ISO-NE CONE and ORTP Analysis

An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 (“FCA-12”) and forward

December 2, 2016



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Section 1:  
Executive Summary

This report contains the results of the estimates of both: i) the Cost of New Entry (“CONE”) and the CONE net of expected revenues (“Net CONE”), and ii) the technology specific Offer Review Trigger Prices (“ORTP”) for use in New England’s Forward Capacity Market (“FCM”). As more fully explained in this report, the CONE and Net CONE values are parameters used in the Forward Capacity Auctions (“FCA”) that are intended to reflect the compensation a new entrant would need from the capacity market (net of expected revenues) in the first year of operation to recover its capital and fixed costs under long-term equilibrium conditions, given reasonable expectations about future market conditions and cost recovery assumptions. Estimating Net CONE is done from the perspective of a hypothetical unit of a particular technology type in a particular location in New England, which is referred to as the “reference” unit. The ORTP values are used as a "screen" for potentially new uncompetitive resource offers in an FCA to protect against the exercise of buyer-side market power that could inappropriately suppress capacity prices. It is a benchmark price down to which a new capacity supply resource can offer freely without justification to ISO New England Inc.’s (“ISO-NE”) Internal Market Monitor (“IMM”).

ISO-NE contracted with Concentric Energy Advisors, Inc. (“Concentric”) to conduct an independent analysis of the CONE/Net CONE and ORTP values for the FCM 2021/2022 Commitment Period. Concentric and its subcontractor, Mott MacDonald (“MM”), worked together to develop the recommendations presented in this report. To arrive at these results, we considered relevant market and technology issues, screened several technologies, and closely evaluated those that met specified CONE and ORTP screening criteria. This evaluation included a detailed analysis of technical specifications, capital and operating costs, and future market conditions to calculate expected revenues and arrive at recommended CONE/Net CONE and ORTP values.

Based on our analysis, we recommend that the simple cycle combustion turbine (“Simple Cycle GT”) be used as the reference technology for FCA-12, which is the relevant auction for the 2021/2022 Commitment Period. The choice of reference unit has a large impact on the Net CONE value and is critical to ensuring that the capacity market will procure capacity sufficient to meet the region’s resource adequacy requirement. The Simple Cycle GT is substantially less expensive than the combined cycle combustion turbine (“Combined Cycle GT”) and the aeroderivative machines, and is an established technology in New England. The Simple Cycle GT technology has participated and cleared in the most recent FCAs, as shown in Table 1 below.

Table 1: Proposed Simple Cycle and Combined Cycle GTs in New England

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Power**  **Plant** | **Generation Technology** | **Estimated In- Service Date** | **Turbine Manufacturer** | **Turbine Type** | **State** | **Approx. Nameplate Capacity (MW)** | **Current Operating Status** |
| Salem  Harbor | Combined Cycle | 6-2017 | General Electric Company | 7F 5-Series | MA | 674 | Under Construction |
| West Medway II | Gas Turbine | 4-2018 | GE Energy | LMS100PA+ | MA | 200 | Advanced Development |
| Towantic Energy Center | Combined Cycle | 5-2018 | GE Energy | 7HA.01 | CT | 785 | Under Construction |
| Wallingford  Energy (LS Power) | Gas Turbine | 6-2018 | GE Energy | LM6000 | CT | 90 | Early Development |
| Bridgeport Harbor Station | Combined Cycle | 6-2019 | GE Energy | TBD | CT | 485 | Early Development |
| Canal 3 | Gas Turbine | 6-2019 | GE Energy | 7HA.02 | MA | 333 | Early Development |
| Clear River Energy Center | Combined Cycle | 6-2019 | Not announced | TBD - G, H, or J Class | RI | 1000 | Early Development |

The active participation of Simple Cycle GTs in recent FCAs differs from the situation that existed when the CONE/Net CONE study was conducted in 2014, where the Combined Cycle GT was the recommended reference technology because there were no Simple Cycle GTs proposed or participating in the FCM at that time. Stakeholders expressed concern regarding the use of the Simple Cycle GT as the reference technology and the non-linear reliability risk between understating and overstating Net CONE under the current demand curve design. Setting aside the fact that the new zonal demand curves mitigate these concerns, our mandate for this CONE/Net CONE study was to evaluate the compensation a hypothetical new entrant would need under long-term equilibrium conditions to enter the market, and recommend the new entrant reference technology.

Given that the market has revealed that the simple cycle technology is a cost-effective technology that has gained commercial acceptance and is economically viable in New England, we believe that the Simple Cycle GT appropriately balances relevant considerations – it is the most economic and proven technology that was evaluated, and is actively being developed in the region. The results of our CONE/Net CONE analysis and ORTP analysis are shown in Table 2.

Table 2: Net CONE Summary for Candidate Reference Technologies (2021$)



Similarly, we have conducted an evaluation of resources that have or are expected to participate in the FCM and have an ORTP above the expected auction starting price. Based on the CONE/Net CONE analysis for the simple cycle and combined cycle gas turbines with appropriate modifications to assumptions to reflect the low end of the competitive range, and a detailed analysis of other resources meeting the stated screening criteria, we recommend the resource specific ORTPs shown in Table 3 below.

Table 3: ORTP Summary for Specific Resources (2021$)



Section 2:  
Introduction

## Background

ISO-NE ensures that sufficient resources are available to meet future demand for electricity through a capacity market mechanism. The FCM is a long-term market that assures resource adequacy, locally and system-wide, and is designed to promote economic investment in new and existing supply and demand resources where and when they are needed. Under this market design, auctions are held annually, three years ahead of the Capacity Commitment Period (June 1, XX to May 31, XX+1), which is intended to provide for a planning period for new entry to allow potential new capacity to compete in the auctions. The Capacity Commitment Period is a year-long period that corresponds to the ISO-NE power year. Thus, sellers commit to provide capacity for one year—for example, June 1, 2021 to May 31, 2022—three-plus years in advance of the Capacity Commitment Period.

The FCA utilizes a downward-sloping demand curve designed to procure sufficient capacity to maintain resource adequacy and reduce price volatility over time, yielding smaller swings in capacity prices when the market moves from conditions of excess supply to periods when new capacity resources are needed. The demand curve’s shape is defined by: (1) the estimated gross entry cost, or CONE for a new capacity resource; and (2) the estimated gross entry cost net of revenues from energy, reserve, and other markets or Net CONE. Net CONE is the levelized capacity revenue that a new resource would need in its first year of operating to be economic, given reasonable assumptions about net revenues. Estimating the CONE/Net CONE values accurately in order to represent the true value that new entrants would need to enter the market is an important design criterion for the sloped demand curve to achieve desired reliability objectives.

In addition, the FCM design includes a mechanism to protect against the price suppressing effects of uncompetitive new resource offers. This mechanism subjects all new entrants in the FCA to a benchmark known as the ORTP. The ORTP acts as a screen for potentially uncompetitive offers from new resources in an FCA. It does so by setting benchmark prices which approximate the Net CONE for each resource, but represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. New supply offers above the ORTP level are presumed to be competitive and not an attempt to suppress the auction clearing price, while offers below the ORTP level must be reviewed by the IMM pursuant to a unit-specific review process. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

## Scope and Objectives

Concentric and MM were retained by ISO-NE to conduct both a CONE/Net CONE study as well as an ORTP study to determine appropriate CONE, Net CONE, and ORTP values for FCA-12, as well as the indices to be used for escalating costs and revenues so that ISO-NE can update the CONE, Net CONE and ORTP values for FCA-13 and FCA-14.

For the calculation of CONE and Net CONE, ISO-NE’s Tariff requires the following:

*“CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.”*

*“Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e)….”[[1]](#footnote-1)*

For the calculation of ORTP values, ISO-NE’s Tariff requires the following:

*“The Offer Review Trigger Price for each of the technology types… shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply”.[[2]](#footnote-2)*

Concentric and MM have conducted both studies simultaneously in an open and transparent process with stakeholders and ISO-NE. Key assumptions and issues were brought to stakeholders for input and feedback in five separate meetings in front of the NEPOOL Markets Committee. These meetings provided important feedback and direction on concepts and metrics relevant to the study process, and provided guidance for consideration of, and recommendations on, key study issues and outcomes.

## Approach

The objective of the CONE/Net CONE and ORTP studies is to calculate values for FCA-12 for the 2021/2022 Capacity Commitment Period. The CONE/Net CONE values must reflect the price needed to attract sufficient new capacity under long-term equilibrium conditions. Consistent with guidance from ISO-NE and the Federal Energy Regulatory Commission (“FERC”), the recommended ORTPs are set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues.

The study process consisted of the four basic tasks outlined below and further described in this report:

* **Resource Screening and Selection.** The first step in the process was the development of screening criteria for the selection of resource types for which to calculate a CONE/Net CONE value and ORTP benchmark values. Those resources that passed the screens were subject to a full evaluation of costs and revenues over the expected life of the facilities.
* **Calculation of CONE.** For each of the selected technologies for the CONE/Net CONE and ORTP analysis, we developed technical specifications, installed capital costs and operating costs over the 20 year expected life of each facility (11 years for Energy Efficiency and Demand Response Resources). Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we calculated a first year revenue requirement that ensured the recovery on and of investment costs. We adjusted selected operating costs, as well as our financial assumptions, for the ORTP calculation to reflect a resource with output under contract consistent with Tariff requirements and to achieve the “low end of the competitive range” objective.
* **Calculation of Expected Revenues.**  We estimated expected revenues for each of the selected technologies, including energy revenues (net of variable costs), ancillary service revenues, renewable energy credit (“REC”) revenues and pay for performance (“PFP”) revenues. The calculation of expected revenues included a review of historic data, an analysis of expected future market conditions, the development of an energy price forecast using a production cost simulation model, a review of current and future expected REC prices, and data provided by ISO-NE on expected future shortage events under long-term equilibrium conditions.
* **Calculation of Net CONE and ORTP.**  Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market in the first year of operation (2021) to determine Net CONE and ORTP values for each resource. For generation resources, capital costs, operating costs, expected non-capacity revenues, and assumptions regarding depreciation, taxes and discount rate were input into a capital budgeting model which was used to calculate the break-even contribution required from the FCM to yield a discounted cash flow with a net present value of zero for the resources. The Net CONE value and ORTP value was set equal to the year-one capacity price output from the model over the life of the facility. The difference between the Net CONE values and the ORTP values is the assumption of costs and revenues reflecting a low end of the competitive range for the ORTP values.

For Energy Efficiency, the methodology used to calculate the ORTP value was the same as that used for generation resources, except that the methodology discounted cash flows over the 11-year contract life. However, the model took into account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. In addition, the model reflected the end-use customer energy savings associated with the efficiency programs, and discounted the cash flows over the 11-year life of the energy efficiency measure.

For Demand Resources, the methodology used to calculate the ORTP value was the same as that used for new generation resources, except that the methodology discounted cash flows over the 11-year contract life. For Demand Resources composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs included new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Resources primarily composed of mass market measures that do not use pre-existing equipment or strategies, incremental costs included equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

Each of these tasks involved a detailed review of historical data, forecast of future prices, and professional judgement in order to calculate estimated values for each technology. These parameters were informed through consultation with ISO-NE and stakeholders in order to ensure the effectiveness and appropriateness of the methods and data used.

## Report Contents

The balance of the report begins with a detailed description of our CONE/Net CONE study and results, including our screening process, development of technical specifications, calculation of capital costs and operating costs, approach to and calculation of financial assumptions, development of net revenue forecasts and final CONE/Net CONE values for candidate reference technologies and the recommended reference technology.

Following the CONE/Net CONE study description and results, the ORTP study is presented. The ORTP study was largely based on the CONE/Net CONE study for gas-fired resources, with some cost and financial assumptions modified to reflect the low end of the competitive range objective. The ORTP study also included a screening of other resource types expected to enter the FCM, and an analysis and recommended values for those resources that passed the screening criteria.

Section 3:  
CONE/Net CONE Study

## Resource Screening Criteria, Process and Selection

We began the CONE/Net CONE study by recognizing the variety of resources that currently participate in the FCM, and the establishment of technology screening criteria to focus the analysis on those resources that are appropriate as candidate reference technologies for determining Net CONE. Based on guidelines approved by the FERC in the last calculation process, we used the following criteria for selecting the appropriate candidate reference technologies for the evaluation of Net CONE values:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions;
2. Must have reliable cost information available to calculate a CONE value using a full “bottom up” analytical approach.

The first principle, that the reference technology must be economic for merchant entry under long-term equilibrium conditions, recognizes that uneconomic technologies will have a higher Net CONE than other alternatives and would set Net CONE higher than required to meet established reliability objectives. In order to determine whether the reference technology is likely to be economic as part of the long-term equilibrium, the resource must meet the following criteria: i) the resource must be of a size that can be used to meet resource adequacy requirements; ii) the resource must have demonstrated commercial interest by merchant developers based on the information available for projects recently completed, under construction, or in the interconnection queue in New England; and iii) the resource must have an estimated Net CONE that is not so high that the technology is unlikely to be part of the long-term equilibrium. As different resource types provide different services other than capacity (e.g., baseload versus peaking operations), several technologies could be economic with the same Net CONE in a long-term equilibrium. However, market conditions will change over the forecast period, such that different technologies can have the lowest Net CONE value over time. For this reason, reference technologies that are clearly expected to be a part of the long-term mix of additions should not be excluded as a candidate reference technology, even if their Net CONE value may be temporarily slightly higher than other technologies.

The second principle is that the reference technology must have reliable cost information available to calculate a CONE/Net CONE value using a full “bottom up” analytical approach. Estimating CONE/Net CONE values requires the development of assumptions about resource specifications, the analysis of potential costs and revenues, the estimation of financial parameters and risks, and the execution of subjective decisions in developing the Net CONE values. Therefore, it is critical that enough data is available to determine a technology’s Net CONE with a reasonably low level of uncertainty.

Several different resources were considered for an evaluation, including gas-fired resources, coal-fired resources, nuclear resources and various renewable resources. Gas-fired resources passed the screening criteria, as they have been proven to be economic for new entry and have numerous sources of historical operating data. As a result, we focused on gas-fired resources in both simple cycle and combined cycle configurations as the appropriate technologies for the CONE/Net CONE analysis.

In terms of the simple cycle technologies, we considered both frame machines and aeroderivative machines. For frame machines, we considered the following key features:

* Can provide reliable generation to the grid for a low capital cost
* Can be installed with fast start capability
* Technology being continuously developed and improved by the manufacturers
* Usually installed for peak power production
* Industrial design intended for long term operation at high efficiencies
* Currently being installed in New England

The Simple Cycle GTs that were considered as candidate simple cycle technologies are shown in Table 4 below.

Table 4: Simple Cycle Frame GTs

|  |  |
| --- | --- |
| Frame Technology | Justification |
| GE7HA.02 | * GE’s newest large frame machine * Currently scheduled to be next in GE test rig * Highest output available for a Frame GT * GE guaranteed performance |
| Siemens 8000H | * Largest installed experience base for large frame gas turbines * Smaller and less efficient than GE ‘s or MHI’s newest machines * Currently working on a new larger more efficient machine |
| MHI M501GAC | * Air cooled large frame gas turbine from previous generation technology |
| MHI 501JAC1 | * New entry into simple cycle market * Not yet installed in simple cycle configuration * Requires negotiation with MHI * Smaller, more expensive from an installed $/kW perspective, small installed base in United States |
| Other Frame Machines | * MHI/Hitachi HH100 targets 7EA retrofits as a drop-in replacement * Alstom/GE GT-24 Not being marketed aggressively by GE |

As a result of the review of the above Simple Cycle GT options, we chose the GE7HA.02 as the frame combustion turbine model on which to conduct a full CONE/Net CONE evaluation. Although not yet in commercial operation, this machine is currently being installed at a generating facility in New England and is the most current frame technology available for simple cycle operation.

For aeroderivative machines, we considered the following key features:

* Fastest to market and fastest to engineer
* Size makes them more expensive in $/kW installed
* LM6000PH or LM6000 PF+ are currently installed in New England
* Can be converted from simple cycle if originally arranged properly

The aeroderivative gas turbines that were considered as candidate simple cycle technologies are shown in Table 5 below.

Table 5: Simple Cycle Aeroderivative GTs

|  |  |
| --- | --- |
| Aeroderivative Technology | Justification |
| GE LM6000PH and LM6000 PF+ | * One of the most widely installed machines in New England * Latest dry-cooled version |
| LM2500 | * High $/kW installed cost * Often utilized in combined heat and power or industrial process applications |
| Rolls Royce Trent | * Viable option to LM6000 family |
| MHI Pratt & Whitney FT8 Swiftpac | * Less efficient machine with small New England installed base |
| Siemens SGT 800 | * Efficient competitor to LM6000 and Trent with small installed base in NE |
| Solar Titan 250 | * Small machine with high heat rate and small installed base in NE |
| GE LMS100PA | * Wet Cooled machine that is designed with some aeroderivative turbine sections and some frame machine sections * Only advanced aeroderivative machine available * Most efficient simple cycle gas turbine available |

As a result of the review of the above aeroderivative machines, we chose the GE LM6000PF+ and the GE LMS100 PA on which to conduct a full CONE/Net CONE evaluation. These machines are currently installed in New England and represent a commercially acceptable and cost effective technology.

Finally, for the combined cycle technologies, we considered the following key features:

* + Can provide reliable generation to the grid
  + Can provide the best thermal efficiency available
  + Utilizes the largest and most efficient gas turbine technology available for combined cycle applications
  + Current frame designs are undergoing a step-change improvement in output and efficiency
  + Currently being installed in New England

The Combined Cycle GTs that were considered as candidate peaking technologies are shown in Table 6 below.

**Table 6: Combined Cycle GTs**

|  |  |
| --- | --- |
| Combined Cycle Frame Technology | Justification |
| GE7HA.02 | * Latest air cooled large frame gas turbine * Highest output available for a Frame GT as of June 2016 * Currently scheduled to be next in GE test rig   + Performance guaranteed by GE |
| GE 7HA.01 | * Currently offered for sale, but expected to be replaced by the 7HA.02 due to improvements in capacity and efficiency * In operation now |
| GE 7FA - .04 thru.06 | * Will continue to be offered for sale, but are smaller and less efficient than the 7HA.02 technologies |
| Siemens 8000H | * Largest installed experience for large frame gas turbines * Smaller and less efficient than GE’s or MHI’s latest technology machines |
| Siemens 8000J? – New machine not officially named yet | * Siemens is working on their next generation machine, but it is not yet available |
| Siemens F Class Machines | * These are not expected to be available in the 2019-2020 time -frame |
| MHI M501J and JAC1 | * M501J is a steam cooled large frame gas turbine   + Slightly lower capacity than the M501JAC1, but with equal heat rate * M501JAC1   + Best heat rate available for a large frame machine, comparable output to a GE7HA.02   + Utilizes an external compressor to provide additional cooling air   + Currently in operation in MHI Tea Point facility in Takasago, Japan   + Performance guaranteed by MHI * M501JAC   + Current development machine that are available for purchase if you negotiate with MHI   + Smaller, more expensive from an installed $/kW perspective, small installed base in United States, and New England in particular. Heat Rate significantly worse than larger frame machines, driving installed $/kW costs higher |
| Other frame machines | * MHI/Hitachi HH100 and Alstom/GE GT-24 not being marketed by GE in the U.S. * Siemens SGT Family – Not a large installed base in New England, not aggressively marketed by Siemens |

As a result of the review of the above Combined Cycle GT options, we chose the GE 7HA.02 as the combined cycle turbine model on which to conduct a full CONE/Net CONE evaluation. This machine is currently being installed in New England in a combined cycle configuration and therefore represents a commercially acceptable and cost effective technology.

We have noted that all of the generating resources that underwent full evaluation utilize turbines developed by GE. This is because GE clearly has most or all of the market share for new turbines being developed in New England at this time. Other gas-fired resources that use turbines from other manufacturers were also considered but were not fully evaluated since they did not reflect the level of activity in New England demonstrated by GE.

We applied the same screening criteria for consideration as a candidate reference technology to other resources that are currently participating in the FCM. These resources did not pass our screening criteria, as shown in Table 7 below.

Table 7: Resource Screening Results

|  |  |  |
| --- | --- | --- |
|  | Economic For Merchant Entry | Reliable Cost Information  for a Full Bottoms Up Approach |
| **On-Shore Wind** | * Higher cost than other CONE alternatives without a contract for output | * Inconsistencies in project size and arrangement that differentiate projects. * A “Standard Design” more than likely would not fit multiple projects |
| **Off-Shore Wind** | * Since no projects are in commercial operation in the US, the economics for merchant entry are unknown | * Since no projects are in commercial operation in the US, there is insufficient data to perform a full analysis |
| **Coal** | * Unlikely to be developed in New England |  |
| **Nuclear** | * Unlikely to be developed in New England |  |
| **Solar** | * Higher cost than other alternatives due to low solar irradiance and high land cost | * Current significant differences in costs and incentives result in inconsistent data |
| **Large-Scale Battery** | * Since no projects are in commercial operation in the US, the economics for merchant entry are unknown | * Since no projects are in commercial operation in the US, there is insufficient data to perform a full analysis |

## Key Assumptions

General assumptions utilized in the CONE technology screening that are applicable to all technologies include assumptions regarding location, plant configuration, interconnections to the gas and electric distribution systems, dual fuel capability, and environmental control capabilities. Each assumption is described below.

### Location

Locations were screened based on two primary criteria: i) locations where energy infrastructure already exists to allow ready access to the electric and gas distribution networks; and ii) locations in which retirements were likely to occur. Preference was given to locations meeting the first and second criteria that were located in close proximity to high-demand areas.

Applying these criteria resulted in the identification of Southeastern Connecticut and Bristol County, Massachusetts as likely candidates. Because Bristol County has fewer projects in development than Southeastern and because significant amounts of capacity are expected to retire in and around Bristol County, the Bristol County location was chosen for the CONE analysis.[[3]](#footnote-3)

### Greenfield versus Brownfield

Both greenfield and brownfield sites were considered since both sites are currently being developed in New England. Due to the fact that brownfield sites are highly variable in terms of characteristics and the extent of the re-use of existing equipment, the ability to reasonably estimate development costs for brownfield sites was challenging and uncertain. Therefore, we assumed that a new entrant would be located on a greenfield site.

### Plant Configuration

Projects being currently developed in New England provide important data points on plant configurations viewed as most viable by the market. A sampling of recent gas-fired projects developed in New England is shown below. Note that these projects represent a mix of combined cycle and simple cycle technologies, and all use turbines manufactured by GE. Additionally, all projects are located in Southern New England.

Table 8: Recent Projects Developed in New England[[4]](#footnote-4)

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Plant Name | Type | Estimated In-Service Date | Turbine Manufacturer | Turbine Type | Location | Nameplate Capacity (MW) |
| Salem Harbor | CC | 2017 | GE | 7F 5-series | MA | 674 |
| West Medway II | GT | 2018 | GE | LMS100 PA+ | MA | 200 |
| Towantic Energy Center | CC | 2018 | GE | 7HA.01 | CT | 785 |
| Wallingford Energy | GT | 2018 | GE | LM6000 | CT | 90 |
| Bridgeport Harbor | CC | 2019 | Not announced | Not announced | CT | 485 |
| Canal 3 | GT | 2019 | GE | 7HA.02 | MA | 333 |
| Clear River Energy Center | CC | 2019 | Not announced | Not announced | RI | 1,000 |

### Interconnection Assumptions

Based on a review of generating plants currently in development and also the availability of gas and electric infrastructure in Bristol County, a 2-mile interconnection to both the gas and electric grids was assumed. The electrical interconnection was assumed to connect to the 345kV system. Required network upgrades were also evaluated based on data provided by ISO-NE on technical upgrade specifications associated with recently developed projects in New England. Based on this information, network upgrade costs were calculated for each reference technology.

