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Long-Term Contracts for Clean Energy Generation Projects Pursuant to Section 83D of Chapter 169 of the Acts of 2008

Quantitative Evaluation Report

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1. Summary and Overview

The Massachusetts ("MA") electric distribution companies (EDCs) issued a Request for Proposals (RFP) in March 2017 for long term contracts for 9,450,000 megawatt-hours per year of clean electric energy supply, renewable energy certificates ("RECs") and environmental attributes ("EAS").[1] The EDCs seek to acquire these supplies, referred to as "Proposed Clean Energy Projects" or "Proposals" to comply with Section 83D of the Massachusetts Green Communities Act. The Massachusetts EDCs retained Tabors Caramanis Rudkevich (TCR) as Evaluation Team Consultant to help them evaluate some of the costs and benefits[2] of the Proposed Clean Energy Project proposals received in response to the RFP. This report summarizes the analyses TCR prepared to evaluate the costs and benefits of the Proposed Clean Energy Projects and the results of those evaluations.

The 83D RFP Evaluation Team reviewed and evaluated the Proposed Clean Energy Project bids using a process described in testimony sponsored by the Commonwealth Department of Energy Resources ("DOER") and EDCs in this proceeding. As part of this process, TCR performed the Stage Two Quantitative Analysis of each Proposal and the Stage Three Quantitative Analysis of each Portfolio of Proposals, as well as certain discrete analyses requested by the Evaluation Team at various points in the evaluation.[3] Appendix 1 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 the 83D Qualitative Team and ranking of each Proposal based on the total of the quantitative and qualitative scores.. Appendix 2 provides the corresponding Stage Three Quantitative Analysis results, quantitative scores, qualitative scores and ranking of each Portfolio.

The TCR Quantitative Analyses used metrics for the two categories of costs and benefits specified in the RFP, i.e. Direct Contract Costs and Benefits ("Direct Costs and Benefits") and Other Costs and Benefits to Retail Consumers ("Indirect Costs and Benefits"). Section 2 describes those metrics.

TCR developed values for each of these metrics in 2017 constant dollars (2017$) for each Proposal / Portfolio by year over a forecast evaluation period of 2019 to 2043 ("evaluation period"). 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 and from the Greenhouse Gas (GHG) Inventory calculation in its Quantitative Workbook for each Proposal Case and Portfolio Case.[4]

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[1] The 83D RFP defines Environmental Attribute to include all of the New England Power Pool Generation Information System Certificates and any other present or future environmental benefits associated with the Firm Service Hydroelectric Generation energy deliveries contracted for as part of this RFP.

[2] The costs and benefits TCR analyzed were a subset of the overall costs and benefits associated with the 83D 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] Certain of the Portfolios analyzed in Stage 3 comprised single bid proposals similar to those analyzed in Stage 2.

[4] DOER provided the specifications for the GHG Inventory calculation.

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TCR developed values for the Indirect 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 83D Base Case, as well as from the GHG Inventory calculation in its Quantitative Workbook for each Proposal Case and Portfolio Case.

Section 3 describes TCR's simulation of the 83D Base Case as well as the Proposal Cases and Portfolio Cases. Appendix 4 provides 83D Base Case results in detail. Appendix 5 provides detailed descriptions of the assumptions used to model the 83D 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 DOER and EDC testimony describes, bid scoring was based on a 100-point scale under which a Proposal / Portfolio could receive a maximum of 75 points based upon the results of its Quantitative Analysis performed by TCR and a maximum of 25 points based upon the results of as separate Qualitative Analysis performed by other members of the Evaluation Team. TCR developed the Quantitative Analysis scores assigned to each Proposal / Portfolio based upon the results of the analyses described in this Report. TCR added these Quantitative Analysis scores to the Qualitative Analysis scores provided to it by other members of the Evaluation Team to calculate the total score of each Proposal / Portfolio. TCR then ranked each Proposal / Portfolio from high to low according to the total scores. Section 5 describes this scoring and ranking.

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2. Evaluation of Costs and Benefits

TCR evaluated costs and benefits of each Proposal and Portfolio based on their respective direct and indirect economic and environmental costs and benefits. The RFP specifies two categories of costs and benefits to be quantified by TCR: Direct Contract Costs and Benefits ("Direct Costs and Benefits") and Other Costs and Benefits to Retail Consumers ("Indirect Costs and Benefits"). The Evaluation Team developed Protocol for 83D Quantitative Metric Calculations, Stage II ("83D Quantitative Protocol') for the quantitative evaluation of these costs and benefits. The 83D Quantitative Protocol, provided in Appendix 3, specifies the "…core measure of comparison" as "…the levelized net unit benefit per MWh of the project expressed in 2017 dollars" and specifies the metrics to be used to calculate these costs and benefits. This section summarizes the metrics and approach from the 83D Quantitative Protocol TCR used to measure each category of costs and benefits and to develop values for each of those metrics.

TCR developed the value for each metric for each Proposal / Portfolio by year over the evaluation period in 2017 constant dollars (2017$). It then calculated the present value for each metric. Finally, it calculated a levelized unit value ($/MWh) for each metric as the present value divided by the present value of the annual energy from the Proposal / Portfolio. Appendix 1 summarizes the Stage Two results, i.e., individual Proposals. Appendix 2 summarizes the Stage Three results, i.e., Portfolios.

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

i. Total Direct Costs include the Direct Cost of Energy, the Direct Cost of Renewable Portfolio Standard (RPS) Class 1 eligible Renewable Energy Credits (RECs), and the Direct Cost of Transmission.[5] The Direct Cost of Energy was calculated from the bid price for energy multiplied by the annual quantity of delivered energy for each year over the proposed contract term. The Direct Cost of Renewable Portfolio Standard (RPS) Class 1 eligible Renewable Energy Credits (RECs) was calculated from the bid price for RECs multiplied by the annual quantity of RECs for each year over the proposed contract term. The Direct Cost of Transmission is the annual bid cost for transmission facilities, over the contract term. The resulting levelized unit value for Total Direct Costs is reported as "Price of Contract" in Column G of Appendix 1 for the Proposals and in Column H of Appendix 2 for the Portfolios.

ii. Total Direct Benefits include the Direct Benefit of Energy, the Direct Benefit of RECs and the Direct Benefit of Clean Energy Credits (CECs).[6] The Direct Energy Benefit is the market value of the energy deliveries from the Project over the proposed contract term, based upon the forecast market energy prices at the delivery point with the Proposal / Portfolio in service, ("Proposal Case" or "Portfolio Case"). The Direct Benefit of RECs and CECs is the avoided cost

[5] There is no direct cost associated with Clean Energy Standard (CES) eligible CECs.

[6] The 83D Quantitative protocol include a provision for including projected revenues from the sale of transmission capacity as a Direct Benefit but none of the Proposals or Portfolios included such projections.

of using these products from the Proposal / Portfolio to meet RPS + CES requirements plus the market value of RECs and CEC surplus to RPS + CES requirements, if any.

The resulting Net Direct Benefit (Cost) is the sum of the above Direct Costs and Direct Benefits. The levelized unit values of the Net Direct Benefit (Cost) are reported in Column N of Appendix 1 for the Proposals and in Column O of Appendix 2 for the Portfolios.

TCR measured the Indirect Benefits of each Proposal and Portfolio by calculating the values of each of the metrics described below.[7] As discussed in Section 3C, Indirect Benefits were not computed for small Proposals.

i. Indirect Energy Price Benefits are the savings over the evaluation period from changes to wholesale energy market costs paid by EDC load in Massachusetts, i.e. from changes to Locational Marginal Prices ("LMP") in Massachusetts in the Proposal Case / Portfolio Case relative to energy market costs paid by EDC load in Massachusetts without the Proposal / Portfolio in service, i.e. the 83D Base Case.

ii. Indirect REC and CEC Price Benefits are the savings over the evaluation period from changes to the costs paid by Massachusetts EDCs for Class 1 REC and CEC based on market prices in the Proposal Case / Portfolio Case relative to the 83D Base Case.

iii. The Global Warming Solutions Act (GWSA) compliance Benefit is the value of the Proposal / Portfolio incremental contribution towards meeting the Massachusetts GWSA, i.e., incremental to compliance with the RPS and the CES in the Proposal Case / Portfolio Case relative to the 83D Base Case.[8]

iv. Economic Impact of Resource Firmness Benefit. This benefit was estimated in terms of the additional indirect energy benefits from a Proposal or Portfolio in a winter when natural gas prices are much higher than average. It measures the value of the incremental reduction in exposure to extreme energy prices in the Proposal Case / Portfolio Case under such a scenario relative to the 83D Base Case, over the evaluation period.

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 O of Appendix 1 for the large Proposals and in Column P of Appendix 2 for the Portfolios.

[7] The 83D Steering Committee ultimately decided to not include the Capacity Price Indirect Benefit metric because it determined the results for this metric from the ENELTYIX modelling to be unreliable. Capacity market price changes resulting from any particular resource addition are difficult to forecast with precision, and can be highly dependent on other factors and assumptions. In addition, ISO-NE changes to Forward Capacity Market (FCM) rules have reduced the ability of state sponsored resources such as those procured pursuant to Section 83D to impact capacity clearing prices significantly in the near-term.

[8] The DOER provided the general principles and methodology for calculating the incremental contribution (MWh) to GWSA compliance. TCR implemented the methodology used in this evaluation based upon the DOER general principles and methodology. DOER provided the initial default unit value per MWh of contribution (20 $/MWh). TCR used this value to calculate the value of the incremental contribution in the initial Stage Two quantitative workbooks. DOER provided the methodology implemented by TCR for calculating the final unit value per MWH of contribution that TCR then used to calculate this metric in its Stage Two and Stage Three evaluations.

Finally, TCR calculated the Net Benefit (Cost) of each Proposal and Portfolio. The levelized unit value of this metric, the core measure for comparison under the 83D Quantitative Protocol, is shown in Column P of Appendix 1 for the large proposals and in Column Q of Appendix 2 for Portfolios. (For small proposals, Net Direct Benefit is the applicable metric.)

TCR also calculated the value of the Net Benefit (Cost). This value equals the present value of the Total Direct Benefits and Total Indirect Benefits less the present value of the Total Direct Costs. This metric is shown in Column Q of Appendix 1 for the large Proposals, in Column O of Appendix 1 for the small Proposals, and in Column R of Appendix 2 for the Portfolios.

TCR developed the values of these metrics in a Quantitative Workbook for each Proposal and each Portfolio.

- TCR developed values for the Direct Cost and Benefit metrics of each Proposal / Portfolio from the bids submitted for each Proposal, from the outputs of its simulation modeling of each Proposal Case and Portfolio Case and from its quantitative evaluation workbook for each Proposal Case and Portfolio Case.
- TCR developed values for the Indirect 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 83D 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 83D 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.

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3. Market Simulations- 83D Base Case and Proposal / Portfolio Cases

TCR's Quantitative Analysis work involved development of many of the values for the metrics used in the calculations of Direct Costs and Benefits as well as Indirect Costs and Benefits from the outputs of its simulation modeling of the 83D Base Case and each Proposal Case and Portfolio Case. This section describes the basic difference between the 83D Base Case and the Proposal / Portfolio Cases. It then describes the ENELYTIX platform TCR used to model each of those Cases and the major input assumptions TCR used in that modeling. Finally, it describes TCR's approach to Quantitative Analysis modelling of small Proposals.

A. 83D Base Case and Proposal / Portfolio Cases

The 83D Base Case provides a "but for" or "counterfactual" projection of carbon emissions as well as energy and capacity costs associated with Massachusetts electricity consumption under a future in which the EDCs do not acquire clean energy under long-term contracts from any of the Proposals received in response to the RFP.[9]

Each Proposal Case and Portfolio Case provides a projection of carbon emissions and costs associated with Massachusetts electricity consumption under a future in which the EDCs acquire the clean energy bid by that Proposal or Portfolio under a long-term contract. TCR used the results from each Proposal Case and Portfolio Case to measure the Direct Costs and Benefits of that Proposal or Portfolio described in Section 2, i.e., these Cases provides the projections of carbon emissions and costs with the Proposal / Portfolio in service.

TCR reflected the difference between the 83D 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 C summarizes each major category of input assumptions TCR used in its modeling and describes the differences in input assumptions between the 83D Base Case and each Proposal / Portfolio Case. Appendix 5 provides detailed descriptions of the assumptions TCR used to model the 83D Base Case and the Proposal / Portfolio Cases, as well as 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 4 provides key results from the ENELYTIX modeling of the 83D Base Case.

TCR used the ENELYTIX computer simulation software tool to simulate the operation of the New England wholesale markets for energy and ancillary services, forward capacity and RECs under the 83D Base Case and for each Proposal / Portfolio Case. ENELYTIX develops internally consistent, detailed projections of

[9] The 83D Base Case is not a plan for the Massachusetts electric sector and should not be viewed as such. TCR used the results from the 83D 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 83D Base Case provides the projections of carbon emissions and costs without and of the Proposals / Portfolios in service.

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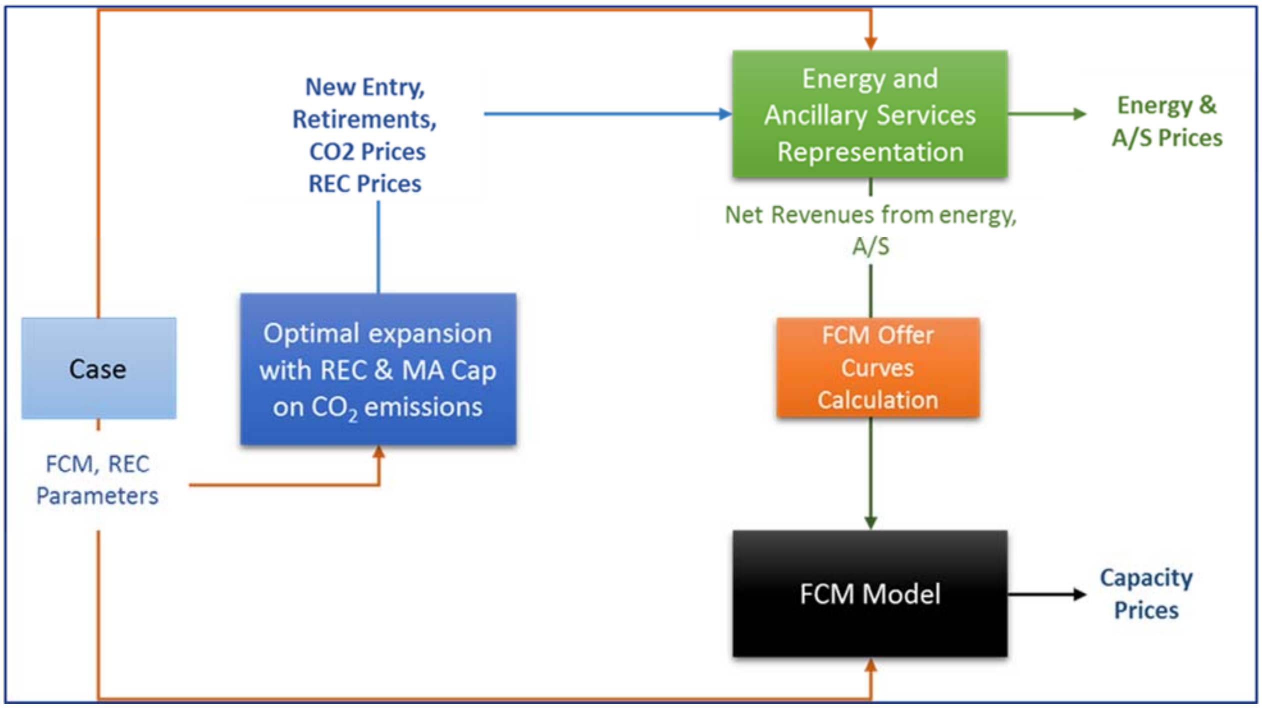
prices in each of those markets as well as of the key physical parameters underlying those prices such as capacity additions and retirements, energy generation by source, carbon emissions and natural gas burn. TCR conducted a separate ENELYTIX computer run for the Base Case and for each Proposal / Portfolio Case being analyzed.

ENELYTIX develops its projections through the interaction of its three key modules: the Capacity Expansion module, the Energy and Ancillary Services (E&AS) module and the Independent System Operator New England ("ISO-NE") FCM module (Figure 1).

Figure 1. Interaction of ENELYTIX modules



The Capacity Expansion module determines an optimal electric system expansion in New England over a long-term planning horizon. Its 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 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 module implements chronological simulations of the Security

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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 ISO-NE FCM module uses Forward Capacity Market (FCM) Offer Curves that TCR develops from results of the Capacity Expansion and E&AS modules. This module models the ISO-NE capacity auction subject to system-wide and zonal installed capacity requirements, Cost of New Entry (CONE) parameters and demand curves.

All three modules use the Power System Optimizer (PSO) market simulator developed by Polaris Systems Optimization, Inc.[10] In addition all three 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.

B. Major Input Assumptions Used to Model 83D Base and Proposal / Portfolio Cases

TCR used ten major categories of input assumptions to model the 83D 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 input assumptions that differed between the 83D Base Case and each Proposal / Portfolio Case were input assumptions regarding Generating Unit Capacity Additions and/or any transmission additions, upgrades, and/or changes required to reflect the particular Proposal / Portfolio under analysis.

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 83D Base Case and each Proposal / Portfolio Case. TCR used the input assumptions in the remaining eight categories to model both the 83D Base Case and each of the Proposal / Portfolio Cases. Appendix 5 provides detailed descriptions of the assumptions for ISO-NE and for the NYISO that TCR used to model the 83D Base Case and the Proposal / Portfolio Cases.

Modeling assumptions with differences between the 83D Base Case and each Proposal / Portfolio Case

Generating Unit Capacity Additions (Scheduled and Optional). This category consists of two groups of assumptions. First, there are the specific generating resources input to ENELYTIX as being in-service during the study horizon, i.e. existing and scheduled. Second, there 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

[10] www.psopt.com

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and environmental constraints existing within the simulation model at various times at least cost, i.e., optional resources.

The 83D Base Case assumed the following specifically identified generating capacity units and sources of RECs would be in-service during the study horizon:

- existing generating units listed in the 2017 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report);
- projects listed in the ISO New England interconnection queue as of June 27, 2017 that were either under construction or had major interconnection studies completed and cleared the latest Forward Capacity Auction prior to June 27, 2017;
- distributed photovoltaic (PV) capacity at levels in the ISO-NE's Final 2017 PV Forecast[11] through 2026 and thereafter at levels extrapolated from the ISO-NE PV Forecast;
- renewable generation projects selected under the New England Clean Energy RFP and under Massachusetts Department of Public Utilities (DPU) review pursuant to that procurement;
- imports of Class 1 eligible REC into ISO-NE from neighboring control areas at their 2015 levels; and
- 1,600 MW of generic offshore resources assumed to be procured through the Massachusetts 83C RFP.

For each Proposal /Portfolio Case ENELYTIX used all of these 83D Base Case assumptions plus one more – the 83D resource(s) from the particular Proposal or Portfolio Case.

For the 83D Base Case and each Project / Portfolio Case ENELYTIX had the option of choosing to simulate addition of generating capacity from other (i.e., non-83D) renewable resources, fossil fuel resources and advanced nuclear 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. This assumption is based on the expectation that the pricing terms of such power-purchasing agreements would reflect the same future economic fundamentals.

Transmission. ENELYTIX provides a detailed representation of the transmission topology and electric characteristics of transmission facilities within ISO-NE and the NYISO. It modeled ISO-NE based on the 2020 SUMMER Peak case and the NYISO system based on the 2017 Market Monitoring Working Group power flow case. For the 83D Base Case, and each Project/Portfolio Case, TCR worked with the 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 Evaluation Team using historical data from 2012 through June 23, 2017 and contingency analyses performed by the Evaluation Team and TCR. TCR modeled the 83D Base Case and each Project / Portfolio Case using the same set of contingency constraints.

11 ISO New England Final 2017 PV Forecast, May 1, 2017.

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The Evaluation Team and TCR worked together to ensure that the ENELYTIX model correctly reflected the necessary transmission upgrades associated with each Proposal it modeled.

Modeling assumptions common to the 83D Base Case and each Proposal / Portfolio Case

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 2026 from the CELT Report. It developed the forecasts for 2027 through 2040 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 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 New England market on an hourly basis, TCR developed hourly load shapes 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 2020/21 level of 959 MW estimated by ISO-NE, that external control areas will provide an additional 1,378 MW and resources within New England will provide 318 MW of Active Demand Response (ADR).

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. 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

[12] TCR did not model New York RPS requirements and compliance.

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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. The allowance prices assumed for NOx and SO_2 emissions are zero because no New England state has emission limits under the Federal Cross State Air Pollution Rule (CSAPR), the source of those allowance prices. TCR developed its CO2 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 CO2 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 "NP PS#3" scenario by 2031, and continuing along the same curve to 2040. TCR developed its NOx and SO_2 allowance price 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 CSAPR. Appendix 5 describes the TCR allowance price assumptions for NYISO

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 2019) plus the ISO-NE approved scheduled retirements as of August 2017. 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 whether it is cost efficient within the simulation to keep the existing unit online or retire and replace it with more efficient generator or with the resource needed to meet environmental constraints.

Generating Unit Operational Characteristics. TCR develops assumptions for the key physical and cost operating parameters of all of 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 June 15, 2017 and the Reference Case forecast assuming no Clean Power Plan (CPP) from the Energy Information Administration (EIA) Annual Energy Outlook 2017 (AEO 2017).[14] The projection of monthly basis through June 2024 is drawn from forward markets for those

[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.

[14] As of June 2017, it was public knowledge that the Environmental Protection Agency (EPA) was developing a proposal to repeal the CPP. EPA issued a proposal to repeal CPP on October 16, 2017.

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products as of June 2017. The projection from July 2024 onward assumes basis will remain relatively constant in 2017$. The projections of distillate and residual to electric generators in New England are drawn from AEO.

C. ENELYTIX Modelling of Small Proposals in Stage Two

In its Stage Two ENELYTIX modelling, TCR classified and modelled certain smaller Proposals slightly differently from the larger Proposals, so as to allow a fair comparison to be made between the two size categories. This treatment provided a more accurate assessment of the impact of Proposals classified as "small", giving them the same opportunity to impact forecast energy generation, emissions and energy market prices and capacity prices as large Proposals.

TCR classified a Proposal as "small" if its generation capacity contribution to the ISO-NE ICR was less than or equal to 140 MW and its annual generation of RECs or EAs was less than 670 GWh. TCR classified Proposals that met those criteria as "small" because it determined they would not cause any changes in capacity additions and retirements projected under the Base Case, nor cause any changes in REC prices projected under the Base Case. TCR selected the 140 MW threshold as the minimum estimated level of ICR contribution that could reduce or delay the need for a generic peaking capacity added under the Base Case and therefore could materially impact the forecast capacity mix. Similarly, TCR estimated that in order to make an impact on REC prices, the new resource would have to produce at least 670 GWh of RECs per year. Based upon those assumptions, TCR's ENELYTIX modeling of small Proposals did not include the Capacity Expansion module. Processing small Proposals through the Capacity Expansion module could cause disproportionally large changes in the forecast capacity mix and create significant variations in projected energy prices that could not be explicitly attributed to the Proposal. Instead, TCR ran the Energy & Ancillary Service module and the Forward Capacity Auction module using the capacity mix projected in the Base Case plus the small 83D Proposal's capacity; also using the REC and CEC prices projected in the Base Case.

Some 83D Proposals had a capacity contribution to ICR less than or equal to 140 MW but had annual generation of RECs or EAs greater than 670 GWh. To determine whether those Proposals should be classified as either "small" or "large" TCR processed them through the Capacity Expansion module to determine if they would affect the REC prices projected in the Base Case. TCR classified Proposals that would not affect the REC prices projected in the Base Case as small, and accordingly used the Base Case capacity mix and REC prices in the Energy and Ancillary Services module for those Proposals. TCR classified Proposals that would affect the REC prices projected in the Base Case as large, and accordingly used the Proposal's capacity mix and REC prices in the Energy and Ancillary Services module.

By treating small 83D Proposals in this manner it was possible to assure that they were treated equivalently to large Proposals and thus had the same opportunity to impact forecast energy prices and emissions.

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 alternative energy and/or transmission pricing options 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 a summary worksheet, a proposal metrics worksheet, a Greenhouse Gas (GHG) Inventory worksheet and 32 supporting worksheets reporting data drawn from the relevant bid, the Proposal / Portfolio Case modeling results and the 83D Base Case modeling results.

This section describes the GHG Inventory worksheet, the Proposal Metrics worksheet and application of the Quantitative Workbook to small Proposals in Stage Two.

A. GHG Inventory Worksheet

The goal of the GHG Inventory Worksheet is to measure the incremental contribution of each Proposal / Portfolio towards meeting the Massachusetts GWSA relative to the 83D Base Case.[15] TCR developed the GHG Inventory Worksheet to estimate the impact of the Proposal /Portfolio on the Massachusetts Department of Environmental Protection GHG Inventory following the general principles and methodology provided by DOER.

The GHG Inventory Worksheet calculates values for two types of GHG emission impacts of a Proposal/Portfolio on Massachusetts. First, it calculates changes in annual emissions (in metric tons of CO_2 equivalent) of grid energy generated in Massachusetts and/or imported into Massachusetts attributable to operation of the Proposal or Portfolio. Second, it calculates the changes in annual emissions associated with RECs and/or EAs from the Proposal/Portfolio used to comply with state RPS and/or the Massachusetts CES as well those that are retired solely for GWSA compliance. The manner in which the Proposal's RECs and/or EAs are treated in each year is a function of market conditions and current law and regulation for compliance in Massachusetts and the other New England states. In particular, the RPS and CES mechanisms each rely on markets, with ACPs, to incentivize new project development and retirements. The only market for EAs under current regulations is CES compliance. Therefore, EAs not used for CES compliance in a given year are retired for GWSA compliance.

The GHG Inventory provides six major outputs by year for the period 2019 to 2040 that are then used as inputs to the calculations of Direct and Indirect Benefits of each Proposal/Portfolio. The six outputs are:

1. RECs from Project (MWh) used towards MA RPS contract gap.
2. RECs from Project (MWh) used towards MA incremental CES contract gap

[15] The Base Case GHG Inventory does not represent full implementation of all policies in the GWSA Clean Energy Compliance Plan (CECP) 2020 Update. Thus, its results should not be interpreted as a prediction of electric sector emissions. Instead, the Base Case GHG Inventory result simply helps determine the incremental impact of a Proposal/Portfolio on the electric sector.

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3. EAs from Project (MWh) used towards MA incremental CES contract gap[16]
4. Residual quantity of RECs (MWh) purchased at market prices and retired to comply with Massachusetts RPS & / or incremental CES
5. RECs from Project (MWh) sold out of state.
6. GWSA compliance contribution (GHG Inventory Impact) of Project in MWh. In each year, this contribution is calculated as the decrease in annual metric tons CO2e under the Proposal Case (Portfolio Case) relative to the Base Case divided by the Base Case emissions rate. (The Base Case emissions rate in a given year is metric tons of CO2 emitted that year divided by MWh of energy consumed in Massachusetts that year.)

B. 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 and Indirect Costs and Benefits of that Proposal / Portfolio. It develops annual values in 2017$ over an evaluation period of 2019 to 2043 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, RECs and transmission from the bid
- Results from ENELYTIX modeling of the relevant Proposal Case /Portfolio Case
- Results from ENELYTIX modeling of the 83D Base Case
- Results from the GHG Inventory worksheet of the relevant Proposal Case /Portfolio Case
- The unit value per MWh of incremental contribution towards GWSA compliance.

C. Application of Quantitative Workbook to Small Proposals in Stage Two

The Evaluation Team concluded that the Indirect Benefits (whether positive or negative) of small Proposals could be attributed to “noise” within the modelling environment rather than legitimate impacts of the projects. Therefore, the Quantitative Workbooks for small Proposals in Stage Two did not calculate Indirect Benefits. Analysis of the results of the E&AS modeling for different small proposals indicated that changes caused by these projects on the projection of energy prices could be influenced by factors not necessarily related to the projects themselves but rather to random factors such as implemented patterns of generator outages.[17]

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[16] Massachusetts RPS contract gap equals the total quantity of RECs required to comply with the Massachusetts RPS in a year minus the quantity of non-83D RECs under contract to comply with Massachusetts RPS in that year. Massachusetts incremental CES contract gap equals the total quantity of CECs required to comply with the CES in a year incremental to the RPS minus the quantity of non-83D CECs under contract to comply with incremental Massachusetts CES in that year.

[17] TCR modeled the same pattern of generator outages in the Base Case and in all Proposal Cases to minimize the effect of these outages on specific projects. However, the effect of outages may be comparable in magnitude or even exceed the size of small projects. The comparative impact of these projects on energy prices could be attributed to the specific pattern of outages used in the model and TCR could not rule out that the comparison would be reversed under a different outage pattern.

5. Scoring and Ranking of Proposals and Portfolios

The Evaluation Team used the results from TCR's Quantitative Analyses and from the Qualitative Analyses performed by other members of the Evaluation Team, to score and then rank Proposals and Portfolios.

The scoring system was based on a 100-point scale. A Proposal / Portfolio could receive a maximum of 75 points based upon the results of its quantitative evaluation and a maximum of 25 points based upon the results of its qualitative evaluation. TCR developed the Quantitative Analysis scores assigned to each Proposal / Portfolio based upon the results of its quantitative evaluations. The 83D Qualitative Team developed the scores assigned to each Proposal / Portfolio based upon the results of their Qualitative Analysis evaluations.

TCR assigned Quantitative Analysis scores to each Proposal / Portfolio based upon results of their respective Quantitative Analysis results pursuant to the following approach:

- assign 75 points to the Proposal / Portfolio with the highest levelized unit Net Benefit, 2017$/MWh, ("top bidder");
- calculate the ratio of the levelized unit Net Benefit of each remaining Proposal / Portfolio to the Levelized Unit Net Benefit of the top bidder; and
- multiply the ratios of each remaining Proposal / Portfolio by the 75 point score of the top bidder in order to determine the score of each remaining Proposal/Portfolio.

The 83D Qualitative Team provided TCR the scores assigned to each Proposal / Portfolio based upon results of their respective Qualitative evaluations.

TCR added the quantitative and qualitative scores to calculate the total score of each Proposal / Portfolio. TCR then ranked each Proposal / Portfolio from high to low according to its total score.

In Stage Two TCR calculated total scores and ranking for large Proposals separate from small Proposals. The separate scoring and ranking are due to the fact that the Quantitative Workbooks for small Proposals in Stage Two did not calculate Indirect Benefits, as explained in Section 4. Appendix 1 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 the 83D Qualitative Team and ranking of each Proposal based on the total of the quantitative and qualitative scores.

In Stage Three TCR calculated total scores and ranking for Portfolios. Appendix 2 provides the corresponding Stage Three Quantitative Analysis results, quantitative scores, qualitative scores and ranking of each Portfolio. The Stage 3 quantitative results for certain Proposals differ from their Stage 2 results primarily because those Proposals reduced the transmission cost component of their bids to reflect changes in the federal income tax law passed in late December 2017.

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Appendix 1 Stage Two Proposal scores and ranking

	A	B	C	D	E	F	G	H	I	J	K	L
1	**83D Large Proposal Results, MedianEA+NoCap**	1/16/2018										
2	**Proposal**	**Capacity (MW), Summer ICAP**	**Technology**	**Delivery Location (ISO New England Load Zone)**	**Start date**	**End date**	**Price of Contract (PPA and Transmission), NPV 2017$/MWH**	**Annual Energy (MWh), CPPD**	**Capacity Factor, per CPPD**	**Annual REC's (MWh), per CPPD**	**Annual EAs (MWh)**	**GHG Inventory Impact (MMT COe avoided vs Base Case 2019 - 2040)**
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	16.88
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	15.42
5	NECEC Hydro Quant Results_2017_12_12	850	Hydro	ME	12/31/2022	12/30/2042	59.34	9,554,940	100%	0	9,554,940	36.61
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	41.77
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	35.17
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	35.17
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	34.30
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	40.06
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	32.55
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	32.55
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	16.88
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9.05
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	23.16
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.32
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.87
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.95
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	12.10
20												
21	**Note re NPT Hydro and NPT Wind Hydro Proposals** - transmission costs assume cost of debt is [redacted]											
22–25	**Note re NECPL TSA indexed -** After 1/16/2018 TCR found the transmission cost component of TSA indexed was incorect. When corrected the NECPL TSA indexed options drop below the NECPL TSA fixed options. There is no impact on Portfolios selected for Stage Three.											

	A	M	N	O	P	Q	R	S	T	U
1	**83D Large Proposal Results, MedianEA+NoCap**									
2	**Proposal**	**GHG Inventory Impact (MMT COe avoided vs Base Case), 2020**	**Net Direct Benefit (cost) NPV 2017$/MWh**	**Net Indirect Benefit (cost) NPV 2017$/MWh**	**Net Total Beneft (Cost) - Direct + Indirect, NPV 2017$/MWH**	**Net Beneft (Cost) $**	**Quantitative Score**	**Qualitative Score Final**	**Total Score at Final Qualitative**	**Rank at Final Qualitative**
3	[redacted]	0.05	23.23	23.24	46.47	$ 2,049,672,653.46	75.00	10.94	85.94	1
4	[redacted]	-0.03	22.26	19.92	42.18	$ 1,664,568,537.00	68.08	12.16	80.24	2
5	NECEC Hydro Quant Results_2017_12_12	0.00	15.41	24.32	39.73	$ 3,875,669,973.14	64.12	15.63	79.74	3
6	[redacted]	0.10	10.31	25.87	36.17	$ 3,890,386,317.53	58.38	18.25	76.63	4
7	[redacted]	0.01	9.63	26.08	35.71	$ 3,284,303,068.51	57.62	18.13	75.75	5
8	[redacted]	0.01	8.97	26.08	35.05	$ 3,223,569,815.20	56.56	19.13	75.68	6
9	[redacted]	-0.01	15.40	21.07	36.47	$ 3,557,165,753.20	58.86	15.68	74.54	7
10	[redacted]	0.01	9.63	23.99	33.62	$ 3,606,849,267.94	54.25	16.98	71.23	8
11	[redacted]	0.01	8.55	22.72	31.28	$ 2,876,788,578.58	50.47	18.14	68.61	9
12	[redacted]	0.01	7.89	22.72	30.62	$ 2,816,055,325.27	49.41	19.14	68.55	10
13	[redacted]	0.04	10.27	23.24	33.51	$ 1,477,913,254.74	54.08	9.85	63.92	11
14	[redacted]	-0.01	16.21	12.59	28.79	$ 564,722,233.05	46.47	12.16	58.63	12
15	[redacted]	0.00	3.06	22.46	25.52	$ 1,508,210,584.58	41.19	9.31	50.50	13
16	[redacted]	-0.02	16.76	5.83	22.59	$ 519,170,652.51	36.46	13.69	50.14	14
17	[redacted]	0.00	15.62	-6.86	8.76	$ 253,626,567.29	14.14	12.79	26.93	15
18	[redacted]	0.03	12.64	-5.52	7.12	$ 206,097,305.64	11.49	14.04	25.53	16
19	[redacted]	0.04	-7.30	15.77	8.47	$ 238,200,098.51	13.67	9.75	23.42	17
20										
21	**Note re NPT Hydro and NPT Wind Hydro Proposals** - transmission costs assume cost of debt is [redacted]									
22	**Note re NECPL TSA indexed -** After 1/16/2018 TCR									
23	found the transmission cost component of TSA									
24	indexed was incorect. When corrected the NECPL TSA indexed options drop below the NECPL TSA fixed									
25	options. There is no impact on Portfolios selected for Stage Three.									

