

**Evaluation of New Jersey Solicitation for  
ORECs for Offshore Wind Capacity  
Framework for Evaluation of Impacts**

**Public Version**

*prepared for the*

New Jersey Board of Public Utilities

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This report has been prepared for the New Jersey Board of Public Utilities (Board) for the sole purpose of describing the methodology used to evaluate the applications submitted in response to the Board's Offshore Wind Solicitation. While Levitan & Associates, Inc. (LAI) believes the assumptions identified herein to be reasonable, there is no assurance that any specific set of assumptions will actually be encountered. LAI gives no assurances except those explicitly set forth herein.

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## GLOSSARY

### Short Form Names

Board	New Jersey Board of Public Utilities
Guidelines	Guidelines for Application Submission for Proposed Offshore Wind Facilities, NJBPU, Sept 17, 2018

### Acronyms and Abbreviations

ACE	Atlantic City Electric	ISO-NE	ISO New England
ACP	Alternative Compliance Payment	ITC	Investment Tax Credit
AEO	Annual Energy Outlook	JCP&L	Jersey Central Power and Light
BOEM	Bureau of Ocean Energy Management	kW	Kilowatt
BPU	New Jersey Board of Public Utilities	kWh	Kilowatt Hour
BRA	Base Residual Auction	LAI	Levitan & Associates, Inc.
BTM	Behind-the-Meter	LCOE	Levelized Cost of Electricity
CapEx	Capital Expenditure	LDA	Local Deliverability Area
CIR	Capacity Interconnection Right	LNOC	Levelized Net OREC Cost
CO <sub>2</sub>	Carbon Dioxide	MAAC	Mid-Atlantic Area Council
CONE	Cost of New Entry	MOPR	Minimum Offer Price Rule
CQ	Clarifying Question	MOU	Memorandum of Understanding
CSA	Construction Service Agreement	MW	Megawatt
DA	Day-Ahead	MWh	Megawatt Hour
E&P	Exploration and Production	NJDEP	New Jersey Department of Environmental Protection
EDC	Electric Distribution Company	NO <sub>x</sub>	Nitrogen Oxides
EIA	Energy Information Administration	NRC	Nuclear Regulatory Commission
EMAAC	Eastern Mid-Atlantic Area Council	NYISO	New York Independent System Operator
EO8	Executive Order No. 8	NYSERDA	New York State Energy Research and Development Authority
EPP	Environmental Protection Plan	O&M	Operation and Maintenance
FCM	Forward Capacity Market	OpEx	Operational Expenditure
FTE	Full Time Equivalent	OREC	Offshore Wind Renewable Energy Certificate
GW	Gigawatt	OSW	Offshore Wind
IESO	Independent Electric System Operator of Ontario		
ISA	Interconnection Service Agreement		
ISO	Independent System Operator		

OWEDA	Offshore Wind Economic Development Act	RPS	Renewable Portfolio Standard
PM	Particulate Matter	RSP	Regional System Plan
POI	Point of Interconnection	RT	Real-Time
PPA	Power Purchase Agreement	RTO	Regional Transmission Organization
PSE&G	Public Service Electric and Gas	SCC	Social Cost of Carbon
PTC	Production Tax Credit	SO <sub>2</sub>	Sulfur Dioxide
PV	Present Value	SWOT	Strengths, Weaknesses, Opportunities and Threats
PVNOC	Present Value of Net OREC Cost	TSD	Technical Support Document
REC	Renewable Energy Certificate	VRR	Variable Resource Requirement
RFP	Request for Proposals	WTG	Wind Turbine Generator
RGGI	Regional Greenhouse Gas Initiative		

## 1 INTRODUCTION

On January 31, 2018 Governor Murphy signed Executive Order No. 8 (EO8) which set a goal of 3,500 Megawatts (MW) of Offshore Wind capacity by 2030 and directed the New Jersey Board of Public Utilities (BPU or the Board) and other implementing State Agencies to “take all necessary action” to fully implement the Offshore Wind Economic Development Act (OWEDA).<sup>1</sup> EO8 Further directed the BPU to proceed with a solicitation of 1,100 MW as a first step in meeting that goal.

OWEDA directed the BPU to establish an offshore wind renewable energy certificate (OREC) program requiring a percentage of electric load be supplied by offshore wind (OSW) to support at least 1,100 Megawatts (MW) of generation from qualified offshore wind facilities. The Board adopted these rules on February 10, 2011 and readopted them with amendments on January 23, 2018 (N.J.A.C. 14:8-6).