### Dual Fuel Assumptions

The candidate reference units were assumed to have backup fuel in the form of No. 2 oil. No. 2 oil is the most commonly installed backup fuel in New England, and publicly available data on the cost to install backup capability and to operate the plant on oil are available. Fuel security consistent with the existence of backup fuel is a prerequisite of this assumption.

### Environmental Assumptions

All plants are designed to be in compliance with federal requirements and regional requirements. This includes Carbon Monoxide (“CO”) Catalysts and Selective Catalytic Reduction (“SCR”) equipment for all simple cycle and combined cycle designs. Dry cooling is also utilized for ease of environmental permitting.

### Cooling System

The plants were designed with dry cooling for primary heat sinks. This was done to maximize potential installation sites and to ease permitting. The simple cycle plants utilize dry fin fan coolers, with the exception of the LMS100PA machine, which utilizes a wet cooled intercooler. The combined cycle plant is designed with an air cooled condenser. While there are more thermally efficient designs available, air cooled condensers are the easiest to permit, do not require significant makeup water, and can be utilized on most sites where reasonable space is available.

### Supplemental Firing

Supplementary firing was provided for the combined cycle design. The duct burners were fired to a 1250° F burner exit gas temperature. This firing rate provides additional peaking capacity while not increasing the cost of the heat recovery steam generator and the steam turbine, or negatively impacting the base combined cycle heat rate significantly.

### Evaporative Cooling

Evaporative coolers were included to provide improved performance on warm low humidity days. Evaporative cooler effectiveness was set at 85%, which is considered reasonable for standard evaporative cooler technology.

### Operating and Maintenance Costs

#### Land Lease

Land was assumed to be leased and recorded as a fixed operation and maintenance (“O&M”) expense. Based on a review of industrial leasing costs we assumed $25,000/acre based on the need to be close to gas and transmission interconnection. This lease rate was multiplied by the estimated land.

#### Property Taxes

Property taxes were assumed to be 3% as more fully described in Section 3.C.

#### Insurance

Insurance costs were assumed to be 0.6% of the overnight capital costs per year, consistent with the assumptions in the 2013 CONE study, which we continue to believe is reasonable.

A summary of assumptions applicable to all reference technologies is shown in Table 9 below.

Table 9: Key Assumptions

|  |  |
| --- | --- |
| Key Assumptions | |
| **Location** | Bristol County, MA |
| **Electric Interconnection** | 2-mile electrical interconnection  (to 345 kV system) plus network upgrades |
| **Gas Interconnection** | 2-mile gas lateral plus metering station |
| **Dual Fuel** | No. 2 oil for backup |
| **Environmental Controls** | Selective Catalytic Reduction  CO catalyst |
| **Cooling** | Dry Cooling for the frame units and aeroderivative  Wet Cooling for the advanced aeroderivative |

## Approach to Determination of Capital Costs

MM, in partnership with Concentric, prepared capital cost estimates for the four candidate reference technologies based on modern construction techniques and materials for electricity generating stations and related facilities. MM developed the major equipment costs, field construction labor hours and quantities to be used for the creation of the cost estimates from the comprehensive MM power plant cost estimating database along with information contained in the GT PRO cost system for power plants of the size and configuration selected for this project. The MM cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle, combined cycle, and aeroderivative projects.

The MM cost estimating database was utilized for contractors submitting quotes “at-risk,” either for the proposal itself or to crosscheck the bid the contractor had developed itself, and for developers and owners to check bids they receive. Many of the projects also include as-built cost details. The database also includes work specific information which generally addresses the civil work associated with a generation project, such as crew and construction equipment required for concrete work. The database is maintained and updated on a regular basis as new project cost estimates are prepared and information and data is received from our clients indicating the results of our work.

As a result of the selected geographic location for all of these projects just South of Boston in Bristol County, and possible competition from other projects for labor, the cost estimates include scheduled overtime in order to attract the most productive craft labor staff. All four cost estimates were based on a fifty-hour per week schedule for the journeymen. This is also based on past experience throughout the country, where many projects start as a forty-hour work week and eventually become sixty-hour week work schedules with the construction crews working six ten-hour days per week. It is common practice to always include overtime costs on major projects in order to avoid issues during construction. In addition to the fifty-hour workweek, we also included some casual overtime in each of the estimates to cover such items as unloading deliveries late in the day to avoid extra charges for the delivery vehicle, pulling electrical cable at night and the potential need to make some installations or modifications on a fast turnaround basis so that other crews can get into an area to complete their work.

### DIRECT COSTS

#### MAJOR EQUIPMENT

Major equipment was priced based on the MM cost database documentation along with information obtained from our clients that have constructed a large number of electric generating plants. Our database is kept current and is checked against market conditions for the time frame basis of the cost estimates. For any specialized major equipment that is not contained in our cost estimate database, we consulted with some of our clients and/or the specialty manufacturers involved in that type of major equipment supply. The MM cost estimates contain detailed information where each piece of major equipment is identified and priced accordingly.

Freight costs for the Major Equipment are generally included within the unit Major Equipment costs for the equipment in the direct cost section of the cost estimates. We included freight costs in the indirect cost section of the cost estimates for a small amount of Major Equipment and bulk materials where we were unable to obtain shipping costs from a supplier. In those instances, freight costs were based on our own estimating experience. Vendor representative costs were included either with the value of the Major Equipment or listed separately in the indirect cost portion of the cost estimates as noted.

#### BALANCE OF PLANT MATERIALS

Balance of Plant bulk material quantities were developed from the MM selected cost estimate model[[5]](#footnote-5) for this project as well as information from other MM power projects. Bulk quantities and sizes were adjusted to suit the major equipment locations displayed on the site plan. Sizes of the various components were also adjusted to suit the varying sizes of the plant capacities as necessary, based on our experience and as indicated on the information developed for this analysis.

The Balance of Plant materials were priced based on market conditions and prices in effect in the U.S. with adjustments to suit any special conditions that may apply in the Bristol County, Massachusetts area. Concrete supply is the one item that is particularly influenced by local costs.

Freight costs for the balance of plant materials were included within the unit material costs for the material in the direct cost section of the cost estimates. Where the pricing developed excluded freight costs, these costs were included in the indirect cost section of the estimates.

#### CONSTRUCTION LABOR

Labor rates were based on union labor rates for the Bristol County, Massachusetts area. The construction labor rates used in the cost estimate were composite craft labor rates for approximately 35 various crafts and included all fringe benefits, workers’ compensation costs and all other required insurances and taxes. Working foreman costs were built into the labor rates while non- working General Foreman costs were included separately in the Construction Management Indirect Cost section of the cost estimates. The construction labor rates used for the various crafts were included in a separate section as part of this estimate package.

Field labor productivity was calculated based on field construction labor conditions for the Bristol County, Massachusetts area. These productivity values are supported by previously completed projects in the general area in which the plant would be located and for which MM has experience, as well as from previously prepared construction site surveys in the Northeast.

### ESTIMATE DETAILS BY MAJOR CATEGORY

#### MAJOR EQUIPMENT FIELD INSTALLATION LABOR

Field construction installation labor hours for major equipment installation were developed from MM’s experience in estimating other projects. MM’s cost estimate model information and discussions with major equipment manufacturers as to installation conditions and component pieces associated with their equipment were also considered. All labor hours were adjusted to suit anticipated productivity levels associated with working in the Bristol County, Massachusetts area. As noted above, productivity values used in the study are consistent with MM’s experience with similar types of construction projects in the general area.

#### SITE WORK

The Bristol County site location is anticipated to require only a minimal amount of additional fill since a specific location within the county was not identified and cut and fill measurements, therefore, could not be quantified. As noted above, it was determined that we would not consider piling for foundations for the same reason as explained for minimal cut and fill operations.

The cost estimates include site drainage, a firewater loop system, the installation of new underground piping, new electrical duct banks and manholes, sanitary sewer piping, miscellaneous light site demolition, erosion control, excavation and backfill for the new foundations, site fencing, roadwork, site restoration and landscaping.

The cost estimates include utility tie-ins at the fence. The final paving of roads was assumed to be accomplished at the conclusion of construction activities.

#### CONCRETE

Concrete quantities were developed from information contained in the MM cost estimate model adjusted to the exact conditions for each of the four projects considering the major equipment required and the proposed plant layout drawing. Field construction labor hours for concrete installation were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

Major concrete work in this section of the cost estimate includes the gas turbine foundation, the SCR foundation, a firewall for the main transformers, a stack foundation, building foundations, pump foundations and the switchyard area.

#### MASONRY

Masonry quantities were developed from information available from the MM cost estimate model and specified building sizes for the project. The major elements of work contained in this section include both interior and exterior CMU walls where needed for the buildings on the project, scaffolding, and all grouting costs for major equipment and structural steel base plates.

Field construction labor hours for masonry work were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

#### STRUCTURAL STEEL/METALS

Structural steel quantities were developed from information available from other MM projects of similar size, as well as the MM cost estimate model used for this project. Field construction labor hours for steel installation were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

Major structural steel work in this section of the cost estimate includes structural and supplementary steel for the Administration building. Platforms, grating, handrails, ladders, anchor bolts, and prime coat painting of the steel are also included unless any of these items are supplied by the manufacturer of the major equipment.

#### BUILDINGS

Material quantities for buildings were developed from building information developed by MM as well as the MM cost estimate model used for this project. As noted, structural steel for buildings is included in the structural steel/metals section of the cost estimate unless the building is a pre-engineered structure. This section consists of the siding, roofing, doors, carpentry, wallboard, acoustical treatment, resilient flooring, fire protection, plumbing and HVAC requirements for the buildings on the project.

The buildings required on this project that are included in this section are the administration/control/machine shop/warehouse building and a guard house.

Field construction labor hours for the building work were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

#### PIPING

Piping quantities contained in the MM cost estimate model were adjusted from the locations of the buildings and major equipment components shown on the general arrangement drawing.

Piping systems included in this section of the cost estimate include auxiliary cooling water, feedwater, fuel gas, lube oil, fuel oil, wastewater, service water, raw water, demineralized water, sampling, process and instrument air and mixed chemical.

Field construction labor hours for the piping systems were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

#### ELECTRICAL

Electrical quantities were developed from the locations of the buildings and major equipment components shown on the general arrangement drawing. In addition, the MM cost estimate model was utilized to determine cable, conduit and cable tray sizes and lengths of a number of required electrical services.

Electrical categories included with this section are site electrical work, power/control and instrumentation for cable and conduit requirements, controls needed for interconnection to the system, area lighting and service requirements, building area lighting and services, public address system, building fire alarms, and a grounding system.

The site electrical section includes site lighting, surveillance equipment, lightning protection, cathodic protection, heat tracing and aviation lighting for the stack.

Field construction labor hours for the electrical systems were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

#### INSTRUMENTATION

Instrumentation quantities were developed from reviewing MM’s experience with other projects and the MM cost estimate model utilized for this cost estimating effort.

The categories contained within this section include the installation and supply of contractor furnished instruments, loop checks and functional check out, instrument stands and material handling and calibration. All instrumentation and control cable, conduit and cable tray associated with the instruments are included in the electrical section of the cost estimate.

Field construction labor hours for the instrumentation systems were calculated and adjusted based on anticipated construction labor productivity derived from MM’s experience with other construction projects in the general area.

#### INSULATION

Estimates for insulation include allowances for both piping and major equipment insulation. MM relied on experience with other projects to develop expected quantities for this project. Information contained in the MM cost estimate model was also utilized in arriving at the allowances selected for use in the cost estimates. Insulation and electrical heat trace required for a cold climate condition were included from the cost estimate model utilized for this project.

#### PAINTING

This section contains all of the painting, sealer and epoxy requirements for the project. Included in this estimate is painting of the masonry walls, painting of wallboard, floor sealer, epoxy coating, finish painting of all steel with two coats over shop-applied primer coat, touch up painting of major equipment, and painting of all uninsulated steel piping.

### INDIRECT COSTS

#### CONSTRUCTION MANAGEMENT

This section of the cost estimate includes a detailed listing of the planned construction management team for the Engineering, Procurement and Construction (“EPC”) Contractor. All owner construction management costs as well as other categories of owner’s costs are included in this cost estimate as noted below in Section III.B.4. Items that are excluded are also so noted.

Costs that are included in this section include a Construction Manager; an assistant construction manager; civil, mechanical, structural, electrical and Instrument and Controls (“I&C”) superintendents; a field office manager; engineering support; cost engineering; planning and scheduling; safety; quality assurance and control; field purchasing and general foremen. The costs are calculated based on the estimated project schedule. The construction manager’s duration on the project includes one month in advance of beginning field operations and one month to close out the project, for a total of two additional months beyond the normal construction duration.

#### TEMPORARY FACILITIES and UTILITIES

This section of the cost estimate includes a detailed listing of the elements needed in order to support the construction management staff and construction of the project. Items that are normally included in this section are site trailers, clean up of trailer area, water, sanitary facilities, field office supplies, site security, fire protection, medical supplies, temporary electrical power distribution system, telephones, copy machines and computer hardware and software.

#### CONSTRUCTION EQUIPMENT and OPERATORS

This section of the cost estimate includes a detailed listing of the construction equipment and operating engineers required in order to construct the mechanical and electrical portion of the project. Civil construction equipment and operating engineer costs are included in the detailed estimate civil section and not in this section. The reason for this is that civil work requires a high amount of construction equipment and historically those costs are included with the construction item to provide the estimate reviewer with a better understanding of the value of that component of the cost estimate. In addition to the construction equipment and operating engineer cost, this section includes the cost of a master mechanic, teamsters, maintenance engineers, fuel, oil and grease, small tools, consumables, and scaffolding.

#### INDIRECT CONSTRUCTION SERVICES and SUPPORT

This section of the cost estimate includes a detailed listing of the services needed in order to support the construction management staff and field forces. Items contained in this section of the cost estimate include continuous and final site clean-up, rubbish removal, safety equipment and supplies, various testing including soils and concrete, survey costs, weather protection, dust control, snow removal, piping radiography and other testing, testing of the grounding system and mechanical, electrical and I&C journeymen support during start-up.

#### INSURANCE/ TAXES/PERMITS/OTHER

This section of the cost estimate includes a detailed listing of a variety of components required in the cost estimate that are not appropriate for inclusion in other sections of the estimate. Items normally included here are Freight Costs for major equipment and bulk materials that are not included in the cost of the Major Equipment as supplied by the manufacturer or in the bulk material unit cost, Travel Costs, Off-loading of major equipment and materials, Heavy Hauling of major equipment components not delivered directly to the site, General Liability and Umbrella Insurance costs, Start-Up Spare Parts, Permits, and Payment and Performance Bonds. Payment and Performance Bonds for the EPC Contractor as well as any subcontractors are part of this EPC cost estimate.

#### A/E ENGINEERING

A/E Engineering costs were calculated based on current information contained in the EPC cost estimate model used for this project and modified as required to support each of the four candidate technologies.

#### START-UP AND TESTING

The costs associated with the start-up and testing of the facility are included in the EPC cost estimates developed for this program. Journeyman stand-by time for mechanical, electrical and instrumentation and control support is included in the Indirect Services and Support Section of each cost estimate.

#### EPC CONTRACTOR CONTINGENCY

The MM EPC cost estimates include the anticipated contingency that will be applied by the EPC contractor based on the conceptual level of the information that is normally available at the time a Request for Proposal is issued for an EPC contractor’s proposal. The contingency percentages used in the cost estimates by MM were based on our past experience of proposing on firm lump sum projects at the conceptual stage where detailed engineering is not available.

#### EPC CONTRACTOR PROFIT

MM evaluated current profit margins of constructors of a suitable size that could adequately perform on a project of this size. MM used 10% for profit and 5% for contractor overhead for the civil, mechanical and electrical and I&C subcontractors for a total of 15% to cover these costs. MM also used a 7% mark-up on the total value of the project for the EPC contractor. It was assumed that, as is typically the case today, the EPC contractor would subcontract all civil, mechanical and electrical and I&C work and function as the general contractor. Therefore, in addition to the 15% mark-up for all of the subcontractors, the EPC contractor includes a 7% mark-up on top of the all the subcontractors as his fee for monitoring their work under the total EPC contract.

### OWNER’S COSTS

#### OWNER’S PROJECT COSTS

These costs typically include the owner’s cost for all the services required in order to obtain all approvals to construct the project including, but not limited to, legal costs, insurance costs, front-end engineering costs, the cost of land, project development and permitting costs. Also included in this section are the owner’s construction management costs as well as the costs associated with the support of an owner’s engineer. Since the cost estimates are based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

#### INTEREST DURING CONSTRUCTION

This section of the cost estimates would normally include costs for interest charges for money borrowed by the owner. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

#### PLANT SPARE PARTS

This section of the cost estimates would normally include costs for operating plant spare parts that an owner would stock to minimize plant downtime should a problem arise. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

#### FURNISHINGS

This section of the cost estimates would normally include costs for plant furnishings that the owner would need for the staff that would be operating the plant. Items normally included in this section would be desks, chairs, tables, lunch room equipment, window shades, computers, etc. Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

#### OWNER’S ESCALATION

Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

#### OWNER’S CONTINGENCY

An owner’s contingency of approximately 5% was included in the cost estimate.

#### ANY OTHER OWNER’S RELATED COSTS

Since the cost estimates were based on the scope of an EPC contract only, these costs were excluded from the cost estimates.

## CONE Technical Specifications and Costs

### 7HA.02 Simple Cycle Gas Turbine

The GE 7HA.02 is a large frame machine representing the current state-of-the-art regarding materials and combustion technology, giving it the highest efficiency available in the simple cycle technology market. In addition to a low minimum load point and high ramp rates that provide for flexible operation, the plant has relatively low capital costs. The 7HA.02 is in the process of entering commercial operation in a variety of locations throughout the country, including the Canal 3 facility in SEMA, which is scheduled to come online in 2019.

The capacity of the 7HA.02 in the simple cycle configuration is assumed to be 338 MW.[[6]](#footnote-6) Based on current market trends, it is assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system. The plant utilizes SCR to control emissions and a CO catalyst. The heat rate of the facility is 9,220 Btu/kWh. Based on a typical configuration, the facility is assumed to be installed on a plot of 8.1 acres.

A summary of the technical specifications is shown in Table 10 below.

Table 10: GE 7HA.02 GT Technical Specifications

|  |  |
| --- | --- |
| Turbine Model | 7HA.02 |
| **Configuration** | Simple cycle frame machine |
| **Net plant capacity (MW)** | 338 |
| **Location** | Bristol County, Massachusetts |
| **Cooling system** | Fin fan coolers |
| **Power augmentation** | Evaporative coolers |
| **Net heat rate (Btu/kWh)** | 9,220 |
| **Environmental controls** | Selective catalytic reduction |
| **Duel-fuel capability** | Natural gas w/ No. 2 oil backup |
| **Black start?** | No |
| **On-site gas compression?** | No |
| **Gas interconnection** | Onsite connection |
| **Electrical interconnection** | Onsite connection |
| **Plot size (acres)** | 8.1 |

#### CAPITAL COSTS

The capital costs for the simple cycle GT were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 11 below.

Table 11: GE 7HA.02 GT Capital Costs



#### Operating and Maintenance Costs

Fixed costs for the facility consist of fixed O&M costs inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section III.B. We have assumed a long-term service agreement (“LTSA”) that would cover parts, labor, and materials for work done up to and including the first major outage.  This was assumed to be a fixed price payment structure with monthly installments.  Outage frequency and durations would be agreed to, but degradation generally is not guaranteed.  Planned outages would be included under the agreement, but unplanned outages would not be covered.

Fixed costs for the GE 7HA.02 Simple Cycle GT are shown in Table 12 below:

Table 12: 7HA.02 Simple Cycle GT Operating Costs

|  |  |
| --- | --- |
| Fixed Expense | Estimated cost |
| Fixed O&M | $38.52/kW-year |
| Site leasing | $25,000/acre/year |
| Property taxes | 3.0% |
| Insurance | 0.6% of installed costs per year |

In addition, Variable O&M (“VOM”) is assumed to be $4.50/MWh based on consultation with MM.

### LM6000PF+ Aeroderivative Gas Turbine

The LM6000PF+ is one of the most widely installed plants in New England and is in widespread commercial use around the world. The unit, which is based on GE jet engine technology, is highly modular and can be engineered, procured, constructed, and enter operation more quickly than any alternative technology operating above 20 MW. While the LM6000 can be utilized in a combined cycle configuration, the simple cycle configuration is more common and was thus selected for review and analysis.

The capacity of the LM6000PF+ was assumed to be 94 MW. Based on current market trends, we assumed this unit would be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system. In addition, we assumed that the plant would utilize SCR to control emissions. The heat rate of the facility was assumed to be 9,774 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 4.5 acres.

A summary of the technical specifications is shown in Table 13 below.

Table 13: LM6000PF+ Technical Specifications

|  |  |
| --- | --- |
| Turbine Model | LM6000PF+ |
| **Configuration** | Two SC Aeroderivative GTs |
| **Net plant capacity (MW)** | 94 |
| **Location** | Bristol County, Massachusetts |
| **Cooling system** | Fin fan coolers |
| **Power augmentation** | Evaporative coolers |
| **Net heat rate (Btu/kWh)** | 9,774 |
| **Environmental controls** | Selective catalytic reduction |
| **Duel-fuel capability** | Natural gas w/ No. 2 oil backup |
| **Black start?** | No |
| **On-site gas compression?** | No |
| **Gas interconnection** | Onsite connection |
| **Electrical interconnection** | Onsite connection |
| **Plot size (acres)** | 4.5 |

#### Capital Costs

The capital costs for the LM6000PF+ were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 14 below.

Table 14: LM6000PF+ Capital Costs



#### Operating and Maintenance Costs

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section III.B. We have assumed a LTSA that include parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service.  The removed rotor would then be serviced and used in the shared rotor program with other plant owners.  This minimizes down time for the aeroderivative plants.  The duration of the LTSA would be up to and including the first major outage.  Planned outages would be included under the agreement, but unplanned outages would not be covered.  Fixed costs for the LM6000 are shown in Table 15 below:

Table 15: LM6000PF+ Fixed Operating Costs

|  |  |
| --- | --- |
| Fixed Expense | Estimated cost |
| Fixed O&M | $83.52/kW-year |
| Site leasing | $25,000/acre/year |
| Property taxes | 3.0% |
| Insurance | 0.6% of installed costs per year |

VOM is assumed to be $5.00/MWh based on consultation with MM.

### LMS100PA Advanced Aeroderivative

The LMS100PA is a relatively new design from GE. While not in widespread use, the unit’s efficiency and relatively low capital cost make it an attractive option for developers and a candidate for selection as the reference unit. The LMS100PA is a “hybrid” design in that it incorporates both frame and aeroderivative turbine technologies to create a unit that is highly efficient and highly flexible.

The LMS100PA is assumed to be installed in a simple cycle configuration. Because of the high efficiency of the turbine, exhaust gases are relatively cold, making the addition of a heat-recovery steam generator uneconomical. As a result, there is no expectation of commercialization of an LMS100 in a combined cycle configuration in New England for the foreseeable future.

The capacity of the LMS100PA was assumed to be 103 MW. Based on current market trends, it was assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system and an SCR to control emissions. The heat rate of the facility was assumed to be 9,021 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 5.7 acres.

A summary of the technical specifications is shown in Table 16 below.

Table 16: LMS100PA Technical Specifications

|  |  |
| --- | --- |
| Turbine model | LMS100PA |
| **Configuration** | SC Advanced Aeroderivative |
| **Net plant capacity (MW)** | 103 |
| **Location** | Bristol County, Massachusetts |
| **Cooling system** | Evaporative coolers |
| **Power augmentation** | Evaporative coolers |
| **Net heat rate (Btu/kWh)** | 9,021 |
| **Environmental controls** | Selective catalytic reduction |
| **Duel-fuel capability** | Natural gas w/ No. 2 oil backup |
| **Black start?** | No |
| **On-site gas compression?** | No |
| **Gas interconnection** | Onsite connection |
| **Electrical interconnection** | Onsite connection |
| **Plot size (acres)** | 5.7 |

#### Capital Costs

The capital costs for the LMS100PA were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 17 below.