	A	B	C	D	E	F	G	H	I	J	K
1	**83D Small Proposal Results, MedianEA**	1/16/2018									
2	**Proposal**	**Capacity (MW), Summer ICAP**	**Technology**	**Delivery Location (ISO New England Load Zone)**	**Start date**	**End date**	**Price of Contract (PPA and Transmission), NPV 2017$/MWH**	**Annual Energy (MWh), CPPD**	**Capacity Factor, per CPPD**	**Annual REC's (MWh), per CPPD**	**Annual EAs (MWh)**
3	[redacted]										
4											
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9											
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22											
23											

	A	L	M	N	O	P	Q	R	S
1	**83D Small Proposal Results, MedianEA**								
2	**Proposal**	**GHG Inventory Impact (MMT COe avoided vs Base Case 2019 - 2040)**	**GHG Inventory Impact (MMT COe avoided vs Base Case), 2020**	**Net Direct Benefit (cost) NPV 2017$/MWh**	**Net Beneft (Cost) $**	**Quantitative Score**	**Qualitative Score Final**	**Total Score at Final Qualitative**	**Rank at Final Qualitative**
3	[redacted]	0.37	0.00	27.89	93,358,992.01	75.00	12.25	87.25	1
4		0.94	0.05	21.71	253,650,412.19	58.38	11.00	69.38	2
5		0.46	0.02	17.33	119,890,050.15	46.60	18.75	65.35	3
6		0.11	0.01	13.71	107,546,974.28	36.87	10.00	46.87	4
7		0.00	0.01	12.98	8,057,484.25	34.92	10.00	44.92	5
8		5.86	-0.02	9.86	760,807,047.37	26.51	12.13	38.64	6
9		0.09	0.02	10.34	141,781,061.74	27.81	10.00	37.81	7
10		0.33	-0.01	10.52	91,956,946.36	28.29	9.25	37.54	8
11		0.11	0.02	9.11	35,761,363.45	24.51	10.00	34.51	9
12		0.07	0.01	7.25	52,054,406.82	19.49	10.00	29.49	10
13		-0.09	0.01	5.85	20,602,901.16	15.72	10.00	25.72	11
14		-0.02	0.02	2.14	-8,188,512.23	5.76	10.50	16.26	12
15		0.08	0.02	1.08	21,284,024.10	2.91	10.00	12.91	13
16		0.17	0.05	-0.26	22,470,993.04	-0.70	10.50	9.80	14
17		5.60	-0.01	-0.86	625,903,843.66	-2.32	10.25	7.93	15
18		0.17	0.02	-7.79	27,370,769.87	-20.96	10.00	-10.96	16
19		2.29	-0.01	-18.67	169,744,176.81	-50.22	10.00	-40.22	17
20		7.31	0.01	-31.97	227,793,308.05	-85.99	7.31	-78.68	18
21		3.57	0.85	-36.68	-5,767,712.75	-98.65	10.00	-88.65	19
22		0.15	-0.02	-37.99	-51,282,889.47	-102.17	0.00	-102.17	20
23		5.52	0.02	-48.28	-574,031,426.61	-129.85	10.50	-119.35	21

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Appendix 2 Stage Three Portfolio scores and ranking

	A	B	C	D	E	F	G	H	I	J	K	L
1	**Stage 3 Portfolio Summary ($16.51 EA)**	1/18/2018										
2	**Proposal**	**Portfolio Number**	**Capacity (MW), Summer ICAP**	**Technology**	**Delivery Location (ISO New England Load Zone)**	**Start date**	**End date**	**Price of Contract (PPA and Transmission), NPV 2017$/MWH**	**Annual Energy (MWh), CPPD**	**Capacity Factor, per CPPD**	**Annual REC's (MWh), per CPPD**	**Annual EAs (MWh)**
3	NECEC Hydro	Portfolio 6	850	Hydro	ME	12/31/2022	12/30/2042	59.05	9,554,940	1.00	0	9,554,940
4	[redacted]	Portfolio 12	[redacted]									
5	[redacted]	Portfolio 3										
6	[redacted]	Portfolio 8										
7	[redacted]	Portfolio 9										
8	[redacted]	Portfolio 7										
9	[redacted]	Portfolio 14										
10	[redacted]	Portfolio 5										
11	[redacted]	Portfolio 10										
12	[redacted]	Portfolio 4										
13	[redacted]	Portfolio 2										
14	[redacted]	Portfolio 13										
15												
16	**Note re NPT Hydro and NPT Wind Hydro Proposals** - transmission costs assume cost of debt is 4.45%.											
17–23	**Note re NECEC bids.** After 1/18/2018 TCR found the transmission cost component of the NECEC Proposals with indexed transmission pricing was not correct. Correcting that calculation improves the net quantitative benefit of the NECEC Hydro and NECEC Hydro Wind projects by approximately 0.3% and does not change their Stage 3 rankings. For NECEC Hydro, this correction increases the absolute net benefits reported in Column 'R' by $12.6 million to a total of $3,916,299,275, improves the levelized unit net benefits reported in Column 'Q' from $40.02/MWh to $40.15/MWh and reduces the unit price of contract reported in Column 'H' from $59.05/MWh to $58.92/MWh											

	A	B	M	N	O	P	Q	R	S	T	U	V
1	**Stage 3 Portfolio Summary ($16.51 EA)**	1/18/2018										
2	**Proposal**	**Portfolio Number**	**GHG Inventory Impact (MMT COe avoided vs Base Case 2019 - 2040)**	**GHG Inventory Impact (MMT COe avoided vs Base Case), 2020**	**Net Direct Benefit (cost) NPV 2017$/MWh**	**Net Indirect Benefit (cost) NPV 2017$/MWh**	**Net Total Beneft (Cost) - Direct + Indirect, NPV 2017$/MWH**	**Net Beneft (Cost) $**	**Quantitative Score**	**Qualitative Score**	**Total Score (Quant + Qual)**	**Rank @ Total Score**
3	NECEC Hydro	Portfolio 6	36.61	0.00	15.70	24.32	40.02	3,903,685,885	75.00	15.63	90.63	1
4	[redacted]	Portfolio 12	37.78	0.06	15.96	22.47	38.43	3,879,300,493	72.02	15.50	87.52	2
5	[redacted]	Portfolio 3	38.69	0.09	15.59	21.89	37.48	3,900,618,174	70.24	15.39	85.63	3
6	[redacted]	Portfolio 8	41.77	0.10	9.74	25.87	35.61	3,829,761,451	66.74	18.25	84.99	4
7	[redacted]	Portfolio 9	35.17	0.01	8.97	26.08	35.05	3,223,569,815	65.68	19.13	84.81	5
8	[redacted]	Portfolio 7	34.30	-0.01	15.69	21.07	36.76	3,585,181,665	68.90	15.68	84.57	6
9	[redacted]	Portfolio 14	36.58	0.05	9.32	25.16	34.49	3,314,316,693	64.64	18.87	83.51	7
10	[redacted]	Portfolio 5	37.92	0.17	9.30	23.32	32.62	3,255,600,444	61.14	18.55	79.69	8
11	[redacted]	Portfolio 10	32.55	0.01	7.89	22.72	30.62	2,816,055,325	57.38	19.14	76.52	9
12	[redacted]	Portfolio 4	29.43	0.17	17.96	11.33	29.29	2,616,586,918	54.90	11.45	66.35	10
13	[redacted]	Portfolio 2	32.75	0.17	15.70	9.91	25.60	2,550,522,459	47.99	11.30	59.29	11
14	[redacted]	Portfolio 13	28.96	0.05	20.24	4.62	24.86	2,733,562,232	46.59	11.85	58.45	12
15												

16 **Note re NPT Hydro and NPT Wind Hydro Proposals** - transmission costs assume cost of debt is 4.45%.

17–23 **Note re NECEC bids.** After 1/18/2018 TCR found the transmission cost component of the NECEC Proposals with indexed transmission pricing was not correct. Correcting that calculation improves the net quantitative benefit of the NECEC Hydro and NECEC Hydro Wind projects by approximately 0.3% and does not change their Stage 3 rankings.

For NECEC Hydro, this correction increases the absolute net benefits reported in Column 'R' by $12.6 million to a total of $3,916,299,275, improves the levelized unit net benefits reported in Column 'Q' from $40.02/MWh to $40.15/MWh and reduces the unit price of contract reported in Column 'H' from $59.05/MWh to $58.92/MWh

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Appendix 3 Protocol for 83D Quantitative Metric Calculations, Stage II

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Protocol for 83D Quantitative Metric Calculations, Stage II

Effective November 1, 2017

This document describes the quantitative metrics and multi-year net present value cost/benefit analysis the evaluation team will use in Stage II to evaluate each of the proposals received in response to the 83D RFP. The inputs to many of those metrics will be drawn from the results of the analytic tool ENELYTIX licensed by Tabors Caramanis Rudkevich (TCR) to perform economic analyses of a Base Case and the individual project cases.

The ultimate unit of comparison of projects

The core measure of comparison will be the levelized net unit benefit per MWh of the project expressed in 2017 dollars ($2017).

The financial parameters to be used in the comparison of projects

- Discount rate (nominal) i.e., WACC 6.99%
- Rate of inflation 2%
- Discount rate (real based on $2017) 4.89%

Allocation of the 75 quantitative points

1. Assign 75 points to the project with the highest total net unit benefit (“top bidder). For projects categorized as small per Attachment D, assign 75 points to the project with the highest total direct net unit benefit.
2. For the large project group and the small project group respectively, calculate the ratio of each remaining project to the top bidder and allocate that proportional number of points to each remaining project.
3. In the instance in which there is a significant outlier as the best bid, set the outlier to 75 points and it will be the #1 ranked bid overall; and then set second highest to 75 points and it will be the #2 ranked bid overall. Calculate the proportional value of all other bids relative to bidder ranked #2.
    a. A significant outlier is defined as a bid whose value is greater than one half the distance from the maximum (not including the outlier) and the minimum.

The criteria for evaluation and the procedure for their calculation

The 83D RFP specifies two categories of quantitative evaluation criteria, Direct Costs & Benefits and Other Costs and Benefits to Retail Customers (Indirect Costs and Benefits). This section describes the calculation procedure, and information sources, for the criteria and metrics the Evaluation Team used for each of those two categories. Attachment A describes inputs and details of specific calculations.

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A. CALCULATION OF DIRECT COSTS & BENEFIT METRICS

1. A Mark to market comparison of the proposals bid price to the projected market price at the delivery point with the project in service
    1. Using the ENELYTIX modeling system to generate hourly, nodal Locational Marginal Prices (LMPs), calculate the annual market value ($) of energy delivered by the Project at the delivery node(s) accounting for the project contract period and contract delivery conditions (peak, off peak, etc). Annual market value ($) equals quantity of energy delivered at node in each hour of year times hourly, nodal LMPs.
    2. Identify the annual project cost of energy as bid.
    3. Calculate the annual net cost (savings) of the energy from the project, i.e. annual project cost of energy as bid minus the market, LMP-based delivered energy value of the project.

2. A mark to market comparison of the price of Class 1 RECs eligible for RPS and/or CES compliance under a contract to their projected market prices at the delivery point with the project in service.
    1. Identify the annual quantity of Class 1 RECs that are required to meet the Class 1 RPS requirements plus incremental CES requirements of the distribution service retail load served by Massachusetts Electric Distribution Companies (EDCs). [1]
    2. Identify the Class 1 RECs that MA EDCs are holding under long-term contracts in each year. (These will be based on MA EDC existing contracts, anticipated MA EDC contracts for Class 1 RECs from projects selected through the New England Clean Energy RFP of November 2015 and Class 1 RECS from the generic 83C resources.)
    3. Calculate the net requirement for class 1 RECs/CECs that could be filled by REC/CECs from the Project (The gap = Step 1 minus Step 2)
    4. Identify the number of annual Class 1 RECs the MA EDCs would acquire from the Project and the total Direct annual cost of those RECs. Direct annual cost equals annual quantity of Project RECs/CECs times Project annual unit cost per REC/CEC as bid.
    5. Calculate the number of REC/CECs to be supplied by the Project to fill all, or a portion, of the gap in required REC/CECs by subtracting Step 4 from Step 3.
    6. Calculate the direct annual dollar benefit of Project REC/CECs 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/CECs (Quantity of Project RECs/CECs used to fill gap times Base Case REC/CEC market price).
    7. Calculate the direct annual dollar benefit of Project REC/CECs sold. This is the total quantity of Project RECs minus the step 5 quantity EDCs use to fill the gap, times the Project Case Market price of REC/CECs (Project RECs surplus to gap times Project case REC/CEC market Price).
    8. Calculate the total direct benefit as the sum of Steps 6 and 7.

[1] TCR will draw these requirements from the inputs to the ENELYTIX modeling system. They exclude the requirements of load served by municipal light plants (MLP) in Massachusetts.

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3. For proposals with associated transmission, the cost associated with the proposed transmission project, including network upgrades
    1. Identify annual project costs for transmission investments as shown in the Project proposal. i.e., annual project cost of transmission as bid separately from energy and Class1 RECs, including estimated network upgrades associated with the proposed project.
    2. The bidder's cost estimates are subject to modification as necessary to assure a reasonable and appropriate estimate of transmission costs, taking into account the risks associated with the proposed project and the bidder's proposed cost containment provisions.
        a. The EDCs have retained an independent transmission cost consultant with a scope of work set forth in an appendix to this protocol (which may be subject to revision if requested by the Evaluation Team). The independent transmission cost consultant will report to the Evaluation Team. The independent transmission cost consultant will opine on the reasonableness of the transmission project cost estimates submitted by the bidder, taking into consideration proposed cost containment provisions. If the independent transmission cost consultant deems the bidder's cost estimates not to be reasonable or appropriate, the consultant will provide its best estimate of transmission costs, including reasonable contingency, taking into consideration proposed cost containment provisions, for use in the quantitative analysis process. Absent strong reasons to the contrary, the Evaluation Team will use the transmission project cost estimates submitted by the bidder if the independent transmission cost consultant finds them to be reasonable and the independent transmission cost consultant's estimate of reasonable transmission costs if the consultant finds that the bidder's estimates are not reasonable.

4. For proposals with associated transmission, the expected revenue from the sales of excess transmission capacity, if any
    1. Identify any positive transmission annual revenue amounts claimed by Proposed Projects.
    2. Evaluate the costing and market value assumptions associated with bidder's calculation of positive transmission revenues.
    3. Calculate the annual reduction to transmission costs associated with the project

SUB-TOTAL OF DIRECT NET BENEFITS OF THE PROPOSED PROJECT

1. Calculate the annual sum of the annual net cost (savings) of the energy from the project, Class 1 RECs from the project and transmission associated with the Proposed Project.

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B. CALCULATION OF INDIRECT COST & BENEFIT METRICS

1. Price change Impacts on LMP and Class 1 REC market prices. These metrics will calculate price change impacts on the energy and Class 1 RECs of the distribution service customers of the EDCs per Attachment A.

The impact of changes to the Locational Marginal Price ("LMP").

1. For the Project case, obtain from ENELYTIX the annual sum of hourly LMPs times load by load zone in Massachusetts. (Load zones in Massachusetts are SEMA, WCMA and NMABO)
2. Adjust the Project case value in each load zone by the proportion of MA EDC distribution service retail load to total load in each load zone per Attachment A.
3. Calculate the LMP-based total cost to MA EDC consumers in the Project case
4. For the Base Case, obtain from ENELYTIX the annual sum of hourly LMPs times load by load zone in Massachusetts.
5. Adjust the Base Case value in each load zone by the proportion of MA EDC distribution service retail load to total load in each load zone per Attachment A
6. Calculate the LMP-based total cost to MA EDC consumers in the Base Case
7. Calculate the price change (energy price change) impact by subtraction of the annual Project case total from the annual Base Case total to arrive at the price change impact of the Project.

The impact of changes to the price for Class 1 RECs/CECs

1. Calculate the annual quantity of Class 1 RECs/CECs that will need to be acquired at market prices beyond the quantity supplied by the Project. This equals the annual Class 1 RPS requirements plus incremental CES requirements of the distribution service retail load served by MA EDCs minus the quantity of RECs/CECs the MA EDCs held under long-term contract minus the quantity of Project 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. The direct and indirect costs and benefits of environmental attributes (EAs), excluding Class 1 RECs, from the Proposal that EDCs use to comply with the CES.
   1. Calculate the direct annual dollar cost of the Project EAs. This is the quantity of EAs the MA EDCs would acquire from the Project times the Project unit cost per EA as bid.
   2. Calculate the portion of EAs EDCs would acquire from the Project and use to meet the CES obligation associated with their default supply service load.
   3. Calculate the direct annual dollar benefit of the portion of EAs EDCs would acquire from the Project to meet the CES obligation. This is the quantity from step 2 times the Base Case Market price for CECs (Quantity of Project EAs that EDCs use to meet CES times Base Case CEC market price).

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4. Calculate the portion of EAs EDCs would acquire from the Project in excess of their CES obligation that EDCs must retire in each year. This is the total quantity of Project EAs in year from step 1 minus the quantity EDCs use to meet their CES obligation from step 2.
5. Calculate the REC/CEC price change benefit of the Project EAs. This is the annual quantity of RECs & CECs that will need to be acquired at market prices to comply with the annual Class 1 RPS requirements plus incremental CES requirements of the distribution service retail load served by MA EDCs minus the quantity of RECs/CECs the MA EDCs hold under long-term contract minus the quantity of Project EAs used to meet the annual requirement (MWh) multiplied by the difference in the REC/CEC market price ($MWh) between the Proposal Case and the Base Case.

3. The value of the Proposal's contribution towards meeting the Global Warming Solutions Act (GWSA) over and above compliance with the RPS and the CES.
    1. Calculate the Incremental Inventory Impact in MWh per Attachment B
    2. Calculate the unit Value ($/MWh) of the Incremental Inventory Impact per Attachment C
    3. Calculate the incremental benefit ($) by multiplying Step 1 times Step 2.

4. The economic impact (positive or negative) associated with the firmness of a resource. This could include the benefits associated with firm delivery as well as the impact on the system of intermittent resources

In order to evaluate the potential impact (positive or negative) of a proposed Project when gas prices are much higher than average, each Project will be compared with the Base Case in terms of LMP-based delivered cost performance during the 3 winter months (December, January and February). The comparison will be between the flat monthly price as used in the Base Case and a scenario using the highest historical 3 winter month spot price variation in the NE Region since 2002.

1. Develop from historical data a scenario using the highest historical 3 winter month spot price variation in the NE Region since 2002, where variation is measured against the average of 3 winter month variation over the period 2002 through 2017.
2. Using the ENELYTIX modeling system, Base case assumptions and the gas price scenario of step 1; calculate for the single power year 2023/2024 the three-month LMP-based cost to MA consumers in 2017 constant dollars.
3. Compare the result of step 2 with the three-month LMP-based cost to MA consumers to identify a percentage difference in total annual costs (% increase or decrease) when gas prices are much higher than average.
4. Using the ENELYTIX modeling system with the Project in place and gas price scenario of step 1, calculate for the single power year 2023/2024 the three-month LMP-based cost to MA consumers. If necessary, bring values to 2017 constant dollars.
5. Compare the results of step 4 with the three-month Project cost to MA consumers in the initial Project case to identify a percentage difference in total costs (% increase or decrease)

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6. Calculate the relative percent impact of response to gas prices much higher than average of the Project to the Base Case by subtracting the percent increase of Step 4 from that of step 5.
7. Apply the percentage increase or decrease in step 6 multiplied by the frequency of 1 in 15 years to the indirect price change benefits calculation for the Project. Apply the same percentage to each year of the project.

5. Impacts associated with the Capacity market

The impact of 83C generic resources and the 83D projects on installed capacity requirements and capacity prices will be modeled according to the existing ISO-NE ICR and FCM rules applicable to those resources. In modeling and analysis of these cases, the 83C generic resources and the 83D Projects will contribute to ICR but those resources will not have any direct impact on FCM clearing prices. The 83C generic resources are assumed to provide a contribution to ICR at a level equal to 20 percent of their nameplate capacity.

Capacity Market

1. Obtain from ENELYTIX the total annual zonal capacity market clearing value paid by consumers in the Project case
2. Adjust the Project case value in each load zone by the proportion of MA EDC distribution service peak demand to total peak demand in the load zone per Attachment A.
3. Obtain from ENELYTIX the total annual zonal capacity market clearing value paid by consumers in the Base Case
4. Adjust the Base Case value in each load zone by the proportion of MA EDC distribution service peak demand to total peak demand in the load zone per Attachment A.
5. Calculate the benefits of changes in capacity value by subtraction of the Project case capacity value from the Base Case capacity value.

TOTAL INDIRECT NET BENEFITS OF THE PROPOSED PROJECT

1. Calculate the annual sum of the indirect benefits.

C. CALCULATION OF THE TOTAL QUANTITATIVE BENEFITS OF THE PROPOSED PROJECT

1. Calculate the annual sum of the direct and indirect benefits.

CALCULATION OF THE TOTAL NET UNIT BENEFIT OF THE PROPOSED PROJECT:

1. Compute the present value of the annual direct costs, direct benefits, and indirect benefits. Annual costs and benefits expressed in nominal dollars should be discounted to a 2017 reference year at the nominal 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 project. The annual energy quantities should be discounted to a 2017 reference year using the real discount rate.

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4. Divide the result of step 2 by the result of step 3 to compute the levelized unit net benefit for the project. This result will be expressed in 2017 constant dollars per MWh.

Attachment A - Inputs and details of specific calculations

Attachment B – Greenhouse Gas Inventory Calculations

Attachment C – Determination of median value ($/MWh) of GWSA compliance

Attachment D – Criteria for Categorizing Projects as Small

Attachment A – Notes re Calculations

This document provides further background on certain of the calculations for the quantitative metrics used to evaluate the proposals received in response to the 83D RFP.[1]

Project energy and REC quantities, costs and market value impacts during PPA period.

- For projects that start / end during a calendar year project quantities and impacts will be reported for relevant partial year periods.
- For projects whose PPA period extends beyond December 2040, project quantities and impacts in 2041 through 2043 will be calculated as follows:
    - Energy, REC and EA quantities will be held at the average of 2037 through 2039 to exclude leap year quantities
    - Costs or values in Rows 10 to 12 and 14 to 16 will be extrapolated based on the 5-year CAGR from 2036 through 2040
    - REC Price held at 2040 value

Project REC and GWSA impacts beyond PPA period

For projects whose PPA period terminates after December 2040, their REC and GWSA impacts from 2041 through 2043 will be calculated based on the following:

- Costs or values in rows 22 to 24 will be extrapolated based on the 5-year CAGR from 2036 through 2040
- Costs or values in row 26 will be held at the average of 2037 through 2039 to exclude leap year quantities
- Residual REC quantity in row 26 will be calculated as quantity in the preceding year plus RECs from project used toward MA RPS and MA incremental CES contract gap in preceding year plus EAs from project used toward MA incremental CES contract gap in preceding year less RECs from project used toward MA RPS and MA incremental CES contract gap in calculation year less EAs from project used toward MA incremental CES contract gap in calculation year
- GWSA compliance contribution in row 27 will be held at 2040 value

Indirect benefits prior to Project COD.

Any difference in reporting quantities between the Base Case and the Proposal Case in years prior to the project commercial online date (COD) is idiosyncratic and qualified as 'noise' within the modelling environment. Therefore implied indirect benefits prior to the project COD arising from this difference will be nullified.

[1] These calculations were developed in conjunction with the 83D Protocol and implemented in the Quantitative Workbooks. They were not documented as an attachment until March 2018.

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Protocol for 83D Quantitative Metric Calculations, Stage II

Attachment B - GHG Inventory Calculation Protocol

In order to calculate the impact an 83D Proposal project ("Proposal" or "Project") or a portfolio of Proposals has on GWSA compliance, the Evaluation Team will utilize the methodology described in this Attachment to estimate the Proposal's or portfolio of Proposals' impact on the Massachusetts Department of Environmental Protection Greenhouse Gas (GHG) Inventory ("Inventory").[2] The Evaluation Team will measure the Incremental Inventory Impact of each Proposal and portfolio of Proposals relative to the 83D Base Case which is a "business as usual" scenario of the New England (NE) electric sector that assumes no clean energy projects are acquired through the 83D Procurement.[3]

The methodology uses a GHG Inventory model (inventory model) to capture the two major types of GHG emission impacts an 83D Proposal has on Massachusetts. First, it captures the changes in emission rates of grid energy generated in Massachusetts and/or imported into Massachusetts caused by the 83D proposal. Second, it captures the changes in emissions caused by the renewable energy credits (RECs) and/or Environmental Attributes (EAs) from the 83D proposal that are used to comply with state renewable portfolio standards (RPS) and/or the Massachusetts Clean Energy Standard (CES) as well those that are retired solely for GWSA compliance. The manner in which the Proposal's RECs and/or EAs are modeled in each year is a function of market conditions and current law and regulation for compliance in Massachusetts and the other New England states. In particular, the RPS and CES mechanisms each rely on markets, with alternative compliance payments (ACPs), to incentivize new project development and retirements. Under current regulations, EAs that are not eligible for CES compliance in a given year do not have other markets and thus will be retired for GWSA compliance.

The Evaluation Team will utilize the methodology to determine the impact of each 83D proposal on the Inventory on a level playing field regardless of the type of underlying 83D energy resource. This methodology will produce the following six major outputs by year for the period 2019 to 2040:

1. RECs from Project (MWh) used towards Massachusetts RPS contract gap.[4]
2. EAs from Project (MWh) used towards Massachusetts incremental CES contract gap

[2] This methodology was developed in conjunction with the 83D Protocol and used to determine the final GWSA compliance benefit of Proposals in Stage Two and Portfolios in Stage Three. It was not documented as an attachment until March 2018.

[3] The Base Case Model amount does not represent the full implementation of all GWSA CECP 2020 Update policies and the associated Inventory results should not be interpreted as a prediction of electric sector emissions. Instead, the Base Case Inventory result is used only to determine the impact of a Proposal or a portfolio of Proposals on the electric sector.

[4] Massachusetts RPS contract gap equals the total quantity of RECs required to comply with the Massachusetts RPS in a year minus the quantity of non-83D RECs under contract to comply with Massachusetts RPS in that year. Massachusetts incremental CES contract gap equals the total quantity of Clean Energy Credits (CECs) required to comply with the Massachusetts CES requirements in a year incremental to the RPS minus the quantity of non-83D CECs under contract to comply with incremental Massachusetts CES in that year.

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3. RECs from Project (MWh) used towards incremental CES contract gap
4. Residual quantity of RECs (MWh) purchased at market prices to comply with Massachusetts RPS & / or incremental CES[5]
5. RECs from Project (MWh) sold out of state.
6. GWSA compliance contribution (GHG Inventory Impact) of Project (MWh).

Those outputs will be inputs to a spreadsheet model ("GHG workbook") that produces outputs used to determine the Direct Benefits and Indirect Benefits of each Proposal and portfolio as well as to calculate the overall GWSA Inventory impact and associated incremental GWSA compliance benefit.

A. GHG Workbook Inputs and Assumptions

The Inventory Impact of a Project is ultimately calculated as a delta between the GHG inventory for that Project's Case and the GHG inventory for the 83D Base Case. The team will use the GHG workbook to calculate the GHG inventory for each Project Case and for the 83D Base Case using outputs from ENELYTIX modeling of those Cases ("the Model") as well as a set of inputs common to each Case. The spreadsheet model will calculate the forecast GHG Inventory for each Case in million metric tons CO2e ("MMT CO2e") for every year between 2019 and 2040.

The GHG workbook calculation will use the following outputs from the Model. Unless noted, the outputs come from the Model's E&AS module.

- Annual Generation (MWh): The total generation in each New England (NE) state, not counting behind-the-meter PV (which is reflected in Annual Load)
- Imports (MWh) from NY, Quebec, and New Brunswick/PEI ("external control areas"): The Base Case assumes imports remain constant at the levels specified in the Base Case assumptions. A Proposal Case may assume imports increase over Base Case levels if the Proposal includes an increase in imports from external control areas
- Annual Total RECs Produced: The number of RECs produced in each NE state and external control area that are retired annually in New England.[6]
- Annual 83D Proposal RECs Produced: The number of RECs produced in each NE state and external control area by the Proposal or portfolio of proposals
- Annual EA Generation from 83D Proposal (MWh): The non-Class 1 clean energy produced in each NE state and external control area by the Proposal or portfolio of Proposals, potentially eligible for compliance with the MASSACHUSETTS Clean Energy Standard (EAs)

[5] GHG workbook calculations of RECs from Project sold out of state and Residual quantity of RECs purchased at market prices to comply with RPS and/or incremental CES are not valid for small 83D projects, as those calculations require outputs from the Model's capacity expansion module, which is not run for those proposals.
[6] The quantities of Annual Total RECs imported from each external control area are adjusted slightly so that the regional REC supply is consistent with the RPS and CES supply and demand conditions as indicated by outputs of the Model's capacity expansion module (REC and CEC prices, and ACP quantities required to comply with all states' RPSs and the Massachusetts CES). These small differences exist because the Model's E&AS module, unlike the capacity expansion module, does not enforce RPS and CES constraints.

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- Annual Non-Biogenic Emissions (metric tons CO2e): Emissions from non-biogenic fuel, per table 1, for each generator in each NE state
- Annual REC Price ($/MWh): The REC price projected by the Model's capacity expansion module[7]
- Annual CEC Price ($/MWh): The price for Massachusetts Clean Energy Certificates projected by the Model's capacity expansion module
- Annual Regional RPS ACP Quantity (MWh): The total quantity of all NE states' RPS requirements minus total RECs produced, when that difference is positive. This quantity is projected by the Model's capacity expansion module.
- Annual Massachusetts CES ACP Quantity (MWh): The quantity by which the incremental CES requirement is projected to exceed the attributes used to meet it. This value is projected by the Model's capacity expansion module.

Tables 2 through 4 provide the values of the following assumptions the inventory calculation will use in addition to those used in ENELYTIX modeling. These assumptions are the same for all cases.

- State loads (MWh). The generation required to supply the retail load of each state in each year.
- Annual Non-83D RECs under Long-Term Contract to Massachusetts EDCs (MWh): The quantity of RECs produced in each NE state and external control area that are (or expected to be) under long-term contract to Massachusetts EDCs. These quantities are the same for all cases.
- Emission rates for imports from external control areas (lbs CO2e/MWh): Emission rates for these imports will remain constant at the levels in the 2014 Massachusetts Department of Environmental Protection (MassDEP) Greenhouse Gas Baseline, Inventory & Projection, consistent with modeling assumptions.
- 2016 REC Oversupply Allocation (%): The percentage of unsettled and reserved certificates in the NEPOOL GIS system that are eligible for the states' Class or Tier 1 RPS (as reported to state regulators for 2016).[8] These quantities are used in the calculation of the Annual REC Oversupply Allocation.

B. GHG Workbook Outputs

Outputs 1, 2 and 3 - Project RECs and EAs retired for compliance with Massachusetts RPS and/or CES[9]

RECs and EAs from Projects in each year are accounted as follows:

a. Non-Proposal RECs under contract to the Massachusetts EDCs are subtracted from their Massachusetts RPS requirement.

[7] Annual REC and CEC prices are used solely in the adjustment of Annual Total RECs imported from each external control area, as described in footnote 6.
[8] These certificates were not retired for compliance for any Class or Tier 1 RPS but were included in the MassDEP Greenhouse Gas Inventory calculation.
[9] The Massachusetts RPS and CES requirements discussed throughout include both the requirements of the Massachusetts EDCs and those of competitive retail suppliers.

b. Proposal RECs. If the remaining RPS compliance gap (if any) is greater than the quantity of Proposal RECs, all Proposal RECs are deemed to be retired for the Massachusetts EDCs' compliance with the Massachusetts RPS (including offsetting Massachusetts competitive suppliers Massachusetts RPS obligations). If the gap is less than the Proposal RECs, then the quantity of Proposal RECs retired for compliance with the Massachusetts RPS is the size of the gap, and any remaining Proposal RECs are available for compliance with the CES.
c. Proposal EAs. If the remaining incremental CES compliance gap (if any) is greater than the quantity of Proposal EAs, all Proposal EAs are deemed to be retired for compliance with the CES, (including offsetting Massachusetts competitive suppliers' Massachusetts CES obligations). If the gap is less than the Proposal EAs, then the quantity of Proposal EAs retired for compliance with the CES is the size of the gap.
d. Remaining Proposal RECs. If there still remains an incremental CES compliance gap, any remaining Proposal RECs can be used to meet it. If the remaining Proposal RECs are less than the gap, all are deemed to be used for compliance with the CES. If the remaining Proposal RECs are greater than the gap, then the quantity deemed to be used for CES compliance is the size of the gap, and any remaining Proposal RECs are deemed available for sale out of state.[10]

Output 4 - Residual RECs purchased at market prices for compliance with MASSACHUSETTSRPS and CES

If, after applying non-Proposal and Proposal RECs to meet the Massachusetts RPS compliance gap, there remains a compliance gap, RECs purchased at market prices will be used for compliance. Those will consist of market RECs from Massachusetts and—if needed—from other NE states and external control areas. In the event of a regional RPS deficiency, the deficiency will be deemed to be consolidated in Connecticut, because it has the lowest RPS ACP.

If, after surplus RECs have been transferred among states to satisfy RPS deficiencies, a CES compliance gap and a surplus of RECs remain, those surplus RECs (beginning with RECs in MA) will be used to satisfy the gap.

Output 5 - Proposal RECs sold out of state

In the calculation, out-of-state sales of Proposal RECs can occur under either of two circumstances. The first circumstance is if Massachusetts obligations are satisfied and a surplus of RECs remains, including Proposal RECs, which is used to satisfy requirements in other NE states. The second circumstance is if there is a regional oversupply of RECs and an allocation of the regional oversupply results in Proposal RECs being transferred to other NE states.

The quantity of Proposal RECs sold out of state in a given year is determined as follows:

- If the Massachusetts RPS and CES obligations of Massachusetts EDCs and competitive suppliers are satisfied and there is a Massachusetts surplus consisting of 83D Proposal RECs and non-contract RECS, referred to here as the "original surplus," that original surplus is used to satisfy

[10] As noted above, Massachusetts RPS and CES requirements discussed throughout include both the requirements of the Massachusetts EDCs and those of competitive retail suppliers. In the calculation, proposal RECs are deemed available for sale out of state only if the entire Massachusetts RPS and CES requirements are satisfied.

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RPS compliance deficiencies in other NE states. After those transfers, there may still be a regional oversupply. Any such oversupply of RECs will be allocated among all NE states such that each state's REC Oversupply Allocation will be the average of its load share, its share of NE RECs generated, and its share of the 2016 REC Oversupply Allocation.

- The total Massachusetts RECs sold out of state is the difference between the original surplus and the quantity of RECs remaining in Massachusetts after transfers to meet deficiencies in other states and allocation of any regional oversupply. The quantity of Proposal RECs sold out of state is the proportion of surplus Proposal RECs in the original surplus multiplied by the total Massachusetts RECs sold out of state.

Output 6 - GWSA compliance contribution (GHG Inventory Impact)

As the composition of energy generated within and imported into Massachusetts changes each year, one MWh of clean energy will offset a different quantity of emissions each year.

For the Base Case and each Proposal Case, the overall emission rate for the Inventory in a year will be calculated as pounds of CO_2 emitted that year divided by MWh of energy consumed in Massachusetts that year. To express the GHG Inventory Impact of each Proposal Case in MWh, the decrease in metric tons CO_2e relative to the Base Case is divided by the Base Case emissions rate (metric tons CO_2e/MWh).

GHG emissions (Metric tons CO_2e) are calculated as:

> *Emissions from Massachusetts generation + Emissions attributed to electricity imports into Massachusetts from other NE states + Emissions attributed to electricity imports into Massachusetts from external control areas*

Emissions from generation in each NE state are an output of the Model. Emissions from imports from each external control area are calculated as the product of the quantity of imports from the external control area and a fixed emissions rate for the external control area.

For each NE state and external control area, generation adjusted for interregional transfers is calculated as:

> *Total generation in state (or energy import from external control area) + Non-Massachusetts RECs assigned to Massachusetts (≥0 for Massachusetts ≤0 for other states/areas) + Proposal EAs assigned to Massachusetts (≥0 for Massachusetts, ≤0 for other states/areas) + Surplus RECs transferred into (+) or out of (-) state for RPS or Massachusetts CES compliance + Transfers of RECs into (+) or out of (-) state/area to allocate regional REC oversupply*

To calculate energy transfers from NE states into Massachusetts, i.e., energy imports to Massachusetts, each state's generation adjusted for interregional transfers is compared to its load to determine whether the state has a surplus or shortfall. All of an external control area's generation (i.e., imports into NE) adjusted for interregional transfers is considered available for transfer. The shortfalls and

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surpluses are tallied, and the share of total shortfalls attributable to Massachusetts is calculated. The energy transfer from a state or external control area into Massachusetts is then:

$$\frac{Massachusetts\ share\ of\ total\ shortfalls\ \times Energy\ transfer\ available\ from\ state/area}{Ratio\ of\ total\ shortfalls\ to\ available\ transfers}$$

Emissions attributed to energy imports into Massachusetts from each NE state are calculated as:

$$\frac{Emissions\ from\ generation\ in\ NE\ state\ \times\ Energy\ transfer\ from\ NE\ state\ into\ Massachusetts}{Generation\ in\ NE\ state\ adjusted\ for\ interregional\ transfers}$$

Emissions attributed to energy imports into MASSACHUSETTS from each external control area are calculated as:

$$\frac{Emissions\ from\ imports\ into\ Massachusetts\ from\ external\ control\ area\ \times\ Energy\ transfer\ from\ area\ into\ Massachusetts}{Generation\ (energy\ imports)\ from\ area\ adjusted\ for\ interregional\ transfers}$$

C. Portfolio Effect

When multiple projects are run as a portfolio, their benefits may not be additive. The above methodology for individual Proposals will be applied to a Portfolio as a whole to determine the direct and indirect benefits for Portfolios in Stage Three.