As defined by the OWEDA, Qualified Offshore Wind Facilities are those which are located “...in the Atlantic Ocean and connected to the electric transmission system in this State.” OWEDA further requires that offshore wind projects deliver a net economic and environmental benefit to the State of New Jersey in order to be deemed eligible to receive ORECs. OWEDA also established that ORECs shall be classified as Class I renewable energy. Hence, OREC production will count toward the annual Class I requirement set by the Renewable Portfolio Standard (RPS).<sup>2</sup>

On September 17, 2018 the Board issued an Order (Board Order) opening the application window for the solicitation of the initial 1.1 GW of OSW capacity in compliance with EO8.<sup>3</sup> The Board Order established the application process and schedule, which were described in detail in the Guidelines for Application Submission for Proposed Offshore Wind Facilities (Guidelines).<sup>4</sup> Per Subsection 2.3 of the Guidelines, the application period closed on December 28, 2018.

The Board reported on December 31, 2018, that applications from three developers were received in response to the solicitation.<sup>5</sup> Each application covered the base project (*i.e.*, 400 MW project size) and project alternatives for a total of fourteen distinct combinations of nameplate and associated infrastructure developments. Throughout this report, the following distinctions in terminology are made: “Application” refers to each of the three submissions and all proposed project alternatives, “Applicant” refers to the proposer entity as specified below, and “Project” or “Offer” refers to a distinct project size and associated infrastructure combination.

Applications for ORECs were received from three entities, hereafter collectively “the Applicants”: Atlantic Shores Offshore Wind, Boardwalk Wind, and Ocean Wind. Atlantic Shores Offshore Wind is a joint venture between EDF Renewables North America and Shell New Energies US LLC. Boardwalk Wind is sponsored wholly by Equinor Wind US LLC. Ocean Wind is backed by Ørsted US Offshore Wind, with the support of PSEG Renewable Generation LLC. The Bureau of Ocean Energy Management (BOEM) lease areas held by each of the Applicants are shown in Figure 1.

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<sup>1</sup> On August 19, 2010, the OWEDA was signed by then New Jersey Governor Christie.

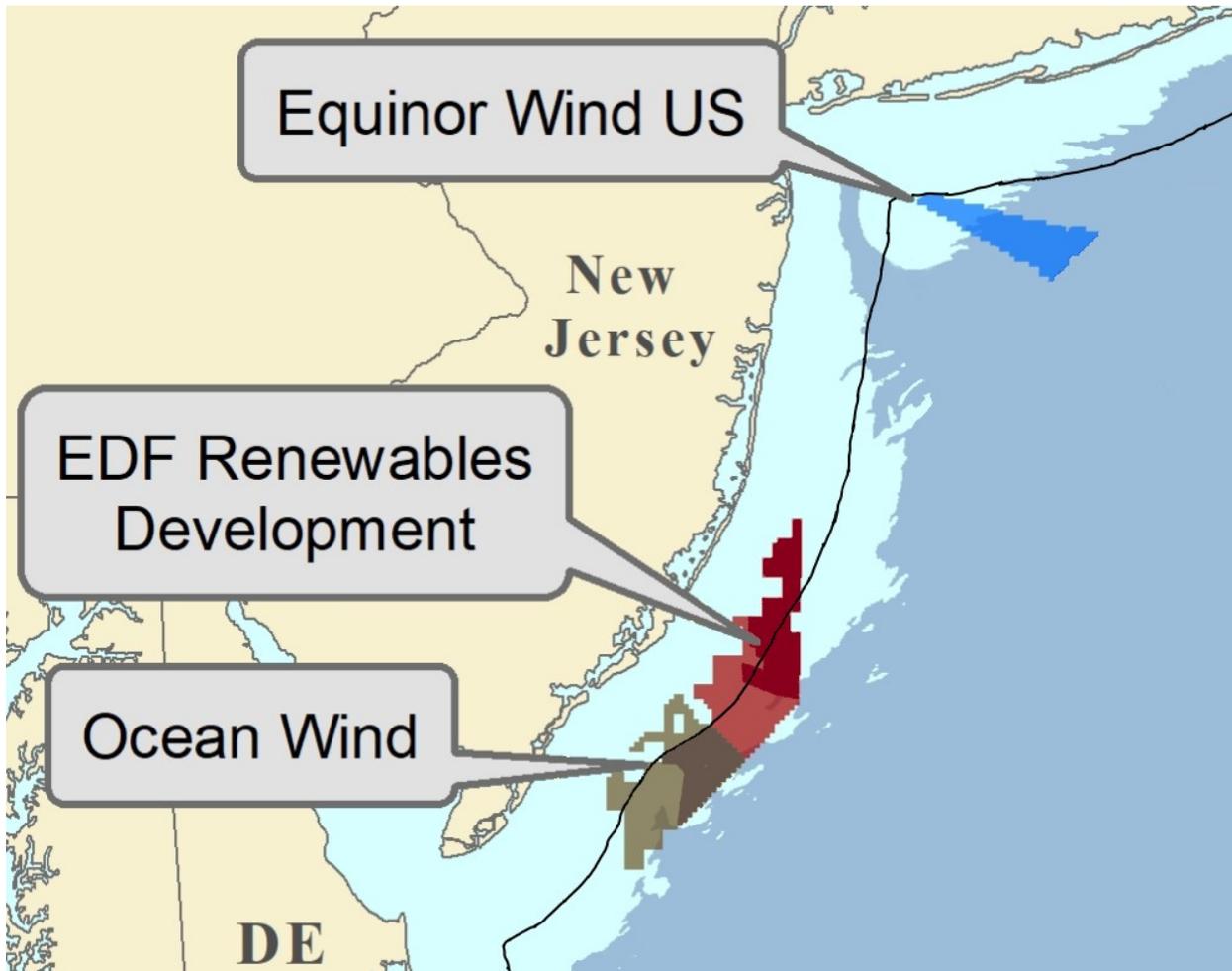
<sup>2</sup> One OREC is equal to one megawatt hour of electric energy produced from a qualified offshore wind facility.