Table 17: LMS100PA Capital Costs



#### Operating and Maintenance Costs

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section III.B. We have assumed a LTSA that include parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service.  The removed rotor would then be serviced and used in the shared rotor program with other plant owners, which minimizes down time for the aeroderivative plants.  The duration of the LTSA would be up to and including the first major outage.  Planned outages would be included under the agreement, but unplanned outages would not be covered.

Fixed costs for the LMS100PA are shown below:

Table 18: LMS100PA Fixed Operating Costs

|  |  |
| --- | --- |
| Fixed Expense | Estimated cost |
| Fixed O&M | $69.00/kW-year |
| Site leasing | $25,000/acre/year |
| Property taxes | 3.0% |
| Insurance | 0.6% of installed costs per year |

VOM is assumed to be $5.00/MWh based on consultation with MM.

### 7HA.02 Combined Cycle Gas Turbine

The Combined Cycle GT utilizes the same combustion turbine as the Simple Cycle GT. However, with the Combined Cycle GT , a HRSG is added to allow for additional generation using exhaust gases. Adding the HRSG increases capital costs significantly; however, doing so also increases plant size and plant efficiency.

The Combined Cycle GT was assumed to have duct firing capability. Duct firing is an option many plant developers choose to provide a highly flexible source of short-notice capacity that can be used to capture revenues during periods of high prices. Because inclusion of duct firing capability appears to be the current prevailing trend among developers, it has been included for purposes of this analysis.

The Combined Cycle GT is assumed to have a baseload capacity of 491 MW and a total capacity of 533 MW when duct firing is engaged. It was assumed to be equipped with both fin fan cooler and evaporative coolers for power augmentation. To control emissions, the plan utilizes both SCR and a CO catalyst. The baseload heat rate of the CC was assumed to be 6,381 Btu/kWh; when duct firing is engaged, the net heat rate increases to 6,546 Btu/kWh. Based on a typical configuration, the facility was assumed to be installed on a plot of 15 acres.

A summary of the technical specifications is shown in Table 19 below.

Table 19: GE7HA.02 Combined Cycle Technical Specifications

|  |  |
| --- | --- |
| Turbine model | 7HA.02 Combined Cycle |
| **Configuration** | Combined Cycle w/ Frame GT |
| **Net baseload capacity (MW)** | 491 |
| **Net capacity w/ duct firing (MW)** | 533 |
| **Location** | Bristol County, Massachusetts |
| **Cooling system** | Fin fan coolers |
| **Power augmentation** | Evaporative coolers |
| **Baseload net heat rate (Btu/kWh)** | 6,381 |
| **Duct firing net heat rate (Btu/kWh)** | 6,546 |
| **Environmental controls** | SCR and CO catalyst |
| **Duel-fuel capability** | Natural gas w/ No. 2 oil backup |
| **Black start?** | No |
| **On-site gas compression?** | No |
| **Gas interconnection** | Onsite connection |
| **Electrical interconnection** | Onsite connection |
| **Plot size (acres)** | 15 |

#### Capital Costs

The capital costs for the GE 7HA.02 Combined Cycle GT were developed by MM through discussions with the manufacturer and reliance on their proprietary database. These capital cost estimates are shown in Table 20 below.

Table 20: GE7HA.02 Combined Cycle Capital Costs



#### Operating and Maintenance Costs

Fixed costs for the facility consist of fixed O&M inclusive of labor, materials, contract services, and associated costs; leasing of the land on which the plant is located, property taxes, and insurance. The costs associated with land lease, property tax, and insurance are discussed in Section 3.D.

Fixed costs are shown below:

Table 21: GE7HA.02 Combined Cycle GT Fixed Operating Costs

|  |  |
| --- | --- |
| Fixed Expense | Estimated Cost |
| Fixed O&M | $60.12/kW-year ($2021) |
| Site leasing | $25,000/acre/year ($2021) |
| Property taxes | 3.0% |
| Insurance | 0.6% of installed costs per year |

VOM is assumed to be $3.50/MWh based on consultation with MM.

### Escalation to 2021 Costs

We escalated capital costs from 2016$ to the beginning of each unit’s construction period using estimates from the Bureau of Labor Statistics’ (“BLS”) Producer Price Indices (“PPI”). We used a 10-year average annual percent change from two BLS PPI indices for different capital cost components.[[7]](#footnote-7)

We escalated fuel costs for the gas turbines using NY Harbor ultra-low-sulfur-diesel (“ULSD”) futures settlements.[[8]](#footnote-8) Our estimate is based on a three-year forward average annual percent change of ULSD futures prices at NY Harbor.

## Financial assumptions

### Financial Inputs

The estimate of CONE/Net CONE is based the revenue required, net of cash flows from market revenues, by a new entrant to recover its capital and operating costs over a 20-year period. This estimate is inclusive of the cost of providing a return to equity investors and debt holders and is based on the reasonable assumption that significant amounts of capital will only be invested if investors anticipate that their investment will generate returns in excess of their cost of capital. Consistent with previous estimates, the CONE/Net CONE value is expressed on a real, levelized basis. That is, the calculation produces a first year payment such that if the payment increases by inflation every year over the twenty-year period, the Net Present Value (“NPV”) of a unit’s costs are equal to the NPV of its revenues over the 20-year period.

It is customary to discount uncertain future cash flows at an after-tax weighted average cost of capital. The appropriate discount rate should reflect systemic financial market risks and project-specific risks of a merchant developer participating in the New England wholesale markets and the return required by investors to compensate for those risks. We recognize that generation projects can be financed under a project financing or balance sheet financing approach. Project financing uses project-specific, “non-recourse” debt, along with a required portion of equity, to finance the construction of a power plant. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual power plant. Balance sheet financing employs debt backed by the project owner itself, which may have significant, diverse resources and assets beyond the individual power plant. While many plants in New England are financed on a “stand-alone” or project-specific basis, the specifics of these financing structures are not publicly available, and are diverse and difficult to represent. Because publicly available data about project-specific financing is not available, we chose a peer group of publicly traded independent power producers (“IPPs”) and used their financial parameters to inform our calculation of the recommended cost of capital. We then made reasonable adjustments to this proxy group data to calculate an after-tax weighted average cost of capital to reflect how a generic new entrant would likely view the risk of merchant development in New England.

Our financing paradigm assumes a reasonable balance between project-specific financing and large corporate balance sheet financing. This paradigm also assumes a parent company will find value in any operating income losses experienced over the life of the facility. Since there is no universally agreed upon convention for modeling tax effects for the purposes of a Net CONE calculation, we believe this assumption is reasonable.

The cost of capital is calculated as the weighted average of the required return for equity holders and cost of debt. In addition to the cost of capital, the key financial inputs to the calculation of CONE/Net CONE include inflation, depreciation, and property taxes. Derivation of each input is described below.

#### Inflation

CONE/Net CONE, and the inputs to calculate CONE/Net CONE are expressed in real (constant) dollars. Inflation is a key factor used to translate projected nominal cost and revenue streams to constant, or real, terms. It is also used in the calculation of a real discount rate, the levelization factor for CONE/Net CONE.

Two estimates of inflation were reviewed to develop the annual inflation outlook of 2%. The Blue Chip Long Term Consensus Forecast provides the most forward looking forecast of inflation.[[9]](#footnote-9) The ten-year average consensus forecast of CPI for all urban consumers is estimated at 2.3% (2018-2027).

Second, we reviewed spreads between yields on Treasury Inflation-Protected Securities (“TIPS”) and conventional U.S. Treasuries. TIPS provide holders a return on their investment that is indexed to CPI to protect holders from inflation risk. Conventional Treasuries do not. As such, the difference in the yields between bonds of each type with the same maturity date, calculated as the conventional yield minus the TIPS yield, reflects the market’s expectation of inflation for the period leading up to the maturity date. A 30-day average of daily yield curves published by the U.S. Treasury at the time of our analysis indicated that the spread in the yields for bonds of each type with 20-year maturities averaged 1.37% over that period.[[10]](#footnote-10)

Based on these inputs, we assumed an average long-term annual inflation rate of 2.0% for all CONE and ORTP calculations.

#### Depreciation

We used a 15 or 20-year tax life according to IRS guidelines using the Modified Accelerated Cost Recovery System (“MACRS”) to depreciate the eligible portion of total installed costs over the forecast period.[[11]](#footnote-11) The federal tax code allows recovery over 15 years for a combustion turbine and over 20 years for a combined cycle resource.

To calculate the annual value of depreciation, the “depreciable costs” for a new resource are the sum of the depreciable capital costs and the accumulated interest during construction (“IDC”). Several capital cost line items are considered non-depreciable, including fuel inventories and working capital, and are not included in total depreciable costs. IDC is calculated based on the assumption that capital structure during the construction period is the same as the overall project, i.e., 60% debt and 7.75% COD.

#### Property Taxes

Property taxes are based on municipal tax rates, which are generally differentiated by business type. A review of Commercial and Industrial (C&I) rates in Massachusetts over the last three years indicated an average rate of 0.2%-4.0% by municipality.

The assumed property tax rate is based on a review of C&I rates in the reference county’s four major cities (Bristol County, Massachusetts) over the period 2013-2015. Based on the following data, a property tax rate of 3.0% was assumed:

Table 22: Municipal Tax Rates for Selected Cities in SEMA*[[12]](#footnote-12)*

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | Attleboro | Fall River | Taunton | New Bedford |
| 2013 | 2.05% | 2.54% | 3.06% | 2.95% |
| 2014 | 2.16% | 2.67% | 3.12% | 3.11% |
| 2015 | 2.13% | 2.81% | 3.32% | 3.36% |

#### Income Tax Rates

We calculated income tax rates based on current federal and state tax rates. The marginal federal income tax rate is 35%.[[13]](#footnote-13) The state income tax rate for Massachusetts is 8.0%.[[14]](#footnote-14) The effective income tax rate is calculated to be 40.2%.[[15]](#footnote-15)

#### Cost of Capital

The Weighted Average Cost of Capital (“WACC”) for an investment represents the blend of rates paid on equity and debt specific to that investment’s capital structure and can be expressed by the following equation:

WACC = ROE \* Weight of Equity + COD \* Weight of Debt

Where:  
ROE = Return on Equity, and  
COD = Cost of Debt

Derivation of each input to the WACC calculation is described below and is based on a peer group of merchant generation companies who may be likely to develop projects in New England. Our initial peer group consisted of the following public traded companies:

* AES Corporation
* Calpine Corporation
* Dynegy Inc.
* NRG Energy, Inc.
* Talen Energy Inc.

We received feedback from stakeholders that the full group of peers does not appropriately represent merchant entry in New England because many hold diverse portfolios with some portion of regulated assets. Specifically, stakeholders expressed concerns about AES’ portfolio, and that Talen’s merger-related activity may skew the results of our analysis. We considered these comments in evaluating the components of cost of capital, as well as the overall cost of capital chosen for the evaluation of CONE and Net CONE; each component is discussed in more detail below.

#### Return on Equity

Return on equity (“ROE”) is the amount of return that would be required by investors to compensate for the risk of making an equity investment in a merchant generation plant. The risk environment determines the hurdle rates for investment. Equity raised for uncontracted, merchant projects requires a higher return to investors than equity raised for contracted projects. For energy and capacity that is fully contracted, the cost of equity reflects a lower level of risk, assuming a significant degree of leverage. For uncontracted merchant capacity, developers target a higher after-tax return on equity based on the perceived high risks of cost recovery in the market. A return on equity of 13.4% represents an appropriate return under equilibrium market risk conditions.

To calculate the appropriate return on equity for this analysis, the Capital Asset Pricing Model (“CAPM”) was used. CAPM is a common analytical approach in financial modeling, and assumes that equity investors base their required returns on a risk-free rate of return, the rate at which they would be compensated for an available investment that carried no risk, plus compensation for the relative risk of a specific security in relation to the broader market. CAPM is expressed by the following equation:

Re = Rf + β (Rm – Rf)

Where:

|  |  |
| --- | --- |
| Re= | Required return on equity |
| Rf = | The risk-free rate |
| β = | Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific security, and |
| Rm = | The return required of the market as a whole |

We reviewed several estimates of a risk-free rate, including the 30-day average of the 30-year Treasury yield curve, as well as estimates from Blue Chip. In addition, we reviewed beta estimates from several sources including Yahoo Finance, Bloomberg, and Value Line. Based on our assumed capital structure of 60/40 (D/E), we re-levered our estimates of beta for inclusion in our CAPM calculation.

Table 23: Peer Group Beta Estimates

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Beta Estimates | | | | |
| Bloomberg[[16]](#footnote-16) | **(2-year Beta)** |  |  |  |
|  | **Levered Beta** | **D/E ratio** | **Unlevered Beta** | **Re-levered beta** |
| AES | 1.07 | 2.28 | 0.45 | 0.86 |
| CPN | 1.17 | 1.65 | 0.59 | 1.12 |
| DYN | 1.28 | 1.60 | 0.65 | 1.24 |
| NRG | 1.17 | 2.61 | 0.46 | 0.87 |
| TLN[[17]](#footnote-17) | 1.32 | 2.30 | 0.55 | 1.05 |
| Value Line[[18]](#footnote-18) | **(5-year Beta)** |  |  |  |
|  | **Levered Beta** | **D/E ratio** | **Unlevered Beta** | **Re-levered beta** |
| AES | 1.15 | 2.28 | 0.49 | 0.92 |
| CPN | 1.00 | 1.65 | 0.50 | 0.95 |
| DYN | 1.45 | 1.60 | 0.74 | 1.41 |
| NRG | 1.10 | 2.61 | 0.43 | 0.81 |
| TLN | NA | 2.30 | NA | NA |

We reviewed two estimates of the overall market return: a historical estimate from Ibbotson; and a forward looking estimate of the S&P 500 Index. The following table shows the calculations for a number of historic and forward looking estimates of ROE.

Table 24: CAPM Analysis

|  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| CAPM | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] |  |
|  |  | **Beta- Relevered** | | | **Market Return** | | | **Market Risk Premium** | | **ROE based on…** | |  |
|  | **Risk-Free**  **Rate** | **Value Line** |  |  |  | **Income return** | |  |  | **Historical** | **Projected** |  |
|  | **Bloomberg** | **Average** | **Historical** | **Gov. Bonds** | **Projected** | **Historical** | **Projected** | **MRP** | **MRP** |  |
|  | ***30-year*** |  |  |  |  |  |  |  |  |  |  |  |
| AES | 2.24% | 0.92 | 0.9 | 0.89 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 8.462% | 11.67% |  |
| CPN | 2.24% | 0.95 | 1.1 | 1.03 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 9.48% | 13.22% |  |
| DYN | 2.24% | 1.41 | 1.2 | 1.32 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 11.50% | 16.28% |  |
| NRG | 2.24% | 0.81 | 0.9 | 0.84 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 8.13% | 11.16% |  |
| TLN | 2.24% | NA | 1.1 | 1.05 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 9.60% | 13.40% |  |
|  |  |  |  |  |  |  |  |  | All | 9.43% | 13.15 | 11.29% |
|  | *10-year* |  |  |  |  |  |  |  |  |  |  |  |
| AES | 3.80% | 0.92 | 0.9 | 0.89 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 10.02% | 11.85% |  |
| CPN | 3.80% | 0.95 | 1.1 | 1.03 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 11.04% | 13.17% |  |
| DYN | 3.80% | 1.41 | 1.2 | 1.32 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 13.06% | 15.78% |  |
| NRG | 3.80% | 0.81 | 0.9 | 0.84 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 9.69% | 11.41% |  |
| TLN | 3.80% | NA | 1.1 | 1.05 | 12.10% | 5.10% | 12.85% | 7.00% | 9.05% | 11.16% | 13.32% |  |
|  |  |  |  |  |  |  |  |  | All | 10.99% | 13.10% | 12.05% |
|  | *30-year* |  |  |  |  |  |  |  |  |  |  |  |
| AES | 4.30% | 0.92 | 0.9 | 0.89 | 12.10% | 5.10% | 12.85% | 7.00% | 8.55% | 10.52% | 11.90% |  |
| CPN | 4.30% | 0.95 | 1.1 | 1.03 | 12.10% | 5.10% | 12.85% | 7.00% | 8.55% | 11.54% | 13.15% |  |
| DYN | 4.30% | 1.41 | 1.2 | 1.32 | 12.10% | 5.10% | 12.85% | 7.00% | 8.55% | 13.56% | 15.61% |  |
| NRG | 4.30% | 0.81 | 0.9 | 0.84 | 12.10% | 5.10% | 12.85% | 7.00% | 8.55% | 10.19% | 11.49% |  |
| TLN | 4.30% | NA | 1.1 | 1.05 | 12.10% | 5.10% | 12.85% | 7.00% | 8.55% | 11.66% | 13.29% |  |
|  |  |  |  |  |  |  |  |  | All | 11.49% | 13.09% | 12.29% |
| Notes: |  |  |  |  |  |  | **All** | | | **10.64%** | **13.11%** | **11.88%** |
| [1] Blue Chip Financial Forecast - Vol. 35, No. 6, June 1, 2016 | | | | | |  |  | | |  |  |  |
| [2] Source: Value Line | | | | |  |  |  |  |  |  |  |  |
| [3] Source: Bloomberg Professional | | | |  |  |  |  |  |  |  |  |  |
| [4] Equals average ([2], [3]) | | |  |  |  |  |  | | |  |  |  |
| [5] Source: 2015 Ibbotson SBBI Valuation Yearbook, Table 6-7, pg 91 | | | | | | |  | | |  |  |  |
| [6] Source: 2015 Ibbotson SBBI Valuation Yearbook, Table 6-7, pg 91 | | | | | | |  |  |  |  |  |  |
| [7] Source: Bloomberg Professional | | | |  |  |  |  |  |  |  |  |  |
| [8] Equals [5] − [6] | |  |  |  |  |  |  |  |  |  |  |  |
| [9] Equals [7] − [1] | |  |  |  |  |  |  |  |  |  |  |  |
| [10] Equals [1] + [4] x [8] | | |  |  |  |  |  |  |  |  |  |  |
| [11] Equals [1] + [4] x [9] | | |  |  |  |  |  |  |  |  |  |  |

We also reviewed these results in light of stakeholder feedback about the appropriate peer group.

Table 25: Summary of CAPM Results by Alternative Peer Group

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  |  | ROE based on… | |  |
|  |  |  | Historical | Projected |  |
| Risk-free Rate |  |  | MRP | MRP | Average |
|  |  |  |  |  |  |
| **Treasury 30-yr** |  | All | 9.43% | 13.15% | 11.29% |
|  | CPN, DYN, NRG, TLN | 9.68% | 13.52% | **11.60%** |
|  | CPN, DYN, NRG | 9.70% | 13.55% | **11.63%** |
|  |  |  |  |  |  |
| **BCFF**  **10-yr** |  | All | 10.99% | 13.10% | 12.05% |
|  | CPN, DYN, NRG, TLN | 11.24% | 13.42% | **12.33%** |
|  | CPN, DYN, NRG | 11.26% | 13.45% | **12.36%** |
|  |  |  |  |  |  |
| **BCFF**  **30-yr** |  | All | 11.49% | 13.09% | 12.29% |
|  | CPN, DYN, NRG, TLN | 11.74% | 13.39% | **12.56%** |
|  | CPN, DYN, NRG | 11.76% | 13.42% | **12.59%** |
|  |  |  |  |  |  |
| **Average** |  | All | 10.64% | 13.11% | 11.88% |
|  | CPN, DYN, NRG, TLN | 10.88% | 13.44% | **12.16%** |
|  | CPN, DYN, NRG | 10.91% | 13.47% | **12.19%** |

As shown in Table 25, forward looking estimates for different combinations of peer companies range from 13.09 to 13.55%. Given stakeholder concerns about appropriate peer comparators, we have determined that an ROE of 13.4% towards the upper end of the range of results is appropriate for the CONE/Net CONE calculation.

#### Cost of Debt

To estimate Cost of Debt (“COD”), we reviewed credit ratings of companies active in the development and commercialization of merchant generation. Of the five original comparators, each has below investment-grade senior unsecured debt ratings ranging from “B” to “BB”. Ratings are estimated by Standard & Poor’s and reported by SNL.[[19]](#footnote-19) We then reviewed historical generic corporate bond yields for B and BB rated companies. Over the period January 1, 2016 through August 1, 2016, bond yields for companies with a B rating averaged 8.12%, while yields for companies with a BB rating averaged 5.59%.

Figure 1: Generic Corporate Bond Yields[[20]](#footnote-20)

A longer-term view of generic corporate debt reveals these averages have been steadily increasing in recent years, with levels peaking in early 2016, as shown in Figure 1. Longer term average costs of debt are lower than recent averages, at 6.57% for a B rating for the period 2013-2016. Given these trends, and that our peer group credit ratings lie between a BB and B rating, we have assumed a cost of debt of 7.75%. This assessment is at the upper end of the range, and is consistent with the increased risk associated with a merchant generating plant operating without a contract.

#### Capital Structure

Capital structure is the ratio of debt to equity used to finance an investment. The appropriate capital structure for a merchant development project can take many forms depending on its particular financing.

To derive an appropriate capital structure for the Net CONE calculation, we reviewed the capital structures of the aforementioned peer group of companies who would be likely to make such an investment. Since each company in the peer group is public, their debt weight, the total market value of the debt outstanding as a percentage of the market value of their total capital (debt plus equity) is available via their filings with the Securities Exchange Commission (“SEC”).

Debt weights for each member of the peer group are shown below:[[21]](#footnote-21)

Figure 2: Peer Group Debt Weights*[[22]](#footnote-22)*

Over the 2015-2016 period, the average capital structure contained a mix of 67% debt and 33% equity.[[23]](#footnote-23) More recently, for the first two quarters of 2016 this average amounts to 75% debt and 25% equity, as shown in Table 26.[[24]](#footnote-24)

Table 26: Total Debt/Total Capitalization[[25]](#footnote-25)

|  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Total Debt/ Total Capitalization (%) | | | | | | | | | | | | |
| Company | **2016Q2** | **2016Q1** | **2015Q4** | **2015Q3** | **2015Q2** | **2015Q1** | **2014Q4** | **2014Q3** | **2014Q2** | **2014Q1** |  | **Average** |
| AES | 69.8 | 70.9 | 75.0 | 74.3 | 68.4 | 68.6 | 68.1 | 67.3 | 65.7 | 67.3 |  | 69.6 |
| CPN | 69.1 | 68.6 | 70.1 | 69.1 | 64.3 | 57.8 | 57.2 | 57.1 | 53.5 | 56.5 |  | 62.3 |
| DYN | 79.7 | 76.7 | 77.5 | 70.5 | 63.2 | 62.1 | 63.1 | 41.0 | 36.5 | 44.5 |  | 61.5 |
| NRG | 80.2 | 81.3 | 82.8 | 79.9 | 72.1 | 70.2 | 68.2 | 66.3 | 59.7 | 62.3 |  | 72.3 |
| TLN | 70.9 | 78.7 | 85.7 | 75.6 | 64.8 | 42.5 | NA | NA | NA | NA |  | 69.7 |
|  |  |  |  |  |  |  |  |  |  | **Average** |  | **67.1** |

While the debt weight of the peer group has, on average, been higher over the last year, we assume this to be a short-duration trend driven by historically low market costs of debt which tend to encourage borrowing over the short term, and depressed equity values. As such, a capital structure more consistent with the longer historical period shown in Figure 2 was assumed. In order to reflect the increased risk of a merchant generator participating in the New England markets, we additionally adjusted the equity weighting upwards to 40% instead of today’s average of 33%. Therefore, an overall capital structure of 60% debt and 40% equity assumes an increased level of return to equity holders.

