project after 2023.

12 TCR did not model New York RPS requirements and compliance.

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assumptions based on emission limits under the Federal Cross State Air Pollution Rule (CSAPR).[13] TCR assumed allowance prices of zero for ISO-NE are zero since no New England state has emission limits under the Federal Cross State Air Pollution Rule ("CSAPR"). Appendix E describes the TCR allowance price assumptions for NYISO

Generating Unit Operational Characteristics. TCR develops assumptions for the key physical and cost operating parameters of all the types of generating units and resources that ENELYTIX models. These include thermal units, nuclear units, hydro, pumped storage hydro, wind and solar PV.

Fuel Prices. TCR developed forecasts of monthly spot gas prices for each gas-fired unit in New England based upon the spot prices at the market hub which serves the unit. The four relevant hubs are Algonquin, Tennessee Zone 6, Tennessee Dracut and Iroquois Zone 2. The forecasts are based upon projections of Henry Hub prices plus projections of basis differential to each hub from the Henry Hub. The projection of annual Henry Hub prices is a blend of forward prices as of October 15, 2018 and the Reference Case forecast from the Energy Information Administration (EIA) Annual Energy Outlook 2018 (AEO 2018). The projections of distillate and residual to electric generators in New England are drawn from AEO.

Due to constraints in pipeline capacity, generating units in New England face shortages in natural gas supply during the winter period. To capture its impact, TCR included a winter fuel switching mechanism in the ENELYTIX model to approximate the economic and environmental impact resulting from dual fuel generators switching from natural gas to fuel oil on winter days with high natural gas prices. Appendix E outlines TCR's modeling approach on fuel switching mechanics.

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13 Some New England states have cap and trade programs for NOx and SO2 but the market is thin, prices are low, and allowances are often granted annually rather than auctioned.

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Section 4. Proposal Evaluation – Quantitative Workbook

TCR's Quantitative Analysis calculated the costs and benefits of each Proposal / Portfolio using a Quantitative Workbook for that Proposal / Portfolio. If a bid included an alternative pricing option for energy and/or transmission for a particular Proposal, TCR prepared a separate Quantitative Workbook for each pricing option included in the bid. The Quantitative Workbook is an EXCEL workbook consisting of

- Summary worksheets, in Nominal $ and 2018$ respectively,
- Proposal Metrics worksheets, in Nominal $ and 2018$
- Worksheets for calculations of REC GHG, NO_x impacts by year
- Worksheets providing key summary outputs from ENELYTIX modeling of the Proposal / Portfolio Case
- A worksheet reporting the PPA pricing for energy and RECs for the Proposal / Portfolio
- Additional supporting worksheets reporting detailed results from ENELYTIX modeling of the Proposal Case

This section describes calculation details of specific worksheets within the Quantitative Workbooks.

4.1: Proposal Metrics Worksheet

The Proposal Metrics worksheet of the Quantitative Workbook for a given Proposal/Portfolio develops values for each of the metrics used to calculate the Direct, Indirect and Other Costs and Benefits of that Proposal Case / Portfolio Case. It develops annual values in 2018$ over an evaluation period of 2021 to 2045 and then calculates their respective present values.

The Proposal Metrics worksheet for each Proposal or Portfolio develops these annual and present values from the following major inputs:

- Prices for energy and RECs from the bid
- Results from ENELYTIX modeling of the relevant Proposal Case /Portfolio Case
- Results from ENELYTIX modeling of the 2018 RI RFP Base Case
- Results from the REC Calculation Worksheet
- Results from the GHG Calculations Worksheet
- Results from the NO_x Calculations Worksheet

4.2: REC Calculation Worksheet

The RECs worksheet begins from projections of the quantity of RECs that will be required to satisfy the Rhode Island RES each year, the quantity of RECs that Narragansett will acquire from its existing contracts for RECs and the quantity of RECs the Proposal / Portfolio will produce each year. The worksheet then calculates the following outputs by year:

1. RECs from Proposal / Portfolio (MWh) used towards Rhode Island RECs contract gap. This equals the annual quantity of RECs that will be required to meet the Rhode Island RES minus the quantity that Narragansett will acquire from its existing contracts for RECs.
2. Residual quantity of RECs (MWh) purchased at market prices to comply with Rhode Island RES requirements. This equals the annual quantity that will be required minus the quantity that will be acquired from existing contracts for RECs minus the quantity from the Proposal / Portfolio that Narragansett will use to meet the Rhode Island RES contract gap.
3. RECs from Proposal / Portfolio (MWh) sold out of state. This equals the annual quantity that the Proposal / Portfolio will produce minus the quantity of RECs from that project that Narragansett will use to meet the Rhode Island RES contract gap

4.3: GHG Emission Calculation Worksheet

The GHG Worksheet begins from ENELYTIX projections of carbon dioxide emissions associated with electricity use in New England by year under the Base Case and under the Proposal Case respectively. It then calculates the reduction in carbon emissions (metric tons) by year under the Proposal Case relative to the Base Case. The workbook then calculates the Rhode Island fraction of New England demand (%) by year and multiplies it with the calculated reduction in carbon emissions, to obtain the reduction in carbon emissions attributable to Rhode Island (metric tons) by year. Projections for in-state demand for New England are obtained from ENELYTIX.

The worksheet also calculates the non-embedded unit value of a reduction in carbon dioxide each year as the difference between the marginal abatement cost of carbon from AESC 2018 of $100 (2018$)/Metric ton and the projected Regional Greenhouse Gas Initiative (“RGGI”) allowance price each year in 2018$/Metric ton.

4.4: NO_x Emission Calculation Worksheet

The NO_x Worksheet begins with ENELYTIX projections of NO_x emissions associated with electricity use in New England by year under the Base Case and under the Proposal Case. It then calculates the reduction in NO_x emissions (metric tons) by year under the Proposal Case relative to the Base Case. The workbook then uses the Rhode Island fraction of New England demand calculated in the GHG worksheet and multiplies it with the calculated reduction in NO_x emissions, to obtain the reduction in NO_x emissions attributable to Rhode Island (metric tons) by year.

The worksheet also calculates the non-embedded unit value of a reduction in NO_x each year as $13,178 (2018$)/Metric ton from AESC 2018.

Section 5. Scoring and Ranking of Proposal Cases and Portfolio Cases

The NG Evaluation Team used the results from TCR's Quantitative Analyses and from the Qualitative Analyses performed by Narragansett, to score and then rank Proposals and Portfolios.

The scoring system was based on a 100-point scale. A Proposal Case / Portfolio Case could receive a maximum of 80 points based upon the results of its quantitative evaluation and a maximum of 20 points based upon the results of its qualitative evaluation. TCR developed the Quantitative Analysis scores assigned to each Proposal Case / Portfolio Case based upon the results of its quantitative evaluations. Narragansett developed the scores assigned to each Proposal Case / Portfolio Case based upon the results of their Qualitative Analysis evaluations.

TCR assigned Quantitative Analysis scores to each Proposal Case / Portfolio Case based upon results of their respective Quantitative Analysis results pursuant to the following approach:

- assign 80 points to the Proposal Case / Portfolio Case with the highest levelized unit Net Benefit, 2018$/MWh, ("top bidder");
- calculate the ratio of the levelized unit Net Benefit of each remaining Proposal Case / Portfolio Case to the Levelized Unit Net Benefit of the top bidder; and
- multiply the ratios of each remaining Proposal Case / Portfolio Case by the 80-point score of the top bidder in order to determine the score of each remaining Proposal/Portfolio.

Narragansett provided TCR the scores assigned to each Proposal Case based upon results of their qualitative evaluations. The qualitative scores for Portfolio Cases were calculated based on the energy-weighted average of the constituent Proposal Cases.

TCR added the quantitative and qualitative scores to calculate the total score of each Proposal Case / Portfolio Case. TCR then ranked each Proposal Case / Portfolio Case from high to low according to its total score. TCR excluded Proposals / Portfolio Cases that did not meet the LTCS threshold as well as Proposals that were withdrawn by the bidders over the course of the evaluation.

Appendix A summarizes the results of TCR's Stage Two Quantitative Analyses of each Proposal, the quantitative scores based on those results, the qualitative scores developed by Narragansett, and ranking of each Proposal Case based on the total of the quantitative and qualitative scores.

In Stage Three TCR calculated total scores and ranking for Portfolios and for Proposals from Stage 2. Appendix B provides the corresponding Stage Three Quantitative Analysis results, quantitative scores, qualitative scores and ranking of each Portfolio Case and Proposal Case.

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APPENDIX A:
Stage Two Proposal Scores and Ranking

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RI RFP Stage Two Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	C	D	E	F	G	H
1	**RI RFP Stage 2 Results**							
2	Ranking Set	All Proposals	<- Dropdown					
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y	<- Dropdown					
4	Results as of	12/30/2019						
5	Proposal Identifier	Resource Type	Contract Maximum Amount (MW)	Proposal Net Capacity Factor (%)	Proposed Annual Delivery (MWh)	PPA Start Date	PPA End Date	ISO-NE Load Zone
6	Gravel Pit Solar - 20Levelized	Solar	50	27%	118,839	12/31/2022	12/30/2042	4004 .Z.CONNECTICUT
7	[redacted]							
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RI RFP Stage Two Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	I	J	K	L	M	N
1	**RI RFP Stage 2 Results**							
2	Ranking Set	All Proposals						
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y						
4	Results as of	12/30/2019						
5	Proposal Identifier	Resource Type	Total Net Direct Benefit (Cost) [2018$/MWh]	Total Net Indirect Benefit (Cost) [2018$/MWh]	Unit Net Benefit (Cost) [2018$/MWh]	Net Benefit (Cost) : Absolute value [2018$/MWh]	Non Embedded Value of C02 reduction (increase) [2018$/MWh]	Non Embedded Value of Nox reduction (increase) [2018$/MWh]
6	Gravel Pit Solar - 20Levelized	Solar	26.33	0.00	26.33	30,856,458	34.41	1.36
7	[redacted]							
8								
9								
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RI RFP Stage Two Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	O	P	Q	R
1	**RI RFP Stage 2 Results**					
2	Ranking Set	All Proposals				
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y				
4	Results as of	12/30/2019				
5	Proposal Identifier	Resource Type	Quant Score	Qual Score	Total Score	Rank
6	Gravel Pit Solar - 20Levelized	Solar	80.00	11.75	91.75	1
7	[redacted]	[redacted]	73.04	12.25	85.29	2
8	[redacted]	[redacted]	70.09	12.00	82.09	3
9	[redacted]	[redacted]	59.37	11.75	71.12	4
10	[redacted]	[redacted]	58.06	12.75	70.81	5
11	[redacted]	[redacted]	55.88	8.75	64.63	6
12	[redacted]	[redacted]	49.77	12.00	61.77	7
13	[redacted]	[redacted]	33.00	9.25	42.25	8
14	[redacted]	[redacted]	30.47	9.50	39.97	9
15	[redacted]	[redacted]	30.08	8.75	38.83	10
16	[redacted]	[redacted]	27.83	8.75	36.58	11
17	[redacted]	[redacted]	24.49	11.50	35.99	12
18	[redacted]	[redacted]	15.86	9.75	25.61	13
19	[redacted]	[redacted]	16.95	8.25	25.20	14
20	[redacted]	[redacted]	16.92	8.25	25.17	15
21	[redacted]	[redacted]	15.62	8.75	24.37	16
22	[redacted]	[redacted]	14.13	8.75	22.88	17
23	[redacted]	[redacted]	2.92	8.25	11.17	18
24	[redacted]	[redacted]	0.12	9.75	9.87	19

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APPENDIX B:
Stage Three Proposal and Portfolio Scores and Ranking

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RI RFP Stage Three Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	C	D	E	F	G	H
1	**RI RFP Stage 3 Results**							
2	Ranking Set	All Proposals + Portfolio	<- Dropdown					
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y	<- Dropdown					
4	Results as of	12/30/2019						
5	Proposal Identifier	Resource Type	Contract Maximum Amount (MW)	Proposal Net Capacity Factor (%)	Proposed Annual Delivery (MWh)	PPA Start Date	PPA End Date	ISO-NE Load Zone
6	Gravel Pit Solar - 20Levelized	Solar	50	27%	118,839	12/31/2022	12/30/2042	4004 .Z.CONNECTICUT
7	[redacted]							
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RI RFP Stage Three Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	I	J	K	L	M	N
1	**RI RFP Stage 3 Results**							
2	Ranking Set	All Proposals + Portfolio						
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y						
4	Results as of	12/30/2019						
5	Proposal Identifier	Resource Type	Total Net Direct Benefit (Cost) [2018$/MWh]	Total Net Indirect Benefit (Cost) [2018$/MWh]	Unit Net Benefit (Cost) [2018$/MWh]	Net Benefit (Cost) : Absolute value [2018$/MWh]	Non Embedded Value of C02 reduction (increase) [2018$/MWh]	Non Embedded Value of Nox reduction (increase) [2018$/MWh]
6	Gravel Pit Solar - 20Levelized	Solar	26.33	0.00	26.33	30,856,458	34.41	1.36
7	[redacted]							
8								
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RI RFP Stage Three Results Summary 2019_12_30
5 Result Summary Sheet

	A	B	O	P	Q	R
1	**RI RFP Stage 3 Results**					
2	Ranking Set	All Proposals + Portfolio				
3	Exclude Proposals with below market direct benefits (Negative Total Net Direct Benefits)	Y				
4	Results as of	12/30/2019				
5	Proposal Identifier	Resource Type	Quant Score	Qual Score	Total Score	Rank
6	Gravel Pit Solar - 20Levelized	Solar	80.00	11.75	91.75	1
7	[redacted]	[redacted]	73.04	12.25	85.29	2
8	[redacted]	[redacted]	70.09	12.00	82.09	3
9	[redacted]	[redacted]	66.27	12.04	78.31	4
10	[redacted]	[redacted]	59.37	11.75	71.12	5
11	[redacted]	[redacted]	58.06	12.75	70.81	6
12	[redacted]	[redacted]	55.88	8.75	64.63	7
13	[redacted]	[redacted]	49.77	12.00	61.77	8
14	[redacted]	[redacted]	33.00	9.25	42.25	9
15	[redacted]	[redacted]	30.47	9.50	39.97	10
16	[redacted]	[redacted]	30.08	8.75	38.83	11
17	[redacted]	[redacted]	27.83	8.75	36.58	12
18	[redacted]	[redacted]	24.49	11.50	35.99	13
19	[redacted]	[redacted]	15.86	9.75	25.61	14
20	[redacted]	[redacted]	16.95	8.25	25.20	15
21	[redacted]	[redacted]	16.92	8.25	25.17	16
22	[redacted]	[redacted]	15.62	8.75	24.37	17
23	[redacted]	[redacted]	14.13	8.75	22.88	18
24	[redacted]	[redacted]	2.92	8.25	11.17	19
25	[redacted]	[redacted]	0.12	9.75	9.87	20

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APPENDIX C: Protocol for Quantitative Evaluation / Price Analysis

C.1: 2018 Rhode Island Long-Term Contracts for Renewable Energy Solicitation: Protocol for Quantitative Evaluation / Price Analysis

2018 Rhode Island Long-Term Contracts for Renewable Energy Solicitation: Protocol for Quantitative Evaluation / Price Analysis

Introduction

National Grid, in consultation with the Rhode Island Office of Energy Resources ("OER") and the Rhode Island Division of Public Utilities and Carriers ("Division"), is soliciting proposals for long-term contracts of up to 400 MW of renewable energy from Newly Developed Renewable Energy Resources[1] ("Proposals") through its RFP for Long-Term Contracts for Renewable Energy issued September 12, 2018 ("2018 RI RFP"). National Grid is seeking these proposals to satisfy its minimum obligation under the Long-Term Contracting Standard for Renewable Energy (the "LTCS") as well as to support the state of Rhode Island's clean energy portfolio goals. The minimum solicitation, under the LTCS, is for 10.74 MW of contract capacity. In total, National Grid may, but is not required to, select up to 400 MW nameplate capacity, of renewable energy projects, if they meet the requirements of the LTCS and additional factors the Rhode Island Public Utilities Commission ("Commission") may consider in its review of discretionary procurements. Proposals are due by noon (12:00 PM EPT) on October 29, 2018. Any contracts will be ultimately subject to the approval of the Commission.

This document describes the quantitative metrics and multi-year net present value cost/benefit analysis the evaluation team (an internal National Grid team) and National Grid's consultant, Tabors Caramanis Rudkevich ("TCR"), will use in Stage II to evaluate Proposals received in response to the 2018 RI RFP.

1. Quantitative evaluation process and measures

A. Background

To be evaluated, for ranking and selection, Proposals must first meet the LTCS requirements. Specifically, Proposals must be "Commercially Reasonable" and bid pricing must be below the forecasted market price of energy and RECs over the term of the proposed contract. The 2018 RI RFP specifies that this price evaluation be based on a comparison of (a) the total contract cost of the products bid, which must include energy and RECs, to (b) the estimated market value of these products, taking into consideration the production profile and location of the proposed project over the term of the proposed contract term and any locational marginal price benefits (i.e., together, Direct Costs & Benefits).

To be selected, Proposals will have to satisfy additional Commission review criteria including the least cost procurement statute, the policy of just and reasonable rates, guidance documents from RIPUC Docket No. 4600 on goals for the energy system and "Benefit-Cost Framework", as well as the rate design principles, to the extent applicable. To assist in the evaluation, ranking and selection of these discretionary procurements the quantitative evaluation will also include Other Costs and Benefits to Retail Customers (i.e., Indirect Costs and Benefits).

[1] "Newly Developed Renewable Energy Resource" as defined in R.I.G.L. § 39-26.1-2(6).

B. Quantitative Evaluation Process and Measures

The quantitative evaluation team will prepare an initial quantitative evaluation of each Proposal to determine whether it meets the required LTCS threshold of being below the forecasted market price of energy and RECs (i.e., "the LTCS threshold"). The initial quantitative evaluation will be based on Direct Costs and Benefits only. The quantitative evaluation measure will be the Total Net Direct Unit Benefit of the proposal expressed as a levelized amount per megawatt-hour ("MWh") in 2018 dollars ($2018). A Proposal that does not meet the LTCS threshold will not be evaluated in the ranking and selection stages.

Proposals that meet the LTCS threshold will be subjected to a quantitative evaluation, based on the sum of the Direct Cost and Benefits and the Indirect Costs and Benefits. The quantitative evaluation will determine the Total Net Unit Benefit of the Proposal, also expressed as a levelized amount per MWh in 2018 dollars ($2018).

The Total Net Unit Benefit will be the metric used for the relative ranking and quantitative scoring of remaining proposals.

2. Financial parameters to be used in quantitative evaluation of proposals

- Discount rate (in nominal dollars) -- i.e., the Weighted Average Cost of Capital of 6.97%[2]
- Rate of inflation of 2%
- Discount rate (real dollars, based on $2018) of 4.87%

3. Allocation of 80 points for quantitative evaluation results

For purposes of ranking and scoring proposals in Stage II, National Grid plans to allocate a maximum of 80 points to Proposals, based on their quantitative evaluation results. The evaluation team will prepare an allocation of the 80 points for ranking and scoring purposes, based on Total Net Unit Benefits.

A. Allocation Based on Total Net Unit Benefits

1. Assign 80 points to the Proposal with the highest Total Net Unit Benefit (i.e., the "top bidder").
2. Calculate the ratio of each remaining Proposal's Total Net Unit Benefit to that of the top bidder and allocate that proportional number of points to these Proposals.
3. If the top bidder is a "significant outlier,"[3] then set the top bidder to 80 points and it will be the #1 ranked Proposal overall; and then set second highest Proposal to 80 points and it will be the #2 ranked bid overall. Calculate the proportional value of all other Proposals relative to Proposal ranked #2.

[2] Source - Narragansett Electric Company d/b/a National Grid, Cost of Capital, For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021. RIPUC Docket Nos. 4770/4780, August 16, 2018.

[3] A significant outlier is defined as a bid whose value is greater than one half the difference between the maximum (not including the outlier) and the minimum total net unit benefits.

4. Quantitative Evaluation of Proposals

This section describes the specific metrics, information sources and calculations that the evaluation team will use to determine the Direct Costs and Benefits, and the Indirect Costs and Benefits, of Proposals and the resulting Total Net Direct Unit Benefits ($/MWh) and Total Net Unit Benefits ($/MWh). For this purpose, the evaluation team will use a quantitative spreadsheet ("Quantitative Workbook"). The Quantitative Workbook will calculate:

- Direct Costs and Benefits of each Proposal by year based upon the bid for that Proposal as well as on results of ENELYTIX simulation modeling of that Proposal Case, as explained further below.[4]
- Indirect Costs and Benefits of each Proposal by year based upon the results of ENELYTIX simulation modeling of that Proposal Case and of the Base Case, as explained further below.
- Costs and benefits over the period 2021 through 2045. It will use extrapolation to calculate values for 2043 through 2045 (i.e., for those years that lie beyond the ENELYTIX modelling period).
- The net present value ("NPV") of those costs and benefits as well as the resulting Total Net Direct Unit Benefits ($/MWh) and Total Net Unit Benefits ($/MWh).

A. ENELYTIX Modeling of Base Case and Proposal Cases

ENELYTIX will model a Base Case and various Proposal Cases. The Base Case will represent a future scenario in which none of the Proposals received in response to the 2018 RI RFP are selected or assumed to have been developed. Each Proposal Case will represent a future scenario in which that Proposal is assumed selected through the 2018 RI RFP and developed.

ENELYTIX will simulate the operation of the New England electricity market over the period 2019 through 2042 for the Base Case and for each Proposal Case. The outputs, or results, from ENELYTIX for each Case will be projections of key physical outputs and market prices for that Case. These results will include projections of annual quantities of energy, Renewable Energy Certificates ("RECs"), greenhouse gas ("GHG") emissions and nitrogen oxide ("NOx") emissions, as well as projections of market prices for energy and RECs.

TCR will work with the evaluation team to develop the input assumptions for the Base Case and for each Proposal Case.

After developing and running the Base Case, TCR will determine the criterion for classifying Proposals as either large or small. This criterion will be based upon the perceived ability of a Proposal to produce a projection of capacity retirements that is different from capacity retirements that are already projected under the Base Case. To make this determination, TCR will determine the minimum capacity at which a Proposal could reduce or delay the need for a generic peaking capacity resource added under the Base Case, and will classify Proposals as small if they fall below the capacity minimum. Then, TCR will model

[4] ENELYTIX is an energy system and market modeling and analytics environment licensed by TCR to simulate the operation of the New England electricity market.

large Proposals using the Capacity Expansion and Energy & Ancillary Service ENELYTIX modules. In addition, TCR will model small Proposals using the Base Case capacity mix plus the small Proposal's capacity in the Capacity Expansion module to obtain new REC prices and use them as inputs to the Energy & Ancillary Service module.

B. CALCULATION OF DIRECT COSTS & BENEFIT METRICS

Based on Proposal bid data and the ENELYTIX modeling results of base case and proposal cases, the evaluation team will express all of the following costs and benefits in 2018 constant dollars, and any cost or benefit inputs expressed in nominal dollars will be deflated to 2018 reference year dollars, based on the rate of inflation:

1. A mark-to-market comparison of a Proposal's bid price for energy to the projected market price for energy at the delivery point with the proposal in service:
    1. Using the ENELYTIX modeling system to generate hourly, nodal Locational Marginal Prices ("LMPs"), calculate the annual market value ($) of energy delivered by the Proposal at the delivery node(s) accounting for the proposal contract period and contract delivery conditions (peak, off peak, etc.). Annual market value ($) equals quantity of energy delivered at node in each hour of year times hourly, nodal LMPs.
    2. Identify the annual proposal cost of energy as bid.
    3. Calculate the annual net cost (savings) of the energy from the proposal, i.e. annual proposal cost of energy as bid minus the market, LMP-based delivered energy value of the proposal.

2. A mark-to-market comparison of the of the proposal's bid price for RECs eligible for Renewable Energy Standard ("RES") compliance to the projected market prices for RECs at the delivery point:
    1. Identify the annual quantity of RECs that are projected to be required to meet the RES requirements of the distribution service retail load served by National Grid.
    2. Identify the RECs that National Grid is holding under long-term contracts and Renewable Energy Growth Program tariff, in each year. (These will be based on National Grid existing contracts, Renewable Energy Growth Program, DG Standard Contracts, anticipated National Grid contracts for RECs from proposals selected through the New England Clean Energy RFP of November 2015 and anticipated RECs from Rhode Island's procurement of Revolution Wind).
    3. Calculate the net requirement for RECs that could be filled by RECs from the Proposal. The Step 3 quantity or "gap" = greater of (Step 1 minus Step 2) and zero.
    4. Identify the number of annual RECs that National Grid would acquire from the Proposal and the total Direct annual cost of those RECs. Direct annual cost equals annual quantity of Proposal RECs times Proposal annual unit cost per New REC as bid.
    5. Identify the number of RECs to be supplied by the Proposal to fill all, or a portion, of the gap in required RECs as the smaller of Step 3 and Step 4.
    6. Calculate the direct annual dollar benefit of Proposal RECs used to fill all, or a portion of the gap from Step 3. This is the cost of avoiding the purchase of the quantity from step 5 at the Base Case Market price for REC (Quantity of Proposal RECs used to fill gap times Base Case REC market price).

7. Calculate the direct annual dollar benefit of Proposal RECs sold. This is the total quantity of Proposal RECs minus the step 5 quantity National Grid use to fill the gap, times the Proposal Case Market price of REC (Proposal RECs surplus to gap times Proposal case REC market Price).
8. Calculate the total direct benefit by subtracting the result from Step 4 from the sum of Steps 6 and 7.

C. CALCULATION OF TOTAL NET DIRECT UNIT BENEFIT

The evaluation team will:

1. Compute the present value of the annual direct costs and annual direct benefits using the real discount rate.
2. Compute the present value of the net direct benefit as the sum of the present values of direct benefits, less the present value of direct costs.
3. Compute the present value of the annual MWh of energy delivered for the proposal. The annual energy quantities should be discounted to a 2018 reference year using the real discount rate.
4. Divide the result of Step 2 by the result of Step 3 to compute the levelized unit net direct benefit for the proposal. This result will be expressed in 2018 constant dollars per MWh.

D. CALCULATION OF INDIRECT COST & BENEFIT METRICS

The evaluation team will express all of the following costs and benefits in 2018 constant dollars, and any cost or benefit inputs expressed in nominal dollars will be deflated to 2018 reference year dollars based on the rate of inflation:

1. Price change Impacts on LMP and REC market prices. These metrics will calculate price change impacts on the energy and RECs of the distribution service customers of National Grid. These calculations will reflect the proportion of National Grid distribution service retail load to total load in the RI load zone in the most recent year for which public statistics are available.

(a) The impact of changes to the Locational Marginal Price ("LMP").

1. For the Proposal case, obtain from ENELYTIX the annual sum of hourly LMPs times load in Rhode Island.
2. Adjust the Proposal case value in the RI load zone by the proportion of National Grid distribution service retail load to total load in the RI load zone.
3. Calculate the LMP-based total cost to National Grid consumers in the Proposal case.
4. For the Base Case, obtain from ENELYTIX the annual sum of hourly LMPs times load in Rhode Island.
5. Adjust the Base Case value in the RI load zone by the proportion of National Grid distribution service retail load to total load in the RI load zone.
6. Calculate the LMP-based total cost to National Grid consumers in the Base Case.
7. Calculate the price change (energy price change) impact by subtraction of the annual Proposal case total from the annual Base Case total to arrive at the price change impact of the Proposal.

(b) The impact of changes to the price for RECs

1. Calculate the annual quantity of RECs that will need to be acquired at market prices beyond the quantity supplied by the Proposal. This equals the annual RECs RES requirements of the distribution service retail load served by National Grid minus the quantity of RECs that National Grid held under long-term contract minus the quantity of Proposal RECs used to meet the annual requirement.
2. Calculate the value of the price change in $MWh as the difference between the Proposal market price for RECs and the Base Case market price for RECs.
3. Calculate the absolute annual indirect benefit of that price change by multiplying the quantity from Step 1 by the price difference from Step 2.

2. Total indirect net benefits of the proposed Proposal:
    1. Calculate the annual sum of the indirect benefits used for relative ranking and quantitative scoring.

E. CALCULATION OF TOTAL NET UNIT BENEFIT

The evaluation team will:

1. Compute the present value of the annual direct costs, annual direct benefits, and annual indirect benefits using the real discount rate.
2. Compute the present value of the net benefit as the sum of the present values of direct benefits and indirect benefits, less the present value of direct costs.
3. Compute the present value of the annual MWh of energy delivered for the proposal. The annual energy quantities should be discounted to a 2018 reference year using the real discount rate.
4. Divide the result of step 2 by the result of step 3 to compute the levelized unit net benefit for the proposal. This result will be expressed in 2018 constant dollars per MWh.

F. CALCULATION OF ADDITIONAL SUPPORTING METRICS[5]

The evaluation team will express all of the following costs and benefits in 2018 constant dollars, and any cost or benefit inputs expressed in nominal dollars will be deflated to 2018 reference year dollars, based on the rate of inflation:

1. The value of proposal contribution toward reducing regional emissions.

(a) Reduction in GHG emissions attributable to Rhode Island and ISO-NE neighboring states electricity consumption.

1. Calculate the quantity of total emissions attributable to Rhode Island and ISO-NE neighboring states for the Proposal Case and for the Base Case.
2. Calculate the annual reduction in quantity of CO_2 emission by subtracting the quantity of emissions for the Proposal Case from the quantity for the Base Case.
3. Calculate the annual non-embedded value of CO_2 per ton as the difference between the cost of carbon established in the 2018 Avoided Energy Supply Costs in New England – 2018

[5] These calculations will be based on the Docket 4600 Benefit-Cost Framework. However, these quantitative metrics will only be used when presenting business case.

Report ("AESC 2018")[6] and the Regional Greenhouse Gas Initiative (RGGI) allowance price projections used in the ENELYTIX model.

4. Calculate the absolute dollar value of non-embedded greenhouse gas reduction benefits by multiplying the reduction quantity from Step 2 by the non-embedded value from Step 3.

(b) Reduction in NOx emissions attributable to Rhode Island and ISO-NE neighboring states electricity consumption.

1. Calculate the quantity of total emissions attributable to Rhode Island and ISO-NE neighboring states for the Proposal Case and for the Base Case using the same methodology as for GHG emissions.
2. Calculate the annual reduction in quantity of NOx emission by subtracting the quantity of emissions for the Proposal Case from the quantity for the Base Case.
3. Calculate the absolute dollar value of non-embedded NOx reduction benefits by multiplying the reduction quantity from Step 2 by the cost of NOx established in AESC 2018.

6 Available at: http://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-June-Release.pdf.

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C.2: Addendum to Protocol

Addendum to the Protocol for Quantitative Evaluation / Price Analysis

This document serves as an addendum to the *2018 Rhode Island Long-Term Contracts for Renewable Energy Solicitation: Protocol for Quantitative Evaluation / Price Analysis* ("Quantitative Protocol"); it provides additional details and amendments to the evaluation process that could not be documented at the time of Protocol freeze i.e. prior to opening of Bids. Section 7 provides a table listing all Proposals and Portfolios evaluated by TCR and identifies how each of them are impacted by the discussions in this document.

1 Clarity on study period, modeling period and extrapolations

Section 4 of the Quantitative Protocol states the Quantitative Workbook covers *"the period 2021 through 2045. It will use extrapolation to calculate values for 2043 through 2045 (i.e., for those years that lie beyond the ENELYTIX modelling period)."* Furthermore, Section 4A states *" ENELYTIX will simulate the operation of the New England electricity market over the period 2019 through 2042 for the Base Case and for each Proposal Case*".

For all Proposal and Portfolio cases, TCR ran the ENELYTIX simulations from 2021 through 2045, and calculated the quantitative metrics using the Quantitative Workbook over the same evaluation horizon. TCR did not use extrapolations in any of its calculations.

2 Calculation of Scores and Ranking for Stage Three Analysis

Upon request of the Evaluation Team, TCR analyzed an additional portfolio of proposals ("Portfolio Case") which was included in the Stage Three analysis. This section describes TCRs Stage Three evaluation process.

1. TCR first developed a Portfolio Case ENELYTIX model using the same fundamental approach used for Proposal Cases described in Section 4A of the Quantitative Protocol. The Portfolio Case inherited all key inputs and assumptions from each of the constituent Proposals which were already modeled during Stage Two.

2. TCR then prepared a Portfolio Case Quantitative Evaluation Workbook based on the Quantitative Metrics described in Sections 4B through 4E of the Quantitative Protocol, consistent with the evaluation criteria and metrics used for all Stage Two Proposal Cases.

3. Finally, TCR prepared a Stage Three summary ranking workbook which scored and ranked the Portfolio Case alongside Stage Two Proposal Cases.

    a. TCR assigned quantitative points (out of a total of 80) across the Proposals and Portfolio per the allocation methodology described in Section 3A of the Quantitative Protocol.
        i. For Stage Two Proposals, TCR used the Total Net Unit Benefits calculated during its Stage Two analysis.

ii. For the Portfolio, TCR used the Total Net Unit Benefit calculated in step 2.

b. TCR assigned qualitative points (out of a total of 20) to all Proposals and Portfolio.
   i. For Stage Two Proposals, TCR used the qualitative score assigned by Narragansett during its Stage Two analysis.
   ii. For the Portfolio Case, TCR calculated the qualitative score based on the weighted average qualitative scores of its constituent proposals. The weight for each Proposal was calculated as its percentage contribution to the total Portfolio annual energy generation which was then multiplied by the qualitative scores allocated in Stage Two and added together.

c. TCR added the qualitative and quantitative scores for all Proposals and Portfolios and ranked them based on their total score (out of 100).

3 Modifications to Bidders reported degradation rates for Photovoltaic (PV) Bids

This section covers TCR's review and recommendation of PV degradation factors to be used to model Proposal Cases in ENELYTIX for all PV Bids submitted in response to the 2018 RI RFP

Summary

TCR's review of the degradation factors in PV bids identified five issues of concern. Based on our review and research TCR recommends using the following assumptions in ENELTYIX modeling of all PV bids

- A degradation factor of 1% for the first month of the bid.
- a linear annual degradation factor of 0.5% per year. This value is consistent with values reported in the literature for c-Si technology, the value used by ISO-NE in its forecast, and the values 17 of the 20 bidders used in their bids. This translates into a linear monthly degradation (after the first month) of 0.04167%

Discussion

TCR's review of the degradation factors in PV bids, described below, identified five issues of concern:

a. Bidder-provided degradation factors that cover only the PPA period but not the entire modeling time horizon
b. Inconsistent approaches used by bidders for monthly variation of degradation factors within each year
c. Inconsistency between degradation factors provided in Bid Document and bid CPPD
d. Some bidders provided no degradation factors in Bid Documents
e. The standard PPA does not appear to require the bidder to achieve the degradation factor provided in the Bid Document or CPPD, or even to employ the specific PV technology or product identified in their CPPD

a. **Bidder-provided degradation factors that cover only the PPA period but not the entire modeling time horizon**. Bidders, in Part V of their CPPD files, provide monthly degradation factors to capture the decline in PV performance over the time -period of their PPA. Since the terms of essentially all PV bid

PPAs expire prior to the end of the evaluation period (2046), bidders have not provided degradation factors that extend through 2046 resulting in a "gap" between the end of their PPA and 2046. TCR has previously handled such gap years by establishing extrapolation assumptions with the caveat that these gap years were no longer than two or three years. In contrast, the PV bids in the RI RFP mostly have 15-year PPAs and are modeled over a 25-year horizon in the ENELYTIX E&AS model. Given the nine-year gap between PPA termination and modeling time horizon for significant number of bids, it would be pertinent to establish degradation factors for these gap years using an approach other than extrapolation.

b. **Inconsistent approaches for monthly variation of degradation factors within each year.** While most bidders apparently assumed no monthly degradation across each year, some bidders assumed linear degradation (e.g., monthly degradation factors equivalent to 1/12 of assumed annual degradation factors), one provided schedules with seasonal variation—including negative degradation factors for some months.
c. **Inconsistency between degradation factors provided in Bid Document and bid CPPD**. As indicated in Table 1 below.
d. **Some bidders provided no degradation factors in Bid Documents**. As indicated in Table 1 below, two bidders provided no degradation factors in their Bid Documents. It would not make sense to model zero degradation for these proposals.
e. **Lack of obligation to use specified PV technology or product**. PV degradation factors reported in the scientific literature vary across technologies. Even within a given technology class, the degradation factors reported by manufacturers vary somewhat from product to product. Given that bidders are not obligated to use the specific product or technology specified in their CPPD, the degradation factors they provide, which are in some cases product-specific, should not be viewed as precisely representative of what would ultimately be installed by the successful bidder.

Finally, a review of the CPPD and Bid document against the issued RFP indicates that the bidders are neither obligated to deliver the quantities of energy reported in their CPPD or Bid documents, nor are any PPA-linked delivery requirements (such as the biennial energy requirement in CPPD Part IV) tied to degradation factors. This calls into question the rationale of relying on bidder-provided degradation factors for purposes of this evaluation.

Given the issues identified above, TCR recommends developing independent assumptions on reasonable degradation factors as well as assumptions on how the factors are applied. These assumptions would be used across all PV bids to ensure a fair and consistent evaluation, regardless of the factors provided by bidders in their bids.

Review of bids – degradation factors and PV technology

Ignoring proposal variations attributed to non-physical parameters such as pricing options and PPA durations, bidders have offered a total of twenty distinct PV bids that range from 20 MW to 150 MW AC nameplate capacities. TCR reviewed the degradation factors referenced within each of their Bid documents as well as the implicit degradation factors calculated from their CPPD files and summarized its findings in Table 1.

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Table 1 As-bid degradation factors

#	Developer / Bidder	Bid	Capacity (MW)	Degradation per Bid Document (per year)	Degradation per CPPD (Part V)
1	Gray Road Solar	Gray Road Solar - 15Escalating / Levelized	[redacted]	[redacted]	[redacted]
2	MacDill	MacDill Solar - 15Levelized	[redacted]	[redacted]	[redacted]
3	FPS	FPS Vernon Solar - 15Escalating	[redacted]	[redacted]	[redacted]
4		FPS Fair Haven Solar - 15Escalating	[redacted]	[redacted]	[redacted]
5		FPS Campton 1 Solar - 15Escalating	[redacted]	[redacted]	[redacted]
6		FPS Peterborough Solar - 15Escalating	[redacted]	[redacted]	[redacted]
7		FPS Berlin Solar - 15Escalating	[redacted]	[redacted]	[redacted]
8		FPS Shaftsbury Solar - 15Escalating	[redacted]	[redacted]	[redacted]
9		FPS Claremont Solar - 15Escalating	[redacted]	[redacted]	[redacted]
10		FPS Campton 2 Solar - 15Escalating	[redacted]	[redacted]	[redacted]
11		FPS Thornton Solar - 15Escalating	[redacted]	[redacted]	[redacted]
12		FPS Plainfield Solar - 15Escalating	[redacted]	[redacted]	[redacted]
13		FPS Sterling Solar - 15Escalating	[redacted]	[redacted]	[redacted]
14		FPS Panton Solar - 15Escalating	[redacted]	[redacted]	[redacted]
15		FPS Alfred Solar - 15Escalating	[redacted]	[redacted]	[redacted]
16	Gravel Pit	Gravel Pit Solar - 15Levelized / 20 Levelized	[redacted]	[redacted]	[redacted]
17	Chariot (NextEra)	Chariot Solar - 15Levelized	[redacted]	[redacted]	[redacted]
18	Tracy Solar	Tracy Solar - 15Escalating	[redacted]	[redacted]	[redacted]
29	Three Corners	Three Corners Solar - 15Levelized	[redacted]	[redacted]	[redacted]
20	Lone Pine (NextEra)	Lone Pine Solar - 15Levelized	[redacted]	[redacted]	[redacted]

With exception to [redacted] all bidders have provided an estimate for their degradation factors that are within reasonable ranges [redacted] within their bid document as noted in the table. TCR compared these degradation factors against their CPPD counterparts and notes of the following:

[redacted]

[redacted]

Please refer to Attachment 1 for a summary of degradation factors obtained from each of the bidders CPPD files.

TCR additionally reviewed the bidders' PV offerings at a high level to verify whether certain trends in degradation factors were linked to technology or hardware differences. TCR notes the following:

1. Information was sparse and difficult to obtain comparable parameters across all bids
2. Although most bidders listed products that employ varieties of c-Si technology, none of the bidders are committed to specific OEMs or PV modules. The information available in the bids was largely available to verify track record and eligibility or as inputs to bidder modeling assumptions.
3. Traceable differences in hardware including racking options (fixed tilt v/s single axis tracking) and module material do not appear to have an impact on the factors estimated.

Please refer to Attachment 2 for a high-level summary of parameters.

Review of reported degradation factors relative to industry practice

In order to understand industry standard/in practice degradation factors, TCR began its literature review by identifying the PV degradation factors that ISO-NE assumes in its forecasting and planning studies. The 2018 PV Forecast[1] assumes linear degradation and uses a 0.5% annual degradation factor which is based on a support study carried out by ICF,[2] and both citing studies by NREL.[3] The NREL study is based on approximately 11,000 data points which are categorized by quality and PV module type. Limiting these data points to high quality studies (multiple measurements) and crystalline silicon modules resulted in a median degradation of 0.5% per year. Although studies note two seasonally-varying drivers of degradation, there is little research that would justify an assumption of a specific monthly degradation profile.

It is widely recognized that PV module performance typically undergoes a brief but rapid degradation at initial deployment before settling into a linear degradation rate.[4,5] Tests done at NREL and Sandia National Laboratories to measure initial light-induced degradation, for several types of c-Si modules, yielded degradation factors ranging between 0.4% and 1.5%.[6]

[1] https://www.iso-ne.com/static-assets/documents/2018/03/a03-2018-pv-forecast.pdf
[2] https://www.iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_report_for_iso_ne_2_27_15.pdf
[3] https://www.nrel.gov/pv/lifetime.html, and "Compendium of photovoltaic degradation factors," Dirk C. Jordan, Sarah R. Kurtz, Kaitlin VanSant, and Jeff Newmiller, *Progress in Photovoltaics: Research & Applications*, Volume 24 (7) – Jul 1, 2016.
[4] J. Lindroos, H. Savin, "Review of light-induced degradation in crystalline silicon solar cells", *Solar Energy Materials & Solar Cells* 147, 2016
[5] Stein, J.S., Robinson, C., King, B., Deline, C., Rummel, S. and Sekulic, B., 2018, June. PV Lifetime Project: Measuring PV Module PerformanceDegradation: 2018 Indoor Flash TestingResults. In *2018 IEEE 7th World Conference on Photovoltaic Energy Conversion (WCPEC)(A Joint Conference of 45th IEEE PVSC, 28th PVSEC & 34th EU PVSEC)* (pp. 0771-0777). IEEE.
[6] *Ibid.*

Conclusion and Recommendation

TCR recommends assuming initial degradation of 1%, applied in the first month.

TCR recommends using a linear degradation rate of 0.5% per year, a value consistent with values reported in the literature for c-Si technology, the value used by ISO-NE in its forecast, and those used by 17 of the 20 bidders in their bids. This translates into a linear monthly degradation (after the first month) of 0.04167%[7]

4 Determination of small and large proposals for capacity expansion model

Background

Section 4A of the quantitative evaluation protocol Narragansett filed with the RI PUC on October 26 states, in part:

> *After developing and running the Base Case, TCR will determine the criterion for classifying Proposals as either large or small. This criterion will be based upon the perceived ability of a Proposal to produce a projection of capacity retirements that is different from capacity retirements that are already projected under the Base Case. To make this determination, TCR will determine the minimum capacity at which a Proposal could reduce or delay the need for a generic peaking capacity resource added under the Base Case, and will classify Proposals as small if they fall below the capacity minimum. Then, TCR will model large Proposals using the Capacity Expansion and Energy & Ancillary Service ENELYTIX modules. In addition, TCR will model small Proposals using the Base Case capacity mix plus the small Proposal's capacity in the Capacity Expansion module to obtain new REC prices and use them as inputs to the Energy & Ancillary Service module.*

Having run the RI RFP Base Case, TCR has determined the criterion for classifying Proposals as either large or small to be 130 MW. Consistent with the protocol and the 130 MW criterion, TCR will model large and small proposals in the Capacity Expansion (CAPEX) module as follows:

- **Large Proposals (ICAP more than 130MW).** CAPEX model takes Base Case model selected unit retirements as an input. CAPEX solves for incremental retirements resulting from proposal capacity addition, for capacity additions as well as for market prices of RECs price and emissions.
- **Small Proposals (ICAP less than 130MW).** CAPEX model takes Base Case model selected unit retirements and capacity additions as inputs. CAPEX only solves for market prices of RECs price and emissions.

Rationale for 130 MW as threshold criterion

Consistent with the protocol, TCR chose 130 MW as the criterion based upon the perceived ability of a Proposal to produce a projection of capacity retirements that is different from capacity retirements that are already projected under the Base Case. TCR made that determination by identifying the minimum capacity at which a Proposal could reduce or delay the need for a generic peaking capacity resource added under the Base Case.

[7] 0.04167% = (1-0.5%)^(1/12)

The CAPEX module in the RI RFP Base Case added the first generic peaking capacity resource (338 MW) in 2037 in response to a projected system wide capacity shortage of 128 MW in that year in the absence of any new addition, as shown in Table 2. It is reasonable to assume that the CAPEX module for a Proposal Case would only delay or change that capacity addition decision if the Proposal was adding more than 128 MW of qualified capacity to the system. Therefore, TCR recommends setting the criterion at 130 MW.