<sup>3</sup> <https://nj.gov/bpu/pdf/boardorders/2018/20180917/9-17-18-8G.pdf>

<sup>4</sup> <https://www.njoffshorewind.com/wp-content/uploads/2018/10/Guidance-Documents-Full-Version-with-appendices.pdf>

<sup>5</sup> <https://www.bpu.state.nj.us/bpu/newsroom/2018/approved/20181231.html>

Figure 1. Applicant Lease Areas



On March 15, 2019, Levitan & Associates, Inc. (LAI) was selected by the Board to assist Board Staff with the evaluation of these applications as directed by EO8. The Guidelines provided the application requirements and the evaluation framework. Subsection 2.4 of the Guidelines provided the basic bid requirements. Applicants could offer projects between 300 MW and 1,100 MW of nameplate capacity. Applicants were required to offer at least one bid for a project at 400 MW. Applicants were required to submit a bid fee of \$150,000 per project covering a base and two alternative bid options; additional options required a fee of \$25,000 per option.

Section 3 of the Guidelines provided the application requirements consistent with OWEDA, the implementing rules at N.J.A.C. 14:8-6, Executive Order No. 8, and the proposed OREC Funding Mechanism Rules. Any other information deemed necessary by the Board may be considered consistent with OWEDA and the implementing rules.

Section 4 of the Guidelines provided the six criteria that form the basis of LAI's evaluation of the three applications contained in this report. Per the Guidelines, the six criteria are:

1. **OREC Purchase Price** – This includes meeting the requirement for a fixed, pay-for-performance price as well as the implied subsidy above market prices.

2. **Economic impacts** – This includes, among other metrics, the number of jobs created by the project, increase in wages, taxes receipts and state gross product for each MW of capacity constructed.
3. **Ratepayer impacts** – This includes the average increase in residential and commercial customer bills. The Board will also consider the timing of any rate impacts.
4. **Environmental impacts** – This includes the net reductions of pollutants for each MWh generated and the feasibility and strength of the applicant’s plan to minimize environmental impacts created by project construction and operation.
5. **The strength of guarantees for economic impacts** – This includes all measures proposed to assure that claimed benefits will materialize as well as plans for maximizing revenue from the sales of energy, capacity and ancillary services.
6. **Likelihood of successful commercial operation** – This includes feasibility of project timelines, permitting plans, equipment and labor supply plans and the current progress displayed in achieving these plans.

LAI utilized three primary sources as the basis for its evaluation of applications: the applications as submitted, responses to clarifying questions (CQs), and supplemental information obtained during and after applicant interviews conducted by LAI and Board staff on May 9, 2019. Following the applicant interviews, applicants were given the opportunity to submit a Best and Final Offer (BAFO) on May 13, 2019, as well as to submit supplemental information designed to clarify prior information submitted in the applicant’s application or CQ responses.