### WACC Calculation and ATWACC

By inputting the assumptions for ROE, COD, and capital structure described above into the WACC calculation yields a WACC of 10.0%, as shown below:

WACC = 13.4% \* 40% + 7.75% \* 60% = 10.0%

We translated these components to a discount rate by reflecting the effect of taxes on the cost of debt to derive an after tax WACC of 8.1%. This rate was then adjusted for inflation to derive a “real ATWACC” of 6.0%.

### Cost of Capital Comparison

The estimate of WACC described above, as well as each of the key inputs, is consistent with findings utilized in the 2013 Net CONE estimate, the most recent calculation of Net CONE conducted by PJM, and the Net CONE value recently recommended by NYISO Staff.[[26]](#footnote-26),[[27]](#footnote-27),[[28]](#footnote-28) Those values are shown in Table 27.

Table 27. Cost of Capital Comparison

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | ISO-NE (2013) | PJM (2013) | NYISO (2016) | ISO-NE (2015) |
| ROE | 13.8% | 13.8% | 13.4% | 13.4% |
| COD | 7.00% | 7.00% | 7.75% | 7.75% |
| *Capital structure:* |  |  |  |  |
| Debt weight | 60% | 60% | 55% | 60% |
| Equity weight | 40% | 40% | 45% | 40% |
| WACC | 9.7% | 9.7% | 10.3% | 10.0% |

## Revenue Offsets

### Energy and Ancillary Services Revenues

#### Overview

The process to estimate the Energy and Ancillary Services (“E&AS”) offset for each candidate reference technology consisted of three primary steps. *First*, in order to estimate energy revenues, a 20-year forecast of locational marginal prices (“LMPs”) for the Southeast Massachusetts (“SEMA”) load zone was developed via simulation. *Second*, revenues earned from participation in wholesale markets were estimated using an algorithm that estimates revenues from the sale of ancillary services (“AS”) and energy based on a projection of AS payment rates, the LMP forecast, and the variable expenses and operating characteristics of each technology type. *Third*, cash flows from the sale of energy and AS were levelized using the financial model described in Section D. Details regarding the calculation of the E&AS offset for the candidate reference units are provided below. Details of major assumptions are shown in Appendix A.

#### LMP Forecast

LMPs were forecasted using AURORAxmp (“AURORA”), a chronological-dispatch simulation model widely used in the energy industry for price forecasting and market analysis. AURORA, which is licensed by EPIS, Inc., allows for the simulation of wholesale electric markets on an hourly basis on a highly granular level.[[29]](#footnote-29) Using this tool, prices for all load zones in New England were forecasted on an hourly basis for the period 2021-2040.

Key inputs to the LMP forecast included a forecast of delivered gas prices, a forecast of emission allowances for carbon dioxide (“CO2”), a load forecast, a schedule of plant additions and retirements, and an outlook on the transmission grid serving New England and connecting New England to neighboring regions.

#### Gas Price Forecast

The gas price forecast was developed using GPCM, the industry-standard tool for long-term price forecasting and simulation of the natural gas markets. GPCM is licensed by RBAC, Inc. (“RBAC”)[[30]](#footnote-30) The forecast is based on RBAC’s 2016Q2 Base Case, which was developed by RBAC and released in spring 2016. The only change made to the 2016Q2 Base Case was the exclusion of Spectra Energy Corporation’s Access Northeast project. Access Northeast is a project supported by contracts with Massachusetts Electric Distribution Companies (“EDCs”), which were approved by the Massachusetts Department of Public Utilities (“MA DPU”) in Docket 15-37. However, the Massachusetts Supreme Judicial Court found in an appellate decision in Docket SJC-12051 that such contracting by the EDCs was not allowable under Massachusetts law. As a result, it was determined that Access Northeast will likely not be completed, and the project was removed from the GPCM simulation.

Other project upgrades located in the Northeast U.S. and Canada that were included in the 2016Q2 Base Case and that were not adjusted are shown below:

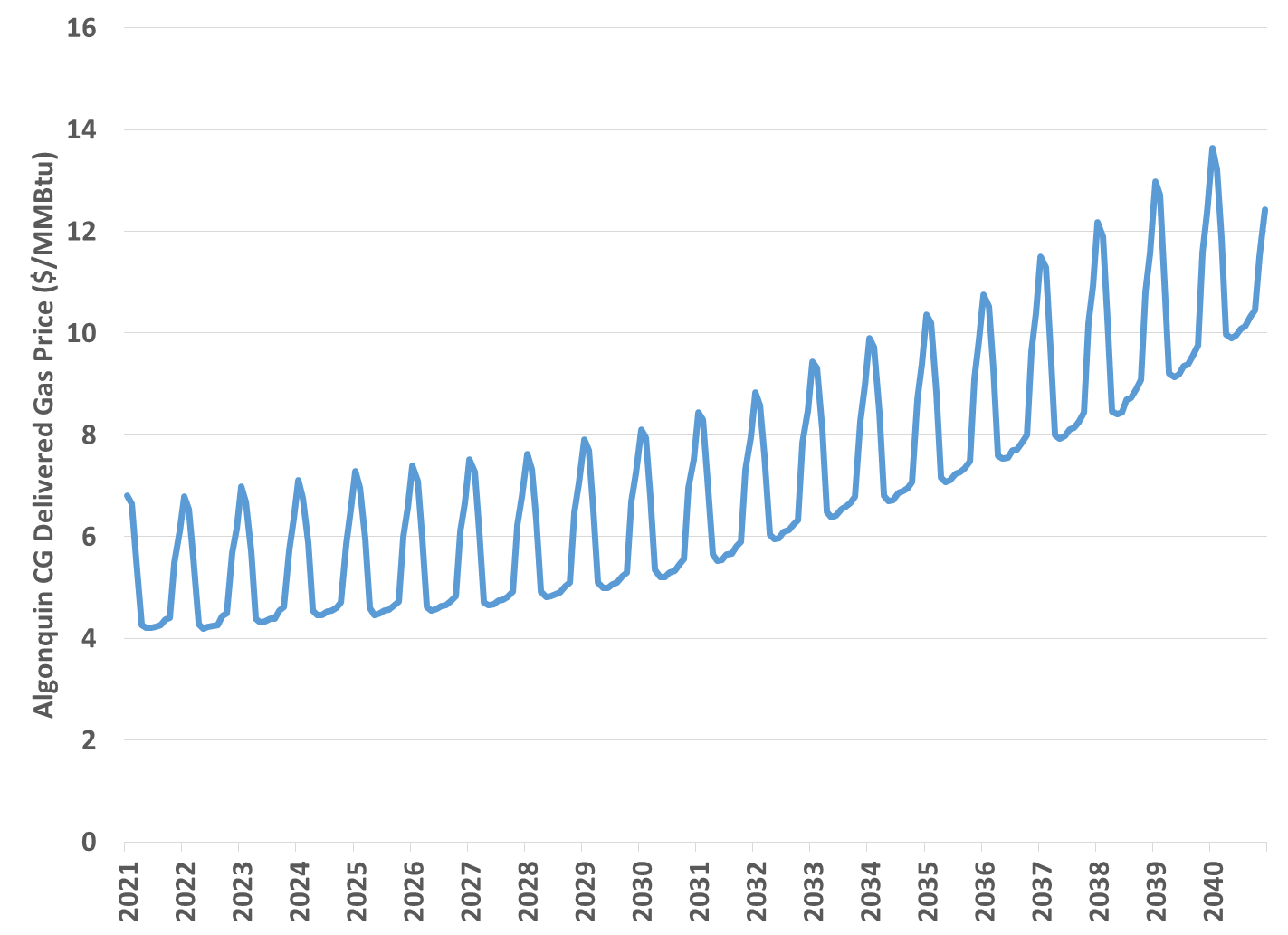
Table 28. Selected Pipeline Expansion Projects Included in the 2016 Q2 RBAC Base Case

|  |  |  |
| --- | --- | --- |
| Pipeline | Project | Capacity (MMcf/d) |
| Algonquin Gas Transmission / Maritimes & Northeast | Atlantic Bridge | 600 |
| Algonquin Gas Transmission / Maritimes & Northeast | Salem Lateral | 115 |
| Algonquin Gas Transmission | Algonquin Incremental Markets | 342 |
| Constitution | New pipeline | 650 |
| Iroquois Gas Transmission System | South-to-North Project | 650 |
| Iroquois Gas Transmission System | Wright Interconnect Project | 650 |
| Portland Natural Gas Transmission System | Coast-to-coast | 300 |
| Tennessee Gas Pipeline | Connecticut Expansion | 72 |
| TransCanada | Eastern Mainline Expansion | 1,203 |

All projects were assumed to enter service before the start of the forecast period in 2021.

The delivered price for the Algonquin Citygates (“Algonquin CG”), the pricing index most relevant to generators in SEMA, is shown below.

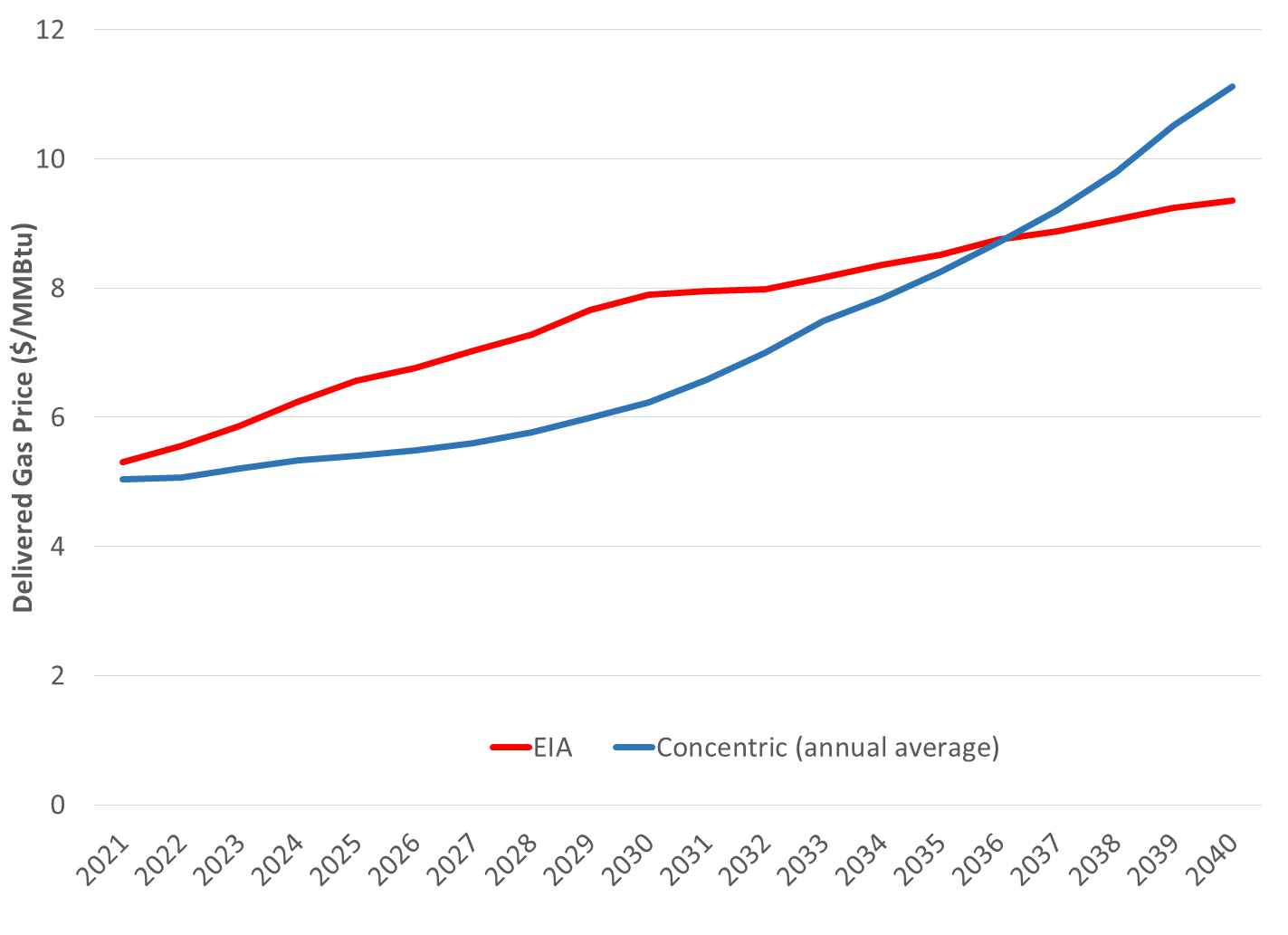
Figure 3: Algonquin CG Price Forecast



The forecast indicates gas prices growing at an average rate of approximately 4.3% per year, on a nominal basis (approximately 2.2%, expressed on a real basis), with more rapid increases in prices observed in the second half of the forecast. Drivers behind rising prices beginning in the early 2030s include upward pressure on the cost of shale gas supply in the Appalachian producing regions, New England’s primary source of gas supply since the late 2000’s, and increasing levels of constraint on the pipelines serving the region as gas demand in New England continues to grow while no major new pipeline expansion projects are added during the forecast period.

Concentric has compared this forecast to other available indices in the public arena and has concluded that it is reasonable. One such comparison is shown in Figure 4, which compares the Algonquin CG forecast to the Energy Information Administration’s (“EIA”) forecast of delivered gas prices for electric power generators in New England, published in the 2016 Annual Energy Outlook.[[31]](#footnote-31),[[32]](#footnote-32)

Figure 4: Comparison of Gas Price Forecast to 2016 AEO*[[33]](#footnote-33)*

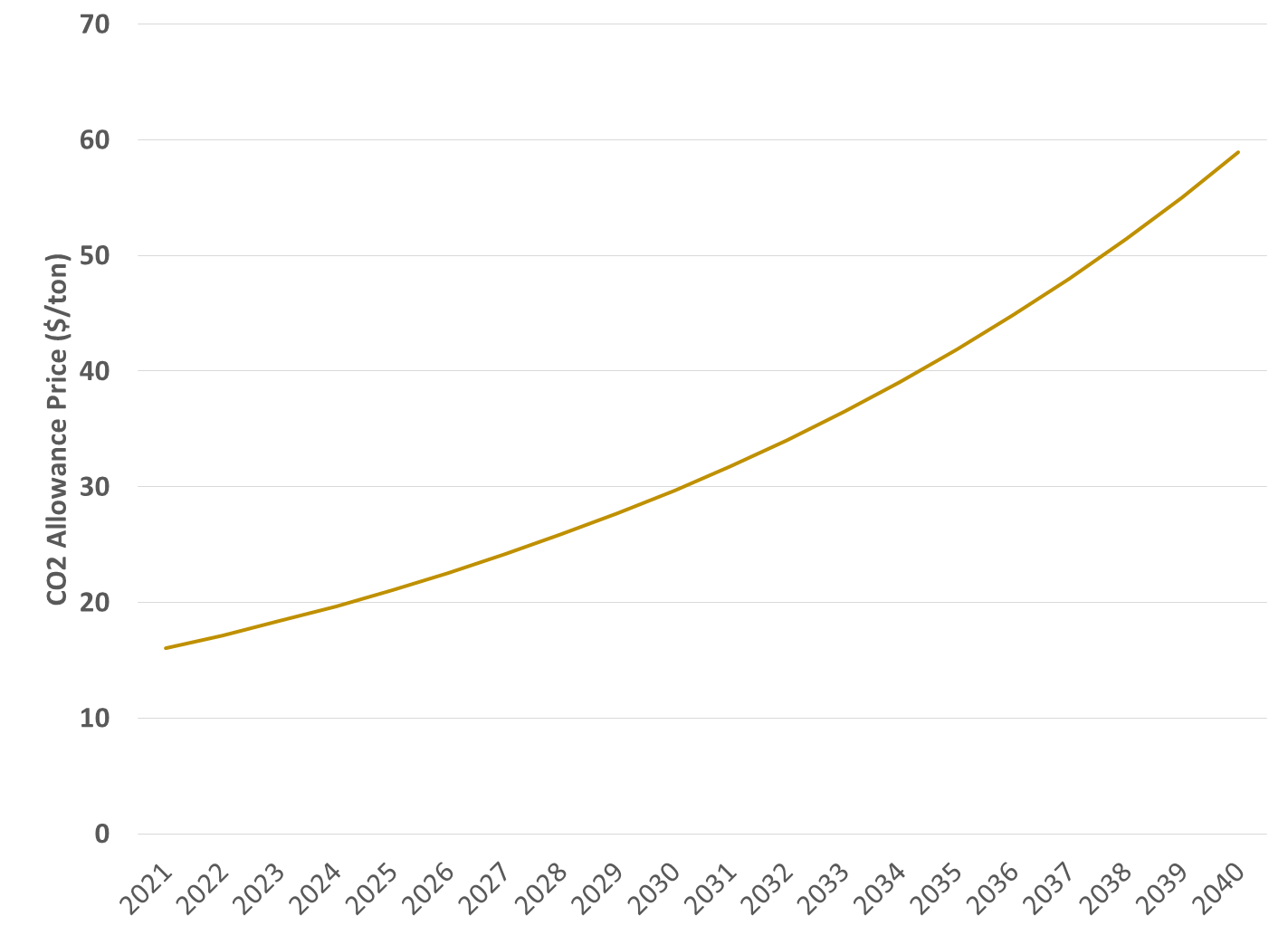


Average prices in the two forecasts are within 10% of each other. The Concentric forecast averages $5.20/MMBtu on a real ($2016) basis for the forecast; the EIA outlook is approximately 8% higher, averaging $5.65/MMBtu.

#### CO2 Allowance Price Forecast

For the CO2 allowance price forecast, Concentric relied on a projection prepared by the vendor of the AURORAxmp model, EPIS. For New England, EPIS modeled the Regional Greenhouse Gas Initiative (“RGGI”) regional budget for the power sector to obtain a RGGI participating state projection of CO2 allowance prices, as shown in Figure 5.[[34]](#footnote-34),[[35]](#footnote-35)

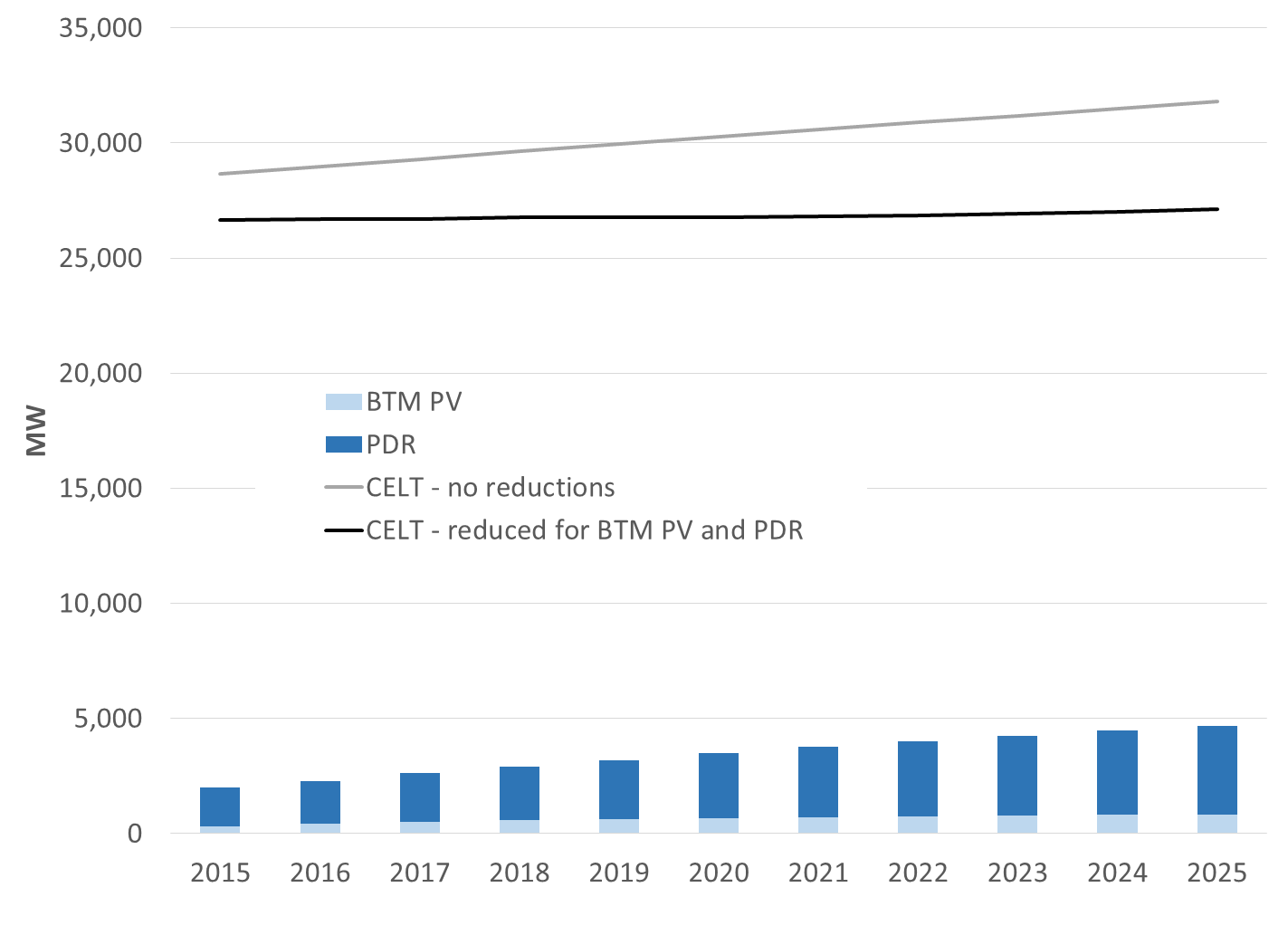
Figure 5: Forecast of CO2 Allowance Prices



#### Load Forecast

The forecast of peak loads was based on the 2016 Capacity, Energy, Load, and Transmission (“2016 CELT”) report, published by ISO-NE. For that forecast, ISO-NE develops a forecast of total electric demand, which is then adjusted downward to account for Passive Demand Response (“PDR”) as well as “behind the meter” photovoltaic (“BTM PV”) capacity.[[36]](#footnote-36) Those forecasts are shown below:

Figure 6: CELT 2016 Load Forecast



For purposes of the market simulation, the load forecast that is adjusted for BTM PV and PDR was utilized. The 2016 CELT provides a forecast through 2025. Thereafter, the forecast was adjusted for by linear extrapolation. The extrapolation calls for annual load growth, net of BTM PV and PDR, of approximately -0.2% beginning in 2026.

The hourly loads, which are required for the LMP forecast, were obtained by modifying (recent year) hourly load shapes to reflect the forecast energy and peak load forecasts.

#### New generation additions

Plants were added to the simulation based on one of several criteria. *First*, plants that had already cleared a capacity auction and had a Capacity Supply Obligation (“CSO”) were added to the generation supply. These plants include the Salem Harbor CC, the West Medway Peaker, the Canal 3 unit, and others. All such plants were added prior to the start of the forecast period.

*Second*, renewable resources are added over the forecast period. For photovoltaic (“PV”) resources, utility-scale plants that have CSOs were added to the generation mix. Following 2019/20, wind capacity was deemed to be more economical than PV for utility-side generation; thus, beginning in 2020/21, all incremental PV was assumed to be added on a BTM basis and was assumed to grow at the same rate as demand.

For wind resources, those plants that had CSOs were added to the generation mix. Additionally, Concentric sought to address the legislative mandate in Massachusetts for EDCs to solicit up to 1,600 MW of offshore wind, provided that such resources are “cost effective”.[[37]](#footnote-37) Based on previous experience in Massachusetts and experience in other states, we have determined that a successful solicitation of the full amount authorized is unlikely.[[38]](#footnote-38) Instead, we have added an offshore wind facility to the generation mix based on an existing project currently in development whose size is approximately 25% of the total offshore capacity authorized in Massachusetts legislation. The offshore facility was added at the beginning of the 2027/28 delivery period, the date mandated by the legislation.