Table 2 RI RFP Base Case Capacity Requirements versus Resources (MW)

Year	Reqts	Capacity before new additions	C - R Excess (Shortage) before new additions	Capacity additions cumulative	Capacity after new additions	C - R Excess (Shortage) after new additions
2021	28,787.0	30,781.0	1,994.0	0.0	30,781.0	1,994.0
2022	28,203.0	30,374.0	2,171.0	0.0	30,374.0	2,171.0
2023	28,177.0	29,569.0	1,392.0	0.0	29,569.0	1,392.0
2024	28,176.0	29,809.0	1,633.0	0.0	29,809.0	1,633.0
2025	28,201.0	29,813.0	1,612.0	0.0	29,813.0	1,612.0
2026	28,261.0	29,816.0	1,555.0	0.0	29,816.0	1,555.0
2027	28,350.0	29,899.0	1,549.0	0.0	29,899.0	1,549.0
2028	28,422.0	29,901.0	1,479.0	0.0	29,901.0	1,479.0
2029	28,614.0	29,984.0	1,370.0	0.0	29,984.0	1,370.0
2030	28,640.0	29,986.0	1,346.0	0.0	29,986.0	1,346.0
2031	28,683.0	29,988.0	1,305.0	0.0	29,988.0	1,305.0
2032	28,676.0	29,990.0	1,314.0	0.0	29,990.0	1,314.0
2033	28,826.0	29,992.0	1,166.0	0.0	29,992.0	1,166.0
2034	28,937.0	29,994.0	1,057.0	0.0	29,994.0	1,057.0
2035	29,047.0	29,995.0	948.0	0.0	29,995.0	948.0
2036	29,086.3	29,137.6	51.3	0.0	29,137.6	51.3
2037	29,267.8	29,139.4	-128.4	338.0	29,477.4	209.6
2038	29,382.0	29,140.8	-241.2	676.0	29,816.8	434.8
2039	29,491.1	29,142.1	-349.0	676.0	29,818.1	327.0
2040	29,509.2	29,143.1	-366.1	676.0	29,819.1	309.9
2041	29,685.8	29,144.6	-541.2	676.0	29,820.6	134.8
2042	29,801.1	29,145.8	-655.3	676.0	29,821.8	20.7
2043	29,915.5	29,147.0	-768.5	1,014.0	30,161.0	245.5
2044	29,947.2	29,147.8	-799.4	1,014.0	30,161.8	214.6
2045	30,143.3	29,149.1	-994.2	1,014.0	30,163.1	19.8

5 Quantification of indirect energy price change impacts for small proposals

This section covers TCR's recommendation on how to identify the RI Energy Market Price Change Impact ("indirect energy price change benefit") attributed to proposals with little or no measurable impact on system production cost, and how to treat that impact.

Summary

TCR recommends using the following criteria to identify proposals that produce a measurable indirect energy price change benefit:

1. The total system production cost of the Proposal Case is statistically different from the total production cost of the base case.
2. The percentage change in total system production cost between the Proposal Case and the base case is more than the 0.5% optimality tolerance range of the ENELYTIX modeling system.

The evaluation of all proposals that meet these two criteria will include an indirect energy price change benefit as calculated in their quantitative evaluation workbooks. The evaluation of proposals that do not meet these two criteria will not include an indirect energy price change benefit.

Attachment 3 summarizes the results of TCRs statistical analysis using this approach.

Discussion

The quantitative evaluation protocol includes provision for the impact of a proposal on the Locational Marginal Price (LMP) relative to the base case as one of the proposal's indirect benefits. In accordance with Section 4A of the quantitative evaluation protocol, TCR calculates this LMP impact as the difference in total Rhode Island load cost (LMP * load) between a Base Case for ISO-NE, i.e. without the proposal in service, and a Proposal Case for New England, i.e. with the individual proposal in service. TCR uses ENELYTIX to simulate ISO-NE operation and LMPs under each Case.

ENELYTIX, like the production cost models employed by ISOs in the Northeast, uses Mixed Integer Programming (MIP) to solve for unit commitment and economic dispatch (UC/ED) solutions that minimize system production cost. To arrive at the optimized solution within an acceptable amount of computational time, MIP accepts any solution that generates production cost within a tolerance range (MIP gap) of the true optimal value. In the ISO-NE and NYISO combined model ENELYTIX used for this RFP, the MIP gap is set to 0.5% of the true optimal production cost.

Because of this nature of MIP modeling, a small incremental energy supply introduced into the ENELYTIX model can produce statistically identical production cost solutions with slightly different UC/ED results, which may introduce small changes in LMPs. TCR has encountered several proposals exhibiting such behavior. Table 3 below summarizes results for [redacted]. Both are 20MW PV bids with near identical characteristics:

Table 3 ENELYTIX Result Summary for June 1, 2030 to June 1, 2031 modelling period

Proposal Name	Nameplate Capacity (MW)	Annual Delivery (MWh	Average Daily Production Cost Change from Base Case (%)	Average Daily ISO-NE Price Change from Base Case (%)	Average Daily RI Price Change from Base Case (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Although both proposals in Table 3 have production costs nearly identical to the base case, their LMPs differ slightly due to deviation in their UC/ED solutions. TCR has concluded that such LMP impacts are not statistically significant and should not be considered as an indirect benefit.

TCR proposes the following criteria to identify proposals with significant LMP impact.

- *Criterion 1: The Proposal Case should have a statistically different system production cost than the base case.*
  TCR will use a statistical test, t-test for mean difference, to determine if the daily system production costs are statistically significantly different from the base case during a sample year in which the proposal is operational.
- *Criterion 2: The Proposal Case production cost should differ from the base case production cost by an amount greater than the 0.5% MIP gap of the model.*
  TCR will calculate daily system production cost change between the base case and the proposal case during a sample year in which the proposal is operational, then compute the average daily impact over that year.

Only proposals that meet <u>both</u> criteria will be considered as having a significant LMP impact and therefore a measurable indirect benefit that will then be incorporated into the evaluation workbook. All remaining proposals, i.e. those proposals determined as not having significant LMP change impacts will be evaluated without consideration for indirect price change benefits in their quantitative analysis.

TCR has tested this approach on several proposal of varying size. Table 4 summarizes test results:

Table 4 Indirect Benefit test based on June 1, 2030 to June 1, 2031 modelling period

Proposal Name	Nameplate Capacity (MW)	Annual Delivery (MWh)	Criterion 1: Prod Cost is Statistically different from Base Case	Criterion 2: Average Daily Production Cost Change from Base Case (%)	Is Price Impact Valid
[redacted]	[redacted]	[redacted]	False	0.05%	False
[redacted]	[redacted]	[redacted]	False	0.03%	False
[redacted]	[redacted]	[redacted]	True	0.21%	False
[redacted]	[redacted]	[redacted]	True	0.74%	True

6 Proposals not included in Stage Two and Stage Three Evaluation

TCR did not include two sets of proposals in its final Stage Two and Stage Three scoring and ranking.

The first set of proposals excluded are those that did not meet the LTCS threshold i.e. the as-bid PPA prices for energy and RECs were greater than the projected market value of the sum of those attributes. Although this was a Stage One threshold requirement per the RFP, TCR required to run ENELYTIX models as part of the Stage Two evaluation process to obtain the projections of energy and REC prices over the PPA period to compare against. TCR calculates and reports this threshold requirement as the “Direct Net Unit Benefits ($/MWh)” under the quantitative evaluation framework, and those Proposals having a negative value are dropped from the scoring and ranking process.

The second set of proposal excluded are those which were withdrawn by the Bidders over the course of the evaluation process. As advised by Narragansett, the following bids have been excluded from TCRs scoring and ranking process:

1. **Number Nine Wind (all bids)-** Project withdrew on 5/14/2019, due to termination of QP417 Large Generator Interconnection Agreement.
2. **FPS Campton 1 & Campton 2 -** Project withdrew on 5/21/2019, due to cost associated with ISO-NE System Impact Study results (more than $50M to interconnect).
3. **Chariot Solar** - Requested withdrawal on 4/8/2019.

7 Listing of TCR Evaluated Proposals and Portfolios

Table 5 below lists all proposals and portfolios that were evaluated by TCR highlighting how they are impacted by each of the discussions in this document.

Table 5 List of Proposals and Portfolios

#	Proposal / Portfolio Identifier	[Section 3] Revised Degradation rates applied	[Section 4] Considered Large for capacity expansion	[Section 5] Indirect Energy Price impact nullified	[Section 6] Proposals Withdrawn (W) and not meeting the LTCS Threshold (NT)
1	[redacted]	-	-	-	-
2	[redacted]	-	-	-	-
3	[redacted]	-	-	Yes	-
4	[redacted]	-	-	-	W / NT
5	[redacted]	-	-	-	W / NT
6	[redacted]	-	-	-	W / NT
7	[redacted]	-	-	-	W / NT
8	[redacted]	-	-	-	W
9	[redacted]	-	-	-	W
10	[redacted]	-	-	-	NT
11	[redacted]	-	-	-	NT
12	[redacted]	-	Yes	-	NT
13	[redacted]	-	Yes	-	NT
14	[redacted]	-	-	Yes	NT
15	[redacted]	-	-	Yes	NT
16	[redacted]	-	-	-	NT
17	[redacted]	-	-	-	NT
18	[redacted]	Yes	-	Yes	W
19	[redacted]	Yes	-	Yes	W
20	[redacted]	Yes	-	Yes	-
21	[redacted]	Yes	-	Yes	-
22	[redacted]	Yes	-	Yes	
23	[redacted]	Yes	-	Yes	-
24	[redacted]	Yes	-	Yes	-

#	Proposal / Portfolio Identifier	[Section 3] Revised Degradation rates applied	[Section 4] Considered Large for capacity expansion	[Section 5] Indirect Energy Price impact nullified	[Section 6] Proposals Withdrawn (W) and not meeting the LTCS Threshold (NT)
25	[redacted]	Yes	-	Yes	-
26		Yes	-	Yes	NT
27		Yes	-	Yes	-
28		Yes	-	Yes	-
29		Yes	-	Yes	-
30		Yes	-	Yes	-
31		Yes	-	Yes	-
32		Yes	-	Yes	W
33		Yes	-	Yes	NT
34		Yes	-	Yes	NT
35		Yes	-	Yes	-
36		Yes	-	Yes	-
37		Yes	-	Yes	-
38		Yes	-	Yes	-
39		Yes	-	Yes	-
40		Yes	Yes	-	-

Attachment 1 – PV Degradation Factors

REDACTED

[redacted]

REDACTED

PV Bid technology 2018_01_08

Attachment 1 - CPPD Degradation

[redacted]

REDACTED

PV Bid technology 2018_01_08

Attachment 1 - CPPD Degradation

[redacted]

NG000183

Attachment 2 – Summary of PV Parameters in Bids

#	Developer / Bidder	Bid	SummerCapacity (MW)	Manufacturer	PV Type	Size (per panel, watts)	Racking	Mounting	Degradation per Bid Document (per year)	BidDocument Source	Degradation per CPPD (Part V), See CPPD Tab for details
1	[redacted]										
2											
3											
4											
5											
6											
7											
8											
9											
10											
11											
12											
13											
14											
15											
16											
17											
18											
19											
20											

REDACTED

Attachment 3 – Results of Statistical Analysis

ATTACHMENT 3 - Results of TCR analysis of measurable indirect price change benefit of RI RFP Proposals

March 20,2019

#	Proposal	Proposal Namplate Capacity (MW)	CPPD Annual Energy (MWh)	Criterion 1: Prod. cost is statistically different		Criterion 2: Prod. cost change is greater than modeling tolerance		Has measurable indirect energy price change benefit?
				pValue of t-test	Meets Criterion 1? [1]	% Change in production cost against Base Case (absolute value)	Meets Criterion 2? [2]	
1	[redacted]			0.00	Yes	2.94%	Yes	Yes
2				0.00	Yes	1.39%	Yes	Yes
3				0.00	Yes	0.97%	Yes	Yes
4				0.00	Yes	0.72%	Yes	Yes
5				0.00	Yes	0.73%	Yes	Yes
6				0.00	Yes	0.56%	Yes	Yes
7				0.00	Yes	0.39%	No	No
8				0.00	Yes	0.24%	No	No
9				0.00	Yes	0.21%	No	No
10				0.00	Yes	0.17%	No	No
11				0.00	Yes	0.17%	No	No
12				0.01	Yes	0.12%	No	No
13				0.01	Yes	0.12%	No	No
14				0.04	Yes	0.10%	No	No
15				0.32	No	0.04%	No	No
16				0.33	No	0.05%	No	No
17				0.38	No	0.05%	No	No
18				0.43	No	0.04%	No	No
19				0.43	No	0.03%	No	No
20				0.52	No	0.03%	No	No
21				0.55	No	0.03%	No	No
22				0.56	No	0.03%	No	No
23				0.66	No	0.01%	No	No
24				0.67	No	0.02%	No	No
25				0.82	No	0.03%	No	No
26				0.83	No	0.02%	No	No
27				0.85	No	0.02%	No	No
28				0.86	No	0.01%	No	No

Notes

[1] p-value **<0.05** indicates that the proposals annual production cost is **statistically different** from the base case

[2] change in production cost **> 0.5%** indicates that the **impact is greater than the model tolerance limits and is attributable to the proposal**

NG000187

APPENDIX D:
2018 RI RFP Base Case Results

Rhode Island Long Term Contracts for Clean Energy : Base Case Results

nationalgrid

December 19, 2018

12/19/2018

Summary / Agenda

1. RI RFP Base Case: What it is and is not
2. Capacity Balance for New England
3. Capacity Mix (MW) by Fuel Type
4. Generation Mix (MWh)
5. Model Selected Capacity Retirements and Additions
6. New England Class 1 RPS and MA CES
7. Projected LMPs by Area ($/MWh)
8. Winter Fuel Switching
9. ENELYTIX Results Workbook Content

1.RI RFP Base Case: What it is and is not

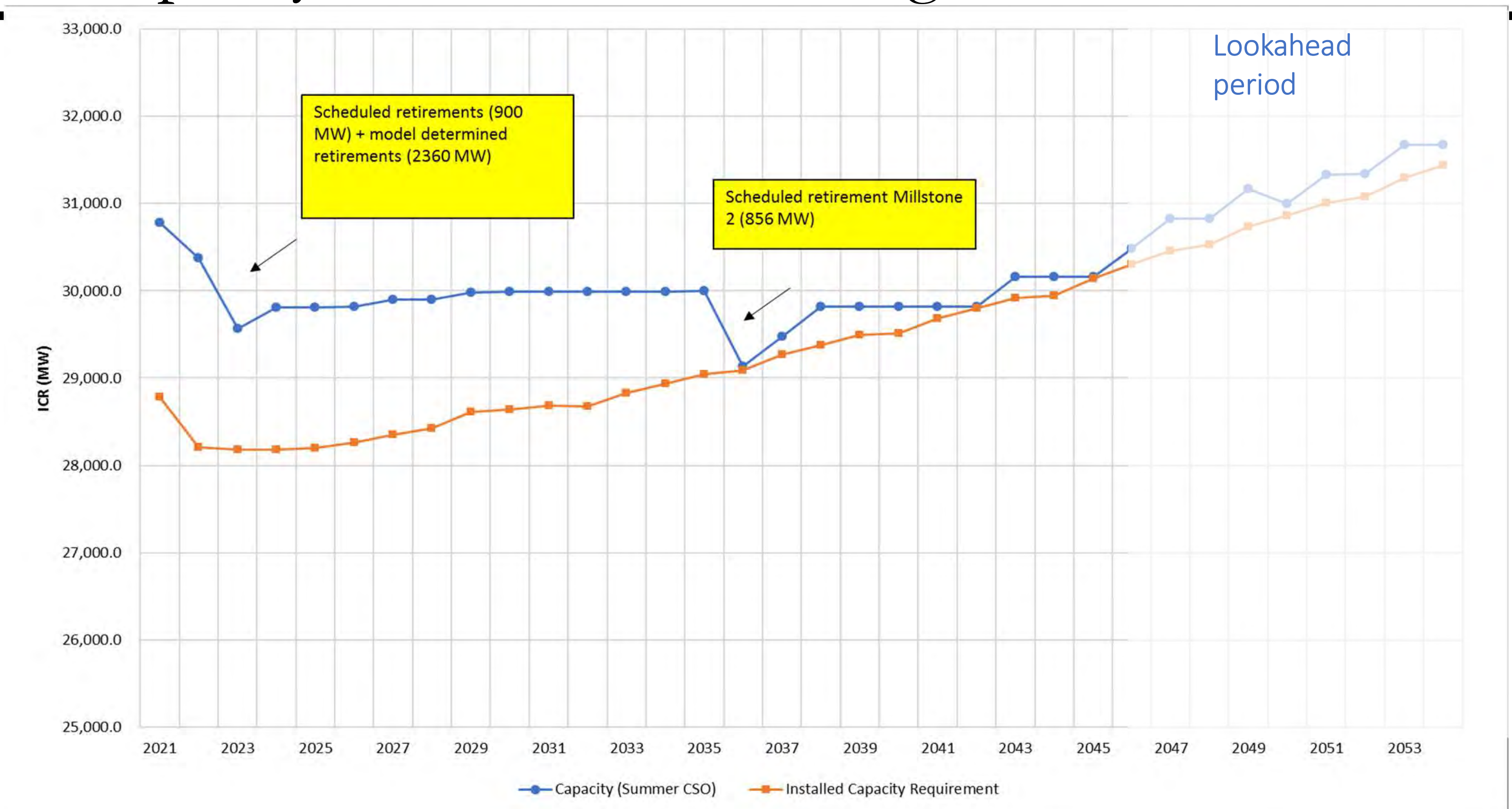
The Base Case is the reference point or benchmark against which we will measure the incremental impacts of each Proposal received in response to the RI RFP. It is a "counterfactual" projection of market parameters for a scenario in which the State does not procure clean energy through this RFP.

It is not a plan for the Rhode Island electric sector and should not be viewed as such.

The Base Case reports costs in 2018$. It assumes:

- Compliance with all legislative requirements and regulations in effect as of October 1, 2018 including class 1 Renewable Portfolio Standard (RPS) regulations in all New England states, the cap on carbon emissions from electric generating units located in MA and the MA Clean Energy Standard (CES) promulgated August 11, 2017
- Implementation of
  - 400 MW of offshore wind procurement by Rhode Island (COD January 2024)
  - CT 2018 Clean energy RFP procurements including 200 MW of offshore wind
  - Resource(s) selected in the MA 83C & 83D procurements, including all associated transmission development
  - 400 MW 83C generic offshore wind units in January 2027 and in January 2029 procured to comply with MA 83C legislation

2.a. Capacity Balance for New England

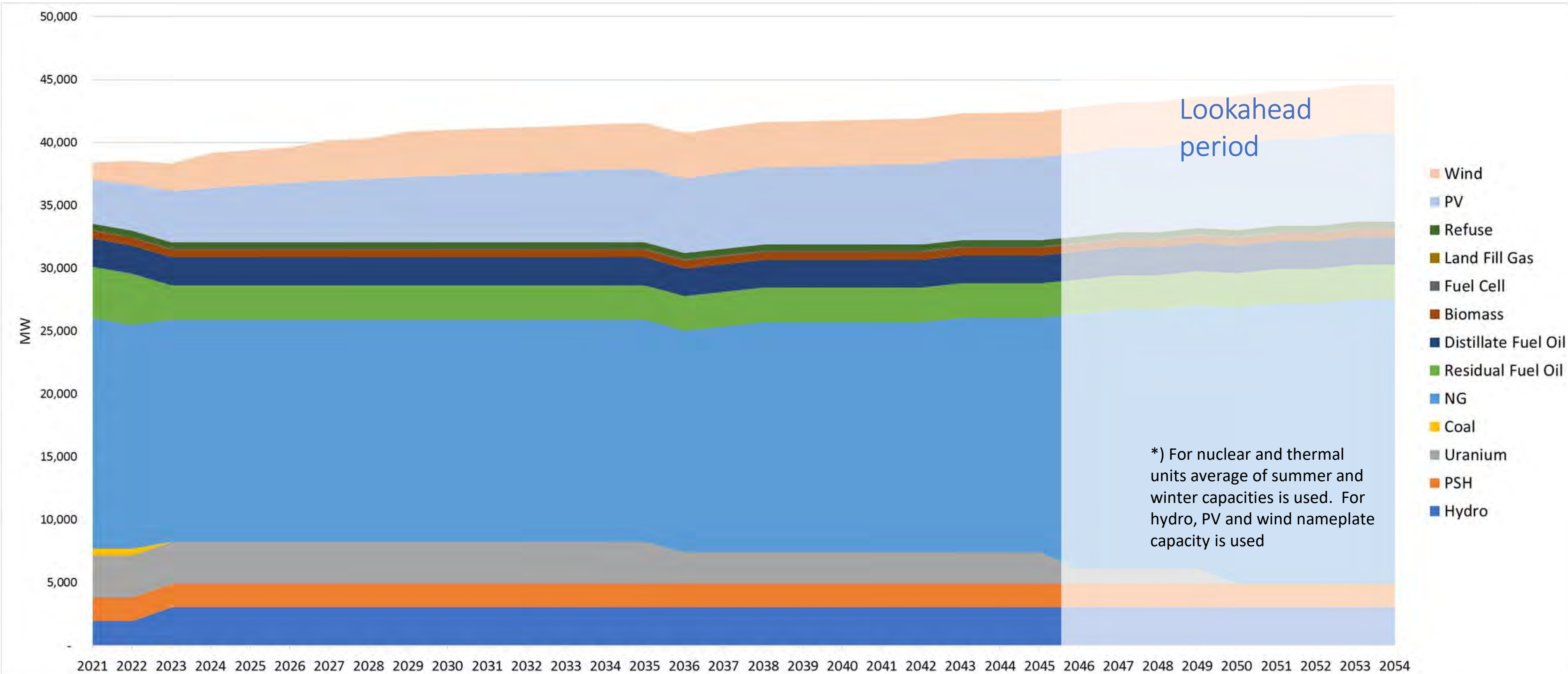


[redacted]

12/19/2018

2.b. Capacity Balance by Zone

3.a. Nameplate Capacity (MW) by Fuel Type



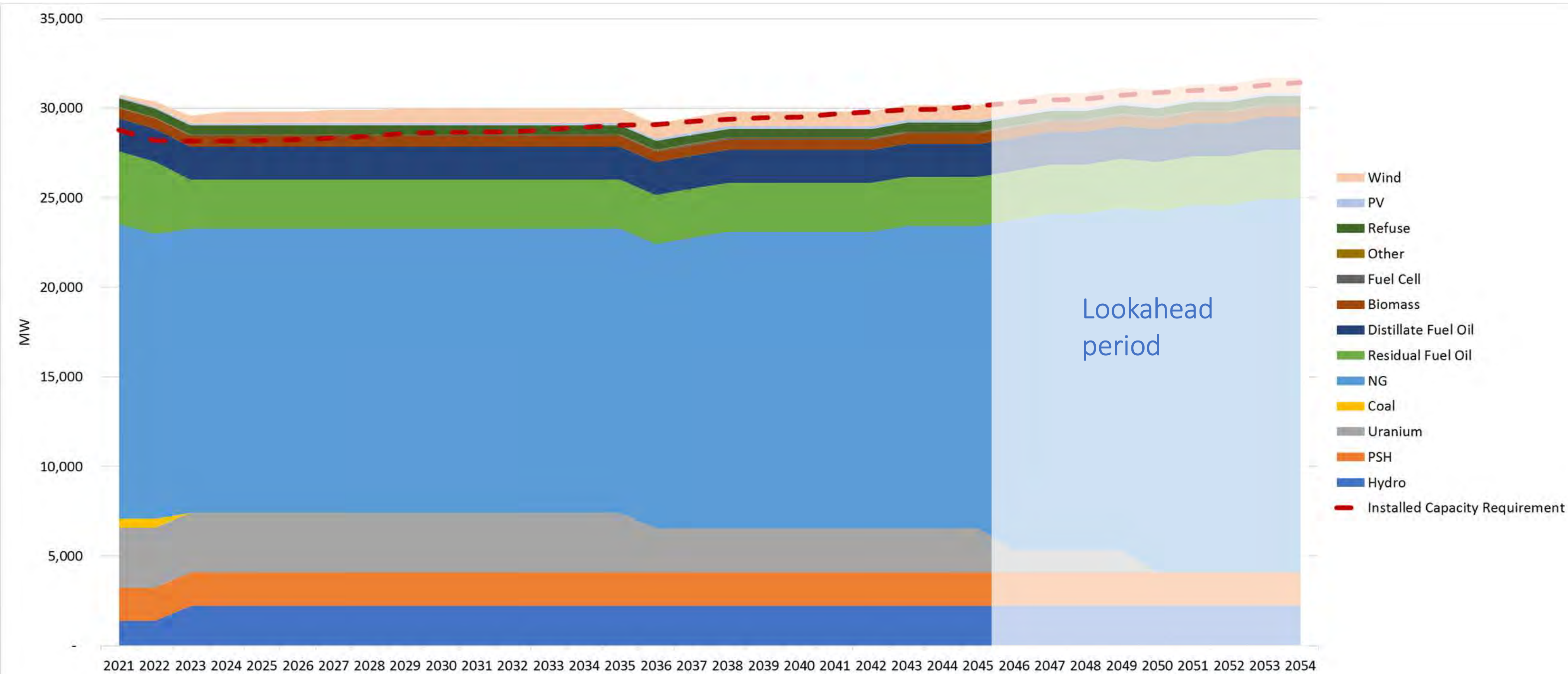
3.b. Nameplate Capacity (MW) by Fuel Type

	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Land Fill Gas	PV	Refuse	Wind	Grand Total
2021	1,962	1,864	3,344	535	18,353	4,054	2,269	622	23	2	3,483	516	1,402	38,428
2022	1,962	1,864	3,344	535	17,793	4,054	2,263	622	23	2	3,764	515	1,802	38,543
2023	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	4,036	515	2,202	38,318
2024	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	4,290	515	2,802	39,172
2025	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	4,528	515	2,802	39,410
2026	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	4,716	515	2,802	39,598
2027	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	4,898	515	3,202	40,181
2028	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,030	515	3,202	40,313
2029	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,187	515	3,602	40,870
2030	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,320	515	3,602	41,003
2031	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,443	515	3,602	41,126
2032	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,544	515	3,602	41,226
2033	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,665	515	3,602	41,348
2034	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,766	515	3,602	41,448
2035	3,052	1,864	3,344	-	17,651	2,738	2,215	624	75	2	5,861	515	3,602	41,543
2036	3,052	1,864	2,485	-	17,651	2,738	2,215	624	75	2	5,936	515	3,602	40,759
2037	3,052	1,864	2,485	-	17,989	2,738	2,215	624	75	2	6,036	515	3,602	41,197
2038	3,052	1,864	2,485	-	18,327	2,738	2,215	624	75	2	6,117	515	3,602	41,616
2039	3,052	1,864	2,485	-	18,327	2,738	2,215	624	75	2	6,194	515	3,602	41,693
2040	3,052	1,864	2,485	-	18,327	2,738	2,215	624	75	2	6,252	515	3,602	41,751
2041	3,052	1,864	2,485	-	18,327	2,738	2,215	624	75	2	6,339	515	3,602	41,838
2042	3,052	1,864	2,485	-	18,327	2,738	2,215	624	75	2	6,406	515	3,602	41,906
2043	3,052	1,864	2,485	-	18,665	2,738	2,215	624	75	2	6,472	515	3,602	42,309
2044	3,052	1,864	2,485	-	18,665	2,738	2,215	624	75	2	6,518	515	3,602	42,355
2045	3,052	1,864	2,485	-	18,665	2,738	2,215	624	75	2	6,595	515	3,602	42,432
2046	3,052	1,864	1,251	-	20,212	2,738	2,215	624	75	2	6,653	515	3,602	42,804
2047	3,052	1,864	1,251	-	20,550	2,738	2,215	624	75	2	6,709	515	3,602	43,198
2048	3,052	1,864	1,251	-	20,550	2,738	2,215	624	75	2	6,747	515	3,602	43,235
2049	3,052	1,864	1,251	-	20,888	2,738	2,215	624	75	2	6,816	515	3,602	43,643
2050	3,052	1,864	-	-	21,954	2,738	2,215	624	75	2	6,868	515	3,802	43,709
2051	3,052	1,864	-	-	22,292	2,738	2,215	624	75	2	6,917	515	3,802	44,097
2052	3,052	1,864	-	-	22,292	2,738	2,215	624	75	2	6,948	515	3,856	44,181
2053	3,052	1,864	-	-	22,630	2,738	2,215	624	75	2	7,012	515	3,856	44,584
2054	3,052	1,864	-	-	22,630	2,738	2,215	624	75	2	7,058	515	3,856	44,629

Lookahead period

[redacted]

3.c. ICAP Capacity Contribution (MW) by Fuel Type



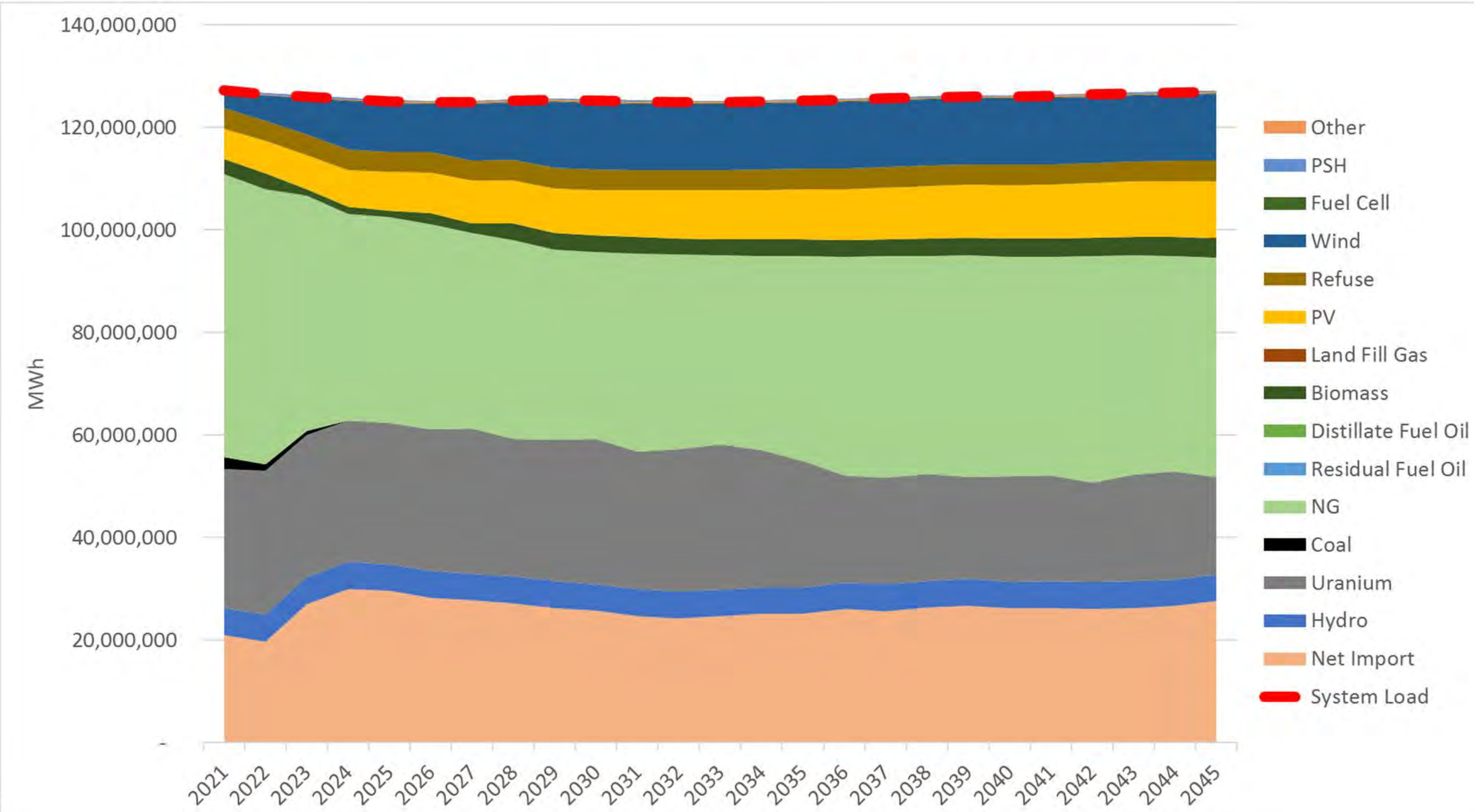
3.d. ICAP Capacity Contribution (MW) by Fuel Type

	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Other	PV	Refuse	Wind	Grand Total	Installed Capacity Requirement
2021	1,383	1,859	3,331	533	16,447	4,026	1,857	572	22	31	98	490	132	30,781	28,787
2022	1,383	1,859	3,331	533	15,887	4,026	1,857	572	22	31	102	490	280	30,374	28,203
2023	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	107	490	428	29,569	28,177
2024	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	112	490	663	29,808	28,176
2025	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	116	490	663	29,812	28,201
2026	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	119	490	663	29,815	28,261
2027	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	122	490	743	29,898	28,350
2028	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	124	490	743	29,901	28,422
2029	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	127	490	823	29,983	28,614
2030	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	129	490	823	29,986	28,640
2031	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	131	490	823	29,988	28,683
2032	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	133	490	823	29,989	28,676
2033	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	135	490	823	29,992	28,826
2034	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	137	490	823	29,993	28,937
2035	2,233	1,859	3,331	-	15,866	2,729	1,847	574	74	31	138	490	823	29,995	29,047
2036	2,233	1,859	2,472	-	15,866	2,729	1,847	574	74	31	140	490	823	29,137	29,086
2037	2,233	1,859	2,472	-	16,204	2,729	1,847	574	74	31	142	490	823	29,477	29,268
2038	2,233	1,859	2,472	-	16,542	2,729	1,847	574	74	31	143	490	823	29,816	29,382
2039	2,233	1,859	2,472	-	16,542	2,729	1,847	574	74	31	144	490	823	29,818	29,491
2040	2,233	1,859	2,472	-	16,542	2,729	1,847	574	74	31	145	490	823	29,819	29,509
2041	2,233	1,859	2,472	-	16,542	2,729	1,847	574	74	31	147	490	823	29,820	29,686
2042	2,233	1,859	2,472	-	16,542	2,729	1,847	574	74	31	148	490	823	29,821	29,801
2043	2,233	1,859	2,472	-	16,880	2,729	1,847	574	74	31	149	490	823	30,161	29,916
2044	2,233	1,859	2,472	-	16,880	2,729	1,847	574	74	31	150	490	823	30,161	29,947
2045	2,233	1,859	2,472	-	16,880	2,729	1,847	574	74	31	151	490	823	30,163	30,143
2046	2,233	1,859	1,247	-	18,427	2,729	1,847	574	74	31	152	490	823	30,486	30,303
2047	2,233	1,859	1,247	-	18,765	2,729	1,847	574	74	31	153	490	823	30,825	30,454
2048	2,233	1,859	1,247	-	18,765	2,729	1,847	574	74	31	154	490	823	30,825	30,526
2049	2,233	1,859	1,247	-	19,103	2,729	1,847	574	74	31	155	490	823	31,165	30,738
2050	2,233	1,859	-	-	20,169	2,729	1,847	574	74	31	156	490	833	30,994	30,862
2051	2,233	1,859	-	-	20,507	2,729	1,847	574	74	31	157	490	833	31,333	31,005
2052	2,233	1,859	-	-	20,507	2,729	1,847	574	74	31	157	490	835	31,336	31,075
2053	2,233	1,859	-	-	20,845	2,729	1,847	574	74	31	159	490	835	31,676	31,293
2054	2,233	1,859	-	-	20,845	2,729	1,847	574	74	31	159	490	835	31,676	31,437

Lookahead period

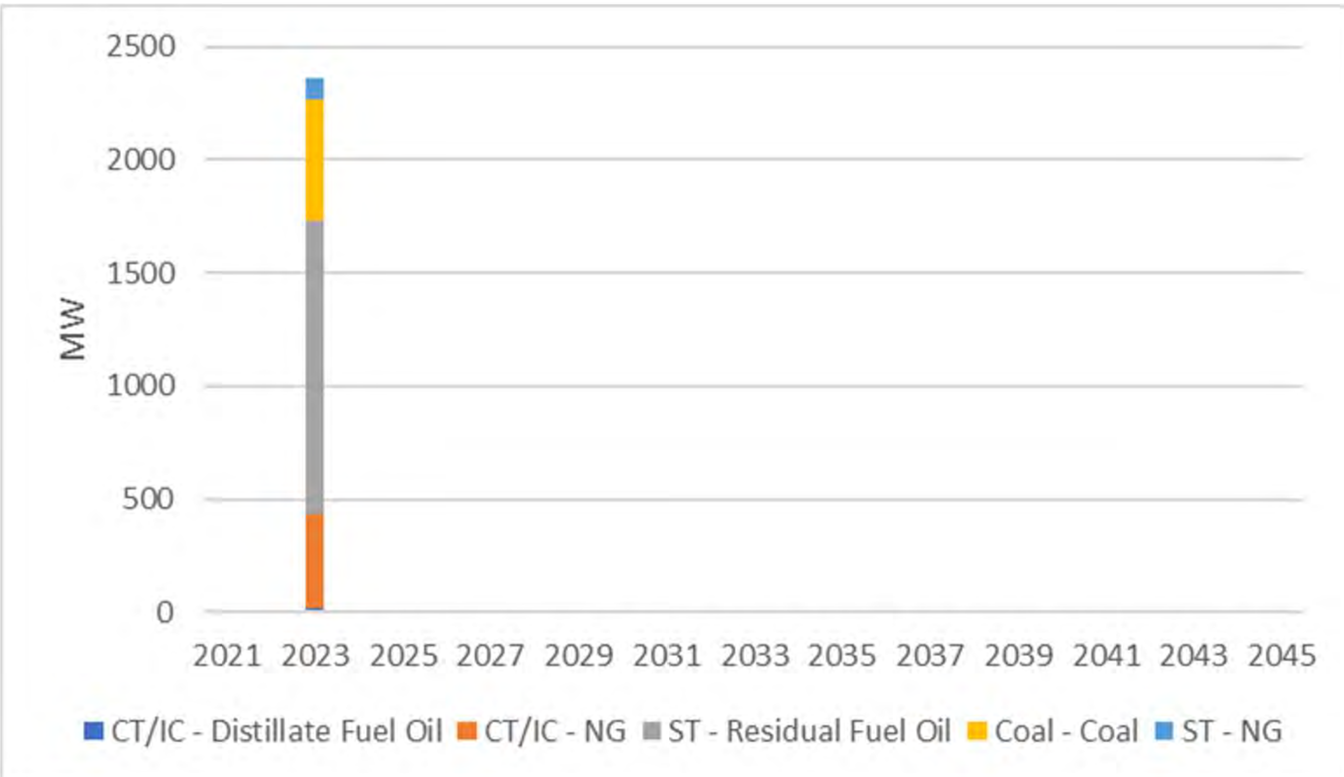
[redacted]

4. Generation Mix (MWh)



12/19/2018

5.a. Model Selected Retirements



2045

All Retirements

2,360 MW

Boiler – Natural Gas

94 MW

Boiler - Coal

533 MW

Boiler - RFO

1,300 MW

Peaker Natural Gas

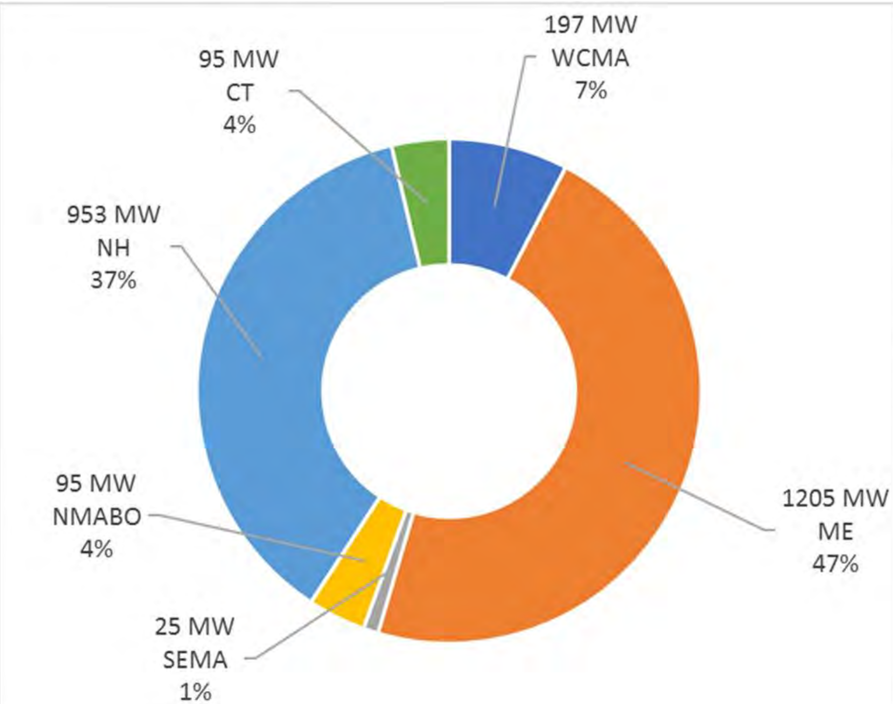
411 MW

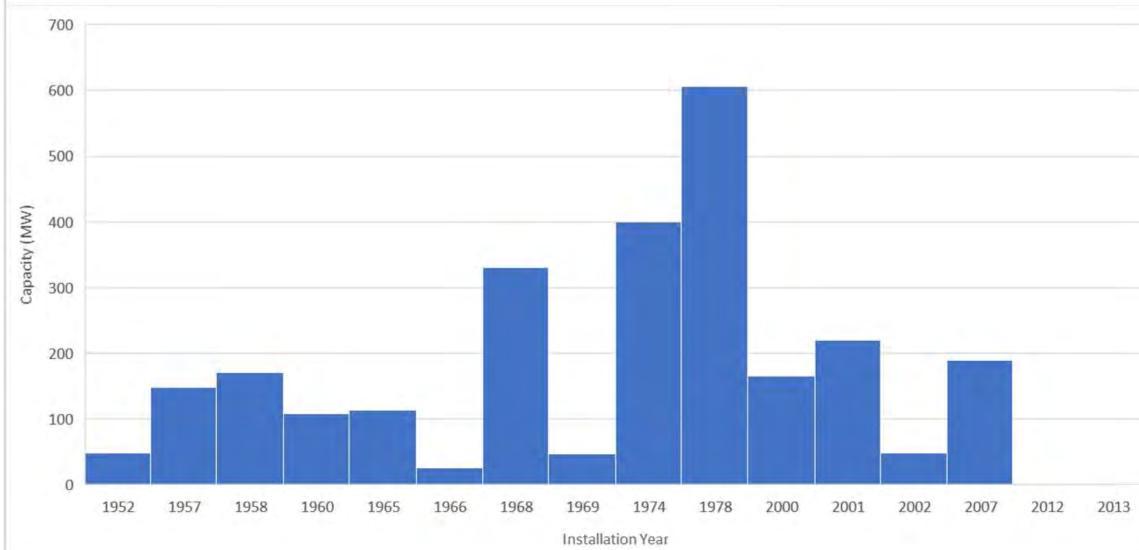
Peaker DFO

21 MW

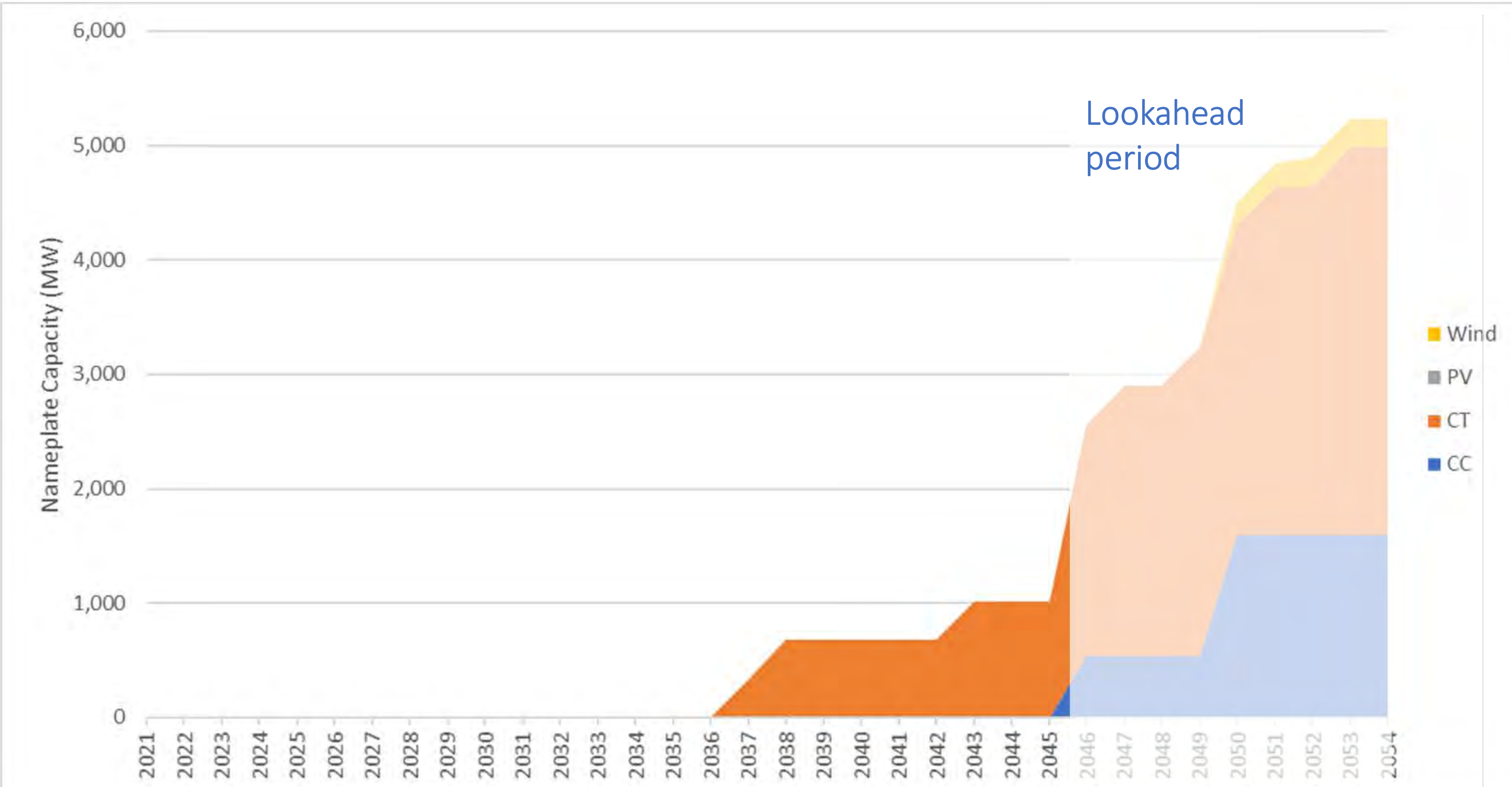
[redacted]