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Table 1. Biogenic and non-biogenic fuels

Non-Biogenic	
	bituminous coal
	sub-bituminous coal
	distillate petroleum
	natural gas
	non-biogenic component of municipal solid waste
	other
	tire derived fuel
	petroleum coke
	residual petroleum
	jet fuel
	kerosene
	waste oil
Biogenic	
	landfill gas
	biogenic component of municipal solid waste
	black liquor
	wood/wood waste solids
	sludge waste

Source: Massachusetts Department of Environmental Protection, Greenhouse Gas Baseline, Inventory & Projection Appendix Q: 2014 Emissions from Electricity Consumed in Massachusetts (https://www.mass.gov/files/documents/2016/11/rk/gwsa-appq.xls)

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TABLE 2. State loads (MWh)

Gross-PDR-BMPV Net Energy for Load (NEL), MWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CT	30,829,742	30,200,581	29,870,553	29,633,090	29,440,459	29,276,677	29,145,045	29,044,845	28,986,818	28,992,328	29,057,087	29,114,922
MA	57,628,092	56,883,751	55,999,861	55,306,784	54,758,306	54,356,415	54,105,490	53,970,188	53,583,787	53,351,771	53,269,802	53,180,300
ME	11,570,614	11,764,537	11,738,226	11,745,363	11,772,473	11,809,583	11,852,296	11,902,944	11,910,057	11,935,090	11,977,462	12,018,954
NH	11,953,722	11,946,796	11,946,423	11,961,552	11,988,853	12,020,899	12,057,577	12,101,244	12,154,394	12,218,725	12,293,603	12,368,872
RI	7,961,362	7,766,821	7,625,623	7,515,922	7,423,231	7,351,121	7,297,267	7,258,043	7,194,123	7,152,344	7,132,153	7,110,481
VT	5,802,881	5,885,747	5,780,263	5,691,750	5,610,623	5,538,935	5,471,951	5,415,011	5,384,757	5,370,763	5,372,501	5,373,482
Total	125,746,413	124,448,232	122,960,948	121,854,460	120,993,945	120,353,629	119,929,626	119,692,275	119,213,936	119,021,022	119,102,606	119,167,012

Gross-PDR-BMPV Net Energy for Load (NEL), MWh	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	29,188,644	29,235,879	29,368,741	29,487,660	29,620,265	29,743,033	29,936,253	30,098,886	30,295,845	30,473,709
MA	53,120,816	53,008,986	53,103,128	53,162,552	53,258,431	53,331,581	53,573,717	53,773,557	54,036,022	54,247,419
ME	12,064,930	12,108,194	12,171,813	12,232,993	12,299,166	12,362,564	12,447,305	12,527,432	12,614,064	12,696,764
NH	12,446,538	12,521,111	12,610,531	12,698,383	12,789,299	12,879,553	12,981,613	13,081,221	13,186,254	13,288,666
RI	7,093,796	7,071,805	7,076,290	7,076,772	7,082,774	7,085,178	7,112,841	7,134,858	7,164,355	7,187,768
VT	5,375,467	5,371,389	5,390,021	5,403,854	5,421,130	5,435,267	5,469,933	5,491,966	5,524,961	5,551,440
Total	119,290,191	119,317,364	119,720,524	120,062,214	120,471,066	120,837,176	121,521,663	122,107,919	122,821,500	123,445,766

Source: Gross-PDR annual energy Forecast (Table 6, 83D Base Case Assumptions) minus forecast of Behind-the-Meter Solar PV from ENELYTIX

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TABLE 3. Non-Proposal RECs under long-term contract to MASSACHUSETTS EDCs (MWh)

	2019	2020	2021	2022	2023	2024	2025	2026
Massachusetts	91,356	91,356	91,356	91,759	1,340,926	1,359,474	2,702,010	2,679,408
Maine	1,214,752	1,271,037	1,218,357	1,218,191	1,218,545	1,219,451	1,218,764	1,217,853
New Hampshire	137,438	159,079	159,255	158,025	21,705	21,647	21,580	21,662
Vermont	-	-	-	-	-	-	-	-
Rhode Island	-	-	16,849	16,796	16,784	16,740	16,680	16,722
Connecticut	11,250	107,940	122,767	122,601	122,527	122,559	122,316	122,271
Sub-total New England	**1,454,796**	**1,629,412**	**1,608,583**	**1,607,373**	**2,720,487**	**2,739,871**	**4,081,351**	**4,057,916**
NY	-	-	13,870	166,441	166,441	166,441	166,441	166,441
Quebec	-	-	-	-	-	-	-	-
NB / PEI	-	-	-	-	-	-	-	-
Total all areas	**1,454,796**	**1,629,412**	**1,622,454**	**1,773,814**	**2,886,928**	**2,906,312**	**4,247,792**	**4,224,357**

	2027	2028	2029	2030	2031	2032	2033	2034
Massachusetts	3,996,917	4,035,097	5,373,755	5,394,073	5,404,021	5,347,195	5,329,043	5,363,703
Maine	1,209,163	1,139,837	1,126,977	1,059,225	659,298	68,253	67,996	67,972
New Hampshire	21,817	21,752	21,709	21,584	21,580	21,846	21,732	21,705
Vermont	-	-	-	-	-	-	-	-
Rhode Island	16,849	16,829	16,793	16,695	16,680	16,880	16,796	16,784
Connecticut	122,767	122,658	122,504	122,415	122,316	122,860	122,601	122,527
Sub-total New England	**5,367,513**	**5,336,173**	**6,661,739**	**6,613,993**	**6,223,895**	**5,577,034**	**5,558,169**	**5,592,691**
NY	166,441	166,441	166,441	166,441	166,441	166,441	166,441	166,441
Quebec	-	-	-	-	-	-	-	-
NB / PEI	-	-	-	-	-	-	-	-
Total all areas	**5,533,954**	**5,502,615**	**6,828,180**	**6,780,434**	**6,390,337**	**5,743,475**	**5,724,610**	**5,759,133**

	2035	2036	2037	2038	2039	2040
Massachusetts	5,373,755	5,423,704	5,348,616	5,329,223	5,329,043	5,390,959
Maine	67,963	67,925	67,557	68,177	67,996	-
New Hampshire	21,709	21,637	21,662	21,817	21,732	-
Vermont	-	-	-	-	-	-
Rhode Island	16,793	16,725	16,722	16,849	16,796	16,838
Connecticut	122,504	122,427	122,271	111,516	50,169	14,473
Sub-total New England	**5,602,726**	**5,652,419**	**5,576,827**	**5,547,583**	**5,485,737**	**5,422,269**
NY	166,441	166,441	166,441	166,441	166,441	152,571
Quebec	-	-	-	-	-	-
NB / PEI	-	-	-	-	-	-
Total all areas	**5,769,167**	**5,818,860**	**5,743,268**	**5,714,024**	**5,652,178**	**5,574,840**

Source: TCR analysis based on estimated 83C resource output and contract data provided by EDCs

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Table 4. Emission rates for imports from external control areas (lbs CO2e/MWh)

Emission Rates lbs CO2e/MWh	
NY	518.26
Quebec	4.67
NB / PEI	669.07

Source: Massachusetts Department of Environmental Protection, Greenhouse Gas Baseline, Inventory & Projection Appendix Q: 2014 Emissions from Electricity Consumed in Massachusetts (https://www.mass.gov/files/documents/2016/11/rk/gwsa-appq.xls)

Table 5. 2016 REC Oversupply Allocation

State	2016 REC Oversupply Allocation
Massachusetts	34%
Maine	49%
New Hampshire	5%
Vermont	1%
Rhode Island	1%
Connecticut	10%

Source: NEPOOL 2016 Unsettled and Reserved Certificate State Regulator Reports, as summarized by Massachusetts DOER.

Attachment C – Value of GWSA Compliance Benefit

This Attachment describes the method to be used to calculate the unit value ($/MWh) of a Proposal's contribution towards meeting the GWSA over and above compliance with the RPS and the CES.[11]

Section 2.3.1.2 of the Request for Proposal under 83D states that the need and responsibility for development of "an economic proxy value for their (the environmental attributes of generation from Incremental Hydroelectric Generation and new Class I RPS eligible resources) contribution to GWSA requirements, … [will be] determined by the Evaluation Team." The logic developed by the Evaluation Team valued one MWh of carbon reduction to be equal to at least the cost of incentivizing one MWh of meeting this procurement cost effectively.

Currently, development of new clean energy is incentivized through the RPS, the CES, and through clean energy procurements such as 83D. If emission reductions cannot be achieved through this procurement, GWSA compliance will need to be met through the RPS, CES, or other electric sector policies, including an additional clean energy procurement. The cost of an additional clean energy procurement in $/MWh can be estimated from the current proposals submitted in response to this procurement. Therefore, the lowest value of one MWh of carbon reduction must be the lesser of the marginal cost of meeting a clean energy procurement or the cost of CES compliance (CES ACP set at 50% the cost of RPS ACP). Because the marginal cost of meeting this procurement will not be known until after the evaluation is complete, the Evaluation Team will use a preliminary value of $20/MWh for the value of one MWh of carbon reductions.

Once the Stage Two evaluation is complete, the Evaluation Team will determine the value of GWSA compliance as follows:

- Calculate the Implicit Cost of the Clean Energy Attribute for each Proposal in $/MWh. This Implicit Cost is equal the total direct cost of the Proposal, including any associated transmission costs, minus the Proposal's market value of energy and revenues from transmission. This Implicit Cost represents the above market cost of clean energy delivery to Massachusetts.
- Determine the marginal cost of meeting this procurement in $/MWh as follows:
    - o rank the Implicit Cost of the Clean Energy Attribute of, and annual energy from, each Proposal from low to high,
    - o calculate the corresponding cumulative annual energy quantity,
    - o identify the Proposal located at the point at which one half of the total energy offered has an Implicit Cost of the Clean Energy Attribute at or below the Implicit Cost of the Clean Energy Attribute of that Proposal and one-half of the total energy offered has an Implicit Cost of the Clean Energy Attribute at or above the Implicit Cost of the Clean Energy Attribute of that Proposal,
    - o the Implicit Cost of the Clean Energy Attribute of that Proposal is the value of GWSA compliance.

[11] This methodology was developed in conjunction with the 83D Protocol and used to determine the final GWSA compliance benefit of Proposals in Stage Two and Portfolios in Stage Three. It was not documented as an attachment until March 2018.

REDACTED

The value of GWSA compliance will be the marginal cost of meeting this procurement if that marginal cost is less than the CES ACP. If not, the CES ACP will be the value of GWSA compliance. The Proposals will be re-ranked using the final value of GWSA compliance in place of $20/MWh preliminary value.

REDACTED

Attachment D – Modelling Small 83D Proposals

83D Proposals will be defined as small projects and modelled in ENELYTIX according to the following two criteria. [12]

1. An 83D Proposal will be defined as a small project if its capacity contribution to ICR is less than or equal to 140 MW and its annual generation of RECs or EAs is less than 670 GWh. Based upon that definition TCR will assume that small 83D Proposals will not cause any changes in the capacity additions and retirements projected under the Base Case, nor cause any changes in REC prices projected under the Base Case. Based upon those assumptions TCR's ENELYTIX modeling of small 83D Proposals will not include the Capacity Expansion Module, but instead will be limited to the Energy & Ancillary Service module and the Forward Capacity Auction module. TCR will run each of those modules using the capacity mix projected in the Base Case plus the small 83D Proposal's capacity, as well as the REC prices projected in the Base Case.

2. For 83D Proposals whose capacity contribution to ICR is less than or equal to 140 MW and whose annual generation of RECs or EAs is greater than 670 GWh, TCR will determine whether those Proposals should be classified as either "small" or "large" by processing them through the Capacity Expansion module to determine if they would affect the REC prices projected in the Base Case. TCR will classify Proposals that would not affect the REC prices projected in the Base Case as small, and accordingly will use the Base Case capacity mix and REC prices in the Energy and Ancillary Services module for those Proposals. TCR will classify Proposals that would affect the REC prices projected in the Base Case as large, and accordingly will use the Proposal's capacity mix and REC prices in the Energy and Ancillary Services module.

This modeling approach provides small 83D projects the same opportunity as large 83D Proposals to impact projected energy generation, emissions, energy market prices and capacity prices.

[12] These calculations were developed in conjunction with the 83D Protocol and implemented in the ENELYTIX modeling and Quantitative Workbooks. They were not documented as an attachment until March 2018.

REDACTED

Appendix 4. 83D Base Case Results

REDACTED

BASE CASE FOR EVALUATION OF 83D PROPOSALS - RESULTS OVERVIEW

FINAL

83D Base Case: What it is and is not

REDACTED

- Base Case is not a plan for the Massachusetts electric sector, and should not be viewed as such.
- [redacted]
-
-

Key Assumptions

REDACTED

- Revised Installed Capacity Requirements (ICRs) and Local Sourcing Requirements (LSRs) to account for contributions from imports from outside of New England and Active Demand Response
- Updated capacity of several generating units to reflect upgrades as cleared in FCA11
- Started analysis in 2019
- Modified RPS requirement in New Hampshire as approved by the NH legislature in mid-July 2018
- Set ACP for the MA CEC requirements in 2019 and 2020 at 75% of the ACP for MA Class 1 RECs. In 2021 and beyond, the MA CEC ACP remains at 50% of Class 1 RECs ACP

Key Assumptions

REDACTED

- Adjustment of capacity factors of existing wind farms to account for actual performance
- Adjustment to capacity factors of projected onshore & offshore wind units to account for losses
- Defined two classes of generic onshore wind to reflect differences in interconnection costs below and above agreed upon new wind capacity addition threshold
- Added a scheduled retirement (Bridgeport Harbor unit #3)
- Two phase approach in capacity expansion model: Phase 1 – Capacity expansion to meet reliability and environmental obligations excluding CES. Phase 2 – dispatch capacity from phase 1 to comply with all obligations including CES. This approach accounts for interaction between Class 1 RPS and CES requirements and impact of CES obligation on Class 1 REC prices
- Updated CES obligations to exclude requirements for Munis
- Refined mapping of generating units to RPS and emission markets
- Implemented seasonal adjustments to New England interface limits
- Implemented staged clearing of renewable resources under long-term contracts in the capacity market (capacity phased in 25% increments over 4 years following year of installation)

Future Generation Capacity

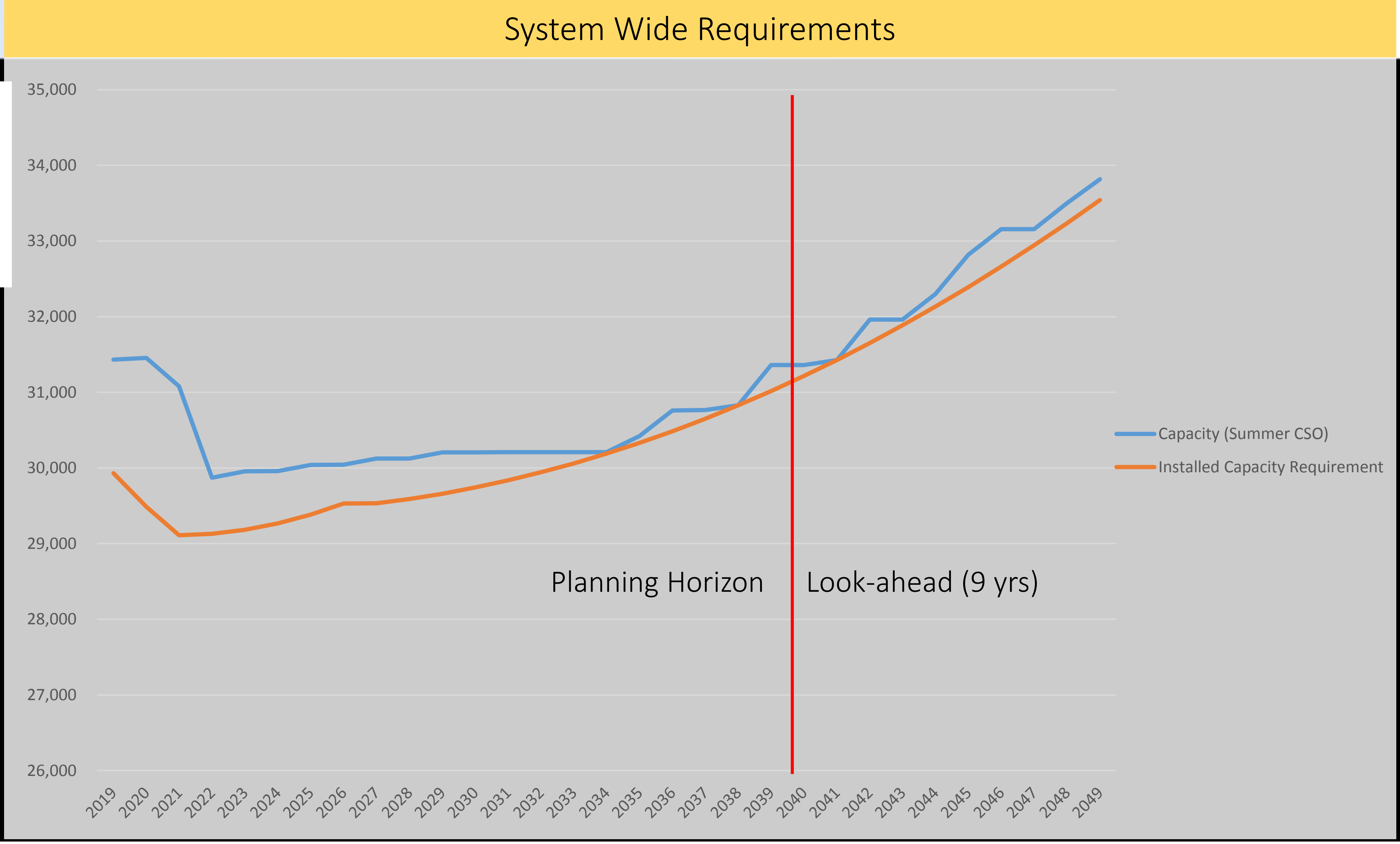
REDACTED

- Capacity Requirements
[redacted]
- [redacted]
- [redacted]

Capacity Balance for New England

REDACTED

Requirements and capacity shown are net of Demand Response and Imports



Capacity Balance by Zone

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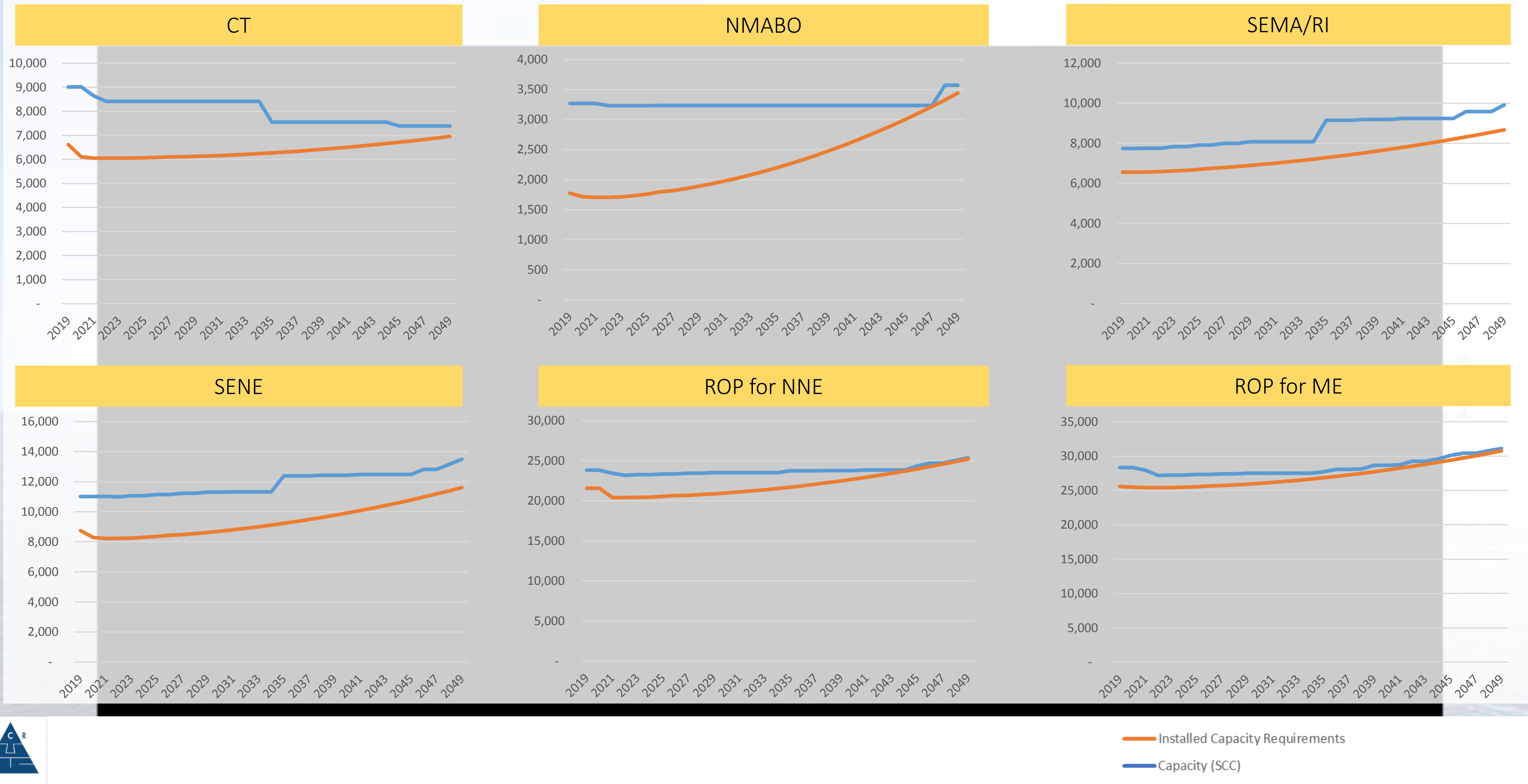
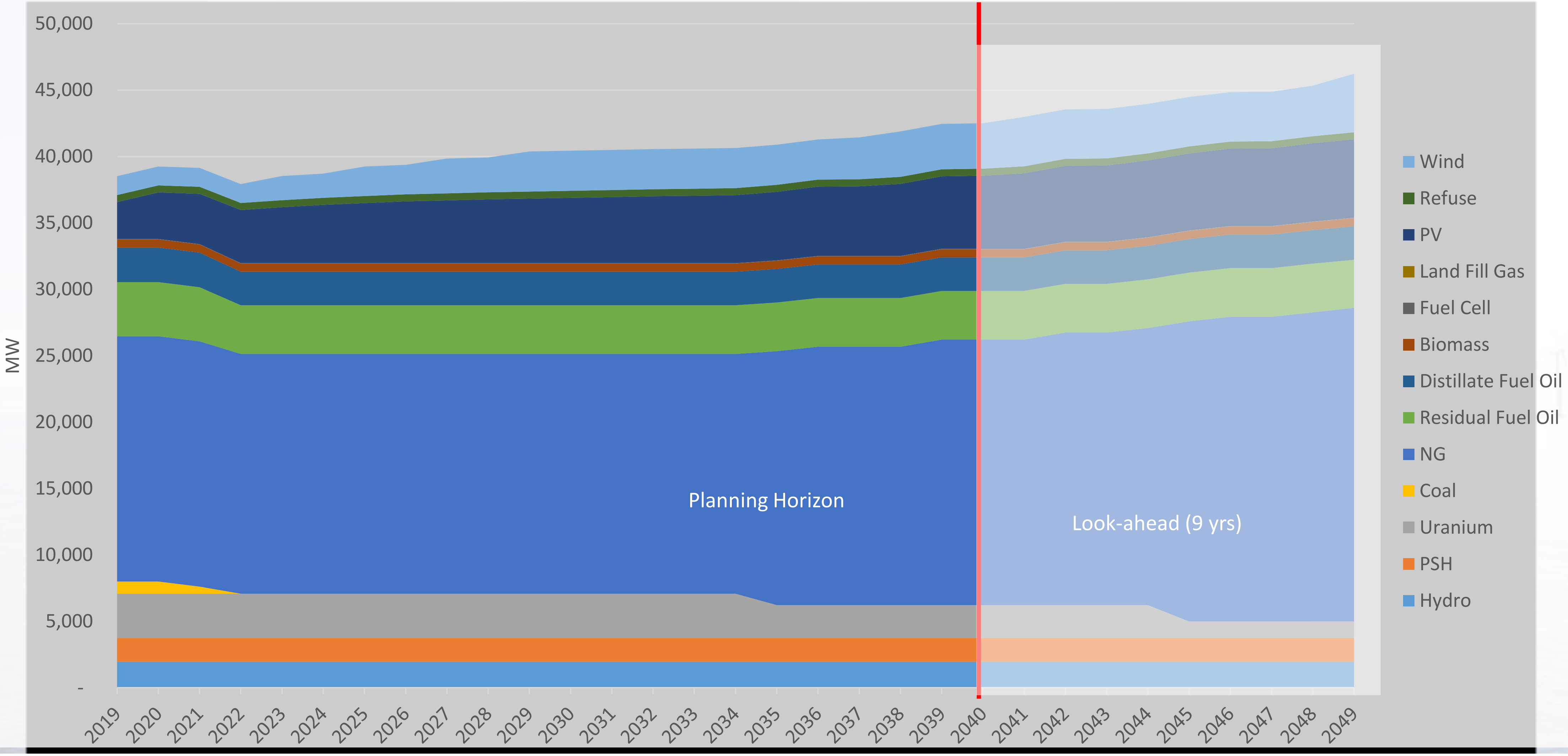


New England Capacity Mix by Generator Type

REDACTED

Capacity Mix by Fuel Type. Installed*) Capacity including Behind-the-Meter PV



*) For nuclear and thermal units average of summer and winter capacities is used. For hydro, PV and wind nameplate capacity is used

New England Capacity Mix by Fuel Type (MW)

REDACTED

(Installed*) Capacity including BTM PV)

	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Land Fill Gas	PV	Refuse	Wind	Grand Total
2019	1,956	1,778	3,342	919	18,468	4,077	2,605	616	23	2	2,782	527	1,422	38,517
2020	1,956	1,778	3,342	919	18,468	4,077	2,605	616	23	2	3,509	527	1,422	39,243
2021	1,956	1,778	3,342	535	18,468	4,077	2,605	616	23	2	3,789	527	1,422	39,139
2022	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,005	527	1,422	37,920
2023	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,213	527	1,822	38,528
2024	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,392	527	1,822	38,708
2025	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,526	527	2,222	39,241
2026	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,655	527	2,222	39,370
2027	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,728	527	2,622	39,843
2028	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,809	527	2,622	39,924
2029	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,861	527	3,022	40,377
2030	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,921	527	3,022	40,436
2031	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	4,976	527	3,022	40,491
2032	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	5,039	527	3,022	40,555
2033	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	5,076	527	3,022	40,591
2034	1,956	1,778	3,342	-	18,055	3,666	2,529	616	23	2	5,121	527	3,022	40,637
2035	1,956	1,778	2,483	-	19,121	3,666	2,529	616	23	2	5,165	527	3,022	40,887
2036	1,956	1,778	2,483	-	19,459	3,666	2,529	616	23	2	5,218	527	3,022	41,278
2037	1,956	1,778	2,483	-	19,459	3,666	2,529	616	23	2	5,245	527	3,153	41,436
2038	1,956	1,778	2,483	-	19,459	3,666	2,529	616	23	2	5,426	527	3,422	41,886
2039	1,956	1,778	2,483	-	19,992	3,666	2,529	616	23	2	5,462	527	3,422	42,455
2040	1,956	1,778	2,483	-	19,992	3,666	2,529	616	23	2	5,509	527	3,422	42,502
2041	1,956	1,778	2,483	-	19,992	3,666	2,529	616	23	2	5,686	527	3,722	42,979
2042	1,956	1,778	2,483	-	20,525	3,666	2,529	616	23	2	5,718	527	3,722	43,544
2043	1,956	1,778	2,483	-	20,525	3,666	2,529	616	23	2	5,748	527	3,722	43,574
2044	1,956	1,778	2,483	-	20,863	3,666	2,529	616	23	2	5,790	527	3,722	43,954
2045	1,956	1,778	1,249	-	22,605	3,666	2,529	616	23	2	5,805	527	3,722	44,477
2046	1,956	1,778	1,249	-	22,943	3,666	2,529	616	23	2	5,832	527	3,722	44,842
2047	1,956	1,778	1,249	-	22,943	3,666	2,529	616	23	2	5,858	527	3,722	44,869
2048	1,956	1,778	1,249	-	23,281	3,666	2,529	616	23	2	5,897	527	3,807	45,331
2049	1,956	1,778	1,249	-	23,619	3,616	2,529	616	23	2	5,908	527	4,405	46,228

*) For nuclear and thermal units average of summer and winter capacities is used. For hydro, PV and wind nameplate capacity is used

New England Capacity Mix by Generator Type

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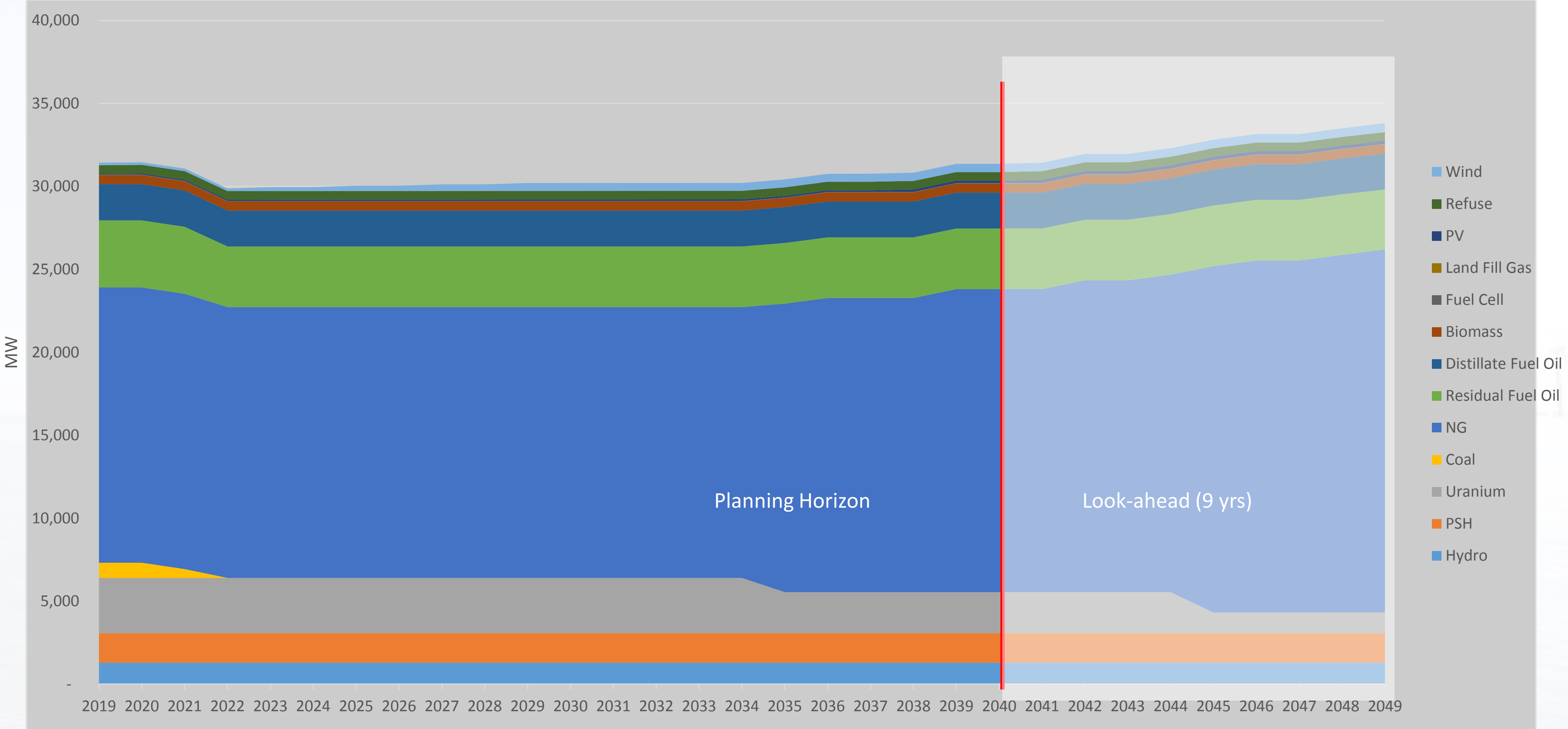
Capacity Mix by Fuel Type. Contribution to ICR (excluding Behind-the-Meter PV)



New England Capacity Mix by Fuel Type (MW)

REDACTED

(contribution to ICR)

	Hydro	PSH	Uranium	Coal	NG	Residual Fuel Oil	Distillate Fuel Oil	Biomass	Fuel Cell	Land Fill Gas	PV	Refuse	Wind	Grand Total
2019	1,291	1,778	3,331	917	16,594	4,040	2,188	552	21	2	50	511	156	31,431
2020	1,291	1,778	3,331	917	16,594	4,040	2,188	552	21	2	74	511	156	31,454
2021	1,291	1,778	3,331	533	16,594	4,040	2,188	552	21	2	80	511	156	31,077
2022	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	84	511	156	29,872
2023	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	88	511	236	29,955
2024	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	91	511	236	29,958
2025	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	93	511	316	30,040
2026	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	95	511	316	30,042
2027	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	96	511	396	30,124
2028	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	97	511	396	30,125
2029	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	98	511	476	30,206
2030	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	99	511	476	30,207
2031	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	100	511	476	30,208
2032	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	101	511	476	30,209
2033	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	102	511	476	30,210
2034	1,291	1,778	3,331	-	16,327	3,655	2,165	552	21	2	103	511	476	30,211
2035	1,291	1,778	2,474	-	17,393	3,655	2,165	552	21	2	104	511	476	30,421
2036	1,291	1,778	2,474	-	17,731	3,655	2,165	552	21	2	105	511	476	30,760
2037	1,291	1,778	2,474	-	17,731	3,655	2,165	552	21	2	105	511	483	30,767
2038	1,291	1,778	2,474	-	17,731	3,655	2,165	552	21	2	152	511	496	30,827
2039	1,291	1,778	2,474	-	18,264	3,655	2,165	552	21	2	152	511	496	31,361
2040	1,291	1,778	2,474	-	18,264	3,655	2,165	552	21	2	153	511	496	31,361
2041	1,291	1,778	2,474	-	18,264	3,655	2,165	552	21	2	204	511	511	31,427
2042	1,291	1,778	2,474	-	18,797	3,655	2,165	552	21	2	205	511	511	31,961
2043	1,291	1,778	2,474	-	18,797	3,655	2,165	552	21	2	205	511	511	31,961
2044	1,291	1,778	2,474	-	19,135	3,655	2,165	552	21	2	206	511	511	32,300
2045	1,291	1,778	1,249	-	20,877	3,655	2,165	552	21	2	206	511	511	32,818
2046	1,291	1,778	1,249	-	21,215	3,655	2,165	552	21	2	207	511	511	33,156
2047	1,291	1,778	1,249	-	21,215	3,655	2,165	552	21	2	207	511	511	33,156
2048	1,291	1,778	1,249	-	21,553	3,655	2,165	552	21	2	208	511	516	33,499
2049	1,291	1,778	1,249	-	21,891	3,605	2,165	552	21	2	208	511	545	33,817

New England Energy Generation Mix

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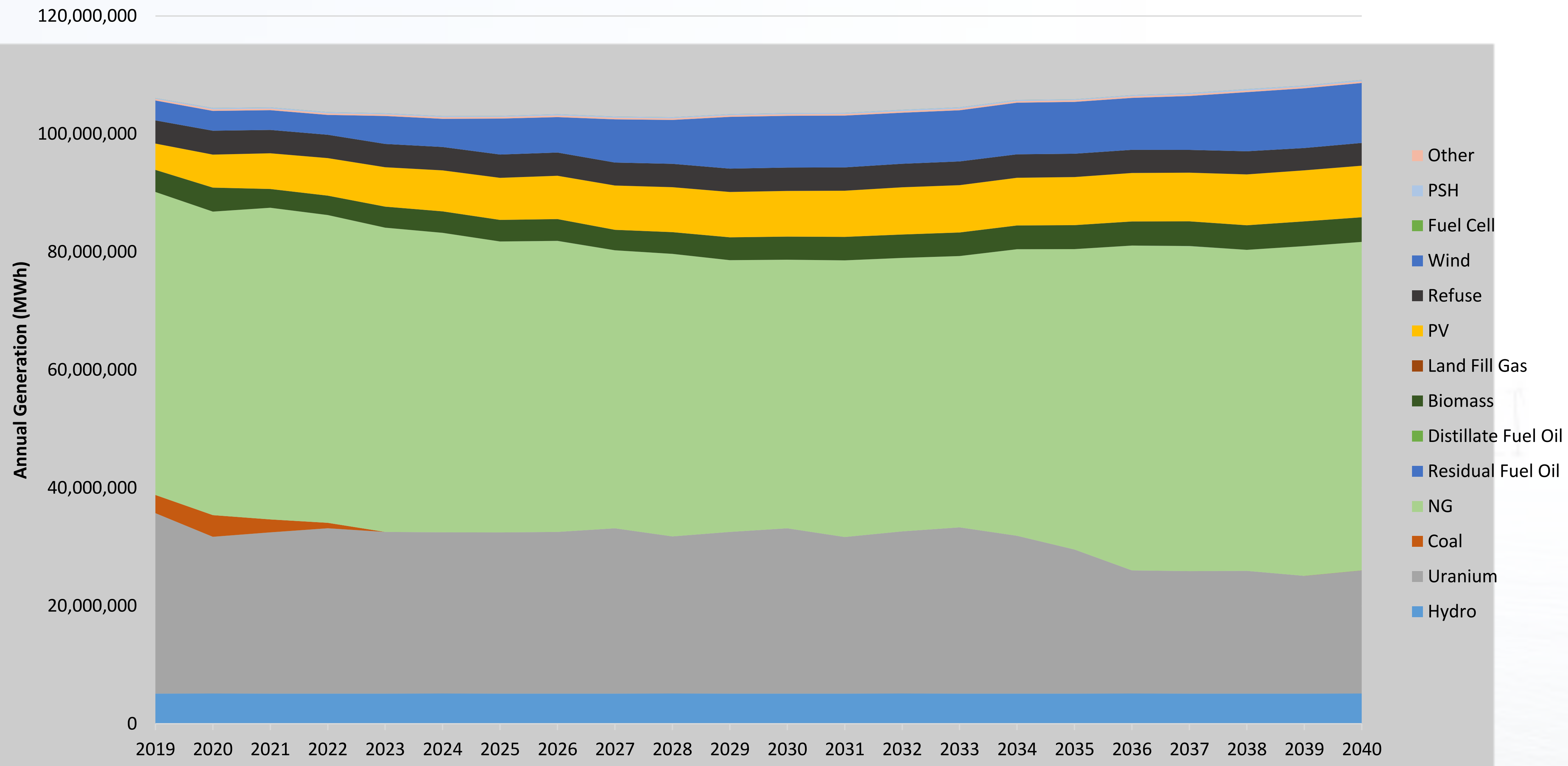