Other wind resources are added over the forecast period to meet load growth.[[39]](#footnote-39) This assumption recognizes two important realities – i) the degree to which state Renewable Portfolio Standards (“RPS”) targets are achieved is not simply a function of state mandates, but rather a combination of forces that can affect the ability of states to meet the mandated RPS requirement in any particular year, as shown in Figure 7 below; and ii) there are ways to meet the RPS mandates that don’t necessarily involve building renewable facilities so assuming that mandates will be met with new renewable facilities will likely overstate the amount of renewable capacity coming into the market over the forecast period.

Figure 7: Total New England RPS Achievement



*Third,* in later years of the forecast, generic gas-fired generation was added to the capacity mix to maintain a reserve margin of 15% in each load zone for reliability purposes. Such resources were added in 2021, 2023, 2025, 2026, 2030, 2031, 2033, 2036, and 2037.

#### Plant Retirements

The retirement of plants is also a multi-step process. *First*, those plants that have announced their intention to retire and do not have a CSO for a future commitment period were removed from the generation mix. These included Bridgeport Harbor, Brayton Point, and the Pilgrim Nuclear Generation Station, and others, all of which retire prior to the beginning of the forecast.

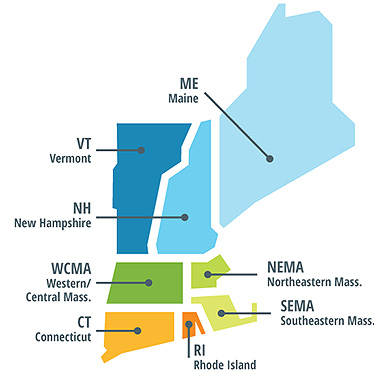
*Second*, older nuclear plants were retired at the end of the current operating licenses. These include Seabrook and Millstone 2.[[40]](#footnote-40)

*Third,* later in the forecast, plants were retired for economic reasons. AURORA includes an iterative, endogenous retirement function that compares the avoidable, going-forward cost of owning and operating a facility to the net revenues (*e.g.* energy revenues minus costs) to be earned by the facility based on the market outlook contained in the forecast. If going-forward costs are expected to be greater than net revenues on a present value basis, the plant is retired. Typically, such retirements are applied to older, non-gas units. These included Canal 1 and Canal 2, Mystic 7, Yarmouth 1-4, and others.

#### Transmission Topology

For purposes of the price forecast, the simulation model was run in a zonal configuration reflecting the New England load zones. A map of the zones is shown below:

Figure 8: ISO-NE Load Zones*[[41]](#footnote-41)*



Transfer limits between zones are based on data obtained from ISO-NE, which are shown in Table 29.

Table 29. Transfer Limits Between Load Zones

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Interface | Limit (MW) |  | Interface | Limit (MW) |
| Boston\_Import(I) | 5700 |  | **NH\_VT(II)** | 1025 |
| SEMA\_RI\_Export | 3400 |  | **WCMA\_CT(III)** | 930 |
| SEMA\_RI\_Import | 1280 |  | **RI\_CT** | 750 |
| CT\_Import | 2950 |  | **NEMA\_SEMA(IV)** | 1500 |
| North\_South(I) | 2675 |  | **WCMA\_NEMA** | 2500 |
| ME\_NH | 2000 |  | **WCMA\_VT** | 900 |
| (I) After the Boston Upgrade Project completion | | | | |
| (II) Not rated in the opposite direction | | | | |
| (III) 1030 MW in the opposite direction | | | | |
| (IV) 750 MW in the opposite direction | | | | |

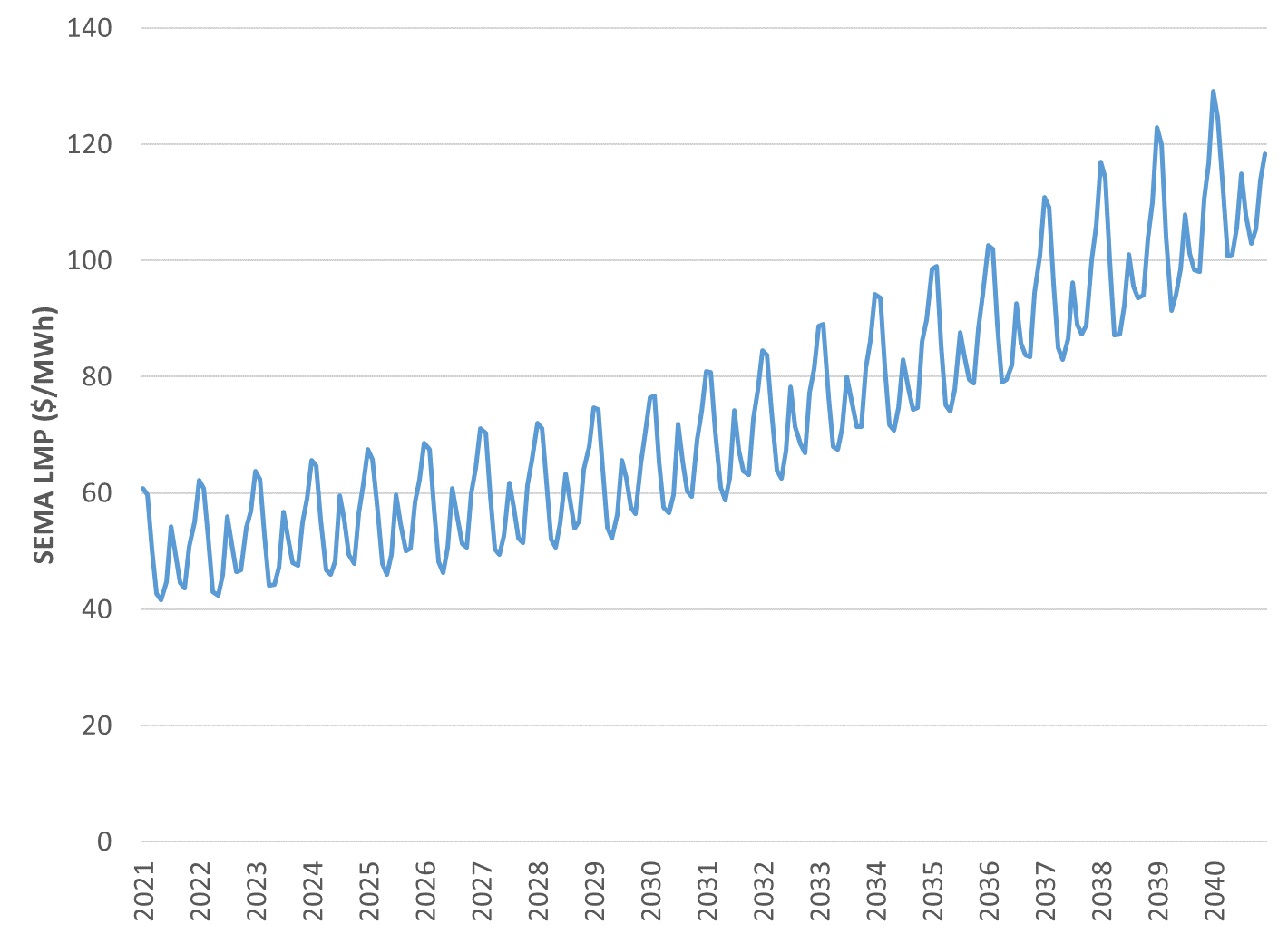
The Greater Boston Upgrades project was assumed to be in place in 2019, with a net increase of 850 MW on the Boston Import interface (N-1), and 575 MW increase on the North-South Interface.[[42]](#footnote-42)

In addition, transmission links with neighboring regions outside of New England were modeled. For the forecast, all external transmission links were held constant with one exception, the addition of a 1,000 MW transmission line between New Hampshire and Quebec, consistent with Section 83C of the Massachusetts Green Communities Act, which *authorizes* the Massachusetts EDCs to contract for offshore wind provided that doing so is cost effective but *requires* contracting for 1,200 MW of land-based renewables. Based on an analysis of market options as well as a review of existing proposed transmission projects, it was determined that the most likely avenue of compliance for the EDCs was the development of a transmission asset to import renewable energy from Canada, where hydroelectric power is abundant and inexpensive. Additionally, significant commercial interest in such projects predates the enactment of Section 83C.

The 1,000 MW line is installed at the beginning of the forecast as an “energy-only” resource. That is to say that there is no capacity associated with the line that contributes to the region’s ability to maintain reserve margins. There are no transmission upgrades associated with the project that would affect transfer limits between the zones within New England.[[43]](#footnote-43)

Based on the above assumptions, a forecast of LMPs for SEMA was developed, as shown below:

Figure 9: SEMA LMP Forecast

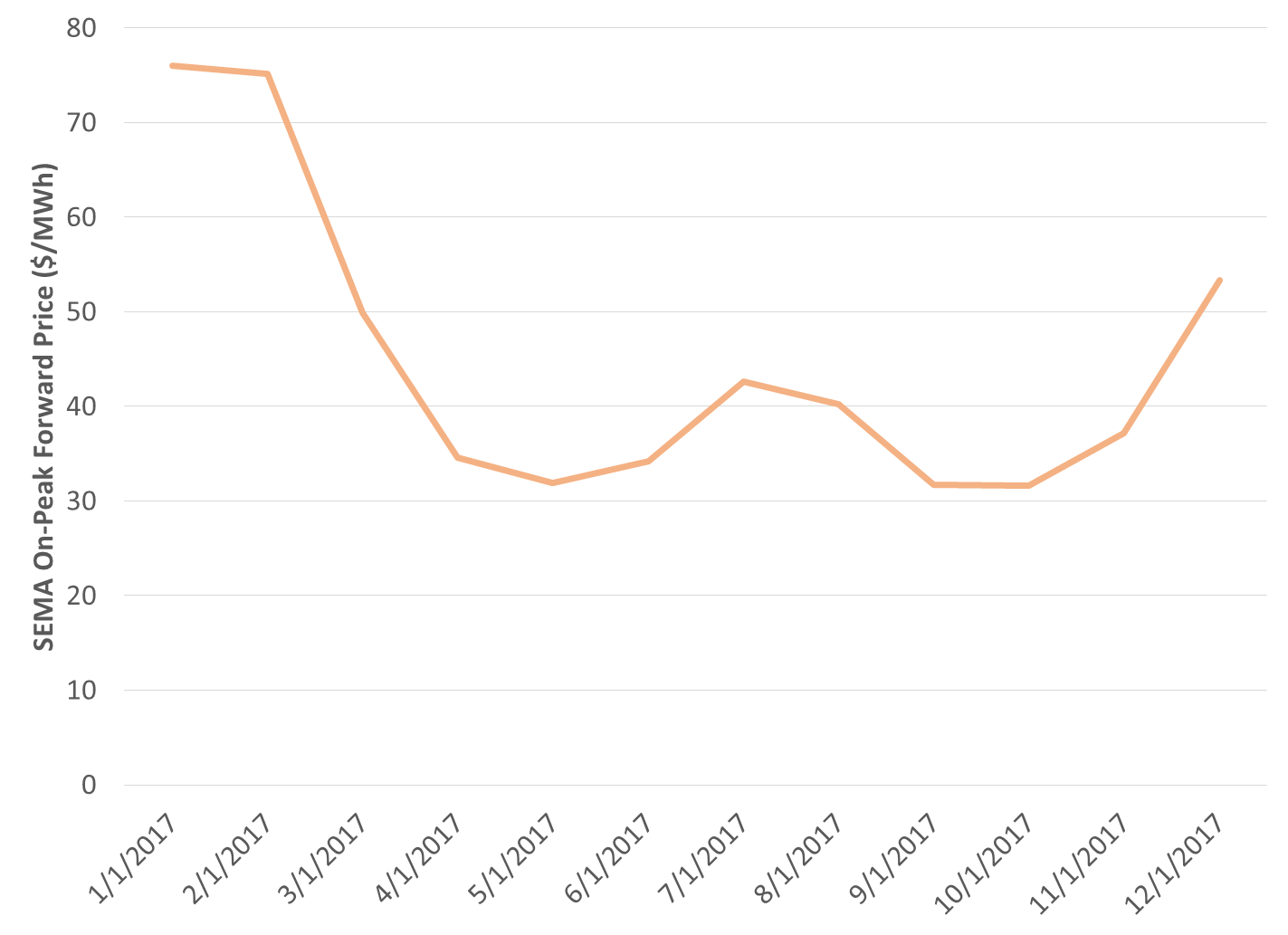


Generally, the forecast follows the contours of the gas price forecast shown in Figure 3. Prices rise moderately through approximately 2030, and more rapidly thereafter, following the same trend in the gas price forecast.

#### Forecast Validation

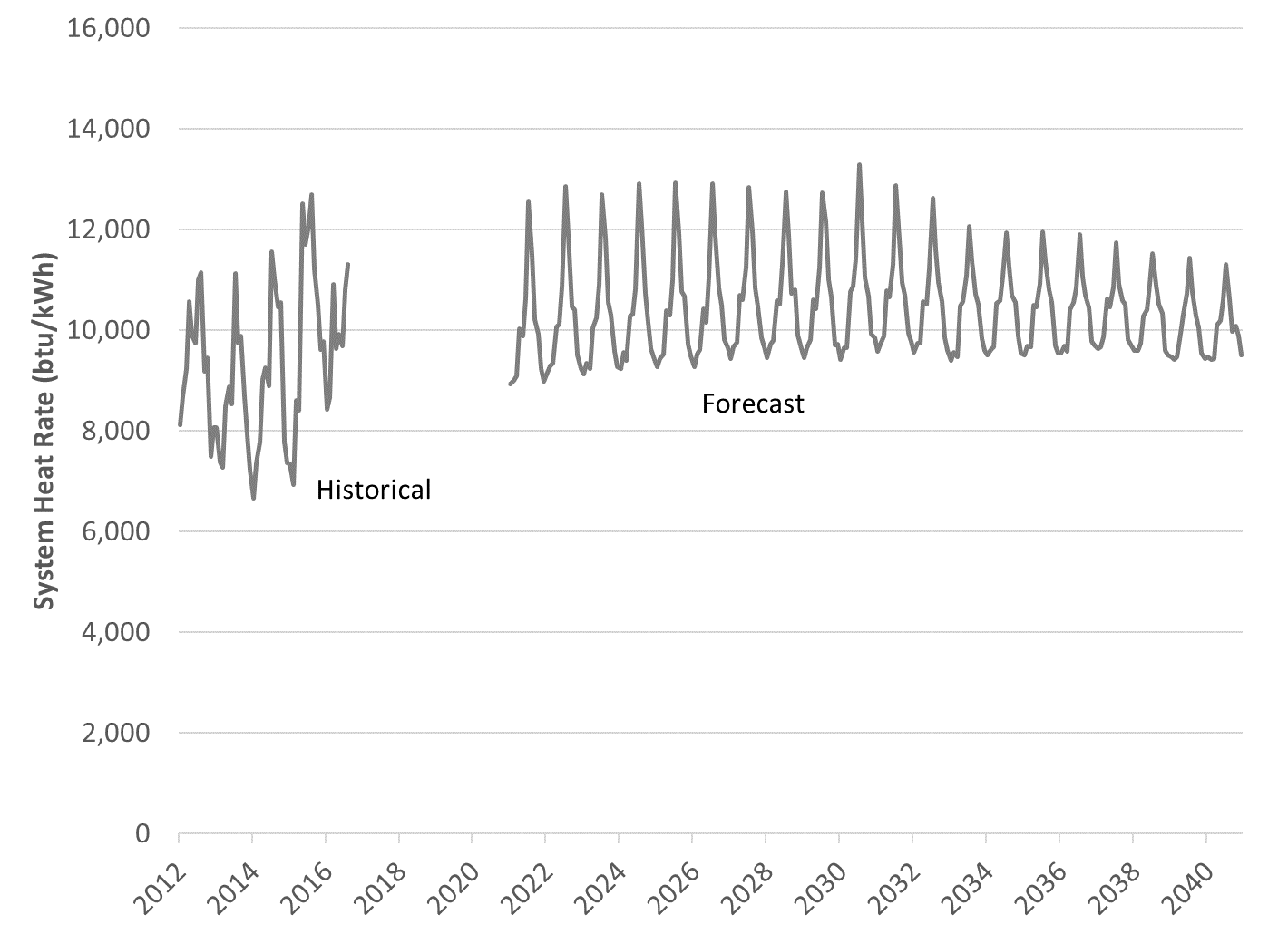
The forecast indicates an expectation of winter-peaking prices, with a smaller peak during the summer months. This is a departure from historical pricing patterns in New England, in which prices were generally higher in the summer, and are primarily due to higher levels of seasonal price differentials in the gas price. This finding has been validated by review of settlements for New England LMP indices in the forward market, which reflect the same expectation in the market. Figure 10 shows the curve for 2017 settlements for on-peak LMPs in SEMA traded on the Intercontinental Exchange (“ICE”) on September 23, 2016.[[44]](#footnote-44) Note the significant peak in the winter months and a smaller peak during July and August.

Figure 10: 2017 Settlements for On-Peak SEMA LMPs



An analysis of System Heat Rates (“SHRs”) was utilized to further validate the forecast. SHRs are the relationship between market gas and market power prices. For any hour, the SHR is equal to the ratio of the LMP, in $/MWh, and the gas price, in $/MMBtu.[[45]](#footnote-45) Figure 11 shows the comparison of historical SHRs for SEMA, calculated using the ratio of the average monthly SEMA price to the average monthly Algonquin CG price, to the forecast SHRs, calculated by the same ratio using the price curves shown in Figure 3 and Figure 9.[[46]](#footnote-46)

Figure 11: Comparison of Historical to Forecast SHRs



The historical period shows a trend of rising SHRs, indicating a “tightening” market in which demand is growing more quickly than generation supply. SHRs in the beginning of the forecast are generally consistent with those observed at the end of the historical period, and remain so through the late 2020s. Thereafter, SHRs begin to fall due to three factors. First, renewables, primarily in the form of new wind entry and BTM PV are added over the course of the forecast, providing an inexpensive source of energy. Second, as older, inefficient plants retire, as described above, they are replaced with new, modern, gas-fired units, which are more economical and increase the efficiency of the market. Third, load growth, net of the adjustments described above is lower than historical rates throughout the forecast.

#### Ancillary Services Payment Rates

Generators in New England can receive payments for voltage regulation, Net Commitment Period Compensation (“NCPC”), Forward Reserves (“FR”), and Real-time Reserves (“RTR”). A gas turbine will not be expected to receive payments for regulation; therefore, this revenue stream is excluded from the estimate ancillary service (“AS”) revenues. Simple Cycle GTs are likely to receive NCPC payments; however, these are “make whole” payments designed to compensate generators who are dispatched out of economic merit to provide reliability services to the market, thus incurring losses. Since our LMP and revenue forecasts are developed on an hourly basis and do not dispatch facilities out of merit, no such losses are incurred. Therefore, NCPC payments are excluded from the estimate of AS revenues.

A new Simple Cycle GT will be expected to provide FR and RTR and thus receive compensation from the market for these services. To estimate the rates at which a GT would be paid for the services, average payment rates were developed based on historical clearing prices in the reserve markets.

***Locational Forward Reserve Market***: For each of the five commitment periods beginning with 2011/2012 through 2015/2016, a seasonal-weighted average clearing price was calculated for each product using the Rest of System Clearing Prices (the location of the reference unit). The Forward Capacity Market Clearing Price was then subtracted from this result to obtain an annual average LFRM price, in units of $ per MW-month. This annual average LFRM price was then divided by the average on-peak hours each month to give the average annual LFRM price in units of $ per MWh. The results for each of the five commitment periods are shown below. Consistent with prior treatments, we computed a final ‘Mid-3’ annual average by taking the average of the three annual values after excluding the highest and lowest outliers. The resulting values are shown in the tables below.

**Forward Reserve Seasonal Average Clearing Prices in $/MWh***(bold values used in the “Mid-3 Average)*

|  |  |  |
| --- | --- | --- |
| **Period** | **LFRM TMNSR ($/MWh)** | **LFRM TMOR ($/MWh)** |
| **2011-12** | 2.38 | 2.38 |
| **2012-13** | 1.19 | 1.19 |
| **2013-14** | 13.88 | 9.60 |
| **2014-15** | 20.89 | 20.89 |
| **2015-16** | 6.35 | 6.35 |
| **Mid-3 Average** | **7.54** | **6.11** |

Prior to applying the rates above in the E&AS model, an adjustment was made to account for penalties in the Forward Reserve Market. The E&AS model does adjust revenues to account for expected unit availability – for example, it is assumed that the unit will not be 100% available for dispatch over the life of the unit. However, this does not fully account for Failure to Reserve penalties due to other conditions. Actual FRM penalties assessed to participants with GT resources that regularly participate in the LFRM were analyzed over the five-year study period (corresponding to the total period covered in the tables above). The Failure to Reserve MWh averaged 2.1% of the total FRM Obligation MWh for the LFRM participants using (only) GT resources to meet their FRM Obligations. The average penalty charges (in dollars) were 3.5[[47]](#footnote-47). Accordingly, the LFRM average revenue values described in the tables immediately above were adjusted by 3.5% to account for the penalties that could be reasonably expected in the Forward Reserve market.

***Real-Time Reserve Market:*** For each of the five commitment periods beginning with 2011/2012 through 2015/2016, an average RTR clearing price was calculated for each RTR product for all off-peak hours.[[48]](#footnote-48) Consistent with the LFRM calculations, a ‘Mid-3’ annual average was calculated using the three annual values that exclude the highest and lowest outliers. The resulting values are shown in the Tables below, in both $/MWh and $/kW-month, and were applied in the E&AS model.

**Real-Time Reserve Average Clearing Prices in $/MWh***(bold values used in the “Mid-3 Average)*

|  |  |  |
| --- | --- | --- |
| **Average Off-Peak Clearing Price** | **RTR TMNSR  ($/MWh)** | **RTR TMOR  ($/MWh)** |
| **2011/12** | 0.05 | 0.05 |
| **2012/13** | 0.67 | 0.66 |
| **2013/14** | 1.97 | 1.70 |
| **2014/15** | 0.96 | 0.96 |
| **2015/16** | 0.39 | 0.39 |
| **Mid-3 Average** | **0.67** | **0.67** |

#### Revenue Forecast - Simple Cycle GT

Revenues for the Simple Cycle GT were estimated using a calculation that approximates a simplified dispatch regime for the facility. In any hour, the GT can receive payments for the sale of one of more of FR, energy, and/or RTR. Derivation of expected sales and net revenues for each payment stream are described below:

*Forward Reserve*

Simple Cycle GTs are paid for FR during weekday, on-peak hours, excluding NERC holidays (hereinafter “FR hours”). On-peak hours are defined as the 16 hours beginning with the eighth hour of the day and ending with the twenty-third hour of the day. In consultation with experts at the General Electric Company (the vendor of the reference GT technology), it was determined that 30% of the unit’s 338 MW unit capability can be delivered from a cold start in 10 minutes and the remaining capability can be delivered in 30 minutes. Therefore, in each eligible FR hour, a GT is expected to receive a payment of $7.54/MWh for 100 MW of 10-minute non-spinning reserve and $6.11 for 238 MW of 30-minute operating reserve, adjusted for inflation, multiplied by its capacity, multiplied by its availability, which is assumed to be 97%.

*Energy*

During FR hours, a Simple Cycle GT is required to offer its energy into the market at a price equal to or greater than the Threshold Daily Price. The Threshold Daily Price is a function of the natural gas price and the Forward Reserve Heat Rate, which is calculated and published by ISO-NE.

For the revenue estimate, the latest available Forward Reserve Heat Rates were held constant for the forecast period. Those heat rates are shown in Table 31:

Table 31: Forward Reserve Heat Rates

|  |  |
| --- | --- |
| **Season**[[49]](#footnote-49) | **Forward Reserve Heat Rate** *(btu/kWh)* |
| Summer | 17,539 |
| Winter | 19,935 |

Thus, for each day of the forecast, the Threshold Daily Price is calculated as the product of the applicable Forward Reserve Heat Rate and the gas price in SEMA.