Quantitative evaluation of projects is based on price. Each applicant submitted an OREC Purchase Price and OREC Pricing Schedule for each project specification with their respective applications. LAI evaluated the levelized OREC Price over 20 years and the OREC Pricing Schedule relative to total project costs as noted in the Guidelines. LAI also projected the levelized Net OREC price for purposes of standardized comparison. Quantitative evaluation reflects the value of energy, capacity, and renewable energy credits (RECs) over the 20-year OREC contract term. To the extent an offshore wind project is able to participate in PJM’s ancillary services markets, additional revenues will ultimately be credited to ratepayers under the refund mechanism contemplated in the Board’s administration of the OREC. No ancillary services revenues have been anticipated in this evaluation, however.<sup>6</sup> Quantitative results are presented on the basis of the Levelized Net OREC Cost (LNOC) in nominal dollars, *i.e.*, with inflation. Hence, the lower the LNOC the lower the ratepayer impact over the OREC term, and vice versa.

Qualitative evaluation is based on characteristics specific to each of the six criteria set forth in the Board’s regulations, per N.J.A.C. 14:8-6.5.(b) and includes a review of the net economic and environmental benefits as required under N.J.A.C. 14:8-6.5.(a).<sup>11</sup> Emphasis is placed on whether claimed economic and environmental benefits pass the threshold set forth in the Board’s regulations. For ease of interpretation, LAI used color-coded qualitative ratings to signify relative strengths or weaknesses. Each offer is assigned a rating based on the information submitted with each application and LAI’s satisfaction regarding the credibility of various representations: Green (Good), Yellow (Acceptable), or Red (Reservations).<sup>7</sup> Qualitative ratings are assigned at the application level unless otherwise specified.

Ultimately, the Board seeks the best value for New Jersey. Best value is a function of price and the net economic and environmental benefits as defined under OWEDA. Price considerations must therefore be weighed against the quantity and strength of net economic and environmental benefits delivered by the

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<sup>6</sup> Guidelines, Attachment: Standard Inputs for Cost-Benefit Analysis

<sup>7</sup> Red shading does not imply a serious or “fatal” flaw.

project or portfolio of projects. LAI's Evaluation Report provides an evaluation of price and ratepayer impacts in the broader context of the claimed economic and environmental benefits. LAI reviewed the claimed benefits and associated guarantees and risks with each project to assist the Board in weighing the benefits versus price. Related strategic considerations affecting prospective procurement initiatives may also weigh in the Board's determination of best value.

The Board relied on LAI's Evaluation Report to consider the relative merits of rival Applicants' submissions to meet the 1,100 MW procurement target. This Public Version of the Evaluation Report omits confidential information.

## 2 OREC PURCHASE PRICE

The OREC Purchase Price was defined in the rules at N.J.A.C. 14:8-6.1 and 6.5.(a).12 as the price per OREC (megawatt hours (MWh)) paid for a Qualified Offshore Wind Project. Hence, the OREC Purchase Price reflects the all-in costs of the project, *i.e.*, the total project capital and operating costs offset by any state or Federal tax or production credits and other subsidies or grants. The OREC Purchase Price is fixed for the first 20 years of project operation and paid on a dollar per MWh for delivered energy. The rules at N.J.A.C. 14:8-6.5.(a).12.(iii) and (vii) required applicants submit an OREC Pricing Schedule with a fixed OREC price for each year of the proposed 20 year term of operation. The first year OREC price is typically the lowest price that may be subject to a rate of inflation over the life of the project. The levelized OREC Price, which reflects the rate of inflation, is the OREC Price used to evaluate projects on a competitive basis. LAI also evaluated the LNOC, which is the OREC Price less the expected value of energy, capacity and environmental attributes. The levelized net OREC Price represents the net price paid by ratepayers. It is expressed on a nominal dollar basis over the 20-year OREC term using a discount rate equal to 7%.

Applicants must commit to refunding all non-OREC revenue streams to ratepayers should other revenue sources be realized during the 20-year OREC term for proposed projects.

### 2.1 Standardization of common variables and calculation methods

In Attachment 7 of the Guidelines, the Board provided a set of standardized inputs for use by applicants submitting an application to sell ORECs. These standardized inputs were meant to serve as a common set of methods and assumptions to be utilized for the cost-benefit analysis submitted with all applications under N.J.A.C 14:8-6.5.(a).11. Standardized inputs from the Board include price projections for energy, capacity, and RECs.

Applicants were allowed to submit alternative market forecasts for energy, capacity, and RECs as part of the application. However, the cost-benefit analysis required the use of standardized market price forecasts. For this reason, applications were not evaluated on the quality of their price forecasts utilized in the cost-benefit analyses.