5.b. Model Selected Retirements





5.c. Model Selected New Capacity Additions



2045

1,014 MW

New Nameplate Capacity

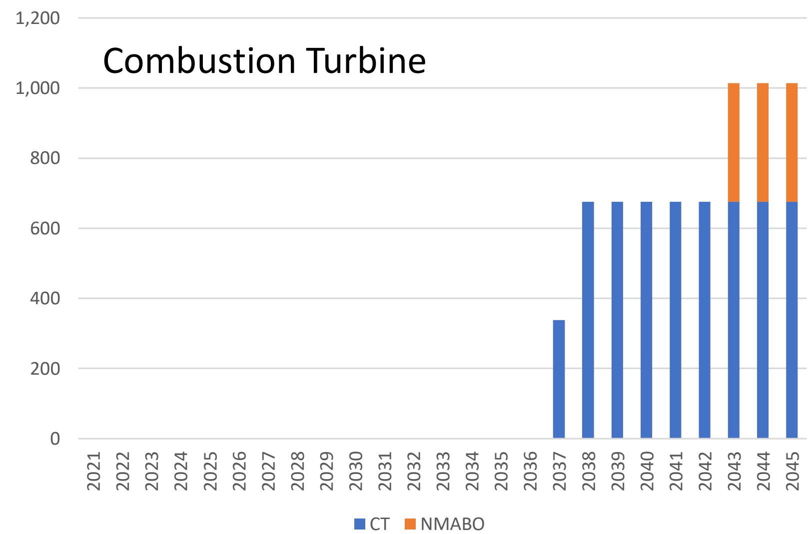
CT (Peakers)

1014 MW

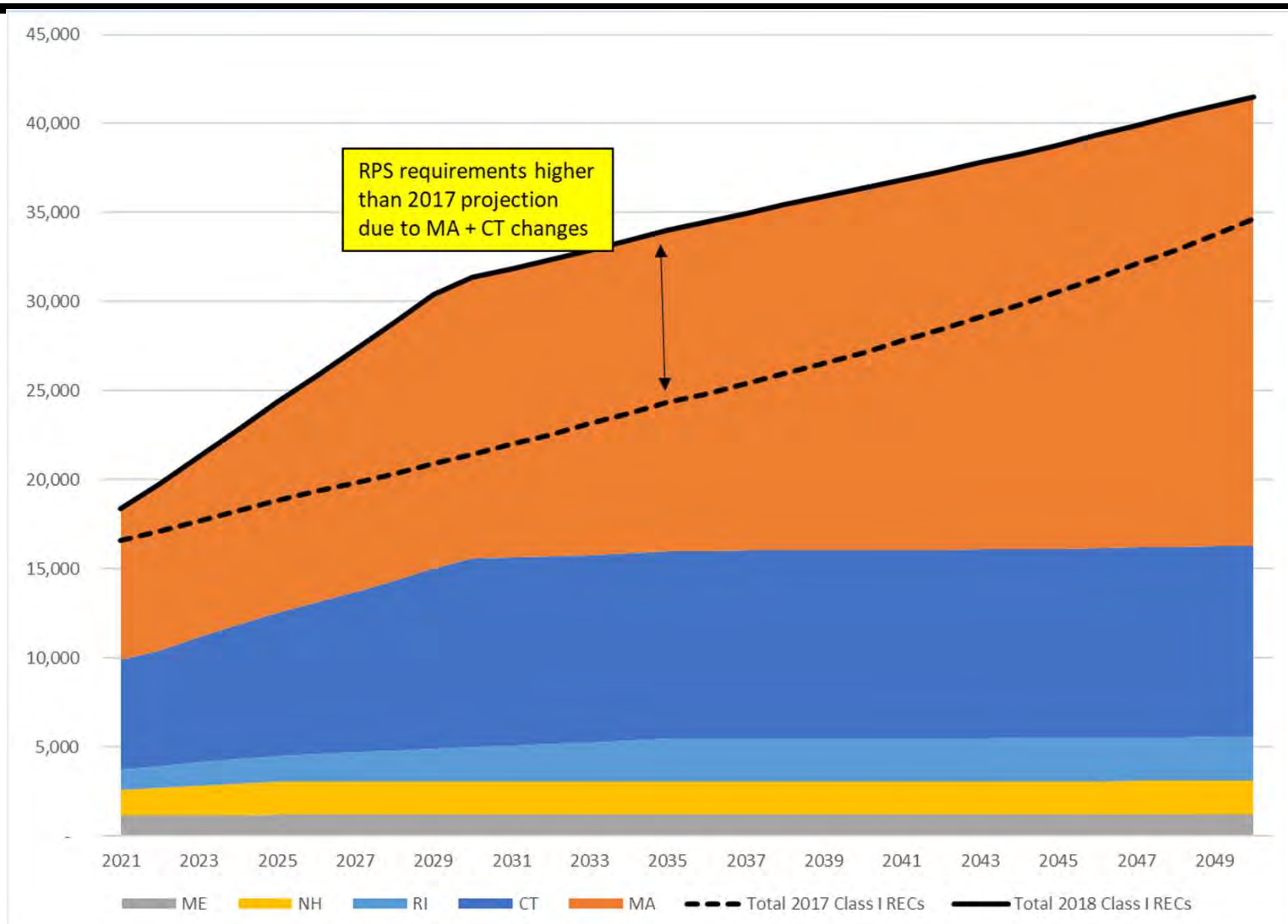
(3 Installations)

5.d. Model Selected New Capacity Additions - Cont'd

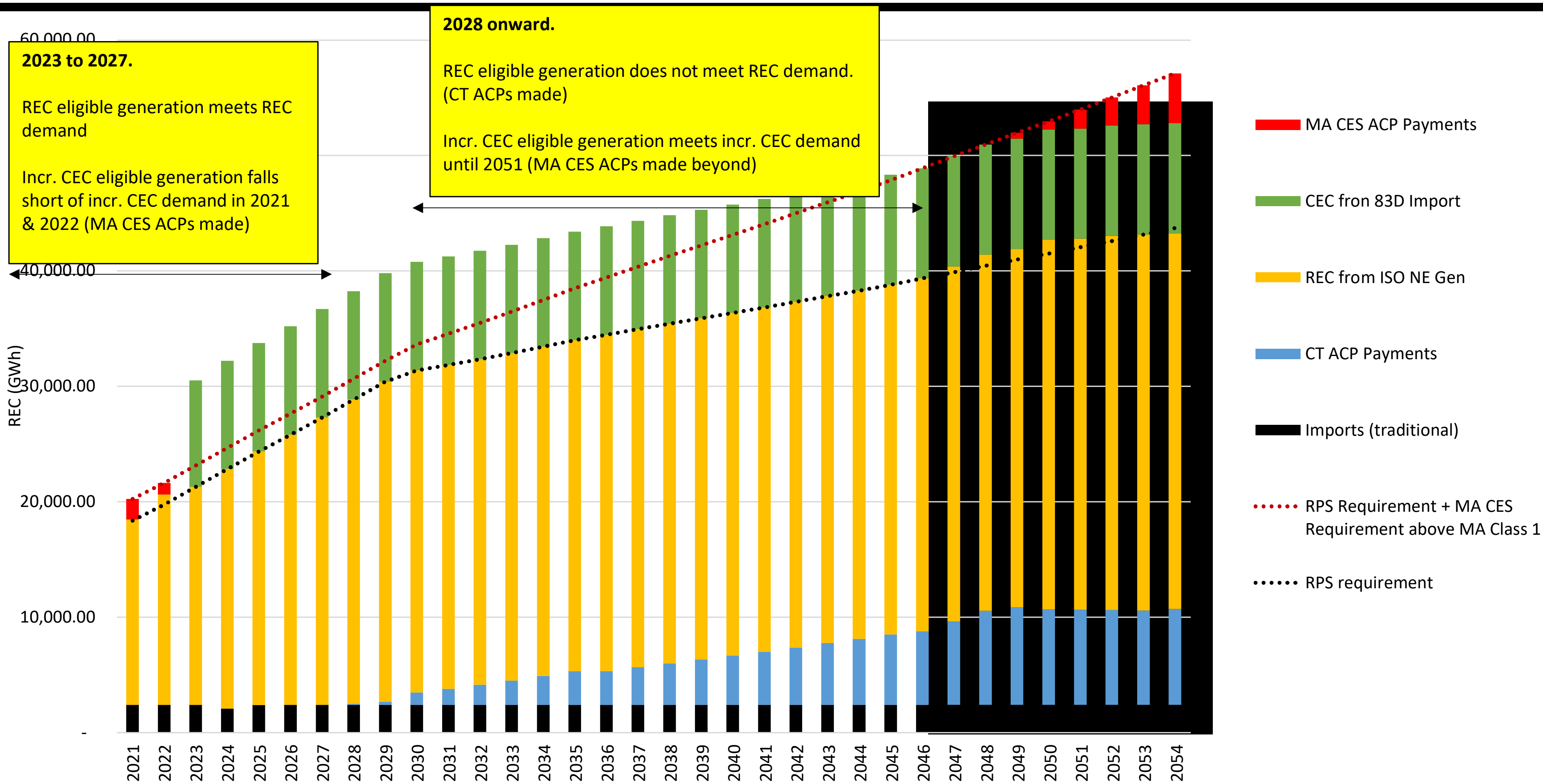
Model Selected Capacity Additions by Load Zone (Nameplate Capacity)



6.a. New England Class 1 RPS Requirements (Input assumption)



6.b. Class 1 RPS and MA CES Requirements vs Resources



6.c. REC and CEC Prices

[redacted]

REDACTED

6.d. Class 1 RPS & CES Reqts & Resources, REC & CEC prices in 2018 US$/MWh

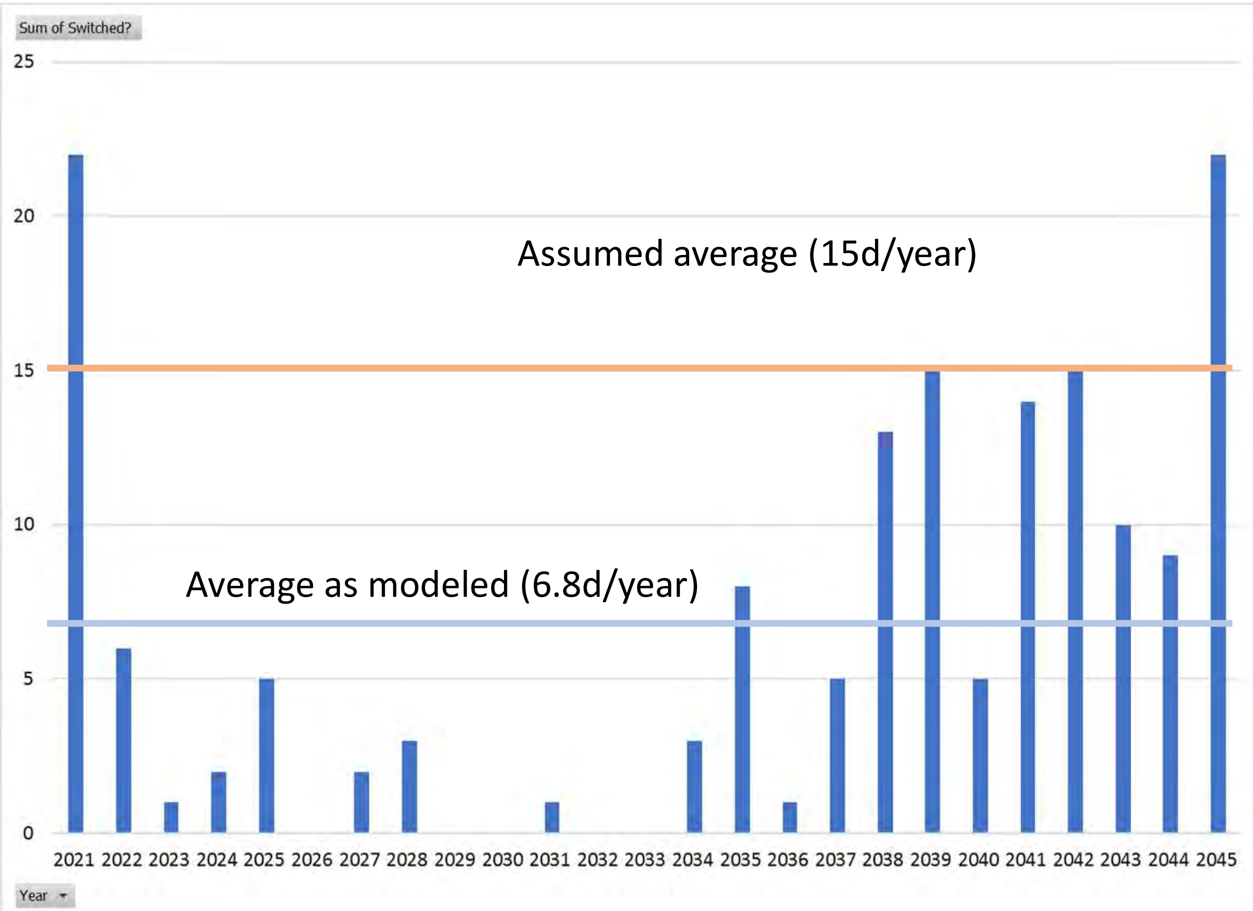
[redacted]

12/19/2018

7. Projected LMPs by Area (2018 US$/MWh)

[redacted]

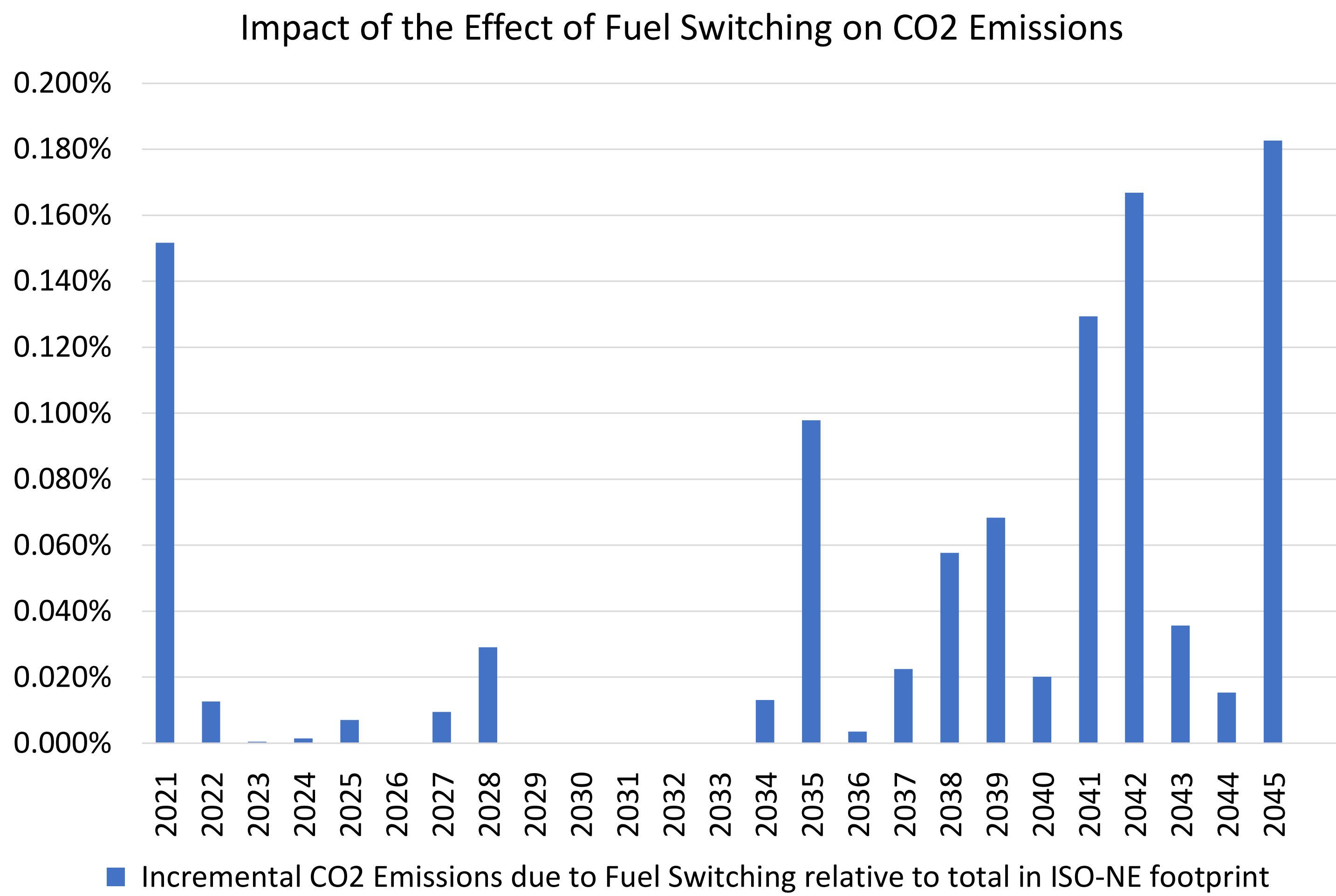
8.a. Winter Fuel Switching



Average number of switches as modeled (6.8 days /year) is lower than assumed average estimated based on the VW Case in 83C (15 days /year)

Two reasons:
1) Additional 600 MW of offshore wind
2) Cap on maximum gas use per day December through February

8c. Winter Fuel Switching



9. ENELYTIX Results Workbook

Tab	Content
1 New Additions	Shows new generation additions as selected by the capacity expansion model. See Input Assumptions Document information on fixed new additions
2 Retirements	Shows generation retirements as selected by the capacity expansion model. See Input Assumptions Document information on fixed retirements
3 GenMix_Gen	Generation mix by fuel type in MWh by year
3a Interchange	Shows imports into New England by Source
4 CFs All	Capacity factor by technology/fuel by year. Capacity factor in each category is computed as total generation by category divided by total capacity and by number of hours in a year
5 CFs New CCs and CTs	Capacity factors for new CC and CT generators suggested by the capacity expansion model
6 CFs Wind and PV	Capacity factors of new wind and PV generators by year by location
7 ProdCostDet	Annual generation and production cost by New England Zone by cost category
8 Gas BurnAnn	Annual natural gas burn by New England generators in MMBtu
9 Fuel Switching	Daily data on fuel switching, switched fuel use and incremental CO2 emissions
10 MA CO2 Emiss	CO2 emissions by generating units in Massachusetts that are subject to CO2 cap. Emissions are in lbs.
11a, b, c SysEmiss	Emissions of CO2, Nox and Sox by generating units in New England by zone and state Emissions are in lbs.
12 AreaLMP_Monthly	LMPs by month by year for each New England Zone reported for On Peak, Off Peak and 24-hour periods
13 AreaLMP_Ann	LMPs by year for each New England Zone reported for On Peak, Off Peak and 24-hour periods
14 AreaLoad &Cost	Load and Load Cost by zone by year. Load Cost in each zone is computed as a product of hourly load and hourly LMP in that zone summed over year
15 CongRent	Congestion rent and count of binding hours for all New England constraints by year
16 Interface Flows	Flows on New England interfaces. Flows are reported daily for each year 2020-2040 on average during On Peak and Off Peak hours of the day
18 Tech_program REC GWh	Detailed layout of REC contribution by source
19 Zone REC GWh	Contribution to REC by Zone
20 CES	CES Requirements and level met via ACP payments
21 REC Rev by Zone	Auxiliary worksheet showing Class 1 REC revenues received by generators by Zone. Used to restate true VOM costs
22 Project Detail	Generation and Revenue Reported for the Project. Not available for the Base Case

APPENDIX E:
2018 RI RFP Base Case Assumptions and Description of ENELYTIX simulation model

E.1: New England Document

REDACTED

Final Report

Base Case for valuation of 2018 RI RFP Proposals -

Input and Modeling Assumptions

New England

Prepared for: **Narragansett Electric Company d/b/a. National Grid**

Tabors Caramanis Rudkevich

January 27, 2020

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DISCLAIMER

Tabors Caramanis Rudkevich, INC (TCR) has been contracted by National Grid to provide the quantitative analyses that will allow National Grid to evaluate the proposals that they receive in response to the Rhode Island Long Term Contracting Standards (LTCS) RFPs. The information provided herein is solely for the purpose of development of a Base Case against which the proposed projects may be compared. Any other use of the materials without the explicit permission of TCR is strictly prohibited.

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CHAPTER 1: Base Case for Evaluation of 2018 RI RFP Proposals – New England Assumptions

This document describes the modeling and input assumptions that the TCR team proposes for the Base Case against which Narragansett Electric Company d/b/a National Grid ("Narragansett") will measure the incremental costs and benefits of each Proposal received in response to request for proposals for long-term contracts for renewable energy ("2018 RI RFP") issued by Narragansett on September 12, 2018. TCR refers to this as the "2018 RI RFP Base Case" or simply "RI RFP Base Case" The complementary document "Base Case Evaluation of 2018 RI RFP Proposals – Input and Modeling Assumptions New York" describes all RI RFP Base Case modeling and input assumptions that are specific to New York. Both reports describe the input and modeling assumptions the TCR team propose for the Base Case against which Narragansett will measure the incremental costs and benefits of each Proposal received in response to the 2018 RI RFP.

1.1: Background

The following legislation, plans and draft regulations provide the background to the development of a Base Case for evaluation of 2018 RI RFP proposals.

1. In 2004 Rhode Island General Assembly enacted a Renewable Energy Standard (RES) targeting 16% Renewable energy by 2019 which mandated electric distribution companies (EDCs) and non-regulated power producers comply with the mandate by supplying a percentage of their retail electric sales from renewable energy sources.
2. In 2009, Rhode Island General Assembly enacted a Long Term Contracting Standard for Renewable Energy (LTCS)[1] requiring EDCs to solicit proposals to procure at least 788,400 MWh or 90 MW ("minimum long-term capacity") of renewable energy under long term contracts each year. The level of minimum long-term capacity procurement was phased from 25% 2010 to 100% in 2014.
3. In 2014, the Resilient Rhode Island Act established the Executive Climate Change Coordinating Council (EC4) which is charged with developing and tracking the implementation of a plan to achieve greenhouse gas emissions reductions below 1990 levels of 10% by 2020, 24% by 2035 and 80% by 2050[2].
4. In 2014, the Affordable Clean Energy Security Act (ACES)[3] established a framework for the Public Utilities Commission (PUC), Division of Public Utilities and Carriers (DPU) and the Office of Energy Resources (OER) to work with the state EDCs and other New England states

1 http://webserver.rilin.state.ri.us/Statutes/title39/39-26.1/INDEX.HTM

2 http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM

3 http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-31/INDEX.HTM

to make strategic investments in large scale hydropower, regional renewable energy resources, natural gas and infrastructure.

5. In 2016, the RES requirements were updated to set a statewide target of 38.5% by 2035 starting at 10% for 2016 and increasing 1.5% each year until 2035[4].
6. In February 2018, Governor Gina M. Raimondo issued a press release directing the "State Energy Team to work with the Utilities to procure 400 MW of Affordable, Clean Energy"[5].

At the time of RFP issuance, Narragansett had already procured approximately 87% of its LTCS requirements and was obligated to procure a minimum additional 10.74 MW (94,124 MWh) of clean energy capacity to replace capacity resulting from termination of an existing long-term contract6. In response to the Governor's press release in 2018, Narragansett may select up to 400 MW of renewable energy projects under this RFP, subject to them meeting the LTCS requirements and PUC approval.

1.2: RI RFP Base Case Design

The 2018 RI RFP Base Case is not a plan for the Rhode Island electric sector, and it should not be viewed as such. Instead, the RI RFP Base Case is a projection of the carbon emission and energy cost implications of a scenario that assumes the additional resources available to meet the mandated renewable requirements for Rhode Island exclude any resources that are bidding into the RI RFP and limited to other expected policy-driven additions and market-driven RPS class 1 eligible resources.

This RI RFP Base Case provides the Evaluation Team a "but for" or "counterfactual" projection of carbon emissions and costs associated with Rhode Island electricity consumption under a future in which Narragansett do not acquire clean energy under long-term contracts with proposals received and selected in response to the 2018 RI RFP. The 2018 RI RFP Base Case serves as a common reference point or benchmark against which the EDCs measure the incremental costs and benefits of each Proposal received in response to the 2018 RI RFP.

The RI RFP Base Case reflects all legislative requirements and regulations in effect as of October 15, 2018 including Renewable Portfolio Standard (RPS) regulations in RI and other New England states including the 310 CMR 7.74, a cap on carbon emissions from electric generating units (EGU) located in MA, and regulation 310 CMR 7.75, a Clean Energy Standard (MA CES). The RI RFP Evaluation Base Case covers the period 2021 through 2045 and expresses cost data in constant 2018$ as of January 1, 2018 unless otherwise noted.

4 http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26/INDEX.HTM

5 https://www.ri.gov/press/view/32439

6 RI 2018 RFP https://ricleanenergyrfp.files.wordpress.com/2018/09/2018-ri-ltc-rfp_draft-04-20-2018revd-08-31-2018-clean-copy.pdf, Page 2, Footnote 7

CHAPTER 2: Modeling Environment

TCR employs ENELYTIX to model the Base Case and Project Cases. Appendix A describes the ENELYTIX platform in detail.

TCR uses ENELYTIX to develop an internally consistent, accurate set of Base Case prices in New England wholesale markets for energy and ancillary services, forward capacity and RECs through the interaction of its two key modules: the Capacity Expansion module and the Energy and Ancillary Services (E&AS) module. Figure 1 illustrates this interaction.

- The Capacity Expansion module determines the long-term optimal electric system expansion in New England subject to relevant resource adequacy and environmental constraints. These include system-wide and zonal installed capacity requirements (ICR), RPS requirements and carbon emission limits on Massachusetts EGUs. This module models the power system footprint at the zonal level consistent with the design of the capacity markets in ISO-NE.
- The Energy and Ancillary Services (E&AS) module simulates the Day-Ahead and Real-Time market operations within the footprint of the ISO-NE and New York Independent System Operator (NYISO) power systems and markets. This model implements chronological simulations of the Security Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED) processes, as well as the structure of the ancillary services in ISO-NE and NYISO markets. The E&AS model is fully nodal, performs true Mixed Integer Programming (MIP) based optimization, uses no heuristics, rigorously optimizes storage facilities, phase shifters and High Voltage Direct Current (HVDC) operation and accounts for marginal transmission losses.

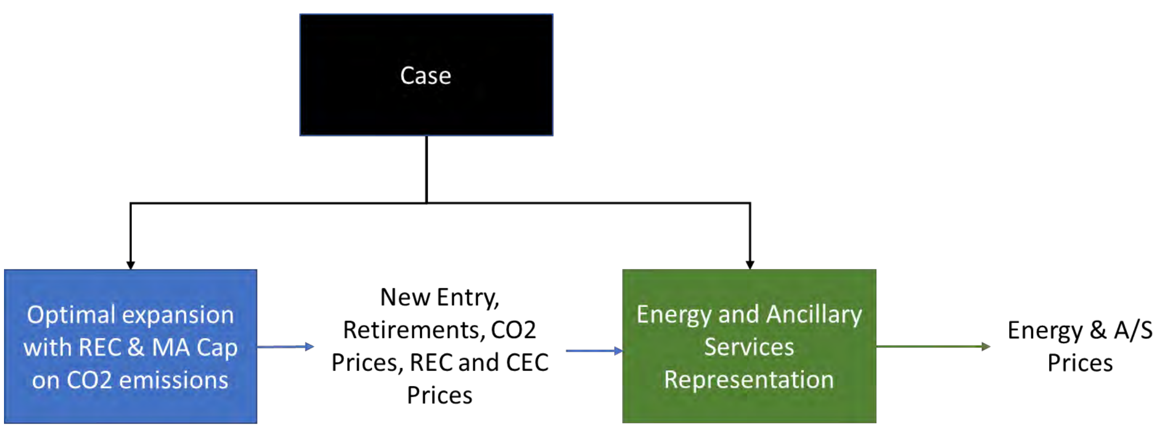

Figure 1. Interactive use of ENELYTIX modules

The sequence of deploying these modules, as illustrated in Figure 1, is as follows:

- Development of the Base Case begins with application of the Capacity Expansion module, which determines the optimal capacity expansion plan and resulting changes to the generation mix over time, Class 1 REC prices, prices for the MA Clean Energy Credits (CEC) and the shadow price of CO_2 in Massachusetts implied by compliance with the hard cap on emissions from EGUs located in Massachusetts.
- Outputs from the Optimal Expansion module are inputs to the Energy and Ancillary Services module. These outputs include new entry and retirement decisions and shadow prices of CO_2 emissions along with the CO_2 shadow prices associated with the Regional Greenhouse Gas Initiative (RGGI) program. The E&AS module provides chronological unit commitment and dispatch modeling. This module among other things calculates locational marginal prices for load and generators, net revenues that each generating unit would receive from the Energy and A/S markets.

Both modules use the Power System Optimizer (PSO) solver developed by Polaris Systems Optimization, Inc.[7] which serves as a key component of the ENELYTIX modeling environment. Within ENELYTIX, all three modules rely on the same dataset for ISO New England and share the economic and operational characteristics of ISO-NE's existing generating units, representation of the electric transmission system, and projection of future electricity demand.

All modules use the input assumptions in Chapter 3 through 14 where applicable as summarized by module in Table 1 below.

Table 1. Applicability of Input and Assumption Categories by ENELYTIX Module

Chapter	Capacity Expansion Module	E&AS Module
3. Transmission	Interfaces only	All transmission constraints
4. Interchange	fixed schedule	economically scheduled
5. Load Forecast	Seasonal Load Duration Curves	Hourly chronological
6. Ancillary Services	N/A	Modeled in detail
7. Installed Capacity Requirements	By Zone	N/A
8. RPS Requirements	Yes	REC Prices from Capacity Expansion

7 www.psopt.com

Chapter	Capacity Expansion Module	E&AS Module
9. MA Clean Energy Standards and Carbon Emissions Regulations	Yes	CO_2 shadow prices from Capacity Expansion
10. Generating Units Retirements	Yes	from Capacity Expansion
11. Generating Units Capacity Additions	Yes	from Capacity Expansion
12. Generating Unit Operational Characteristics	Yes	Yes
13. Fuel Prices	Yes	Yes
14. Emission Rates and Allowance Prices	Yes	Yes

2.1: Capacity Expansion Module

The discussion that follows summarizes the methodology used by the Capacity Expansion Model to simulate EGU investment and retirement decisions and calculate market prices for energy, RECs and CECs and shadow prices for Massachusetts CO_2 emissions. The specific values of the input assumptions the Capacity Expansion Model uses to model the Base Case are provided in the remaining chapters of this document unless indicated otherwise.

The Capacity Expansion Module solves a dynamic multi-year optimization problem using a MIP optimization solver. The problem is solved over a 35- year optimization horizon (2021 – 2056). The objective function is to minimize the net present value of the total cost, i.e., capital, fuel and operating, of the generation fleet serving the wholesale market within the ISO-NE electrical footprint.

These costs are minimized subject to the resource adequacy, operational and environmental constraints. By respecting these constraints, the optimization algorithm explicitly evaluates the needs for:

- energy delivered to each load zone to meet consumers demand in that zone,
- installed capacity in each reliability zone to assure resource adequacy (reliability) of the system,
- curbing CO_2 emissions by generating plants in Massachusetts to comply with the final 310 CMR 7.74 rules,
- energy produced by new renewable resources procured to comply with state-specific Class 1 RPS and Massachusetts CES requirements, and
- retaining the power flow within the capacity of the transmission network.

While processing these requirements, the algorithm evaluates trade-offs between the capital and operating costs of existing and new resources vis-à-vis their ability to meet these requirements and standard operating constraints. Through finding the global minimum for the net present value of total costs, the algorithms identify the optimal resource mix, locational and technology specific new build decisions and retirement decisions. It also computes shadow prices for environmental constraints.

The resource adequacy constraints are specified in terms of installed capacity requirements for the ISO-NE system as whole and for reliability zones within ISO-NE as depicted in Figure 2. These requirements are met by maintaining sufficient generating capacity within each of these reliability zones.

ISO New England performs annual resource adequacy assessment to develop locational requirements which are then used as inputs to develop parameters for the Forward Capacity Market. This assessment, however, is prepared only for the year for which it conducts Forward Capacity Auction (FCA). The most recent FCA12 covered the 2021/22 capacity year. Using statistical data for past resource adequacy analyses performed by ISO-NE, forward projections of electricity demand and future limits on transmission interfaces defining reliability zones, TCR develops forward looking estimates of installed capacity requirements for all zones. Chapter 7 presents these estimates.

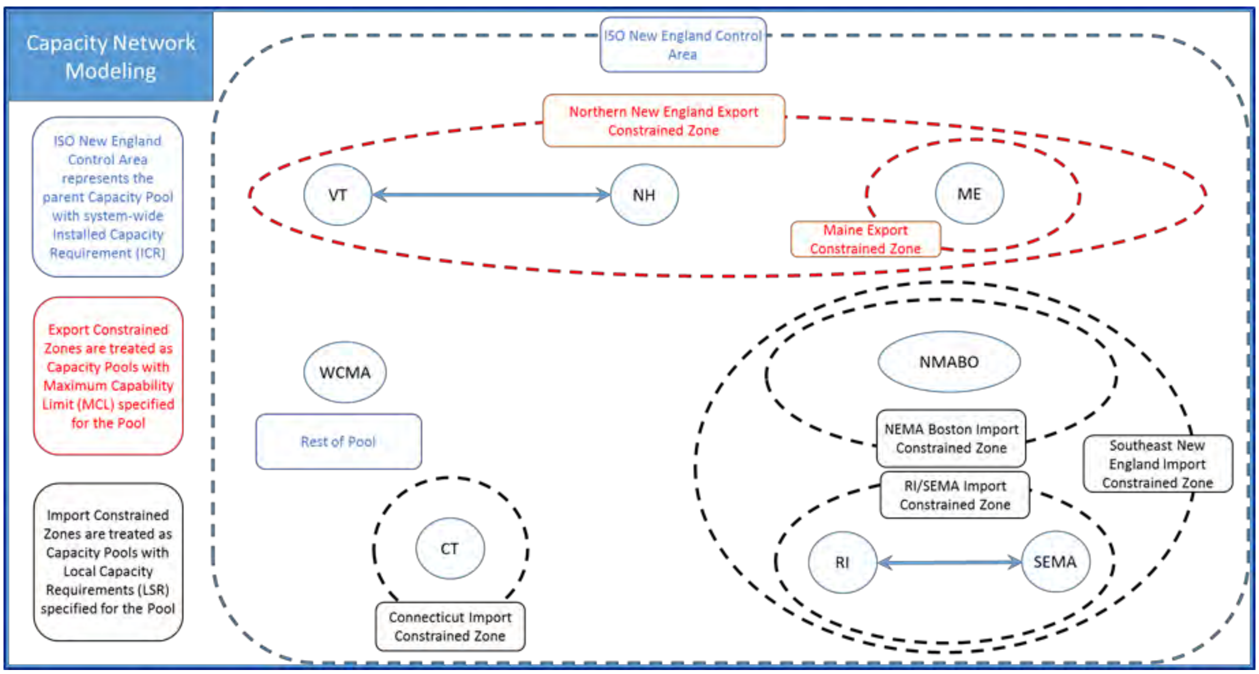

Figure 2 Representation of the Resource Adequacy Constraints in ISO-NE

Capacity expansion module provides a simplified representation of electric system operation compared to that of the E&AS module. Simplifications are necessary to reduce the size of the optimization problem and achieve computational tractability. The module uses three major simplifications.

1) It relies on load duration curves instead of chronological hourly modeling of electricity demand

2) It uses non-chronological dispatch of generation and does not model the unit commitment process
3) It includes representation of transmission interfaces but does not model any other constraints or contingencies.

The model represents load duration curves for three seasons – Summer (June – October), Winter (December – March) and Shoulder (April, May, October and November). Load in each season is represented by blocks of various duration and magnitude that are assumed to remain constant within each block. TCR's load representation for this module includes 12 blocks for Summer, 10 blocks for Winter and 8 blocks for Shoulder periods as depicted graphically in Figure 3.

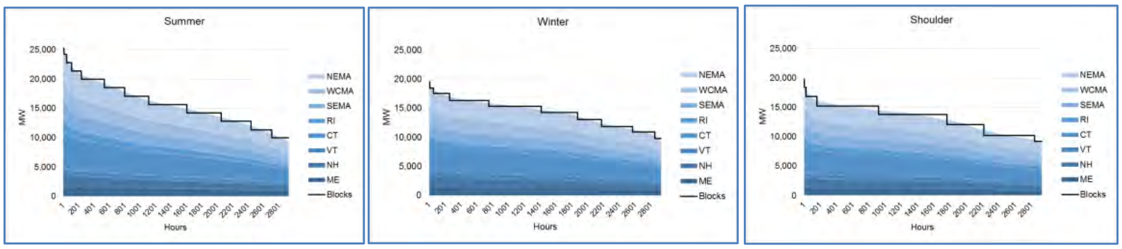

Figure 3. Seasonal Load Duration Curves and their Representation in Capacity Expansion Module

This load representation uniquely determines the season and block for each hour of the year. Using that relationship, the module develops average availability of variable resources such as wind and solar by block and season. Capacities of thermal and nuclear units are de-rated in the Shoulder season to account for planned maintenance. Additional derating accounting for forced outages is applied in all seasons.

To reflect the impact of operational constraints on the new build and retirement decisions, the module effectively simulates economic dispatch subject to transmission constraints represented by interfaces monitored by ISO-NE. In computing the impact of generation and loads on interface flows, the full representation of the transmission network which reflects both Kirchhoff's laws (the current law and the voltage law) is used.

The environmental constraints include requirements for state-by-state procurement of electric energy generated by renewable resources, as well as emissions requirements. The module represents each state's year-by-year Class 1 RPS requirements, Massachusetts CES requirements, state-specific resource eligibility, limitations on certificate banking and borrowing, and alternative compliance payment (ACP) prices that change over time. By statute, Class 1 RPS ACPs for Massachusetts, Maine, and Rhode Island are indexed to inflation, so in our model they are held constant in real terms at their 2018 levels. The Massachusetts value for 2018 is $68.95 per MWh. Connecticut's ACP is fixed in nominal terms at $55 per MWh in 2018 and reduces to $40 nominal per MWh in 2021, which we deflate in real terms over the study time horizon for modeling purposes. New Hampshire's ACP, currently $56.54 per MWh, increases at half the rate of inflation, so for modeling purposes we deflate it in real terms at half the assumed rate of inflation. By statute, the Massachusetts CES ACP for 2018-2020 is 75%

of the Massachusetts RPS ACP, and 50% of the RPS ACP thereafter. The module represents as a constraint the proposed CO_2 emission cap rules applicable to generators located in Massachusetts. The module uses projected RGGI CO_2 emission allowance prices as an input. Chapters 8, 9 and 14 discuss the detailed input assumptions and data sources.

The module determines Class 1 REC prices as the shadow price of the constraint associated with both meeting all states' RPS requirements through the addition of Class 1 eligible resources and meeting the Massachusetts incremental CES requirement through the addition of either Class 1 eligible resources or CES-eligible hydro resources. The module determines Massachusetts CES Clean Energy Certificate (CEC) prices as the Class 1 REC price minus the shadow price of the constraint associated with meeting all states' RPS requirements. The resulting REC and CEC prices in each year reflects the premiums that the marginal RPS and CES resources need above the energy and capacity market revenues they would receive, to recover their costs.

The capacity expansion module uses a two-phase approach: The *first phase* makes system expansion and retirement decisions subject to all resource adequacy, operational and environmental constraints <u>except for CES obligations</u>. The *second phase* dispatches the resources from phase 1 to comply with all obligations including CES, without allowing any additional capacity to be added or retired. This approach serves to create a true counter-factual system expansion case: first, it projects future generation mix in the absence of MA CES obligations and then it values the impact of CES requirements imposed on such a system. Shadow prices for Class 1 RPS and CES requirements obtained in the second phase are used as projection of Class REC and CEC prices, respectively.

The capacity of a given renewable resource type that can be built in a given year is subject to several constraints in the model:

- the estimated remaining technical potential for that resource type in each location
- the estimated maximum single-build capacity that of the resource type

Chapter 11 describes the characteristics of potential renewable resource capacity additions available to the capacity expansion module.

Our projections constrain Class 1 REC and Massachusetts CEC prices to be not less than \$2/MWh (except in the presence of a higher administratively set floor price) nor more than \$2/MWh below the ACP. The \$2/MWh reflects the estimated transaction cost associated with buying and selling RECs and CECs in the market.

2.2: Energy and Ancillary Services Module

The ENELYTIX E&AS module is a detailed chronological production costing simulation model which implements SCUC and SCED based simulation of the electricity markets in ISO-NE and NYISO. This module embodies the most detailed operational representation of these electric markets and underlying power systems. In the balance of this document we provide the detailed inputs and assumptions underlying the models and algorithms as shown in Figure 4 below.

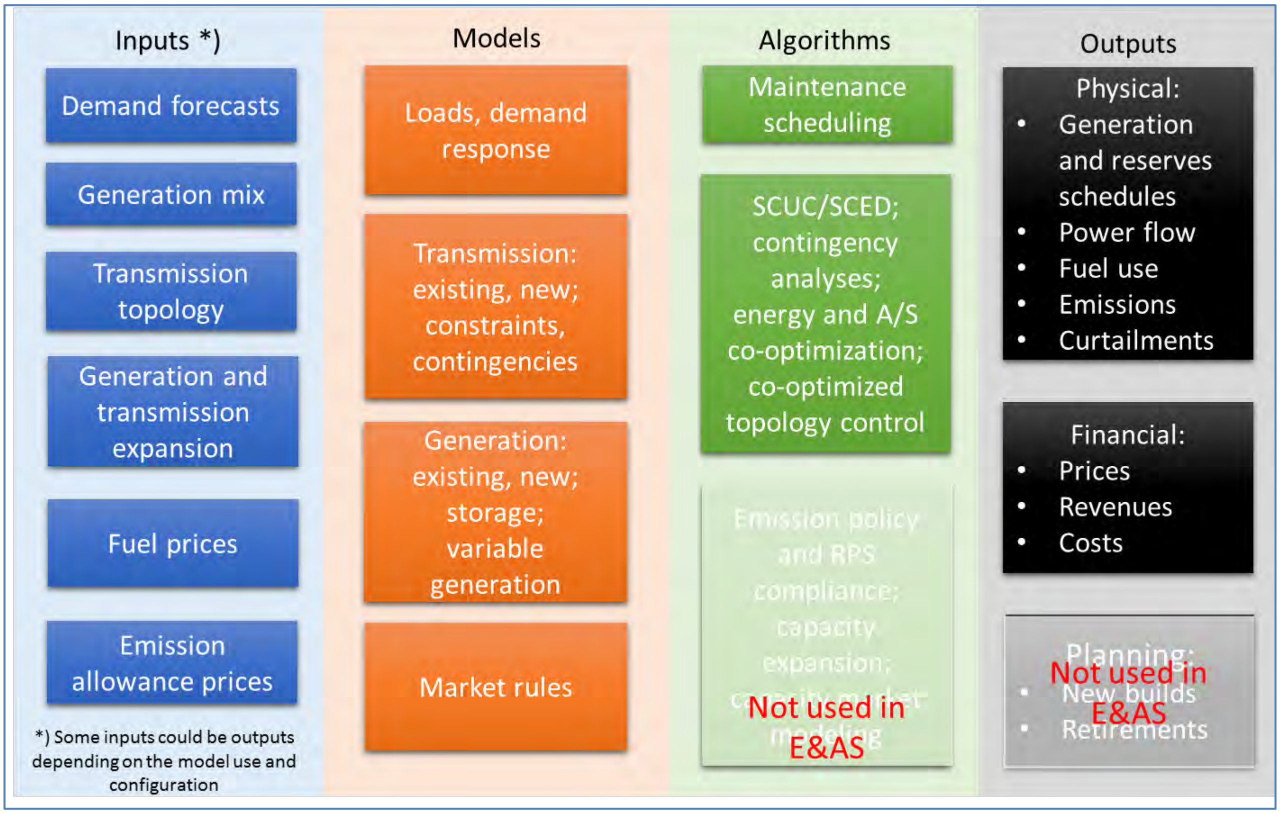

Figure 4. Schematic of the E&AS Module

CHAPTER 3: Transmission

The geographic footprint modeled by ENELYTIX encompasses the six New England states: Maine, Massachusetts, New Hampshire, Vermont, Rhode Island, and Connecticut, whose electricity movement and wholesale markets are coordinated by ISO-NE. In addition, the model of the E&AS markets incorporates a detailed representation of the NYISO system.[8]

The physical location of all network resources is organized using substation and node mapping. The transmission topology and electric characteristics of transmission facilities for ISO-NE is modeled on the 2020 SUMMER Peak case obtained by EDCs from ISO-NE which is combined with the representation of the NYISO system obtained from the 2017 MMWG power flow case. TCR personnel formatted power flow information to make it usable by ENELYTIX. TCR mapped New England generators and load areas to bus bars and electrical nodes (eNodes) associated with bus bars according to specifications provided by ISO-NE. Mapping of NYISO and generators and loads was provided by Newton Energy Group, ENELYTIX vendor.

ENELYTIX model organizes physical location of all network resources and loads using bus bars and node mapping. Generators and mapped to bus bars / electrical nodes (eNodes). Bus bars are mapped to NYISO zones and to specific areas outside NYISO system. The mapping of load nodes to NYISO zones and areas outside NYISO is used by ENELYTIX to allocate area load forecast to individual buses in proportion to bus specific loads in the power flow case.

TCR monitored all transmission constraints that was included in evaluation of MA 83D and 83C_I RFPs. In developing this list of transmission constraints, TCR included the following information

1. all major ISO New England interfaces and frequently binding constraints assembled by EDCs using historical data from 2012 through June 23, 2017
2. additional constraint contingency pairs from TCR's contingency analysis
3. Interface definitions and operating limits provided electronically by ISO-NE. TCR verified these interface limits against the ISO_NE's Planning Transfer Capability Report (2015-16 assessment)

In addition to the list of constraints that was monitored in MA 83D and 83C_I proposal evaluation, TCR also included the following contingency and constraints:

1. Contingency and constraint pairs associated with 83C_I selected proposal.
2. Additional constraints provided by the EDCs to reflect transmission updates and other RFPs in ISO-NE.

8 Transmission topology and operating limits represent Critical Energy Infrastructure Information (CEII). No CEII data is included in this document.