Model Selected New Capacity Additions - Buildout

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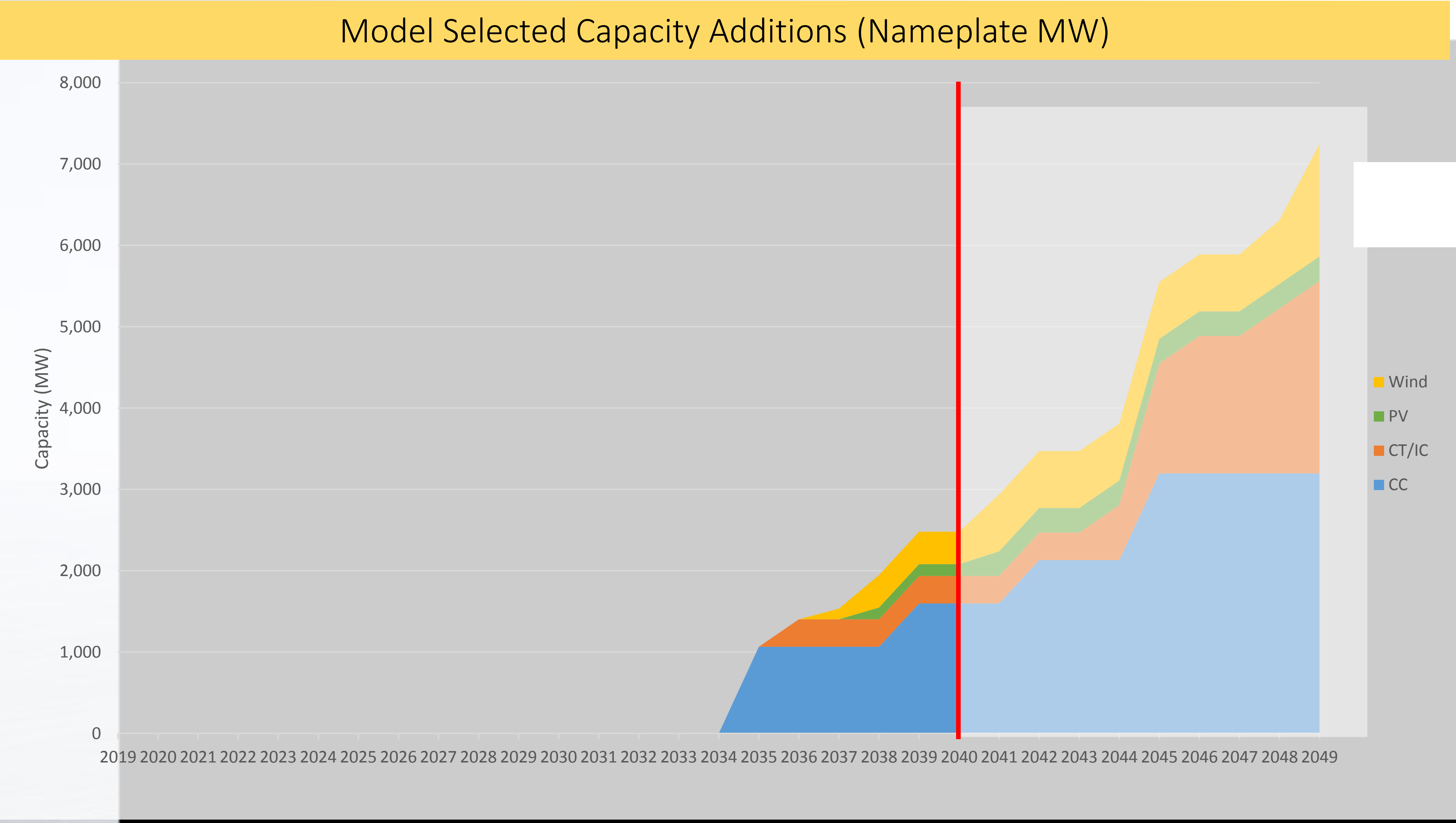

2040

2,481 MW
New Nameplate Capacity

Onshore Wind
400 MW
(20 MW to SCC)

PV
144 MW
(46 MW to SCC)

CT (Peakers)
388 MW
(1 Installation)

CCGT
1,599 MW
(3 Installations)

[redacted]

Model Selected New Capacity Additions – Cont'd

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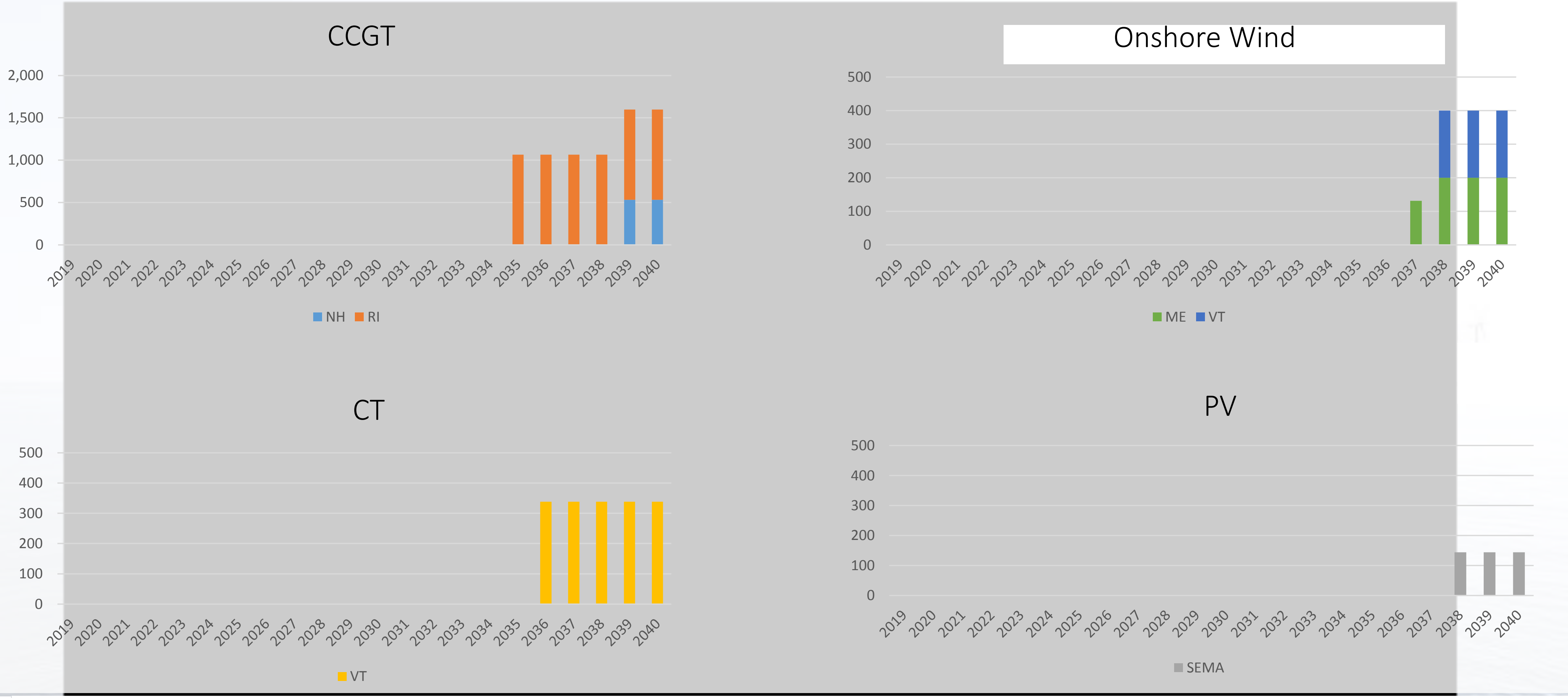
Model Selected Capacity Additions by **Load Zone (Nameplate Capacity)**



Model Selected *) Retirement of Existing Generation

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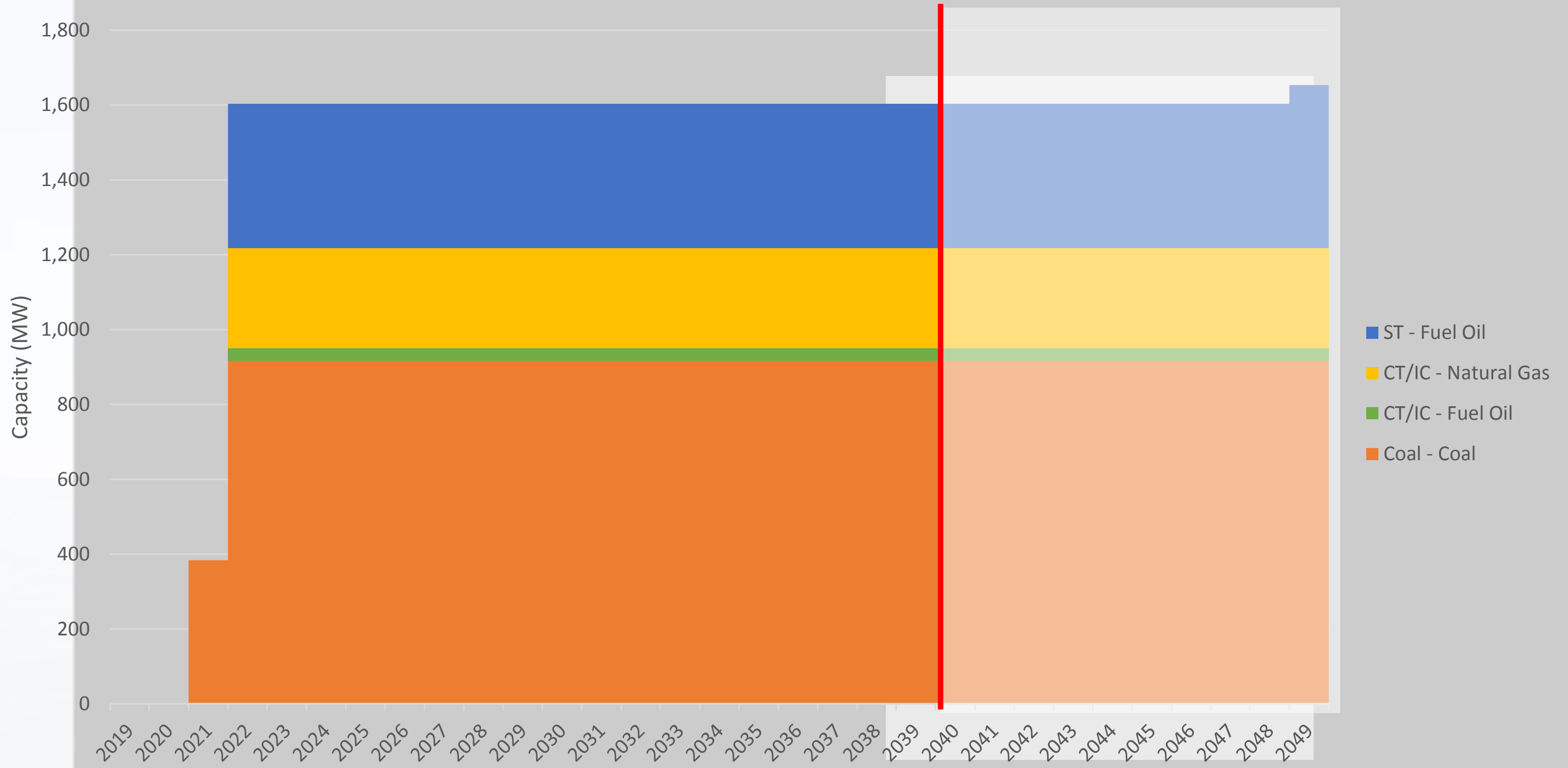
Model Selected Retirement of Existing Generation



2040

All Retirements

1,603 MW

Boiler – Fuel Oil

386 MW

CT/IC Natural Gas

267 MW

CT/IC – Fuel Oil

34 MW

Coal *)

916 MW

*) Includes Bridgeport Harbor 3 which is a "forced" retirement, not model selected

[redacted]

Model Selected Retirements by Region and Vintage

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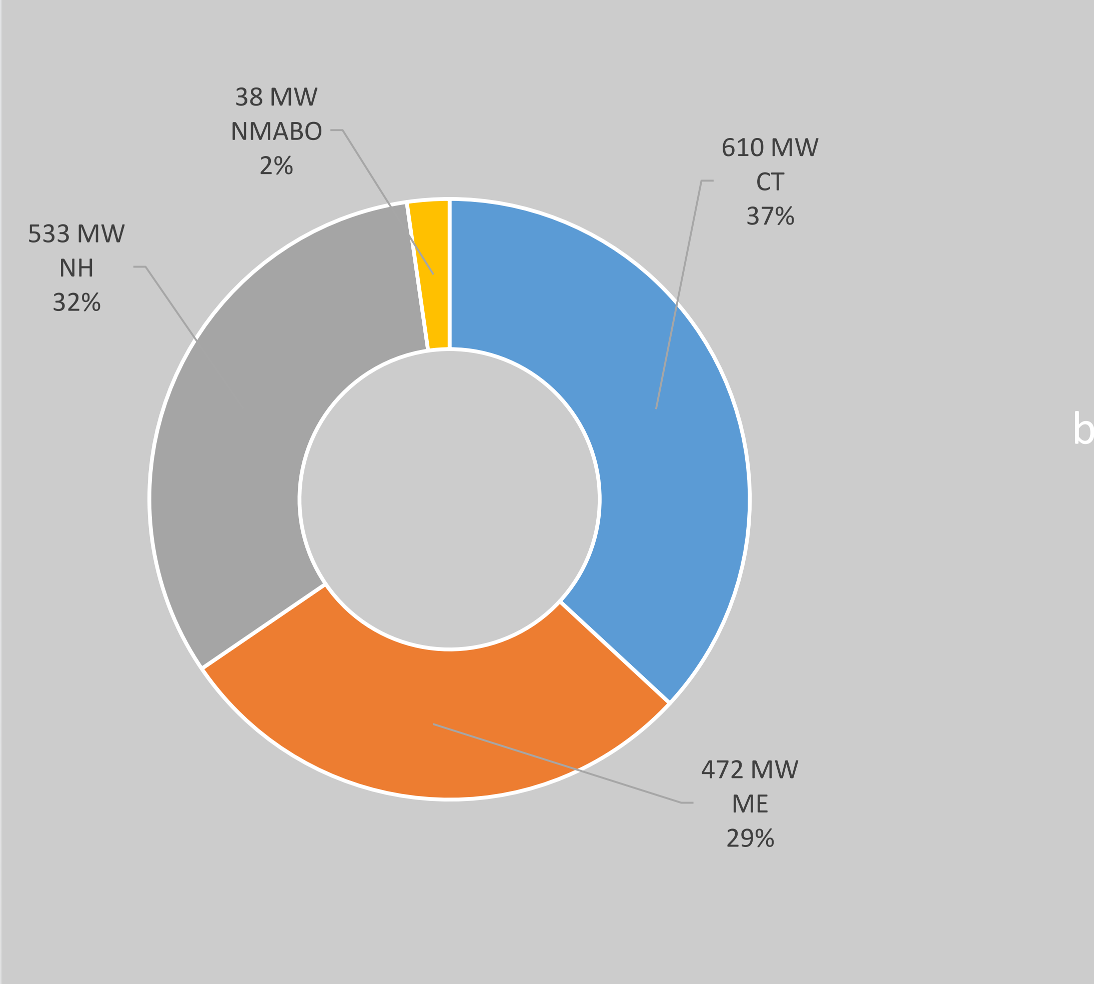
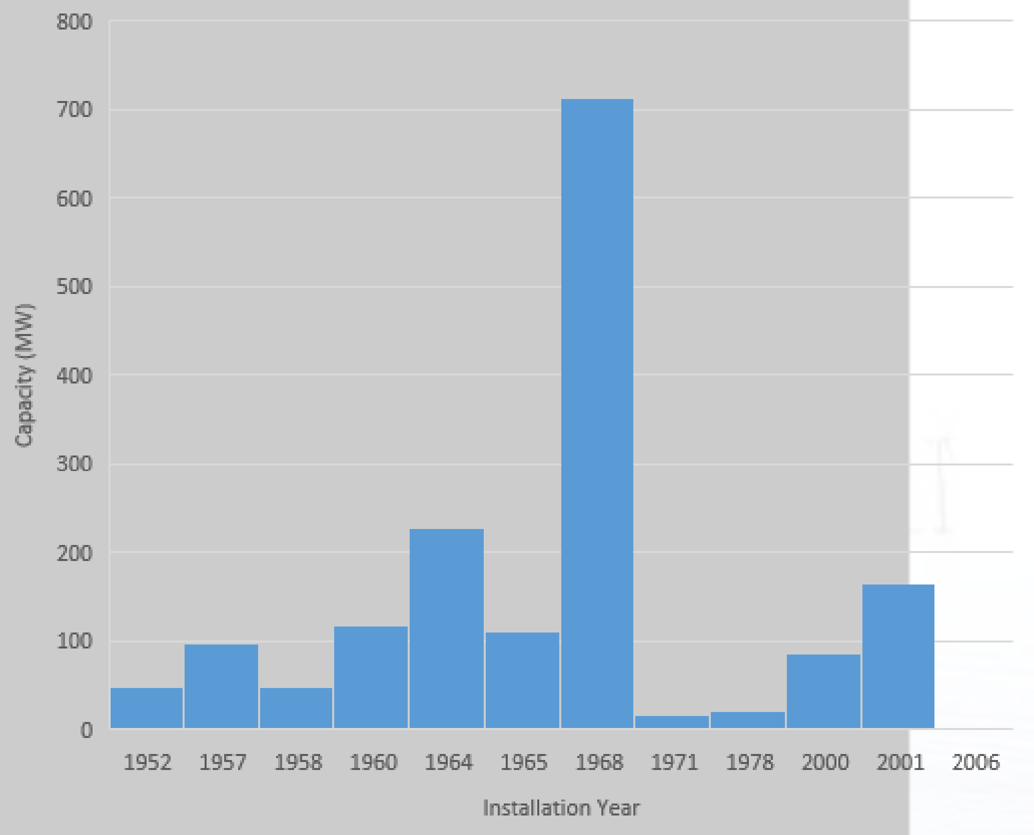
Retirements by Load Zone (2040)



b

Retiring Capacity by Vintage (2040)



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New England Class 1 RPS and MA CES

REDACTED

- [redacted]

New England Class 1 RPS + MA CES

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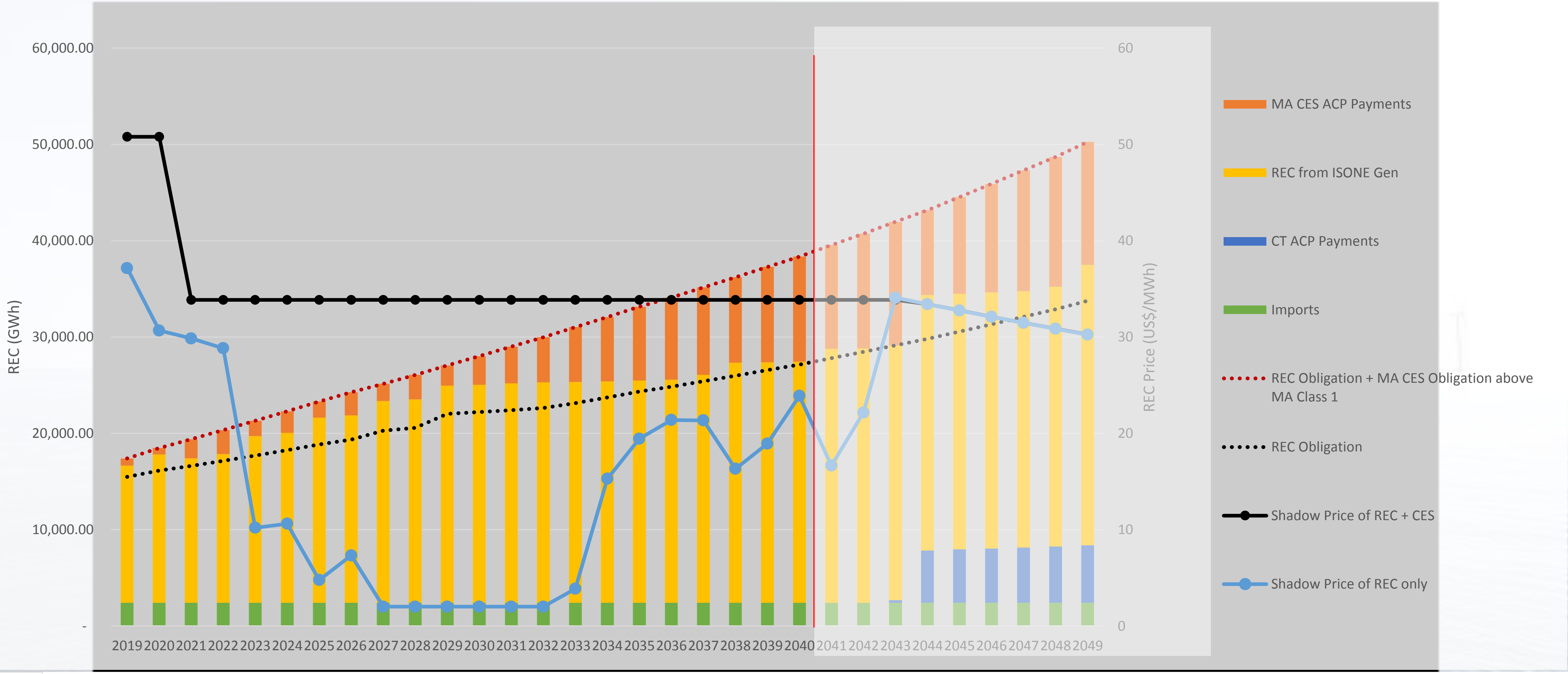
Projected RECs & REC prices from Class I RPS + MA CES



MA CO2 Emission Cap

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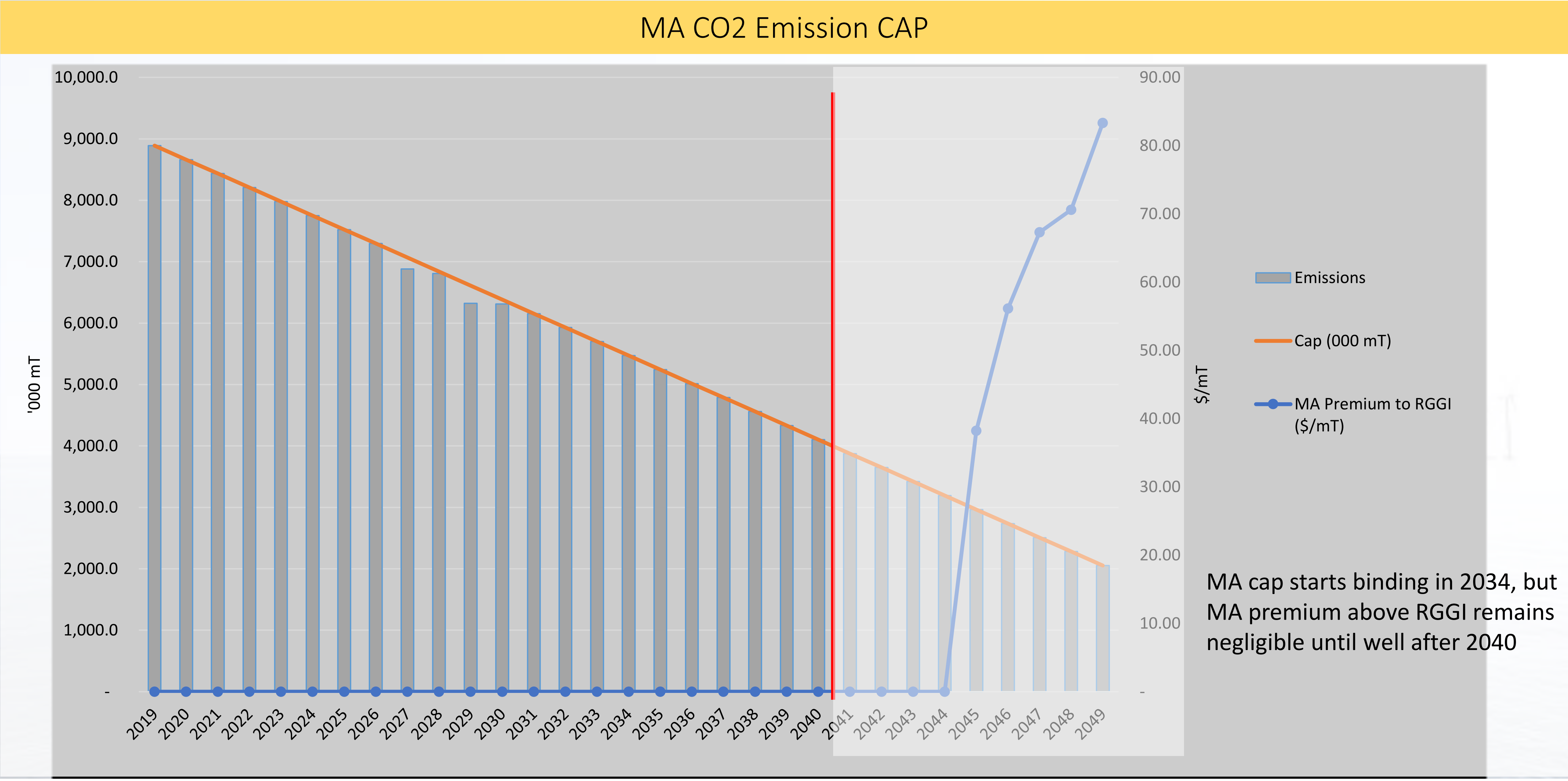

MA cap starts binding in 2034, but MA premium above RGGI remains negligible until well after 2040

Projected LMPs by Area ($/MWh)

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Cycle | Period | Case

a_Ar_AreaLoadPrice

[redacted]

LMP Premium above VT Zone ($/MWh)

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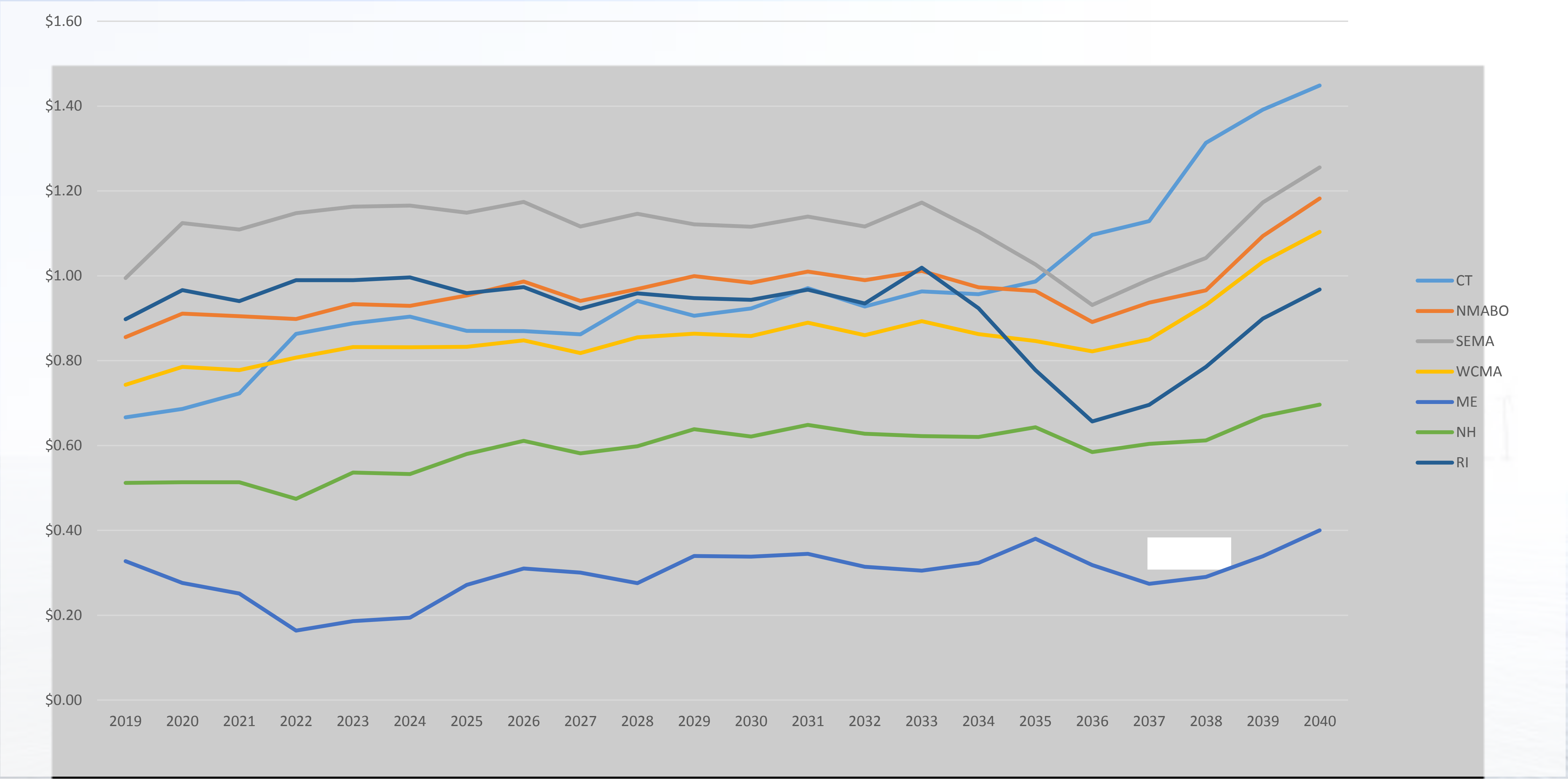

Projected Capacity Price ($/kW-month)

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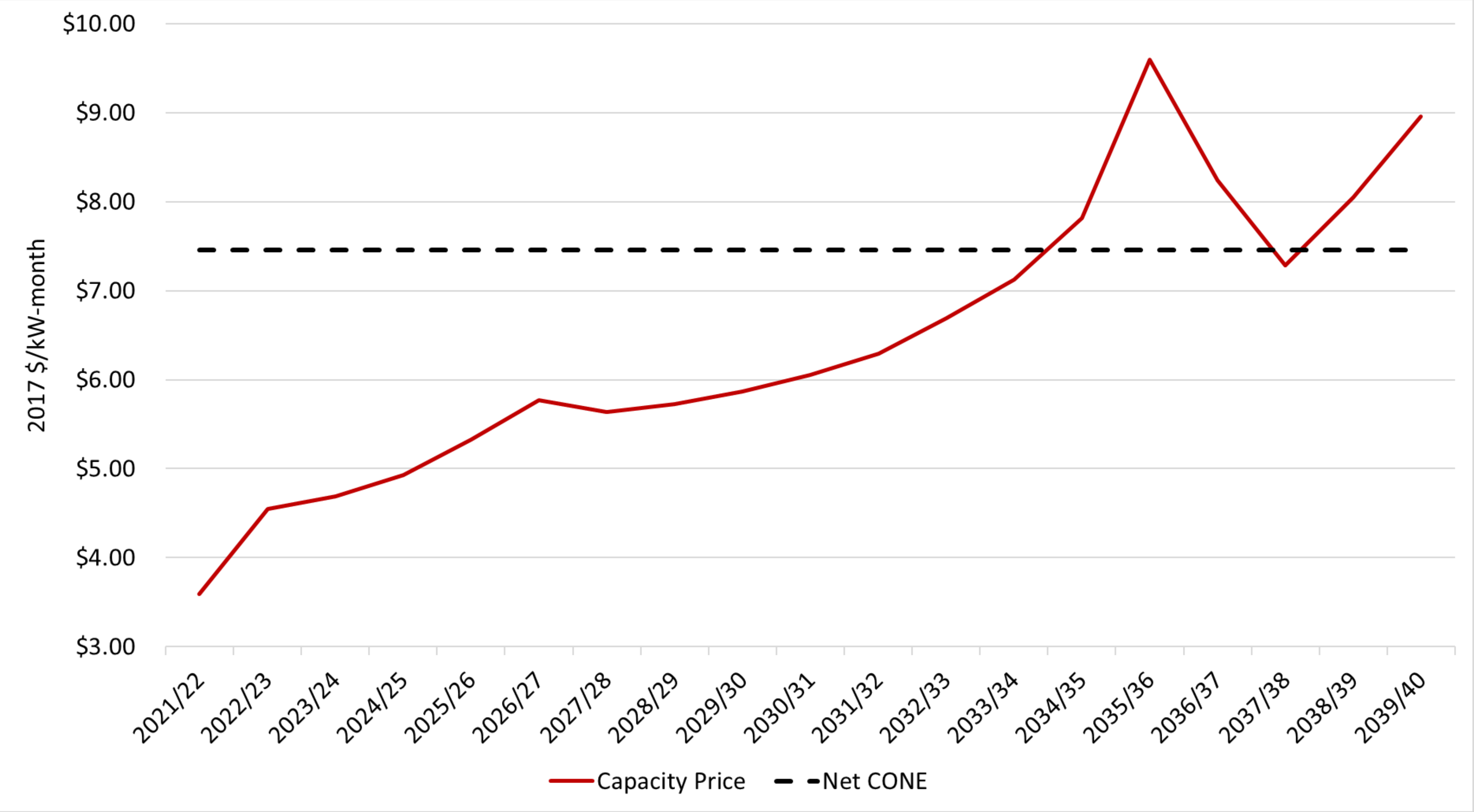

[redacted]

FCA	Capacity Price ($/kW-month)	Capacity Price ($/kW-year)
2021/22	$ 3.59	$ 43.11
2022/23	$ 4.55	$ 54.55
2023/24	$ 4.69	$ 56.32
2024/25	$ 4.92	$ 59.09
2025/26	$ 5.33	$ 63.95
2026/27	$ 5.77	$ 69.26
2027/28	$ 5.63	$ 67.60
2028/29	$ 5.73	$ 68.71
2029/30	$ 5.87	$ 70.38
2030/31	$ 6.06	$ 72.67
2031/32	$ 6.29	$ 75.54
2032/33	$ 6.69	$ 80.27
2033/34	$ 7.13	$ 85.51
2034/35	$ 7.81	$ 93.77
2035/36	$ 9.60	$ 115.17
2036/37	$ 8.24	$ 98.93
2037/38	$ 7.29	$ 87.45
2038/39	$ 8.05	$ 96.59
2039/40	$ 8.96	$ 107.51

Projected Capacity Price (discussion)

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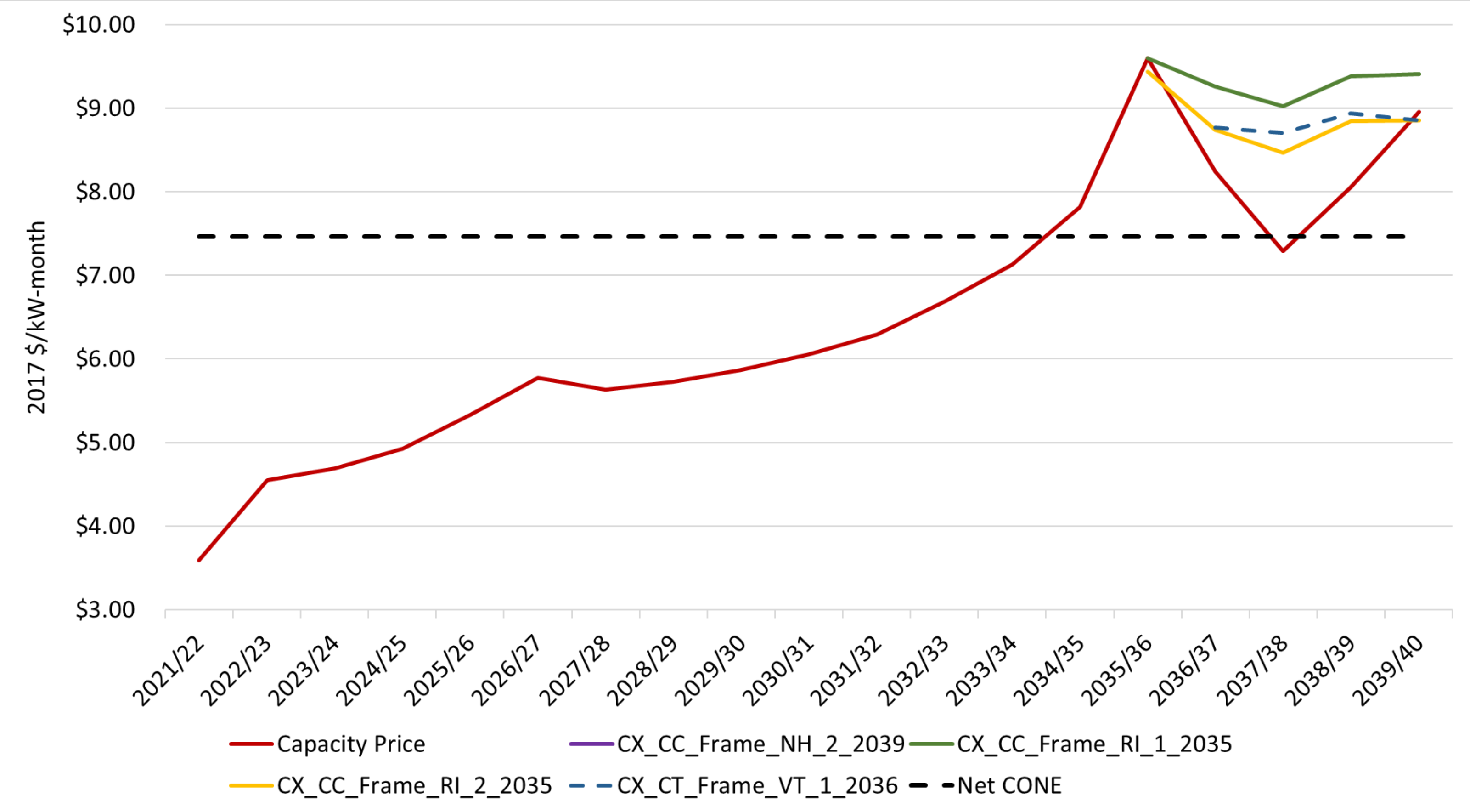
- [redacted]

FCA Prices vs. REDACTED "Missing Money"



Solid lines: missing money for CCGT build-out and FCA price
Dotted line: missing money for SCGT build-outs and NetCONE

Missing money computed on a per kW-month basis as
capital charge plus
FOM minus
operating margin