The unit is assumed to sell energy and receive revenues during FR hours if the LMP is higher than the Threshold Daily price *and* if the LMP is high enough to cover the unit’s operating costs, which include the gas cost, its cost of CO2, and its VOM. Each unit’s gas cost is calculated as the gas price multiplied by its operating heat rate (rather than the Forward Reserve Heat Rate).

During non-FR hours, the unit will sell energy and receive revenues in any hour in which its operating costs are lower than the LMP. During non-FR hours, there is no requirement that the unit offer energy at the Threshold Daily Price.

In any hour in which the plant sells energy, its revenues are equal to the difference of the LMP less its operating costs (natural gas, VOM, and CO2), multiplied by its capacity multiplied by its availability. Revenues are based on the unit’s actual operating heat rate rather than the Forward Reserve Heat Rate.

*Real-time Reserve*

For any non-FR hour, the plant will be paid for RT reserves if it is not operating in the energy market. Payments for such hours is equal to the applicable RT payment rate multiplied by its capacity for each product (10-minute or 30-minute) multiplied by its availability.

#### Revenue Forecast – Combined Cycle, Aero, & Hybrid

The process by which the E&AS offset is calculated for other candidate reference technologies is similar to the calculation for the Simple Cycle GT. The same LMP and gas forecasts are used, the gas-turbines are dispatched in the same manner, and the process by which the cash flows are levelized to calculate the offset remains the same. Variations in the procedure for each technology are described below.

*Combined Cycle –* The combined cycle unit has different operating characteristics than the simple cycle units, which are input into the energy revenues algorithm. Additionally, analysis of historical data indicates that combined cycle units earn the wide majority of their revenues from the sale of energy, rather than from the sale of AS, and that AS revenues are reasonably predictable if energy revenues are known. Based on this analysis, the AS adder for a CC is assumed to be equal to 0.9% of its energy revenues.

*LM6000 and LMS100* – Both the LM6000 and LMS100 have different operating characteristics than the simple cycle frame unit, which are input into the energy revenues algorithm. The AS assumption for each is the same as for the simple cycle frame unit.

### Pay for Performance

ISO-NE’s pay for performance” (“PFP”) mechanism is designed to encourage resource performance consistent with its assumed capacity obligation. Under PFP, a resource that underperforms will forfeit some or all capacity payments awarded in a FCA. Resources that perform in its place will receive these capacity payments. Exposing resource owners to the risk of forfeiting capacity payments for underperformance, as well as providing them the opportunity to receive more compensation for over performance, is designed to incent resource owners to make investments that ensure their resource can perform.

In calculating expected compensation for CONE technologies, we consulted with ISO-NE and stakeholders, and reviewed and discussed ISO-NE’s most recent study on expected system conditions and shortage hours over the life of the generating facilities. A review of historical data shows relatively few shortage hours since the PFP mechanism was implemented. However, it is important to note that the objective of the CONE/Net CONE analysis is to calculate what a merchant developer would need to enter the market given reasonable expectations of future system conditions. Historical data reflects a system that has enjoyed substantial excess capacity of approximately 3,000 MW, so that using this data to extrapolate future system conditions is not appropriate.

In fact, ISO-NE’s recently released shortage hour event analysis shows relatively few shortage hours in the near term. However, it is expected that much of the existing capacity excess, which began to dissipate over the most recent three capacity auctions and now stands at 1,416 MW, will continue to decrease over time. Beyond year three, ISO-NE does not expect current excess capacity conditions to persist and is modeling a system at equilibrium after the three-year transition period ends. This is consistent with our started assumption of calculating CONE/Net CONE under long-term equilibrium conditions.

Based on ISO-NE’s most recently published analysis, we have assumed six shortage hours for years one through three by extrapolating between the shortage hour values at a capacity surplus of 1,200 MW and 1,600 MW as shown in the ISO-NE analysis.[[50]](#footnote-50) For years four and beyond, we have assumed a system at equilibrium with assumed shortage events at 11.3 hours per year. We have assumed penalty rates of $3,500/MWh for years one through three, and $5,455/MWh beginning in year four consistent with rates filed and accepted by the FERC in ISO-NE’s PFP filing.[[51]](#footnote-51) This penalty rate was not recalculated based on the new shortage hour analysis since it is not a formulaic rate but rather a filed rate with the FERC. Therefore, a recalculation would be high speculative at this time. A balancing ratio of 0.85 was used, consistent with previous ISO-NE analysis.

We have assumed a performance score of 0.92 for a combined-cycle generator based on ISO-NE analysis this technology.[[52]](#footnote-52) For a simple cycle generator, we have assumed a performance score of 0.98 consistent with the expected forced outage rate for this technology based on consultation with MM and the assumption that a state-of-the-art fast-start unit would generally be expected to capture shortage hour revenues unless on an outage. Our shortage hour assumptions are shown in Table 32 below.

Table 32: Shortage Hour Assumptions

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Technology** | **Scarcity Hours at Criteria (hrs)** | **Performance Payment Rate ($/mWh)** | **Average Actual Performance (%)** | **Average Balancing Ratio (%)** | **Net Performance Payments ($/kW-mo)** |  |
| Combined Cycle | 11.3 | $5,455 | 0.92 | 0.85 | 0.36 | years 4 - 20 |
| Combustion Turbine | 0.98 | 0.67 |
| Combined Cycle | 6 | $3,500 | 0.92 | 0.85 | 0.12 | years 1-3 |
| Combustion Turbine | 0.98 | 0.23 |

#### Levelization

Levelization of the E&AS revenues is conducted in the same manner as the other cash flows of relevance. The total levelized value of the E&AS offset for the GT is $3.31/kW-month, which is comprised of $0.25/kW-month for energy, $2.58/kW-month for ancillary services, and $0.48/kW-month for PFP.

Table 33: Levelized Offset by Technology

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Levelized Offset (2021$/kW-mo)** | **Energy** | **Ancillary Services** | **PFP** | **Total** |
| Combustion Turbine | 0.25 | 2.58 | 0.48 | 3.31 |
| Combined Cycle | 5.31 | 0.05 | 0.26 | 5.62 |
| Aero | 0.22 | 2.93 | 0.48 | 3.63 |
| Hybrid | 0.26 | 2.93 | 0.48 | 3.67 |

## CONE Calculation and Results

The CONE/Net CONE is calculated as the revenue required for entry in the first year of operation, or CONE, less the expected first year revenue offsets. A summary of the CONE/Net CONE values for the evaluated technologies are shown in Table 34 below.

Table 34: Net CONE Summary for Candidate Reference Technologies (2021$)



## CONE Annual Update Process

### E&AS Revenues

Periodically, the E&AS offset is updated to reflect changes in expectations regarding the profitability of merchant generators entering the market. The current procedure is described in Market Rule 1 Section III.13.2.4.[[53]](#footnote-53)

Concentric is proposing a change to the update procedure that relies on publicly available forward prices to quantify the change in profitability expectations. For the reference unit, profitability is a function of the spread between electric prices and delivered gas prices. Therefore, the E&AS update will be based on changes to the relationship between electric forwards and gas forwards, both of which are publicly available from ICE. Calculations will be based on settlements for the 2021/2022, which is currently the farthest date forward in time for which power settlements are available.

Calculations will be based on three contracts on ICE, an Algonquin Citygate basis swap (ICE contract code ALQ), the Henry Hub futures price (H), and the MassHub DA On-Peak Future (NEP). The basis swap is added to the Henry Hub futures prices to create an index for a delivered Algonquin CG price. The ratio of the power price to the delivered gas price is then calculated for each month, after which the twelve monthly ratios are averaged. Table 35 shows the calculation using settlements on ICE from September 23, 2016:

Table 35: Calculation of Power: Gas Ratio for E&AS Offset Update



In the future, these calculations will be performed again using the same indices and for the same settlement periods. The average ratio that results will be compared to the ratio shown above. The percentage difference (positive or negative) in the ratios will be applied to the E&AS offset.

Timing of the E&AS update will be determined by ISO-NE.

### Capital and Fixed Costs Updates

Pursuant to Tariff requirements, for years in which no full recalculation of CONE/Net CONE values is performed, the CONE/Net CONE values associated with the reference technology will be updated pursuant to the cost indices contained in Market Rule 1 Section III.A.21.2. for each relevant cost component. Indices covering the most recent 12 months at the time will be compared against the current values to calculate the appropriate escalation rates.

Section 4:  
ORTP Study

## Introduction

ISO-NE ensures that sufficient resources are available to meet future demand for electricity through the FCM. Under the FCM design, auctions are held annually, three years in advance of the period during which resources must deliver their capacity. Resources compete in the auctions to obtain a commitment to supply capacity in exchange for a market-priced capacity payment. These payments support the development of new resources and retain existing resources when and where they are needed.

The FCM design includes a mechanism to protect against the price suppressing effects of uncompetitive new resource offers. This mechanism subjects all new entrants in the FCA to a benchmark known as the ORTP. The ORTP acts as a "screen" for potentially new uncompetitive resources offers in an FCA. It does so by setting benchmark prices intended to represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. New supply offers above the ORTP level are presumed to be competitive and not an attempt to suppress the auction clearing price, while offers below the ORTP level must be reviewed by the IMM pursuant to a unit-specific review process. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

## Approach

The objective of this ORTP study was to develop updated ORTP values for FCA-12 for a 2021/2022 Commitment Period. Consistent with guidance from ISO-NE and FERC, the recommended ORTPs presented in this report were set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues. In addition, consistent with Tariff requirements, all resources were assumed to have a contract for their output.[[54]](#footnote-54)

The study process consisted of the four basic tasks outlined below and further described in the balance of this report:

1. **Resource Screening and Selection**. The first step in the process was the development of screening criteria for the selection of resource types for which to calculate an ORTP. Those resources that passed the screen were subject to a full evaluation of costs and revenues over the expected life of the facility
2. **Calculation of CONE.** Recognizing the low end of the competitive range requirement for the ORTP values, we developed technical specifications, installed capital costs and operating costs over the 20 year expected life of the facility (11 years for Energy Efficiency and Demand Response) for each of the selected technologies. Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we calculated a first year revenue requirement that ensured the recovery on and of investment costs.
3. **Calculation of Expected Revenues.** We estimated expected revenues for each of the selected technologies, including energy revenues (net of variable costs), ancillary service revenues, REC revenues and pay for performance PFP revenues.
4. **Calculation of Net CONE.** Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market in the first year of operation (2021) at a net present value of zero over the forecast period. This Net CONE represents the recommended ORTP level.

Each of these tasks involved a detailed review of historical data, forecast of future prices, and professional judgement in order to calculate benchmark prices for each technology. These parameters were informed through consultation with ISO-NE and stakeholders in four separate meetings in order to ensure the effectiveness and appropriateness of the methods and data used.

## Resource Screening Criteria, Process and Selection

We began our ORTP study by establishing the criteria against which we would screen potential resources for the calculation of an ORTP value. The screening criteria used and reviewed with stakeholders consistent with the criteria accepted by the FERC in the 2013 ORTP study, was as follows:

* + Must represent technologies that have been installed in the region and participated in recent FCAs;
  + Must have reliable cost information available to calculate an ORTP using a full “bottom-up” analytical approach;
  + Must have a first year revenue requirement below the FCA starting price.

These criteria were applied consistently to potential resources identified in consultation with stakeholders. Ultimately, the criteria were used to select a subset of resources for which a full evaluation would be conducted and an ORTP would be established. Resources that were considered in the screening process, and the outcome of that process are shown in Table 36 below.

Table 36: Resource Screening Results

|  |  |  |  |
| --- | --- | --- | --- |
| Technology Type | Installed in New England and Participated in Recent FCAs \* | Reliable “Bottom Up” Cost Data | 1st Year Revenue Requirements < FCA Starting Price |
| **Simple Cycle Gas Turbine** | Yes | Yes | Yes |
| **Combined Cycle Gas Turbine** | Yes | Yes | Yes |
| **On-Shore Wind** | Yes | Yes | Yes |
| **Solar** | Yes | Yes | Yes |
| **Biomass** | Yes | No | N/A |
| **Off-Shore Wind** | No | No | N/A |
| **Batteries** | No | No | N/A |

We were asked by stakeholders to consider off-shore wind, biomass, solar, and batteries in the ORTP process. In terms of off-shore wind, there are no off-shore wind projects in operation in the U.S., although there is a demonstration project that has entered a test phase in Rhode Island. Stakeholders suggested a review and application of data from off-shore wind projects operating in Europe. However, in consultation with MM, we determined that data from off-shore wind resources in Europe cannot be reasonably applied to a hypothetical off-shore wind farm in New England.

In considering biomass resources, it was determined that the variability of fuel and fuel gathering costs, as well as high initial capital costs, does not justify the calculation of a resource-specific ORTP.

Regarding battery technology, we determined that this technology is still in the development stages and that no reliable data exists on which to base an ORTP calculation.

An ORTP for solar resources ultimately was not recommended, although the industry has seen dramatic cost reductions over the past three years. Based on a conservative estimate for installed costs of approximately $2,100/kW (in 2016$) (compared to an assumed value of $3,139//kW in the 2013 ORTP study), we determined that costs remain too high to justify an ORTP below the expected auction starting price based on our recommended Net CONE technology and the associated value presented in this report.[[55]](#footnote-55) In order for the ORTP for a solar resource to fall below the assumed auction starting price, the capacity factor for the solar resource must be approximately 18%. A review of historical data provided by ISO-NE showed a system-wide weighted average capacity factor of approximately 14%, which does not support an 18% capacity factor assumption.

We received input from stakeholders on the lack of a calculated ORTP value for some resources and the recommended ORTP value for other resources. It is important to note that FERC has opined on the absence of a resource-specific ORTP value. In its February 2014 Order, the FERC confirmed that the lack of a resource-specific ORTP value does not create undue uncertainty or impose an unduly discriminatory burden on a developer. The FERC went on to state:

“To the extent that a resource owner, including a consumer-owned utility, believes that its costs are lower than the applicable trigger price, it can seek a lower offer floor by submitting its unit-specific costs to the IMM.”[[56]](#footnote-56)

Based on the screening process as described above, we selected the following resources for which to calculate an ORTP value:

* + Simple Cycle GT
  + Combined Cycle GT
  + Onshore Wind
  + Energy Efficiency
  + Large Demand Response (Large DR)
  + Mass Market Demand Response (Mass Market DR)

## Financial Assumptions

Similar to the calculation of Net CONE, the calculation of ORTP requires a real discount rate to translate uncertain future cash-flows to a levelized first year revenue requirement. The approach to determining the appropriate discount rate for ORTP values is identical to the approach taken for the calculation of Net CONE, except that the ORTP tariff specifies a contract for non-capacity revenues. As such, the inputs for cost of capital have to be adjusted accordingly to reflect a lower risk than that of the CONE calculation. Ultimately, the ORTP values reflect the “low end of the competitive range,” and therefore require lower returns to equity and debt holders.

We determined that 7.3% is an appropriate after-tax weighted average cost of capital at which to evaluate ORTP values. This nominal discount rate is consistent with previous ORTP studies in New England.

To derive this ATWACC, we adjusted inputs to the cost of capital to reflect the low end of the competitive range and to account for the lower risk associated with contract-backed energy revenues. First, we adjusted the cost of debt to more closely reflect the generic corporate debt of a higher rated company. Instead of a cost of debt of 7.75% which aligns closely with a B rated company, we assumed a lower cost of debt of 6.5%, which is more in line with the average costs of debt for a company with a B+ rating.

Second, we adjust the return on equity a full percentage point lower to reflect contracted revenues according to the Power Purchase Agreement (“PPA”) assumption specific in the tariff. We estimated ROE using the CAPM, equal to a risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company’s “beta.” As discussed in Section 3.D, we reviewed estimates from Blue Chip, Value Line, Ibbotson, and Bloomberg for the inputs to the CAPM. We maintained the same approach for the calculation of beta as that of CONE. Instead of basing our ROE on the high end of the competitive range using a forward looking estimate, we relied on the average results from the historical and forward looking estimates, with a resulting return on equity of 12.4%.

We maintained the assumed capital structure of 60/40 (D/E), and assume an overall after tax cost of capital of 7.3%, consistent with findings in previous ORTP studies.[[57]](#footnote-57)

## Gas-fired Generation ORTP

### Technical Specifications

The calculation of both simple cycle and combined cycle ORTPs were based on the technical specifications developed in the CONE/Net CONE process described in this report and shown in Table 37 below. A stakeholder questioned the use of the combined cycle 7HA.02 as the reference unit for the combined cycle ORTP calculation since it is not clear that this model of generating resource has cleared in a recent FCA, thus violating one of our screening criteria. We believe this choice of technology is appropriate for the ORTP calculation and meets the screening criteria. Combined cycle resources have cleared in recent FCAs. While the specific choice of combined cycle machine has not been announced in all cases, the GE7HA.02 combined cycle machine is consistent with the assumption that the latest technology will be utilized at these sites.

Table 37: Gas-Fired Resource Technical Specifications

|  |  |  |
| --- | --- | --- |
|  | Combined Cycle GT | Simple Cycle GT |
| **Model** | 7HA.02 | 7HA.02 |
| **Capacity (MW)** | 533 | 338 |
| **Net Heat Rate (btu/kWh)** | 6,546 | 9,220 |
| **Qualified Capacity (%)** | 100 | 100 |
| **Duct firing** | Yes | No |
| **Primary fuel** | Natural gas | Natural gas |
| **Backup fuel** | No. 2 oil | No. 2 oil |
| **Location** | Bristol County, MA | Bristol County, MA |
| **Net Plant Capacity (MW)** | 533 | 338 |
| **Interconnection** | * 2 mile electrical interconnection (to 345 kV system) plus network upgrades * 2 mile gas lateral plus metering station | * 2 mile electrical interconnection (to 345 kV system) plus network upgrades * 2 mile gas lateral plus metering station |
| **Environmental controls** | SCR and CO catalyst | SCR and CO catalyst |
| **Plot size *(acres)*** | 15.0 | 8.1 |

### Capital/Operating Costs

The capital costs for both simple cycle and combined cycle gas turbines were based on the capital costs calculated as part of the CONE/Net CONE analysis. Costs for insurance, electrical interconnection, property taxes, and contingency were reduced consistent with calculating a “low-end of the competitive range” value. Specifically, insurance was adjusted from 0.6% of overnight costs used in the CONE study to 0.3% for the ORTP study; electrical interconnection costs were reduced by 10% from the CONE values, property taxes were reduced from 3% to 1% to represent the negotiation of a *Payment In-Lieu-of Taxes* (“PILOT”) agreement, and contingency was reduced by 5% from the CONE values. The resulting overnight costs and fixed O&M costs are shown below.

Table 38: Comparison of Costs – CONE/ORTP

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Technology** | **Combined Cycle CONE** | **Combined Cycle ORTP** | **Simple Cycle GT CONE** | **Simple Cycle GT ORTP** |
| **Total Overnight Costs (2016$)** | $517,699,000 | $512,417,050 | $263,399,000 | $259,411,500 |
| **Fixed O&M (2021$/kW-mo)** | $5.01 | $3.87 | $3.21 | $2.47 |

### Revenue Offsets

The process by which the E&AS offset is calculated for ORTP gas-fired technologies is identical to the calculation for CONE/Net CONE. The same LMP and gas forecasts were used, the gas-turbines were dispatched in the same manner, and the process by which the cash flows were levelized to calculate the offset remains the same.

While the tariff requires that the ORTP calculation assume that the output from the generating resource is sold pursuant to a PPA, we have applied the same energy and ancillary service revenue stream developed in the CONE/Net CONE analysis to the ORTP calculation. Based on our experience, future price forecasts provide an unbiased expectation of market prices in both the short-term markets as well as under a PPA structure.

Similarly, expected PFP revenues for the simple cycle and combined cycle gas turbines are consistent with those used in the CONE/Net CONE analysis.

### ORTP Calculation

Based on the above cost estimates, financial assumptions and projected revenues, the recommended ORTP value is $6.503/kW-mo for a Simple Cycle GT, and $7.856/kW-mo for a Combined Cycle GT. The components of the calculation of this value are shown in Table 39 below.

Table 39: Gas Turbine ORTP Calculation

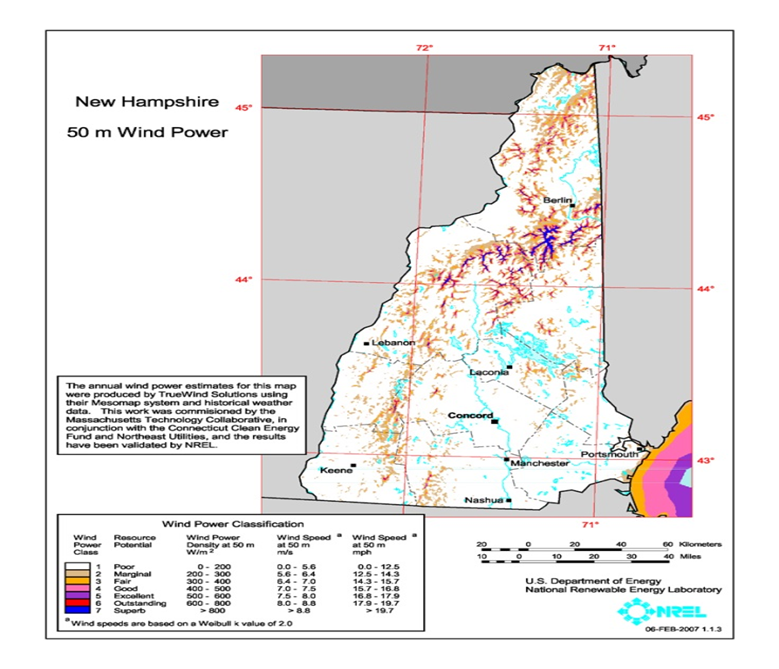


## On-Shore Wind

### Technical specifications

Our calculation of an ORTP value for an onshore wind farm began with developing assumptions about the appropriate size and location of a representative onshore wind farm in New England. A review of wind farms that participated in the most recent FCA, as well as wind farms currently in the interconnection queue, showed a large range of proposed sizes, ranging from 5 MW to 600 MW. In addition, a review of wind farms participating in the past two FCAs revealed sizes ranging from 20 MW to 80 MW of nameplate capacity. In determining an appropriate size for the reference wind unit, we weighted the range of wind resource participating in the most recent FCAs more heavily than the size of the wind resources in the interconnection queue since our criteria for screening wind resources was focused on resources that have recently participated in an FCA. Based on this information, the 60 MW reference wind farm size chosen for the 2013 ORTP study, and a discussion with stakeholders, we believe an onshore wind farm size of 52 MW, comprised of seventeen General Electric machines is an appropriate size on which to base our ORTP analysis.

In terms of location, wind resources are most appropriately located in areas with elevation differential and accessible transmission. Altitude improves wind resources in general, giving Northern New England a locational advantage. Available transmission to deliver the output from wind farms to load centers is an equally important consideration. We reviewed potential locations including New Hampshire, portions of Vermont, Maine, Western Massachusetts, and North Western Connecticut with these factors in mind. In light of these considerations and in consultation with MM, we determined central New Hampshire to be an appropriate location, as shown in Figure 12 below. This location is consistent with current operating and proposed wind farms, which are primarily located in Vermont, Maine and New Hampshire.

Figure 12: Wind Potential in New Hampshire

To estimate an appropriate capacity factor, we considered wind farms currently being offered into the FCA, as well as wind farms that have entered commercial operation in the past five years. A review of data provided by ISO-NE on wind farms that participated in the most recent FCA showed that estimated capacity factors had a large range, from 16% to 43%. Based on operating data provided by ISO-NE on five wind farms with a nameplate capacity over 20 MW that have been in operation since 2012, we calculated an average capacity factor of approximately 29%. The efficiency of wind farms is expected to increase by 10% by 2020, therefore we believe that an upward adjustment to the capacity factor to 32% for the reference onshore wind farm is appropriate.