CHAPTER 4: Interchange

ENELYTIX models New England interchanges with neighboring regions as follows:

- NYISO interchanges, hourly economic dispatch
  - Cross Sound Cable HVDC interconnection with NYISO
  - Roseton AC interface with NYSIO
- Quebec interchanges, hourly schedules from 2012 because the values that year are representative of the 2014 to 2018 levels
  - Phases I and II Interface with Hydro Quebec via HVDC
  - Highgate interface with Hydro Quebec via HVDC
- New Brunswick interface at Keswig external node, hourly schedule from 2018

In all instances TCR calendar shifts the interchange flow data for each forecast year to assure that the flow levels remain synchronized with the load pattern in ISO New England.

Table 2 Scheduled Net Interchange Summary

	Total MWh	Average MW	Max MW	Min MW
NYISO-ISONE interchange	N/A	N/A	N/A	N/A
HQ (P1&P2) to ISO-NE	6,244,838	1,325	1,845	0
HQ (Highgate) to ISO-NE	800,033	85	226	0
NB to ISO-NE	2,155,245	230	988	0

CHAPTER 5: Load Forecast

This chapter describes the method TCR uses to develop the forecasts of annual energy and peak load which are inputs to ENELYTIX. These are forecasts of energy and peak load before ("Gross") and after the impacts of reductions due to passive demand response (PDR), i.e. forecasts of Gross and of Gross-PDR. ENELYTIX uses the Gross – PDR forecasts to represent annual energy and peak load requirements over the planning horizon.

The chapter also describes the method used to develop forecasts of annual energy net of the impacts of reductions from behind the meter PV (BTM PV or BMPV). These forecasts, known as the Net Energy Load (NEL) or 'Gross-PV-PDR', are used to represent the annual energy requirements of retail customers over the planning horizon.

Finally, this chapter describes the method TCR uses to develop the hourly shape of the Gross-PDR energy forecast.

TCR develops the Base Case load forecast through 2027 from the 2018 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report), the most recent ISO-NE forecast, extrapolating the values for 2028-2045.

5.1: Forecasts of Gross-PDR Annual Energy and Peak Load, 2021 – 2045

TCR develops the Gross – PDR load forecasts through 2027 from the 2018 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report). TCR develops forecasts for 2028 through 2045 using separate extrapolations for the Gross and PDR components.

5.1.1: 2018 CELT Forecast for 2021 - 2027

The 2018 CELT report provides forecasts of Gross, Gross-PDR and Gross-PV-PDR for annual energy and peak load through 2028. These forecasts are reported for the system level and are determined as generation plus imports minus exports minus pumping for pumped storage.

Table 3 and Table 4 summarize the ISO-NE forecasts of annual energy and peak load by ISO-NE load zone for 2021 through 2027 from the 2018 ISO New England CELT Report. These are forecasts of energy and peak requirements net of the impacts of reductions due to past, present and future energy efficiency measures, referred to as PDR. ISO-NE labels these forecasts "Gross-PDR," and TCR uses them in the RI RFP Base Case to represent the energy and peak load requirements.

The forecasts are coincidental "50/50" forecasts. Coincidental forecast reflects the zonal peak at the time ISO-NE system reaches peak demand instead of the true zonal peak. The 50/50 forecasts represent the median value of the distribution of demand based on different weather scenarios.

The forecasts are taken from tabs 2A and through 2B of the ISO New England CELT 2018 Forecast data file (2018 CELT), the most recent CELT Report. TCR makes slight adjustments to the outer years of the PDR energy and peak in order to align them with the long-term forecasts obtained from the most recent version of the EIA Annual Energy Outlook (AEO 2018).

Table 3. Gross-PDR Annual Energy Forecast Summary by ISO-NE Area (GWh)

Zone	2021	2022	2023	2024	2025	2026	2027
CT	30,525	30,416	30,340	30,251	30,169	30,122	30,101
ME	12,031	12,088	12,169	12,238	12,304	12,380	12,465
MA	58,614	58,115	57,756	57,437	57,183	57,058	57,034
SEMA*	15,998	15,863	15,765	15,677	15,607	15,570	15,563
WCMA*	16,621	16,476	16,372	16,279	16,205	16,169	16,160
NMABO*	25,996	25,776	25,619	25,481	25,371	25,319	25,312
NH	12,115	12,144	12,183	12,210	12,230	12,264	12,304
RI	7,695	7,553	7,427	7,313	7,219	7,150	7,104
VT	6,201	6,150	6,105	6,062	6,023	5,993	5,974
ISO-NE	**127,179**	**126,468**	**125,981**	**125,511**	**125,129**	**124,968**	**124,981**

Table 4. Gross-PDR Coincident Summer Peak Load Forecast Summary by ISO-NE Area (MW)

Zone	2021	2022	2023	2024	2025	2026	2027
CT	6,818	6,804	6,795	6,787	6,783	6,784	6,789
ME	1,975	1,974	1,976	1,977	1,978	1,981	1,985
MA	12,648	12,603	12,577	12,563	12,564	12,582	12,617
SEMA*	3,494	3,484	3,479	3,477	3,479	3,485	3,497
WCMA*	3,564	3,553	3,547	3,545	3,547	3,554	3,564
NMABO*	5,590	5,567	5,552	5,543	5,540	5,545	5,557
NH	2,441	2,450	2,461	2,470	2,479	2,490	2,502
RI	1,878	1,871	1,866	1,863	1,863	1,866	1,871
VT	1,008	1,001	995	991	986	983	981
ISO-NE	**26,769**	**26,704**	**26,668**	**26,651**	**26,655**	**26,687**	**26,745**

* Note – Energy and peak loads for MA are aggregate of values for SEMA, WCMA and NMABO zones.

5.1.2: TCR Forecast of annual energy and peak load, 2028 - 2045

TCR develops forecasts for 2028 to 2045 by making separate projections of New England gross demand and PDR and then subtracting the PDR projections from the gross demand projection to obtain the Gross-PDR forecasts.

Gross Peak and Energy: TCR assumes linear growth for gross peak and energy for ISO-NE control area and load zones. To develop the forecast, TCR used the five-year compound growth rate (CAGR) from CELT's 2022-2027 forecast and applied the CAGR to 2027 CELT forecast.

PDR Peak Contribution and Energy: TCR calculates the growth in PDR as the difference between the Gross energy for ISO-NE projection and the long-term projection for NEL obtained from AEO 2018, less the projected growth of PV to obtain the forecasted PDR energy. TCR then uses a curve fit extrapolation of the % peak contribution obtained from CELT's 2021-2027 forecast to obtain the PDR contribution to peak. Table 5 summarizes the projected growth in PDR MW and GWh

Table 5. TCR Forecast of Gross Annual Energy and PDR capacity

ISO-NE	2028	2030	2035	2040	2045
PDR (MW)	4,656	5,004	6,080	7,182	8,180
PDR Energy (GWh)	30,529	33,437	40,658	47,572	54,698

Table 6 and Table 7 report the resulting projections of Gross-PDR annual energy and peak load by state by year. Figure 5 and Figure 6 plot the resulting projections of Gross-PDR annual energy and peak load by state by year.

Table 6. Gross - PDR Annual Energy Forecast summary by state (GWh)

State	2028	2029	2030	2031	2032	2033	2034	2035	2036
CT	30,168	30,218	30,164	30,129	30,120	30,128	30,171	30,214	30,258
ME	12,480	12,488	12,453	12,427	12,413	12,406	12,415	12,425	12,436
MA	57,153	57,238	57,126	57,052	57,026	57,033	57,108	57,185	57,262
NH	12,322	12,332	12,299	12,275	12,262	12,258	12,268	12,279	12,291
RI	7,118	7,129	7,114	7,105	7,101	7,102	7,111	7,120	7,129
VT	5,998	6,018	6,018	6,021	6,028	6,038	6,053	6,069	6,084
ISO-NE	**125,238**	**125,422**	**125,173**	**125,008**	**124,949**	**124,963**	**125,125**	**125,291**	**125,458**
State	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
CT	30,302	30,350	30,392	30,414	30,452	30,501	30,549	30,586	30,644
ME	12,447	12,460	12,471	12,473	12,483	12,498	12,513	12,523	12,542
MA	57,339	57,425	57,501	57,537	57,605	57,694	57,781	57,847	57,953
NH	12,303	12,317	12,329	12,332	12,343	12,358	12,374	12,384	12,404
RI	7,139	7,149	7,159	7,163	7,171	7,182	7,193	7,201	7,214
VT	6,098	6,113	6,127	6,137	6,149	6,164	6,178	6,189	6,205
ISO-NE	**125,626**	**125,813**	**125,978**	**126,055**	**126,202**	**126,396**	**126,587**	**126,729**	**126,961**

Table 7. Gross - PDR Annual Peak Forecast summary by ISO-NE states (MW)

State	2028	2029	2030	2031	2032	2033	2034	2035	2036
CT	6,798	6,838	6,836	6,837	6,824	6,852	6,869	6,886	6,884
ME	1,988	2,000	1,999	1,999	1,996	2,004	2,009	2,014	2,013
MA	12,634	12,709	12,704	12,706	12,682	12,735	12,767	12,798	12,794
NH	2,506	2,521	2,520	2,520	2,515	2,526	2,532	2,538	2,538
RI	1,874	1,885	1,884	1,885	1,881	1,889	1,894	1,898	1,898
VT	983	988	988	988	986	990	993	995	995
ISO-NE	**26,782**	**26,941**	**26,930**	**26,934**	**26,884**	**26,995**	**27,063**	**27,130**	**27,121**
State	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
CT	6,919	6,936	6,952	6,943	6,976	6,993	7,009	7,003	7,040
ME	2,024	2,029	2,033	2,031	2,040	2,045	2,050	2,048	2,059
MA	12,859	12,891	12,920	12,904	12,965	12,996	13,026	13,015	13,084
NH	2,551	2,557	2,563	2,559	2,572	2,578	2,584	2,581	2,595
RI	1,907	1,912	1,916	1,914	1,923	1,928	1,932	1,930	1,941
VT	1,000	1,003	1,005	1,004	1,008	1,011	1,013	1,012	1,018
ISO-NE	**27,259**	**27,326**	**27,388**	**27,354**	**27,484**	**27,549**	**27,612**	**27,588**	**27,735**

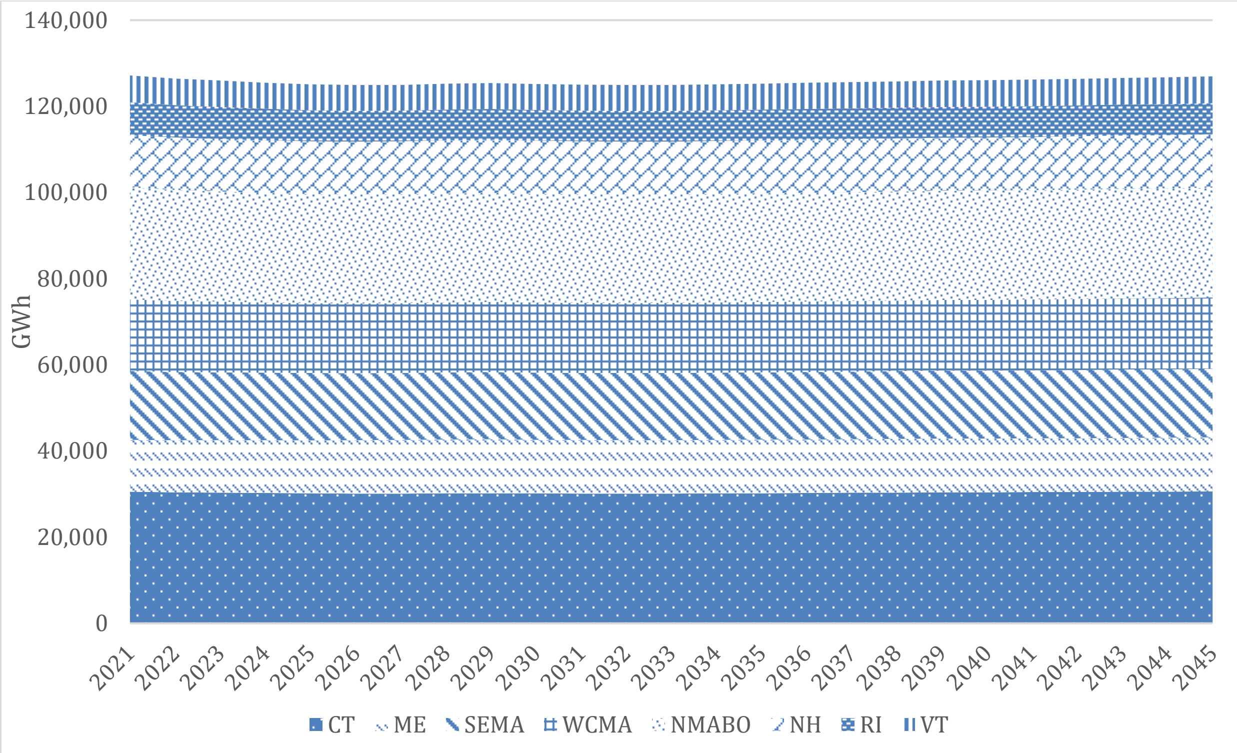

Figure 5: TCR forecast Gross - PDR Annual Energy by zone (GWh)

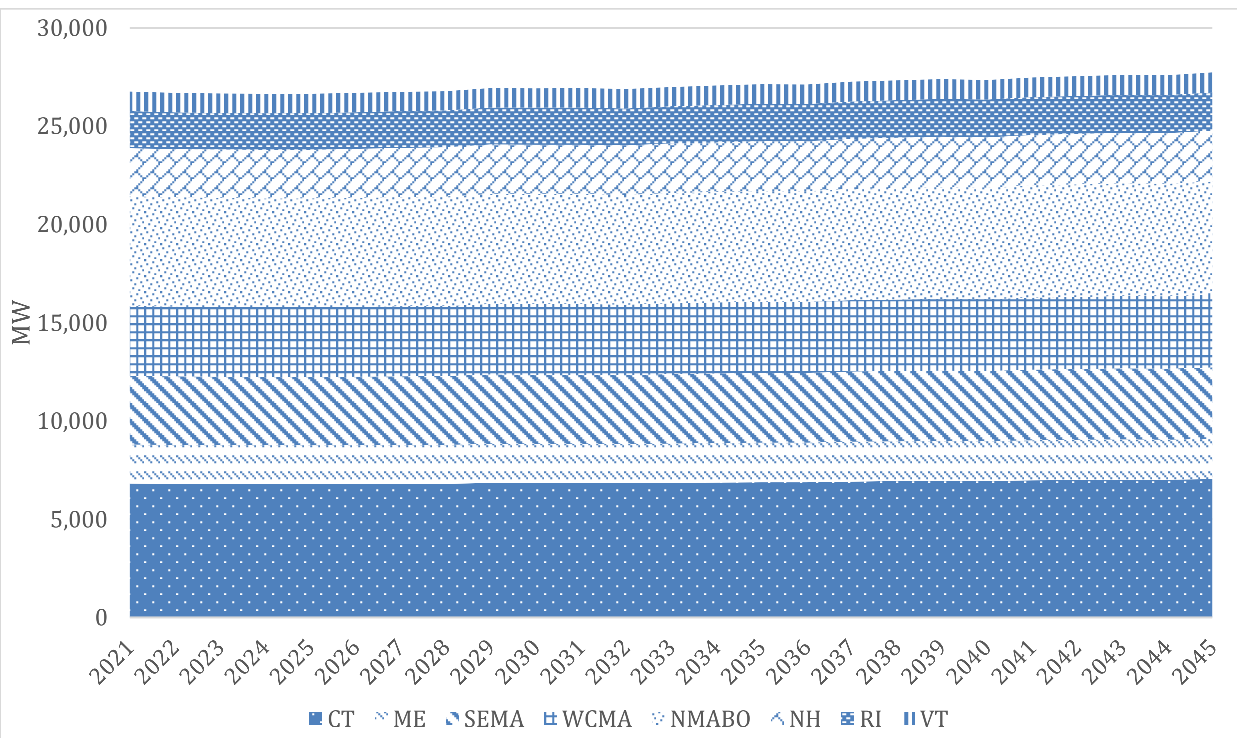

Figure 6: TCR Gross - PDR Peak Forecast by zone (GW)

5.2: Forecasts of NEL (Gross – PV – PDR) Annual Energy, 2021 - 2045

TCR developed a forecast of energy requirements net of the impacts of reductions from behind the meter PV (BTM PV or BMPV). This forecast, which corresponds to the obligation for retail metered load, is referred to as Net Energy for Load (NEL) and as "Gross-PV-PDR."

TCR developed this forecast in order to estimate annual state RPS obligations and the MA CES obligations to use as inputs to ENELYTIX. This forecast is required to calculate those obligations because state regulations specify these obligations as a fraction of metered retail sales measured at the system level, i.e., including transmission and distribution losses. Chapter 8 describes the calculation of, and reports, those RPS and CES requirements.

TCR developed the Gross – PV - PDR forecasts through 2027 from the 2018 CELT Report. It adopted the forecasts for 2028 through 2045 based on the AEO 2018 long term NEL forecast. The PV energy component for 2028 through 2045 was developed based on the ISO-NE 2018 PV Forecast[9].

5.3: Hourly Load Shape

In order to simulate the ISO New England market on an hourly basis, TCR requires an hourly load shape for each simulated time frame and area modeled. Figure 7 plots the load shapes TCR constructed for each area from the following data:

- 2012 historical load shapes by ISO-NE load zone.[10] ENELYTIX uses 2012 load profiles to be consistent with calendar 2012 NREL wind generation profiles, the most recent detailed data available from NREL for New England.
- Annual energy and summer/winter peak forecasts for the study period

To develop hourly load forecasts for future years, ENELYTIX load algorithms first calendar shifts the template load profile to align days of the week and NERC holidays from 2012 to the forecast year. The ENELYTIX algorithm then modifies the calendar shifted template profiles in such a manner that the resulting load shape exhibits the hourly pattern close to that of the template profile while the total energy for the year matches the energy forecast and summer and winter peaks matches the summer and winter peak forecast.

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9 https://www.iso-ne.com/static-assets/documents/2018/03/a03-2018-pv-forecast.pdf

10 2012 SMD Hourly Data, ISO-NE < https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info>

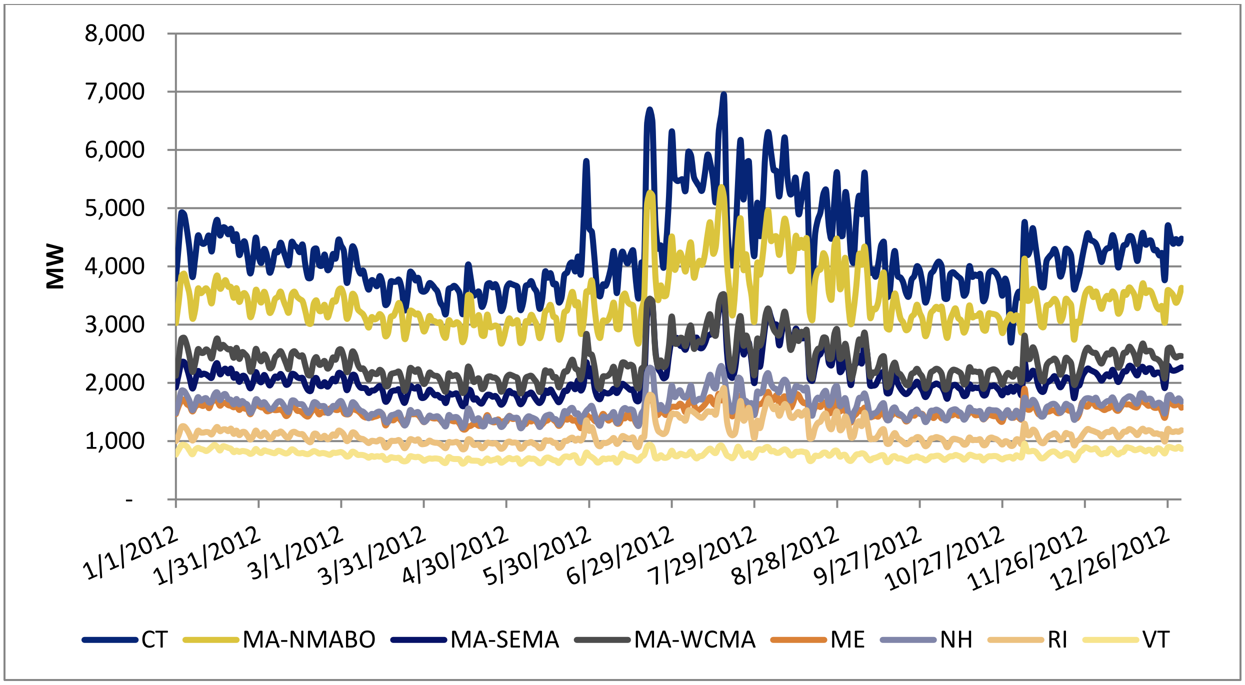

Figure 7: ISO Historical Load Shape, 2012

CHAPTER 6: Ancillary Services

ENELYTIX models four types of Ancillary Services in New England: Regulation, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve. Reserves are cascading – excess regulation counts toward spinning reserves. Excess spinning reserves counts toward Non-spinning. Spinning reserve requirements are considered bi-directional. Non-Spinning reserves can be provided by offline peaking capacity and can handle upward ramping only.

- Regulation must be provided by online resources at the level of ramp rate (in MW/min) limited by a 5-minute activation time.
- Ten-Minute Spinning Reserve (TMSR) must be provided by online resources at the level of ramp rate (MW/min) limited by a 10-minute activation time. Hydro can provide Synchronized reserve up to 50% of its dispatch range.
- Ten-Minute Non-Spinning Reserve (TMNSR) is provided by offline resources capable of supplying energy within 10 minutes of notices. TMNSR can only be provided by quick start capable CTs and Internal Combustion (IC) units.
- Thirty-Minute Operating Reserve (TMOR) can be provided by either on-line or off-line resources with less than 30 minutes activation time.

Table 8 summarizes reserve requirements in ISO-NE.

Table 8. ISO-NE Regulation and Reserve Requirements

Reserve Type	Requirement (MW)
Regulation	Hourly schedule per ISO-NE requirements
Ten min spinning reserves	820
Ten min non-spinning reserves	820
Thirty min operating reserves	750

Hydro generators are assumed to provide regulation and reserves for up to 50% of available dispatch range. Nuclear and wind provide no ancillary services.

CHAPTER 7: Installed Capacity Requirement (ICR)

7.1: System-wide Installed Capacity Requirement (ICR)

Table 9 summarizes TCR's proposed projections. The TCR projections are based on the analyses described earlier in Chapter 5. PDR resources are modeled as price takers.

Table 9. Projection of System-Wide ICR

	FCA 10	FCA 11	FCA 12	TCR Projection					
Power Year	2019/20	2020/21	2021/22	2023/24	2024/25	2029/30	2034/35	2039/40	2044/45
Gross Peak (MW)	30,582	30,391	30,287	29,994	30,245	30,486	31,684	32,950	34,266
Gross ICR (ICR + Tie Benefits)	36,862	36,815	36,596	36,377	36,681	36,974	38,427	39,962	41,558
Gross Margin	120.5%	121.1%	120.8%	121.3%	121.3%	121.3%	121.3%	121.3%	121.3%
Peak Net of PV (MW)	29,861	29,601	29,436	29,093	29,300	29,506	30,597	31,794	33,060
ICR (MW)	35,126	35,034	34,683	34,413	34,675	34,931	36,278	37,744	39,290
Margin	17.60%	18.40%	17.80%	18.30%	18.30%	18.40%	18.60%	18.70%	18.80%
HQICCs (MW)	975	959	958	958	958	958	958	958	958
Net ICR (MW)	34,151	34,075	33,725	33,455	33,717	33,973	35,320	36,786	38,332
PDR (MW)	2,369	2,791	2,975	3,290	3,577	3,835	4,744	5,887	6,878
ADR, Imports and PDR adjustment (MW)	1,768	1,798	1,962	1,962	1,962	1,962	1,962	1,962	1,962
Net ICR less PDR, ADR & Imports (MW)	**30,014**	**29,486**	**28,787**	**28,203**	**28,177**	**28,176**	**28,614**	**28,937**	**29,491**

Starting with the data provided in the three most recent ICR studies, TCR estimates implied reserve margin requirements – the difference between ICR and projected summer peak demand divided by the net (gross-PV) peak demand. A simple average of these margins is 21.3 %. TCR assumes that this margin will persist into the future and used this assumption to develop the future ICR projection.

TCR assumes that the future import capacity from Hydro Quebec will remain at the 2021/22 level of 958 MW estimated by ISO-NE. This assumption reflects the annual capacity typically available from the existing supply agreement with Hydro Quebec.

Finally, TCR assumes external control areas and Active Demand Response (ADR) resources within New-England will provide an additional 1,962 MW. These assumptions are based upon the average quantities of capacity that cleared in ISO-NE Forward Capacity Auctions 10 through 12.

7.2: Local Sourcing Requirement (LSR) for Import Constrained Zones

Local Sourcing Requirements are minimum levels of installed capacity that must be procured within an import constrained zone. FCA 12 identified Southeast New England (SENE), consisting of NMABO, SEMA and RI, to be the only zone requiring LSR. Table 10 summarizes TCR's projection of Local Sourcing Requirements for SENE.

Table 10. Local Sourcing Requirements for Import Constrained Zones

	FCA 12	TCR Projection							
Power Year	2021 /22	2022 /23	2023 /24	2024 /25	2025 /26	2030 /31	2035 /36	2040 /41	2045 /46
NEMA/Boston	1,979	1,975	1,980	1,990	2,007	2,194	2,394	2,615	2,882
RI/SEMA	6,497	6,495	6,502	6,515	6,538	6,775	7,045	7,341	7,687
SENE	8,421	8,477	8,479	8,492	8,521	8,889	9,297	9,749	10,294
CT	6,172	5,702	5,690	5,686	5,685	5,694	5,657	5,625	5,628
CT+MA+RI	21,035	20,275	20,225	20,200	20,203	20,519	20,830	21,189	21,687
All but ME	25,299	24,591	24,540	24,518	24,520	24,848	25,151	25,507	26,020

Starting with the data provided in ISO-NE ICR studies available as of October 2018, TCR estimates implied reserve margin requirements for all import constrained zones. The implied reserve margin was computed as a difference between the sum of LSR and N-1 contingency import limit into the zone and the 90/10 peak demand in that zone divided by the 90/10 peak demand. 90/10 peak demand is the ISO New England estimated summer peak which is likely to occur under the 1 in 10 years most critical weather conditions.

For each zone, TCR computes a simple average using historical data from past FCAs in which that zone was evaluated by ISO-NE as potentially binding. TCR then assumed that the implied margin for each zone will remain constant in the future and used that estimate to derive future LSR values. The last two rows in Table 10 represent LSR projections for rest of pool zones, CT+MA+RI and "All but ME". TCR uses these to model export constrained zones of Northern New England and Maine, respectively, as discussed in Chapter 2.

7.3: Contribution of Resources toward ICR

For resources listed in ISO-NE CELT 2018 Generator List as well as scheduled new additions, TCR used the Summer Cleared Capacity based on the results of FCA 12. Units reporting dynamic de-list capacity were assumed to contribute the sum of their cleared capacity and their delist capacity.

For scheduled clean energy procurement additions that did not participate in FCA12, TCR assumed their ICAP contribution based on its analysis of similar clean energy procurement resources that have summer cleared capacities in FCA 12.

For model-built resources, TCR used the following assumptions to model their contribution to the ICR:

- Offshore wind: 20%. ISO-NE has used this value in various of its planning studies.
- Onshore wind: 10.8%. This value is the ratio of Summer Claimed Capability over nameplate capacity for wind units in the CELT generation list.
- Utility-scale and non-BTM distributed solar PV: 32%. This value is set in between the 2020 peak load contribution in CELT for BMPV (34%) and anticipated future reduction in that level due to the shift in the time of peak load occurrence caused by the addition of PVs.
- Conventional combined cycle (CC) gas turbine units and simple cycle gas turbine units (GT): 100%

CHAPTER 8: Renewable Portfolio Standard (RPS) Requirements

This Chapter describes the forecast requirement for Class 1 RPS resources over the study period.

As described in Chapter 2, TCR configures the ENELYTIX Capacity Expansion Module to model Class 1 RPS requirements and resources for all New England states except Vermont, which does not have a Class 1 RPS requirement equivalent to those of the other five states. Over the study time horizon, TCR expects negligible interaction between secondary tiers and the Class 1 REC markets; only Class 1 requirements are modeled, therefore, in order to project new Class 1 eligible renewable additions and Massachusetts Class 1 REC prices.[11]

With the exception of Vermont, the eligibility criteria for Class 1 RPS programs in each of the New England states have a great deal of overlap, and the resulting high level of "fungibility" of new resources' environmental attributes creates a linkage among the Class 1 REC markets of the other five states. This means that they must all be modeled to project REC prices in each.

Figure 8 illustrates the process TCR used to determine state-specific Class 1 RPS energy targets by year for each of the five states.

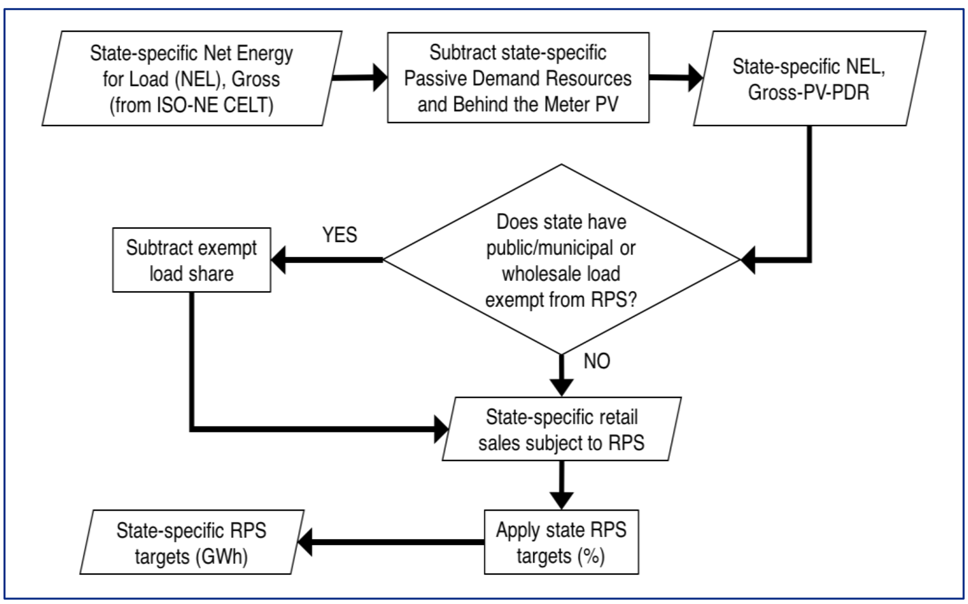

Figure 8. Process used to project state specific RPS energy targets

11 The New Hampshire Class II (solar) requirement (0.3 percent of RPS-obligated load) has been added to our Class 1 requirement, given that the distributed solar resources likely to count toward it are included in the distributed PV forecast represented in the model.

TCR projects RPS requirements using the following data:

- Projections of NEL from Chapter 5.
- Load share for load serving entities (LSEs) and certain wholesale load exempt from state RPS requirements.
- Annual RPS targets for each state[12], expressed as a percentage of sales to end-use customers for obligated (non-exempt) load-serving entities.

For a given state, the forecast requirement for Class 1 RPS energy is equal to the forecast load of load LSEs obligated to comply with the RPS multiplied by the annual Class 1 RPS percentage target. The forecast load of LSEs obligated to comply with each RPS is equal to the Gross-PV-PDR forecast of NEL by state, reduced by exempt load.

Table 11. Exemptions from RPS Obligations

State	Percentage of Load Exempt from RPS Requirements
CT	7.9%
MA*	17.4%
ME	2.2%
NH	1.7%
RI	2.5%
* MA Includes approximately 14% exempt retail and 3.4% exempt wholesale load.	

TCR derives the shares of NEL exempt from RPS obligations used in its calculation from state RPS compliance reports, ISO-NE historical NEL data, and EIA data. Table 12 provides a full listing of projected New England RPS requirements.[13]

12 TCR models state RPS targets per regulations as of October 15, 2018.

13 Sources: (a) 2019-2027: ISO-NE 2018 CELT and PV Forecast, reduced for PDR and BMPV. Post-2027 energy, PDR, and BMPV values based on TCR calculations. 2028-2045: TCR projection of Gross-PV-PDR energy load forecast (see Chapter 5); (b) Values based on RPS compliance reports, ISO-NE historical NEL data, and EIA data; (d) Massachusetts: MGL ch. 25A, Section 11F, as amended by Chapter 227 of the Acts of 2018, Section 12. (https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25A/Section11F, https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227) Connecticut: Connecticut Renewable Portfolio Standard, Connecticut Public Utilities Regulatory Authority. (https://www.ct.gov/pura/cwp/view.asp?a=3354&q=415186) Rhode Island: RES Obligation Targets, by Compliance Year, for Both New and Existing Resources, Rhode Island Public Utilities Commission, (http://www.ripuc.ri.gov/utilityinfo/RES-Annual-Targets.pdf.) New Hampshire: SB 129, enacted July 2017. (http://gencourt.state.nh.us/bill_status/billText.aspx?sy=2017&id=957&txtFormat=pdf&v=current.) Maine: Maine Renewable Portfolio Standard, Maine Public Utilities Commission. (https://www.maine.gov/mpuc/electricity/RPSMain.htm.)

Table 12. Projected RPS Requirements

(a) Net Energy for Load (NEL) Gross-PV-PDR Forecast (GWh)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	29,639	29,432	29,271	29,112	28,967	28,857	28,776	28,800	28,806	28,712	28,641	28,597
MA	57,058	56,425	55,932	55,477	55,113	54,910	54,812	54,858	54,870	54,691	54,555	54,472
ME	11,941	11,986	12,055	12,111	12,165	12,228	12,301	12,311	12,314	12,274	12,243	12,224
NH	11,980	11,994	12,018	12,030	12,037	12,055	12,081	12,091	12,094	12,055	12,025	12,006
RI	7,563	7,399	7,250	7,113	6,998	6,908	6,840	6,845	6,847	6,825	6,808	6,797
(b) RPS-exempt load as a proportion of NEL												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
MA	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%
ME	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	27,295	27,105	26,956	26,810	26,676	26,575	26,500	26,522	26,528	26,442	26,376	26,336
MA	47,143	46,620	46,212	45,837	45,536	45,368	45,287	45,325	45,335	45,188	45,075	45,006
ME	11,677	11,721	11,788	11,843	11,896	11,958	12,029	12,039	12,041	12,002	11,972	11,954
NH	11,780	11,794	11,818	11,830	11,836	11,854	11,880	11,890	11,893	11,854	11,824	11,806
RI	7,374	7,214	7,069	6,936	6,823	6,735	6,669	6,674	6,676	6,654	6,637	6,627
(d) Class 1 RPS Requirements (%) *												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	22.5%	24.0%	26.0%	28.0%	30.0%	32.0%	34.0%	36.0%	38.0%	40.0%	40.0%	40.0%
MA	18.0%	20.0%	22.0%	24.0%	26.0%	28.0%	30.0%	32.0%	34.0%	35.0%	36.0%	37.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	12.1%	13.0%	13.9%	14.8%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
RI	15.5%	17.0%	18.5%	20.0%	21.5%	23.0%	24.5%	26.0%	27.5%	29.0%	30.5%	32.0%
(e) Class 1 RPS Requirements (GWh) = (c) x (d)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	6,141	6,505	7,009	7,507	8,003	8,504	9,010	9,548	10,081	10,577	10,550	10,534
MA	8,486	9,324	10,167	11,001	11,839	12,703	13,586	14,504	15,414	15,816	16,227	16,652
ME	1,168	1,172	1,179	1,184	1,190	1,196	1,203	1,204	1,204	1,200	1,197	1,195
NH	1,425	1,533	1,643	1,751	1,858	1,861	1,865	1,867	1,867	1,861	1,856	1,854
RI	1,143	1,226	1,308	1,387	1,467	1,549	1,634	1,735	1,836	1,930	2,024	2,121

* NH Requirement includes Class II solar (0.7%)

Table 12. Projected RPS Requirements (cont.)

(a) Net Energy for Load (NEL) Gross-PV-PDR Forecast (GWh)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	28,573	28,586	28,600	28,617	28,635	28,659	28,679	28,678	28,695	28,724	28,752	28,770
MA	54,425	54,450	54,478	54,510	54,545	54,590	54,627	54,625	54,658	54,713	54,767	54,801
ME	12,214	12,219	12,226	12,233	12,241	12,251	12,259	12,259	12,266	12,278	12,291	12,298
NH	11,996	12,001	12,008	12,015	12,022	12,032	12,041	12,040	12,047	12,060	12,072	12,079
RI	6,791	6,794	6,798	6,802	6,806	6,812	6,817	6,816	6,820	6,827	6,834	6,838
(b) RPS-exempt load as a proportion of NEL												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%	7.9%
MA	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%	17.4%
ME	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%	2.2%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	26,313	26,325	26,339	26,354	26,371	26,393	26,411	26,410	26,426	26,452	26,479	26,495
MA	44,968	44,988	45,011	45,038	45,066	45,104	45,134	45,133	45,160	45,205	45,250	45,278
ME	11,944	11,949	11,955	11,962	11,970	11,980	11,988	11,988	11,995	12,007	12,019	12,026
NH	11,796	11,801	11,808	11,814	11,822	11,832	11,840	11,840	11,847	11,858	11,870	11,878
RI	6,622	6,625	6,628	6,632	6,636	6,642	6,646	6,646	6,650	6,657	6,663	6,667
(d) Class 1 RPS Requirements (%) *												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
MA	38.0%	39.0%	40.0%	41.0%	42.0%	43.0%	44.0%	45.0%	46.0%	47.0%	48.0%	49.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%	15.7%
RI	33.5%	35.0%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%
(e) Class 1 RPS Requirements (GWh) = (c) x (d)												
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CT	10,525	10,530	10,536	10,542	10,548	10,557	10,564	10,564	10,570	10,581	10,591	10,598
MA	17,088	17,545	18,005	18,465	18,928	19,395	19,859	20,310	20,774	21,247	21,720	22,186
ME	1,194	1,195	1,196	1,196	1,197	1,198	1,199	1,199	1,199	1,201	1,202	1,203
NH	1,852	1,853	1,854	1,855	1,856	1,858	1,859	1,859	1,860	1,862	1,864	1,865
RI	2,218	2,319	2,419	2,421	2,422	2,424	2,426	2,426	2,427	2,430	2,432	2,434

* NH Requirement includes Class II solar (0.7%)

CHAPTER 9: Massachusetts Carbon Emission Regulations and Clean Energy Standard

The 2018 RI RFP Base Case uses the two regulations affecting the Massachusetts electric sector promulgated on August 11, 2017 which are modeled under the 2018 RI RFP Base Case as they impact capacity planning within the ISO-NE footprint. These are regulation 310 CMR 7.74, a cap on carbon emissions from EGUs located in MA, and regulation 310 CMR 7.75, the CES.

9.1: Cap on carbon emissions, regulation 310 CMR 7.74

The regulation imposes an annual physical cap on CO_2 emissions from EGUs located in the Commonwealth. EGUs are classed as either "New Facilities" or "Existing Facilities", with separate specific caps on aggregate emissions applicable to EGUs in each category, plus an aggregate cap on emissions from all EGUs (i.e., aggregate cap). Individual EGUs are allowed to use "over-compliance credits" in order to comply with their unit specific limits. Table 13 presents the limits for new and existing EGUs for select years. The sum of these is the aggregate limit.[14]

Table 13: Aggregate Limits in Select Years, 2022-2040

Year	Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2021	8,435,192	6,935,192	1,500,000
2022	8,207,213	6,707,213	1,500,000
2023	7,979,235	6,479,235	1,500,000
2024	7,751,257	6,251,257	1,500,000
2025	7,523,279	6,023,279	1,500,000
2026	7,295,301	6,095,301	1,200,000
2027	7,067,323	5,904,823	1,162,500
2028	6,839,345	5,714,345	1,125,000

14 Massachusetts Department of Environmental Protection, "BACKGROUND DOCUMENT ON PROPOSED NEW AND AMENDED REGULATIONS: 310 CMR 7.00 and 310 CMR 60.00 Air Pollution Control for Stationary and Mobile Sources," December 16, 2016. Table 13is reproduced from Table 3 in this report.

Year	Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2029	6,611,366	5,523,866	1,087,500
2030	6,383,388	5,333,388	1,050,000
. . .	(- 2.5% of 2018 /yr)		
2040	4,103,607	3,428,607	675,000
. . .	(- 2.5% of 2018 /yr)		

The rule defines *New Facilities* as EGUs located in Massachusetts that have less than 10 years operational history as well as those that are scheduled for commissioning during the 2018 – 2025 time period. The only significant new EGU subject to the New Facility Cap is the Salem Harbor unit, which came into service in 2017.

Table 14 lists the *Existing facilities* that are subject to the Existing Facility cap according to Table 4 in the DEP December document.[15]

Table 14: Facility Limits as % of total Cap

Facility Name	2013-2015 Average Generation (MWh)	% of Total Generation
ANP Bellingham Energy Company, LLC	2,238,927	12%
ANP Blackstone Energy Company, LLC	2,049,400	11%
Bellingham	507,609	3%
Berkshire Power	1,137,483	6%
Canal Station	265,266	1%
Cleary Flood	131,311	1%
Dartmouth Power	125,833	1%
Deer Island Treatment	2,584	0%
Dighton	859,904	4%
Fore River Energy Center	3,236,599	17%
Kendall Square	1,219,559	6%

15 Ibid, p. 39.

Facility Name	2013-2015 Average Generation (MWh)	% of Total Generation
MASSPOWER	791,485	4%
Medway Station	4,172	0%
Milford Power, LLC	387,564	2%
Millennium Power Partners	1,723,289	9%
Mystic	3,945,784	21%
Pittsfield Generating	208,106	1%
Potter (Braintree Electric)	63,569	0%
Stony Brook	179,176	1%
Tanner Street Generation	95,400	0%
Waters River	4,131	0%
West Springfield	39,933	0%

9.2: Clean Energy Standard, regulation 310 CMR 7.75

The regulation requires retail electricity sellers, excluding Municipal Light Plants (MLPs), to procure CECs or pay the CES ACP. The affected retail electricity sellers are investor-owned distribution companies providing standard offer service and competitive energy suppliers. CECs, referred to as "clean energy attributes", are expressed in megawatt hours (MWh). The quantity of CECs sellers are required to acquire each year (the "standard") is a specified percentage of their electricity sales, expressed in MWh

Table 15 presents our forecast of CES requirements over the study period. This forecast is based on the NEL (Gross-PV-PDR) from Chapter 5 and an assumption that the annual net energy load of MLPs remains at 14%, its level in 2017, over the study period.[16]

9.2.1: Compliance

Retail electricity sellers are allowed to comply with the CES by acquiring RPS Class 1 RECs, by acquiring CECs from DEP-approved new clean energy generation from non-RPS eligible technologies built after 2010, or by paying an ACP. By statute, the CES ACP is set 75% of the Massachusetts Class 1 ACP for 2018-2020 and 50% of the Class 1 ACP thereafter. The rule contains provisions specifying geographic eligibility and banking of CECs. Imports of new clean energy generation from Canada are imported through transmission capacity that comes online after 2017.

16 TCR calculation from data in Figure 2, Mass DEP GHG Reporting Program Summary Report For Retail Sellers of Electricity Emissions Year 2012, DEP, April 2015

In the RI RFP Base Case, compliance with the CES is not enforced as a constraint in the Capacity Expansion optimization. The annual cost of compliance, however, is quantified in a post-modeling calculation as the product of any shortfall in meeting a given year's target and the CES ACP for that year.[17]

17 More precisely, the ACP is modeled in the 83C II Base Case as a soft constraint with a very small cost of $0.01/MWh, so that compliance with the CES can be easily tracked, and the cost accounted for afterward.

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Table 15. CES requirements, 2021 to 2045

Requirements, %		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MA Class 1 RPS & CES Requirements - % of Applicable Load														
MA Class 1 RPS		16.0%	17.0%	18.0%	19.0%	20.0%	21.0%	22.0%	23.0%	24.0%	25.0%	26.0%	27.0%	28.0%
CES		22.0%	24.0%	26.0%	28.0%	30.0%	32.0%	34.0%	36.0%	38.0%	40.0%	42.0%	44.0%	46.0%
CES incr to Class 1 RPS		6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%	16.0%	17.0%	18.0%
CES applicable to MLP Load		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Requirements, GWh														
MA Load per ISO NE CELT 2018, GROSS-PV-PDR	GWh	56,008	55,308	54,757	54,351	54,094	53,968	53,594	53,357	53,271	53,170	53,109	53,024	53,105
wholesale load exempt from CES	%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%
wholesale load exempt from CES	GWh	1,891	1,868	1,849	1,835	1,827	1,823	1,810	1,802	1,799	1,796	1,794	1,791	1,793
MLP load	%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
MLP load	GWh	7,841	7,743	7,666	7,609	7,573	7,555	7,503	7,470	7,458	7,444	7,435	7,423	7,435
non-MLP load subject to CES	GWh	46,275	45,697	45,242	44,906	44,694	44,590	44,281	44,085	44,014	43,931	43,880	43,810	43,877
CES Requirements, non-MLP	GWh	**10,181**	**10,967**	**11,763**	**12,574**	**13,408**	**14,269**	**15,055**	**15,871**	**16,725**	**17,572**	**18,430**	**19,276**	**20,184**
Requirements, %		**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	
MA Class 1 RPS & CES Requirements - % of Applicable Load														
MA Class 1 RPS		29.0%	30.0%	31.0%	32.0%	33.0%	34.0%	35.0%	36.0%	37.0%	38.0%	39.0%	40.0%	
CES		48.0%	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%	62.0%	64.0%	66.0%	68.0%	70.0%	
Draft CES incr to Class 1 RPS		19.0%	20.0%	21.0%	22.0%	23.0%	24.0%	25.0%	26.0%	27.0%	28.0%	29.0%	30.0%	
CES applicable to MLP Load		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Requirements, GWh														
MA Load per ISO NE CELT 2018, GROSS-PV-PDR	GWh	53,163	53,260	53,325	53,571	53,785	54,038	54,255	54,256	54,257	54,258	54,259	54,260	
wholesale load exempt from CES	%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	
wholesale load exempt from CES	GWh	1,795	1,799	1,801	1,809	1,816	1,825	1,832	1,832	1,832	1,832	1,832	1,832	
MLP load	%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	
MLP load	GWh	7,443	7,456	7,466	7,500	7,530	7,565	7,596	7,596	7,596	7,596	7,596	7,596	
non-MLP load subject to CES	GWh	43,925	44,005	44,059	44,262	44,439	44,648	44,827	44,828	44,829	44,830	44,830	44,831	
CES Requirements, non-MLP	GWh	**21,084**	**22,002**	**22,911**	**23,901**	**24,886**	**25,896**	**26,896**	**35,389**	**43,882**	**52,376**	**60,870**	**69,364**	

CHAPTER 10: Generating Unit Retirements

Table 16 summarizes the ISO-NE approved scheduled retirements. TCR obtains this list of retirements from S&P Global' s data services and cross verifies the retirements against the relevant ISO-NE Seasonal Claimed Capability reports for specific units to see which month ISO-NE turned off, or will turn off, the particular unit.[18]

Table 16. ISO-NE approved capacity retirements

Name	Energy Area	Generation/Fuel Type	Summer Capacity (MW)	Retire Date
Retirements Per ISO-NE retirement Tracker				
MYSTIC 7	NEMA	ST-OIL	559.77	6/1/2022
BUNKER RD #12 GAS TURB	SEMA	GT - OIL	3.01	6/1/2022
BUNKER RD #13 GAS TURB	SEMA	GT - OIL	3.28	6/1/2022
BRIDGEPORT HARBOR 3	CT	ST – COAL	384.98	6/1/2021
HIGHGATE FALLS	VT	HYD	7.75	6/1/2021
L Street Jet	NEMA	ST-OIL	21.77	6/1/2020
Retirement per NRC license expiration				
PILGRIM	SEMA	ST-NUC	677.3	6/1/2019
MILLSTONE POINT 2	CT	ST-NUC	856.52	7/1/2035
MILLSTONE POINT 3	CT	ST-NUC	1225	11/1/2045

Over the study period ENELYTIX analyzes the economics of existing thermal units to determine whether their projected revenues compared to their projected variable operating costs justifies retiring any of those units. The ENELYTIX capacity expansion optimization algorithm evaluates the trade-off between the need to keep the generating unit online to meet resource adequacy requirements against making an investment into another generating unit to satisfy environmental constraints and/or producing energy at lower operating cost. Table 17 presents our assumptions regarding fixed O&M costs of existing units which are a key input to this evaluation.