Wind units have no missing money due to high REC payments set by MA CEC ACP

Base Case Results Workbook

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Tab	Content
New Additions	Shows new generation additions as selected by the capacity expansion model. See Input Assumptions Document informaton on fixed new additions
Retirements	Shows generation retirments as selected by the capacity exapansion model. See Input Assumptions Document information on fixed retirements
GenMix_Gen	Generation mix by fuel type in MWh by year
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
CFs New CCs and CTs	Capacity factors for new CC and Ct generators suggested by the capacity expansion model
CFs Wind and PV	Capacty factors of new windand PV generators by year by location
ProdCostDet	Annual generation and productin cost by New England Zone by cost category
Gas BurnAnn	Annual natural gas bur by New England generators in Mmbtu
DailyGasBurn	Daily gas burn in MMbtu/day as simulated for years 2020 and 2039
MA CO2 Emiss	CO2 emissions by generating units in Massachussets that are subject to CO2 cap. Emissions are in lbs
SysEmiss	CO2 emissions by generating units in New England by zone and state. Emissions are in lbs
AreaLMP_Monthly	LMPs by month by year for each New England Zone reported for OnPeak, OffPeak and 24-hour periods
AreaLMP_Ann	LMPs by year for each New England Zone reported for OnPeak, OffPeak and 24-hour periods
AreaLoad &Cost	Load and Load Cost by zone by year. Load Cost in eazh zone is computed as a product of hourly load and hourly LMP in that zone summed over year
CongRent	Congestion rent and count of binding hours for all New England constraints by year
InterfaceFlows	Flows on New England interfaces. Flows are reported daily for each year 2020-2040 on average during OnPeak and OffPeak hours of the day
Cap Prices	Capacity Prices in $/kW-month computed by capability period
Tech REC GWh	Contribution to RECs by technology
Techprogram REC GWh	Delailed layout of REC contribution by source
Zone REC GWh	Contribution to REC by Zone
CEC	CEC Requirements and level met via ACP payments
REC Rev by Zone	Auxiliary worksheet showing Class 1 REC revenues received by generators by Zone. Used to restate true VOM costs

[redacted]

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Natural Gas Burn Analysis

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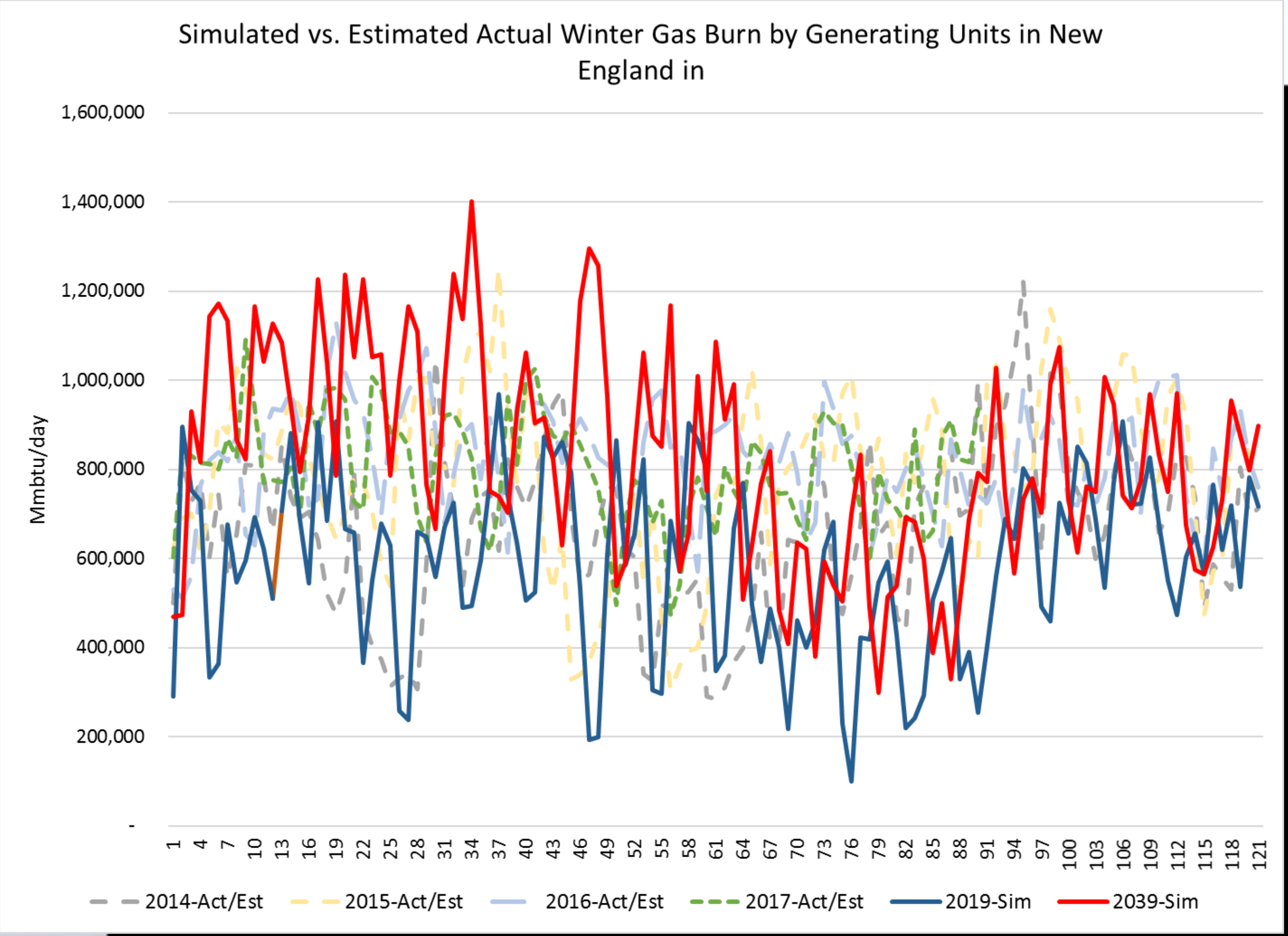
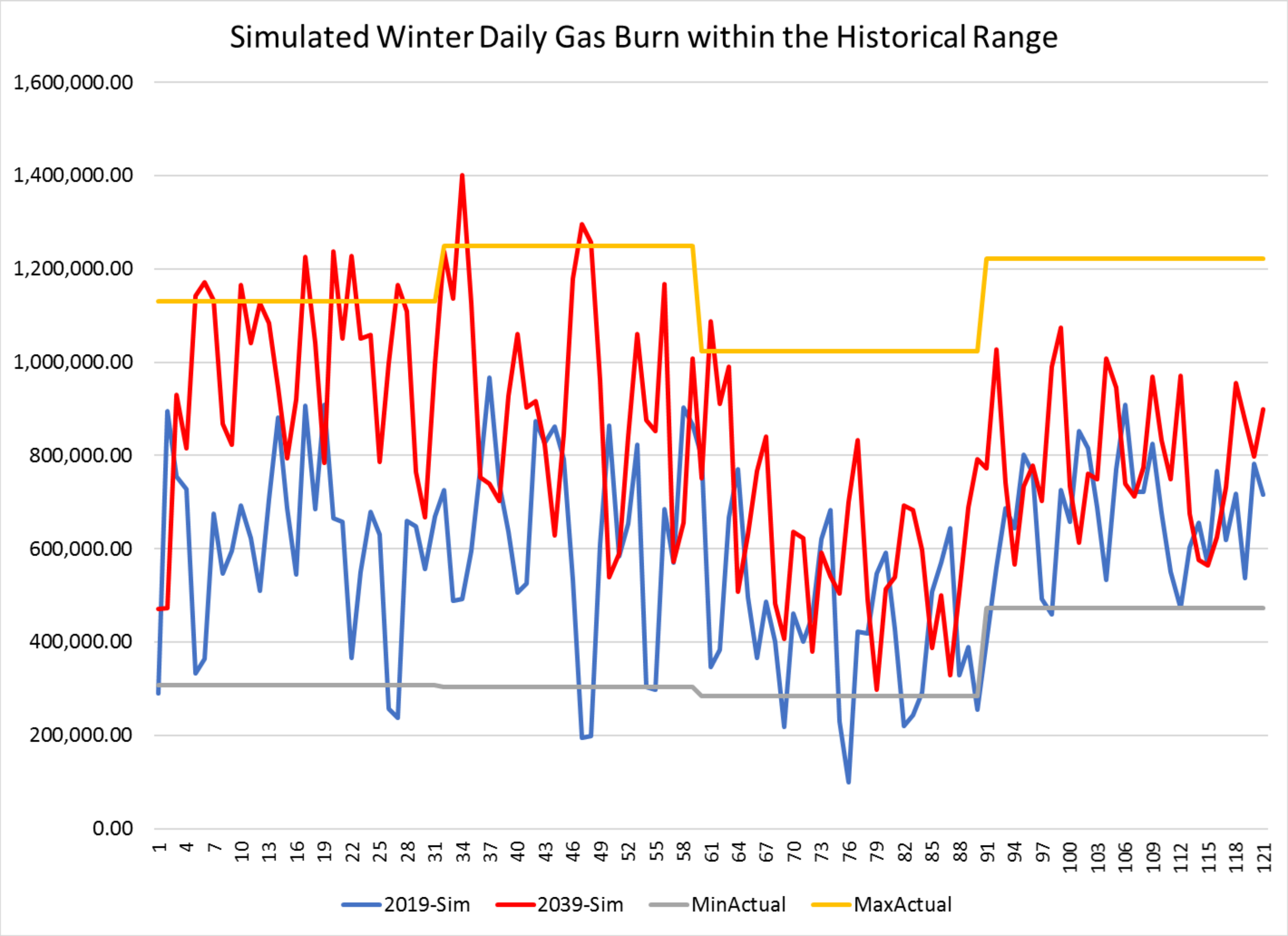


Dotted lines represent historical daily gas burn by generators in New England during [redacted] nd [redacted] y-March [redacted] gas burn [redacted] EMS [redacted]

Natural Gas Burn REDACTED Analysis (cont'd)



Upper and lower bounds represent the [redacted] 2014- [redacted] uary, [redacted] pectively [redacted]

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Appendix 5 83D Base Case Assumptions (New England and New York) including Description of ENELYTIX Simulation model

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BASE CASE FOR EVALUATION OF 83D PROPOSALS -

INPUT AND MODELING ASSUMPTIONS

NEW ENGLAND

Tabors Caramanis Rudkevich
75 Park Plaza, Fourth Floor, Boston MA 02116

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DISCLAIMER

Tabors Caramanis Rudkevich, INC (TCR) has been contracted by the Massachusetts Electric Distribution Companies (EDCs), Eversource, National Grid and Utilicorp to provide the quantitative analyses that will allow the EDCs to evaluate the proposals that they receive in response to the 83D and 83C 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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Acronyms

Acronym	Meaning
ACP	Alternative Compliance Price
BMPV	Behind-the-meter PV
CC	Combined Cycle
CES	Clean Energy Standard
GT	Combustion/Gas Turbine
GWSA	Global Warming Solutions Act
HD	Hydro Power
IC	Internal Combustion (reciprocating) Engine
NG	Natural Gas
PDR	Passive Demand Response
PS	Pumped Storage Unit
PV	Photovoltaic
REC	Renewable Energy Certificate, Renewable Energy Credit
RPS	Renewable Portfolio Standard
ST	Steam Turbine
WT	Wind Turbine
SUN	Solar
WAT	Water
WND	Wind
BIO	Biomass

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1. BASE CASE FOR EVALUATION OF 83D PROPOSALS – NEW ENGLAND ASSUMPTIONS

This document describes the modeling and input assumptions that the TCR team proposes for the Base Case against which the Massachusetts electric distribution companies ("EDCs") will measure the incremental costs and benefits of each Proposal received in response to the 83D RFP. TCR refers to this as the "83D Base Case." The complementary document "Base Case Evaluation of 83D Proposals – Input and Modeling Assumptions New York" describes all 83D 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 the EDCs will measure the incremental costs and benefits of each Proposal received in response to the 83D RFP.

A. **Background**

The following legislation, plans and draft regulations provide the background to the development of a Base Case for evaluation of 83D proposals.

- The Global Warming Solutions Act of 2008 (GWSA) requires Massachusetts to reduce the greenhouse gas (GHG) emissions in its GHG inventory to "a 2050 statewide emissions limit that is at least 80 per cent below the 1990 level."
- In 2010, to start the Commonwealth on a path towards meeting that target, the Secretary of the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) set a statewide GHG emissions reduction limit of 25% for 2020 and released a plan to meet that 2020 target.
- In December 2015, the EEA released an update to that plan for 2020, the 2015 Update Massachusetts Clean Energy and Climate Plan for 2020 ("CECP Update"). The CECP Update includes discussion of policies that would deliver additional GHG reductions over the 2020–2030 time frame and beyond. For the electric sector, the policies for 2020 and beyond included clean energy imports and a clean energy standard (CES).
- In August 2016, the State legislature passed An Act to Promote Energy Diversity requiring the Massachusetts EDCs to issue two Requests for Proposals (RFPs) for supplies of clean energy to help Massachusetts achieve its GWSA targets. The 83D RFPs are for long term contracts for renewable energy certificates ("RECs"), for energy, or a combination of RECs and energy, if applicable, for approximately 9,450,000 MWh to be procured pursuant to cost-effective long-term contracts by 2022. The 83C RFPS are for long term contracts for RECs for energy or for a combination of both RECs and energy from offshore wind energy generation equal to approximately 1,600 megawatts of aggregate nameplate capacity not later than June 30, 2027.

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- In August 2017, Massachusetts promulgated new regulations and amendments designed to limit and reduce GHG emissions in Massachusetts. The regulations for the electric sector, 310 CMR 7.74 and 310 CMR 7.75, are a cap on carbon emissions from electric generating units (EGU) located in MA, and a CES. A Massachusetts Department of Environmental Protection (DEP) background document anticipates that the clean energy supplies Massachusetts EDCs contract through the 83C and 83D RFP process will "…deliver adequate quantities of clean energy that count toward CES compliance…"[1]

B. **83D Base Case Design**

The 83D Base Case is not a plan for the Massachusetts electric sector, and it should not be viewed as such. Instead, the 83D 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 regulations promulgated in August 2017 are limited to generic 83C resources, other expected policy-driven additions and market-driven RPS class 1 eligible resources.

This 83D Base Case provides the Evaluation Team a "but for" or "counterfactual" projection of carbon emissions and costs associated with MA electricity consumption under a future in which the EDCs do not acquire 9,450 GWh of clean energy under long-term contracts with proposals received and selected in response to the 83D RFP. The 83D 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 83D RFP.

The 83D Base Case reflects all legislative requirements and regulations in effect as of August 11, 2017 including Renewable Portfolio Standard (RPS) regulations in MA and other New England states and the two regulations affecting the electric sector promulgated on August 11, 2017. These are regulation 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 (CES). Finally, the 83D Base Case also assumes generic offshore resources are brought into service per Section 83C of Energy Diversity Act of 2016. The 83D Evaluation Base Case covers the period 2019 through 2040 and expresses cost data in constant 2017$ as of January 1, 2017 unless otherwise noted.

[1] ___. *Background Document on Proposed New and Amended Regulations*, DEP, December 16, 2016. Page 33

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2. MODELING ENVIRONMENT

TCR employs ENELYTIX to model the Base Case and Project Cases. Appendix 1 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 three key modules: the Capacity Expansion module, the Energy and Ancillary Services (E&AS) module and the ISO-NE Forward Capacity Market (FCM) 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 electric generating units (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 MIP-based optimization, uses no heuristics, rigorously optimizes storage facilities, phase shifters and HVDC operation and accounts for marginal transmission losses.
- TCR develops Forward Capacity Market (FCM) Offer Curves using results of the Capacity Expansion and E&AS modules. These are an input to the FCM module.
- The ISO-NE FCM module models the ISO-NE capacity auction subject to system-wide and zonal installed capacity requirements, CONE parameters and demand curves.

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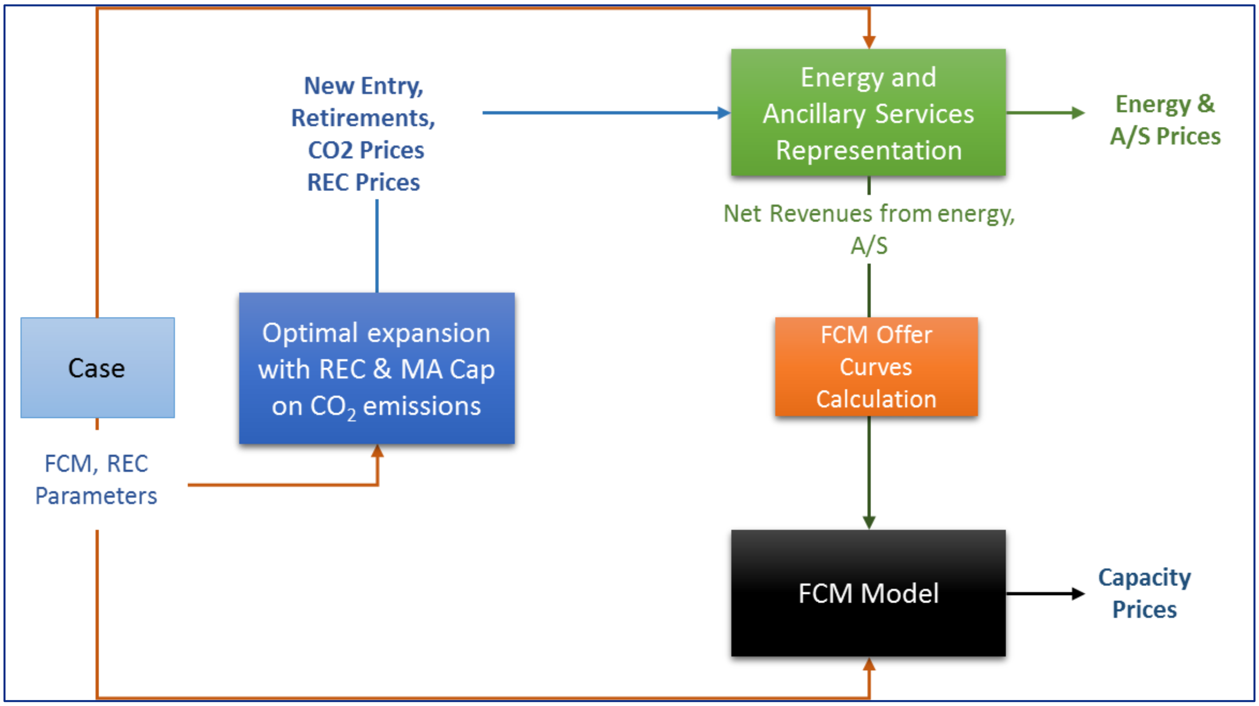
Figure 1. Interactive use of ENELYTIX modules



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 CO2 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 CO2 emissions along with the CO2 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.
- The results of the E&AS market simulations and REC prices from the Capacity Expansion Module are post-processed by the FCM Offer Curve Module to compare each unit's annual net revenues to its fixed cost requirement to calculate the "missing money" each unit will seek to recover in the capacity market, and to develop each unit's "FCM offer curve" for each power year.
- The FCM offer curves from the E&AS module are inputs to the FCM model, which computes capacity market prices.

All three modules use the Power System Optimizer (PSO) solver developed by Polaris Systems Optimization, Inc.[2] 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 Sections 3 through 14 where applicable as summarized by module in Table 1 below.

Table 1. Applicability of Input and Assumption Categories by ENELYTIX Module

Section	**Capacity Expansion Module**	**E&AS Module**	**FCM Module**
3. *Transmission*	Interfaces only	All transmission constraints	N/A
4. *Load Forecast*	Seasonal Load Duration Curves	Hourly chronological	N/A
5. *Ancillary Services*	N/A	Modeled in detail	N/A
6. *Installed Capacity Requirements*	By Zone	N/A	By Zone
7. *RPS Requirements*	Yes	REC Prices from Capacity Expansion	REC Prices from Capacity Expansion
8. *MA Clean Energy Standards and Carbon Emissions Regulations*	Yes	CO2 shadow prices from Capacity Expansion	N/A
9. *Generating Units Retirements*	Yes	from Capacity Expansion	from Capacity Expansion
10. *Generating Units Capacity Additions*	Yes	from Capacity Expansion	from Capacity Expansion
11. *Generating Unit Operational Characteristics*	Yes	Yes	N/A
12. *Fuel Prices*	Yes	Yes	N/A
13. *Emission Rates and Allowance Prices*	Yes	Yes	N/A

A. Capacity Expansion Module

The discussion that follows summarizes the methodology used by the Capacity Expansion Model to

[2] www.psopt.com

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simulate electric generating unit (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 sections of this document unless indicated otherwise.

The Capacity Expansion Module solves a dynamic multi-year optimization problem using a Mixed Integer Programming (MIP) optimization solver. The problem is solved over a 30- year optimization horizon (2019 – 2050). 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 draft 310 CMR 7.74 rules,
- energy produced by new renewable resources procured to comply with state-specific Class 1 RPS 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 identifies 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 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 FCA11 covered the 2020/21 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. Section 6 presents these estimates.

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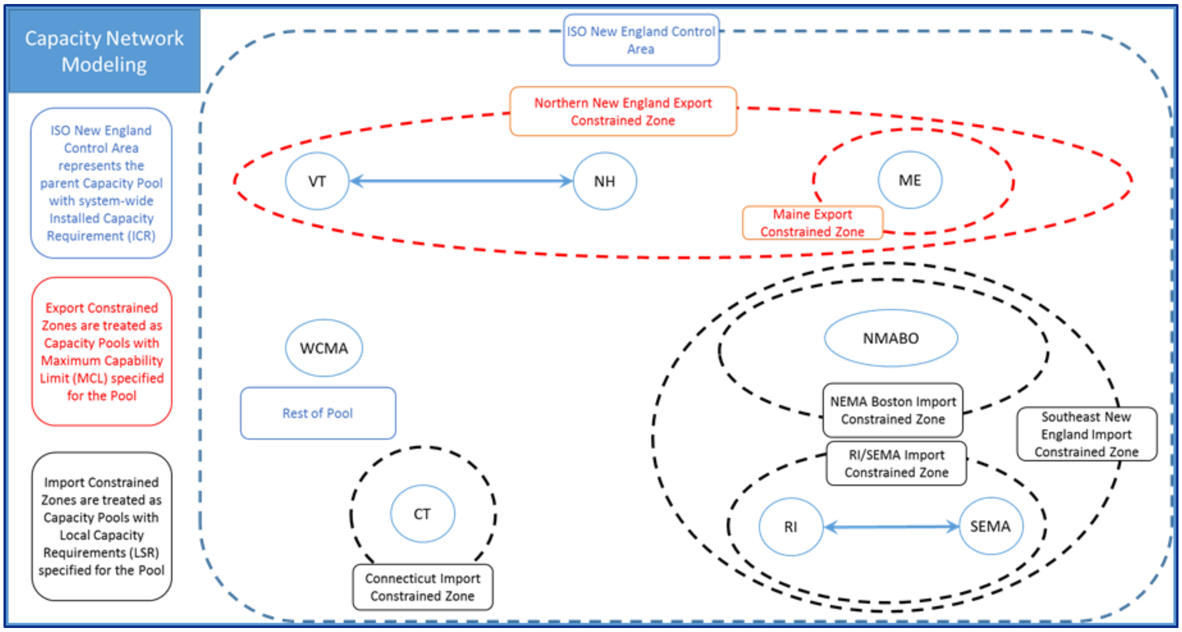
Figure 2 Representation of the Resource Adequacy Constraints in ISO-NE



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.

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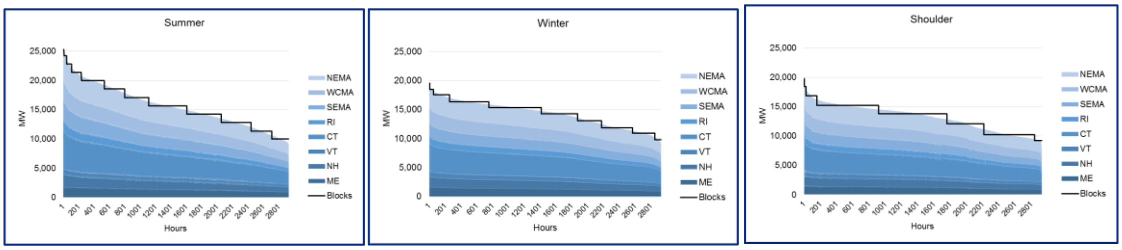
Figure 3. Seasonal Load Duration Curves and their Representation in Capacity Expansion Module



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 2017 levels. The Massachusetts value for 2017 is $67.70 per MWh. Connecticut's ACP is fixed in nominal terms at $55, which we deflate in real terms over the study time horizon for modeling purposes. New Hampshire's ACP, currently $56.02/ 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 CO2 emission cap rules applicable to generators located in Massachusetts. The module uses projected RGGI CO2 emission allowance prices as an input. Sections 7, 8 and 13 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

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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 except for CES obligations. 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 83D CES obligations and then it values the impact of 83D 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 capacity that of the resource type

Section 10 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 in the market.

B. **Energy and Ancillary Services Module**

The ENELYTIX E&AS module is a detailed chronological production costing simulation model which implements security constrained unit commitment (SCUC) and economic dispatch (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.

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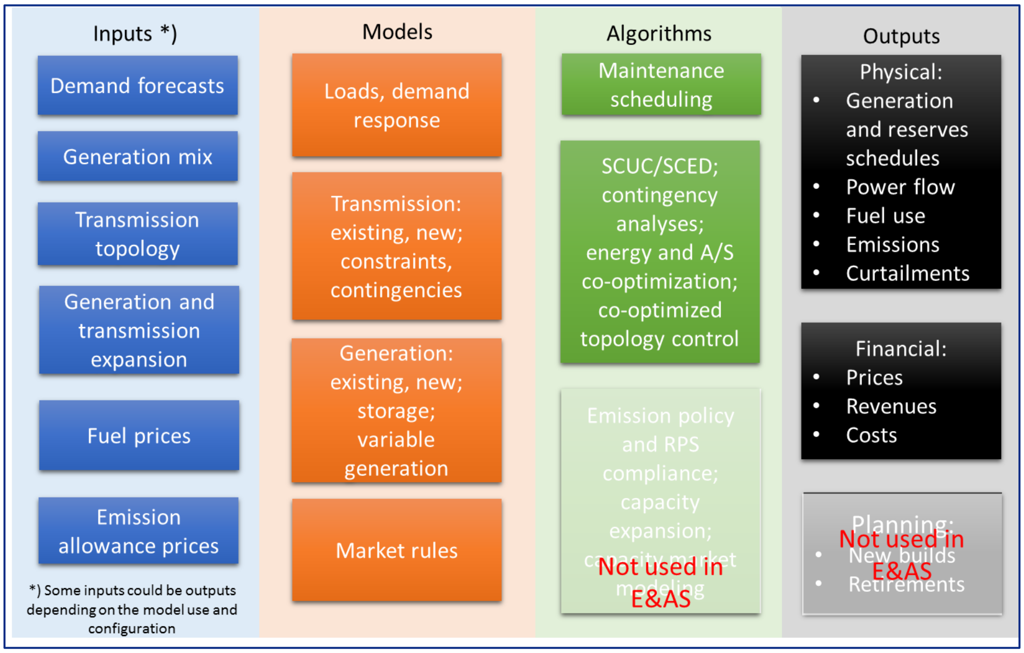
Figure 4. Schematic of the E&AS Module



C. **Forward Capacity Market Module**

TCR models the capacity market in New England as a least cost selection of resources satisfying system-wide and locational reliability (installed capacity) requirements, as depicted in Figure 2. As shown in this figure, installed capacity requirements in New England are set as follows:

- System-wide Installed Capacity Requirement (ICR). For the purpose of the study, we work with ICRs that are net of capacity supply provided by imports from Hydro Quebec across HVDC interties.
- Local Sourcing Requirements (LSRs) for import constraint zones. Although the most recent Forward Capacity Auction (FCA11) considered only one import constrained zone (Southeast New England), other zones may become import constrained due to generator retirements and load growth. Therefore, TCR models all potentially import constrained zones including NMABO, RI/SEMA and CT
- Maximum Capacity Limits (MCLs) for export constrained zones. FCA11 considered only one export constrained zone – Northern New England. However, future capacity additions could make Maine an export constrained zone again and therefore it is also modeled as a constrained zone.

Section 6 describes local capacity requirements in greater detail.

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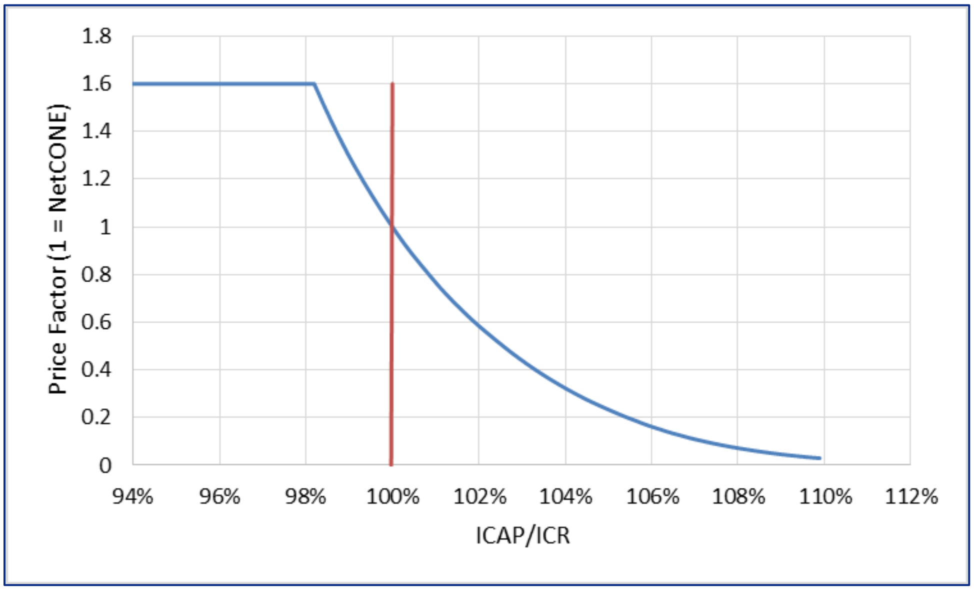
i. Demand Curve Assumptions

In July 2016, FERC accepted[3] ISO-NE's proposal[4] for a new "Marginal Reliability Impact" (MRI) based approach to develop system wide and zone specific sloped demand curves for FCA 11 (2020/2021). The shape of the system-wide demand curve is shown in Figure 5 and represented in relative terms: as ratio of installed capacity (ICAP) to ICR on the horizontal axis and as a ratio of capacity price to Net CONE – on the vertical axis. As shown in this figure, if the ICAP exactly equals the ICR, i.e., ICP/ICR = 100%, the capacity price exactly equals the Net CONE.

Figure 5. ISO-NE System-wide Demand Curve in Relative Units



The demand curve for an import constrained zone reflects the incremental capacity pricing in effect in the zone if installed capacity falls below the Local Sourcing Requirement level as shown in Figure 6 which depicts the shape of the demand curve for an import constrained zone derived from the demand curve for the SENE zone developed by ISO-NE England for FCA11. The horizontal axis represents the ratio of the total supply capacity available for the import constrained zone to the required supply capacity. Here the supply capacity is represented as the sum of capacity installed within the zone plus the import interface limit into the zone. For the purpose of market modeling, TCR applies this shape to all zones and scale it in proportion to the projected level of total supply for the import constrained zone in question.

To model an export constrained zone, TCR relies on the fact that the zone is export constrained if, and only if, the complementary zone (Rest of Pool) is import constrained and that MCL + LSR = ICR.

[3]FERC Docket ER16-1434 Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14287974
[4] ISO-NE and NEPOOL filing to FERC Available at: https://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf

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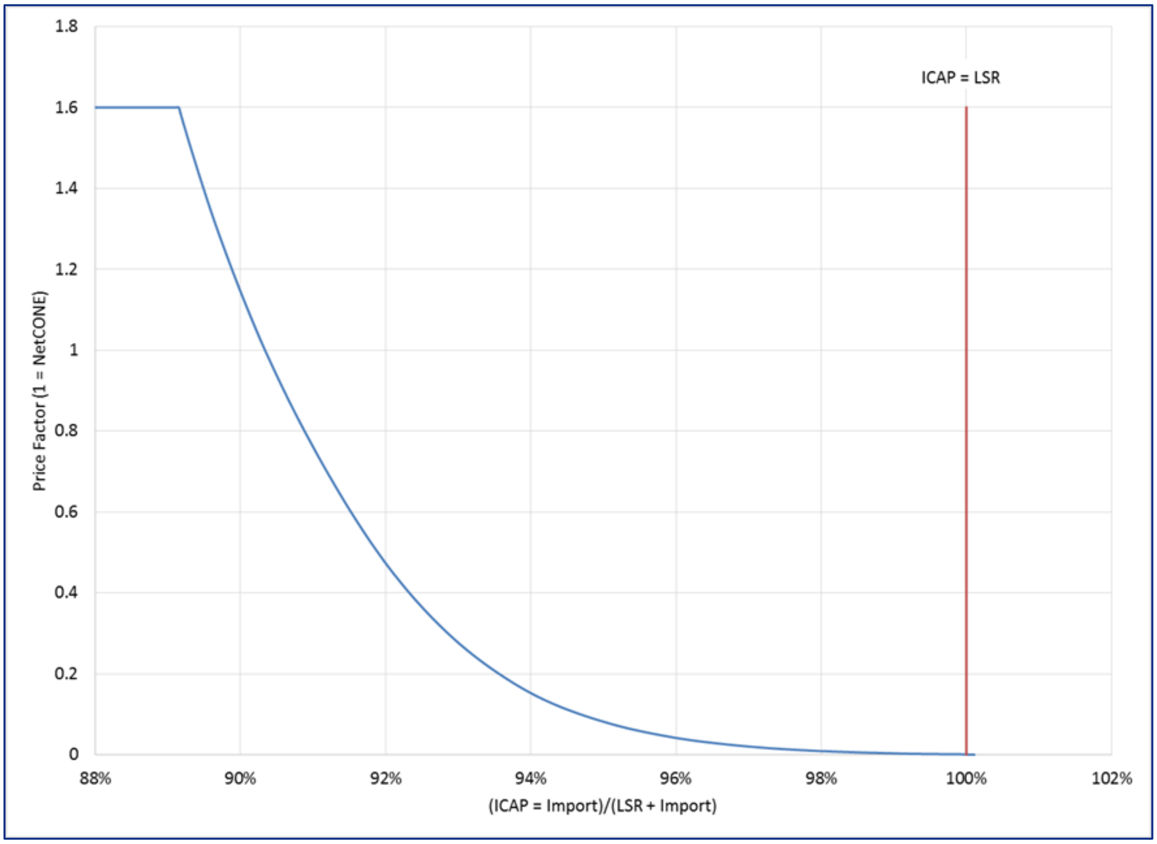
Where MCL is the Maximum Capacity Limit of the export constrained zone and LSR is locational sourcing requirement of the corresponding Rest of Pool zone. Thus, for export constrained zone (e.g., Northern New England, Maine), the model includes LSRs for complementary Rest of Pool zones ("CT + MA + RI", and "all but Maine", respectively).

Figure 6. Import Constrained Zone Demand Curve (Relative Units)



TCR uses the ISO New England Net CONE values for FCA12 as filed with FERC on January 13, 2017 as shown in Table 2. TCR scales this curve each year in proportion to LSR.

Table 2. CONE and Net CONE Assumptions

Parameter	Value in real 2017 $/kW-year
CONE	10.53
Net CONE	7.46
1.6 x Net CONE	11.93

ii. Supply Offers to the FCM

ENELYTIX assumes that generators will set their offers to the FCM at a level which would recover their estimate of the revenue shortfall between the total revenues they require and the net revenues they expect to receive in the energy, REC and CEC markets. TCR models generators' offers in dollars per kW-

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year of installed capacity measured as the generator's fixed costs minus its net revenues from markets for energy, ancillary services, RECs and CECs. For existing generators, fixed costs account for fixed O&M costs only since their capital costs are "sunk." For new generators, i.e. units forecast to come online during the commitment period, fixed costs include annualized capital costs and fixed O&M costs. Net revenues the all generators receive include operating margins earned in the energy market, revenues from providing ancillary services plus payment for RECs and CECs, if any.

Consistently with ISO New England rules, for capacity additions under PPA, such as 83D and 83C projects, TCR assumes that these capacities do not participate in the FCA market in the first year and will be allowed a phase in participation in the capacity market over subsequent 4 years. Thus, a 100 MW project added in year Y, would be able to offer to the FCA market 25 MW in year Y+1, 50 MW – in Y + 2, 75 MW in Y + 3 and 100 MW in Y + 4 and thereafter.

Section 10 presents the assumptions for generator capital and fixed O&M costs TCR uses to model supply offers to the FCM

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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.[5]

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.

In ENELYTIX, eNodes are modeled as children of bus bars and bus bars in the powerflow model. The mapping of bus bars to Zones allows ENELYTIX to allocate area load forecasts to load busses in proportion to the initial state from the powerflow. The use of both bus bars and eNodes allows users to distinguish between electrical and physical connections. This is useful in that it allows tracking of power-flow values of different injectors to the same bus. The powerflow model from ISO-NE was solved to develop an initial state for injections and flows.

In determining a representative list of transmission constraints to monitor, TCR includes all major ISO New England interfaces and frequently binding constraints assembled by EDCs using historical data from 2012 through June 23, 2017 and other contingency constraints EDCs deemed necessary to be included in the model. In addition to this list, TCR conducted N-1 contingency analysis using ENELYTIX added constraint contingency pairs that were not already on the list provided by the EDCs. Interface definitions and operating limits were provided electronically by ISO-NE. TCR verified these interface limits against the ISO-NE's Planning Transfer Capability Report (2015-16 assessment). TCR also applies seasonal limits on interfaces not scheduled to be upgraded by year 2019 where sufficient statistical data exist to support derivation of seasonal limits. The purpose of using seasonal limits is to reflect the effect of transmission maintenance outages on transfer capability of interfaces.

[5] Transmission topology and operating limits represent Critical Energy Infrastructure Information (CEII). No CEII data is included in this document.

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4. LOAD FORECAST

This section 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 section 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 section describes the method TCR uses to develop the hourly shape of the Gross-PDR energy forecast.

TCR develops the Base Case load forecast through 2026 from the 2017 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report) , the most recent ISO-NE forecast, extrapolating the values for 2027-2040.