### 2.2 Projection of common commodity prices for energy, capacity, and RECs

Quantitative evaluation of applications was completed using the Guidelines' market price forecasts as well as LAI's independent forecasts of energy, capacity, and RECs over the OREC contract term. The value of ancillary services is not included in the estimation of Net OREC price, and applicants were instructed not to include ancillary services revenues in their analyses.

#### 2.2.1 BPU prices as Applicant guidance

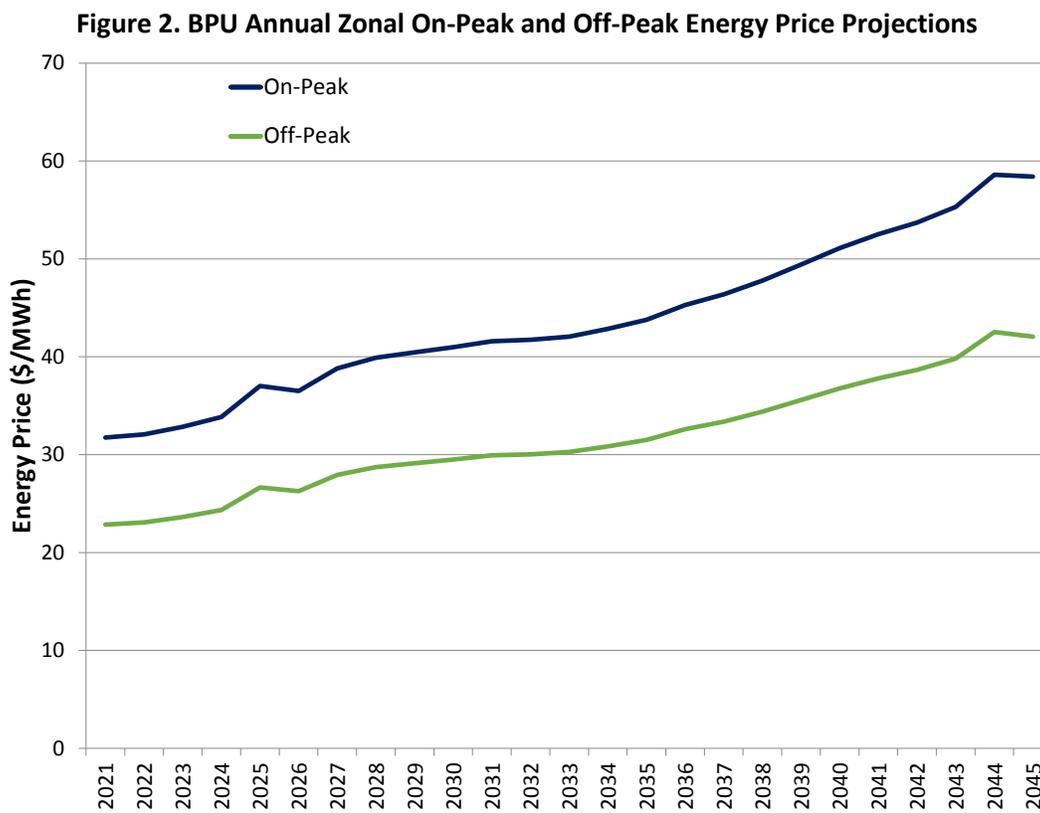
The Board provided price projections for energy, capacity, and RECs. The method used to generate these price projections is in Attachment 7 of the Guidelines.

The Board provided forecasted near-term on-peak and off-peak energy prices based on NYMEX futures through 2021 at the PJM Western Hub. The Board applied a calculated ratio of on-peak to off-peak prices. The Board accounted for the historical difference in energy prices among the electric distribution company (EDC) zones in New Jersey and the PJM Western Hub price.<sup>8</sup> From 2021 through 2045, zonal energy prices reflect the reference case annual growth rate from the 2018 Annual Energy Outlook (AEO).