18 https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx

Table 17 Fixed O&M Requirements by Technology

Unit Type / Technology	FOM ($/kW-yr)	Source
Combined Cycle Gas Turbine	56.9	1
Gas Turbine (Aeroderivative)	65.3	1
Gas Turbine (Frame)	36.4	1
Coal Boiler	79.95	2
Gas/Oil Boiler	42.86	4
Nuclear*	109.3	2
Biomass	407.4	2
Hydro*	36.8	3
Solar Photovoltaic*	23.4	2
Wind Onshore*	61.0	2
Wind offshore*	83.8	2
Notes		
- All costs adjusted to 2018$		
- Regional costs adjusted to New England Region, as applicable		
*Units not considered for retirement		

Sources	
1. ISO NE	CEA ISO-NE CONE and ORTP Analysis (https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf)
2. EIA	EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 EIA- Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generating Plants, April 2017 EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013
3. NREL	NREL - 2016 Annual Technology Baseline, September 2016
4. EIPC	https://www.eipconline.com/uploads/MRN-NEEM_Modeling_assumptions_Draft_Jan_25_2011_Input_Tables_Exhibits.xls

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CHAPTER 11:
Generating Unit Capacity Additions

TCR uses the existing generating units listed in the ISO-NE 2018 CELT Report, tab 2.1, Generator list.[19]

11.1: Capacity additions in the ISO-NE interconnection queue

Table 18 summarizes projected near-term new generation additions drawn from the TCR database for this project. These are projects listed in ISO New England's interconnection queue as of October 15, 2018, which are either under construction or which have had major interconnection studies completed and have cleared the latest Forward Capacity Auction (FCA) completed as of October 2018.[20,21]

Table 18. Generation Capacity Additions

Name	Energy Area	Type	Summer Capacity (MW)	In effect / COD
Upgrades to existing units				
MILFORD POWER (UPGRADE)	SEMA	Natural Gas	202 (+53)	6/1/2020
J. COCKWELL 1 & 2 (UPGRADE)	WCMA	Pumped Storage	582.6 (+80)	6/1/2021
New additions per FCA 11 – 12 (excludes units procured under contract)				
WALLINGFORD ENERGY CENTER	CT	Natural Gas	90	5/4/2018
FOOTPRINT COMBINED CYCLE UNIT (SALEM HARBOR)	NMABO	Natural Gas	674	5/15/2018
MEDWAY PEAKER - SEMARI	SEMA	Fuel Oil	207.7	5/31/2018
SILVER LAKE PV	WCMA	PV	5	6/1/2018
BRIDGEPORT HARBOR 5	CT	Natural Gas	509.6	5/31/2019
CANAL3	SEMA	Natural Gas	333	5/31/2019
CPV TOWANTIC ENERGY CENTER	CT	Natural Gas	745	6/1/2018

19 https://www.iso-ne.com/system-planning/system-plans-studies/celt/?document-type=CELT%20Reports
20 https://irtt.iso-ne.com/reports/external
21 https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

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Name	Energy Area	Type	Summer Capacity (MW)	In effect / COD
ANTRIM WIND RESOURCE	NH	Wind	5	6/1/2019
BURRILLVILLE ENERGY CENTER 3 (CLEAR RIVER)	RI	Natural Gas	485	6/1/2019
HOLIDAY HILL COMMUNITY WIND	WCMA	Wind	5	6/1/2019
BRIDGEWATER	NH	Biomass	14.65	6/1/2019
MMWEC SIMPLE CYCLE GAS TURBINE	NMABO	Natural Gas	57.967	6/1/2020

11.2: Class 1 Renewable Energy Resource Additions

The ENELYTIX capacity expansion module determines the quantity of new Class 1 eligible renewable energy resources needed to satisfy Class 1 RPS requirements in each state each year.

The following discussion describes TCR's assumptions regarding distributed PV additions, assumed 83C generic resource additions, class 1 REC imports, near-term renewable additions, and generic market-driven additions.

11.2.1: Distributed PV Resources

Because distributed PV development is largely driven by policies other than the Class 1 RPS requirements—such as Solar Massachusetts Renewable Target ("SMART") and the Small Scale Renewable Energy Growth and Renewable Energy Fund programs in Rhode Island—TCR uses ISO-NE's Final 2018 PV Forecast to project distributed PV additions, rather than add them using the Capacity Expansion model in response to the market.[22] All distributed PV generation additions through 2027 in the ISO-NE PV Forecast are assumed in the Base Case to come to fruition. TCR forecast distributed PV for the remainder of the study horizon by extrapolating the ISO-NE PV Forecast using a curve fit.

The forecast breaks PV into two types—behind the meter, and non-BTM distributed PV. Non-BTM PV are allowed to provide energy and capacity, whereas BMPV can only provide energy. Non-BTM PV resources are assumed to provide a contribution to ICR at a level equal to 32 percent of their nameplate capacity. In representing the Massachusetts RPS rules in the Capacity Expansion module, TCR assumes that all distributed PV energy can count against or reduce the Class 1 RPS requirement.[23] TCR assumes distributed PV in Vermont counts toward the Vermont Distributed Generation (Tier 1)

22 ISO New England Final 2018 PV Forecast, March 19, 2018 ("ISO-NE PV Forecast"). The PV forecast includes detailed estimates of installations in each state, developed in conjunction with those states. The projected new entry is primarily policy-driven, but includes a post-policy component; both components embody explicit realization rates that vary over the period. In incorporating the PV forecast, TCR removed non-BTM PV installed and already existing through 2018, so as not to double-count these resources, already included as part of the CELT Generation List.

23 Reducing the requirement (as in the Solar Carve-outs) or being counted toward it (as in the SMART program) are effectively the same thing from a modeling perspective.

requirement (not represented in our model), and do not allow it to count toward Class 1 requirements elsewhere.

11.2.2: Class 1 REC Imports

Resources located outside ISO-NE provide RECs used to comply with Class 1 RPS obligations in each of the states. Imports of RECs are required to be coupled with energy import transactions. TCR assumes that RECs imported into ISO-NE to comply with Class 1 RPS requirements remain constant at their 2015 levels throughout the study time horizon. TCR estimates the 2015 level, based upon the most recent public data available from state RPS compliance reports and the NEPOOL GIS, to be 2,400 GWh, about 22.8% of the combined 2015 Class 1 requirements.

11.2.3: Near-Term Class 1 Renewable Resource Additions

Table 18 listed renewable additions in the ISO-NE interconnection queue having cleared the FCA. In addition to those projects, TCR assumes renewable generation projects selected under recent clean energy RFPs. Table 19 lists those projects. TCR assembled the data on each project based on inputs from the EDCs.

Table 19. Additions from New England Clean Energy RFP

Name	Location	Project Type	Nameplate Capacity (MW)	Online Date
New England Clean Energy RFP (2016/17)				
CANDLEWOOD	CT	PV	20	10/1/2018
DEEPWATER	CT	PV	26.4	12/1/2018
RES WOODS HILL	CT	PV	20	12/1/2020
RES HOPE-SCITUATE	RI	PV	20	12/1/2020
RANGER SANFORD	ME	PV	49.36	10/1/2019
RANGER CHINOOK	NH	PV	30	10/1/2019
RANGER FARMINGTON	ME	PV	49.36	10/1/2019
RANGER QUINEBAUG	CT	PV	49.36	10/1/2019
CT Small Scale Clean Energy RFP (2016/17)				
PAWCATUCK SOLAR CENTER	CT	PV	15	1/1/2020
SWANTOWN ROAD SOLAR	CT	PV	6	1/1/2018
LITCHFIELD SOLAR PLANT	CT	PV	19.8	1/1/2020
NORTH STONINGTON SOLAR PLANT	CT	PV	9.99	1/1/2020
W. PORTSMOUTH ST. SOLAR	NH	PV	14.69	1/1/2020
CONSTITUTION SOLAR	CT	PV	19.59	1/1/2020

Name	Location	Project Type	Nameplate Capacity (MW)	Online Date
HIGHGATE SOLAR	VT	PV	19.6	1/1/2020
HINCKLEY SOLAR	ME	PV	19.58	1/1/2020
RANDOLPH CENTER SOLAR	VT	PV	19.58	1/1/2020
SHELDON SOLAR	VT	PV	19.63	1/1/2020
WINSLOW SOLAR	ME	PV	19.58	1/1/2020
DAVENPORT SOLAR	VT	PV	19.58	1/1/2020
NUTMEG SOLAR	CT	PV	19.6	1/1/2020
WALLINGFORD RENEWABLE ENERGY (WRE)	CT	PV	19.99	1/1/2019
GRE-29-WATERFORD-CT	CT	PV	17.73	1/1/2020
COOLIDGE SOLAR II	VT	PV	19.59	1/1/2020
KIDDER HILL COMMUNITY WIND	VT	Wind	5	1/1/2019
SWANTON WIND	VT	Wind	17.5	1/1/2019
MINUTEMAN WIND PROJECT	CT	Wind	12.5	7/1/2018
MA83C and MA83D Procurements				
NECEC HYDRO	HQ Import / ME	Hydro	1,090	1/1/2023
VINEYARD WIND	SEMA	Offshore Wind	800	1/1/2023
83C GENERIC RESOURCE 1	SEMA / RI	Offshore wind	400	1/1/2027
83C GENERIC RESOURCE 2	SEMA / RI	Offshore wind	400	1/1/2029
RI Deepwater Wind Procurement under ACES				
REVOLUTION WIND 400	RI	Offshore wind	400	1/1/2024
CT 2018 RFP				
REVOLUTION WIND 200	RI	Offshore Wind	200	1/1/2024
TURNING EARTH	CT	Biomass	1.6	1/1/2023
ENERGY AND INNOVATION PARK FUEL CELL	CT	Fuel Cell	19.98	1/1/2023

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Name	Location	Project Type	Nameplate Capacity (MW)	Online Date
BLOOM COLCHESTER	CT	Fuel Cell	10	1/1/2023
HARTFORD FUEL CELL	CT	Fuel Cell	7.4	1/1/2023
DERBY FUEL CELL	CT	Fuel Cell	14.8	1/1/2023

11.2.4: Generic Market-Driven Class 1 Renewable Resource Additions

The Federal Production Tax Credit (PTC), renewed in December 2015, is scheduled to phase out by 2020, such that only resources beginning construction before the end of 2019 are eligible. The Investment Tax Credit (ITC) for large wind is scheduled to be eliminated by 2020. TCR does not model the PTC or the ITC in the Base Case.

All distributed PV additions are assumed to be already represented in the ISO-NE PV Forecast resources; as a result, the only candidate PV additions available to the capacity expansion model are utility-scale PV.

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Table 20 presents our assumptions regarding the technical potential of Class 1 eligible resources by technology, drawn from U.S. Renewable Energy Technical Potentials, A GIS-Based Analysis, Anthony Lopez, Billy Roberts, Donna Heimiller, Nate Blair, and Gian Porro, NREL Technical Report NREL/TP-6A20-51946, July 2012.[24]

24 http://en.openei.org/doe-opendata/dataset/5346c5c2-be26-4be7-9663-b5a98cbb7527/resource/01fe78a8-77b6-4c59-bc36-cae177ee86c3/download/usretechpotential.pdf

Table 20. Technical Potential for Installed Renewable Capacity by Resource Type and State

Technology		CT	ME	MA	NH	RI	VT	Total
Capacity (GW)								
Hydro	Conventional	0.2	0.9	0.3	0.4	0.0	0.4	2.2
	New Stream Reach Dev.							
Wind	Onshore	0.0	11.3	1.0	2.1	0.0	2.9	17.4
	Offshore	7.2	147.4	184.1	3.5	21.0		363.1
PV	Utility-scale	17.1	660.6	62.5	37.9	10.0	36.5	824.7
Biomass	Gaseous	0.1	0.0	0.1	0.0	0.1	0.0	0.3
Energy (GWh/year)								
Hydro	Conventional	922	3,916	1,197	1,741	59	1,710	9,546
	New Stream Reach Dev.							
Wind	Onshore	62	28,743	2,827	5,706	130	7,796	45,264
	Offshore	26,545	631,960	799,344	14,478	89,115		1,561,442
PV	Utility-scale	27,344	1,103,543	99,674	61,154	15,424	56,360	1,363,500
Biomass	Gaseous	415	125	1,104	390	474	203	2,710

Table 20 highlights the on-shore wind potential in Maine because TCR assumed that only 25 percent of the 11.3 GW potential listed would be available for generic market-driven new additions. This limit is due to transmission capacity limits in Maine, in particular the Orrington interface which is a significant bottleneck to moving wind energy southward. Approximately 25 percent (by capacity) of Maine wind generation projects in the ISO-NE interconnection queue with Active status as of July 2017 (about 3,800 MW) are listed as interconnecting to substations south of Orrington. Therefore, TCR only made 25 percent of the 11.3 GW potential listed for Maine available to the capacity expansion model for generic market-driven new additions. Furthermore, TCR assumed that only a fraction of the wind potential could be realized without major transmission upgrades. In consultation with EDCs, TCR assumed without transmission upgrades up to 200 MW of wind could added in each state of Maine, New Hampshire and Vermont. Additional 100 MW was assumed to be feasible to add in the WCMA zone. Above these limits, additional capital costs were associated with on-shore wind additions, as reflected in Table 21.

Table 21 presents capital and operating cost assumptions for generic market-driven renewable resource additions.

Table 21. Assumed Capital, FOM, and VOM Costs for generic market driven renewable additions

Unit Type / Technology	Capital Cost ($/kW)	FOM ($/kW-yr)	Variable O&M ($/MWh)	Source
Hydro	6,242.4	36.8	-	2
Solar Photovoltaic	2,710.1	23.4	-	1
Wind Onshore	2,695.6	61.0	-	1
High Cost Onshore Wind *	3450.6	61.0	-	1,3
Wind offshore	7,059.4	83.8	-	1
Notes				
- All costs adjusted to 2018$				
- Regional costs adjusted to New England Region, as applicable				
* Higher cost reflective of assumed transmission upgrades allowing capacity to be built beyond the allowable threshold				
Sources				
1. EIA	EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 EIA- Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generating Plants, April 2017 EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013			
2. NREL	NREL - 2016 Annual Technology Baseline, September 2016			
3. ISO-Ne ME resource integration study	https://www.iso-ne.com/static-assets/documents/2018/03/final_maine_resource_integration_study_report_non_ceii.pdf			

11.3: Generic Fossil Fuel and Nuclear Resource Additions

Generic fossil fuel resource additions include dual-fuel capable combined cycle and simple cycle gas turbine generating units. For these technologies, TCR relies on unit characteristics and cost assumptions as specified in the Concentric Energy Advisors' (CEA) report prepared for ISO-NE; filed with FERC in support of its application for the FCA12 parameters.[25]. TCR also considers Advanced

25 Available online at https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

Nuclear options. Table 22 presents capital and operating cost assumptions for generic market-driven fossil resource additions.

Table 22. Assumed Capital, FOM, and VOM Costs for generic market driven non-renewable additions

Unit Type / Technology	Capital Cost ($/kW)	FOM ($/kW-yr)	Variable O&M ($/MWh)	Source
Combined Cycle Gas Turbine	1,062.8	56.9	3.3	1
Gas Turbine (Aeroderivative)	1,604.5	65.3	4.7	1
Gas Turbine (Frame)	851.7	36.4	4.3	1
Nuclear	6,482.1	109.3	2.6	2
Biomass	9,359.5	407.4	20	2
Notes				
- All costs adjusted to 2018$				
- Regional costs adjusted to New England Region, as applicable				
Sources				
1. ISO NE	CEA ISO-NE CONE and ORTP Analysis (https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf)			
2. EIA	EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016 EIA- Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generating Plants, April 2017 EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013			

11.4: Financial Assumptions for Generic Resource Additions

The base case uses common financing assumptions for all market-driven unit additions, both fossil fuel and renewable. These assumptions include a 20-year financing period, and a real after tax weighted average cost of capital (WACC) of 6.0%. The WACC is based on the results of an analysis by Concentric Energy Advisors prepared for ISO New England, which assumes uncontracted merchant development, and is based on costs of equity and debt that are commensurate with a merchant project's perceived risks of cost recovery in the market, which are higher than those of a project whose revenues are contracted under a PPA.[26] The use of a WACC based on merchant rather than contracted development reflects the Base Case assumption that only merchant development will be possible

26 ISO-NE CONE and ORTP Analysis. Concentric Energy Advisors. Prepared for ISO New England, January 13, 2017, p. 48.

because the market will not bring about the development of resources with long-term PPAs in the absence of mandated procurements such as 83C.

CHAPTER 12: Generating Unit Operating Characteristics

12.1: Generator Aggregation

To optimize model computation time, TCR aggregates all units below 20 MWs by type, fuel and energy area into a smaller set of units. Full load heat rates for the aggregates are calculated as the average of the individual units and all other parameters are inherited from the unit type.

12.2: Thermal Unit Characteristics

Thermal generation characteristics are generally determined by a generator's technology and fuel type. These characteristics include heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

TCR developed generator outage and heat rate data from information by similar unit type as obtained from both the North American Electric Reliability Corporation (NERC) Generating Availability Report and power industry data provided by S&P Global.

Each thermal unit type has a distinct normalized incremental heat rate curve. The normalized heat rate curve is scaled by the full load heat rate (FLHR) to produce unit specific heat curve. Table 23 summarizes the shape of normalized heat rate curve used in ENELYTIX.

Table 23: Normalized incremental heat rate curve

Unit Type	Blocks (Total)	Block	Capacity Range (% of Max)	Heat Rate (% of FLHR)
CT	1	1	100%	100%
CC	4	1	50%	113%
		2	51% ~ 67%	75%
		3	68% ~ 83%	86%
		4	84% ~ 100%	100%
ST (Coal)	4	1	0% ~ 50%	106%
		2	51% ~ 65%	90%
		3	66% ~ 95%	95%
		4	96% ~ 100%	100%
ST (Other)	4	1	25%	118%
		2	26% ~ 50%	90%
		3	51% ~ 80%	95%
		4	81% ~ 100%	100%

Source: ENELYTIX® data set

As an example, for a 500 MW CC with a 7,000 Btu/KWh FLHR, the minimum load block would be its minimum generation of 250 MW at a heat rate of 7,910 Btu/KWh, the 2nd incremental block would be 251 MW ~ 335 MW at a heat rate of 5,250 Btu/KWh, the 3rd increment would be 336 MW ~ 415 MW at a

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heat rate of 6,020 Btu/KWh, and the final block would be 416 MW ~ 500 MW at a heat rate of 7,000 Btu/KWh.

Table 24 summarizes other operating parameter assumptions by unit type for thermal generators. The abbreviations in the unit type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (**g**as, **o**il, **c**oal, **b**iomass, **r**efuse) and the numbers identify the size of generating units mapped to that type.

Table 24: Other thermal unit operating parameters by unit type

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	AvgNumFO	VOM	Startup Cost Cold ($/MWh)
CCg100 (0-100MW)	6	8	4.29	6.29361	2.5	35
CCg100+ (100-9999MW)	6	8	4.29	6.29361	2.5	35
CCgo100 (0-100MW)	6	8	4.29	6.29361	2.5	35
CCgo100+ (100-9999MW)	6	8	4.29	6.29361	2.5	35
GTg20 (0-20MW)	1	1	18.6	7.17047	10	0
GTg50 (20-50MW)	1	1	12.97	5.97854	10	0
GTgo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTgo50 (20-50MW)	1	1	12.97	5.97854	10	0
GTo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTo50 (20-50MW)	1	1	12.97	5.97854	10	0
GTo50+ (50-9999MW)	1	1	9.29	8.83609	10	0
ICb+ (0-500MW)	1	1	11.63	5.36087	10	0
ICg20 (0-20MW)	1	1	21.16	8.15737	10	0
ICg50 (20-50MW)	1	1	11.54	5.31938	10	0
ICg50+ (50-500MW)	1	1	11.54	5.31938	10	0
ICgo20 (0-20MW)	1	1	21.16	8.15737	10	0
ICgo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICgo50 + (50-500MW)	1	1	11.54	5.31938	10	0
ICo20 (0-20MW)	1	1	21.16	8.15737	10	0
ICo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICo50+ (50-500MW)	1	1	11.54	5.31938	10	0
STb+ (0-500MW)	1	1	10.26	6.60348	0	35
STc100 (0-100MW)	24	12	8.32	6.62999	5	45
STc250 (100-250MW)	24	12	6.47	7.56834	4	45
STc600+ (600-9999MW)	24	12	7.05	8.24258	2	45
STg100 (0-100MW)	10	8	10.34	3.04348	6	40
STg200 (100-200MW)	10	8	8.42	6.23223	5	40
STg600 (200-600MW)	10	8	8.35	8.25635	4	40
STgo100 (0-100MW)	10	8	10.34	3.04348	6	40

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	AvgNumFO	VOM	Startup Cost Cold ($/MWh)
STgo200 (100-200MW)	10	8	8.42	6.23223	5	40
STgo600 (200-600MW)	10	8	8.35	8.25635	4	40
STo100 (0-100MW)	10	8	10.34	3.39285	6	40
STo200 (100-200MW)	10	8	8.42	8.38989	5	40
STo600 (200-600MW)	10	8	8.35	5.96487	4	40
STo600+ (600-9999MW)	10	8	14.55	22.7626	3	40
STr+ (0-500MW)	10	8	10.26	6.60348	2	40
NUC-BWR1000MW+	164	164	2.19	1.26865	0	90
NUC-BWR (800-1000MW)	164	164	1.66	1.61458	0	90
NUC-BWR (400-799MW)	164	164	3.27	2.44982	0	90
NUC-PWR1000MW+	164	164	4.02	2.29472	0	90
NUC-PWR (800-1000MW)	164	164	3.02	1.03991	0	90
NUC-PWR (400-799MW)	164	164	3.02	2.03373	0	90

Source: ENELYTIX® data set

12.2.1: Nuclear Unit Operating Characteristics

Nuclear plants are modeled as special thermal units in ENELYTIX. In general, nuclear facilities are treated as must run units and assumed to run except for periods during generator maintenance and forced outage. Current refueling schedules are obtained from roadtech.com[27]. Future schedules are estimated per specified periodicity.

12.3: Hydro Electric Generator Characteristics

TCR models hydro electric generators as energy constrained generators that output energy in relation to daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. TCR obtains historic hydro generation MWh from EIA and S&P Global database. Based on this historic information, TCR develops daily maximum energy output for each hydro power plant in ISO-NE. Subject to this maximum energy output constraint, TCR allows ENELYTIX® to optimize hourly energy output of each hydro electric generator to minimize system-wide production costs in each hour of the day.

12.4: Pumped Hydro Storage Facilities

TCR models pumped storage with the following specifications obtained from the National Hydroelectric Power Resource Study prepared for the U.S. Army Engineer Institute of Water Resources.

- Max Storage: Unit Capacity * Number of Storage hours
- Min Storage: 10% of Max Storage
- Min MW: Pumping Capacity
- Efficiency: Annual Output/Annual Pumping Energy

27 https://www.roadtechs.com/shutdown/shutdown.php?region=n

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12.5: Wind Facilities

Wind generation is represented as hourly generation profile in ENELYTIX®. TCR assembles wind generation profiles from the National Renewable Energy Laboratory (NREL)'s Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data.[28] TCR maps each wind power plant to the nearest NREL site based on the plant's location. For selected ISO-NE wind plants where the EDCs provided NREL site IDs and historic capacity factors, TCR mapped plants to corresponding NREL sites and reshaped NREL wind data to match EDC provided historic capacity factor. The resulting normalized NREL site schedule is scaled to the installed capacity of the corresponding wind site and then calendar-shifted for each forecast year making it synchronized with load profiles and interchange schedules.

12.6: Solar Photovoltaics Facilities

Like wind facilities, photovoltaic (PV) generators are also represented as hourly generation profiles in ENELYTIX®. TCR obtains solar irradiation data from weather station closest to a PV generator's location and uses NREL's PVWatts® Calculator to estimate the site's energy production. TCR assumes all utility scale PV facilities are fixed array installations with characteristics summarized in Table 25.

Table 25: Photovoltaic parameter assumptions

PV Parameter	Assumption
Elevation (m)	5
Module Type	Standard
Array Type	Fixed (Open Rack)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14
Invert Efficiency (%)	96

Source: ENELYTIX® data set

28 https://www.nrel.gov/grid/wind-toolkit.html

CHAPTER 13: Fuel Prices

13.1: Natural Gas Spot Prices in New England

TCR develops projections of the monthly spot price of natural gas to each gas-fired unit in New England based upon the projections of spot prices at the market hub which serves the unit. The four relevant hubs are Algonquin, Tennessee Zone 6, Tennessee Dracut and Iroquois Zone 1. Appendix B provides our forecast of monthly spot prices at those hubs in 2018$/MMBtu for the period January 2021 through December 2045.

The projections of natural gas spot prices at each market hub equals the TCR projection of monthly Henry Hub prices plus the TCR projection of monthly basis differential to each market hub from the Henry Hub.

13.1.1: Henry Hub Prices

TCR begins by developing a projection of annual Henry Hub prices and then develops monthly Henry Hub prices from those annual prices. TCR uses Henry Hub as a base commodity forecast because of the quantity of forecast and trading data available for it.

The projection of annual Henry Hub prices is a blend of forward prices and a public long-term forecast. The forward prices are from S&P Global as of October 15th, 2018. The long-term forecast is the Reference Case forecast assuming no Clean Power Plan (CPP) from the Energy Information Administration (EIA) Annual Energy Outlook 2018 (AEO 2018). TCR uses forward prices in the near-term as they reflect current market conditions. and AEO 2018 forecast for the long-term as it reflects the outlook regarding fundamentals of demand and supply. This is the standard approach TCR uses in its long-term modeling and is the approach the Avoided Energy Supply Cost (AESC) studies have used since 2007.

Figure 9 plots TCR's forecast of annual Henry Hub prices, S&P Global's Henry Hub futures as well as the AEO 2018 forecasts for Reference Case.

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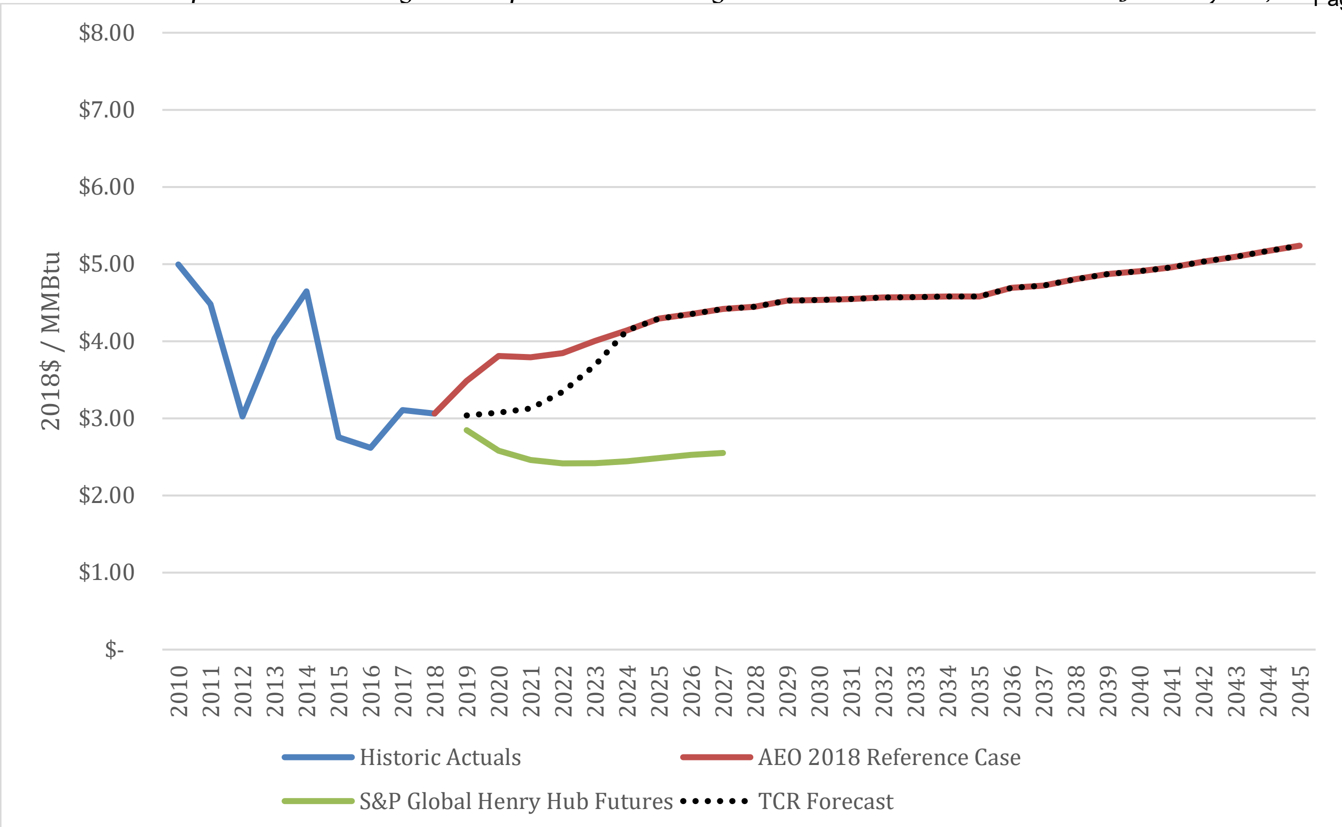

Figure 9. TCR and AEO 2018 projections of Henry Hub prices, 2018$

TCR develops its projection of monthly Henry Hub prices from its projection of annual prices using the historical ratios of monthly prices at Henry Hub to annual prices at Henry Hub

13.1.2: Spot gas prices in New England

TCR develops projections of the monthly spot price of natural gas to each gas-fired unit in New England based upon the projections of spot prices at the market hub which serves the unit. The projections of natural gas spot prices at each market hub equals the TCR projection of monthly Henry Hub prices plus the TCR projection of monthly basis differential to each market hub from the Henry Hub.

TCR develops its projection of monthly basis between Henry Hub and each New England market hub for the period January 2021 through December 2026 from projections of basis for those hubs drawn from SNL. TCR develops its projection of monthly basis between Henry Hub and each New England market hub from January 2028 onward based upon an assumption that basis will remain relatively constant in 2018$ dollars over that period.

Figure 10 plots the TCR forecast of monthly spot prices at the Henry Hub and the Algonquin hub in 2018$. This Figure indicates that the TCR forecast of gas prices to electric generating units shows significant variation between prices in winter months and prices in summer months.

The projections of monthly basis underlying the TCR projections of monthly spot gas prices in New England are consistent with two basic assumptions regarding gas pipeline capacity over the study period, 2021 - 2045. First, TCR assumes gas utilities will be able to acquire any additional capacity they may need to meet growth in their retail load. Second, TCR assumes that the gas pipeline capacity available to deliver gas to electric generating units on average each day, particularly in the winter months of December through February, will be limited to the pipeline capacity expected to be in-service as of November 2020 less the aggregate quantity of gas utilities require each day.

TCR calculated separate gas prices for Mystic units 8 and 9 to address potential fuel scarcity issues for the period after termination of their reliability must run (RMR) agreements. These assumptions are discussed in Appendix D.

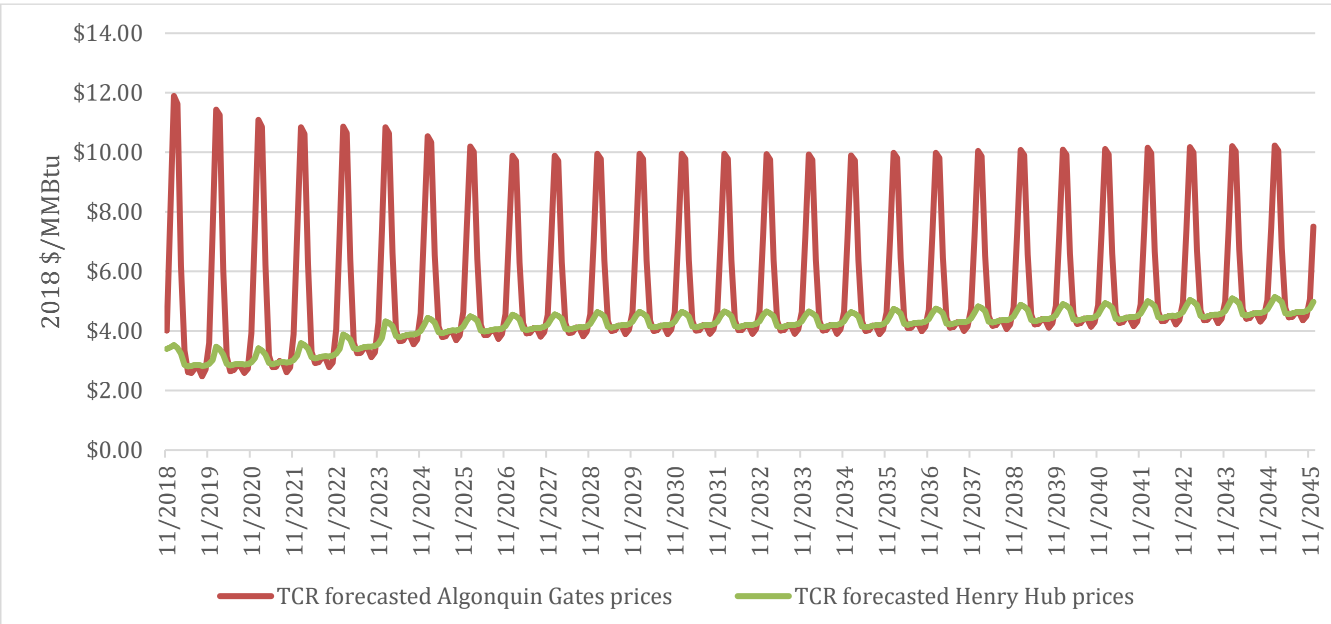

Figure 10. Projections of spot prices in New England (2018$/MMBtu)

Table 26 presents our assumptions regarding gas pipeline capacity as of November 2020 and average daily demand in the winter months of December through January. TCR developed the assumptions regarding capacity based upon data reported in the AESC 2018 report and on data reported by the Northeast Gas Association. The estimates of average daily gas use by gas utilities (LDCs) and electric generating units during the three major winter months of December, January and February is based upon actual gas use in those months in 2015/2016 and in 2017/2018. A comparison of the average daily gas use data and the assumed gas pipeline and direct delivery capacity indicates that the issue of adequate pipeline capacity to serve gas-fired generating units primarily occurs on days of peak gas use during those three months rather than on days of average gas use throughout the winter, i.e., on 10 to 20 days per winter rather than on every day during the winter.

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Table 26. Assumptions regarding gas pipeline capacity serving New England

TCR assumptions re gas delivery capacity and average demand (Dec, Jan, Feb) New England (Bcf/d)				
Major Sources of Capacity	**Existing January 2018 (1)**	**Additions in service by November 2020 (1, 2)**		**Projected in service - November 2020**
	Bcf/d	**addition**	**Bcf/d**	**Bcf/d**
Algonquin (ALG)	1.82	Atlantic Bridge	0.13	1.95
Tennessee (TGP)	1.39	Station 261	0.10	1.49
Iroquois	0.26			0.26
Portland Natural Gas (PNGTS)	0.21	Portland Xpress	0.05	0.26
Vermont Gas	0.07	Vaughan Mainline Expansion	0.04	0.11
M&N Pipeline	0.83			0.83
Distrigas to Mystic units	0.70			0.70
Total	**5.28**			**5.61**
Projected Average daily demand Dec - Feb (3)				
LDCs				2.17
Electric Generating units				0.90
Total				3.07
Sources				
1. Synapse Energy Economics. *Amended AESC 2018.* pp 35-36.				
2. Northeast Gas Association. *Planned Enhancements, Northeast Natural Gas Pipeline Systems (10-17-18).*				
3. TCR analysis of EIA statistics on gas use by month by state in New England.				

TCR's assumption regarding the availability of adequate gas pipeline capacity to serve gas-fired units on most winter days over the study period, recognizing that some gas-fired units that dual-fuel capability, is informed by the following facts and assumptions. First, starting in June 2018, gas-fired capacity will be subject to the new ISO NE performance requirements and face financial penalties for non-performance. Second, based upon TCR's modeling of the Vineyard Wind 800 MW GLL Case, the average quantity of gas per day required by gas-fired units during the study period, particularly on winter days, is likely to be less than the average daily quantity assumed for the winter of 2020/2021, as described in our fuel switching memo.

13.2: Prices of distillate and residual fuel oil for electric generation in New England.

Table Appendix B-2 in Appendix B provides the 2018 RI RFP Phase II Base Case projections of distillate and residual to electric generators in New England from 2021 to 2045. These projections are drawn from AEO 2018 and expressed in 2018$.

13.3: Winter fuel switching for dual fuel generators

Because of natural gas pipeline supply constraint in New England, generators often experience gas shortages in extreme winter days. During gas shortage days, dual fuel generators switch fuel from natural gas to fuel oil due to economic reasons and/or operational requirements. TCR modeled winter fuel switching mechanic to approximate the economic and environmental impact resulting from dual fuel generators switching from natural gas to fuel oil on winter days with high natural gas prices. Appendix C outlines TCR's modeling approach on fuel switching mechanics.

13.4: Uranium Prices

TCR develops uranium prices using the pricing calculator created by the Bulletin of the Atomic Scientist[29]. The calculator estimates the cost of electricity assuming the nuclear fuel cycle is "Once-Through". TCR omits all capital related cost associated with the cost of electricity from the calculator. The resulting uranium price is 0.99 Nominal $/MMBtu, which TCR assumed to be fixed.

13.5: Coal Prices

TCR develops plant level coal price from S&P Global's power plant operations data base. TCR derives coal cost in $/MMBtu by dividing S&P Global reported annual cost of coal delivered ($/ton) by annual average heat content of coal burned (Btu/lbs.). Based on this method, TCR calculates the exact coal cost for plants where data is available. For plants without sufficient data, TCR assumes the average cost from other coal plants in the same area and/or state.

TCR developed coal cost for this project using 2015-2017 coal price data by plant from S&P Global Services and converted said prices to real 2018 $/MMBtu. TCR assumes the prices reported in will remain at those levels over the study period.

29 http://thebulletin.org/nuclear-fuel-cycle-cost-calculator/model

CHAPTER 14: Emission Rates

14.1: Emission Rates

Emission rates for NO_x and SO_2 are obtained from historical S&P Global's Unit and Plant emission rates data. For future generating units under construction for which there are no emission rates, generic EIA emission data are used.[30] For existing units for which no emission rates were reported, emission rate by fuel type from EIA is used.[31] CO_2 emission rates by fuel type are taken from EPA's "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems."[32]

14.2: Greenhouse Gas Emission Allowance Prices

TCR developed its CO_2 allowance price assumptions based upon a review of projections RGGI prepared as part of its 2017 Program. RGGI, as part of its 2016 Program Review, developed a new Model Rule, and projected corresponding CO_2 emissions and prices for six representative years over the period 2017-2031 (the Base Model Rule Policy Case). RGGI also ran studies to test the sensitivity of its projections to changes in various assumptions such as gas prices, nuclear retirements, transmission additions between Canada and New England, renewable costs, the addition of 1600 MW offshore wind, and whether a national policy (i.e., the Clean Power Plan) would be in place. The RGGI simulations of the Model Rule and associated sensitivity studies are documented in RGGI Program Review meeting materials.[33]

TCR, based upon its review of the RGGI scenarios, developed the Base Case CO_2 allowance price using a curve fit to RGGI's 2017 Model Rule Policy Case projection. TCRs projection assumes that the RGGI prices initially start at the "MRPS, no national program" case and gradually transition to the "MRPS, national program, high emissions sensitivity" case starting in 2022 through 2030, and continue with that trajectory for the remainder of the study period. Table 27 presents the Base Case CO_2 allowance price assumptions.

Table 27. Base Case CO_2 Allowance Price Assumptions (201$/short ton)

Year	2021	2022	2023	2024	2025	2026	2027	2028	2029
Price	6.01	6.24	7.12	8.07	9.10	10.22	11.43	12.74	14.16
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
Price	15.68	16.43	17.22	18.05	18.92	19.82	20.76	21.74	22.75
Year	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**		
Price	23.81	24.90	26.03	27.20	28.40	29.64	30.92		

30 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

31 https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

32 https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

33 "Draft 2017 Model Rule Policy Scenario Overview," prepared for RGGI by ICF International, September 25, 2017. Numeric values for CO_2 prices taken from Draft_IPM_Results_Model_Rule.xlsx. Available at https://www.rggi.org/program-overview-and-design/program-review.

Figure **11** plots the Base Case price assumptions as well as the RGGI projections for the various Model Rule Policy Scenarios.

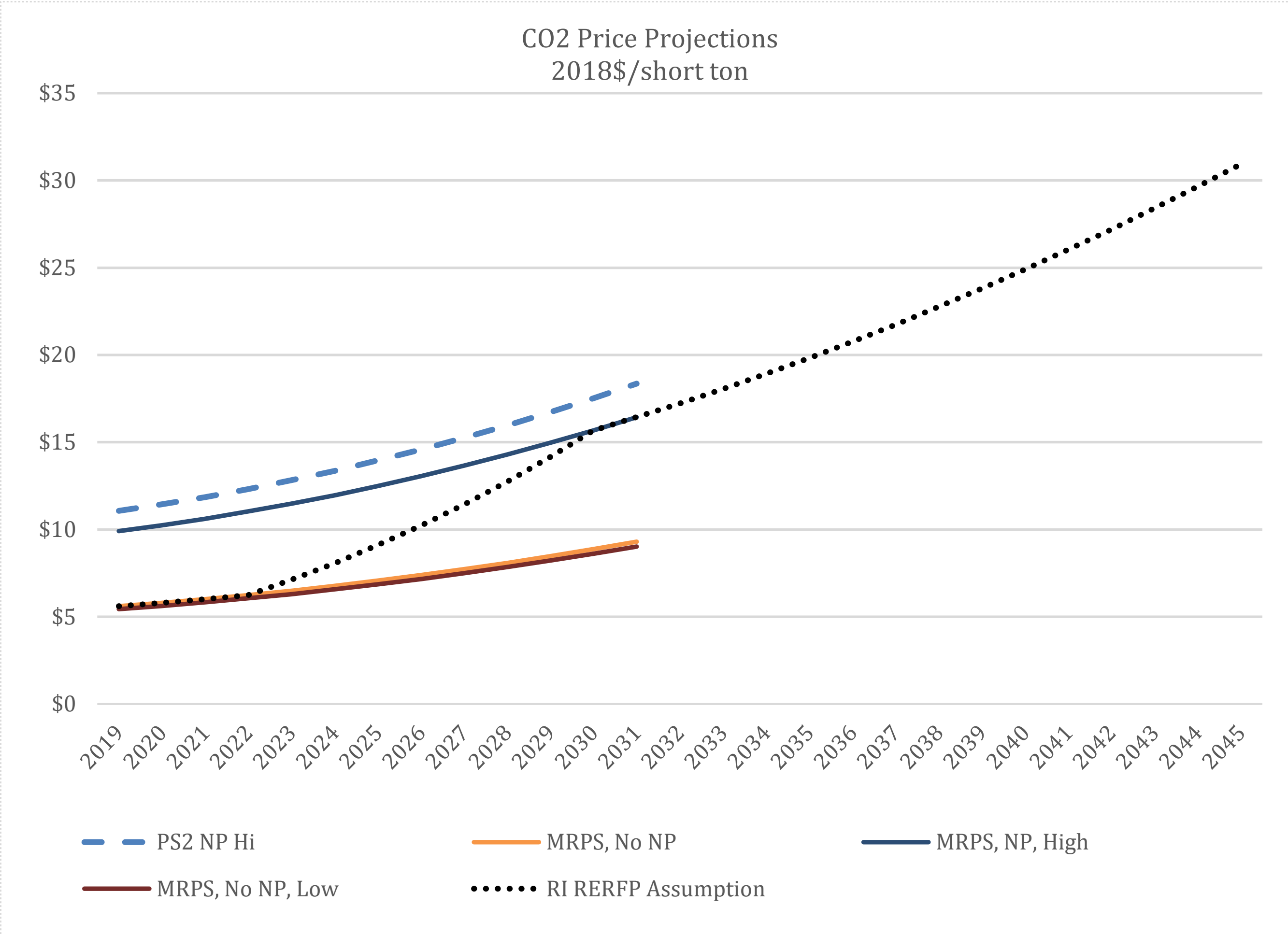

Figure 11**. RI RFP Base Case Assumptions relative to RGGI and ISO-NE CO2 Allowance Price Projections as of August 1, 2017**

14.3: NO_x and SO_2

TCR assumed allowance prices of zero for NO_x and SO_2 emissions. The Federal Cross State Air Pollution Rule (CSAPR) establishes NO_x and SO_2 emission limits, and no New England state has emission limits under CSAPR. Therefore, CSAPR allowance prices are not applicable to New England generators.