To determine a reasonable qualified capacity, we reviewed the tariff requirements and the process by which wind farms are assigned a qualified capacity in the New England capacity market. According to the tariff, an intermittent resource’s qualified capacity value for the summer and winter periods is set equal to the median of the net output during the summer and winter reliability hours for the previous five years.[[58]](#footnote-58) [[59]](#footnote-59) Since the qualified capacity of the wind resource is based on capacity factor during reliability hours as calculated above, we assumed a qualified capacity of 30% consistent with the results of this calculation and a low end of the range approach to calculating an ORTP.

The specifications for the reference onshore wind resource is shown in Table 40.

Table 40: Reference Onshore Wind Farm Specifications

|  |  |
| --- | --- |
| Specifications | Onshore Wind |
| Turbine Model | General Electric |
| Turbine Size | 3 MWe |
| Net Plant Capacity | 52 MW |
| Qualified Capacity | 30% |
| Capacity Factor | 32% |
| Location | Central New Hampshire |
| Plot Size | 3,600 acres |
| Electrical Interconnection | 115kV along existing transmission corridor |

### Capital Costs

Capital costs for onshore wind farms vary significantly from project to project due to site specific conditions and costs. In calculating an appropriate capital cost for the reference wind farm, we consulted MM, reviewed recent FCA submissions by wind developers for the latest available technologies, and reviewed publicly available data on the capital costs of wind farms. A review of the most recent FCA submissions showed that capital costs for similarly sized wind farms varied by over 25%. The installed costs submitted by participants is not provided in enough granularity to determine the specific sources of variation. Our assumed overnight costs for the reference wind farm are shown in Table 41 below. The overnight costs represent a decrease in the assumed cost for the reference wind farm from the 2013 ORTP study of $3,063/kW, reflecting the declining cost trajectory for wind farm installations.

Table 41: Reference Onshore Wind Farm Overnight Costs (2016$)



Tax credits are currently available for eligible renewable resources in the form of a Production Tax Credit (“PTC”) and the Investment Tax Credit (“ITC"). In our ORTP calculations, we have included the value of the PTC for wind. We assumed that the tax credits will continue to be available at their current respective rates through 2021. For the onshore wind ORTP calculation, the PTC is estimated to be $0.15/kWh in 2021 dollars, based on current rules and our assumed inflation rate.

### Fixed O&M Costs

We estimated fixed O&M costs for onshore wind farms through consultation with MM and a review of the most recent FCA qualification materials provided by ISO-NE.

Land lease costs are typically negotiated and are therefore difficult to calculate. We assumed that 3,600 acres of land would be leased at a cost of approximately $860,000 or $240/acre, which is consistent with our review of ISO-NE data.

A property tax rate of 1% was assumed based on a review of independent power projects in New England that have entered into agreements for PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. This assumption was based on the fact that resources subject to PILOT agreements will have property tax expenses in each year of operation that will not vary significantly so that an average payment better reflects actual PILOT agreement structures. Based on this assumed rate, the property taxes for the onshore wind farm were estimated at approximately $130,000 per year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the assumption contained in the 2013 ORTP study, which continues to be reasonable. Annual insurance costs were estimated to be approximately $440,000 in 2021 dollars.

Ongoing maintenance costs were assumed to be approximately $1,800,000 per year based on a review of recent FCA submissions by onshore wind farms and consultation with MM.

Each of the above assumptions are an estimation of costs, since information on each of these cost categories is very limited and extremely site specific. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference onshore wind farm of $5.30/kw-month. A comparison of this all-in fixed O&M cost to recent FCA submissions shows this cost to be appropriately conservative, and less than the $6.88/kW-month assumed in the 2013 ORTP study.

### Revenue offsets

Revenue offsets for the reference onshore wind farm include energy market revenues as well as revenues from renewable energy certificates (“REC’s) and the PFP mechanism in the FCM.

To calculate energy margins, we assumed no variable costs so that the energy margins are equal to energy revenues. To calculate energy revenues, a projection of production, differentiated by month and time of day, was applied to the LMP forecast. Production assumptions were based on actual production data provided by ISO-NE. Wind resources do not receive AS revenues.

To calculate estimated REC revenues, we considered existing Renewable Portfolio Standards (“RPS”) in New England, the expected entry of increasing renewable resources, and a third-party REC price projection. We have assumed a REC price over the forecast period of $26.50/MWh, which we believe appropriately reflects an expected future value of RECs in New England.

To calculate estimated PFP revenues, we reviewed the most recent ISO-NE projections of scarcity hours in New England, as more fully described in Section 3.E. We extrapolated a value of 6 hours of scarcity conditions per year over the next 3 years based on current excess capacity levels, and 11.3 hours over the balance of the forecast period. In addition, we obtained information from ISO-NE on the actual performance of onshore wind resources during Reserve Constraint Penalty Factor (“RCPF”) hours over the last three years. This data showed that wind resources had a 93% performance rate. Assuming an 85% balancing ratio, wind resources are expected to receive PFP revenues of $0.04/kW-month for years 1-3 of the forecast period and $0.23/kW-month over the balance of the forecast period, as shown in Table 42 below.

Table 42: Expected Onshore Wind Farm PFP Revenues

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **Technology** | **Scarcity Hours at Criteria (hrs)** | **Performance Payment Rate ($/mWh)** | **Average Actual Performance (%)** | **Average Balancing Ratio (%)** | **Net Performance Payments ($/kW-mo)** |  |
| Wind | 11.3 | $5,455 | 0.93 | 0.85 | 0.23 | years 4 - 20 |
| Wind | 6 | $3,500 | 0.93 | 0.85 | 0.04 | years 1-3 |

### ORTP Calculation

Based on the cost and revenue estimates, as well as our financial assumptions for the ORTP analysis, the first year revenue requirement from the capacity market for the reference onshore wind farm is $11.025/kW-mo, as shown in in Table 43 below. Therefore, we recommend an ORTP value for onshore wind of $11.025/kW-month.

Table 43: Wind Resource ORTP Calculation

|  |  |
| --- | --- |
|  |  |
| **Installed Capacity (MW)** | 52 |
| **Qualified Capacity (MW)** | 15.6 |
| **Capital Costs (Overnight) (2016$/kW)** | 2,596 |
| **ATWACC** | 7.30% |
| **Fixed O&M ($/kW-mo)** | $5.30 |
| **Gross CONE ($/kW-mo)** | $30.54 |
| **Revenue Offsets ($/kW-mo)** | $19.52 |
| **ORTP ($/kW-mo)** | $11.025 |

## Energy Efficiency ORTP

### Technical Specifications

Energy efficiency (“EE”) resources participate in the FCM consistent with the manner in which supply-side resources participate. Companies that operate EE programs are permitted to enter peak-load reductions into the FCM.

Many of the existing EE programs are established through state-sponsored mandates and implemented by each state’s investor-owned utilities. As defined in Section I of the ISO’s tariff, EE includes installed measures (e.g., any combination of products, equipment, systems, services, practices, and strategies) on end-use customer facilities that reduce the total amount of electrical energy needed while delivering a comparable or improved level of end-use service. These measures can include the installation of more energy-efficient lighting, motors, refrigeration, HVAC (heating, ventilation, and air conditioning) equipment and control systems, and alternative operations and maintenance procedures. The programs generally cover the residential, commercial, and industrial sectors.

In calculating an appropriate ORTP for EE programs, we reviewed all investor -owned utility energy efficiency programs in New England. There are currently forty-six EE programs, excluding programs targeted towards low-income customers.[[60]](#footnote-60) Table 44 shows the EE programs that have been included in our ORTP calculation.

Table 44: Energy Efficiency Programs Included in ORTP Analysis[[61]](#footnote-61)

The investor-owned utility filings for the above programs contain information on forecasted program costs and savings. A review of these filings showed a potential annualized savings of 1,994,937 MWh and approximately 285 MW of summer peak-load savings at the customer meter over an estimated measure life of 11 years consistent with the average of existing programs. In order to present the information contained in the filings on a consistent basis, we adjusted the program size to 1 MW of capacity by the ratio of the annual energy savings to the peak load reduction. Based on this calculation, we assumed that a 1 MW EE measure would be expected to provide 7,009 MWh of annual energy savings.

### Capital Costs

We calculated the total capital costs of the EE programs using data from the investor-owned utility annual EE program annual reports.[[62]](#footnote-62) The total costs of the programs are shown below in Table 45.

Table 45: Energy Efficiency Programs Costs



### Revenue Offsets

The calculation of revenue offsets includes both the value of the energy saved at the wholesale level, as well as avoided transmission and distribution costs. For the energy-related savings, we used the average forecasted on-peak locational marginal price produced by the Aurora simulation model for 2021 through 2031. For transmission and distribution cost savings, we used the Connecticut Light & Power avoided transmission and distribution costs that are used in their analyses of efficiency measure cost-effectiveness. The CL&P avoided T&D cost in 2015 was $33.44/kW-yr in 2015 dollars. Our analysis assumes the equivalent value in 2021 dollar of $37.66/kW-yr.

### ORTP Calculation

Based on the estimated program savings and costs contained in the investor-owned utility filings, the Net CONE calculation is $-2.16/kW-month. Therefore, we recommend an ORTP value for EE programs of $0.00/kW-month.

Table 46: Energy Efficiency Program ORTP Calculation



## Demand Response Resource ORTP

### Technical Specifications

Demand response resources, like other supply resources, are competitive assets that help meet New England’s electricity needs. By reducing consumption, demand resources can help ensure enough electricity is available to maintain grid reliability. Demand resources can take many forms. They can be a capacity product, type of equipment, system, service, practice, or strategy—almost anything that verifiably reduces end-use demand for electricity from the power system. (Reductions must be verified using an ISO-accepted measurement and verification protocol.) Demand response resources vary in size and type. As a result, capital costs span a large range.

Consistent with the categories established in the 2013 ORTP study, we assumed two classes of demand response with the following characteristics:

* Large DR – medium-sized commercial facility with a 2 MW peak load and the ability to reduce load by 25% assumed to be 500 kW. We assumed that the control technologies and systems required to implement the assumed peak load reduction are already in place, consistent with conservative cost assumptions to determine an ORTP at the low end of competitive range.
* Mass Market DR – a measure implemented by an investor-owned utility or state program focused on residential or small commercial customers that control specific end-use processes and can provide 1 kW of demand reduction.

### Capital Costs

To determine the ORTP for Demand Response, Concentric reviewed the methodology, data, and analysis from the 2013 Offer Review Trigger Price Study (“2013 ORTP Study”). The 2013 ORTP Study identified challenges to obtaining detailed cost information due to (1) the variation in demand response resources, including in cost and type; and (2) limited available detailed data required to determine the ORTP. These challenges still apply.

As the 2013 ORTP study approach and resulting ORTP recommendations were based largely on interviews with DR aggregators, Concentric reached out to six DR aggregators to assess whether the information and methodology used in the 2013 ORTP study was still applicable. Several Interviewees offered general support for the ORTP methodology, values, assumptions, and ORTP recommendation from the 2013 study (i.e., that these continue to be applicable/ appropriate). Interviewees suggested variations to some of the values used in 2013. However, the majority of interviewees believed that the equipment costs, customer incentives and sales representative commission costs used in the 2013 study continued to be appropriate and fall within a reasonable range.

Based on this information, we used the capital costs contained in the 2013 ORTP study to estimate the equivalent costs in 2021, and assumed a total cost of $3,700. For the customer incentive payments, we assumed that these payments are 70% of the auction clearing price, consistent with the 2013 ORTP study, or approximately $4.92/kW-month. We assumed a 1% sales commission. This information is shown in Table 45 below.

For Mass Market DR, we used the information contained in the 2013 ORTP study, as well as information gained from our interviews. Interviewees generally agreed that it is appropriate to maintain the methodology from the 2013 ORTP study of keeping the two tiers of demand response in case such resources were to materialize going forward. Given a lack of additional cost information, we have adjusted the capital cost information contained in the 2013 ORTP Study for inflation. These values are shown in Tables 47 and 48 below.

Table 47: Large DR, Capital and Annual Cost Estimates

|  |  |
| --- | --- |
| Cost Components | Cost (2021$) |
| Equipment Costs | 3,700 |
| Customer Incentives | 4,330 |
| Sales Commission | 420 |

Table 48: Mass Market DR, Capital and Annual Cost Estimates

|  |  |
| --- | --- |
| Cost Components | Cost (2021$) |
| Mktg, Sales and Recruitment | 42 |
| Equipment Costs | 133 |
| Customer Incentives | 42 |
| ***Total Installation Costs*** | ***218*** |
| Annual Customer Incentives | 42 |
| O&M Costs | 11 |
| Software/Communication | 11 |

### ORTP Calculation

Based on the cost estimates detailed above and the financial assumptions shown in Section 4.D, we recommend an ORTP value for Large DR of $1.01 as shown in Table 49 below.

Table 49: Large DR ORTP Calculation

|  |  |  |
| --- | --- | --- |
| Large Commercial and Industrial  (Load Management C&I) | | |
|  | **Assumptions** | **Value**  **($/kW-mo)** |
| **Demand Reduction (kW)** | 500 |  |
| **Contract Life (years)** | 3 |  |
| **ATWACC (%)** | 7.3% |  |
| **Capacity Clearing Price** | $7.03 |  |
| **Reconfiguration Auction Clearing Price** | $1.03 |  |
| **Customer Incentive** | 70% of Reconfiguration Clearing Price | $0.72 |
| **Sales Commission** | 1% of FCA Clearing Price | $0.07 |
| **Equipment Costs** |  | $0.22 |
| **ORTP Value ($/kW-mo)** |  | $1.01 |

Based on the cost estimates detailed above and the financial assumptions shown in Section 4.D, we recommend an ORTP value for Mass Market DR of $7.56 as shown in Table 50 below.

Table 50: Mass Market DR ORTP Calculation

|  |  |
| --- | --- |
| Mass Market  (Load Management Residential) | |
|  | **Assumptions / Value** |
| Demand Reduction (kW) | 1 |
| Contract Life (years) | 10 |
| ATWACC (%) | 7.3% |
| Installation Costs | $2.25 |
| Annual Customer Incentives | $3.54 |
| O&M Costs | $0.88 |
| Software/Communication | $0.88 |
| ORTP Value ($/kW-mo) | $7.56 |

## ORTP Annual Update Process

### E&AS Revenues

E&AS revenues for gas-fired technologies will be updated consistent with the proposed update process contained in Section 4.K. For wind facilities, profitability is a function of the overall level of energy prices, not the spread between energy and gas prices. Therefore, the calculation supporting the adjustment of the energy portion of the E&AS offset is based only on the NEP futures. As of September 23, 2016, the average NEP settlement for 2021/2022 is $45.86/MWh. In the future, that average will be calculated again. The percentage difference (positive or negative) in the averages will be applied to the energy portion of the E&AS offset.

### Capital and Fixed costs updates

Pursuant to tariff requirements, for years in which no full recalculation of CONE/Net CONE values is performed, the CONE/Net CONE values associated with the reference technology will be updated pursuant to the cost indices contained in Market Rule 1 Section III.A.21.2. for each relevant cost component. Indices covering the most recent 12 months at the time will be compared against the current values to calculate the appropriate escalation rates.

Appendix

Table A.1 below, shows average monthly prices for SEMA for On-Peak and Off-Peak hours for the forecast period 2021 to 2040.

Table A.1. Average Monthly On-Peak and Off-Peak SEMA LMPs (nominal $/MWh)

|  |  |  |
| --- | --- | --- |
| Month | Average On-Peak SEMA LMP *($/MWh)* | Average Off-Peak SEMA LMP *($/MWh)* |
| Jan-21 | 65.73 | 57.15 |
| Feb-21 | 64.75 | 55.23 |
| Mar-21 | 54.53 | 45.85 |
| Apr-21 | 45.76 | 39.68 |
| May-21 | 45.29 | 38.72 |
| Jun-21 | 50.31 | 39.49 |
| Jul-21 | 67.62 | 43.30 |
| Aug-21 | 58.57 | 41.06 |
| Sep-21 | 48.61 | 41.05 |
| Oct-21 | 47.74 | 40.25 |
| Nov-21 | 55.06 | 47.10 |
| Dec-21 | 59.38 | 50.80 |
| Jan-22 | 66.32 | 58.85 |
| Feb-22 | 65.41 | 56.70 |
| Mar-22 | 57.13 | 47.32 |
| Apr-22 | 46.33 | 40.14 |
| May-22 | 46.12 | 39.42 |
| Jun-22 | 51.93 | 40.28 |
| Jul-22 | 70.65 | 44.74 |
| Aug-22 | 60.70 | 41.76 |
| Sep-22 | 51.52 | 42.02 |
| Oct-22 | 52.16 | 42.18 |
| Nov-22 | 58.05 | 50.67 |
| Dec-22 | 61.12 | 53.46 |
| Jan-23 | 68.40 | 60.05 |
| Feb-23 | 66.91 | 58.19 |
| Mar-23 | 57.44 | 48.05 |
| Apr-23 | 47.39 | 41.44 |
| May-23 | 48.07 | 40.75 |
| Jun-23 | 53.16 | 41.55 |
| Jul-23 | 70.89 | 45.97 |
| Aug-23 | 61.17 | 43.51 |
| Sep-23 | 53.36 | 43.56 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Oct-23 | 52.05 | 43.39 |
| Nov-23 | 58.88 | 51.67 |
| Dec-23 | 63.48 | 55.69 |
| Jan-24 | 70.47 | 60.87 |
| Feb-24 | 69.54 | 60.14 |
| Mar-24 | 60.40 | 51.01 |
| Apr-24 | 49.97 | 43.71 |
| May-24 | 50.02 | 42.41 |
| Jun-24 | 54.38 | 43.55 |
| Jul-24 | 72.53 | 47.84 |
| Aug-24 | 65.53 | 46.24 |
| Sep-24 | 55.21 | 44.65 |
| Oct-24 | 51.89 | 43.82 |
| Nov-24 | 61.12 | 52.87 |
| Dec-24 | 66.23 | 57.79 |
| Jan-25 | 72.44 | 63.02 |
| Feb-25 | 70.14 | 61.67 |
| Mar-25 | 61.41 | 52.67 |
| Apr-25 | 51.00 | 44.81 |
| May-25 | 49.94 | 42.62 |
| Jun-25 | 55.36 | 44.22 |
| Jul-25 | 72.54 | 48.11 |
| Aug-25 | 64.75 | 46.53 |
| Sep-25 | 55.39 | 45.31 |
| Oct-25 | 55.34 | 45.66 |
| Nov-25 | 62.83 | 55.17 |
| Dec-25 | 66.69 | 58.46 |
| Jan-26 | 73.36 | 64.52 |
| Feb-26 | 72.05 | 63.44 |
| Mar-26 | 62.19 | 52.66 |
| Apr-26 | 51.31 | 45.03 |
| May-26 | 50.85 | 42.74 |
| Jun-26 | 56.31 | 45.32 |
| Jul-26 | 72.77 | 48.91 |
| Aug-26 | 64.74 | 47.96 |
| Sep-26 | 57.00 | 46.14 |
| Oct-26 | 55.13 | 46.70 |
| Nov-26 | 64.42 | 56.37 |
| Dec-26 | 68.76 | 60.29 |
| Jan-27 | 76.13 | 67.22 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Feb-27 | 75.79 | 65.36 |
| Mar-27 | 64.43 | 54.49 |
| Apr-27 | 53.52 | 47.41 |
| May-27 | 53.69 | 46.16 |
| Jun-27 | 58.55 | 46.93 |
| Jul-27 | 74.88 | 50.80 |
| Aug-27 | 66.79 | 48.75 |
| Sep-27 | 57.38 | 47.67 |
| Oct-27 | 55.85 | 47.69 |
| Nov-27 | 65.74 | 57.56 |
| Dec-27 | 69.93 | 61.67 |
| Jan-28 | 77.50 | 67.60 |
| Feb-28 | 76.36 | 66.19 |
| Mar-28 | 66.57 | 56.85 |
| Apr-28 | 55.59 | 49.34 |
| May-28 | 55.11 | 46.62 |
| Jun-28 | 61.14 | 48.74 |
| Jul-28 | 77.40 | 52.65 |
| Aug-28 | 67.29 | 49.95 |
| Sep-28 | 58.95 | 49.84 |
| Oct-28 | 60.67 | 50.33 |
| Nov-28 | 68.20 | 60.54 |
| Dec-28 | 72.69 | 64.40 |
| Jan-29 | 80.04 | 69.98 |
| Feb-29 | 79.58 | 69.58 |
| Mar-29 | 69.00 | 59.18 |
| Apr-29 | 57.95 | 50.62 |
| May-29 | 56.85 | 47.91 |
| Jun-29 | 62.28 | 51.04 |
| Jul-29 | 78.79 | 54.87 |
| Aug-29 | 72.30 | 52.79 |
| Sep-29 | 64.28 | 52.49 |
| Oct-29 | 61.36 | 51.61 |
| Nov-29 | 69.53 | 61.26 |
| Dec-29 | 75.29 | 67.00 |
| Jan-30 | 81.90 | 71.48 |
| Feb-30 | 81.99 | 71.83 |
| Mar-30 | 70.23 | 61.26 |
| Apr-30 | 61.28 | 53.95 |
| May-30 | 60.63 | 52.86 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Jun-30 | 66.40 | 54.27 |
| Jul-30 | 86.98 | 58.35 |
| Aug-30 | 76.09 | 55.86 |
| Sep-30 | 66.53 | 55.27 |
| Oct-30 | 64.26 | 54.54 |
| Nov-30 | 74.31 | 65.14 |
| Dec-30 | 78.89 | 70.17 |
| Jan-31 | 86.32 | 76.09 |
| Feb-31 | 86.51 | 75.63 |
| Mar-31 | 75.91 | 65.91 |
| Apr-31 | 64.58 | 57.53 |
| May-31 | 63.11 | 55.25 |
| Jun-31 | 69.04 | 57.03 |
| Jul-31 | 88.27 | 61.59 |
| Aug-31 | 77.36 | 59.19 |
| Sep-31 | 69.68 | 58.44 |
| Oct-31 | 68.27 | 58.13 |
| Nov-31 | 78.23 | 68.92 |
| Dec-31 | 82.43 | 73.55 |
| Jan-32 | 90.24 | 79.68 |
| Feb-32 | 90.08 | 78.27 |
| Mar-32 | 79.16 | 68.92 |
| Apr-32 | 67.58 | 60.47 |
| May-32 | 67.43 | 58.70 |
| Jun-32 | 74.22 | 60.81 |
| Jul-32 | 93.22 | 65.96 |
| Aug-32 | 80.70 | 63.14 |
| Sep-32 | 74.86 | 62.68 |
| Oct-32 | 72.86 | 62.07 |
| Nov-32 | 82.98 | 72.49 |
| Dec-32 | 86.07 | 76.94 |
| Jan-33 | 94.66 | 83.72 |
| Feb-33 | 95.28 | 83.38 |
| Mar-33 | 81.15 | 71.87 |
| Apr-33 | 71.92 | 64.51 |
| May-33 | 72.04 | 63.67 |
| Jun-33 | 78.19 | 64.58 |
| Jul-33 | 93.91 | 69.39 |
| Aug-33 | 84.03 | 66.87 |
| Sep-33 | 77.20 | 66.39 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Oct-33 | 76.93 | 66.85 |
| Nov-33 | 86.88 | 76.97 |
| Dec-33 | 91.04 | 82.23 |
| Jan-34 | 100.23 | 89.04 |
| Feb-34 | 99.65 | 88.03 |
| Mar-34 | 86.29 | 76.94 |
| Apr-34 | 75.47 | 68.61 |
| May-34 | 75.63 | 66.54 |
| Jun-34 | 81.92 | 67.86 |
| Jul-34 | 97.27 | 72.20 |
| Aug-34 | 86.13 | 69.86 |
| Sep-34 | 80.72 | 69.27 |
| Oct-34 | 80.37 | 69.61 |
| Nov-34 | 91.49 | 81.37 |
| Dec-34 | 94.80 | 85.93 |
| Jan-35 | 105.11 | 92.51 |
| Feb-35 | 105.71 | 92.80 |
| Mar-35 | 89.88 | 81.04 |
| Apr-35 | 79.14 | 71.71 |
| May-35 | 79.18 | 69.45 |
| Jun-35 | 84.85 | 71.70 |
| Jul-35 | 101.64 | 76.12 |
| Aug-35 | 93.18 | 73.66 |
| Sep-35 | 87.00 | 73.90 |
| Oct-35 | 84.89 | 72.96 |
| Nov-35 | 93.11 | 83.95 |
| Dec-35 | 99.79 | 90.17 |
| Jan-36 | 109.07 | 96.92 |
| Feb-36 | 108.63 | 95.68 |
| Mar-36 | 93.59 | 84.93 |
| Apr-36 | 83.28 | 74.98 |
| May-36 | 85.02 | 74.87 |
| Jun-36 | 89.29 | 75.52 |
| Jul-36 | 107.04 | 79.67 |
| Aug-36 | 95.28 | 77.88 |
| Sep-36 | 91.05 | 77.42 |
| Oct-36 | 89.63 | 77.34 |
| Nov-36 | 100.38 | 90.07 |
| Dec-36 | 106.41 | 96.34 |
| Jan-37 | 117.06 | 105.71 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Feb-37 | 115.90 | 103.09 |
| Mar-37 | 101.01 | 91.25 |
| Apr-37 | 89.06 | 81.08 |
| May-37 | 88.56 | 78.61 |
| Jun-37 | 93.97 | 79.56 |
| Jul-37 | 109.47 | 83.13 |
| Aug-37 | 98.08 | 81.67 |
| Sep-37 | 94.01 | 81.56 |
| Oct-37 | 95.65 | 82.74 |
| Nov-37 | 106.90 | 94.64 |
| Dec-37 | 111.41 | 101.11 |
| Jan-38 | 123.71 | 111.74 |
| Feb-38 | 120.94 | 108.02 |
| Mar-38 | 104.83 | 95.00 |
| Apr-38 | 91.13 | 83.19 |
| May-38 | 93.71 | 82.53 |
| Jun-38 | 99.88 | 84.96 |
| Jul-38 | 115.11 | 89.58 |
| Aug-38 | 105.13 | 86.99 |
| Sep-38 | 100.79 | 87.24 |
| Oct-38 | 100.79 | 88.30 |
| Nov-38 | 110.34 | 98.16 |
| Dec-38 | 115.40 | 104.79 |
| Jan-39 | 130.40 | 116.65 |
| Feb-39 | 126.71 | 113.72 |
| Mar-39 | 109.52 | 98.48 |
| Apr-39 | 96.07 | 87.27 |
| May-39 | 100.99 | 88.69 |
| Jun-39 | 106.63 | 90.89 |
| Jul-39 | 123.98 | 95.87 |
| Aug-39 | 110.20 | 92.33 |
| Sep-39 | 105.73 | 91.93 |
| Oct-39 | 104.92 | 92.31 |
| Nov-39 | 117.57 | 104.50 |
| Dec-39 | 122.58 | 112.02 |
| Jan-40 | 136.99 | 122.63 |
| Feb-40 | 131.52 | 117.95 |
| Mar-40 | 117.86 | 106.23 |
| Apr-40 | 106.89 | 95.22 |
| May-40 | 108.83 | 93.90 |
| Month | **Average On-Peak SEMA LMP ($/MWh)** | **Average Off-Peak SEMA LMP ($/MWh)** |
| Jun-40 | 114.96 | 97.57 |
| Jul-40 | 129.88 | 102.72 |
| Aug-40 | 116.63 | 98.91 |
| Sep-40 | 111.49 | 96.63 |
| Oct-40 | 113.47 | 97.64 |
| Nov-40 | 121.16 | 107.53 |
| Dec-40 | 124.80 | 113.44 |