A. **Forecasts of Gross-PDR Annual Energy and Peak Load, 2019 - 2026**

TCR develops the Gross – PDR load forecasts through 2026 from the 2017 ISO New England Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report). TCR develops forecasts for 2027 through 2040 using separate extrapolations for the Gross and PDR components.

i. **2017 CELT Forecast for 2019 - 2026**

The 2017 CELT report provides forecasts of Gross, Gross-PDR and Gross-PV-PDR for annual energy and peak load through 2026. 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 2019 through 2026 from the 2017 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 passive demand response (PDR). ISO-NE labels these forecasts "Gross-PDR," and TCR uses them in the 83D 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.

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The forecasts are taken from tabs 2A and through 2BC of the ISO New England CELT 2017 Forecast data file (2017 CELT), the most recent CELT Report.

Table 3. Gross-PDR Annual Energy Forecast Summary by ISO-NE Area (GWh)

Zone	2019	2020	2021	2022	2023	2024	2025	2026
CT	31,617	31,126	30,871	30,690	30,553	30,445	30,362	30,312
ME	11,622	11,825	11,807	11,821	11,856	11,901	11,952	12,010
MA	59,055	58,437	57,684	57,101	56,664	56,349	56,144	56,070
*SEMA**	16,238	16,086	15,895	15,750	15,645	15,573	15,532	15,525
*WCMA**	17,013	16,835	16,618	16,450	16,324	16,234	16,175	16,153
*NMABO**	25,803	25,516	25,171	24,901	24,694	24,542	24,439	24,391
NH	12,059	12,062	12,071	12,094	12,129	12,169	12,213	12,265
RI	8,036	7,861	7,736	7,634	7,547	7,481	7,433	7,400
VT	6,147	6,263	6,189	6,128	6,075	6,031	5,992	5,962
ISO-NE	**128,536**	**127,573**	**126,358**	**125,468**	**124,824**	**124,376**	**124,096**	**124,018**

Table 4. Gross-PDR Coincident Summer Peak Load Forecast Summary by ISO-NE Area (MW)

Zone	2019	2020	2021	2022	2023	2024	2025	2026
CT	7,106	7,039	7,025	7,017	7,013	7,014	7,019	7,030
ME	2,004	2,052	2,056	2,064	2,074	2,086	2,098	2,110
MA	12,668	12,620	12,585	12,570	12,574	12,595	12,631	12,687
*SEMA**	3,576	3,585	3,589	3,597	3,610	3,627	3,648	3,674
*WCMA**	3,601	3,624	3,617	3,616	3,620	3,629	3,642	3,660
*NMABO**	5,490	5,411	5,379	5,356	5,343	5,338	5,341	5,353
NH	2,531	2,539	2,554	2,571	2,588	2,606	2,624	2,645
RI	1,873	1,855	1,850	1,848	1,848	1,851	1,856	1,862
VT	1,008	1,036	1,029	1,024	1,019	1,014	1,010	1,009
ISO-NE	**27,192**	**27,146**	**27,104**	**27,096**	**27,118**	**27,168**	**27,243**	**27,345**

* Note – Energy and peak loads for MA are aggregate of values for SEMA, WCMA and NMABO zones.

ii. **TCR Forecast of annual energy and peak load, 2027 - 2040**

TCR develops forecasts for 2027 to 2040 by making separate projections of New England gross demand and PDR and then subtracting the PDR projections from the gross demand projection. TCR makes these separate projections because New England gross demand and PDR are each growing at different rates. Table 5 summarizes the projected growth in PDR MW and GWH

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Table 5. TCR Forecast of Gross Annual Energy and PDR capacity

ISO-NE	2027	2030	2035	2040
PDR (MW)	4,752	5,401	6,307	6,996
PDR Energy (GWh)	30,338	34,482	40,272	44,789

Gross Peak and Energy: TCR assumes an exponential 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 2021-2026 forecast and applied the CAGR to 2026 CELT forecast.

Table 6 and Table 7 report 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	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
CT	30,290	30,318	30,396	30,470	30,558	30,640	30,777
ME	12,020	12,047	12,090	12,133	12,180	12,226	12,290
MA	55,734	55,539	55,480	55,410	55,378	55,326	55,426
NH	12,322	12,389	12,466	12,543	12,622	12,702	12,792
RI	7,340	7,301	7,282	7,262	7,247	7,229	7,234
VT	5,946	5,943	5,950	5,957	5,967	5,976	5,997
ISO-NE	**123,651**	**123,536**	**123,664**	**123,774**	**123,952**	**124,099**	**124,517**
State	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CT	30,909	31,054	31,192	31,389	31,577	31,781	31,974
ME	12,353	12,420	12,485	12,570	12,652	12,739	12,823
MA	55,507	55,627	55,720	55,979	56,213	56,485	56,726
NH	12,881	12,974	13,066	13,169	13,271	13,377	13,482
RI	7,236	7,243	7,247	7,275	7,300	7,330	7,356
VT	6,017	6,040	6,061	6,096	6,129	6,165	6,199
ISO-NE	**124,903**	**125,358**	**125,770**	**126,478**	**127,143**	**127,877**	**128,559**

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Table 7. Gross - PDR Annual Peak Forecast summary by ISO-NE states (MW)

State	2027	2028	2029	2030	2031	2032	2033
CT	7,049	7,080	7,114	7,150	7,188	7,229	7,273
ME	2,118	2,129	2,141	2,153	2,166	2,180	2,194
MA	12,675	12,695	12,721	12,753	12,792	12,838	12,890
NH	2,661	2,680	2,699	2,719	2,739	2,760	2,782
RI	1,860	1,862	1,866	1,870	1,875	1,882	1,889
VT	1,009	1,012	1,016	1,020	1,024	1,029	1,034
ISO-NE	27,376	27,461	27,558	27,667	27,787	27,919	28,064
State	2034	2035	2036	2037	2038	2039	2040
CT	7,319	7,368	7,420	7,474	7,531	7,591	7,653
ME	2,209	2,225	2,241	2,258	2,276	2,295	2,314
MA	12,948	13,013	13,085	13,163	13,248	13,339	13,437
NH	2,804	2,827	2,851	2,875	2,900	2,925	2,951
RI	1,897	1,906	1,916	1,928	1,940	1,953	1,967
VT	1,040	1,046	1,052	1,059	1,067	1,074	1,083
ISO-NE	28,220	28,388	28,568	28,760	28,963	29,179	29,407

Figure 7 and Figure 8 plot the resulting projections of Gross-PDR annual energy and peak load by state by year.

Figure 7: TCR forecast Gross - PDR Annual Energy by state (GWh)

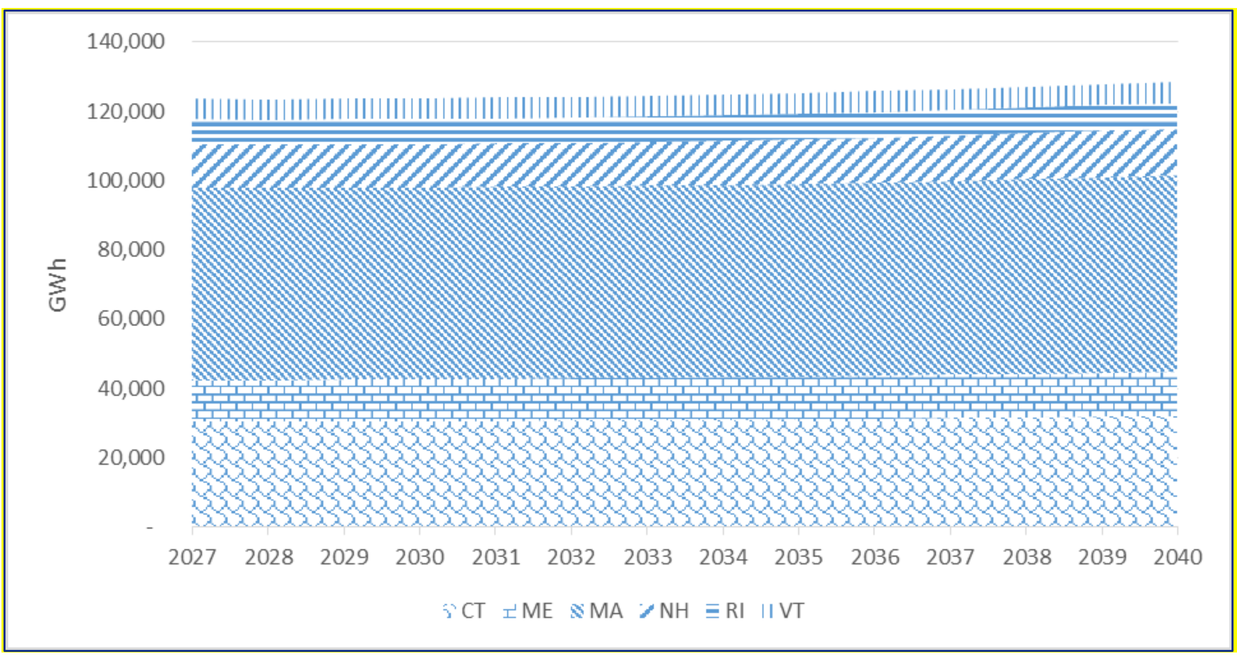

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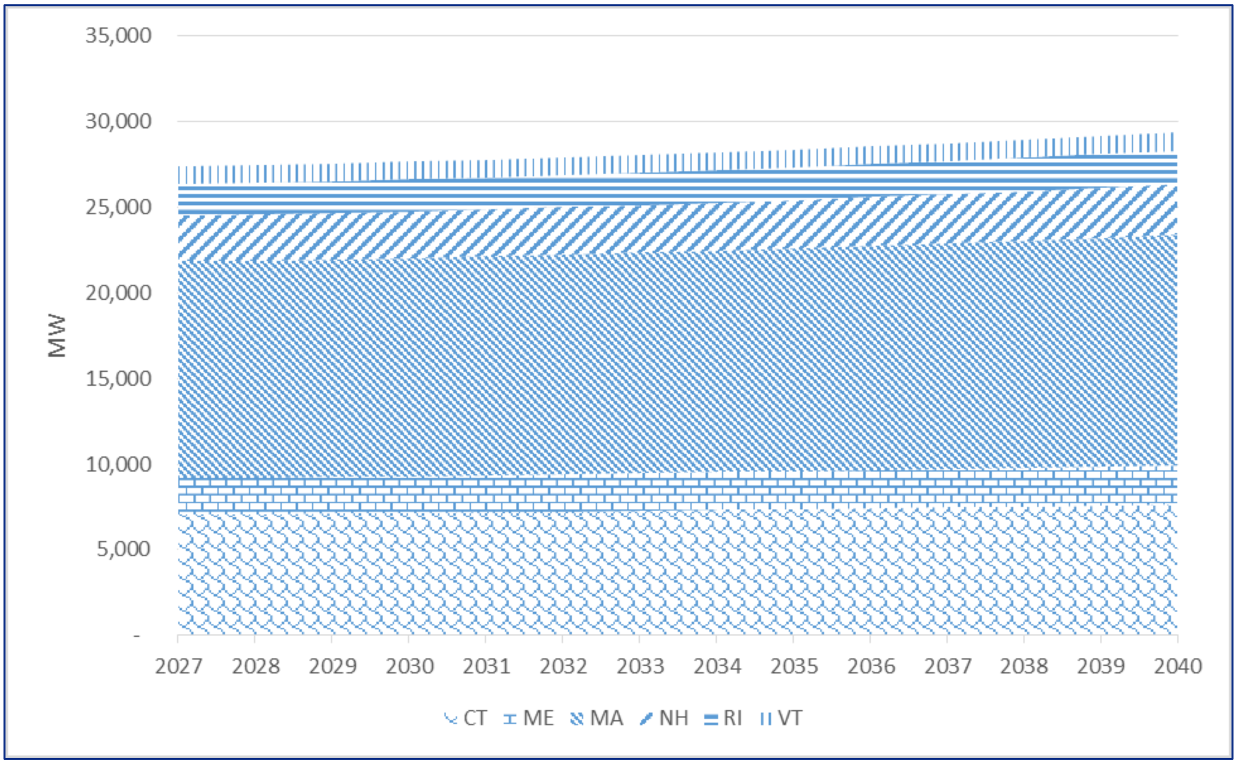
Figure 8: TCR Gross - PDR Peak Forecast by state (MW)



B. **Forecasts of NEL (Gross – PV – PDR) Annual Energy, 2019 - 2026**

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 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. Section 7 describes the calculation of, and reports, those RPS and CES requirements.

TCR developed the Gross – PV - PDR forecasts through 2026 from the 2017 CELT Report. It developed the forecasts for 2027 through 2040 using curve fit extrapolations of generation from BMPV PV annual energy and subtracting that generation from the Gross-PDR forecast described in Section 4.A.

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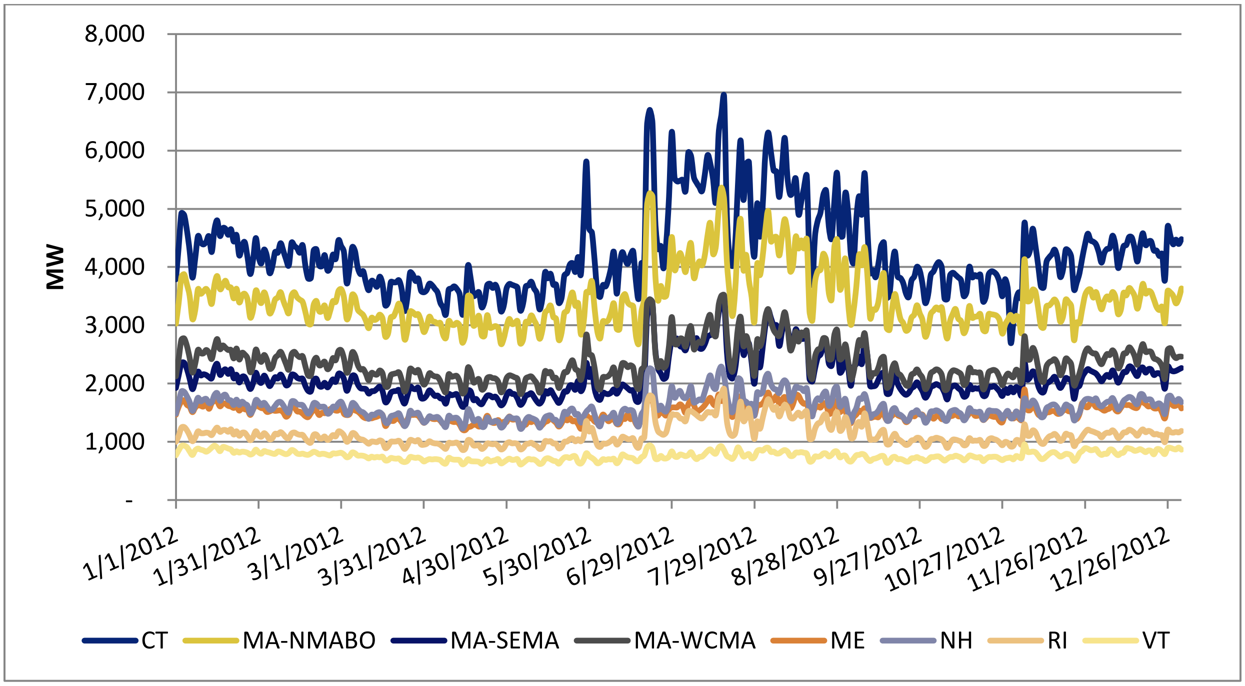
C. **Hourly Load Shape**

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 9 plots the load shapes TCR constructed for each area from the following data:

- 2012 historical load shapes by ISO-NE zone.[6] 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

Figure 9: ISO Historical Load Shape, 2012



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.

[6] 2012 SMD Hourly Data, ISO-NE < https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info>

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5. 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.

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6. INSTALLED CAPACITY REQUIREMENT (ICR)

A. System-wide Installed Capacity Requirement (ICR)

Table 9 summarizes TCR's proposed projections. The TCR projections are based on the analyses described earlier in Section 4. PDR resources are modeled as price takers.

Table 9. Projection of System-Wide ICR

	ISO-NE		TCR Projection						
Period	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2029/30	2034/35	2039/40
FCA	10	11	12	13	14	15	20	25	30
Peak Net of PV (MW)	29,861	29,601	29,436	29,694	29,960	30,231	31,473	32,679	33,951
ICR (MW)	35,142	35,034	34,989	35,311	35,642	35,978	37,508	38,988	40,546
Margin	17.69%	18.35%	18.87%	18.92%	18.97%	19.01%	19.18%	19.31%	19.42%
HQ ICC (MW)	953	959	959	959	959	959	959	959	959
Other Imports plus ADR (MW)	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696	1,696
Net ICR (MW)	32,493	32,379	32,334	32,656	32,987	33,323	34,853	36,333	37,891
PDR (MW)	2,561	2,893	3,223	3,527	3,805	4,055	5,193	6,143	6,875
Net ICR less PDR + Imports	29,932	29,486	29,111	29,129	29,182	29,268	29,660	30,190	31,015

Starting with the data provided in the four 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 20.5%. 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 2020/21 level of 959 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 will provide an additional 1,378 MW and resources within New-England will provide 318 MW of Active Demand Response (ADR). These two assumption are based upon the average quantities of capacity that cleared in ISO-NE Forward Capacity Auctions 9, 10 and 11.

B. 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 10 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.

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Table 10. Local Sourcing Requirements for Import Constrained Zones

	2020/21	2021/22	2022/23	2023/24	2024/25	2029/30	2034/35	2039/40
NEMA/Boston	1,716	1,704	1,704	1,713	1,732	1,889	2,137	2,477
RI/SEMA	6,564	6,572	6,592	6,620	6,657	6,897	7,214	7,616
SENE	8,291	8,221	8,225	8,249	8,293	8,619	9,106	9,765
CT	6,113	6,054	6,050	6,052	6,058	6,126	6,242	6,420
CT+MA+RI	21,580	20,418	20,402	20,419	20,468	20,872	21,533	22,477
All but ME	25,475	25,421	25,402	25,417	25,464	25,910	26,661	27,722

Starting with the data provided in ISO-NE ICR studies available as of August 2017, 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 Section 3.

C. **Contribution of Variable Resources toward ICR**

TCR uses Summer Claimed Capability values that are available for existing and scheduled additions of variable resources. For new additions of variable resources for which Summer Claimed Capability values were not available TCR uses the following assumptions to model their contribution to the ICR:

- Offshore wind: 20% of nameplate capacity. ISO-NE has used this value in various planning studies.
- Onshore wind: 11% of nameplate capacity. This value is the ratio of Summer Claimed Capability over nameplate capacity for wind units in the CELT generation list.
- Hydro: 66% of nameplate capacity. This value is the ratio of Summer Claimed Capability over nameplate capacity for hydro units in the CELT generation list.

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- 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.

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7. RENEWABLE PORTFOLIO STANDARD (RPS) REQUIREMENTS

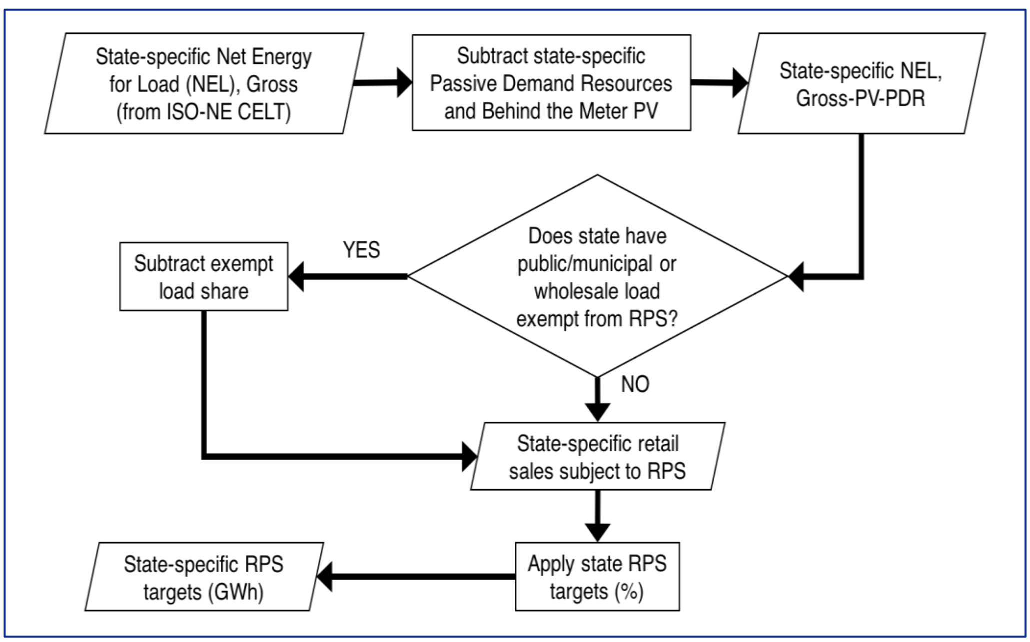
This section describes the forecast requirement for Class 1 RPS resources over the study period.

As described in Section 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, therefore TCR need only model Class 1 requirements in order to project new Class 1 eligible renewable additions and Massachusetts Class 1 REC prices.[7]

With the exception of Vermont, Class 1 RPS programs for each of the New England states have eligibility criteria that have a great deal of overlap, and the resulting "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 10 illustrates the process TCR used to determine state-specific Class 1 RPS energy targets by year for each of the five states.

Figure 10. Process used to project state-specific RPS energy targets.



[7] 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 section 4.B.
- Load share for load serving entities (LSEs) and certain wholesale load exempt from state RPS requirements.
- Annual RPS targets for each state, expressed as a percentage of sales to end-use customers for obligated (non-exempt) load-serving entities.

For a given state, the forecast requirements 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	8.1%
MA*	17.4%
ME	2.2%
NH	1.7%
RI	2.6%
* MA Includes approx. 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.

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Table 12. Projected RPS Requirements

(a) Net Energy for Load (NEL) Gross-PV-PDR Forecast (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	30,198	29,876	29,635	29,441	29,278	29,141	29,039	28,994	28,997	29,058
MA	56,880	56,008	55,308	54,757	54,351	54,094	53,968	53,594	53,357	53,271
ME	11,765	11,738	11,745	11,773	11,810	11,852	11,902	11,911	11,935	11,978
NH	11,946	11,947	11,962	11,989	12,021	12,057	12,101	12,155	12,219	12,294
RI	7,766	7,626	7,516	7,423	7,351	7,296	7,257	7,195	7,153	7,132

(b) RPS-exempt load as a proportion of NEL

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
MA	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%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%

(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	27,760	27,465	27,244	27,065	26,915	26,789	26,696	26,654	26,657	26,712
MA	46,996	46,275	45,697	45,242	44,906	44,694	44,590	44,281	44,085	44,014
ME	11,504	11,479	11,486	11,512	11,548	11,590	11,639	11,647	11,671	11,713
NH	11,747	11,748	11,762	11,789	11,820	11,856	11,899	11,953	12,015	12,089
RI	7,565	7,428	7,321	7,231	7,160	7,107	7,069	7,008	6,967	6,947

(d) Class 1 RPS Requirements (%)*

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
MA	15.0%	16.0%	17.0%	18.0%	19.0%	20.0%	21.0%	22.0%	23.0%	24.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	10.8%	11.7%	12.6%	13.5%	14.4%	15.3%	15.3%	15.3%	15.3%	15.3%
RI	14.0%	15.5%	17.0%	18.5%	20.0%	21.5%	23.0%	24.5%	26.0%	27.5%

(e) Class 1 RPS Requirements (GWh) = (c) x (d)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
CT	5,552	5,493	5,449	5,413	5,383	5,358	5,339	5,331	5,331	5,342
MA	7,049	7,404	7,769	8,144	8,532	8,939	9,364	9,742	10,140	10,563
ME	1,150	1,148	1,149	1,151	1,155	1,159	1,164	1,165	1,167	1,171
NH	1,269	1,375	1,482	1,592	1,702	1,814	1,821	1,829	1,838	1,850
RI	1,059	1,151	1,245	1,338	1,432	1,528	1,626	1,717	1,812	1,911

* NH Requirement includes Class II solar (0.3%)

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Table 12. Projected RPS Requirements (cont.)[8]

(a) Net Energy for Load (NEL) Gross-PV-PDR Forecast (GWh)

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	29,113	29,184	29,246	29,372	29,489	29,621	29,741	29,930	30,107	30,299	30,478
MA	53,170	53,109	53,024	53,105	53,163	53,260	53,325	53,571	53,785	54,038	54,255
ME	12,019	12,065	12,109	12,172	12,233	12,299	12,363	12,447	12,528	12,614	12,697
NH	12,368	12,446	12,522	12,611	12,698	12,789	12,879	12,981	13,082	13,187	13,289
RI	7,110	7,093	7,073	7,076	7,077	7,083	7,085	7,112	7,135	7,164	7,188

(b) RPS-exempt load as a proportion of NEL

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
MA	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%
NH	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
RI	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%	2.6%

(c) NEL Subject to RPS Obligations (GWh) = (a) x (1 - b)

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	26,763	26,829	26,886	27,001	27,109	27,230	27,341	27,514	27,677	27,854	28,018
MA	43,931	43,880	43,810	43,877	43,925	44,005	44,059	44,262	44,439	44,648	44,827
ME	11,753	11,798	11,841	11,903	11,963	12,027	12,089	12,171	12,251	12,335	12,416
NH	12,162	12,238	12,314	12,401	12,487	12,576	12,664	12,765	12,864	12,967	13,068
RI	6,925	6,909	6,889	6,893	6,893	6,899	6,901	6,928	6,951	6,979	7,002

(d) Class 1 RPS Requirements (%)*

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
MA	25.0%	26.0%	27.0%	28.0%	29.0%	30.0%	31.0%	32.0%	33.0%	34.0%	35.0%
ME	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
NH	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%	15.3%
RI	29.0%	30.5%	32.0%	33.5%	35.0%	36.5%	36.5%	36.5%	36.5%	36.5%	36.5%

(e) Class 1 RPS Requirements (GWh) = (c) x (d)

	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
CT	5,353	5,366	5,377	5,400	5,422	5,446	5,468	5,503	5,535	5,571	5,604
MA	10,983	11,409	11,829	12,286	12,738	13,201	13,658	14,164	14,665	15,180	15,689
ME	1,175	1,180	1,184	1,190	1,196	1,203	1,209	1,217	1,225	1,234	1,242
NH	1,861	1,872	1,884	1,897	1,910	1,924	1,938	1,953	1,968	1,984	1,999
RI	2,008	2,107	2,205	2,309	2,413	2,518	2,519	2,529	2,537	2,547	2,556

* NH Requirement includes Class II solar (0.3%)

[8] Sources: (a) 2020-2026: ISO-NE 2017 CELT, https://www.iso-ne.com/system-planning/system-plans-studies/celt; 2027-2040: TCR projection of Gross-PV-PDR energy load forecast (see Section 4); (b) Values based on RPS compliance reports, ISO-NE historical NEL data, and EIA data; (d) Rhode Island: H.B. 7413, enacted June 2016, http://webserver.rilin.state.ri.us/BillText/BillText16/HouseText16/H7413A.pdf. Other states: ISO-NE RPS Spreadsheet, https://www.iso-ne.com/static-assets/documents/2016/05/a3_2016_economic_study_scope_of_work_rps_spreadsheet.xlsx.

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8. MASSACHUSETTS CARBON EMISSION REGULATIONS AND CLEAN ENERGY STANDARD

The 83D Base Case uses the two regulations affecting the electric sector promulgated on August 11, 2017. These are regulation 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 (CES).

A. **Cap on carbon emissions, regulation 310 CMR 7.74**

The regulation imposes an annual physical cap on CO_2 emissions from electric generation units (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 are the aggregate limit.[9]

[9] 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 1 is reproduced from Table 3 in this report.

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Table 13: Aggregate Limits in Select Years, 2018-2040

Year	Aggregate GHG Emissions Limit	Existing Facility Aggregate GHG Emissions Limit	New Facility Aggregate GHG Emissions Limit
2018	9,119,126	7,619,126	1,500,000
2019	8,891,148	7,391,148	1,500,000
2020	8,663,170	7,163,170	1,500,000
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
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 that was scheduled to come 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.[10]

[10] Ibid, p. 39.

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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%
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%

B. **CES, regulation 310 CMR 7.75**

The regulation requires retail electricity sellers, excluding Municipal Light Plants (MLPs), to procure clean energy credits (CECs). 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 Section 4 and an assumption that the annual net energy load of MLPs remains at 14%, its level in 2015, over the study period.[11]

[11] 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

iii. **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.

In the 83D 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.[12]

[12] More precisely, the ACP is modeled in the 83D 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, 2020 to 2040

Requirements, %		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
MA Class 1 RPS & CES Requirements - % of Applicable Load												
MA Class 1 RPS		15.0%	16.0%	17.0%	18.0%	19.0%	20.0%	21.0%	22.0%	23.0%	24.0%	25.0%
CES		20.0%	22.0%	24.0%	26.0%	28.0%	30.0%	32.0%	34.0%	36.0%	38.0%	40.0%
Draft CES incr to Class 1 RPS		5.0%	6.0%	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%	15.0%
CES applicable to Municipal Light Plant (MLP) load		0.0%	6.5%	8.1%	9.8%	11.5%	13.3%	15.2%	17.1%	19.1%	21.2%	23.3%
Requirements, GWh												
MA Load per ISO NE CELT 2017, GROSS-PV-PDR	GWh	56,880	56,008	55,308	54,757	54,351	54,094	53,968	53,594	53,357	53,271	53,170
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%
wholesale load exempt from CES	GWh	1,921	1,891	1,868	1,849	1,835	1,827	1,823	1,810	1,802	1,799	1,796
MLP load	%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
MLP load subject to CES	GWh	7,963	7,841	7,743	7,666	7,609	7,573	7,555	7,503	7,470	7,458	7,444
non-MLP load subject to CES	GWh	46,996	46,275	45,697	45,242	44,906	44,694	44,590	44,281	44,085	44,014	43,931
CES Requirements - MLP + non-MLP	GWh	**9,399**	**10,693**	**11,597**	**12,514**	**13,451**	**14,418**	**15,417**	**16,341**	**17,300**	**18,306**	**19,309**

Requirements, %		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
MA Class 1 RPS & CES Requirements - % of Applicable Load											
MA Class 1 RPS		26.0%	27.0%	28.0%	29.0%	30.0%	31.0%	32.0%	33.0%	34.0%	35.0%
CES		42.0%	44.0%	46.0%	48.0%	50.0%	52.0%	54.0%	56.0%	58.0%	60.0%
Draft CES incr to Class 1 RPS		16.0%	17.0%	18.0%	19.0%	20.0%	21.0%	22.0%	23.0%	24.0%	25.0%
CES applicable to Municipal Light Plant (MLP) load		25.5%	27.8%	30.1%	32.5%	35.0%	37.5%	40.1%	42.8%	45.5%	48.3%
Requirements, GWh											
MA Load per ISO NE CELT 2017, GROSS-PV-PDR	GWh	53,109	53,024	53,105	53,163	53,260	53,325	53,571	53,785	54,038	54,255
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%
wholesale load exempt from CES	GWh	1,794	1,791	1,793	1,795	1,799	1,801	1,809	1,816	1,825	1,832
MLP load	%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
MLP load subject to CES	GWh	7,435	7,423	7,435	7,443	7,456	7,466	7,500	7,530	7,565	7,596
non-MLP load subject to CES	GWh	43,880	43,810	43,877	43,925	44,005	44,059	44,262	44,439	44,648	44,827
CES Requirements - MLP + non-MLP	GWh	**20,328**	**21,340**	**22,424**	**23,505**	**24,612**	**25,713**	**26,911**	**28,109**	**29,341**	**30,567**

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9. GENERATING UNIT RETIREMENTS

Table 16 summarizes the major actual generation retirements since 2014 and 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 SCC reports for specific units to see which month ISO-NE turned off, or will turn off, the particular unit.[13] The Capacity Expansion Module assumes no further nuclear unit retirements occur through 2040.

Table 16. ISO-NE approved capacity retirements

Name	Energy Type	Fuel Type	Summer Capacity (MW)	Winter Capacity (MW)	Retire Date	Energy Area
SALEM HARBOR 3	STc250	Coal	149.90	149.90	6/1/2014	NMABO
SALEM HARBOR 4	STo600	Fuel Oil	437.40	437.40	6/1/2014	NMABO
VT YANKEE NUCLEAR PWR STATION	NUC-BWR800	Uranium	619.40	615.00	12/1/2014	VT
POTTER DIESEL 1	ICo20	Fuel Oil	2.30	2.30	6/1/2015	SEMA
L STREET JET	GTo50	Fuel Oil	16.03	21.77	10/1/2016	NMABO
BRAYTON PT 1	STc250	Coal	225.23	233.22	5/1/2017	SEMA
BRAYTON PT 2	STc250	Coal	234.80	236.94	5/1/2017	SEMA
BRAYTON PT 3	STc600+	Coal	573.85	584.90	5/1/2017	SEMA
BRAYTON PT 4	STo600	Fuel Oil	430.35	432.67	6/1/2017	SEMA
PILGRIM NUCLEAR POWER STATION	NUC-BWR800	Uranium	670.46	683.42	6/1/2019	SEMA
BRIDGEPORT HARBOR 3[14]	STC600	Coal	383.426	384.984	6/1/2021	CT
MILLSTONE POINT 2	NUC-PWR1000	Uranium	856.52	859.04	7/1/2035	CT
MILLSTONE POINT 3	NUC-PWR+	Uranium	1225.00	1233.63	11/1/2045	CT

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.

[13] https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx

[14] Section 7.6 of ISO-NE Planning Procedures No. 10

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Table 17 Fixed O&M Requirements by Technology

Unit Type	FOM ($/kW-yr)
STc [1]	78.39
CCg [3]	55.76
CTg [3]	35.73
CTo/IC [4]	18.80
Stog [4]	42.02
Nuclear [1]	107.19
Hydro* [2]	15.64
PSH* [2]	19.42
PV [1]	22.86
Solar Thermal [2]	72.55
Wind Onshore [1]	41.01
Biomass [1]	116.46

Notes:
- All costs adjusted to 2017$ values
- EIA sourced costs adjusted for New England region, as applicable

* Units not considered for retirement

Sources

(1) EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016

(2) EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013

(3) CEA INO-NE CONE and ORTP Analysis (https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf)

(4) http://www.eipconline.com/uploads/MRN-NEEM_Modeling_Assumptions_Draft_Jan_25_2011_Input_Tables_Exhibits.xls

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10.GENERATING UNIT CAPACITY ADDITIONS

TCR uses the existing generating units listed in the ISO-NE 2017 CELT Report, tab 2.1, Generator list.[15]

A. **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 June 27, 2017, 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 August 2017*.[16,17]

[15] https://www.iso-ne.com/system-planning/system-plans-studies/celt/?document-type=CELT%20Reports
[16] https://irtt.iso-ne.com/reports/external
[17] https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

Table 18. Generation Capacity Additions in the ISO New England interconnection Queue

Name	Technology	Fuel	Summer Capacity (MW)	Winter Capacity (MW)	In-service Date	Energy Area	RPS Eligibility
Berkshire Wind Increase	Wind	Wind	1.75	5.67	1/1/2017	WCMA	Yes
MAT-2 (MATEP Combined Cycle)	CCgo100	Natural Gas	13.85	13.85	6/1/2017	NMABO	No
MATEP -3rd CTG	GTgo50+	Natural Gas	16.86	18.63	6/1/2017	NMABO	No
Southbridge Landfill Gas to Energy 17-18	ICr20	Refuse	2.40	2.40	6/1/2017	WCMA	Yes
Thundermist Hydropower	Hydro	Water	0.00	0.63	6/1/2017	RI	Yes
Wallingford Energy Center	GTgo50+	Natural Gas	100.00	100.00	4/1/2018	CT	No
Medway Peaker - SEMARI	GTo50+	Fuel Oil	207.70	207.70	5/31/2018	SEMA	No
CPV Towantic Energy Center	CCgo100+	Natural Gas	745.00	775.00	6/1/2018	CT	No
Footprint Combined Cycle Unit	CCg100+	Natural Gas	715.60	715.60	6/1/2018	NMABO	No
Bridgeport Harbor 5	CCgo100+	Natural Gas	509.60	509.60	5/31/2019	CT	No
CANAL3	GTgo50+	Natural Gas	333.00	333.00	5/31/2019	SEMA	No
Antrim Wind Resource	Wind	Wind	5.00	9.90	6/1/2019	NH	Yes
BRIDGEWATER	STb100	Biomass	14.65	14.77	6/1/2019	NH	Yes
Burrillville Energy Center 3 (Clear River)	CCgo100+	Natural Gas	485.00	485.00	6/1/2019	RI	No
Deerfield Wind Project	Wind	Wind	8.10	13.60	6/1/2019	WCMA	Yes
Holiday Hill Community Wind	Wind	Wind	0.78	1.20	6/1/2019	WCMA	Yes
Mass Mid-State Solar	PV	Solar	7.11	0.00	6/1/2019	WCMA	Yes
Future Gen Wind	Wind	Wind	2.70	2.80	6/1/2020	SEMA	Yes
FUTURE GEN WIND	Wind	Wind	1.39	0.00	6/1/2020	SEMA	Yes

B. **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.

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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.

i. 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 REG and REF programs in Rhode Island—TCR uses ISO New England's Final 2017 PV Forecast to project distributed PV additions, rather than add them using the Capacity Expansion model in response to the market.[18] All distributed PV generation additions through 2026 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.[19] TCR assumes distributed PV in Vermont counts toward the Vermont Distributed Generation (Tier 1) requirement (not represented in our model), and do not allow it to count toward Class 1 requirements elsewhere.

ii. Generic 83C Resources

TCR assumes additions from generic offshore resources developed through the 83C RFP start on a staggered schedule beginning 2023, as discussed in Section 10. TCR assumes these resources will sell their energy, Class 1 RECs and capacity at market prices. TCR does not assume a contract premium over market prices, or any incremental transmission costs associated with bringing these resources online unless the Evaluation Team provides such assumptions. Table 19 lists our capacity and online date assumptions for generic 83C additions. The first 1200 MW interconnects to the existing system at the "National Grid, 345 kV Brayton Point Substation, Somerset, MA," and the final 400 MW interconnects "Near Barnstable 115 kV Substation." These resources are assumed to provide a contribution to ICR at a level equal to 20 percent of their nameplate capacity.