SO_2. With the retirement of Brayton Point, SO_2 emissions in New England have dropped to levels near zero and correspondingly we assume zero value to SO_2 allowances.

NO_x. In accordance with Governor Baker's Executive Order 562 and to meet ongoing federal Clean Air Act requirements, MA DEP in August 2016 proposed to replace the Massachusetts Clean Air Interstate Rule (310 CMR 7.32) with a new Ozone Season Nitrogen Oxides Control (310 CMR 7.34). The rule is intended to meet a 2017 (and beyond) budget for NO_x emissions from large fossil-fuel-fired electric power and steam generating units during the ozone season (May 1st through September 30th). The

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proposed Massachusetts Ozone Season NO_x budget is 1,799 tons. Given that NO_x ozone season emissions from all sources have been decreasing, and over the past five years have ranged between 975 and 1,620 tons. As a result, we ascribe zero value to NO_x allowances in Massachusetts.

On September 9, 2016, US EPA approved a State Implementation Plan revision submitted by Connecticut. This revision continues to allow facilities to create and/or use emission credits using NO_x Emission Trading and Agreement Orders (TAOs) to comply with the NO_x emission limits required by RCSA section 22a-174-22 (Control of Nitrogen Oxides), which imposes emissions rate limits on generators. It is possible that under this rule NO_x DERCs, or allowances, will have value to certain individual generators. Lacking evidence of a liquid market or visible pricing for such allowances in Connecticut, we are assuming their value to be zero.

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GLOSSARY

Term	Definition
10MNSR	10 Minute Non-Spinning Reserve
10MSR	10 Minute Spinning Reserve
30MR	30 Minute Reserves
ACP	Alternative Compliance Payments
ADR	Active Demand Response
AEO	Annual Energy Outlook
AESC	Avoided Energy Supply Cost
ALG	Algonquin
BIO	Biomass
BMPV/ BTM PV	Behind-the-meter Photovoltaic
CAGR	Compound Annual Growth Rate
CC	Combined Cycle
CEA	Concentric Energy Advisors
CEC	Clean Energy Credits
CECP	Clean Energy and Climate Plan
CEII	Critical Energy Infrastructure Information
CELT	Capacity, Energy, Loads, and Transmission
CES	Clean Energy Standard
CMR	Code of Massachusetts Regulations
COD	Commercial Operation/Online Date
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollutions Rule
CT	Combustion Turbine
CT PURA	Connecticut Public Utilities Regulatory Authority
DA	Day-ahead
DEP	Department of Environmental Protection

Term	Definition
DERC	Discrete Emission Reduction Credits
DFO	Distillate Fuel Oil
E&AS	Energy and Ancillary Services
EDC	Electric Distribution Company
EEA	Energy and Environmental Affairs
EFORd	Effective Forced Outage Rates
EGU	Electric Generating Units
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FOM	Fixed Operation & Maintenance
GHG	Greenhouse Gas
Gold Book	NYISO's Load & Capacity Data Report
GSC	Generator Supply Curve
GT	Gas Turbine
GWSA	Global Warming Solutions Act
HD	Hydro Power
HVDC	High Voltage Direct Current
IC	Internal Combustion (reciprocating) Engine
ICAP	Installed Capacity
ICR	Installed Capacity Requirements
ITC	Investment Tax Credit
Kirchhoff's laws	the current law and the voltage law
LDC	Load Distribution Company

Term	Definition
LMP	Locational Marginal Price
LSE	Load Serving Entity
LSR	Local Sourcing Requirement
MA DEP	Massachusetts Department of Environmental Protection
MIP	Mixed Integer Programming
MLP	Municipal Light Plant
MMD	Market Model Database
NEL	Net Energy Load
NEPOOL GIS	New England Power Pool Generation Information System
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NREL	National Renewable Energy Laboratory
PDR	Passive Demand Response
PME	Power Market Explorer
PNGTS	Portland Natural Gas
PPA	Power Purchase Agreement
PS	Pumped Storage Unit
PSO	Power System Optimizer
PTC	Production Tax Credit
PV	Photovoltaic
PVWatts®	NREL's PV Calculator
RCSA	Regulations of Connecticut State Agencies
REC	Renewable Energy Certificate, Renewable Energy Credit
RFO	Residual Fuel Oil
RFP	Requests for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard

Term	Definition
RT	Real-time
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment
SENE	Southeast New England
SMART	Solar Massachusetts Renewable Target
ST	Steam Turbine
SUN	Solar Powered
TAO	Trading and Agreement Orders
TARA tool	Transmission Adequacy & Reliability Assessment tool
TGP	Tennessee Gas Pipeline
TMNSR	Ten-Minute Non-Spinning Reserve
TMOR	Thirty-Minute Operating Reserve
TMSR	Ten-Minute Spinning Reserve
VOM	Variable Operation & Maintenance
WACC	weighted average cost of capital
WAT	Water
WIND (NREL)	Wind Integration National Dataset
WT	Wind Turbine

APPENDIX A: ENELYTIX

This Appendix describes the computer model and analytical capability TCR uses to support the evaluation of 83C II Proposed Clean Energy Projects.

A.1: ENELYTIX® and Power System Optimizer (PSO)

ENELYTIX®[34] is a cloud-based energy market simulation environment implemented on Amazon EC2 commercial cloud.

A central element of ENELYTIX is the Power System Optimizer ("PSO"), an advanced simulator of power markets. PSO provides ENELYTIX the capability to accurately model the decision processes used in a wide range of power planning and market structures including long-term system expansion, capacity markets, Day-ahead energy markets and Real-time energy markets. ENELYTIX has this capability because it can configure PSO to determine the optimum solution to each market structure. Figure A-1 illustrates the four key components of the PSO analytical structure: Inputs, Models, Algorithms and Outputs.

As a system expansion optimization model, PSO integrates resource adequacy requirements with the specific design of the capacity market and with the environmental compliance policies, such as state-level and regional Renewable Portfolio Standards (RPS) and emission constraints.

As a production cost model, PSO is built on a Mixed Integer Programming (MIP) based unit commitment and economic dispatch structure that simulates the operation of the electric power system. PSO determines the security-constrained commitment and dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area. PSO supports both hourly and sub hourly timescales. In this project, the PSO is set up to model unit commitment (DA market) and an economic dispatch (RT market). In the commitment process, generating units in a region are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load and required operating reserves in the region for the next day. PSO then uses the set of committed units to dispatch the system on an hourly real-time basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs. The unit commitment in PSO is formulated as a mixed integer linear programming optimization problem which is solved to the true optima using the commercial CPLEX solver.

As an FCM Capacity Market Model, PSO is configured to simulate the outcome of the ISO-NE's Forward Capacity Auction subject to market specific rules and parameters develop projections of capacity prices.

34 ENELYTIX® is a registered trademark of Newton Energy Group, LLC.

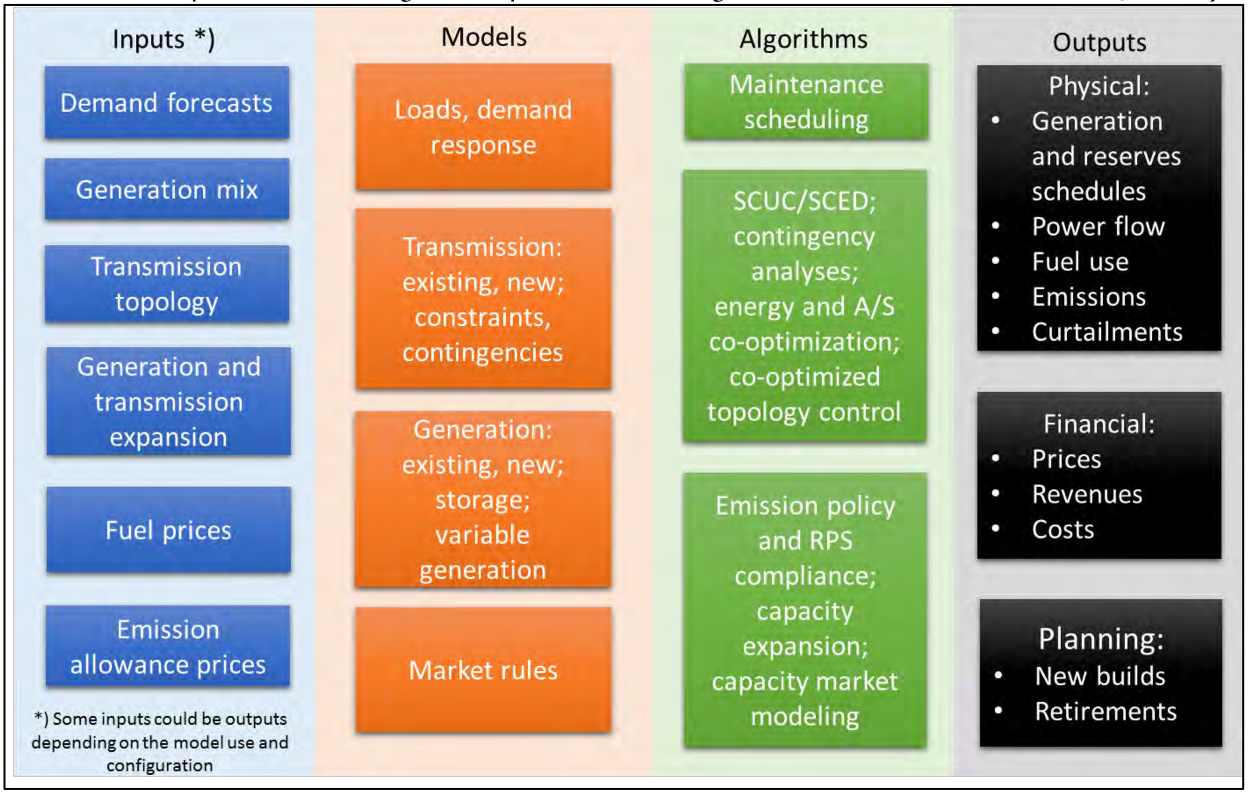

Figure A - 1. Analytical Structure of PSO

The ENELYTIX/PSO modeling environment provides a realistic, objective and highly defendable analyses of the physical and financial performance of power systems, in particular power systems integrating variable renewable resources. The critical advantage of PSO over traditional production costing modeling tools is its ability to model the concurrent dynamics of:

- uncertainty of future conditions of the power system;
- the scope, physical capabilities and economics of options available to the system operator to respond to these uncertain conditions;
- the timing and optionality or irreversibility of operator's decisions to exercise these options.

By capturing these concurrent dynamics, ENELYTIX/PSO avoids the generally recognized inability of traditional simulation tools to reflect the effect of operational decisions on the physics of the power system, price formation and financial performance of physical and financial assets.

A.1.1: Modeling the Impact of Uncertainty

System operators deal with a number of uncertainties in the data they use for their day-ahead decisions that ultimately impact operations and prices in the real-time market. These uncertainties typically include differences between forecast and actual load; forecast and actual output of variable generation; and forecast versus actual generation and transmission outages.

ENELYTIX/PSO offers the most realistic representation of the impact of those uncertainties between day-ahead decisions and real-time dispatch. ENELYTIX/PSO provides information, data structures and algorithms necessary for the realistic representation of these uncertainties including different load

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shapes and wind patterns for modeling the Day-ahead and Real-time markets. It also has embedded methods for incorporating forecast errors if explicit forecasts are not available, and model representation of time points at which the system becomes aware of generator outages.

System operators' options for responding to these uncertainties include (1) generation commitment decisions based on day-ahead and intra-day reliability assessments, (2) forward-looking procurement of ancillary services and (3) deployment of reserves when uncertainty is realized. ENELYTIX/PSO provides unique capabilities to model the process by which system operators rely on these options. The model allows the user to specify the decision timing and (at each decision point) to determine classes of decisions that are still provisional and can be revisited at a later stage, and classes of decisions that are final and therefore irreversible. These capabilities are critical for an accurate representation of forward commitments, actual dispatch decisions, curtailments, emergence of scarcity events and corresponding price formation. The ENELYTIX/PSO represents these concurrent dynamics through the use of the decision cycle logic and rolling horizon optimization.

A.1.2: ENELYTIX modeling architecture

ENELYTIX provides the advanced modeling features of PSO and the scalability of cloud computing. With the ENELYTIX cloud-based architecture, TCR can generate, simulate and post process a large number of Cases in a matter of hours. What we can turn around in an hour competing models require 10 days.

Figure A-2 illustrates the ENELYTIX architecture. This Figure highlights the system services that support parallel processing of simulation projects. As shown in that Figure, a Project consists of Tasks. Each Task is a collection of Cases, and each Case is partitioned into Segments which could be processed in parallel. In ENELYTIX, implementation of a Task *is a single-click* experience. Once the Task is launched, it invokes a process in which all user requested Cases are generated at once out of the Market Model Database (MMD) pre-populated with model data. Cases are formed by specifying alternative versions of inputs (e.g. alternative supply options or portfolios of such options, load forecast, new entry and retirement assumptions or fuel price sensitivities, types and requirements for ancillary services and myriads of other alternatives the user may need to explore and compare against each other within the same task).

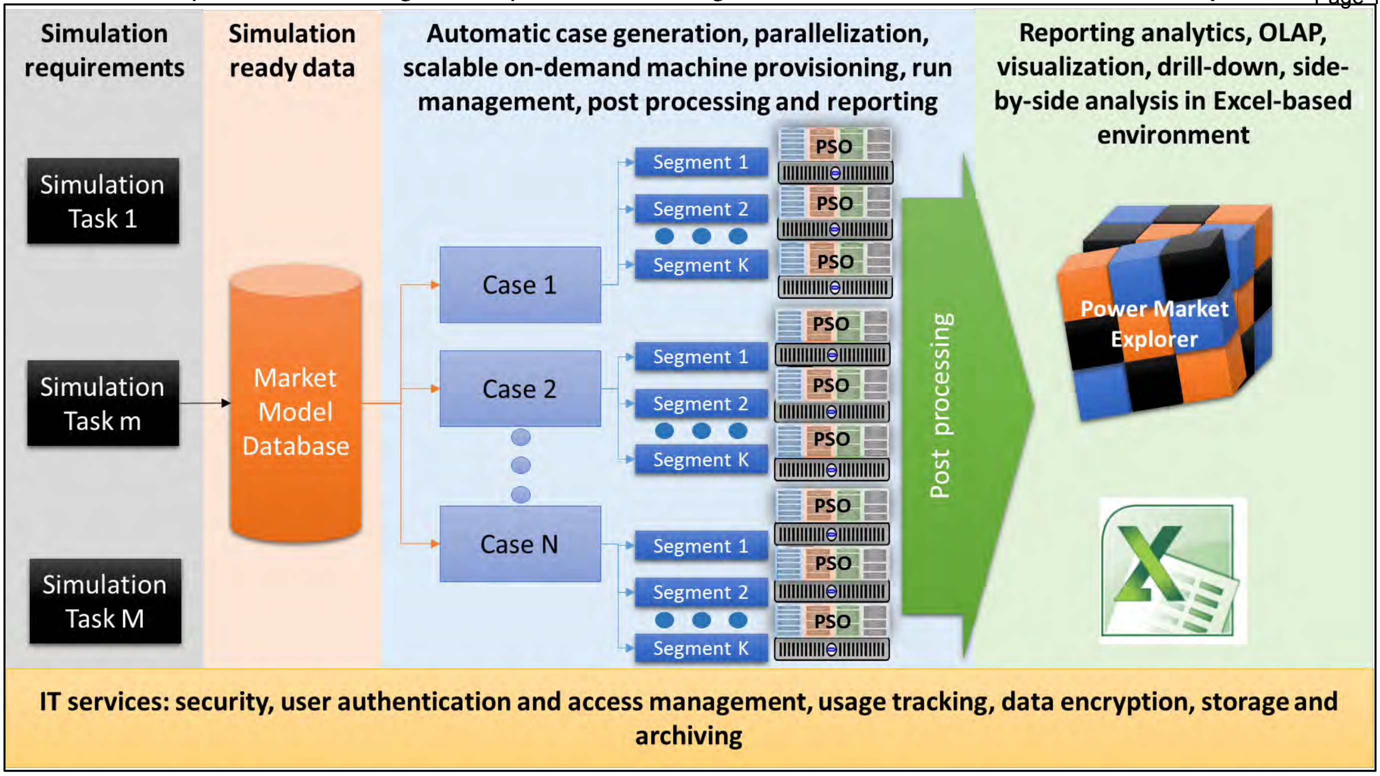

Figure A-2. Schematic of ENELYTIX Architecture

ENELYTIX automatically partitions each Case into Segments for parallel execution. Segments are queued and sent to servers dynamically procured on the cloud to be processed with PSO.

ENELYTIX collects output results, merges Segment related outputs corresponding to the same Case and sends both outputs and inputs to the Power Market Explorer (PME) Cube. PME is a multi-dimensional cube structure directly accessible from an Excel workbook on the user's desktop or laptop which provides self-service analytics for detailed exploration of output results in their entirety, side-by-side comparisons across cases, decision cycles, over time and numerous other dimensions. With PME, the user obtains instantaneous report generation via PivotTables and graphics via PivotCharts extracted directly from the PME cube. Although configurable, PME already comes with conveniently pre-calculated metrics including wholesale consumer payments, system-wide and regional adjusted production costs, emissions, curtailments, fuel use and detailed reports on assets' physical and financial performance.

ENELYTIX complies with high standards of data security properly protecting confidential and Critical Energy Infrastructure Information (CEII).

For additional information about ENELYTIX, visit www.enelytix.com.

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APPENDIX B: Fuel Price Forecast

B.1: Natural Gas Forecast Prices

Table Appendix B-1. Monthly Spot Gas Pries (2018 $/MMBtu)

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
1/2021	11.9055	12.0805	7.0880	12.1555
2/2021	11.6733	11.8483	6.9920	11.9233
3/2021	6.7109	6.8859	4.3277	6.9609
4/2021	3.4294	3.6794	2.9082	3.3994
5/2021	3.0090	3.2590	2.8159	2.9790
6/2021	3.0334	3.2834	2.9646	3.0034
7/2021	3.2426	3.4926	3.0071	3.2126
8/2021	3.1920	3.4420	2.9948	3.1620
9/2021	2.8532	3.1032	2.8466	2.8232
10/2021	3.0323	3.2823	3.0075	3.0023
11/2021	4.2691	4.4441	3.4874	4.5191
12/2021	7.9314	8.1064	4.6093	8.1814
1/2022	11.9253	12.1003	7.2430	12.1753
2/2022	11.7062	11.8812	7.1566	11.9562
3/2022	6.8841	7.0591	4.5699	7.1341
4/2022	3.6559	3.9059	3.2122	3.6259
5/2022	3.2481	3.4981	3.1230	3.2181
6/2022	3.2714	3.5214	3.2718	3.2414
7/2022	3.4757	3.7257	3.3141	3.4457
8/2022	3.4318	3.6818	3.3072	3.4018
9/2022	3.1078	3.3578	3.1658	3.0778
10/2022	3.2921	3.5421	3.3365	3.2621
11/2022	4.5540	4.7290	3.7551	4.8040
12/2022	8.1963	8.3713	4.8738	8.4463
1/2023	12.2369	12.4119	7.5489	12.4869
2/2023	12.0190	12.1940	7.4630	12.2690
3/2023	7.2553	7.4303	4.9337	7.5053
4/2023	4.0851	4.3351	3.6496	4.0551

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
5/2023	3.6872	3.9372	3.5704	3.6572
6/2023	3.7173	3.9673	3.7266	3.6873
7/2023	3.9290	4.1790	3.7763	3.8990
8/2023	3.8904	4.1404	3.7747	3.8604
9/2023	3.5702	3.8202	3.6367	3.5402
10/2023	3.7629	4.0129	3.8163	3.7329
11/2023	4.9191	5.0941	4.1831	5.1691
12/2023	8.4770	8.6520	5.3097	8.7270
1/2024	12.5196	12.6946	8.0584	12.7696
2/2024	12.3071	12.4821	7.9729	12.5571
3/2024	7.6912	7.8662	5.4888	7.9412
4/2024	4.6589	4.9089	4.2276	4.6289
5/2024	4.2525	4.5025	4.1404	4.2225
6/2024	4.2876	4.5376	4.3023	4.2576
7/2024	4.5052	4.7552	4.3575	4.4752
8/2024	4.4727	4.7227	4.3620	4.4427
9/2024	4.1586	4.4086	4.2303	4.1286
10/2024	4.3581	4.6081	4.4171	4.3281
11/2024	5.4126	5.5876	4.7363	5.6626
12/2024	8.8923	9.0673	5.8724	9.1423
1/2025	12.4568	12.6318	8.2111	12.7068
2/2025	12.2512	12.4262	8.1275	12.5012
3/2025	7.7758	7.9508	5.6866	8.0258
4/2025	4.9348	5.1848	4.5074	4.9048
5/2025	4.5268	4.7768	4.4193	4.4968
6/2025	4.5629	4.8129	4.5827	4.5329
7/2025	4.7821	5.0321	4.6391	4.7521
8/2025	4.7500	5.0000	4.6442	4.7200
9/2025	4.4337	4.6837	4.5103	4.4037
10/2025	4.6380	4.8880	4.7022	4.6080
11/2025	5.5865	5.7615	4.9670	5.8365
12/2025	8.9807	9.1557	6.1009	9.2307
1/2026	12.3452	12.5202	8.3042	12.5952
2/2026	12.1456	12.3206	8.2220	12.3956
3/2026	7.8044	7.9794	5.8227	8.0544

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
4/2026	5.1202	5.3702	4.6966	5.0902
5/2026	4.7115	4.9615	4.6082	4.6815
6/2026	4.7336	4.9836	4.7582	4.7036
7/2026	4.9393	5.1893	4.8009	4.9093
8/2026	4.9087	5.1587	4.8075	4.8787
9/2026	4.5917	4.8417	4.6731	4.5617
10/2026	4.7910	5.0410	4.8602	4.7610
11/2026	5.6345	5.8095	5.0689	5.8845
12/2026	8.9200	9.0950	6.1733	9.1700
1/2027	12.2386	12.4136	8.3921	12.4886
2/2027	12.0443	12.2193	8.3108	12.2943
3/2027	7.8296	8.0046	5.9501	8.0796
4/2027	5.2984	5.5484	4.8783	5.2684
5/2027	4.8869	5.1369	4.7877	4.8569
6/2027	4.9180	5.1680	4.9471	4.8880
7/2027	5.1312	5.3812	4.9971	5.1012
8/2027	5.0973	5.3473	5.0004	5.0673
9/2027	4.7813	5.0313	4.8672	4.7513
10/2027	4.9813	5.2313	5.0552	4.9513
11/2027	5.7263	5.9013	5.2118	5.9763
12/2027	8.9259	9.1009	6.3055	9.1759
1/2028	12.5181	12.6966	8.5946	12.7731
2/2028	12.3196	12.4981	8.5114	12.5746
3/2028	8.0198	8.1983	6.1028	8.2748
4/2028	5.4356	5.6906	5.0071	5.4050
5/2028	5.0156	5.2706	4.9144	4.9850
6/2028	5.0477	5.3027	5.0773	5.0171
7/2028	5.2654	5.5204	5.1287	5.2348
8/2028	5.2310	5.4860	5.1322	5.2004
9/2028	4.9087	5.1637	4.9964	4.8781
10/2028	5.1130	5.3680	5.1884	5.0824
11/2028	5.8737	6.0522	5.3489	6.1287
12/2028	9.1389	9.3174	6.4661	9.3939
1/2029	12.8723	13.0543	8.8704	13.1324
2/2029	12.6687	12.8508	8.7844	12.9288

REDACTED

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
3/2029	8.2810	8.4630	6.3255	8.5411
4/2029	5.6376	5.8977	5.2006	5.6064
5/2029	5.2087	5.4688	5.1055	5.1775
6/2029	5.2422	5.5023	5.2725	5.2110
7/2029	5.4652	5.7253	5.3257	5.4340
8/2029	5.4307	5.6908	5.3299	5.3995
9/2029	5.1021	5.3622	5.1915	5.0709
10/2029	5.3114	5.5715	5.3883	5.2802
11/2029	6.0894	6.2715	5.5541	6.3495
12/2029	9.4246	9.6066	6.6983	9.6847
1/2030	13.1446	13.3303	9.0627	13.4099
2/2030	12.9368	13.1226	8.9748	13.2022
3/2030	8.4610	8.6467	6.4665	8.7263
4/2030	5.7638	6.0291	5.3180	5.7319
5/2030	5.3262	5.5915	5.2209	5.2943
6/2030	5.3605	5.6258	5.3913	5.3286
7/2030	5.5881	5.8534	5.4458	5.5562
8/2030	5.5530	5.8183	5.4501	5.5211
9/2030	5.2178	5.4831	5.3090	5.1860
10/2030	5.4314	5.6967	5.5099	5.3996
11/2030	6.2253	6.4110	5.6793	6.4906
12/2030	9.6278	9.8135	6.8470	9.8931
1/2031	13.4240	13.6134	9.2604	13.6946
2/2031	13.2119	13.4014	9.1707	13.4825
3/2031	8.6463	8.8357	6.6118	8.9169
4/2031	5.8939	6.1645	5.4392	5.8614
5/2031	5.4474	5.7180	5.3401	5.4150
6/2031	5.4826	5.7532	5.5141	5.4501
7/2031	5.7149	5.9855	5.5697	5.6824
8/2031	5.6791	5.9497	5.5743	5.6467
9/2031	5.3373	5.6079	5.4303	5.3049
10/2031	5.5553	5.8260	5.6353	5.5229
11/2031	6.3654	6.5548	5.8085	6.6360
12/2031	9.8367	10.0262	7.0003	10.1073
1/2032	13.7188	13.9120	9.4719	13.9948

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
2/2032	13.5022	13.6954	9.3801	13.7782
3/2032	8.8447	9.0379	6.7696	9.1207
4/2032	6.0354	6.3114	5.5716	6.0023
5/2032	5.5799	5.8559	5.4703	5.5467
6/2032	5.6159	5.8919	5.6480	5.5828
7/2032	5.8531	6.1291	5.7050	5.8200
8/2032	5.8168	6.0928	5.7098	5.7837
9/2032	5.4682	5.7442	5.5630	5.4350
10/2032	5.6908	5.9668	5.7724	5.6577
11/2032	6.5176	6.7108	5.9495	6.7936
12/2032	10.0595	10.2527	7.1664	10.3355
1/2033	13.9984	14.1954	9.6666	14.2799
2/2033	13.7774	13.9745	9.5729	14.0589
3/2033	9.0266	9.2237	6.9100	9.3082
4/2033	6.1608	6.4423	5.6877	6.1270
5/2033	5.6961	5.9777	5.5844	5.6623
6/2033	5.7329	6.0145	5.7657	5.6991
7/2033	5.9749	6.2564	5.8239	5.9411
8/2033	5.9379	6.2194	5.8288	5.9041
9/2033	5.5823	5.8639	5.6790	5.5485
10/2033	5.8094	6.0910	5.8926	5.7756
11/2033	6.6528	6.8499	6.0734	6.9344
12/2033	10.2659	10.4629	7.3149	10.5474
1/2034	14.2938	14.4948	9.8754	14.5810
2/2034	14.0682	14.2693	9.7796	14.3554
3/2034	9.2221	9.4232	7.0632	9.5093
4/2034	6.2979	6.5851	5.8154	6.2635
5/2034	5.8238	6.1110	5.7099	5.7894
6/2034	5.8615	6.1487	5.8949	5.8270
7/2034	6.1084	6.3956	5.9544	6.0740
8/2034	6.0708	6.3580	5.9595	6.0363
9/2034	5.7081	5.9953	5.8068	5.6737
10/2034	5.9399	6.2271	6.0248	5.9054
11/2034	6.8005	7.0015	6.2095	7.0877
12/2034	10.4865	10.6875	7.4765	10.7737

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
1/2035	14.5779	14.7829	10.0711	14.8708
2/2035	14.3478	14.5528	9.9734	14.6407
3/2035	9.4048	9.6099	7.2027	9.6977
4/2035	6.4222	6.7152	5.9300	6.3871
5/2035	5.9387	6.2316	5.8225	5.9035
6/2035	5.9771	6.2700	6.0112	5.9419
7/2035	6.2290	6.5219	6.0718	6.1938
8/2035	6.1905	6.4835	6.0770	6.1554
9/2035	5.8206	6.1135	5.9213	5.7855
10/2035	6.0570	6.3499	6.1436	6.0219
11/2035	6.9348	7.1399	6.3320	7.2277
12/2035	10.6944	10.8995	7.6242	10.9873
1/2036	15.0418	15.2509	10.4449	15.3406
2/2036	14.8054	15.0145	10.3435	15.1042
3/2036	9.7601	9.9692	7.5139	10.0589
4/2036	6.7057	7.0044	6.2036	6.6698
5/2036	6.2114	6.5102	6.0929	6.1756
6/2036	6.2520	6.5508	6.2868	6.2161
7/2036	6.5104	6.8092	6.3501	6.4745
8/2036	6.4722	6.7709	6.3563	6.4363
9/2036	6.0951	6.3939	6.1978	6.0592
10/2036	6.3377	6.6365	6.4260	6.3019
11/2036	7.2366	7.4457	6.6217	7.5353
12/2036	11.0792	11.2883	7.9475	11.3779
1/2037	15.3850	15.5984	10.6962	15.6898
2/2037	15.1435	15.3568	10.5924	15.4482
3/2037	9.9964	10.2098	7.7053	10.3012
4/2037	6.8779	7.1827	6.3658	6.8414
5/2037	6.3736	6.6783	6.2526	6.3370
6/2037	6.4153	6.7200	6.4507	6.3787
7/2037	6.6792	6.9839	6.5157	6.6426
8/2037	6.6404	6.9452	6.5223	6.6039
9/2037	6.2559	6.5606	6.3606	6.2193
10/2037	6.5037	6.8085	6.5938	6.4672
11/2037	7.4214	7.6347	6.7942	7.7262

REDACTED

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
12/2037	11.3428	11.5561	8.1485	11.6475
1/2038	15.8268	16.0443	11.0441	16.1376
2/2038	15.5790	15.7966	10.9369	15.8898
3/2038	10.3263	10.5439	7.9894	10.6372
4/2038	7.1360	7.4468	6.6136	7.0987
5/2038	6.6207	6.9316	6.4974	6.5834
6/2038	6.6643	6.9752	6.7005	6.6270
7/2038	6.9347	7.2455	6.7679	6.8974
8/2038	6.8959	7.2067	6.7754	6.8586
9/2038	6.5039	6.8147	6.6107	6.4666
10/2038	6.7578	7.0687	6.8497	6.7205
11/2038	7.6966	7.9142	7.0569	8.0074
12/2038	11.7025	11.9200	8.4443	12.0133
1/2039	16.2477	16.4696	11.3694	16.5647
2/2039	15.9939	16.2158	11.2589	16.3110
3/2039	10.6341	10.8560	8.2504	10.9512
4/2039	7.3725	7.6896	6.8397	7.3345
5/2039	6.8464	7.1634	6.7206	6.8083
6/2039	6.8917	7.2087	6.9286	6.8536
7/2039	7.1683	7.4854	6.9983	7.1303
8/2039	7.1294	7.4464	7.0065	7.0913
9/2039	6.7297	7.0467	6.8386	6.6916
10/2039	6.9896	7.3066	7.0833	6.9515
11/2039	7.9492	8.1712	7.2967	8.2663
12/2039	12.0399	12.2619	8.7166	12.3570
1/2040	16.6403	16.8667	11.6645	16.9637
2/2040	16.3808	16.6072	11.5511	16.7042
3/2040	10.9124	11.1388	8.4811	11.2358
4/2040	7.5808	7.9042	7.0374	7.5420
5/2040	7.0438	7.3672	6.9154	7.0049
6/2040	7.0905	7.4139	7.1282	7.0517
7/2040	7.3733	7.6967	7.1998	7.3345
8/2040	7.3339	7.6573	7.2086	7.2951
9/2040	6.9263	7.2497	7.0374	6.8875
10/2040	7.1920	7.5154	7.2876	7.1532

REDACTED

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
11/2040	8.1723	8.3986	7.5067	8.4957
12/2040	12.3478	12.5742	8.9581	12.6712
1/2041	17.0519	17.2828	11.9765	17.3817
2/2041	16.7863	17.0173	11.8601	17.1162
3/2041	11.2070	11.4380	8.7271	11.5369
4/2041	7.8032	8.1331	7.2489	7.7637
5/2041	7.2550	7.5848	7.1241	7.2154
6/2041	7.3033	7.6332	7.3417	7.2637
7/2041	7.5924	7.9223	7.4155	7.5528
8/2041	7.5527	7.8825	7.4248	7.5131
9/2041	7.1370	7.4669	7.2504	7.0975
10/2041	7.4087	7.7386	7.5063	7.3692
11/2041	8.4102	8.6411	7.7313	8.7400
12/2041	12.6728	12.9037	9.2153	13.0027
1/2042	17.5246	17.7601	12.3477	17.8610
2/2042	17.2524	17.4879	12.2276	17.5889
3/2042	11.5589	11.7944	9.0293	11.8953
4/2042	8.0777	8.4141	7.5123	8.0373
5/2042	7.5177	7.8541	7.3842	7.4773
6/2042	7.5680	7.9045	7.6072	7.5276
7/2042	7.8640	8.2005	7.6836	7.8237
8/2042	7.8242	8.1607	7.6938	7.7839
9/2042	7.4005	7.7370	7.5161	7.3601
10/2042	7.6788	8.0152	7.7782	7.6384
11/2042	8.7029	8.9384	8.0105	9.0394
12/2042	13.0568	13.2923	9.5301	13.3933
1/2043	17.9793	18.2195	12.6989	18.3225
2/2043	17.7006	17.9409	12.5753	18.0438
3/2043	11.8912	12.1314	9.3110	12.2344
4/2043	8.3329	8.6761	7.7562	8.2918
5/2043	7.7611	8.1043	7.6250	7.7199
6/2043	7.8133	8.1565	7.8533	7.7721
7/2043	8.1162	8.4594	7.9321	8.0750
8/2043	8.0761	8.4193	7.9431	8.0350
9/2043	7.6441	7.9873	7.7620	7.6029

Date	Algon Gates	Tennessee at Dracut	Iroquois Zone 1	Tennessee Zone
10/2043	7.9288	8.2720	8.0303	7.8876
11/2043	8.9756	9.2158	8.2693	9.3188
12/2043	13.4212	13.6615	9.8240	13.7644
1/2044	18.4764	18.7215	13.0904	18.8265
2/2044	18.1908	18.4358	12.9630	18.5408
3/2044	12.2624	12.5074	9.6306	12.6124
4/2044	8.6232	8.9733	8.0350	8.5812
5/2044	8.0392	8.3892	7.9003	7.9972
6/2044	8.0935	8.4436	8.1343	8.0515
7/2044	8.4036	8.7537	8.2158	8.3616
8/2044	8.3635	8.7136	8.2279	8.3215
9/2044	7.9231	8.2731	8.0434	7.8811
10/2044	8.2147	8.5647	8.3182	8.1727
11/2044	9.2851	9.5302	8.5647	9.6352
12/2044	13.8260	14.0710	10.1568	14.1760
1/2045	18.9710	19.2209	13.4772	19.3280
2/2045	18.6783	18.9283	13.3460	19.0354
3/2045	12.6288	12.8788	9.9445	12.9859
4/2045	8.9081	9.2652	8.3081	8.8653
5/2045	8.3116	8.6687	8.1700	8.2688
6/2045	8.3681	8.7251	8.4096	8.3252
7/2045	8.6854	9.0425	8.4939	8.6426
8/2045	8.6453	9.0023	8.5069	8.6024
9/2045	8.1962	8.5532	8.3189	8.1533
10/2045	8.4947	8.8518	8.6002	8.4518
11/2045	9.5891	9.8390	8.8543	9.9462
12/2045	14.2264	14.4763	10.4838	14.5834

B.2: Fuel Oil Prices Projection

Table Appendix B-2. Fuel Oil Prices Projection 2022-2046

Year	Distillate Oil Price (2018 $/MMBtu)	Residual Oil Price (2018 $/MMBtu)
2021	19.61	13.29
2022	19.96	12.77
2023	20.12	12.12
2024	20.30	12.21
2025	20.40	12.22

2026	20.42	12.46
2027	20.70	12.67
2028	20.92	12.83
2029	21.31	13.14
2030	21.52	13.32
2031	21.89	13.61
2032	22.14	13.75
2033	22.42	13.95
2034	22.70	14.12
2035	22.82	14.32
2036	22.93	14.39
2037	23.46	14.77
2038	23.58	14.91
2039	23.84	15.11
2040	24.05	15.27
2041	24.29	15.43
2042	24.32	15.52
2043	24.42	15.58
2044	24.45	15.58
2045	24.49	15.62

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APPENDIX C: Winter Fuel Switching Modelling

To estimate the impact on market operations and incremental CO2 emissions resulting from dual-fuel unit switching from gas to fuel oil on winter days with high gas prices TCR has developed an approach to modeling that switching. That approach involves the following key steps:

1. Estimate the number of days when switching from gas to oil is assumed to occur each year. To develop that estimate, TCR reviewed historical prices for No.2 Distillate fuel oil to identify days when Fuel oil 2 price dropped below the price of natural gas and take an average of that over several years[35].
2. Reviewed daily gas burn quantities during winter months from the MA 83C cases and develop a 'gas burn limit' such that the number of days in the simulation in which the gas burn exceeds the limit is equal to the assumed number of days of fuel switching identified in step 1 above.
3. Imposed the gas burn limit on all gas-fired power plants over the winter period i.e. December through February. Introduced a penalty cost for exceeding the burn limit equal to the price of fuel oil. Imposing that constraint emulates the fuel switching process in which only limited number of dual-fuel units will switch to oil
4. Developed a CO2 emission multiplier to adjust for additional emissions from fuel oil operation and apply it over the period that the penalty cost is applied for the base case and each proposal case.

35 TCR did not estimate the number of fuel switching days based on projections of gas prices and fuel prices as these projections were not granular enough for the analysis.

C.1: Estimating number of fuel switching days each year

In order to determine the number of days that the price of natural exceeded the price of fuel oil, TCR reviewed historic prices over a ten-year period for the following fuels:

- Henry Hub Natural Gas Spot Price36, Daily, Nominal Dollars per MMBTU (for reference only)
- Algonquin Gate Natural Gas Spot Price37, Daily, Nominal Dollars per MMBTU
- New York Harbor No.2 Fuel Oil38 (Distillate Fuel Oil / DFO), Monthly, Nominal Dollars per Gallon39
- New York Harbor No.6 Fuel Oil40 (Residual Fuel Oil / RFO), Monthly, Nominal Dollars per Barrel41

Figure C-1 provides a summary of the reviewed fuel prices in Nominal $/MMBTU with each vertical gridline representing the first day of the calendar year. TCR assumed that the fuel oil prices reported for each month held constant during that month and that gas prices on days for which there were no reported prices, i.e. gaps, were equal to prices reported for the most recent preceding day.

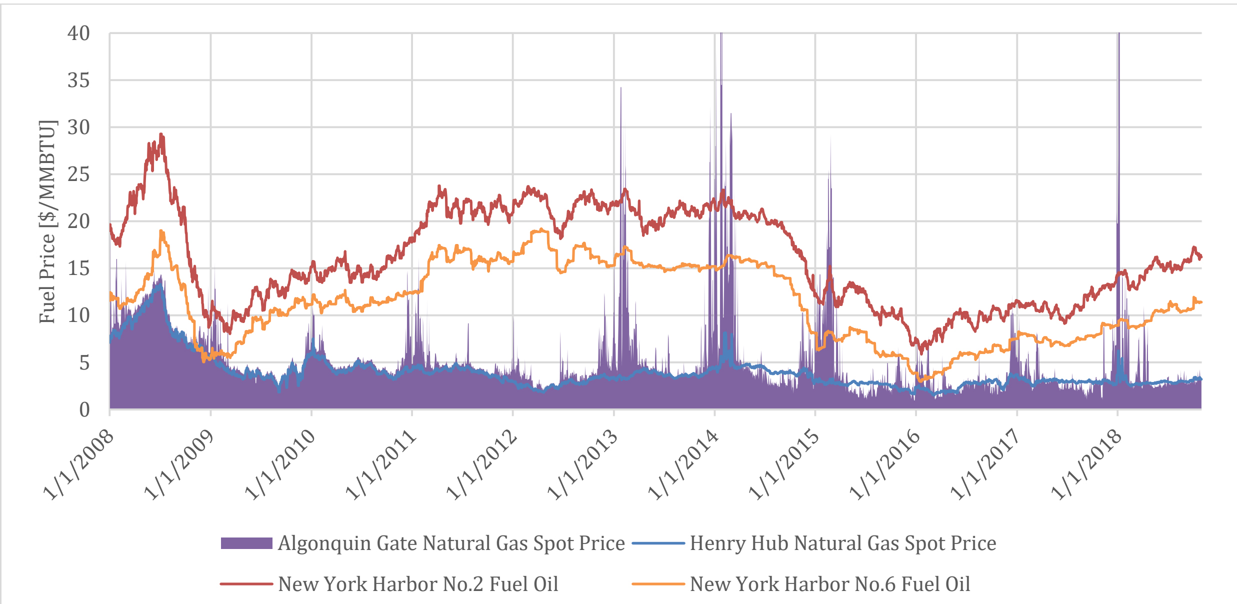

Figure C-1. Graph of historical fuel prices

36 EIA / Thomson Reuters (https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm)

37 S&P Global (https://platform.marketintelligence.spglobal.com/)

38 EIA / Thomson Reuters (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EER_EPD2F_PF4_Y35NY_DPG&f=M)

39 1 Gallon No.2 = 138.690 BTU, 1 Gallon No.6 = 149,690 BTU
(https://www.ct.gov/deep/lib/deep/energy/energyprice/energy_conversion_factors.pdf)

40 NYMEX / S&P Global (https://platform.marketintelligence.spglobal.com/)

41 1 Barrel = 42 Gallons, see footnote 4 for gallons to BTU

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TCR determined the aggregate number of days in each December, January, February period, i.e. 'three winter month period", on which the gas spot price at the Algonquin City Gate (i) exceeded the price of No.2 Fuel Oil (DFO), and (ii) exceeded the price of No.6 Fuel Oil (RFO) respectively.

TCR developed a representative number of 'days-per-three winter month winter-period' on which dual-fuel generators would switch from natural gas to their respective secondary fuels based on price by averaging the aggregate number of days in excess of fuel oil prices for the most recent six three winter month periods, i.e. winter of 2012/2013 through winter of 2017/2018. The representative number of 'days-per-three winter month -period' for dual-fuel units capable of switching to DFO is fifteen days and for duel-fuel units capable of switching to RFO is thirty-five days.

Figure C-2 provides the results of this analysis.

Calculation 1 Number of Days Gas Price exceeds No.2 Fuel Oil Price (DFO)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	1	7	0	0	0	4	14	7	1	0	11
Feb	0	2	0	0	0	4	12	19	2	0	0
Dec	1	0	0	0	0	6	1	0	1	5	

Winter of	2008 / 2009	2009 / 2010	2010 / 2011	2011 / 2012	2012 / 2013	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018
Days	10	0	0	0	8	32	27	3	1	16

6 yr Average 15 Days

Calculation 2 Number of Days Gas Price exceeds No.6 Fuel Oil Price (RFO)

Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	7	28	0	4	0	6	18	24	28	1	17
Feb	8	11	0	0	0	13	18	28	9	0	7
Dec	31	0	2	0	0	10	4	3	14	8	

Winter of	2008 / 2009	2009 / 2010	2010 / 2011	2011 / 2012	2012 / 2013	2013 / 2014	2014 / 2015	2015 / 2016	2016 / 2017	2017 / 2018
Days	70	0	6	0	19	46	56	40	15	32

6 yr Average 35 Days

Figure C-2. Number of days in winter period with fuel price exceeding the price of fuel oil

TCR determined how it should apply these results in its ENELTYIX modeling by identifying the percentage of ISO-NE gas-fired capacity capable of switching to DFO and to RFO respectively. A review of the ISO-NE CELT 2018[42] generators list indicates that of the 5.5 GW of gas-fired units that have dual-fuel capability, 98%[43] list DFO as their secondary fuel. Based upon those statistics TCR proposes to assume fifteen days of fuel switching during the three winter month periods on average over the study period.

42 https://www.iso-ne.com/static-assets/documents/2018/04/2018_celt_report.xls

43 Combined Cycle and Combustion Turbine (peaker) units represent 5,416 MW of a total 5,511 MW Natural gas based dual-fuel generation capacity listed in CELT. West Springfield 3 is a 95 MW steam turbine unit and is the only generator that lists RFO as a secondary fuel. The impact of RFO switchover was concluded to not be significant to the analysis and ignored.

C.2: **Develop daily gas burn limit**

Having developed an assumed average number of fuel switching days per three winter month period, TCR developed an assumed "daily gas burn limit" (MMBtu/day) beyond which dual-fuel gas-fired generators would switch to fuel oil. TCR developed the daily gas burn limit from the results of its ENELYTIX modelling of the New England electricity market for the Vineyard Wind 800 GLL case (MA 83C), as that case most closely represents the generation mix TCR expects for the RI RFP Base Case.

TCR developed the daily gas burn limit from the results of the Vineyard Wind 800 GLL case in two basic steps. First, TCR started with a draft assumed limit and determined the number of days in each three-winter month period on which the daily gas burn quantity exceeded that draft assumed limit. TCR used those results to revise (calibrate) the draft limit until it determined the burn quantity per day at which the average number of days per three-month period exceeding it over all winter periods in the study period for that case, i.e. 2021/22 through 2041/42, would be fifteen days. The resulting daily gas burn limit assumption is 820,000 MMBTU / day.