Plant additions and retirements from the Aurora simulation are shown below. For each year, the amount of capacity added and/or retired is aggregate and includes the total change for each category in that year. Behind-the-meter resources are excluded.

Table A.2. Total Plant Additions and Retirements by Year (MW)

|  |  |  |
| --- | --- | --- |
| Year | Addition | Retirements |
| 2021 | 772 | 560 |
| 2022 | 0 | 556 |
| 2023 | 386 | 547 |
| 2024 | 0 | 827 |
| 2025 | 386 | 354 |
| 2026 | 436 | 0 |
| 2027 | 326 | 0 |
| 2028 | 0 | 0 |
| 2029 | 50 | 330 |
| 2030 | 386 | 1,247 |
| 2031 | 386 | 0 |
| 2032 | 0 | 0 |
| 2033 | 772 | 0 |
| 2034 | 0 | 0 |
| 2035 | 0 | 876 |
| 2036 | 386 | 0 |
| 2037 | 436 | 0 |
| 2038 | 0 | 0 |
| 2039 | 0 | 0 |
| 2040 | 0 | 0 |

The load forecast used in the Aurora simulations is shown below in Table A.3 and Table A.4. As discussed above, the load forecast is based on the CELT report published by ISO-NE.

Table A.3. ISO New England Projected Load (GWh)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
| 2021 | 11,325 | 9,926 | 10,280 | 9,226 | 9,626 | 10,696 | 13,214 | 11,913 | 10,126 | 9,619 | 9,780 | 10,963 | 126,693 |
| 2022 | 11,301 | 9,862 | 10,210 | 9,132 | 9,637 | 10,740 | 13,136 | 11,901 | 10,022 | 9,564 | 9,767 | 10,910 | 126,182 |
| 2023 | 11,315 | 9,813 | 10,140 | 9,036 | 9,677 | 10,776 | 13,123 | 11,844 | 9,904 | 9,544 | 9,750 | 10,866 | 125,790 |
| 2024 | 11,208 | 10,268 | 10,142 | 9,116 | 9,445 | 10,281 | 13,161 | 11,979 | 10,067 | 9,536 | 9,507 | 10,757 | 125,467 |
| 2025 | 11,266 | 9,875 | 10,122 | 9,101 | 9,442 | 10,383 | 13,202 | 11,905 | 10,071 | 9,528 | 9,513 | 10,804 | 125,212 |
| 2026 | 11,230 | 9,826 | 10,098 | 9,047 | 9,396 | 10,465 | 13,221 | 11,825 | 10,016 | 9,460 | 9,536 | 10,808 | 124,927 |
| 2027 | 11,183 | 9,780 | 10,077 | 8,988 | 9,385 | 10,542 | 13,183 | 11,807 | 9,941 | 9,380 | 9,576 | 10,802 | 124,644 |
| 2028 | 11,155 | 10,055 | 9,963 | 8,824 | 9,476 | 10,653 | 13,100 | 11,756 | 9,737 | 9,337 | 9,577 | 10,728 | 124,362 |
| 2029 | 11,146 | 9,848 | 10,099 | 8,958 | 9,281 | 10,175 | 13,116 | 12,030 | 10,001 | 9,404 | 9,388 | 10,638 | 124,082 |
| 2030 | 11,159 | 9,808 | 10,002 | 8,944 | 9,268 | 10,171 | 13,188 | 11,943 | 9,947 | 9,365 | 9,357 | 10,654 | 123,805 |
| 2031 | 11,159 | 9,761 | 9,948 | 8,894 | 9,229 | 10,248 | 13,207 | 11,836 | 9,920 | 9,322 | 9,331 | 10,672 | 123,529 |
| 2032 | 11,095 | 9,992 | 9,901 | 8,781 | 9,176 | 10,411 | 13,164 | 11,720 | 9,781 | 9,172 | 9,398 | 10,663 | 123,255 |
| 2033 | 11,092 | 9,635 | 9,882 | 8,734 | 9,247 | 10,514 | 13,127 | 11,760 | 9,721 | 9,169 | 9,440 | 10,662 | 122,982 |
| 2034 | 11,121 | 9,593 | 9,819 | 8,641 | 9,305 | 10,568 | 13,126 | 11,711 | 9,604 | 9,161 | 9,435 | 10,627 | 122,712 |
| 2035 | 11,041 | 9,740 | 9,934 | 8,753 | 9,070 | 10,038 | 13,122 | 11,976 | 9,855 | 9,201 | 9,209 | 10,506 | 122,443 |
| 2036 | 11,029 | 10,013 | 9,776 | 8,691 | 9,022 | 10,112 | 13,197 | 11,759 | 9,769 | 9,121 | 9,151 | 10,538 | 122,176 |
| 2037 | 11,039 | 9,619 | 9,785 | 8,668 | 9,010 | 10,236 | 13,242 | 11,700 | 9,741 | 9,083 | 9,212 | 10,575 | 121,911 |
| 2038 | 10,991 | 9,571 | 9,767 | 8,609 | 9,002 | 10,324 | 13,203 | 11,683 | 9,662 | 9,000 | 9,261 | 10,573 | 121,648 |
| 2039 | 10,991 | 9,522 | 9,714 | 8,527 | 9,045 | 10,404 | 13,140 | 11,698 | 9,568 | 8,965 | 9,273 | 10,540 | 121,386 |
| 2040 | 10,998 | 9,792 | 9,556 | 8,409 | 9,134 | 10,467 | 13,147 | 11,594 | 9,315 | 8,971 | 9,261 | 10,482 | 121,126 |

Table A.4. ISO New England Projected Peak Load (MW)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Annual |
| 2021 | 19,795 | 19,095 | 17,656 | 15,612 | 16,679 | 22,230 | 26,355 | 21,704 | 19,510 | 16,412 | 17,972 | 19,152 | 26,355 |
| 2022 | 19,789 | 18,610 | 17,486 | 15,423 | 16,900 | 22,242 | 26,405 | 21,714 | 19,068 | 16,376 | 17,949 | 19,141 | 26,405 |
| 2023 | 19,795 | 18,460 | 17,414 | 15,389 | 17,304 | 22,269 | 26,472 | 21,738 | 19,066 | 16,350 | 17,939 | 19,142 | 26,472 |
| 2024 | 19,778 | 19,055 | 17,573 | 15,861 | 16,565 | 20,042 | 26,544 | 21,750 | 19,485 | 16,293 | 17,424 | 18,779 | 26,544 |
| 2025 | 19,825 | 19,097 | 17,605 | 15,715 | 16,591 | 20,630 | 26,636 | 21,810 | 19,529 | 16,317 | 17,455 | 18,819 | 26,636 |
| 2026 | 19,846 | 19,111 | 17,604 | 15,606 | 16,580 | 20,796 | 26,722 | 21,851 | 19,546 | 16,304 | 17,937 | 19,173 | 26,722 |
| 2027 | 19,879 | 19,135 | 17,612 | 15,449 | 16,573 | 22,441 | 26,818 | 21,899 | 19,570 | 16,297 | 17,949 | 19,201 | 26,818 |
| 2028 | 19,885 | 18,629 | 17,376 | 15,247 | 17,255 | 22,474 | 26,904 | 21,927 | 19,107 | 16,258 | 17,931 | 19,199 | 26,904 |
| 2029 | 19,915 | 19,156 | 17,714 | 15,817 | 16,550 | 20,181 | 26,987 | 22,362 | 19,603 | 16,270 | 17,452 | 18,870 | 26,987 |
| 2030 | 19,937 | 19,171 | 17,608 | 15,801 | 16,540 | 20,204 | 27,076 | 22,019 | 19,622 | 16,258 | 17,452 | 18,882 | 27,076 |
| 2031 | 19,961 | 19,188 | 17,609 | 15,609 | 16,531 | 20,803 | 27,166 | 22,062 | 19,641 | 16,248 | 17,452 | 18,896 | 27,166 |
| 2032 | 19,964 | 19,179 | 17,581 | 15,311 | 16,488 | 22,648 | 27,254 | 22,088 | 19,637 | 16,203 | 17,937 | 19,252 | 27,254 |
| 2033 | 20,024 | 18,709 | 17,462 | 15,178 | 16,798 | 22,718 | 27,356 | 22,158 | 19,205 | 16,234 | 17,982 | 19,309 | 27,356 |
| 2034 | 20,049 | 18,561 | 17,402 | 15,159 | 17,268 | 22,766 | 27,448 | 22,203 | 19,221 | 16,224 | 17,989 | 19,328 | 27,448 |
| 2035 | 20,061 | 19,256 | 17,731 | 15,728 | 16,498 | 20,328 | 27,532 | 22,643 | 19,724 | 16,207 | 17,457 | 18,956 | 27,532 |
| 2036 | 20,065 | 19,249 | 17,593 | 15,493 | 16,456 | 20,938 | 27,623 | 22,268 | 19,722 | 16,164 | 17,429 | 18,946 | 27,623 |
| 2037 | 20,112 | 19,291 | 17,625 | 15,413 | 16,481 | 21,135 | 27,719 | 22,330 | 19,767 | 16,188 | 17,998 | 19,372 | 27,719 |
| 2038 | 20,151 | 19,320 | 17,636 | 15,243 | 16,478 | 22,959 | 27,821 | 22,384 | 19,795 | 16,183 | 18,014 | 19,405 | 27,821 |
| 2039 | 20,180 | 18,789 | 17,473 | 15,064 | 16,763 | 23,010 | 27,917 | 22,433 | 19,306 | 16,179 | 18,025 | 19,428 | 27,917 |
| 2040 | 20,187 | 18,609 | 17,383 | 15,012 | 17,448 | 23,046 | 28,010 | 22,465 | 18,670 | 16,235 | 18,007 | 19,428 | 28,010 |

1. Market Rule 1 Section III.13.2.4. [↑](#footnote-ref-1)
2. Market Rule 1 Section III.A.21.1.2. [↑](#footnote-ref-2)
3. Brayton Point and Pilgrim Nuclear Generating Station are each expected to retire prior to 2020. Brayton Point is located in Bristol County and Pilgrim is located in neighboring Plymouth County. The combined capacity of the two plants is in excess of 2,200 MW. [↑](#footnote-ref-3)
4. SNL Financial [↑](#footnote-ref-4)
5. An estimate for a previously estimated Power Plant was used to layout the framework for the estimate. That framework is referred to here as the “model.” [↑](#footnote-ref-5)
6. All capacity values are stated on a net basis [↑](#footnote-ref-6)
7. BLS PPI WPU1197; BLS PPI WPUID612: not seasonally adjusted, annual average percent change 2006-2015. [↑](#footnote-ref-7)
8. ULSD Forward Curve as of September 7, 2016; CME Group. [↑](#footnote-ref-8)
9. Blue Chip Economic Indicators, Vol. 41, No. 3, March 2016. [↑](#footnote-ref-9)
10. June 10, 2016 – July 22, 2016. [↑](#footnote-ref-10)
11. Table B-2, IRS Publication 946. Half-Year Convention. [↑](#footnote-ref-11)
12. Massachusetts Department of Revenue, 2016, https://dlsgateway.dor.state.ma.us/gateway/Public/WebForms/TaxRate/ReportTRApprovalPublic.aspx. [↑](#footnote-ref-12)
13. Internal Revenue Service, 2015 Instructions for Form 1120, U.S. Corporation Income Tax Return.  
    January 21, 2016. Available at http://www.irs.gov/pub/irs-pdf/i1120.pdf. [↑](#footnote-ref-13)
14. Massachusetts Department of Revenue, 2016. Available at: http://www.mass.gov/dor/businesses/current-tax-info/guide-to-employer-tax-obligations/business-income-taxes/corporations/corporate-excise-tax.html. [↑](#footnote-ref-14)
15. Massachusetts assumed as the reference location for all technologies except onshore wind. Therefore, a state income tax rate of 8% is assumed for all CONE and ORTP calculations except that of onshore wind, for which a state tax rate of 8.5% is assumed (New Hampshire). [↑](#footnote-ref-15)
16. Bloomberg as of September 2016. [↑](#footnote-ref-16)
17. We received feedback from stakeholders that the CAPM analysis for Talen should use a pre-merger beta estimate. Talen’s beta as of June 1, 2016, or pre-merger announcement, was 1.39 according to Bloomberg. This beta estimate for Talen does not change our ROE recommendation of 13.4%. [↑](#footnote-ref-17)
18. Value Line as of June, September 2016. [↑](#footnote-ref-18)
19. SNL Financial [↑](#footnote-ref-19)
20. BofA Merrill Lynch, BofA Merrill Lynch US High Yield B and BB Effective Yield©, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/BAMLH0A2HYB[B]EY. [↑](#footnote-ref-20)
21. Debt weights for Talen are unavailable prior to the company’s founding in the first quarter of 2015. [↑](#footnote-ref-21)
22. Source: Bloomberg, LP [↑](#footnote-ref-22)
23. Bloomberg. Six quarters of data was evaluated for Talen. [↑](#footnote-ref-23)
24. For the limited peer group (CPN, DYN, NRG) the 10 quarter average is 65% debt, and the two quarter average is 76% debt. [↑](#footnote-ref-24)
25. Bloomberg Professional [↑](#footnote-ref-25)
26. FERC Docket ER14-1639-000, Testimony of Dr. Samuel A. Newell and Mr. Christopher Ungate of behalf of ISO-NE Regarding the Net Cost f New Entry for the Forward Capacity Market Demand Curve, April 1, 2014. [↑](#footnote-ref-26)
27. Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, The Brattle Group and Sargent & Lundy, May 15, 2014. [↑](#footnote-ref-27)
28. Study to Establish New York Electricity Market ICAP Demand Curve Parameters, Analysis Group Inc. and Lummus Consultants International, Inc. June 23, 2016. [↑](#footnote-ref-28)
29. See <http://epis.com/aurora_xmp/> for more detail regarding AURORA. [↑](#footnote-ref-29)
30. See <https://rbac.com/> for more detail regarding GPCM. [↑](#footnote-ref-30)
31. See Table 3.1 of the 2016 AEO. [↑](#footnote-ref-31)
32. For purposes of comparison, the EIA forecast, which is shown in real dollars, was escalated at an inflation rate of 2.0% consistent with the inflation input used elsewhere in this analysis, rather than by the escalation rate provided in the AEO. [↑](#footnote-ref-32)
33. Prices in this section are expressed in nominal dollars unless otherwise indicated. [↑](#footnote-ref-33)
34. Participating RGGI states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont. [↑](#footnote-ref-34)
35. The Clean Power Plan, finalized in October of 2015, requires each state to hit a CO2 target by 2030, with reductions to begin in 2022. States have the option to comply with CO2 rate targets by way of a lb/MWh or a mass-based target, the latter being in part included to encourage inter-state emissions trading through initiatives such as RGGI. [↑](#footnote-ref-35)
36. BTM PV is photovoltaic capacity installed at customer locations that generally serves to reduce customer demand from the grid rather than add generation to the system. Rooftop solar is an example of BTM PV. [↑](#footnote-ref-36)
37. Bill H.4568 was signed into law in August 2016. The new law inserts a new section, 83C, into the Green Communities Act, requiring that EDCs procure approximately 1,200 MW of renewable energy and additionally provides for separate authorization (not requirement) to procure up to 1,600MW of offshore wind, providing that such a procurement can be accomplished on a “reasonable” and “cost effective” basis. Because of the requirement for cost effectiveness, it has been assumed that procurement of the full 1,600 MW would not be achieved. Instead, we have chosen to add a resource to the generation mix of roughly 25%. [↑](#footnote-ref-37)
38. The Deepwater Wind facility is expected to be commercialized later in 2016. When it is brought online, it will be the first offshore wind facility operating in New England. Since Deepwater received a CSO in FCA10, it is included in the simulation model. [↑](#footnote-ref-38)
39. Wind resources are added in discrete increments of 50 MW; thus, wind resources are not necessarily added in every year of the forecast. [↑](#footnote-ref-39)
40. There are two operational reactors at the Millstone facility, Millstone 2 and Millstone 3. The operating license for Millstone 2 expires in 2035 and was removed from the simulation in that year. Millstone 3 holds an Extended Operating License that runs through 2045 and was therefore not removed. [↑](#footnote-ref-40)
41. *Source:* ISO-NE [↑](#footnote-ref-41)
42. ISO-NE Planning Advisor Committee, “Forward Capacity Auction 11, Transmission Transfer Capabilities & Capacity Zone Development”, March 22, 2016. [↑](#footnote-ref-42)
43. The most current information available regarding transfer limits and the effect of new import projects on those limits is the analysis conducted by ISO-NE’s Planning Advisory Committee (PAC), which were made public in March 2016. At that time, the PAC found that transfer limits for FCA 11 would be unaffected by the installation of a transmission project between Ontario and New Hampshire. The project being reviewed by the PAC is similar to the one being contemplated for purposes of this analysis. The PAC findings are available at https://www.iso-ne.com/static-assets/documents/2016/03/a2\_fca11\_zonal\_boundary\_determinations.pdf [↑](#footnote-ref-43)
44. ICE contract code IMB [↑](#footnote-ref-44)
45. The result is then multiplied by 1,000, since SHRs are most typically expressed in btu/kWh. [↑](#footnote-ref-45)
46. Data used to calculate the historical SHRs provided by SNL. [↑](#footnote-ref-46)
47. The Failure-to-Reserve penalty rate is the maximum value of 1.5 multiplied by the FRM Payment Rate, or the RTR Rate minus the FRM Payment Rate. The Failure-to-Activate penalty rate is the maximum of 2.25 multiplied by the FRM Payment Rate, or the applicable nodal LMP. [↑](#footnote-ref-47)
48. Off-peak hours are hours ending 1 through 7 and 23, on non-NERC holiday weekdays [↑](#footnote-ref-48)
49. For FR, the Summer Reserve Period runs June through September and the Winter Reserve Period is all remaining months. [↑](#footnote-ref-49)
50. ISO-NE Power Supply Planning Committee Presentation, <https://www.iso-ne.com/static-> assets/documents/2016/10/PSPC10132016\_A2\_2020-21\_Reserve\_Deficiencies\_Hours\_Final.pdf. [↑](#footnote-ref-50)
51. ISO-NE Pay for Performance FERC Filing in Docket No. ER14-1050-000. [↑](#footnote-ref-51)
52. Testimony of Dr. Matthew White, Docket No. ER14-1050-000, January 17, 2014, pg 110. [↑](#footnote-ref-52)
53. The offset update is also described in Appendix A Section 21.1.2.e(4) of Market Rule 1 Appendix A Section 21.1.2.e(4). [↑](#footnote-ref-53)
54. Market Rule 1 Appendix A Section III.A.21.1.2 [↑](#footnote-ref-54)
55. Our estimated installed cost reflects an assumed a 7% annual capital cost improvement from 2015 to 2021 and an O&M cost decrease of approximately 30% from 2015 to 2021. [↑](#footnote-ref-55)
56. Cite FERC Order [↑](#footnote-ref-56)
57. Brattle, 2013. [↑](#footnote-ref-57)
58. ISO-NE Market Rule 1 Section III.13.1.2.2.1. [↑](#footnote-ref-58)
59. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource’s net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. [↑](#footnote-ref-59)
60. Low income programs were excluded to remain consistent with the previous *2013 Offer Review Trigger Prices Study* conducted by The Brattle Group. These programs include: Home Energy Solutions Income Eligible (CT), Single Family Income Based (MA), Multi Family Income Based (MA), Low-Income Direct Install Initiatives (ME), and Income Eligible (RI). [↑](#footnote-ref-60)
61. Connecticut: Eversource Energy, et al., 2015.

    Massachusetts: National Grid, et al., 2015.

    Maine: Efficiency Maine, 2015.

    New Hampshire: Granite State Electric Company, et al., 2015.

    Rhode Island: National Grid, et al., 2015.

    Vermont: Efficiency Vermont, 2016. [↑](#footnote-ref-61)
62. Please note: the reports are provided as fiscal years and therefore time periods likely vary. [↑](#footnote-ref-62)