[18] ISO New England Final 2017 PV Forecast, May 1, 2017 ("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 2017, so as not to double-count these resources, already included as part of the CELT Generation List.

[19] 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.

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Table 19. Assumed Additions of Section 83C Clean Energy Resources

Resource	Source	Capacity (MW)	Online Date
Wind	Offshore wind	400	12/31/2022
Wind	Offshore wind	400	12/31/2024
Wind	Offshore wind	400	12/31/2026
Wind	Offshore wind	400	12/31/2028

iii. 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.

iv. Near-Term Class 1 Renewable Resource Additions

Table 18 listed renewable additions in the ISO-NE interconnection queue. In addition to those projects, Table 20 lists the renewable generation projects selected under the New England Clean Energy RFP and currently under contract negotiation pursuant to that procurement will be built. TCR assembles the data on each project from the New England Clean Energy RFP website, cleanenergyrpf.com/bids.

Table 20. Additions from New England Clean Energy RFP

Bidder	Project	Location	Project Type	Nameplate Capacity (MW)
Ameresco	Candlewood Solar	New Medford, CT	PV	20.0
Deepwater Wind	DWW Solar plant	Simsbury, CT	PV	26.4
RES Americas	[Redacted]	RI	PV	20.0
RES Americas	[Redacted]	Eastern, CT	PV	20.0
Ranger Solar	Multiple PV Projects	CT, ME, NH	PV	178.0

TCR includes approximately 320 MW of New England solar and wind projects with nameplate capacity of 5 MW and above selected in Connecticut's Small Scale Clean Energy RFP, whose executed contracts were filed with CT PURA in June 2017.

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v. 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) is scheduled to drop to minimal levels 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.

Table 21 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.[20]

Table 21. Technical Potential for Installed Renewable Capacity by Resource Type and State

Technology		**CT**	**ME**	**MA**	**NH**	**RI**	**VT**	**Total**
Capacity (GW)								
Hydro	Conventional New Stream Reach Dev.	0.2	0.9	0.3	0.4	0.0	0.4	**2.2**
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 New Stream Reach Dev.	922	3,916	1,197	1,741	59	1,710	**9,546**
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**

[20] http://en.openei.org/doe-opendata/dataset/5346c5c2-be26-4be7-9663-b5a98cbb7527/resource/01fe78a8-77b6-4c59-bc36-cae177ee86c3/download/usretechpotential.pdf

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Table 21 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 22.

Table 22 presents capital and operating cost assumptions for generic market-driven renewable resource additions.

Table 22. Assumed Capital, FOM, and VOM Costs for generic market driven renewable additions

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Technology	Detail	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Hydro	Conventional (4)	3,249	15.6	-
	New Stream Reach Dev. (small) (5)	6,829	125.7	-
	New Stream Reach Dev.(large) (5)	6,120	36.1	-
Wind	Onshore (3)	2,643	59.8	-
	Onshore (transmission upgrade) (6)	3,383	59.8	-
	Offshore (4)	6,921	82.2	-
PV	Utility-scale (2)	2,657	22.9	-
Biomass	Gasified (4)	9,176	399.4	19.6

Notes:
- All costs adjusted to 2017$ values
- EIA sourced costs adjusted for New England region, as applicable
- PV costs in terms of AC nameplate capacity

Sources

(2) EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016

(3) EIA- Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generating Plants, April 2017

(4) EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013

(5) NREL - 2016 Annual Technology Baseline, September 2016

(6) Source (1) + TCR Estimates from ISO-NE2016/17 Maine Resource Integration Study – Scenarios and Cost Estimates

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C. 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.[21]. TCR also considers Advanced Nuclear options. Table 23 presents capital and operating cost assumptions for generic market-driven fossil resource additions.

Table 23. Assumed Capital, FOM, and VOM Costs for generic market driven fossil additions

Technology	Detail	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
Combined Cycle (1)	Advanced	1,042	55.8	3.2
Combustion Turbine (1)	Advanced - Industrial	835	35.7	4.2
	Advanced - Aeroderivative	1,573	64.0	4.6
	Conventional - Aeroderivative	1,957	77.5	4.6
Notes:				
- All costs adjusted to 2017$ values				
- EIA sourced costs adjusted for New England region, as applicable				
- PV costs in terms of AC nameplate capacity				
Sources				
(1) CEA ISO-NE CONE and ORTP Analysis (https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf)				
(2) EIA- Capital Cost Estimates for Utility Scale Electricity Generating Plants, November 2016				
(3) EIA- Addendum: Capital Cost Estimates for Additional Utility Scale Electric Generating Plants, April 2017				
(4) EIA- Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, April 2013				
(5) NREL - 2016 Annual Technology Baseline, September 2016				
(6) Source (1) + TCR Estimates from ISO-NE2016/17 Maine Resource Integration Study – Scenarios and Cost Estimates				

D. 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

[21] Available online at https://www.iso-ne.com/static-assets/documents/2017/01/cone_and_ortp_updates.pdf

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risks of cost recovery in the market, which are higher than those of a project whose revenues are contracted under a PPA.[22] The use of a WACC based on merchant rather than contracted development reflects the Base Case assumption that only merchant development will be possible because the market will not bring about the development of resources with long-term PPAs in the absence of mandated procurements such as 83D.

[22] ISO-NE CONE and ORTP Analysis. Concentric Energy Advisors. Prepared for ISO New England, January 13, 2017, p. 48.

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11.GENERATING UNIT OPERATIONAL CHARACTERISTICS

A. Thermal Units

Thermal generation characteristics are generally determined by unit 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 obtains capacity ratings for ISO-NE units from the 2017 CELT report. TCR develops Fully Loaded Heat Rates (FLHRs) data based on TCR research using historical heat rate data obtained from S&P Global. Forced outage rates are per ISO-NE publication[23], planned outage rates are from the North American Electric Reliability Corporation (NERC) Generating Availability Report. For Variable O&M costs, TCR plan to use assumptions by unit type for existing units as provided by TCR. These assumptions are consistent with modeling these units in other markets. For new unit's, assumptions are based on ISO-NE and EIA information with ISO-NE information taking preference.

Due to the large number of small generating units, TCR aggregates all units below 20 MWs by type and size 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.

Heat rate curves are modeled as a function of full load heat rate ("FLHR") by unit type:

- CT: Single block at 100% capacity at 100% of FLHR.
- CC: 4 blocks: 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR. As an example, for a 500 MW CC with a 7000 Btu/KWh FLHR, the minimum load block would be 250 MW at a heat rate of 7910, the 2nd step would be 85 MW at a heat rate of 5250, the 3rd step would be 80 MW at a heat rate of 6020, and the 4th step would be 85 MW at a heat rate of 7000.
- Steam Coal for all MW: 4 blocks: 50% capacity at 106% of FLHR, 65% capacity at 90%, 95% capacity at 95% FLHR, and 100% capacity at 100% FLHR.
- Steam Gas for all MW: 4 blocks: 25% capacity at 118% of FLHR, 50% capacity at 90%, 80% capacity at 95% FLHR, and 100% capacity at 100% FLHR.

Table 24 shows other assumptions by type for thermal plants. 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 (gas, oil, coal, refuse) and the numbers identify the size of generating units mapped to that type.

[23] https://www.iso-ne.com/static-assets/documents/genrtion_resrcs/gads/class_ave_2010.pdf

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Table 24. Thermal Unit Assumptions by Type and Size

Unit Type	Min. Up Time (h)	Min. Down Time (h)	EFORd (%)	VOM ($/MWh)	Startup Cost ($/MW-Start)
CCbg100	1	1	3.95	0	35
CCg100	6	8	3.95	2.5	35
CCg100+	6	8	3.95	2.5	35
CCgo100	6	8	3.95	2.5	35
CCgo100+	6	8	3.95	2.5	35
CCR	1	1	3.95	0	35
GTb20	1	1	8.19	0	35
GTb50	1	1	8.19	0	35
GTg20	1	1	18.38	10	0
GTg50	1	1	12.13	10	0
GTg50+	1	1	9.6	10	0
GTgo20	1	1	18.38	10	0
GTgo50	1	1	12.13	10	0
GTgo50+	1	1	9.6	10	0
GTo20	1	1	6.89	10	0
GTo50	1	1	6.89	10	0
GTo50+	1	1	18.99	10	0
IC20	1	1	6.89	10	0
IC50	1	1	6.89	10	0
IC50+	1	1	18.99	10	0
ICb20	1	1	8.19	0	35
ICg20	1	1	10.85	10	0
ICg50	1	1	10.85	10	0
ICgo20	1	1	10.85	10	0
ICgo50	1	1	10.85	10	0
ICo20	1	1	6.89	10	0
ICo50	1	1	6.89	10	0
ICr50	10	8	12.13	2	40
ICro50	10	8	12.13	2	40
IGCC	6	8	3.95	2.5	35
NUC-BWR1000MW+	164	164	3.27	0	35
NUC-BWR(900-1000MW)	164	164	1.48	0	35
NUC-BWR(800-899MW)	164	164	3.27	0	35
NUC-PWR1000MW+	164	164	1.64	0	35
NUC-PWR(900-1000MW)	164	164	1.48	0	35
NUC-PWR(800-899MW)	164	164	1.48	0	35

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Unit Type	Min. Up Time (h)	Min. Down Time (h)	EFORd (%)	VOM ($/MWh)	Startup Cost ($/MW-Start)
STb100	1	1	8.19	0	35
STbc100	1	1	8.19	0	35
STbg100	1	1	8.19	0	35
STbo100	1	1	8.19	0	35
STc100 (1-99MW)	24	12	11.25	5	45
STc250 (100-250MW)	24	12	8.41	4	45
STc600 (250-599MW)	24	12	7.91	3	45
STc600+ (600-799MW)	24	12	6.46	2	45
STg100 (1-99MW)	10	8	10.85	6	40
STg200 (100-199MW)	10	8	8.25	5	40
STgc100 (1-99MW)	10	8	10.85	6	40
STgo100 (1-99MW)	10	8	10.85	6	40
STgo200 (100-199MW)	10	8	8.25	5	40
STgo600 (200-599MW)	10	8	11.79	4	40
STgo600+ (600MW+)	10	8	11.79	3	40
STo100	10	8	6.89	6	40
STo200	10	8	18.99	5	40
STo600	10	8	5.07	4	40
STo600+	10	8	6.99	3	40
STr100	10	8	12.13	2	40
STrc100	10	8	12.13	2	40
STrg100	10	8	12.13	2	40
STro100	10	8	12.13	2	40

Source: TCR Analysis

B. **Nuclear Units**

Nuclear plants are assumed to run when available, and have minimum up and down times of roughly one week (164 hours). Capacity ratings, planned outage rates and forced outage rates are the same as those obtained from ISO-NE and the NERC Generating Availability Report. The values represent a normalized annual rate that does not directly capture the timing of refueling outages. In general, nuclear facilities are treated as must run units. Production costs were modeled using TCR input assumptions for fuel and variable O&M.

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C. **Hydro and Pumped Storage Hydro (PSH)**

Hydro units are specified as a daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Of those, TCR assumes that hydro plants use 40% of the daily energy at the same level in each hour of the day. The remaining 60% of the daily energy is optimally scheduled by ENELYTIX to minimize system-wide production costs. Daily energy is estimated using plant specific capacity factors under the assumption that hydro conditions do not vary significantly across seasons. January 2012 to December 2012, patterns are used for ISO-NE to match the year of the respective load shape.

TCR models pumped storage units using 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

D. **Wind**

TCR models onshore and offshore wind generation using hourly generation profiles. The ENELYTIX database stores wind generation profiles provided by the National Renewable Energy Laboratory (NREL) Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data[24] for both ISO-NE and NYISO. ENELYTIX uses NREL wind generation profiles based on 2012 weather data to be consistent with the 2012 load profiles described in Section 4.

TCR methodology distinguishes three groups of wind farms:

- Group 1. Existing wind farms with available historical generation data from the 2016 EIA Form 923
- Group 2. Existing wind farms with no data in the 2016 EIA Form 923 and future wind farms with rotor heights at about 80 meters;
- Group 3. Known future wind farms with rotor height at 100 meters or above, Block Island offshore wind and generic future wind farms.

TCR uses the following approach to develop 2012 hourly shapes for windfarms in each Group.

Group 1. Set target net capacity factors using historical generation data from EIA Form 923. Determine 2012 hourly shapes for NREL wind recording location nearest to the wind farm location by using NREL WIND Toolkit information to identify the NREL site with capacity factor

[24] https://www.nrel.gov/grid/wind-toolkit.html

closely approximating the target capacity factor for the wind farm. Develop hourly shapes using a TCR proprietary algorithm to modify the NREL wind location hourly shape to correspond to the target capacity factor.

Group 2. Set target net capacity factor at 27.8%, the average across Group 1. Determine 2012 hourly shapes for NREL wind recording location nearest to the wind farm location by using NREL WIND Toolkit information to identify the NREL site with capacity factor closely approximating the target capacity factor for the wind farm. Develop hourly shapes using a TCR proprietary algorithm to modify the NREL wind location hourly shape to correspond to the target capacity factor.

Group 3 – Set target net capacity factor at capacity factor for wind recording location nearest to the forecast location of the future wind farm reduced for losses using a 12.4% loss factor. Determine 2012 hourly shapes for NREL wind recording location nearest to the wind farm. Develop hourly shapes using a TCR proprietary algorithm to modify the NREL wind location hourly shape to correspond to the target capacity factor.

E. **Solar Photovoltaics**

PV generation is represented in the model using hourly generation profiles for three system sizes in each of the six states (for a total of 18 profiles). TCR develops the profiles using the NREL SAM PV Watts module and 2012 weather data files obtained from NREL. TCR selected the array types and tilt based on the system size and location to conform to typical practice in New England. The profiles are then suitable for representing utility-scale PV resources.

For distributed PV, the profiles are scaled such that their capacity factors match those implied by a comparison of nameplate capacity to energy output in the ISO-NE PV Forecast. Those capacity factors are lower in part because the energy component (but not nameplate MW) has been grossed up by ISO-NE for losses at the system level. Adjusting the distributed PV profiles in this way results in energy and nameplate capacity values that are both consistent with those in the ISO-NE forecast.

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12.FUEL PRICES

A. Natural Gas Spot Prices in New England

TCR determines the monthly spot gas price to 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 1. Table B-1 in Appendix B provides our forecast of monthly spot prices at those hubs in 2017$/MMBtu for the period January 2019 through December 2040, as well as the underlying forecast of monthly Henry Hub prices.

The projections of natural gas spot prices at each hub equals our projection of monthly Henry Hub prices plus our projection of monthly basis differential to each hub from the Henry Hub.

i. 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. We use Henry Hub 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 SNL as of June 15, 2017. The long-term forecast is the Reference Case forecast assuming no Clean Power Plan (CPP) from the Energy Information Administration (EIA) Annual Energy Outlook 2017 (AEO 2017). We use forward prices in the near-term as they reflect current market conditions. We use the AEO 2017 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 11 plots our forecast of annual Henry Hub prices as well as the AEO 2017 forecasts for four Cases - Reference Case, Reference Case with CPP, High Oil and gas resource and technology and low Oil and gas resource and technology. The TCR forecast matches the Reference Case with CPP forecast from 2022 onward.

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Figure 11. TCR and AEO 2017 projections of Henry Hub prices, nominal $

[redacted]

vi. **Spot gas prices in New England**

[redacted]

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[redacted]

Figure 12 Projections of spot prices in New England (2017$/MMBtu)

[redacted]

[redacted]

[25] ISO-NE. 2016 Economic Studies, Phase 1 Assumptions, June 16, 2016, pages 6 – 8.

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The Table also presents our estimates of average daily gas use between December and February during those two periods by gas utilities (LDCs) and electric generating units. The average daily gas use data and assumptions indicates that the issue of adequate pipeline capacity to serve generating units may primarily be a peak winter day issue, i.e., 10 to 20 days per winter, rather than an average winter day issue.

Table 25 Assumptions regarding gas pipeline capacity serving New England

Major Sources of Capacity	**Existing 2016**	**Additions 2017 / 2018**		**Projected November 2019**
	Bcf/d	addition	Bcf/d	Bcf/d
Pipelines	2018 /19			
Algonquin (ALG)	1.440	AIM + Atlantic Bridge	0.47	1.910
Tennessee (TGP)	1.320	CT	0.07	1.390
Iroquois	0.260			0.260
Portland Natural Gas (PNGTS)	0.190	C2C	0.11	0.300
M&N Pipeline	0.833			0.833
Distrigas to Mystic units	0.300			0.300
Total in bound contracted capacity	4.34			4.99
Projected Average daily demand Dec - Feb				
LDCs				2.52
Electric Generating units				1.18
Total				3.70

TCR's assumption regarding the availability of adequate gas pipeline capacity to serve gas-fired units during winter months, and in particular on peak winter days, over the study period is informed by the following facts. We note that the 2020/2021 FCA has cleared and the capacity that cleared in that FCA is sufficient to replace the Brayton Point retirement. In addition, that capacity is required to be able to meet the new ISO NE performance requirements, as they face financial penalties for non-performance. We also note that our load forecasts indicate that from 2021/ 2022 onward the need for capacity additions will not be driven by load growth but instead will be driven primarily by economic retirement of older existing units and by the impact of the Massachusetts cap on carbon emissions. Finally, we are assuming that new fossil additions will be dual-fuel.

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B. **Prices of distillate and residual fuel oil for electric generation in New England.**

Table B-2 in Appendix B provides the 83D Base Case projections of distillate and residual to electric generators in New England from 2020 to 2040. These projections are drawn from AEO 2017 and expressed in 2017$.

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13.EMISSION RATES AND ALLOWANCES

A. Emission Rates

Emission rates for NOx and SO2 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.[26] For existing units for which no emission rates were reported, emission rate by fuel type from EIA are used.[27] CO2 emission rates by fuel type are taken from EPA's "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems".[28]

A. Greenhouse Gas Emission Allowance Prices

TCR developed its CO2 allowance price assumptions based upon a review of projections RGGI prepared as part of its 2016 Program Review and of the assumptions in ISO New England's 2016 Economic Study and 2017 Economic Study. [29]

RGGI, as part of its 2016 Program Review, commissioned a number of policy scenarios ("PS") which differ by the amounts of annual decline in the RGGI CO2 cap from 2021 to 2030 (2.5% to 3.5%), by the initial cap reduction in 2019, and by an additional banking adjustment from 2021-2025. For those PS RGGI also ran studies to test the sensitivity of their 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 their PS and associated sensitivity studies projected CO2 price values for six representative years over the period 2017-2031, as documented in RGGI Program Review meeting materials.[30]

Table 26 below summarizes the assumptions underlying RGGI policy scenarios 2 and 3.

[26] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

[27] https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

[28] https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

[29] 2017 Economic Study, presentation to ISO-NE Planning Advisory Committee, February 14, 2018 (https://www.iso-ne.com/static-assets/documents/2018/02/a3_2017_economic_study.pdf) and 2016 Economic Study: Carbon Allowance Cost Sensitivity Draft Results presentation to Planning Advisory Committee, April 19, 2017 (https://www.iso-ne.com/static-assets/documents/2017/04/a6_2016_economic_study_carbon_cost_.pdf).

[30] "Draft 2017 Policy Scenario Overview," prepared for RGGI by ICF International, June 27, 2017. Numeric values for CO2 prices taken from DRAFT_Results_PS2_NoNP.xlsx and DRAFT_Results_PS3_NP.xlsx. Available at http://rggi.org/design/2016-program-review/rggi-meetings.

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Table 26. Assumptions in RGGI Policy Scenarios 2 and 3.

Assumption	**No NP PS#2**	**NP PS#3**
RGGI Base Cap	No initial reduction; 3.5% annual decline 2021-2030	Reduction of 6.5% in 2019; decline of 3.0% annually from 2021-2030
Banking Adjustment	25 million short tons, 2021-2025	
National Program	None	States outside of RGGI subject to mass-based goals covering existing and new sources
Gas Prices (2017-2031 Avg., 2015$/MMBtu)	Average of AEO 2017 Reference Case and High Resource Case ($3.84)	
Nuclear Retirements	Pilgrim retires in 2019; Indian Point retires in 2020/2021	
Transmission	Includes 1,050 MW line from Canada to New England, 2022	
Renewable Costs	NREL 2016 Base Case	

Figure 13 plots curve fits of all RGGI projections for policy scenarios 2 and 3, along with the 2030 value assumed in the main scenarios of ISO New England's 2016 Economic Study and 2017 Economic Study.

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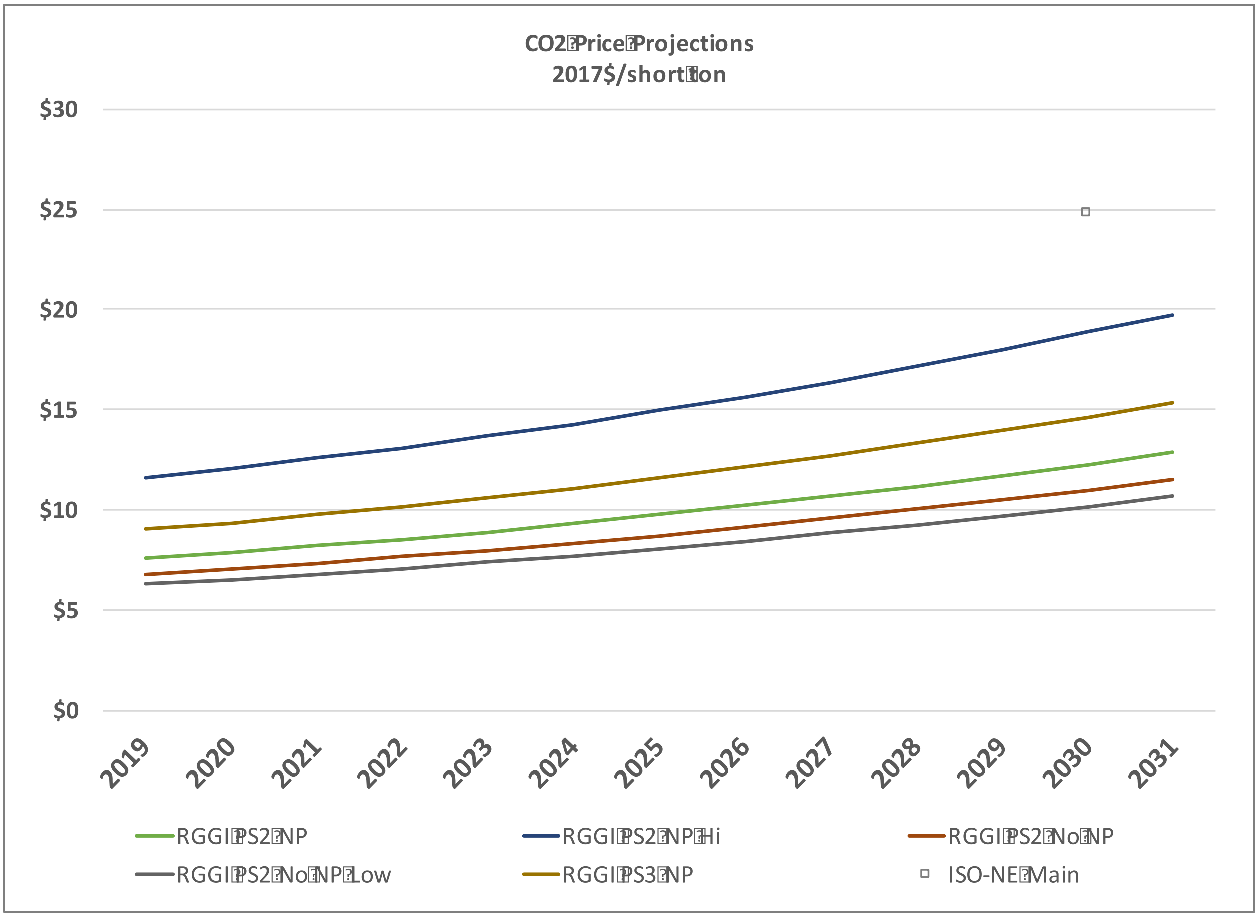
Figure 13. RGGI and ISO-NE CO2 Allowance Price Projections as of August 1, 2017



TCR, based upon its review of the RGGI and ISO-NE scenarios, developed the Base Case CO2 allowance price assumptions using 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 "NP PS#3" scenario by 2031, and continuing along the same curve to 2040. Table 27 presents the Base Case CO2 allowance price assumptions.

Table 27. Base Case CO2 Allowance Price Assumptions (2017$/short ton)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
7.01	$7.43	$7.89	$8.41	$8.98	$9.59	$10.26	$10.98	$11.75	$12.57	$13.43
2030	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
$14.35	$15.32	$16.34	$17.41	$18.53	$19.70	$20.92	$22.18	$23.50	$24.87	$26.29

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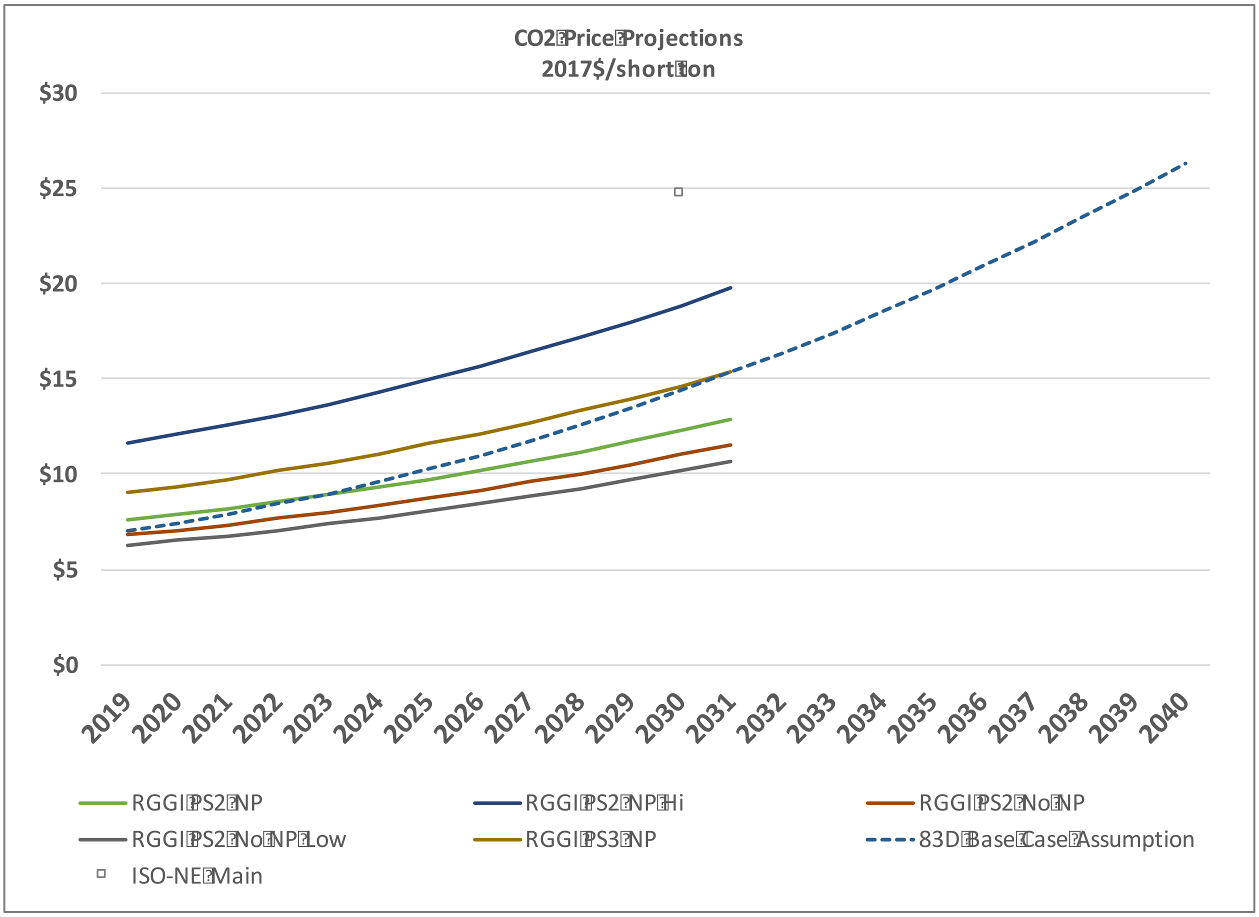
Figure 14 plots the Base Case price assumptions as well as all RGGI projections for policy scenarios 2 and 3 and the 2030 value assumed in the main scenarios of ISO New England's 2016 Economic Study and 2017 Economic Study.

Figure 14. 83D Base Case Assumptions relative to RGGI and ISO-NE CO2 Allowance Price Projections as of August 1, 2017



The Massachusetts Executive Office of Energy and Environmental Affairs and Department of Environmental Protection released a report on August 21, 2017 which provides a projected trajectory of RGGI CO2 prices and an alternative trajectory for sensitivity purposes.[31] On August 23, 2017, RGGI announced proposed rules for 2020 to 2030, which would then go to each of the RGGI states for approval. RGGI's proposed rules included a proposed cap, an Emissions Containment Reserve (ECR) which acts similar to a price floor, and a Cost Containment Reserve (CCR) which acts similar to a price ceiling. Figure 15, which includes the ECR, CCR, and the two Synapse price trajectories (Main and Alt RGGI), indicates that the CO2 allowance price assumptions in the Base Case are consistent with expectations of increasing allowance prices over time.

[31] "Analysis of Massachusetts Electricity Sector Regulations: Electricity Bill and CO2 Emissions Impacts," Synapse Energy Economics, Sustainable Energy Advantage, and ERG, August 2017 (http://www.mass.gov/eea/docs/dep/air/climate/3dapp-study.pdf)

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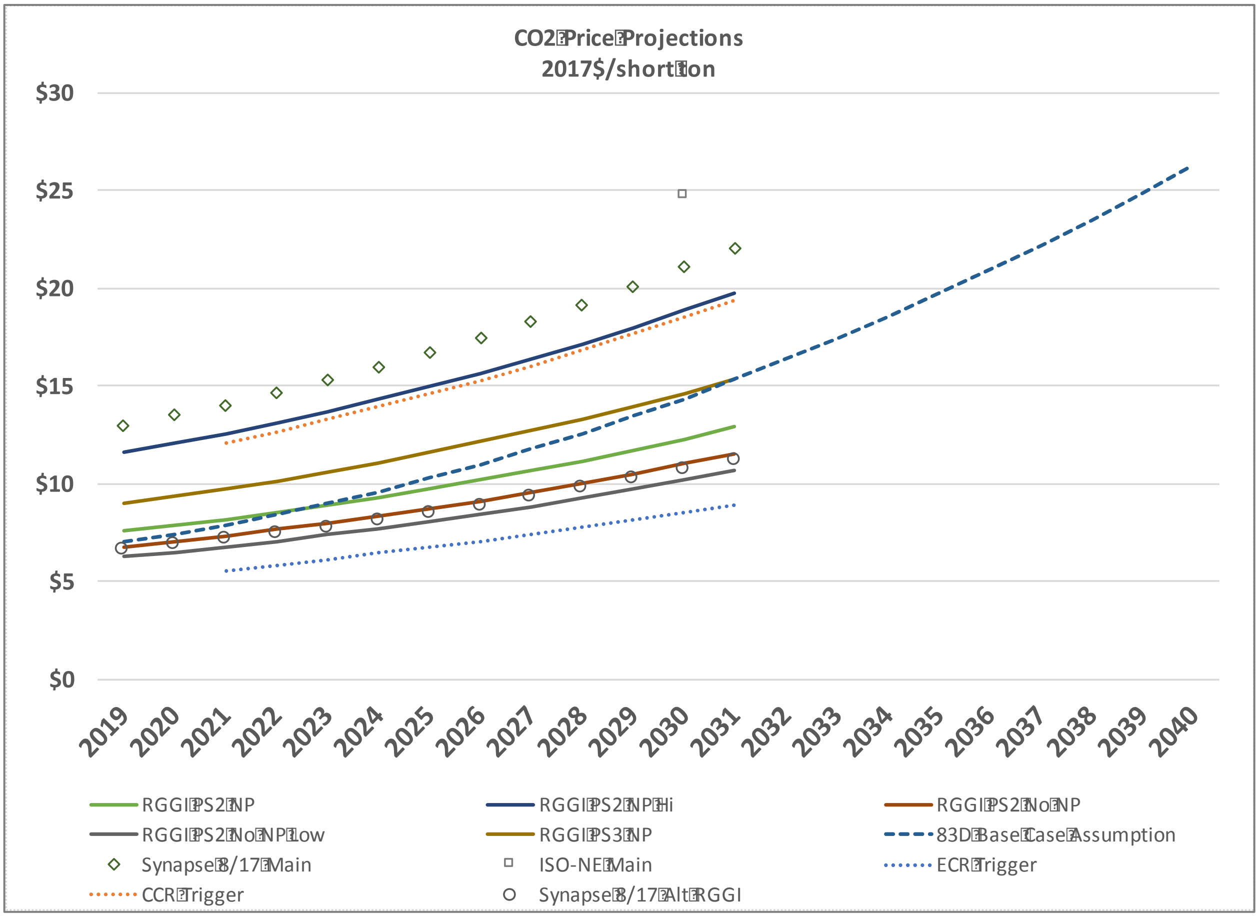
Figure 15. 83D Base Case Assumptions relative to RGGI, ISO-NE and Synapse CO2 Allowance Price Projections as of August 28, 2017



B. **NOx and SO2**

TCR proposes allowance prices of zero for NOx and SO2 emission. The Federal Cross State Air Pollution Rule (CSAPR) establishes NOx and SO2 emission limits, and no New England state has emission limits under CSAPR. Therefore, CSAPR allowance prices are not applicable to New England generators.

SO2. With the retirement of Brayton Point, SO2 emissions in New England have dropped to levels near zero and correspondingly we assume zero value to SO2 allowances.

NOx. 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 NOx 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 NOx budget is 1,799 tons. Given that NOx 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 NOx 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 NOx Emission Trading and Agreement Orders (TAOs) to comply with the NOx 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 NOx 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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14.INTERCHANGE DATA

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
    - Norwalk to Northport Cable (NNC) AC interface with NYISO
- Quebec interchanges, hourly schedules from 2012 because the values that year are representative of the 2014 to 2016 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 2016

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.

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APPENDIX A

This Appendix describes the computer model and analytical capability TCR uses to support the evaluation of 83C and 83D Proposed Clean Energy Projects.

ENELYTIX® and Power System Optimizer (PSO)

ENELYTIX®[32] 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.

[32] ENELYTIX® is a registered trademark of Newton Energy Group, LLC.

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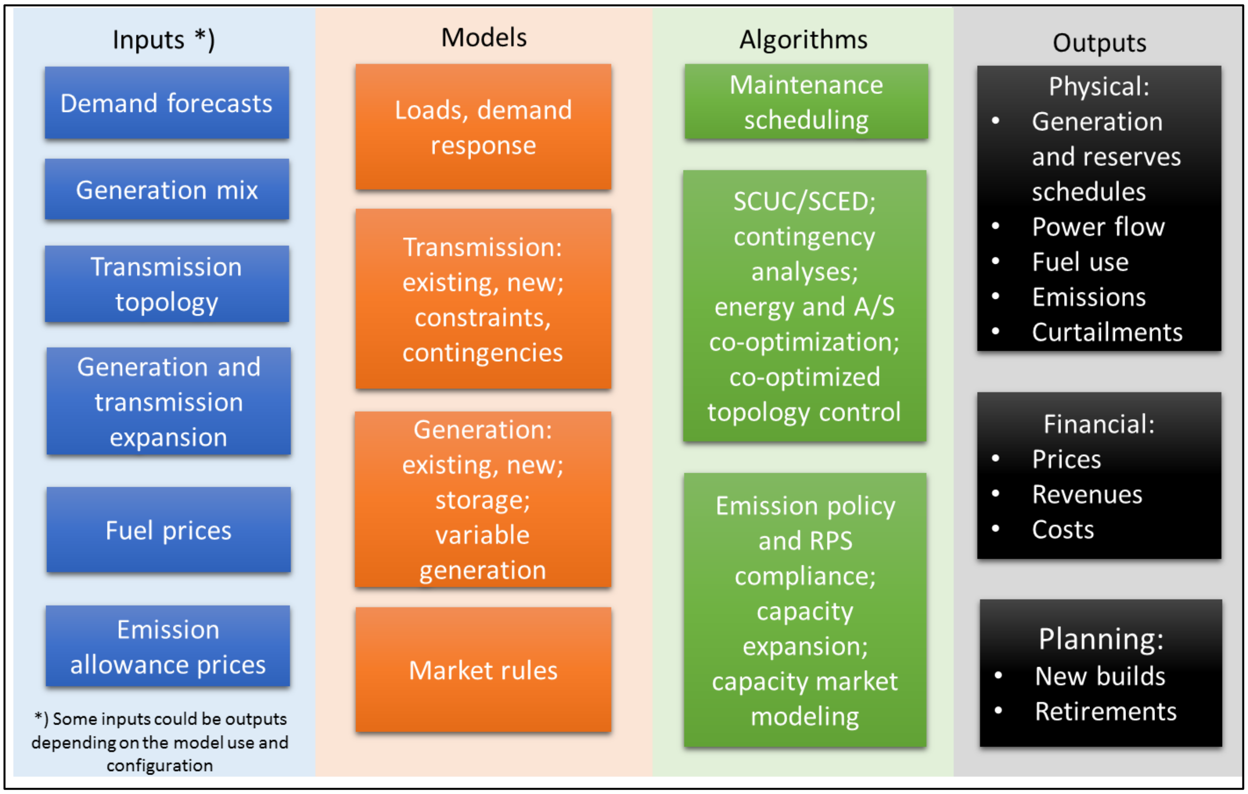
Figure A - 1. Analytical Structure of PSO



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.