Figure C-3 plots the daily gas burn limit and the average daily gas burn quantities by month in each of the three winter month periods from the Vineyard Wind 800 GLL case

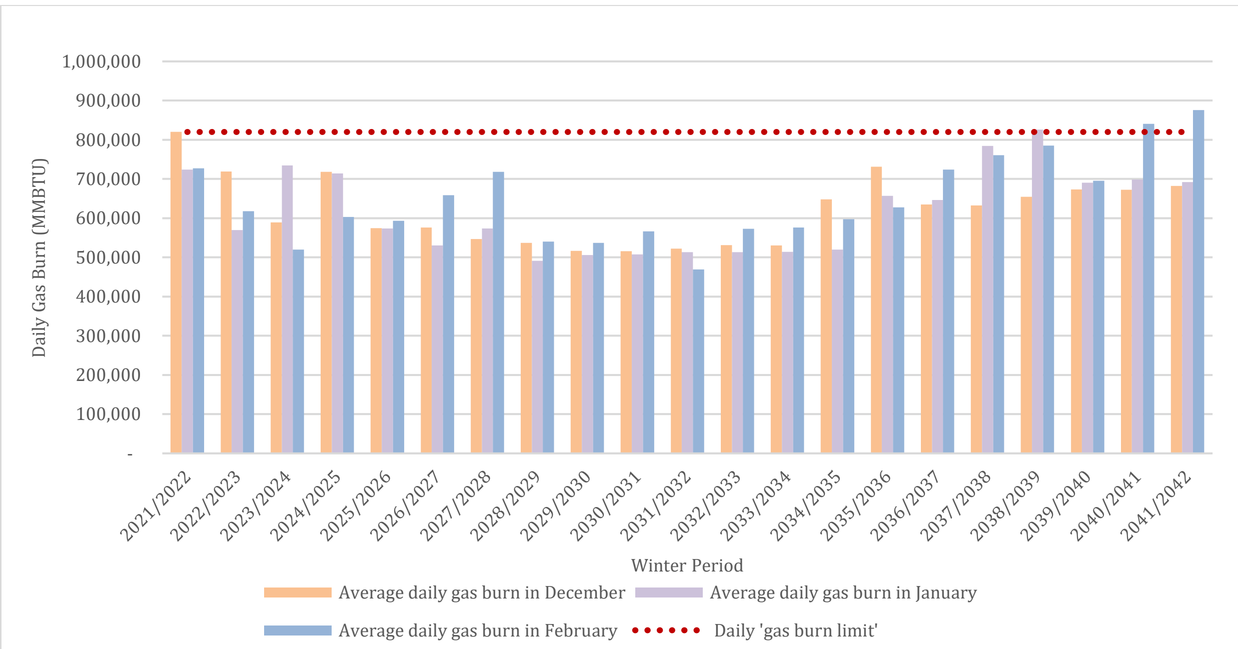

Figure C-3. Gas Burn Limit Analysis, Vineyard Wind 800 GLL case

Figure C-4 presents the number of days in each three-winter month period on which the projected daily gas burn exceeds the daily gas burn imit.

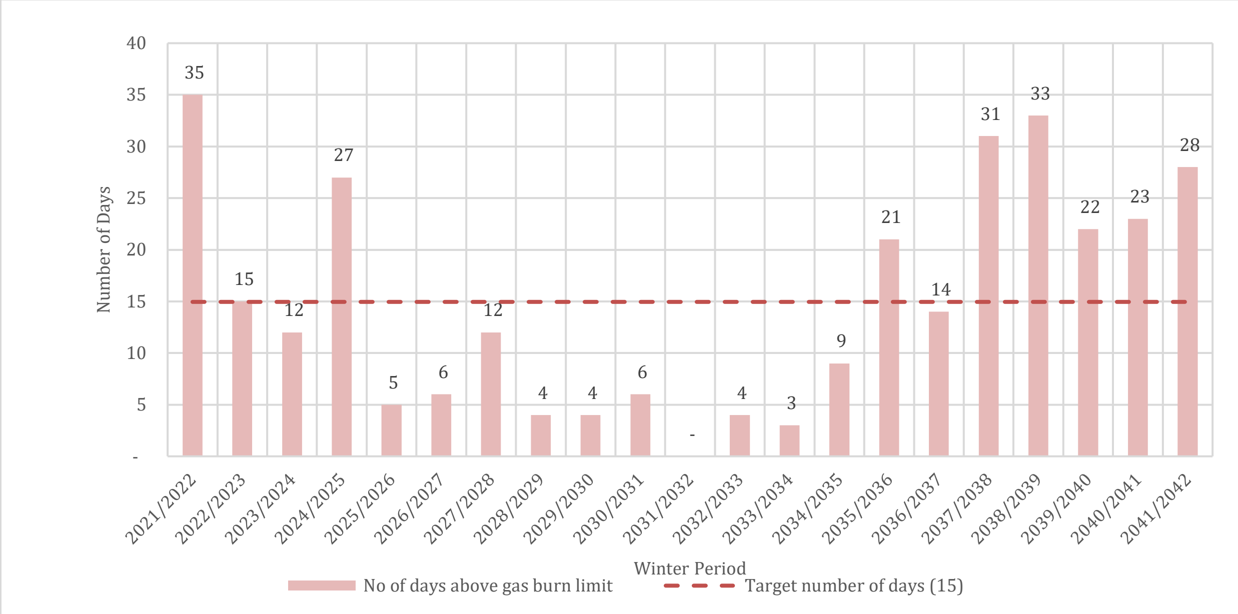

Figure C-4. Days exceeding daily gas burn limit by three-month winter period, Vineyard Wind 800 GLL case

C.3: Impose gas burn limit on all gas fired generators

In its ENELYTIX modeling TCR proposes to impose penalty costs on daily gas use in December through January that exceeds the daily gas burn limit established in step (b). TCR will impose these penalty costs in the base case and each proposal case. The penalty cost imposed for exceeding this limit will represent the incremental costs associated with operating on fuel oil. The penalty costs will be as follows:

a. **Premium on fuel cost:** Penalty cost per MMBTU equal to the price difference between the projected prices of DFO in New England and the project prices of natural gas, averaged across all New England natural gas hubs.
b. **Premium on cost of GHG emissions:** Penalty cost per MMBTU equal to the RGGI price in that given year multiplied by the difference in the GHG emission factors for DFO and natural gas

C.4: Develop GHG emission multipliers to adjust additional GHG emission from fuel oil

To account for adjustments to reported GHG emission outside the ENELYTIX model, TCR applied a GHG emission multiplier of 44.3 lbs. CO_2/MMBTU for each MMBTU that is reported to be in violation of the constraint set in step (c). This multiplier is calculated as the difference in CO_2 emission factors for DFO and natural gas as reported by EIA[44].

44 https://www.eia.gov/environment/emissions/co2_vol_mass.php

APPENDIX D:
Mystic Units 8 & 9 Fuel Price Assumptions

TCR proposes the RI RFP Base Case Assumes that Mystic 8 & 9 units continue to operate over the study period. TCR will develop price assumptions for LNG specific to these units for the period after their RMR agreements terminate. The LNG price assumptions will reflect anticipated differences in prices of LNG to the units in winter versus summer.

D.1: Background

On July 13,2018 FERC accepted[45] the filing by Constellation Mystic Power, LLC (Mystic) pertaining a Reliability Must Run (RMR) agreement executed between Mystic, Exelon Generation Company LLC (Exelon) and ISO-NE. Previously, ISO-NE rejected Exelon's retirement de-list bids for their Mystic 8 & 9 natural gas fired units, and requested FERC to accept the RMR agreement that would allow them to retain those units and ensure fuel security in New England. The RMR agreement provides a cost of service compensation to Mystic for continued operation of Mystic 8 & 9 for the two years associated with the capacity commitment periods FCA 13 and FCA 14, beginning June 1, 2022 through May 31, 2024 (RMR period). It is unclear at this point whether the Mystic Units will continue operation beyond the RMR period.

To capture this future uncertainty, TCR will assume the Mystic units could continue operation over the study period but allow the capacity expansion simulation to 'predict' if, and when, the units retire based on a system wide economics. The outcome of this decision will rely on revised input assumptions for the price of fuel available to the Mystic units over the study period.

D.2: Revised input assumptions – price of Mystic 8 & 9 fuel gas

The Mystic Units exclusively source their natural gas from the Everett LNG import terminal (Distrigas Facility). The import terminal is currently owned by Engie Gas & LNG Holdings LLC but in the process of being purchased by Exelon, who are also the owners of the Mystic units. Recognizing that the units do not have direct access to pipeline gas, TCR assumes that they would remain reliant on LNG imports beyond the termination of the RMR agreement and that the price of fuel available to them in a given month 'MM' of year 'YY' will be calculated as:

Price of Natural Gas (YY,MM) = max {Price of Natural gas at Algonquin Hub (YY,MM), Price of LNG (YY)}

Where, *Price of LNG (YY) = Dutch TTF[46] price (YY) + $1/MMBTU[47]*

D.3: Forecasting the Price of Dutch TTF

To obtain LNG prices for the Mystic 8 & 9 units beyond the RMR for the entire study period, TCR developed projections of Dutch TTF prices using Dutch TTF natural gas futures available on the

45 FERC Filing: https://www.ferc.gov/CalendarFiles/20180713175746-ER18-1639-000.pdf

46 Natural gas futures at the Dutch Title Transfer Facility (TTF) virtual trading point

47 Adjustment costs to account for logistics and delivery to New England

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intercontinental exchange (ICE)48 and a linear regression to projected prices of crude oil. There is a strong correlation between prices of natural gas and crude oil in European energy markets. Refer to Figure D-1 for TCR LNG price projection.

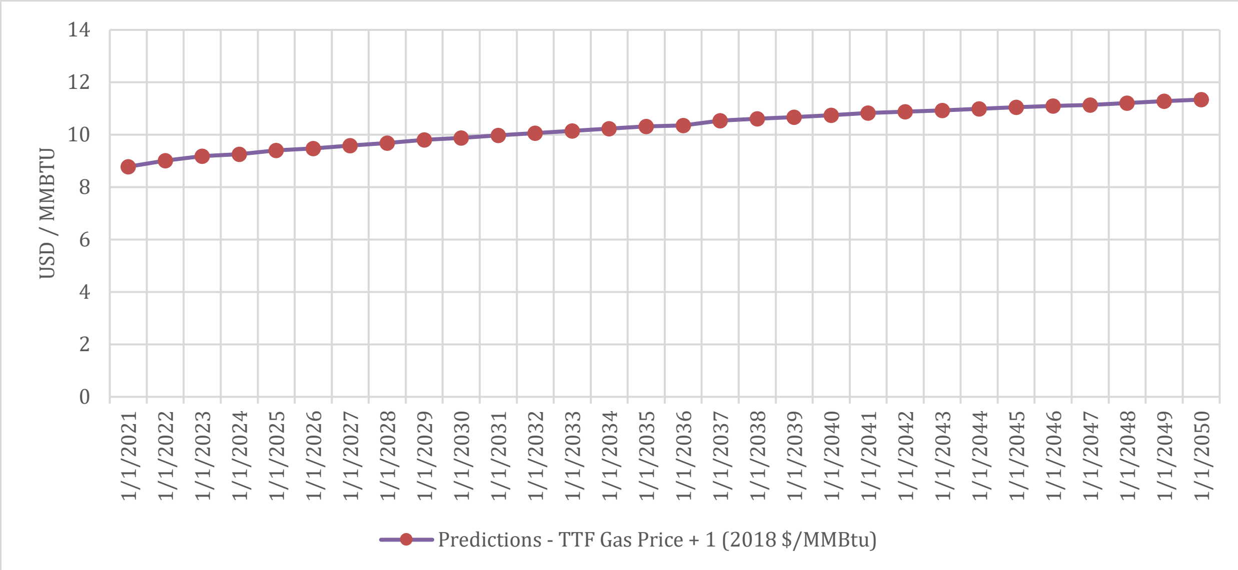

Figure D-1 Projected prices for LNG (Dutch TTF +$1)

D.4: Regression Analysis

TCR developed projections for natural gas prices for Dutch TTF by regressing historic natural gas prices reported for Dutch TTF against the historic prices for crude oil (WTI index) over the five-year period (October 2013 through October 2018). Figure D-2 presents the monthly historical prices obtained for natural gas at Dutch TTF49, converted from Euro/MWh to 2018$/MMBTU50, as well as the monthly historical prices obtained for crude oil51 represented in 2018$/Barrel.

TCR used the 5-year historic monthly data that was used to produce Figure D-2 as the inputs to a linear regression model (y = m*x + c) The model uses crude oil price [2018$/Barrel] as the predictor variable (x) and the Dutch TTF Natural gas price [2018$/MMBTU] as the response variable (y). The linear regression results in an R-squared value of 0.69 with coefficients of 0.0697 [Barrels/MMBTU] for the slope (m) and 2.51 [2018$/MMBTU] as the intercept (c). Refer to Figure D-3.

The coefficients of regression were applied to the annual projections of crude oil52 to obtain the annual prices of natural gas at Dutch TTF.

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48 https://www.theice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=1660802&span=2

49 Quandl, Settled Price (https://www.quandl.com/data/CHRIS/ICE_TFM1-Endex-Dutch-TTF-Gas-Base-Load-Futures-Continuous-Contract)

50 Historical average monthly Euro to USD conversion factors from S&P Global (https://platform.marketintelligence.spglobal.com/), 1 Wh = 3.142 BTU, inflation rates to 2018$ from CPI Index (https://www.bls.gov/regions/new-england/data/consumerpriceindex_us_table.htm)

51 EIA / Thomson Reuters (http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm)

52 EIA AEO 2018, West Texas Intermediate Spot (https://www.eia.gov/outlooks/aeo/tables_ref.php)

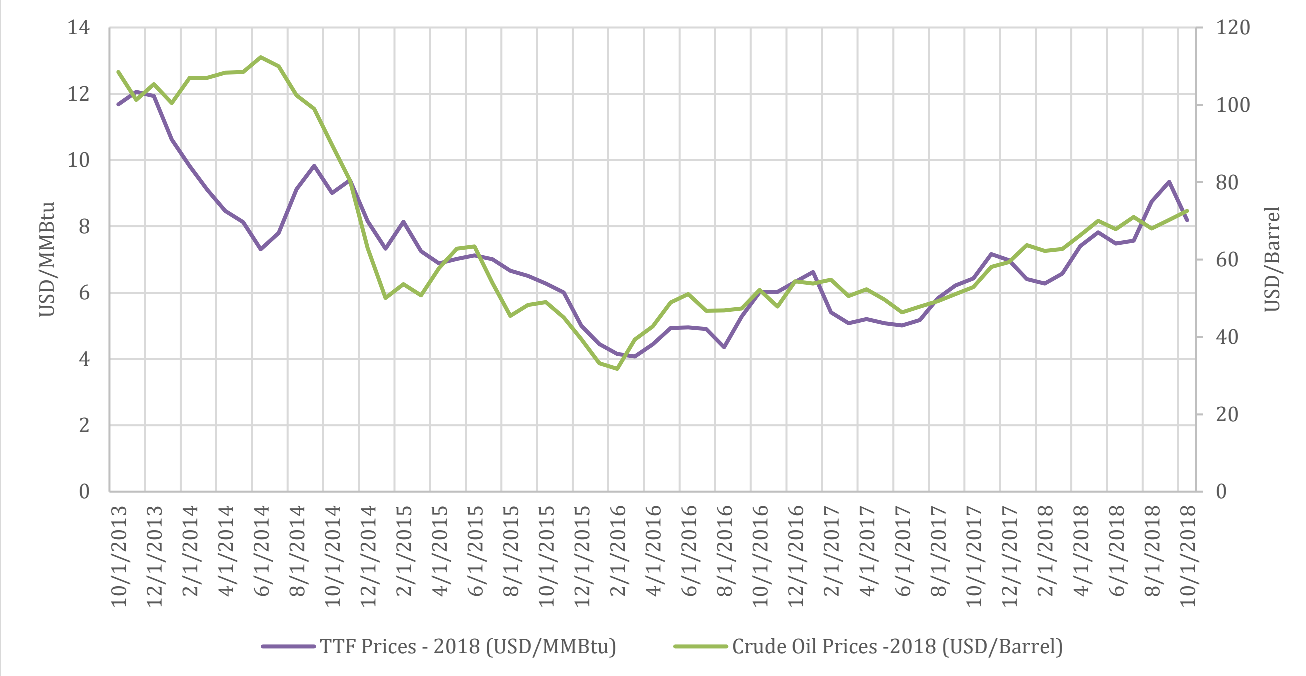

Figure D-2 Historical prices of Dutch TTF natural gas and crude oil in 2018$

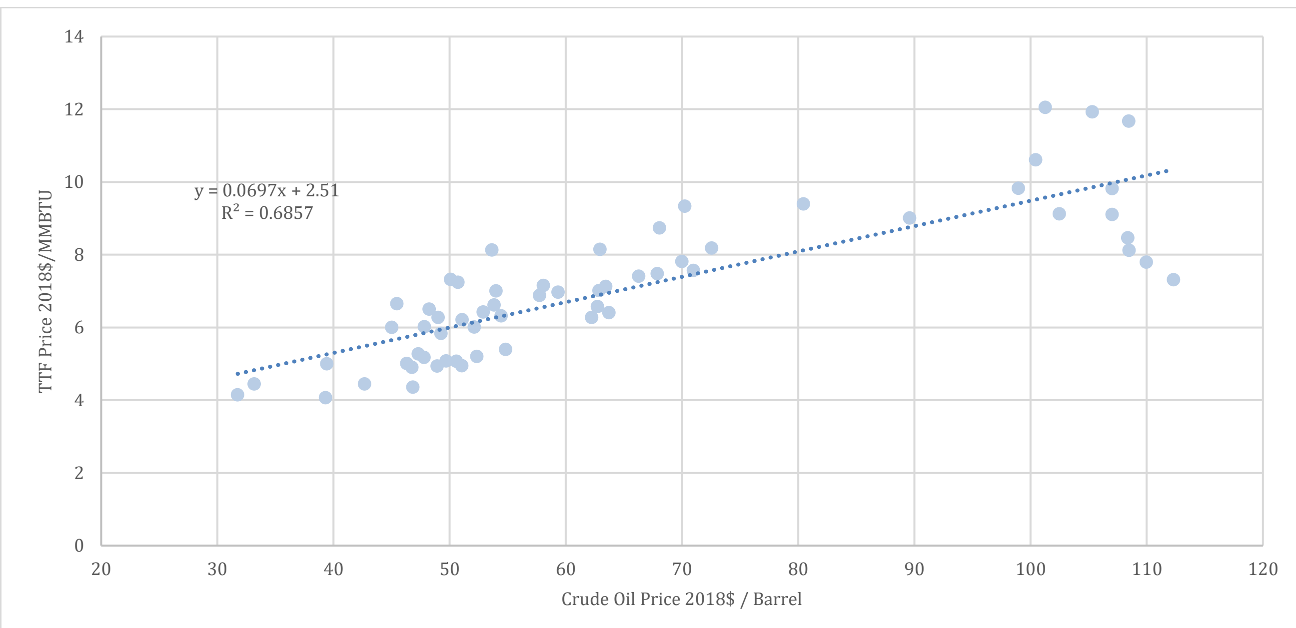

Figure D-3 Regression results

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E.2: New York Document

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T C R

Final Report

Base Case for Evaluation of 2018 RI RFP Proposals -

Input and Modeling Assumptions

New York

Prepared for: **Narragansett Electric Company d/b/a. National Grid**

Tabors Caramanis Rudkevich

January 27, 2020

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CHAPTER 1:
Model Overview and Footprint

This document describes the modeling and input assumptions specific to New York that the TCR team propose for the Base Case against which Narragansett Electric Company d/b/a National Grid ("Narragansett") will measure the incremental costs and benefits of each Proposal received in response to the request for proposals for long-term contracts for renewable energy (2018 RI RFP") issued by Narragansett on September 12, 2018. TCR refers to this as the "2018 RI RFP Base Case" or simply the "RI RFP Base Case".

The complementary document "Base Case Evaluation of 2018 RI RFP Proposals – Input and Modeling Assumptions New England" describes all 2018 RI RFP Base Case modeling and input assumptions that are common to both New York and New England.

1.1: Model footprint

TCR will model the New York Energy and Ancillary Services (E&AS) market to simulate day-ahead and real-time economic transactions between ISO-NE and NYISO. To that end, TCR will use ENELYTIX's production costing capability to simulate the operation of the two neighboring markets – ISO-NE and NYISO. The New England assumptions document describes the ENELYTIX modeling environment as applied to E&AS markets.

TCR will not model the New York ISO capacity expansion, RPS compliance or capacity market.

CHAPTER 2: Transmission Topology

ENELYTIX® model organizes physical location of all network resources and loads using bus bar and node mapping. The NYISO transmission topology was modeled based on 2015 FERC 715 powerflow fillings for summer peak 2017. TCR verified the power flow model against the NYISO queue to make sure that essential projects are represented in the power flow case. Generators are mapped to bus bars/electrical nodes (eNodes). Bus bars are mapped to NYISO areas and to specific areas outside NYISO system. The mapping of load nodes to NYISO areas and external zones outside NYISO is used by ENELYTIX® to allocate area load forecasts to individual buses in proportion to bus specific loads in the power flow case.

In determining a representative list of transmission constraints to monitor, TCR included all major NYISO interfaces and critical contingencies. The set of contingencies to monitor and enforce was provided by PowerGEM based on the contingency analysis PowerGEM performed using their TARA tool and complemented by TCR analysis of historically binding constraints. However, to make the Energy and Ancillary Services model run faster, all contingencies exclusively in NY were omitted. TCR developed limits for interfaces based on information provided in NYISO planning studies. Table 1 shows the Interface limits applied.

Table 1. Interface limits

Constraint Name	Summer Max (MW)	Summer Min (MW)	Winter Max (MW)	Winter Min (MW)
DYSINGER-EAST	1,740	-9,999	1,740	-9,999
WEST-CENTRAL	400	-9,999	400	-9,999
MOSES-SOUTH	2,350	-9,999	2,350	-9,999
CENTRAL-EAST	2,350	-9,999	2,350	-9,999
TOTAL-EAST	4,850	-9,999	4,850	-9,999
UPNY-CONED	4,950	-9,999	4,950	-9,999
DNWDIE-SOUTH-PI	5,625	-9,999	5,625	-9,999

CHAPTER 3: System Demand

To simulate hourly operation of NYISO, ENELYTIX® requires hourly demand data of NYISO planning areas. TCR computes hourly forecast for each area by scaling hourly historic load shape to match the forecasted monthly energy and peak forecast for each NYISO area.

Goldbook 2018 projects energy and peak forecast to 2038. for the purpose of the 83C_II model, TCR assumes the load in NYISO would remain constant at 2038 level until the end of the study period.

3.1: Load Forecast

Table 2 and Table 3 summarize the forecasts of annual energy and peak load by NYISO load zones from 2021 through 2045. These forecasts reflect NYISO projections of energy reductions resulting from statewide energy efficiency programs, modified new building codes and appliance efficiency standards, the impact of retail solar PV, and rising load due to greater penetration of electric vehicles. NYISO labels these as "Baseline" forecasts.

The forecasts of annual energy and peak demand for 2021 through 2045 are from the New York 2018 Gold Book[1] ("2018 Gold Book"), the most recent available version. TCR assumes the demand would be constant after 2038

1 NYISO: 2018 Load and Capacity Report

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Table 2. 50/50 annual energy by NYISO zone (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2021	14,972	9,648	15,533	6,039	7,460	11,569	9,382	2,887	5,820	51,173	20,084	154,567
2022	14,908	9,605	15,444	6,031	7,408	11,496	9,310	2,882	5,808	50,992	20,014	153,898
2023	14,869	9,582	15,386	6,026	7,374	11,451	9,259	2,884	5,811	50,942	20,009	153,593
2024	14,842	9,570	15,346	6,022	7,349	11,418	9,222	2,889	5,823	50,954	20,041	153,476
2025	14,821	9,565	15,315	6,019	7,330	11,393	9,194	2,896	5,838	50,989	20,094	153,454
2026	14,806	9,566	15,292	6,017	7,315	11,373	9,174	2,904	5,855	51,043	20,159	153,504
2027	14,803	9,575	15,284	6,016	7,307	11,364	9,165	2,915	5,878	51,143	20,241	153,691
2028	14,805	9,588	15,281	6,016	7,303	11,360	9,162	2,926	5,901	51,259	20,325	153,926
2029	14,807	9,601	15,279	6,015	7,299	11,356	9,161	2,936	5,923	51,361	20,396	154,134
2030	14,803	9,610	15,271	6,014	7,292	11,347	9,158	2,945	5,939	51,426	20,448	154,253
2031	14,799	9,618	15,263	6,012	7,286	11,338	9,157	2,952	5,953	51,476	20,490	154,344
2032	14,794	9,625	15,255	6,011	7,280	11,328	9,156	2,958	5,965	51,522	20,527	154,421
2033	14,793	9,633	15,252	6,010	7,277	11,322	9,158	2,963	5,978	51,587	20,568	154,541
2034	14,795	9,644	15,253	6,010	7,275	11,318	9,165	2,970	5,993	51,674	20,614	154,711
2035	14,806	9,659	15,264	6,011	7,279	11,321	9,177	2,977	6,011	51,797	20,670	154,972
2036	14,819	9,675	15,277	6,011	7,284	11,326	9,193	2,985	6,030	51,936	20,728	155,264
2037	14,834	9,692	15,294	6,012	7,291	11,332	9,211	2,993	6,050	52,091	20,789	155,589
2038 - 2045	14,849	9,710	15,311	6,013	7,299	11,339	9,232	3,000	6,070	52,251	20,850	155,924

Table 3. Noncoincidental summer peak by NYISO zone (MW)

Year	A	B	C	D	E	F	G	H	I	J	K
2021	2,902	2,030	2,849	744	1,331	2,340	2,208	679	1,460	11,363	5,246
2022	2,892	2,023	2,833	743	1,323	2,327	2,191	679	1,458	11,336	5,231
2023	2,886	2,020	2,823	742	1,316	2,320	2,179	679	1,458	11,328	5,229
2024	2,883	2,019	2,817	742	1,312	2,316	2,171	680	1,460	11,335	5,237
2025	2,883	2,021	2,814	741	1,310	2,314	2,167	681	1,463	11,350	5,251
2026	2,884	2,023	2,814	741	1,309	2,314	2,165	683	1,466	11,372	5,268
2027	2,887	2,027	2,815	741	1,309	2,315	2,164	685	1,470	11,399	5,287
2028	2,890	2,031	2,817	741	1,309	2,317	2,165	687	1,474	11,429	5,306
2029	2,894	2,036	2,820	741	1,310	2,319	2,167	689	1,478	11,457	5,324
2030	2,899	2,040	2,823	741	1,311	2,321	2,169	690	1,481	11,481	5,341
2031	2,903	2,044	2,826	741	1,312	2,322	2,171	692	1,483	11,503	5,354
2032	2,906	2,049	2,828	741	1,313	2,324	2,174	693	1,486	11,523	5,367
2033	2,909	2,053	2,831	741	1,314	2,325	2,176	693	1,488	11,544	5,378
2034	2,913	2,057	2,835	741	1,316	2,327	2,180	694	1,490	11,567	5,391
2035	2,918	2,061	2,839	741	1,318	2,329	2,184	695	1,493	11,595	5,403
2036	2,923	2,066	2,843	741	1,320	2,331	2,188	696	1,495	11,624	5,416
2037	2,927	2,070	2,849	741	1,323	2,334	2,193	697	1,498	11,654	5,429
2038 - 2045	2,932	2,074	2,854	741	1,325	2,338	2,200	698	1,500	11,688	5,442

3.2: Hourly Load Shapes

TCR develops load forecast based on 2012 load shape to align load shape with NREL's photovoltaic and wind shape data, which are only available based on 2012 weather pattern.

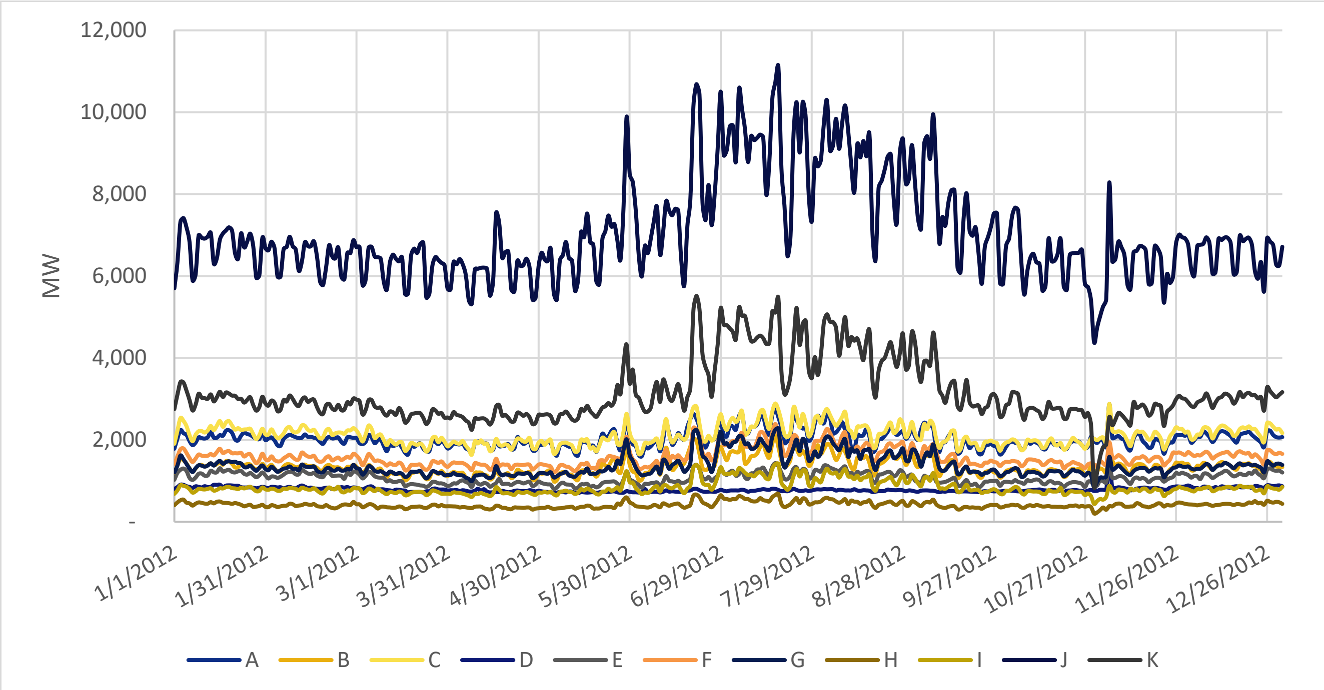

Figure 1. NYISO 2012 historic hourly load

CHAPTER 4:
Ancillary Service Requirements

Following NYISO's structure of ancillary services, TCR models three types of reserves: 10 minute spinning (10MSR), 10 minute non-spinning (10MNSR) and 30 minute reserves (30MR). Reserves are cascading, excess higher quality reserves counted toward meeting lower quality reserve requirements. Excess 10MSR counted toward 10MNSR requirements and both excess 10MSR and 10MNSR reserves counted toward 30MR. Spinning reserves are based upon NERC requirements. In addition, NYISO has locational requirements for the reserves on Long Island and near Central East. TCR assumes that hydro can provide regulation and spinning reserves for up to 50% of its available dispatch range. Non-spinning reserves could be provided by GTs and Internal Combustion (IC) units. Nuclear and renewable resources provide no reserves. Table 4 summarizes reserve requirements in NYISO.

Table 4. New York ISO reserve requirements

Reserve Type	Area	Requirement (MW)
10MSR	NYISO	665
10MNSR	NYISO	665
30MR	NYISO	665
10MSR	ENY (Zones F-K)	330
10MNSR	ENY	870
10MNSR	K	120
30MR	K	150 Off-peak /420 On-peak

CHAPTER 5: Generating Capacity

TCR obtains operating and planned NYISO generating assets from MA83D and MA83C_I quantitative evaluation model dataset, which is based on 2017 NYISO Goldbook. For RI RFP, TCR updated NYISO generating facility dataset based on 2018 NYISO Goldbook updates. Generator capacity and fuel conversion were updated according to 2018 Goldbook release.

5.1: Scheduled generator additions:

TCR obtained scheduled capacity additions using the NYISO interconnection queue and S&P Global' s generation asset database. TCR obtains a listing of projects that are currently under construction from both sources and then cross references them to obtain a complete collection of scheduled generation additions and upgrades. Table 5 summarizes TCR's scheduled generator additions in the model.

Table 5. Scheduled Generation Additions and Update

Name	Energy Area	Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	In-Service Date	Fuel Type
Cricket Valley CC1	G	CCg100+	365.5	365.5	3/1/2020	NG
Cricket Valley CC2	G	CCg100+	365.5	365.5	3/1/2020	NG
Cricket Valley CC3	G	CCg100+	365.5	365.5	3/1/2020	NG

5.2: Scheduled retirements:

TCR obtained approved NYISO generation retirements from 2018 Gold Book. Table 6 summarizes approved retirement.

Table 6. NYISO Approved Retirements

Name	Energy Area	Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Retirement Date	Fuel Type
Indian Point 2	H	NUC-PWR+	1016.1	1025.9	4/1/2020	Uranium
Indian Point 3	H	NUC-PWR+	1037.9	1039.9	4/1/2021	Uranium

CHAPTER 6:
Generating Unit Operating Characteristics

6.1: Generator Aggregation

To optimize model computation time, TCR aggregates all units below 20 MWs by type, fuel and area into a smaller set of units. Full load heat rates for the aggregates are calculated as the average of the individual units and all other parameters are inherited from the unit type.

6.2: Thermal Unit Characteristics

Thermal generation characteristics are generally determined by a generator's technology and fuel type. These characteristics include heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

TCR developed generator outage and heat rate data from information by similar unit type as obtained from both the North American Electric Reliability Corporation (NERC) Generating Availability Report and power industry data provided by S&P Global.

Each thermal unit type has a distinct normalized incremental heat rate curve. The normalized heat rate curve is scaled by the full load heat rate (FLHR) to produce unit specific heat curve. Table 7 summarizes the shape of normalized heat rate curve used in ENELYTIX.

Table 7. Normalized incremental heat rate curve

Unit Type	Blocks (Total)	Block	Capacity Range (% of Max)	Heat Rate (% of FLHR)
CT	1	1	100%	100%
CC	4	1	50%	113%
		2	51% ~ 67%	75%
		3	68% ~ 83%	86%
		4	84% ~ 100%	100%
ST (Coal)	4	1	0% ~ 50%	106%
		2	51% ~ 65%	90%
		3	66% ~ 95%	95%
		4	96% ~ 100%	100%
ST (Other)	4	1	25%	118%
		2	26% ~ 50%	90%
		3	51% ~ 80%	95%
		4	81% ~ 100%	100%

Source: ENELYTIX® data set

As an example, for a 500 MW CC with a 7,000 Btu/KWh FLHR, the minimum load block would be its minimum generation of 250 MW at a heat rate of 7,910 Btu/KWh, the 2nd incremental block would be 251 MW ~ 335 MW at a heat rate of 5,250 Btu/KWh, the 3rd increment would be 336 MW ~ 415 MW at a heat rate of 6,020 Btu/KWh, and the final block would be 416 MW ~ 500 MW at a heat rate of 7,000 Btu/KWh.

Table 8 summarizes other operating character assumptions by unit type for thermal generators. The abbreviations in the unit type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (**g**as, **o**il, **c**oal, **b**iomass, **r**efuse) and the numbers identify the size of generating units mapped to that type.

Table 8. Other thermal unit operating parameters by unit type

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	AvgNumFO	VOM	Startup Cost Cold ($/MWh)
CCg100 (0-100MW)	6	8	4.29	6.29361	2.5	35
CCg100+ (100-9999MW)	6	8	4.29	6.29361	2.5	35
CCgo100 (0-100MW)	6	8	4.29	6.29361	2.5	35
CCgo100+ (100-9999MW)	6	8	4.29	6.29361	2.5	35
GTg20 (0-20MW)	1	1	18.6	7.17047	10	0
GTg50 (20-50MW)	1	1	12.97	5.97854	10	0
GTgo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTgo50 (20-50MW)	1	1	12.97	5.97854	10	0
GTo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTo20 (0-20MW)	1	1	18.6	7.17047	10	0
GTo50 (20-50MW)	1	1	12.97	5.97854	10	0
GTo50+ (50-9999MW)	1	1	9.29	8.83609	10	0
ICb+ (0-500MW)	1	1	11.63	5.36087	10	0
ICg20 (0-20MW)	1	1	21.16	8.15737	10	0
ICg50 (20-50MW)	1	1	11.54	5.31938	10	0
ICg50+ (50-500MW)	1	1	11.54	5.31938	10	0
ICgo20 (0-20MW)	1	1	21.16	8.15737	10	0
ICgo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICgo50 + (50-500MW)	1	1	11.54	5.31938	10	0
ICo20 (0-20MW)	1	1	21.16	8.15737	10	0
ICo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICo50 (20-50MW)	1	1	11.54	5.31938	10	0
ICo50+ (50-500MW)	1	1	11.54	5.31938	10	0
STb+ (0-500MW)	1	1	10.26	6.60348	0	35
STc100 (0-100MW)	24	12	8.32	6.62999	5	45
STc250 (100-250MW)	24	12	6.47	7.56834	4	45
STc600+ (600-9999MW)	24	12	7.05	8.24258	2	45
STg100 (0-100MW)	10	8	10.34	3.04348	6	40
STg200 (100-200MW)	10	8	8.42	6.23223	5	40
STg600 (200-600MW)	10	8	8.35	8.25635	4	40
STgo100 (0-100MW)	10	8	10.34	3.04348	6	40
STgo200 (100-200MW)	10	8	8.42	6.23223	5	40
STgo600 (200-600MW)	10	8	8.35	8.25635	4	40
STo100 (0-100MW)	10	8	10.34	3.39285	6	40
STo200 (100-200MW)	10	8	8.42	8.38989	5	40

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	AvgNumFO	VOM	Startup Cost Cold ($/MWh)
STo600 (200-600MW)	10	8	8.35	5.96487	4	40
STo600+ (600-9999MW)	10	8	14.55	22.7626	3	40
STr+ (0-500MW)	10	8	10.26	6.60348	2	40
NUC-BWR1000MW+	164	164	2.19	1.26865	0	90
NUC-BWR (800-1000MW)	164	164	1.66	1.61458	0	90
NUC-BWR (400-799MW)	164	164	3.27	2.44982	0	90
NUC-PWR1000MW+	164	164	4.02	2.29472	0	90
NUC-PWR (800-1000MW)	164	164	3.02	1.03991	0	90
NUC-PWR (400-799MW)	164	164	3.02	2.03373	0	90

Source: ENELYTIX® data set

6.2.1: Nuclear Unit Operating Characteristics

Nuclear plants are modeled as special thermal units in ENELYTIX. In general, nuclear facilities are treated as must run units and assumed to run when available except for periods during generator maintenance and forced outage. Current refueling schedules are obtained from roadtech.com[2]. Future schedules are estimated per specified periodicity.

6.3: Hydro Electric Generator Characteristics

TCR models hydro electric generators as energy constrained generators that output energy in relation to daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. TCR obtains historic hydro generation MWh from EIA and S&P Global database. Based on this historic information, TCR develops daily maximum energy output for each hydro power plant in NYISO. Subject to this maximum energy output constraint, TCR allows ENELYTIX® to optimize hourly energy output of each hydro electric generator to minimize system-wide production costs in each hour of the day.

6.4: Pumped Hydro Storage Facilities

TCR models pumped storage with the following specifications obtained from the National Hydroelectric Power Resource Study prepared for the U.S. Army Engineer Institute of Water Resources.

- Max Storage: Unit Capacity * Number of Storage hours
- Min Storage: 10% of Max Storage
- Min MW: Pumping Capacity
- Efficiency: Annual Output/Annual Pumping Energy

2 https://www.roadtechs.com/shutdown/shutdown.php?region=n

6.5: Wind Facilities

Wind generation is represented as hourly generation profile in ENELYTIX®. TCR assembles wind generation profiles from the National Renewable Energy Laboratory (NREL)'s Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data.[3] TCR maps each wind power plant to the nearest NREL site based on the plant's location. For wind plants with known historic capacity factor, TCR further screens for NREL wind sites that have capacity factor within delta of 2% from historical average capacity factor inside a 50-mile radius range from the plant's location. The resulting normalized NREL site schedule is scaled to the installed capacity of the corresponding wind site and then calendar-shifted for each forecast year making it synchronized with load profiles and interchange schedules.

6.6: Solar Photovoltaics Facilities

Like wind facilities, photovoltaic (PV) generators are also represented as hourly generation profiles in ENELYTIX®. TCR obtains solar irradiation data from weather station closest to a PV generator's location and uses NREL's PVWatts® Calculator to estimate the site's energy production. TCR assumes all utility scale PV facilities are fixed array installations with characteristics summarized in Table 9.

Table 9. Photovoltaic parameter assumptions

PV Parameter	Assumption
Elevation (m)	5
Module Type	Standard
Array Type	Fixed (Open Rack)
Array Tilt (deg)	20
Array Azimuth (deg)	180
System Losses (%)	14
Invert Efficiency (%)	96

Source: ENELYTIX® data set

3 https://www.nrel.gov/grid/wind-toolkit.html

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CHAPTER 7:
Fuel Cost

7.1: Natural Gas Prices

TCR develops monthly spot gas price forecast for each natural gas market hub serving NYISO and neighboring system using OTC Global Holdings forward curves as of October 15th, 2018 for short term projections and the EIA Annual Energy Outlook (AEO 2018) reference case for long term projections. Additional details on TCRs methodology for developing prices at hubs is provided in the New England document. The relevant hubs serving NYISO are Niagara, Iroquois Waddington, Iroquois Zone 1, Iroquois Zone 2, Millennium Pipeline, Transco Zone 6 NY.

Figure 2 below summarizes TCR's natural gas hub price projection during the study period.

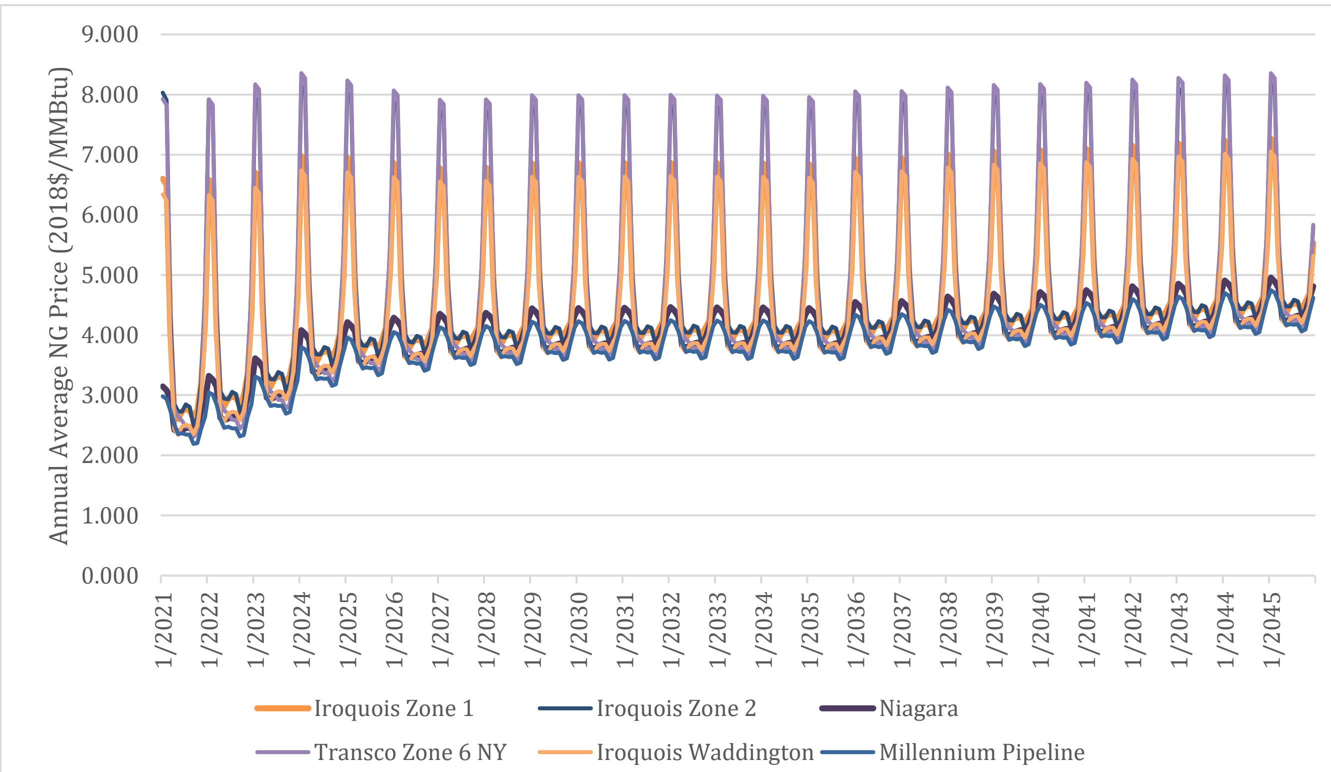

Figure 2. Projection of spot natural gas prices by NYISO pipeline hub (2018$/MMBtu)

7.2: Fuel Oil Prices

TCR obtained annual distillate and residual fuel oil price forecast from AEO 2018 reference case projection. TCR uses fuel oil prices projection for electric power sector in MidAtlantic region from AEO 2018's reference forecast case. TCR converted AEO 2018's price, which is reported in 2017 real dollar value, to 2018 real dollar value to be consistent with other price data used in the model.