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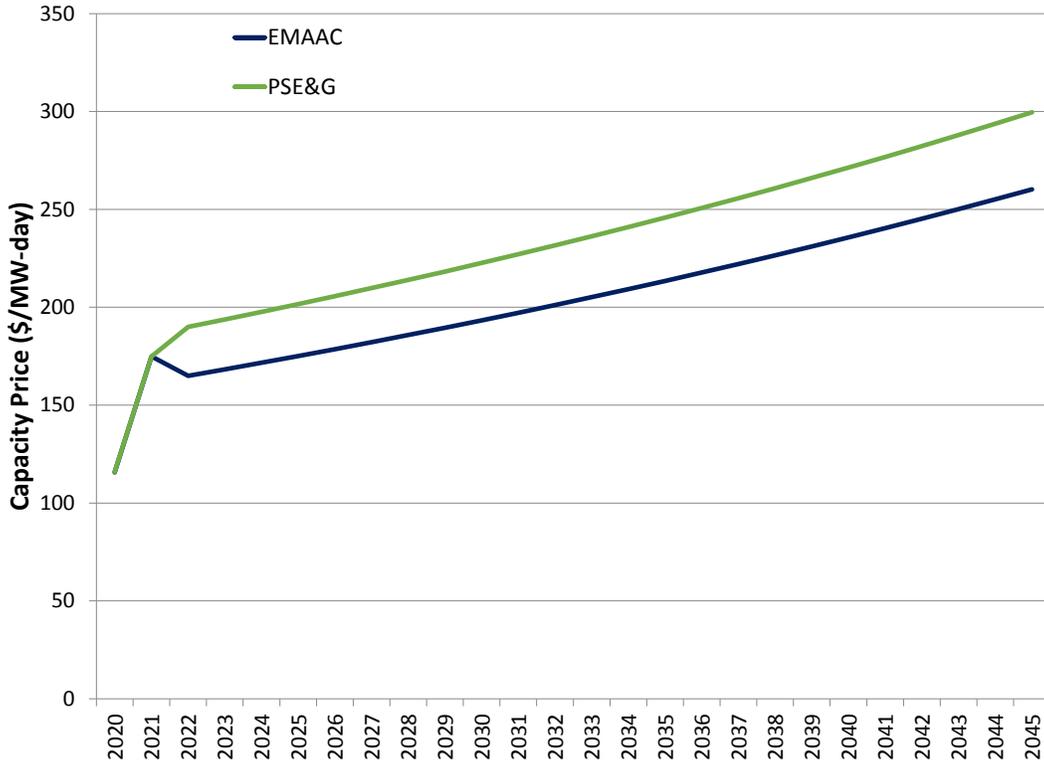
<sup>8</sup> [https://www.cmegroup.com/trading/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp\\_quotes\\_settlements\\_futures.html#tradeDate=08%2F24%2F2018](https://www.cmegroup.com/trading/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp_quotes_settlements_futures.html#tradeDate=08%2F24%2F2018)

Figure 2 shows the average on-peak and off-peak energy prices across the four EDC zones.



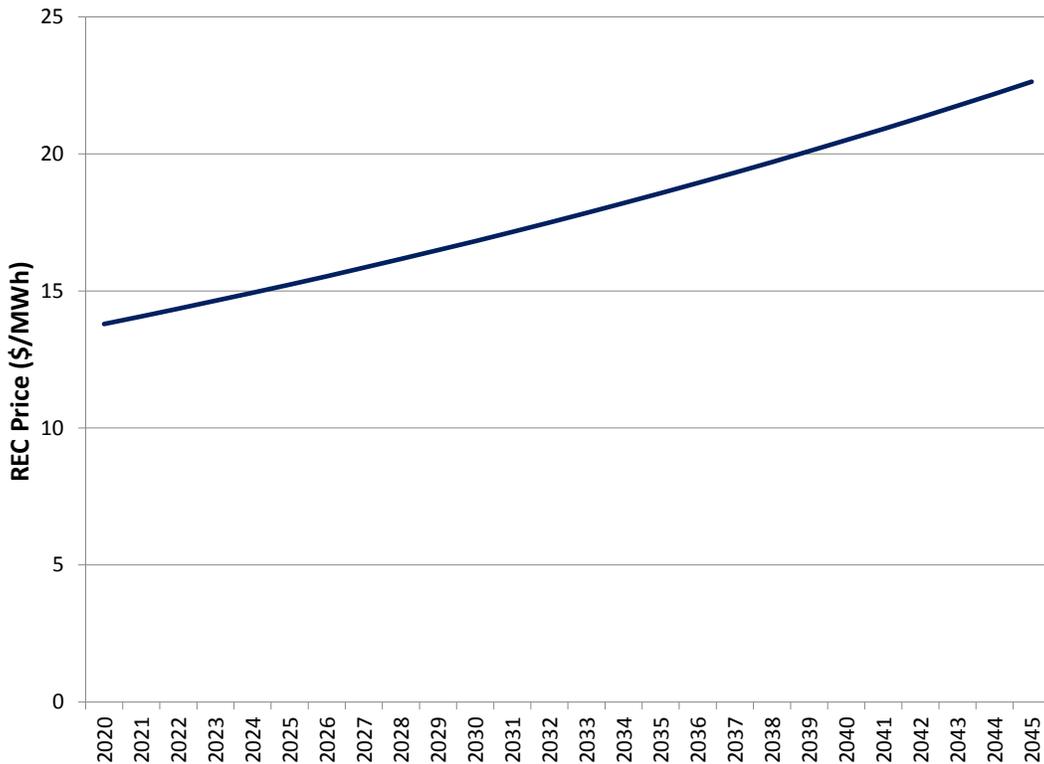
The Board forecasted capacity prices for the four EDCs in New Jersey by applying a 2% inflation rate to recent PJM Base Residual Auction (BRA) results. The 2% rate is the Federal Reserve’s target inflation rate, and has been adopted in recent years in many industry studies. Public Service Electric and Gas (PSE&G) cleared higher than the rest of the Eastern Mid-Atlantic Area Council (EMAAC) in the most recent BRA for the 2021/2022 delivery year, separating from the EMAAC price at which Atlantic City Electric (ACE), Jersey Central Power and Light (JCP&L), and Rockland Electric Company are expected to clear. Therefore PSE&G capacity prices are expected to remain higher than those in the other three New Jersey zones, which are all expected to clear at the EMAAC price. Capacity prices provided by energy year (*i.e.*, June to May) are shown in Figure 3.