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

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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 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.

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).

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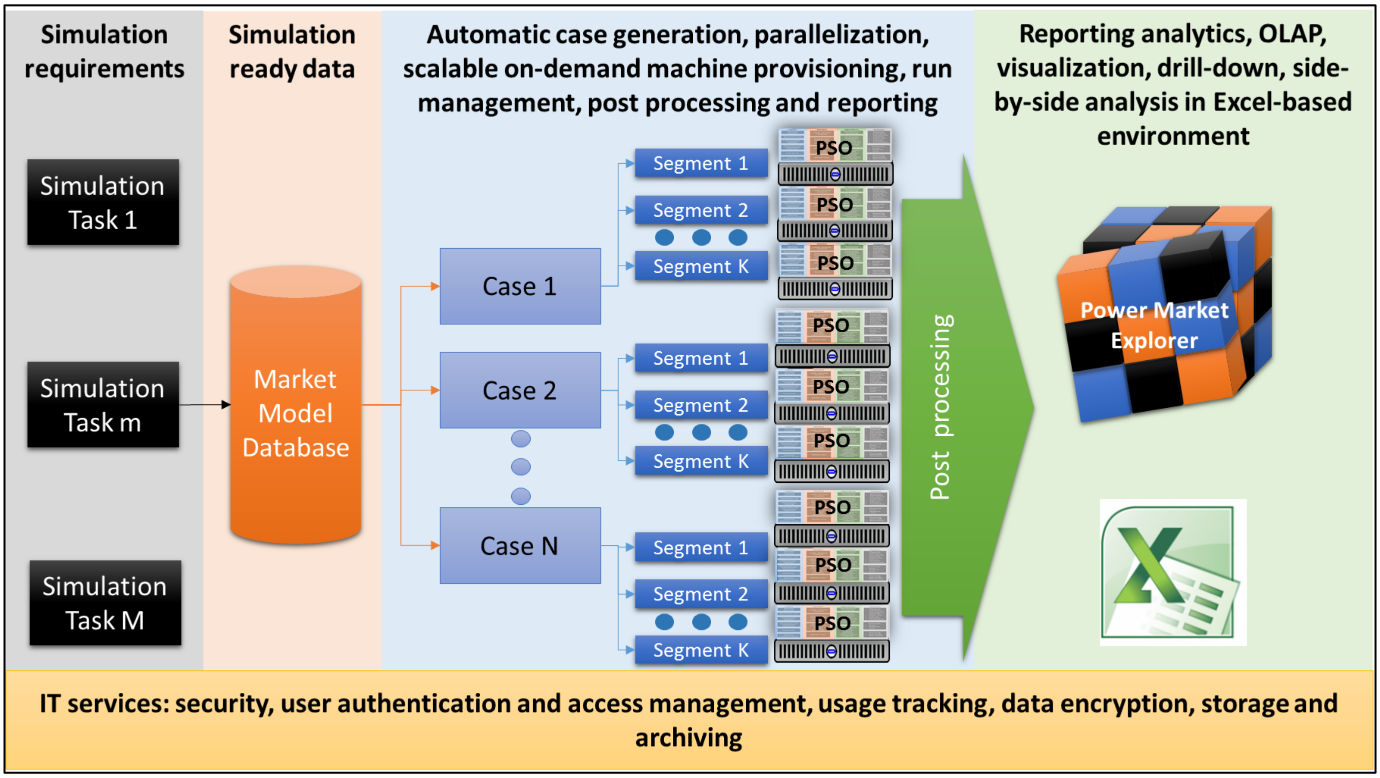
Figure A-2. Schematic of ENELYTIX Architecture



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

Table B-1 Monthly Spot Gas Prices

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TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New England gas prices

Spot Gas Prices, 2017$ / MMBtu

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APPENDIX B

Table B-2 Distillate and Residual Prices

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83 D Base Case
Distillate and Residual Prices to Electric Power Plants (2017$/MMBtu)

	New England (1)		New York (2)	
Year	Distillate	Residual	Distillate	Residual
	2017$ /MMbtu	2017$ /MMbtu	2017$ /MMbtu	2017$ /MMbtu
2017	$ 14.46	$ 10.36	$ 14.57	$ 10.44
2018	$ 16.10	$ 11.49	$ 16.93	$ 11.37
2019	$ 16.94	$ 11.95	$ 18.50	$ 11.62
2020	$ 17.18	$ 12.04	$ 19.45	$ 11.51
2021	$ 17.31	$ 11.97	$ 20.29	$ 11.22
2022	$ 17.32	$ 11.77	$ 21.03	$ 10.83
2023	$ 17.66	$ 12.15	$ 21.37	$ 11.20
2024	$ 17.99	$ 12.44	$ 21.69	$ 11.49
2025	$ 18.48	$ 12.84	$ 22.18	$ 11.90
2026	$ 18.85	$ 13.18	$ 22.56	$ 12.23
2027	$ 19.05	$ 13.31	$ 22.76	$ 12.36
2028	$ 19.10	$ 13.37	$ 22.80	$ 12.42
2029	$ 19.32	$ 13.62	$ 23.02	$ 12.67
2030	$ 19.79	$ 13.95	$ 23.49	$ 13.01
2031	$ 20.21	$ 14.29	$ 23.91	$ 13.34
2032	$ 20.71	$ 14.66	$ 24.41	$ 13.72
2033	$ 20.63	$ 14.65	$ 24.33	$ 13.70
2034	$ 20.94	$ 14.92	$ 24.64	$ 13.97
2035	$ 21.16	$ 15.05	$ 24.86	$ 14.11
2036	$ 21.70	$ 15.48	$ 25.40	$ 14.54
2037	$ 21.78	$ 15.57	$ 25.48	$ 14.62
2038	$ 21.95	$ 15.67	$ 25.65	$ 14.72
2039	$ 22.32	$ 15.88	$ 26.03	$ 14.93
2040	$ 22.53	$ 16.05	$ 26.23	$ 15.10
2041	$ 22.57	$ 16.23	$ 26.27	$ 15.28
2042	$ 22.62	$ 16.18	$ 26.33	$ 15.24
2043	$ 22.69	$ 16.23	$ 26.39	$ 15.28
2044	$ 22.79	$ 16.31	$ 26.49	$ 15.36
2045	$ 22.88	$ 16.40	$ 26.58	$ 15.45
2046	$ 23.05	$ 16.55	$ 26.76	$ 15.60
2047	$ 23.40	$ 16.76	$ 27.11	$ 15.82
2048	$ 23.42	$ 16.80	$ 27.13	$ 15.85
2049	$ 23.61	$ 16.96	$ 27.32	$ 16.01
2050	$ 23.90	$ 17.17	$ 27.60	$ 16.23

Sources/ Notes

1 AEO 2017 Energy Prices to Electric Power , 2016$, Reference case
2 AEO 2017 Energy Prices to Electric Power , 2016$, Reference case
3 inflator from 2016$ to 2017$ 1.018

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BASE CASE FOR EVALUATION OF 83D PROPOSALS -

INPUT AND MODELING ASSUMPTIONS

NEW YORK

Tabors Caramanis Rudkevich
75 Park Plaza, Fourth Floor, Boston MA 02116

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DISCLAIMER

Tabors Caramanis Rudkevich, INC (TCR) has been contracted by the Massachusetts Electric Distribution Companies (EDCs), Eversource, National Grid and Utilicorp to provide the quantitative analyses that will allow the EDCs to evaluate the proposals that they receive in response to the 83D and 83C 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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Acronyms

Acronym	Meaning
CC	Combined Cycle
GT	Combustion/Gas Turbine
HD	Hydro Power
NG	Natural Gas
PS	Pumped Storage Unit
PV	Photovoltaic
ST	Steam Turbine
WT	Wind Turbine
SUN	Solar
WAT	Water
WND	Wind
BIO	Biomass

1. BASE CASE FOR EVALUATION OF 83D PROPOSALS – NEW YORK ASSUMPTIONS

This document describes the modeling and input assumptions specific to New York that the TCR team propose for the Base Case against which the Massachusetts electric distribution companies ("EDCs") will measure the incremental costs and benefits of each Proposal received in response to the 83D RFP. TCR refers to this as the "83D Base Case".

The complementary document "Base Case Evaluation of 83D Proposals – Input and Modeling Assumptions New England" describes all 83D Base Case modeling and input assumptions that are common to both New York and New England.

2. MODELING ENVIRONMENT

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.

3. TRANSMISSION

The physical location of all network resources is organized using substation and node mapping. The 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 were mapped to bus bars/electrical nodes (eNodes). Bus bars were mapped to substations and substations were in turn mapped to NYISO Zones. In ENELYTIX, eNodes were modeled as children of bus bars and bus bars are synonymous with buses in the powerflow model. The mapping of bus bars to Zones allowed ENELYTIX to allocate area load forecasts to load buses in proportion to the initial state from the powerflow. The use of both bus bars and eNodes allows users to distinguish between electrical and physical connections. This is useful in that it allows tracking of power-flow values of different injectors to the same bus. The powerflow model was solved to develop an initial state for injections and flows. While the topology for NYISO will be modeled on the MMWG 2017 case from the 2015 FERC 715 powerflow filing, TCR will add the following transmission upgrades: A new substation (North Rockland) will be added between the existing Buchanan South and Laden Town Substations. While the BUCHANAN S-NORTHRCKLD-1 and LADENTWN-NORTHRCKLD-1 will have been adequately represented because they are radial lines and mirror the BUCHANAN S-LADENTWN-1 line, there is a new 345/138 KV transformer between North Rockland and Lovet. To represent this, TCR intend to replace the single BUCHANAN S-LADENTWN-1 line with the new

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BUCHANAN S-NORTHRCKLD-1 and LADENTWN-NORTHRCKLD-1 lines so that the NORTHRCKLD-LOVET138-1 transformer can be included. Table 1 summarizes TCR's transmission adjustments.

Table 1. : Transmission upgrades to NYISO

BRANCH NAME	BRANCH NUMBER	FROM ENODE	TO ENODE	CIRCUIT	VOLTAGE	BASE MW
BUCHANAN S-NORTHRCKLD-1	126263-146874-1	126263	146874	1	345	-1005.1
LADENTWN-NORTHRCKLD-1	126290-146874-1	126290	146874	1	345	1084.7
NORTHRCKLD-LOVET138-1	146874-146766-1	146874	146766	1	345	77.4
WATRC345-WATRC230-2	130757-130768-2	130757	130768	2	345	114.2

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.[1] Table 2 shows the Interface limits applied.

Table 2: Interface limits

Constraint Name	Summer Max (MW)	Summer Min (MW)	Winter Max (MW)	Winter Min (MW)
DYSINGER-EAST	1740	-9999	1740	-9999
WEST-CENTRAL	400	-9999	400	-9999
MOSES-SOUTH	2350	-9999	2350	-9999
CENTRAL-EAST	2350	-9999	2350	-9999
TOTAL-EAST	4850	-9999	4850	-9999
UPNY-CONED	4950	-9999	4950	-9999
DNWDIE-SOUTH-Pl	5625	-9999	5625	-9999

[1] Table 2.3.1, 2015 Comprehensive Area Transmission Review Of the New York State Bulk Power Transmission System (Study Year 2020). NYISO, 01 June 2016. <http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp>

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4. LOAD FORECAST

A. **Annual energy and peak load**

Table 3 and Table 4 summarize the forecasts of annual energy and peak load by NYISO load zones for 2020 through 2050. 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 are coincidental "50/50" forecasts, which mean that the zonal peaks reflect the demand at the time of system peak instead of zonal peak and the value of the forecast is the median of the distribution of energy demand based on different weather scenarios.

The forecasts of annual energy and peak demand for 2020 through 2027 are from the New York 2017 Gold Book[2] (2017 Gold Book), the most recent available version. TCR assumes the demand would be constant after 2027.

[2] NYISO: 2017 Load and Capacity Report

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Table 3. 50/50 Annual Energy by NYISO zone (GWh)

Zone	2020	2021	2022	2023	2024	2025	2026	2027	2028-2050
A	15,461	15,432	15,425	15,419	15,411	15,406	15,406	15,406	15,406
B	9,712	9,687	9,664	9,643	9,626	9,614	9,606	9,601	9,601
C	16,023	16,006	15,990	15,979	15,968	15,961	15,954	15,946	15,946
D	4,498	4,497	4,493	4,488	4,482	4,474	4,471	4,467	4,467
E	7,843	7,833	7,824	7,824	7,824	7,824	7,824	7,824	7,824
F	12,395	12,427	12,454	12,478	12,499	12,515	12,527	12,535	12,535
G	9,611	9,575	9,554	9,537	9,530	9,521	9,518	9,517	9,517
H	2,783	2,768	2,761	2,755	2,751	2,748	2,746	2,744	2,744
I	5,966	5,933	5,918	5,906	5,897	5,890	5,886	5,882	5,882
J	52,029	51,344	51,079	50,903	50,772	50,690	50,651	50,612	50,612
K	20,431	20,353	20,282	20,366	20,375	20,366	20,331	20,437	20,437
Total	156,752	155,855	155,444	155,298	155,135	155,009	154,920	154,971	154,971

Table 4. 50/50 Coincident Summer peak by NYISO zone (MW)

Zone	2020	2021	2022	2023	2024	2025	2026	2027	2028-2050
A	2,659	2,661	2,663	2,665	2,666	2,667	2,668	2,669	2,669
B	2,009	2,013	2,017	2,021	2,026	2,028	2,029	2,032	2,032
C	2,862	2,865	2,868	2,870	2,874	2,875	2,877	2,879	2,879
D	509	509	509	510	510	510	510	510	510
E	1,421	1,422	1,423	1,424	1,426	1,426	1,427	1,428	1,428
F	2,406	2,407	2,408	2,409	2,410	2,410	2,410	2,410	2,410
G	2,180	2,169	2,157	2,151	2,145	2,140	2,136	2,132	2,132
H	648	643	643	645	646	648	649	651	651
I	1,473	1,465	1,468	1,471	1,476	1,482	1,491	1,495	1,495
J	11,693	11,724	11,742	11,773	11,808	11,862	11,930	11,965	11,965
K	5,133	5,131	5,136	5,157	5,165	5,184	5,197	5,227	5,227
Total	32,993	33,009	33,034	33,096	33,152	33,232	33,324	33,398	33,398

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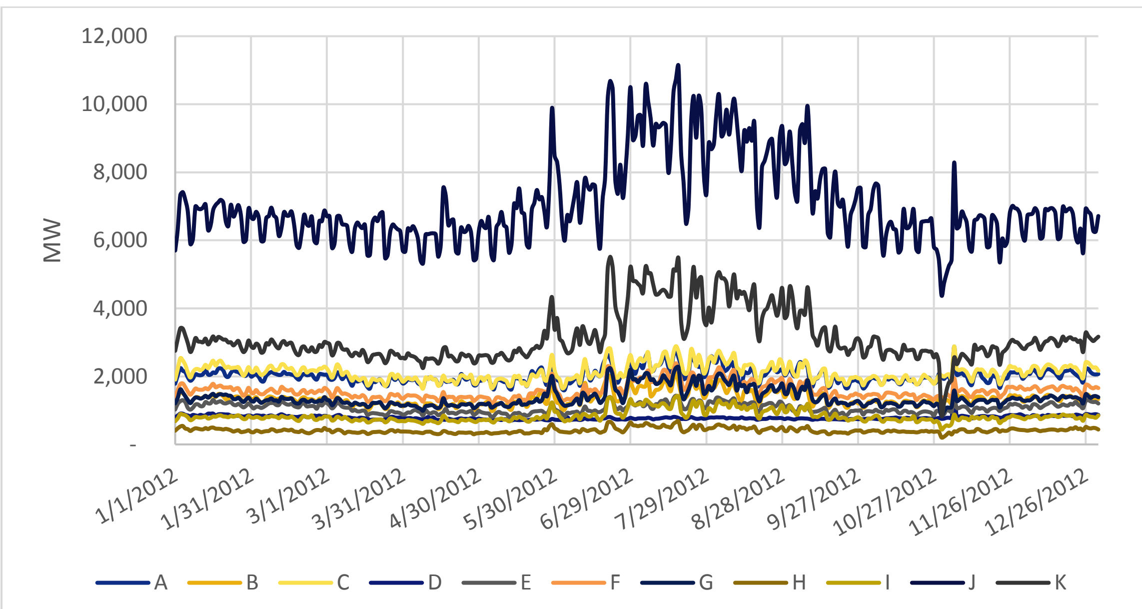
B. **Hourly Load Shape**

TCR needs an hourly load shape for each simulated time frame and area modeled to simulate the New York energy market on an hourly basis. TCR constructed load shapes for each area from the following data:

- 2012 historical load shapes by NYISO zone
- Annual energy and summer/winter peak forecasts for the study period

TCR uses 2012 historical load shapes by Zone as template load profiles in order to be consistent with the 2012 wind generation patterns provided by the National Renewable Energy Laboratory (NREL), the most recent year for which NREL provides those patterns. Figure 1 plots those load shapes.

Figure 1 NYISO 2012 Load Shapes



The first step in the process is to shift the template load profiles to align days of the week between Feb-2011 and Jan-2012 which served as the template year for NYISO-2021-2022. TCR then used the above data to modify hourly load profiles in such a manner that the resulting load profiles exhibited the hourly pattern close to that of the historical load profiles while the total energy and peak matched the energy

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and peak forecasts for each month. TCR obtained historical hourly load profiles by Area for the period January 1, 2012 through January 1, 2012 from the NYISO website.[3]

5. OPERATING RESERVES

Following NYISO's structure of ancillary services, TCR models 3 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 5 summarizes reserve requirements in NYISO.

Table 5: New York ISO reserve requirements[4]

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

6. INSTALLED CAPACITY REQUIREMENT

TCR's assessment of NYISO capacity balance, i.e., projected load compared to existing capacity plus confirmed generation additions and retirements, indicates no need for generic capacity additions. Existing capacity plus confirmed generation additions are sufficient to meet resource adequacy requirements in NYISO over the modeling horizon. (Note that TCR assumes zero demand growth beyond year 2026 for the purpose of this study).

[3] NYISO Load Data release.
<http://www.nyiso.com/public/markets_operations/market_data/load_data/index.jsp>
[4] http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

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7. RENEWABLE PORTFOLIO STANDARD (RPS) REQUIREMENTS

In this project, TCR does not model RPS programs in New York.

8. GENERATING UNIT RETIREMENTS

Table 6 summarizes generation units scheduled to be retired as of 2020 and beyond from the 2017 Gold Book.[5]

Table 6. NYISO approved capacity retirements

Name	Unit Type	Fuel Type	Capacity (MW)	Retire Date	Zone
Cayuga1	STc250	Coal	151.6	7/1/2017	C
Cayuga2	STc250	Coal	158.9	7/1/2017	C
Shoreham GT3	STb100	Biomass	47.4	8/13/2017	K
Shoreham GT3	STb100	Biomass	15.7	8/13/2017	K
Freeport CT1	GTgo50+	NG	47.5	10/31/2017	K
Indian Pt. 2[6]	NUC-PWR+	Nuclear	1026.5	4/1/2020	H
Indian Pt. 3[7]	NUC-PWR+	Nuclear	1040.2	4/1/2021	H

9. GENERATING UNIT CAPACITY ADDITIONS

TCR will use the existing generating units listed in Table III-2 of the 2017 NYISO Gold book.

A. Capacity Additions in NYISO interconnection queue

Table 7 lists known near-term new generation additions. These are projects listed in Table IV-1 of the 2017 NYISO Gold book and are projects that have entered the class year 2017 or are projects that are potential candidates for a Class Year Study after Class Year 2017, i.e., Large Generating Facilities with Operating Committee approved System Reliability Impact Studies and Small Generating Facilities that have completed a comparable milestone and for which non-Local System Upgrade Facilities are required.

ww.nyiso.com/public/.../2017_Load_and_Capacity_Data_Report.pdf

[6] https://www.nytimes.com/2017/01/09/nyregion/cuomo-indian-point-nuclear-plant.html

[7] https://www.nytimes.com/2017/01/09/nyregion/cuomo-indian-point-nuclear-plant.html

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Table 7. Generation Capacity Additions

Name	Unit Type	Fuel Type	Summer Capacity (MW)	Winter Capacity (MW)	In-service Date	Energy Area
CPV Valley CC	CCg100+	NG	677	690	2/1/2018	G
Cricket Valley CC1	CCg100+	NG	356.5	356.5	1/1/2020	G
Cricket Valley CC2	CCg100+	NG	356.5	356.5	1/1/2020	G
Cricket Valley CC3	CCg100+	NG	356.5	356.5	1/1/2020	G
Black Oak Wind	Wind	Wind	16.1	16.1	12/1/2017	C
Roaring Brook Wind	Wind	Wind	78	78	12/1/2017	A
Shoreham PV	PV	PV	25	25	12/1/2017	K

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10. GENERATING UNIT OPERATIONAL CHARACTERISTICS

A. **Thermal Units**

Thermal generation characteristics are generally determined by unit 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.

Capacity ratings in the ENELYTIX database were obtained from S&P Global. For generator outage and heat rate data TCR uses 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. For variable O&M costs, TCR uses assumptions by unit type for existing and planned units that are consistent with their modeling of these units in other markets.

Due to the large number of small generating units, TCR aggregates all units below 20 MWs by type and size 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.

Heat rate curves are modeled as a function of full load heat rate ("FLHR") by unit type:

- CT: Single block at 100% capacity at 100% of FLHR.
- CC: 4 blocks: 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR. As an example, for a 500 MW CC with a 7000 Btu/KWh FLHR, the minimum load block would be 250 MW at a heat rate of 7910, the 2nd step would be 85 MW at a heat rate of 5250, the 3rd step would be 80 MW at a heat rate of 6020, and the 4th step would be 85 MW at a heat rate of 7000.
- Steam Coal for all MW: 4 blocks: 50% capacity at 106% of FLHR, 65% capacity at 90%, 95% capacity at 95% FLHR, and 100% capacity at 100% FLHR.
- Steam Gas for all MW: 4 blocks: 25% capacity at 118% of FLHR, 50% capacity at 90%, 80% capacity at 95% FLHR, and 100% capacity at 100% FLHR.

Table 8 shows other assumptions by type for thermal plants. 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, **r**efuse) and the numbers identify the size of generating units mapped to that type.

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Table 8. Thermal Unit Assumptions by Type and Size

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd	VOM ($/MWh)	Startup Cost ($/MW-start)	Startup Failure Rate
CCg100	6	8	4.35	2.5	35	0.01
CTb50 (1-19MW)	1	1	19.73	0	35	0.06
CTb50 (20-49MW)	1	1	10.56	0	35	0.03
CTg50 (1-19MW)	1	1	19.73	10	0	0.06
CTg50 (20-49MW)	1	1	10.56	10	0	0.03
CTg50+	1	1	7.25	10	0	0.02
ICr50 (0-50MW)	10	8	19.73	2	40	0.06
NUC-PWR (400-799MW)	164	164	2.58	0	35	0
NUC-BWR (400-799MW)	164	164	3.24	0	35	0.02
NUC-PWR (800-999MW)	164	164	4.34	0	35	0.01
NUC-BWR (800-999MW)	164	164	1.8	0	35	0.05
NUC-PWR (1000+MW)	164	164	2.88	0	35	0.004
NUC-BWR (1000+MW)	164	164	2.82	0	35	0.025
STc100 (0-100MW)	24	12	10.64	5	45	0.02
STc200 (100-199MW)	24	12	6.3	4	45	0.03
STc300 (200-299MW)	24	12	7.1	4	45	0.03
STc400 (300-399MW)	24	12	6.85	3	45	0.04
STc600 (400-599MW)	24	12	7.82	3	45	0.06
STc800 (600-799MW)	24	12	6.71	2	45	0.03
STc1000 (800-999MW)	24	12	4.65	2	45	0.04
STc1000+ (1000+MW)	24	12	8.62	2	45	0.06
STg100 (0-100MW)	10	8	12.55	6	40	0.009
STg200+ (100-200MW)	10	8	7.28	5	40	0.01
STgo300 (200-299MW)	10	8	6.67	4	40	0.02
STgo400 (300-399MW)	10	8	5.41	4	40	0.02
STgo500 (400-599MW)	10	8	9.06	4	40	0.03
STgo600 (600-799MW)	10	8	9.48	3	40	0.05
STgo600+	10	8	1.93	3	40	0.02
STo100 (1-99MW)	10	8	3.54	6	40	0.006
STo200 (0-200MW)	10	8	5.6	5	40	0.02
STo600 (200-299MW)	10	8	10.59	4	40	0.02
STo600 (300-399MW)	10	8	4.53	4	40	0.02
STo600 (400-599MW)	10	8	4.45	4	40	0.01
STo600+ (600-799MW)	10	8	41.26	3	40	0.03
STo600+ (800-999MW)	10	8	14.36	3	40	0.09
STr	10	8	10.26	2	40	0.02

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Source: TCR Analysis

B. **Nuclear Units**

Nuclear plants are assumed to run when available, and have minimum up and down times of approximately one week (164 hours). Capacity ratings, planned outage rates and forced outage rates are the same as those obtained from the NERC Generating Availability Report. The values represent a normalized annual rate that does not directly capture the timing of refueling outages. In general, nuclear facilities are treated as must run units. Production costs were modeled using TCR input assumptions for fuel and variable O&M.

Table 9 lists nuclear units by area with their summer and winter capacity.

Table 9: Nuclear Units by area and capacity.

Name	Area	Summer Capacity (MW)	Winter Capacity (MW)
Fitzpatrick1	C	881.8	851.1
IndianPt2 (retires 4/2020)	H	1024.5	1031.3
IndianPt3 (retires 4/2021)	H	1044.2	1044.3
NineMilePt 1	C	637.1	636.4
NineMilePt 2	C	1287.2	1287.2
Ginna	B	581.5	582.1

C. **Hydro and Pumped Storage**

Hydro units are specified as a daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Of those, TCR will assume that hydro plants used 40% of the daily energy at the same level in each hour of the day. The remaining 60% of the daily energy is optimally scheduled by ENELYTIX to minimize system-wide production costs. Daily energy will be estimated using plant specific capacity factors under the assumption that hydro conditions do not vary significantly across seasons. Patterns for January 2012 to December 2012 are used for ISO-NE to match the year of the respective load shape.

Pumped Storage units are modeled 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

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D. **Wind**

Wind generation is represented in the model using hourly generation profiles assembled by ENELYTIX. The ENELYTIX database stores wind generation profiles provided by the National Renewable Energy Laboratory (NREL) Wind Integration National Dataset (WIND) Toolkit dataset based on 2012 weather data for both ISO-Ne and NYISO.[8] Each wind site in NYISO is mapped to the nearest NREL wind site to obtain the appropriate hourly schedule. The resulting 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.

E. **Solar Photovoltaics**

TCR assumed all existing and potential PV additions as fixed array type installations. Location specific profiles from NREL's PVWatts® Calculator[9] which estimates the energy production of grid-connected solar installations   profiles based on the following assumptions:

• 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

PV generation is represented in the model using hourly generation profiles developed using the NREL SAM PV Watts module, with weather data files obtained from NREL.

F. **Biomass**

TCR models biomass as dispatchable generation subject to generation technology parameters and fuel.

11. FUEL PRICES

A. **Natural Gas spot prices in New York**

TCR determines the monthly spot gas price to each gas-fired unit in New York based upon the spot prices at the market hub which serves the unit. The relevant hubs for New York are Niagara, Iroquois Waddington, Iroquois Zone 1, Iroquois Zone 2 and Transco Zone 6 NY.

[8] https://www.nrel.gov/grid/wind-toolkit.html

[9] http://pvwatts.nrel.gov/pvwatts.php

Table 14 in Appendix A provides our forecast of monthly spot prices at those hubs in 2017$/MMBtu for the period January 2020 through December 2040, as well as the underlying forecast of monthly Henry Hub prices.

TCR developed those projections using the methodology described in the New England document.

B. Prices of Distillate and residual fuel oil for electric generation in New York

Appendix A in the New England document provides our forecast of distillate and residual to electric generators in New England and New York from 2020 to 2040. TCR developed those projections using the methodology described in the New England document.

C. Coal Prices

Coal prices were obtained by dividing the cost of coal delivered yearly in $/ton by the coal burned heat content in Btu/lb to get $/Btu value. TCR obtained 2015-2017 coal price data by plant from SNL Financial Services and converted them to 2017 $/MMBtu. TCR assumes the prices reported in Table 10 will remain at those levels over the study period.

Table 10: 2015 Coal prices in Nominal $/MMBtu

Name	Area	Price ($/MMBtu)
Dunkirk	A	1.78
Fort Drum	E	2.23
Somerset	A	2.62

D. Uranium

TCR will develop uranium prices using the pricing calculator created by the Bulletin of the Atomic Scientist[10]. The calculator estimates the cost of electricity assuming that the nuclear fuel cycle is "Once-Through". TCR omitted all capital related cost associated with the cost of electricity from the calculator. Additionally, the calculator failed to account for Variable Operation and Maintenance cost which EIA estimates at 2.14[11] $/MMBtu. The resulting uranium price was 0.99 Nominal $/MMBtu which TCR assumed to be fixed.

Table 11 lists the parameters the calculator uses.

[10] http://thebulletin.org/nuclear-fuel-cycle-cost-calculator/model

[11] http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

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Table 11: List of parameters used in nuclear price calculator

Parameter	Unit	Value	Std. Deviation
LWR Fuel Burnup/Utilization	GWd/t	43	0
Overnight Cost	$/kWe	144	56.6
Operation & Maintenance	Mill.$/GWe-yr	8.5	8.5
Interest Rate	%	0	0.0057
Uranium Price	$/kgU	79	47.6
UF6 Conversion Cost	$/kgU	12	2.45
Enrichment Cost	$/SWU	26.0042	2.76263
LWR Fuel Fabrication Cost	$/kgHM	350	61.23
Spent Fuel Interim Dry Storage Cost	$/kgHM	0	0
Geologic Disposal Cost	Mill. $/kWe-hr	0	0
Fissile Product Conditioning Cost	$/kg FP	4600	909.2
Reactor Construction Time	In Yrs.	0	0.2
Reactor Economic Lifetime	In Yrs.	30	3
LWR Reactor Capacity	MWe/yr	1000	0
LWR Capacity Factor		0.9	0
LWR Thermal Efficiency		0.32	0
LWR Inventory	kgHM/MWe	78	0
Fabrication Loss		0.01	0
Enrichment Loss		0.005	0
Conversion Loss		0.005	0
Feed Enrichment	%w/f of U235 in feed	0.00711	0
Tails Enrichment	%w/f of U235 in tails	0.003	0
FR Fuel Burnup/Utilization	GWd/t	100	0
Spent LEU Reprocessing Cost	$/kgHM	385	67.4
Overnight Cost	$/kWe	4600	1385.6
FR Operation & Maintenance	Mill.$/GWe-yr	313	141.5
FR Fuel Reprocessing	$/kgHM	6000	1124
FR Fuel Fabrication Cost	$/kgHM	826.67	143.91
High Level Waste Disposal Cost	$/kgHM	5417	1381
FR Capacity Factor		0.9	0
FR Thermal Efficiency		0.38	0
Transuranic (TRU) Waste Inventory	Metric Tons RU/GWe	7.5	0
Loss of TRU during LEU Reprocessing		0.005	0
Loss of TRU in FR Fuel Fabrication		0.005	0
Loss of TRU in FR Fuel Reprocessing		0.005	0
Conversion Ratio		0.75	0
Pu Loss during MOX Fuel Fabrication		0.005	0
MOX Fuel Fabrication Cost	$/kgHM	3750	872
MOX Fuel Burnup/Utilization	GWd/t	43	0

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12. EMISSION RATES AND ALLOWANCES

A. Emission rates

TCR will use emission rates for NOx and SO2 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 will be used. On the other hand, for existing units for which no emission rates were reported, emission rate by fuel type from EIA will be used[12]. CO2 emission rates by fuel type are taken from EPA's "Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems"[13].

B. Emission allowance prices

TCR will use CO2 allowance prices projected by RGGI as part of its ongoing 2016 Program Review. The New England document describes these assumptions.

For sulfur dioxide (SO2) and nitrogen oxides (NOx) TCR will use emission allowance prices obtained from S&P Global's assessment of emission allowances created under the Cross-State Air Pollution Rule (CSAPR). Under CSAPR, "Seasonal" emission is the summer season from May 1 to October 31 while "Annual" emission refers to the rest of the year. Figure 7 and Table 12 present the different groups and pricing schemes used as of May 1, 2017.

Table 12: Forecast of Emissions 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 Grp 1	2.75	2.86 Allowances is 2000lbs	0.0039
CSAPR SO2 Grp 2	3.25	2.86 Allowances is 2000lbs	0.0046

[12] https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf
[13]

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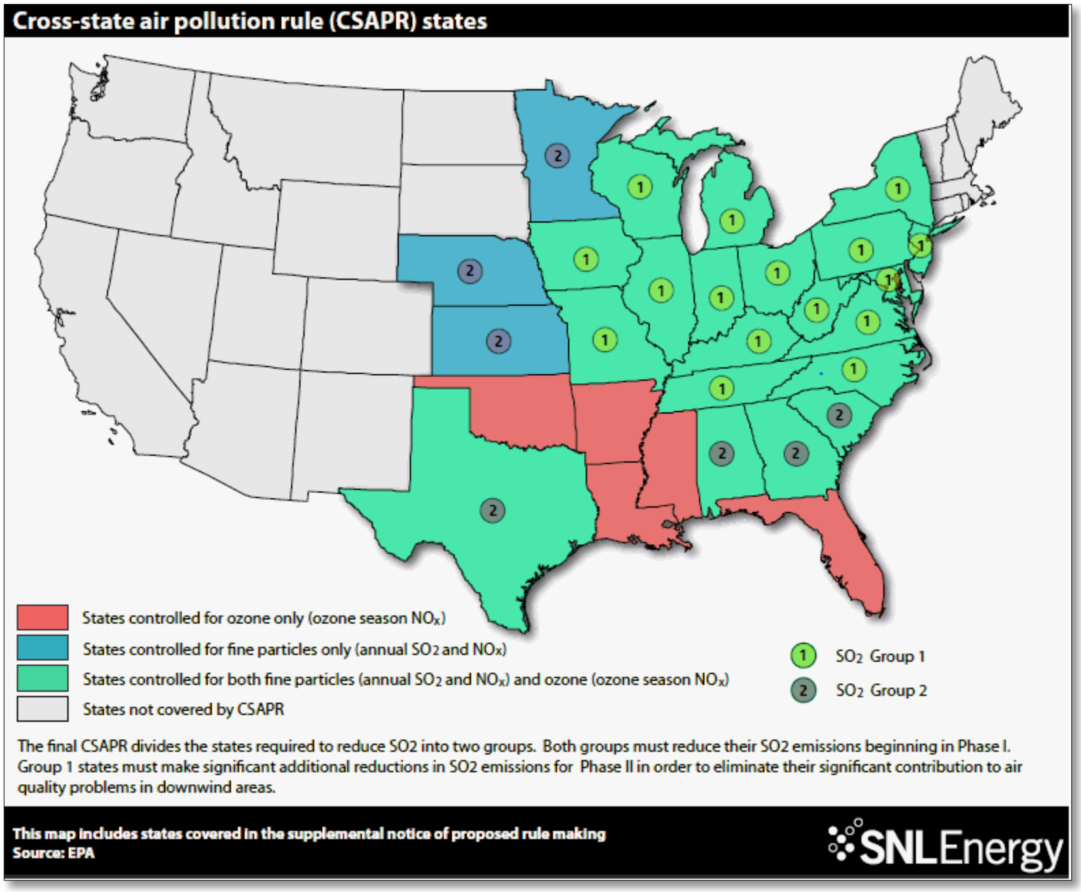
Figure 7: Pricing Groups for Emissions



Under CSAPR, "Seasonal" is the summer season from May 1 to October 31 while "Annual" refers to the rest of the year. The State of New York belongs to SO2 emission group 1.

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13. INTERCHANGE DATA

TCR will model interchange flows between New York and New England as described in the New England document. TCR obtained interchange flows between New York and its remaining neighboring areas from historical hourly data reported by NYISO for January 2016 through December 2016.[14] Those interchanges are between NYISO and Hydro Quebec (HQ), Ontario (IESO), and neighboring zones of PJM Interconnection (RECO, PSEG, PENELEC and JCPL). Table 13 summarizes flow on each external interface in 2016.

Table 13 NYISO interchange flow summary, 2016

	Max Import (MW)	Max Export (MW)	Avg Import (MW)	Avg Export (MW)
NYISO-HQ(Cedars)	199	(100)	99	(0)
NYISO-HQ(Chateauguay)	1,614	(800)	1,265	(0)
NYISO-IESO	1,605	(1,175)	881	(8)
NYISO-PJM(Hdsn)	410	-	8	-
NYISO-PJM(Keysn)	2,302	(1,005)	369	(73)
NYISO-PJM(Ldl)	315	(315)	152	(16)
NYISO-PJM(Nptn)	660	-	560	-

NYISO provides interchange data on an aggregate basis with no allocation to individual branches forming inter-system tie lines. ENELYTIX represents the transmission with each area external to NYISO by assigning their loads and generators as specified in the power flow. ENELYTIX scaled external generators to balance the load in each external area subject to specified interchange schedules. This process provided a dynamic allocation of interchange flows between individual branches.

TCR modeled individual interchange lines such as the Hudson Transmission Partners (HTP), Neptune (NEPT), and Linden Variable Frequency Transformer (LIND VFT) as a combination of a generator and a load allowing simulations of bidirectional flows across these interchanges. TCR mapped these loads and generation to specific eNodes corresponding to points of physical interconnection in NYISO, and assigned these eNodes to distinct areas in NYISO.

[14] NYISO, Power Grid Data, Interface Limits and Flow. 2012

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APPENDIX A

Table 14 Monthly Spot Gas prices

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TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

REDACTED

TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]

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TCR Fuel Price assumptions New England and New York

HH & New York spot gas prices

Spot Gas Prices, 2017$ / MMBtu

[redacted]