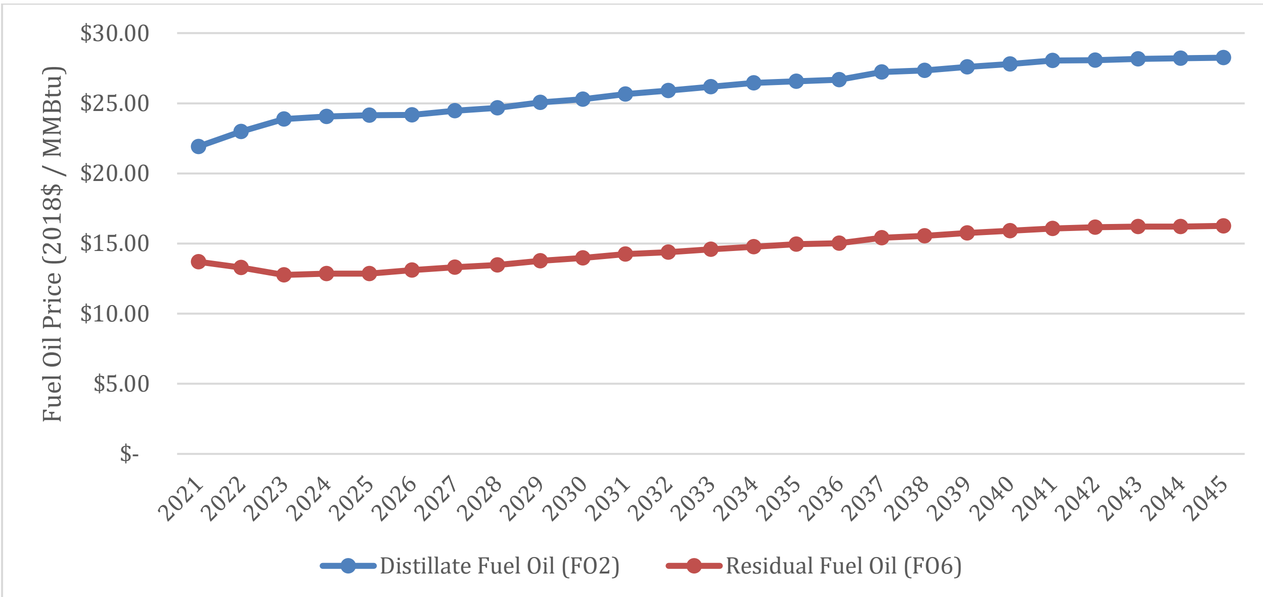

Figure 3. Projection of fuel oil price (2018$/MMBtu)

Source: EIA Annual Energy Outlook 2018

7.3: Uranium Prices

TCR develops uranium prices using the pricing calculator created by the Bulletin of the Atomic Scientist[4]. The calculator estimates the cost of electricity assuming the nuclear fuel cycle is "Once-Through". TCR omits all capital related cost associated with the cost of electricity from the calculator. The resulting uranium price is 0.99 Nominal $/MMBtu, which TCR assumed to be fixed.

4 http://thebulletin.org/nuclear-fuel-cycle-cost-calculator/model

7.4: Coal Prices

TCR develops plant level coal price from S&P Global's power plant operations data base. TCR derives coal cost in $/MMBtu by dividing S&P Global reported annual cost of coal delivered ($/ton) by annual average heat content of coal burned (Btu/lbs.). Based on this method, TCR calculates the exact coal cost for plants where data is available. For plants without sufficient data, TCR assumes the average cost from other coal plants in the same area and/or state.

TCR developed coal cost for this project using 2015-2017 coal price data by plant from S&P Global Services and converted said prices to real 2018 $/MMBtu. TCR assumes the prices reported in will remain at those levels over the study period.

Table 10 summarizes coal price for the two remaining coal fired power plants in NYISO.

Table 10. Coal price ($/MMBtu)

Name	Area	Price ($/MMBtu)
Cayuga 1	C	2.03
Somerset	A	2.04

Source: ENELYTIX® data set

CHAPTER 8: Emission Rates and Allowances

The two active emission control programs in NYISO footprint are the Regional Greenhouse Gas Initiative (RGGI) programs for Carbon dioxide and the Cross-State Air Pollutions Rule (CSAPR) for sulfur dioxide and nitrogen oxides emissions. TCR models both programs in this model.

8.1: Emission Programs

8.1.1: Regional Greenhouse Gas Initiative

New York participates in Regional Greenhouse Gas Initiative (RGGI) program. In this NYISO simulation, TCR uses CO_2 allowance price projection that it developed for New England, which is reproduced below in Figure 4.

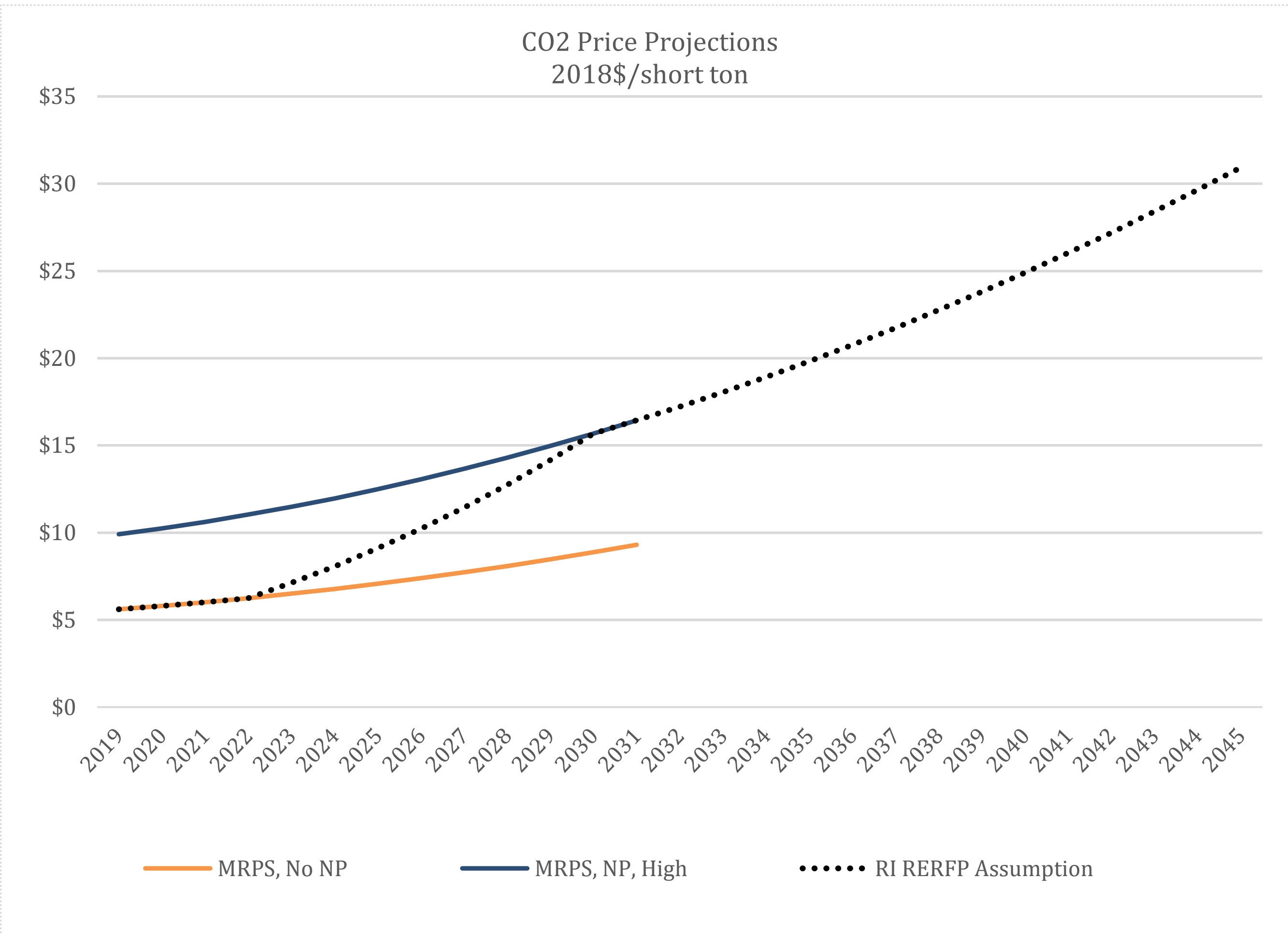

Figure 4. Projection of RGGI allowance price ($/short Ton)

8.1.2: Cross State Air Pollution Rule

The state of New York is covered by Cross State Air Pollution Rule (CSAPR) for both fine particles (SO_2 and annual NO_x) and ozone (seasonal NO_x). Figure 5 shows a map of CSAPR program coverage. In CSAPR terminology, "Seasonal NO_x" emission is the summer season from May 1 to October 31 while "Annual NO_x" emission refers to the rest of the year.

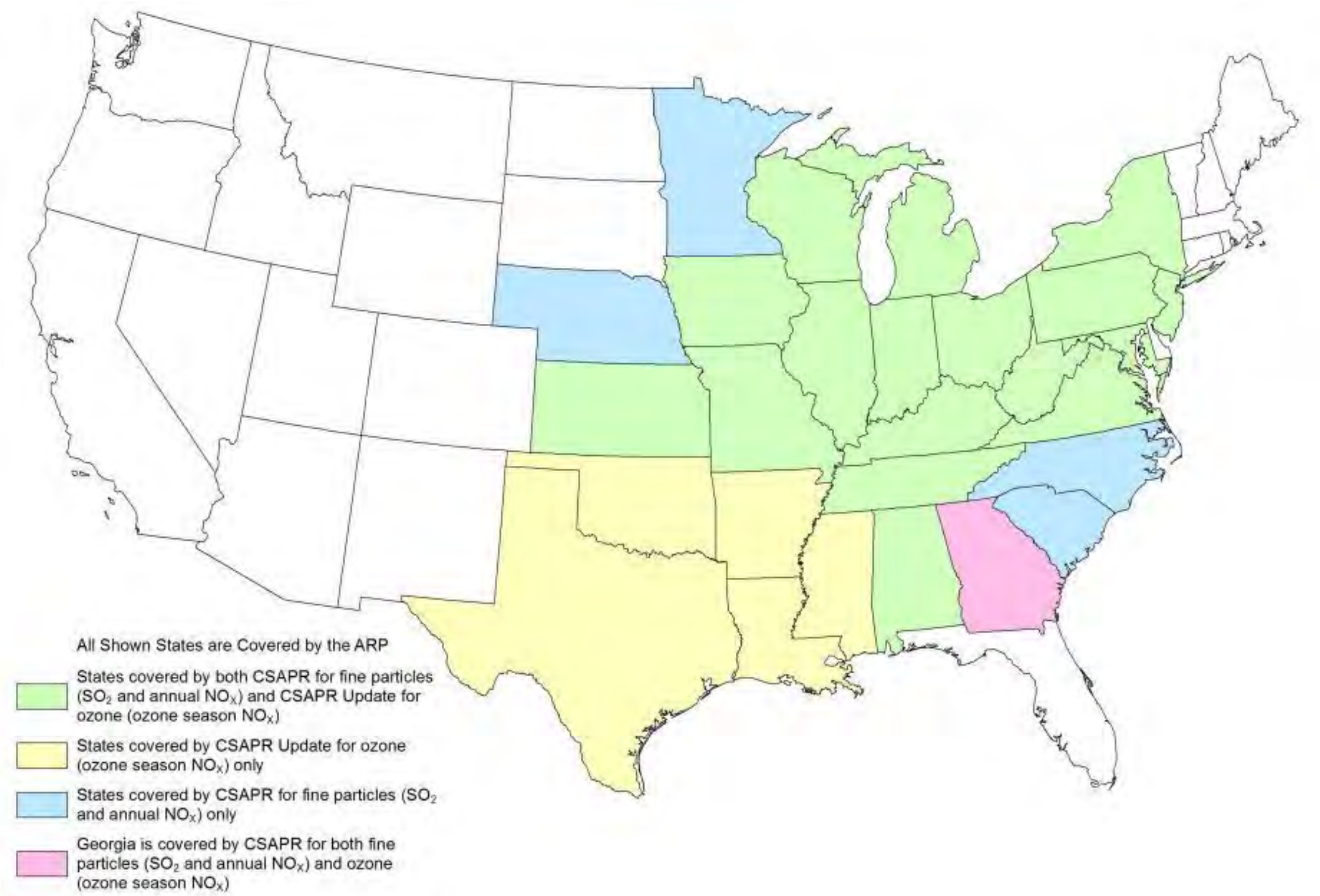

Figure 5. Map of states covered by CSAPR programs

Source: EPA

TCR obtains CSAPR programs' emission allowance prices from S&P Global's assessment of CSAPR program. Table 11 summarizes CSAPR prices used in the model.

Table 11. CSAPR emission allowance prices

Emission Type	$ per Allowance	Allowance	$/lbs
CSAPR NOx Seasonal	625	1 Allowance is 2000lbs	0.3125
CSAPR NOx Annual	3.5	1 Allowance is 2000lbs	0.0018
CSAPR SO2	2.75	2.86 Allowances is 2000lbs	0.0039

Source: ENELYTIX® data set

8.2: Emission Rates

TCR obtains generator unit level emission rates from three sources: S&P Global's historic unit emissions data base, S&P Global's simulated Generator Supply Curve (GSC) data base and EIA's generic future unit characteristics. For existing thermal units, TCR uses S&P Global's historic emission rates. For existing units without historic data, TCR uses GSC emissions data. Finally, for existing units without historic and GSC data, and future units not yet operating, TCR uses EIA's generic rates.

GLOSSARY

Term	Definition
10MNSR	10 Minute Non-Spinning Reserve
10MSR	10 Minute Spinning Reserve
30MR	30 Minute Reserves
ACP	Alternative Compliance Payments
ADR	Active Demand Response
AEO	Annual Energy Outlook
AESC	Avoided Energy Supply Cost
ALG	Algonquin
BIO	Biomass
BMPV/ BTM PV	Behind-the-meter Photovoltaic
CAGR	Compound Annual Growth Rate
CC	Combined Cycle
CEA	Concentric Energy Advisors
CEC	Clean Energy Credits
CECP	Clean Energy and Climate Plan
CEII	Critical Energy Infrastructure Information
CELT	Capacity, Energy, Loads, and Transmission
CES	Clean Energy Standard
CMR	Code of Massachusetts Regulations
COD	Commercial Operation/Online Date
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollutions Rule
CT	Combustion Turbine
CT PURA	Connecticut Public Utilities Regulatory Authority
DA	Day-ahead
DEP	Department of Environmental Protection
DERC	Discrete Emission Reduction Credits

Term	Definition
DFO	Distillate Fuel Oil
E&AS	Energy and Ancillary Services
EDC	Electric Distribution Company
EEA	Energy and Environmental Affairs
EFORd	Effective Forced Outage Rates
EGU	Electric Generating Units
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EPA	Environmental Protection Agency
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FOM	Fixed Operation & Maintenance
GHG	Greenhouse Gas
Gold Book	NYISO's Load & Capacity Data Report
GSC	Generator Supply Curve
GT	Gas Turbine
GWSA	Global Warming Solutions Act
HD	Hydro Power
HVDC	High Voltage Direct Current
IC	Internal Combustion (reciprocating) Engine
ICAP	Installed Capacity
ICR	Installed Capacity Requirements
ITC	Investment Tax Credit
Kirchhoff's laws	the current law and the voltage law
LDC	Load Distribution Company
LMP	Locational Marginal Price
LSE	Load Serving Entity

Term	Definition
LSR	Local Sourcing Requirement
MA DEP	Massachusetts Department of Environmental Protection
MIP	Mixed Integer Programming
MLP	Municipal Light Plant
MMD	Market Model Database
NEL	Net Energy Load
NEPOOL GIS	New England Power Pool Generation Information System
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NREL	National Renewable Energy Laboratory
PDR	Passive Demand Response
PME	Power Market Explorer
PNGTS	Portland Natural Gas
PPA	Power Purchase Agreement
PS	Pumped Storage Unit
PSO	Power System Optimizer
PTC	Production Tax Credit
PV	Photovoltaic
PVWatts®	NREL's PV Calculator
RCSA	Regulations of Connecticut State Agencies
REC	Renewable Energy Certificate, Renewable Energy Credit
RFO	Residual Fuel Oil
RFP	Requests for Proposal
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability Must Run
RPS	Renewable Portfolio Standard
RT	Real-time
SCED	Security Constrained Economic Dispatch
SCUC	Security Constrained Unit Commitment

Term	Definition
SENE	Southeast New England
SMART	Solar Massachusetts Renewable Target
ST	Steam Turbine
SUN	Solar Powered
TAO	Trading and Agreement Orders
TARA tool	Transmission Adequacy & Reliability Assessment tool
TGP	Tennessee Gas Pipeline
TMNSR	Ten-Minute Non-Spinning Reserve
TMOR	Thirty-Minute Operating Reserve
TMSR	Ten-Minute Spinning Reserve
VOM	Variable Operation & Maintenance
WACC	weighted average cost of capital
WAT	Water
WIND (NREL)	Wind Integration National Dataset
WT	Wind Turbine

APPENDIX A: Fuel Price Forecast

A.1: Natural Gas Prices

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
1/2021	6.603	8.030	3.146	7.926	6.342	2.980
2/2021	6.500	7.908	3.080	7.828	6.240	2.936
3/2021	4.015	4.348	2.936	4.042	3.755	2.740
4/2021	2.693	2.861	2.426	2.772	2.433	2.516
5/2021	2.602	2.734	2.386	2.647	2.343	2.356
6/2021	2.734	2.723	2.417	2.579	2.476	2.372
7/2021	2.767	2.848	2.452	2.483	2.510	2.347
8/2021	2.750	2.805	2.461	2.471	2.493	2.343
9/2021	2.609	2.497	2.447	2.306	2.352	2.192
10/2021	2.751	2.624	2.465	2.374	2.495	2.204
11/2021	3.183	3.227	2.748	3.035	2.928	2.444
12/2021	4.199	4.669	2.903	4.590	3.944	2.638
1/2022	6.584	7.918	3.319	7.921	6.330	3.045
2/2022	6.493	7.809	3.262	7.833	6.239	3.011
3/2022	4.138	4.440	3.146	4.197	3.884	2.852
4/2022	2.903	3.066	2.622	2.864	2.650	2.605
5/2022	2.817	2.945	2.586	2.750	2.564	2.460
6/2022	2.945	2.933	2.616	2.686	2.693	2.474
7/2022	2.977	3.055	2.649	2.595	2.725	2.450
8/2022	2.965	3.018	2.662	2.589	2.714	2.452
9/2022	2.833	2.722	2.654	2.442	2.582	2.318
10/2022	2.979	2.854	2.680	2.513	2.729	2.337
11/2022	3.346	3.377	2.969	3.273	3.097	2.642
12/2022	4.335	4.768	3.135	4.819	4.086	2.844
1/2023	6.701	7.949	3.615	8.172	6.452	3.314
2/2023	6.611	7.842	3.558	8.083	6.363	3.279
3/2023	4.362	4.636	3.452	4.509	4.114	3.134
4/2023	3.220	3.379	2.960	3.167	2.973	2.956
5/2023	3.144	3.268	2.933	3.064	2.897	2.820
6/2023	3.275	3.262	2.966	3.007	3.028	2.838
7/2023	3.311	3.386	3.004	2.924	3.066	2.820
8/2023	3.303	3.353	3.021	2.922	3.058	2.825
9/2023	3.176	3.066	3.016	2.781	2.932	2.695
10/2023	3.326	3.202	3.048	2.856	3.082	2.720
11/2023	3.638	3.657	3.328	3.556	3.395	3.023
12/2023	4.609	5.007	3.513	5.055	4.366	3.244
1/2024	6.981	8.148	4.080	8.358	6.738	3.802

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Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
2/2024	6.893	8.045	4.022	8.272	6.651	3.766
3/2024	4.736	4.984	3.916	4.862	4.494	3.620
4/2024	3.640	3.795	3.399	3.606	3.399	3.407
5/2024	3.558	3.679	3.365	3.496	3.318	3.264
6/2024	3.690	3.676	3.402	3.444	3.450	3.286
7/2024	3.730	3.802	3.443	3.365	3.490	3.272
8/2024	3.726	3.774	3.464	3.367	3.487	3.281
9/2024	3.606	3.498	3.464	3.233	3.368	3.157
10/2024	3.758	3.635	3.499	3.312	3.520	3.186
11/2024	4.022	4.029	3.773	3.932	3.784	3.487
12/2024	4.976	5.343	3.977	5.386	4.739	3.728
1/2025	6.944	8.037	4.216	8.235	6.708	3.958
2/2025	6.860	7.939	4.159	8.153	6.624	3.923
3/2025	4.790	5.015	4.054	4.897	4.555	3.778
4/2025	3.790	3.940	3.566	3.772	3.554	3.585
5/2025	3.708	3.825	3.531	3.663	3.473	3.442
6/2025	3.838	3.823	3.568	3.611	3.603	3.464
7/2025	3.877	3.947	3.609	3.534	3.643	3.450
8/2025	3.874	3.920	3.630	3.536	3.641	3.460
9/2025	3.755	3.647	3.628	3.402	3.522	3.334
10/2025	3.907	3.785	3.666	3.483	3.674	3.366
11/2025	4.119	4.116	3.926	4.022	3.887	3.658
12/2025	5.049	5.386	4.138	5.427	4.818	3.907
1/2026	6.859	7.883	4.289	8.070	6.628	4.052
2/2026	6.779	7.789	4.234	7.992	6.548	4.017
3/2026	4.792	4.994	4.131	4.880	4.561	3.874
4/2026	3.858	4.004	3.650	3.855	3.628	3.679
5/2026	3.778	3.892	3.616	3.748	3.548	3.537
6/2026	3.893	3.878	3.640	3.685	3.664	3.547
7/2026	3.921	3.988	3.669	3.597	3.692	3.522
8/2026	3.919	3.963	3.691	3.601	3.691	3.533
9/2026	3.802	3.696	3.689	3.467	3.574	3.408
10/2026	3.947	3.826	3.723	3.543	3.720	3.435
11/2026	4.109	4.096	3.966	4.006	3.882	3.715
12/2026	4.994	5.304	4.164	5.341	4.768	3.950
1/2027	6.777	7.737	4.353	7.914	6.551	4.133
2/2027	6.699	7.647	4.298	7.838	6.473	4.098
3/2027	4.787	4.969	4.196	4.859	4.562	3.956
4/2027	3.917	4.060	3.724	3.928	3.693	3.762
5/2027	3.837	3.948	3.689	3.821	3.613	3.620
6/2027	3.958	3.942	3.720	3.766	3.734	3.637
7/2027	3.991	4.055	3.754	3.685	3.767	3.618

REDACTED

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
8/2027	3.986	4.028	3.773	3.685	3.763	3.625
9/2027	3.872	3.767	3.772	3.555	3.650	3.503
10/2027	4.014	3.895	3.805	3.629	3.792	3.529
11/2027	4.131	4.110	4.035	4.023	3.909	3.800
12/2027	4.989	5.273	4.232	5.308	4.767	4.035
1/2028	6.787	7.745	4.370	7.922	6.562	4.150
2/2028	6.710	7.655	4.315	7.847	6.485	4.116
3/2028	4.802	4.984	4.213	4.874	4.578	3.974
4/2028	3.933	4.075	3.740	3.944	3.709	3.778
5/2028	3.854	3.964	3.705	3.837	3.630	3.637
6/2028	3.974	3.958	3.737	3.782	3.751	3.654
7/2028	4.007	4.072	3.771	3.702	3.784	3.635
8/2028	4.003	4.045	3.791	3.703	3.780	3.643
9/2028	3.890	3.785	3.790	3.573	3.668	3.521
10/2028	4.032	3.913	3.824	3.648	3.810	3.548
11/2028	4.150	4.129	4.053	4.042	3.928	3.819
12/2028	5.007	5.292	4.252	5.326	4.786	4.055
1/2029	6.857	7.814	4.443	7.990	6.632	4.224
2/2029	6.779	7.723	4.387	7.914	6.554	4.189
3/2029	4.873	5.054	4.284	4.945	4.648	4.045
4/2029	3.999	4.141	3.807	4.010	3.775	3.844
5/2029	3.919	4.029	3.771	3.903	3.695	3.703
6/2029	4.040	4.024	3.803	3.849	3.817	3.721
7/2029	4.074	4.138	3.838	3.769	3.851	3.702
8/2029	4.070	4.112	3.858	3.770	3.847	3.710
9/2029	3.957	3.852	3.858	3.641	3.735	3.589
10/2029	4.100	3.981	3.891	3.716	3.878	3.616
11/2029	4.219	4.198	4.123	4.111	3.997	3.888
12/2029	5.079	5.363	4.325	5.397	4.858	4.128
1/2030	6.860	7.815	4.449	7.991	6.635	4.230
2/2030	6.781	7.724	4.393	7.915	6.557	4.194
3/2030	4.877	5.059	4.290	4.949	4.653	4.051
4/2030	4.004	4.146	3.812	4.015	3.780	3.849
5/2030	3.924	4.034	3.776	3.907	3.700	3.708
6/2030	4.045	4.029	3.808	3.854	3.822	3.726
7/2030	4.078	4.143	3.843	3.774	3.856	3.708
8/2030	4.074	4.116	3.863	3.775	3.852	3.715
9/2030	3.962	3.857	3.862	3.646	3.740	3.594
10/2030	4.104	3.986	3.896	3.721	3.883	3.621
11/2030	4.223	4.202	4.127	4.116	4.002	3.893
12/2030	5.083	5.366	4.329	5.400	4.862	4.133
1/2031	6.862	7.816	4.454	7.991	6.637	4.236

REDACTED

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
2/2031	6.783	7.725	4.398	7.915	6.559	4.200
3/2031	4.882	5.063	4.295	4.953	4.658	4.057
4/2031	4.009	4.150	3.817	4.020	3.785	3.854
5/2031	3.929	4.039	3.781	3.912	3.706	3.713
6/2031	4.049	4.033	3.813	3.858	3.827	3.731
7/2031	4.083	4.147	3.848	3.779	3.861	3.713
8/2031	4.079	4.121	3.867	3.780	3.857	3.720
9/2031	3.966	3.862	3.867	3.651	3.745	3.599
10/2031	4.109	3.990	3.901	3.726	3.888	3.626
11/2031	4.227	4.207	4.131	4.120	4.007	3.898
12/2031	5.085	5.368	4.334	5.403	4.865	4.137
1/2032	6.869	7.821	4.465	7.996	6.644	4.247
2/2032	6.790	7.730	4.409	7.920	6.566	4.211
3/2032	4.891	5.072	4.306	4.963	4.668	4.068
4/2032	4.018	4.160	3.827	4.029	3.795	3.864
5/2032	3.938	4.048	3.791	3.922	3.716	3.723
6/2032	4.059	4.043	3.823	3.868	3.837	3.741
7/2032	4.092	4.157	3.858	3.789	3.871	3.723
8/2032	4.088	4.130	3.877	3.790	3.867	3.731
9/2032	3.976	3.871	3.877	3.661	3.755	3.609
10/2032	4.118	4.000	3.911	3.736	3.898	3.637
11/2032	4.237	4.216	4.141	4.130	4.017	3.908
12/2032	5.094	5.377	4.344	5.411	4.874	4.148
1/2033	6.859	7.809	4.461	7.984	6.635	4.243
2/2033	6.780	7.718	4.404	7.908	6.557	4.207
3/2033	4.885	5.066	4.301	4.957	4.662	4.063
4/2033	4.014	4.155	3.823	4.025	3.791	3.860
5/2033	3.934	4.043	3.786	3.917	3.711	3.719
6/2033	4.054	4.038	3.819	3.864	3.832	3.737
7/2033	4.087	4.151	3.853	3.785	3.866	3.718
8/2033	4.083	4.125	3.873	3.786	3.862	3.726
9/2033	3.971	3.867	3.872	3.657	3.751	3.605
10/2033	4.113	3.995	3.906	3.731	3.893	3.632
11/2033	4.231	4.211	4.136	4.124	4.012	3.903
12/2033	5.087	5.369	4.338	5.403	4.868	4.143
1/2034	6.855	7.803	4.462	7.978	6.632	4.244
2/2034	6.776	7.712	4.405	7.901	6.553	4.208
3/2034	4.885	5.065	4.302	4.956	4.662	4.065
4/2034	4.014	4.155	3.824	4.025	3.792	3.861
5/2034	3.934	4.044	3.788	3.918	3.713	3.720
6/2034	4.054	4.038	3.820	3.864	3.833	3.738
7/2034	4.088	4.152	3.854	3.786	3.867	3.720

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
8/2034	4.084	4.125	3.873	3.787	3.863	3.727
9/2034	3.972	3.867	3.873	3.658	3.752	3.606
10/2034	4.113	3.995	3.906	3.733	3.893	3.634
11/2034	4.231	4.211	4.136	4.125	4.012	3.904
12/2034	5.085	5.366	4.338	5.401	4.867	4.143
1/2035	6.837	7.783	4.450	7.957	6.615	4.233
2/2035	6.758	7.692	4.393	7.881	6.536	4.197
3/2035	4.872	5.051	4.290	4.943	4.650	4.054
4/2035	4.004	4.144	3.813	4.014	3.782	3.851
5/2035	3.924	4.033	3.777	3.907	3.702	3.710
6/2035	4.043	4.027	3.809	3.854	3.823	3.727
7/2035	4.076	4.140	3.844	3.775	3.856	3.709
8/2035	4.072	4.114	3.863	3.776	3.852	3.717
9/2035	3.960	3.857	3.862	3.648	3.741	3.596
10/2035	4.102	3.984	3.896	3.722	3.883	3.623
11/2035	4.219	4.199	4.124	4.113	4.001	3.893
12/2035	5.071	5.351	4.326	5.386	4.853	4.132
1/2036	6.934	7.878	4.553	8.051	6.712	4.336
2/2036	6.854	7.785	4.495	7.974	6.632	4.299
3/2036	4.970	5.149	4.389	5.041	4.748	4.153
4/2036	4.095	4.235	3.905	4.106	3.874	3.943
5/2036	4.015	4.123	3.869	3.998	3.794	3.801
6/2036	4.134	4.119	3.901	3.946	3.914	3.820
7/2036	4.168	4.232	3.936	3.868	3.949	3.802
8/2036	4.165	4.206	3.956	3.869	3.945	3.810
9/2036	4.053	3.949	3.955	3.741	3.834	3.690
10/2036	4.194	4.077	3.989	3.816	3.976	3.717
11/2036	4.314	4.293	4.219	4.208	4.096	3.988
12/2036	5.168	5.447	4.425	5.482	4.950	4.231
1/2037	6.942	7.883	4.567	8.056	6.721	4.352
2/2037	6.862	7.790	4.510	7.978	6.641	4.314
3/2037	4.982	5.161	4.404	5.053	4.761	4.168
4/2037	4.108	4.248	3.919	4.119	3.888	3.956
5/2037	4.028	4.136	3.882	4.011	3.808	3.815
6/2037	4.147	4.132	3.914	3.959	3.928	3.833
7/2037	4.181	4.245	3.950	3.882	3.962	3.816
8/2037	4.178	4.219	3.969	3.883	3.959	3.824
9/2037	4.066	3.963	3.968	3.755	3.848	3.704
10/2037	4.207	4.091	4.003	3.830	3.990	3.732
11/2037	4.327	4.307	4.233	4.221	4.110	4.003
12/2037	5.180	5.459	4.439	5.493	4.963	4.246
1/2038	7.007	7.945	4.639	8.118	6.786	4.424

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
2/2038	6.926	7.852	4.581	8.040	6.706	4.386
3/2038	5.050	5.228	4.473	5.121	4.830	4.239
4/2038	4.173	4.312	3.984	4.183	3.953	4.021
5/2038	4.092	4.200	3.946	4.075	3.872	3.879
6/2038	4.212	4.196	3.979	4.024	3.993	3.898
7/2038	4.246	4.309	4.015	3.947	4.028	3.882
8/2038	4.243	4.284	4.035	3.949	4.025	3.890
9/2038	4.132	4.029	4.034	3.822	3.914	3.771
10/2038	4.273	4.157	4.069	3.897	4.056	3.799
11/2038	4.394	4.374	4.300	4.288	4.177	4.070
12/2038	5.248	5.526	4.509	5.560	5.032	4.316
1/2039	7.053	7.988	4.691	8.160	6.832	4.477
2/2039	6.971	7.894	4.632	8.081	6.751	4.438
3/2039	5.099	5.276	4.523	5.169	4.879	4.289
4/2039	4.219	4.358	4.031	4.230	4.000	4.068
5/2039	4.137	4.245	3.993	4.121	3.919	3.926
6/2039	4.257	4.242	4.026	4.070	4.039	3.945
7/2039	4.292	4.355	4.062	3.994	4.074	3.929
8/2039	4.289	4.330	4.082	3.996	4.072	3.938
9/2039	4.178	4.076	4.081	3.869	3.961	3.818
10/2039	4.320	4.204	4.116	3.944	4.103	3.847
11/2039	4.441	4.421	4.348	4.336	4.225	4.119
12/2039	5.296	5.573	4.559	5.607	5.080	4.367
1/2040	7.073	8.006	4.719	8.178	6.854	4.505
2/2040	6.991	7.912	4.659	8.098	6.772	4.465
3/2040	5.123	5.300	4.550	5.193	4.904	4.316
4/2040	4.243	4.382	4.055	4.254	4.025	4.092
5/2040	4.162	4.269	4.017	4.145	3.944	3.951
6/2040	4.281	4.266	4.051	4.095	4.064	3.970
7/2040	4.316	4.379	4.087	4.019	4.099	3.954
8/2040	4.313	4.354	4.107	4.021	4.097	3.963
9/2040	4.203	4.100	4.106	3.895	3.987	3.844
10/2040	4.344	4.228	4.141	3.970	4.128	3.873
11/2040	4.466	4.446	4.372	4.361	4.251	4.144
12/2040	5.319	5.596	4.585	5.629	5.104	4.393
1/2041	7.098	8.028	4.751	8.199	6.879	4.538
2/2041	7.015	7.933	4.691	8.119	6.797	4.497
3/2041	5.152	5.329	4.580	5.222	4.934	4.348
4/2041	4.271	4.409	4.084	4.282	4.054	4.121
5/2041	4.190	4.297	4.046	4.174	3.972	3.979
6/2041	4.309	4.294	4.079	4.123	4.093	3.999
7/2041	4.344	4.407	4.116	4.048	4.128	3.984

REDACTED

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
8/2041	4.341	4.382	4.135	4.051	4.125	3.992
9/2041	4.231	4.129	4.134	3.924	4.016	3.873
10/2041	4.372	4.257	4.170	3.999	4.157	3.902
11/2041	4.495	4.474	4.401	4.390	4.280	4.174
12/2041	5.347	5.622	4.615	5.656	5.133	4.424
1/2042	7.150	8.077	4.811	8.248	6.932	4.599
2/2042	7.067	7.982	4.750	8.167	6.849	4.558
3/2042	5.209	5.385	4.639	5.278	4.991	4.407
4/2042	4.325	4.463	4.139	4.336	4.108	4.175
5/2042	4.243	4.350	4.100	4.227	4.026	4.033
6/2042	4.363	4.347	4.133	4.177	4.147	4.053
7/2042	4.398	4.460	4.170	4.103	4.182	4.038
8/2042	4.395	4.436	4.190	4.105	4.180	4.047
9/2042	4.285	4.184	4.189	3.979	4.070	3.929
10/2042	4.426	4.311	4.224	4.055	4.212	3.958
11/2042	4.549	4.529	4.457	4.445	4.335	4.230
12/2042	5.402	5.676	4.673	5.710	5.188	4.482
1/2043	7.184	8.108	4.853	8.278	6.967	4.641
2/2043	7.100	8.012	4.791	8.196	6.883	4.600
3/2043	5.247	5.422	4.679	5.316	5.030	4.448
4/2043	4.362	4.499	4.176	4.373	4.146	4.213
5/2043	4.280	4.386	4.137	4.264	4.064	4.071
6/2043	4.399	4.384	4.171	4.214	4.184	4.091
7/2043	4.434	4.497	4.207	4.141	4.220	4.076
8/2043	4.432	4.472	4.227	4.143	4.217	4.085
9/2043	4.322	4.221	4.226	4.017	4.108	3.967
10/2043	4.463	4.348	4.262	4.093	4.249	3.996
11/2043	4.587	4.567	4.494	4.483	4.373	4.268
12/2043	5.438	5.712	4.712	5.745	5.225	4.522
1/2044	7.232	8.152	4.910	8.321	7.015	4.699
2/2044	7.147	8.055	4.848	8.239	6.931	4.657
3/2044	5.299	5.474	4.734	5.369	5.084	4.504
4/2044	4.413	4.549	4.228	4.423	4.197	4.264
5/2044	4.330	4.436	4.188	4.314	4.115	4.122
6/2044	4.449	4.434	4.222	4.265	4.235	4.142
7/2044	4.485	4.547	4.259	4.192	4.271	4.128
8/2044	4.483	4.523	4.279	4.195	4.269	4.137
9/2044	4.373	4.272	4.278	4.069	4.160	4.020
10/2044	4.514	4.400	4.314	4.145	4.301	4.049
11/2044	4.638	4.618	4.546	4.535	4.426	4.321
12/2044	5.489	5.762	4.766	5.795	5.278	4.577
1/2045	7.269	8.186	4.957	8.354	7.054	4.747

REDACTED

Term	Iroquois Zone 1	Iroquois Zone 2	Niagara	Transco Zone 6 NY	Iroquois Waddington	Millennium Pipeline
2/2045	7.184	8.088	4.894	8.271	6.969	4.704
3/2045	5.342	5.516	4.779	5.411	5.127	4.550
4/2045	4.454	4.590	4.270	4.465	4.240	4.306
5/2045	4.371	4.477	4.230	4.356	4.157	4.164
6/2045	4.490	4.475	4.264	4.307	4.277	4.185
7/2045	4.526	4.588	4.301	4.235	4.313	4.171
8/2045	4.524	4.564	4.321	4.238	4.311	4.180
9/2045	4.415	4.315	4.320	4.113	4.203	4.063
10/2045	4.555	4.442	4.356	4.188	4.344	4.093
11/2045	4.680	4.661	4.589	4.578	4.469	4.365
12/2045	5.531	5.802	4.810	5.835	5.320	4.622

Rhode Island Renewable Energy Long Term Contract RFP
Docket 4600 Benefit-Cost Framework - Applicable Category Summary

Power System Level (Cost/Benefit Categories)

			(NPV in 2018$)	Description of quantitative values or reason for exclusion:
(1)	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-	Applicable/Quantifiable	$54,871,248	Market value of Energy from Project.
(2)	Renewable Energy Credit Cost/Value	Applicable/Quantifiable	$24,451,273	Market value of Project RECs retired (used) for RES or sold.
(3)	Retail Supplier Risk Premium	Not Applicable (N/A)	$0	PPA is a long term contract for wholesale power supply at a fixed price.
(4)	Forward Commitment: Capacity Value	Applicable/Not Quantifiable	-	Beyond the capabilities of the modeling system to quantify accurately. Neutral impact.
(5)	Forward Commitment: Avoided Ancillary Services Value	Applicable/Not Quantifiable	-	Beyond the capabilities of the modeling system to quantify accurately. Negative impact, insignificant.
(6)	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Applicable/Quantifiable	($48,466,063)	PPA cost of energy and RECs.
(7)	Electric Transmission Capacity Costs / Value	Applicable/Quantifiable	$0	The Proposal contains a fixed PPA price for energy and REC, with all interconnection and transmission upgrades included in PPA price. The project is commitment to interconnect to the ISO-NE "PTF" at the Capacity Capability Interconnection Standard, as defined by ISO-NE.
(8)	Electric transmission infrastructure costs for Site Specific Resources	Applicable/Quantifiable	$0	The Proposal contains a fixed PPA price for energy and REC, with all interconnection and transmission upgrades included in PPA price. The project is required to interconnect to the ISO-NE "PTF" at the Capacity Capability Interconnection Standard, as defined by ISO-NE.
(9)	Net risk benefits to utility system operations (generation, transmission, distribution)	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". This resource is not a DER.
(10)	Option value of individual resources	Applicable/Quantifiable	$2,219,724	RI Energy Market Price Change Impact + RI REC Market Price Change Impact + Benefit to Rhode Island Gas Customers due to Gas Use Reduction (Benefits)
	Option value of individual resources	Applicable/Quantifiable	($2,117,159)	RI Energy Market Price Change Impact + RI REC Market Price Change Impact (Revenue Reduction for existing Long Term Contracts)
	Option value of individual resources	Applicable/Quantifiable	$34,089,848	Other NE States Energy Market Price Change Impact + Other NE States REC Market Price Change Impact + Benefit to Other NE States Gas Customers due to Gas Use Reduction (Benefits)
	Option value of individual resources	Applicable/Quantifiable	($5,800,212)	Other NE States Energy Market Price Change Impact + Other NE States REC Market Price Change Impact (Revenue Reduction for existing Long Term Contracts)
(11)	Investment under Uncertainty: Real Options Cost / Value	Applicable/Quantifiable	Included in categories (1,2,6,10)	Project was selected based on a competitive process of multiple proposals. Evaluation and benefit cost analysis was compared to a basecase that provided a "but for" or "counterfactual" projection of the costs of electric energy, RECs, and carbon emissions associated with Rhode Island electricity consumption under a future in which no proposals are selected.
(12)	Energy Demand Reduction Induced Price Effect	N/A	$0	Generation supply is not an Energy DRIPE, but the proposal's indirect benefit impact on market LMP price change and REC price change is listed above.
(13)	Greenhouse gas compliance costs (Embedded Cost)	Applicable/Quantifiable	Included in category (1)	Greenhouse gas compliance costs (RGGI) is embedded as a fuel related cost in the model analysis to determine the quantitative market impacts listed above.
(14)	Criteria air pollutant and other environmental compliance costs	Applicable/Not quantifiable	-	Not significant value to quantify or differentiate between project. Positive impact, insignificant.
(15)	Innovation and Learning by Doing	Applicable/Not quantifiable	-	The benefits of innovation in the solar industry and by the developer have been captured in the bid pricing of the contract, including, but not limited to any potential federal tax credits, Postive impact, insignificant.
(16)	Distribution capacity costs	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(17)	Distribution delivery costs	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(18)	Distribution system safety loss/gain	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(19)	Distribution system performance	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(20)	Utility low income	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(21)	Distribution system and customer reliability / resilience impacts	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.
(22)	Distribution system safety loss/gain	N/A	$0	Generation supply will be interconnected at the ISO-NE "PTF". Distribution level category is not applicable to this project.

Customer Level (Cost/Benefit Categories)

(23)	Program participant / prosumer benefits / costs	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(24)	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(25)	Low-Income Participant Benefits	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(26)	Consumer Empowerment & Choice	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(27)	Non-participant (equity) rate and bill impacts	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.

Societal Level (Cost/Benefit Categories)

(28)	Greenhouse gas externality costs	Applicable/Quantifiable	$40,320,033	Impact of Reduction in GHG Emissions
(29)	Criteria air pollutant and other environmental externality costs	Applicable/Quantifiable	$1,593,093	Impact of Reduction in NOx Emissions
(30)	Conservation and community benefits	Applicable/Not quantifiable	-	The project must be reviewed and approved by the Connecticut Siting Council, which preempts local permit requirements. Development and Management Plan must then be approved by CSC, and stormwater and dewatering discharge permit must be issued by Connecticut Department of Energy and Environmental Protection. Gravel Pit Solar is strategically sited on a gravel mine, is not visible from homes or roads, has no sensitive natural resources, thereby minimizing and avoiding environmental impacts. Additionally, using the latest inverter technology, tracking panel rack systems, bi-facial panels, and the newest engineering approaches the proposed project will produce substantially more energy from a smaller footprint than similar solar projects. In consideration of land use impact the Gravel Pit Solar project has a direct societal benefit relative to the development and deployment of other projects mounted on greenfield parcels which can disrupt the carbon absorption capacity of forest, open space and farmland. Positive impact, unknown magnitude.
(31)	Non-energy costs/benefits: Economic Development	Applicable/Quantifiable	$121,371	Economic Benefit to Rhode Island. The project made a commitment to invest at least $300,000 in training RI new energy workforce.
(32)	Innovation and knowledge spillover	Applicable/Not quantifiable	-	The DESRI-North Light team has developed, constructed, and operated over 300 MW of new solar in ISO-NE. DESRI Renewables' parent company D.E. Shaw Renewable Investments, LLC (DESRI) was formed in 2011, and is an experienced owner operator of utility-scale solar across the U.S. Their total portfolio includes projects of comparable size. Positive impact, small.
(33)	Societal Low-Income Impacts	N/A	$0	Proposed rate recovery through distribution rates applicable to all distribution customers.
(34)	Public Health	Applicable/Not quantifiable	Included in category (28) and (29)	Pollutants emitted by the electric power sector cause damage to human health, including increased morbidity and mortality. Over the course of its operating life, the Gravel Pit Solar project will displace thermal generation which will result in reduced emissions of harmful pollutants, which can be translated to societal benefits. The societal benefits for GHG and NOx emissions reduction are listed above in (28) and (29). Positive impact, significant.
(35)	National Security and US international influence	Applicable/Not quantifiable	Included in category (1) and (28)	The project will contribute to reducing oil consumption, attributed to winter fuel switching, by approximately 330,000 Bbls. The economic and environmental impacts have been captured in the market value and GHG emission reduction listed in (1) and (28). Positive impact, small.

Total Net Benefits:	**$101,283,156**

Comparison to Programs that have performed the RI Benefit Cost Test

Program	Total Benefits ($ Million)	Total Cost ($ Million)	RI Test Benefit/Cost	Data Source
Gravel Pit Solar	$158	$58	2.73	Schedule NG-4 : Rhode Island Benefit Cost Test
Revolution Wind	$5,552	$2,049	2.71	Docket No. 4929: Attachment PUC 3-7-A, Rhode Island Benefit Cost Test [1]
Energy Efficiency (2020 Program Year)	$603	$130	4.64	Docket No. 4979: 2020 Energy Efficiency Program Plan -Table E-5
Energy Efficiency (2019 Program Year)	$506	$126	4.00	Docket No. 4888: 2019 Energy Efficiency Program Plan -Table E-5

[1] In the Docket 4929 written order, issued on June 7, 2019, the RIPUC ordered that the remuneration calculated on the cost of the payments made under the power purchase agreement is hereby denied which adjusts the RI Test Benefit/Cost to 2.76.

Comparison to Levelized Cost of Other Programs

Program	Levelized Nominal Cost $/MWh
Gravel Pit Solar	$52.95 /MWh
CERFP - Long Term Contracts (Weighted Average of 8 Projects)	$90.26 /MWh
Revolution Wind	$98.43 /MWh
Net Metering *(Bill Credit Rates as of 10/1/2019)*	$177.28 /MWh
RE Growth (2019 Program Year)	$181.83 /MWh
RE Growth (2018 Program Year)	$183.11 /MWh