**Figure 3. BPU Energy Year Capacity Prices Projections**



New Jersey Class I REC prices shown in Figure 4 were forecasted by applying an escalation rate of 2% to reflect inflation to the June 2016 through May 2017 average Class I REC prices of \$13 per REC.

**Figure 4. BPU New Jersey Class I REC Price Projections**



## 2.2.2 LAI market forecast as second opinion

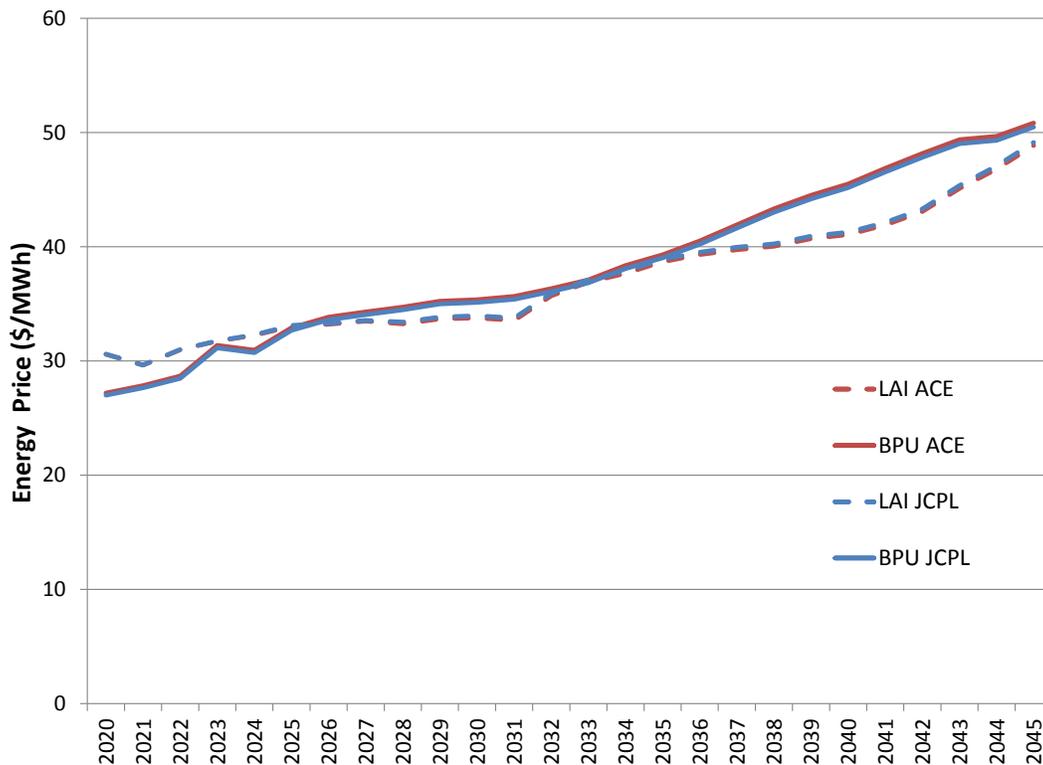
In addition to the Board forecast, LAI performed an independent assessment of future energy, capacity, and REC prices. To simulate wholesale electric market dynamics in PJM, we used Aurora, a chronological dispatch simulation model licensed by Energy Exemplar. New Jersey Class I REC prices were forecasted using LAI's proprietary REC price forecasting model.<sup>9</sup> We also utilized Aurora to estimate the emissions reduction benefits ascribable to offshore wind entry in New Jersey. We simulated market outcomes through 2050 and extrapolated the results through thirty years of OSW project operation for estimation of emissions effects.

A discussion of the key building block assumptions used in LAI's production simulation model is presented in Appendix A.

### 2.2.2.1 Zonal Aurora Energy Price Forecast

LAI's forecast of zonal energy prices is similar to the prices from Guidelines. LAI's forecasted prices for ACE and JCP&L each averaged around \$37.50/MWh from 2020 to 2045. BPU's guideline prices averaged around \$39/MWh over the same period.

**Figure 5. BPU and LAI Energy Price Forecasts**



Energy prices shown in Figure 5 are expressed in nominal dollars. Reflecting the anticipated continued abundance of relatively inexpensive natural gas delivered to gas-fired power plants across PJM and neighboring regional transmission organizations (RTOs) energy prices are expected to remain relatively low cost over the forecast period. In real terms, that is, without inflation, energy prices remain close to

<sup>9</sup> The REC price forecast was based on equilibrium market assumptions and therefore does not address the potential impact of large increments of offshore wind added to the resource mix and resultant REC clearing prices in New Jersey over the OREC term.

\$30/MWh over the forecast period.<sup>10</sup> This trend reflects limited changes to the system heat rate and delivered gas prices that remain stable in real terms. See Figure A3 of Appendix A.

### 2.2.2.2 Nodal-zonal Energy Price Spread

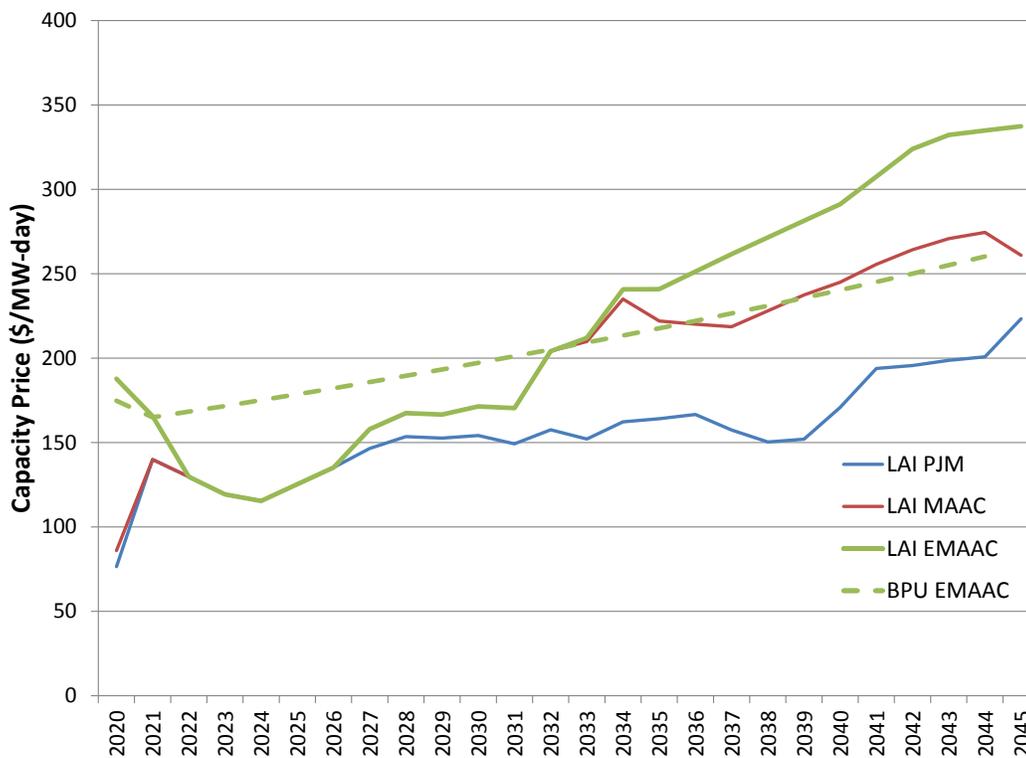
The Aurora simulation model produces energy prices at the zonal level. The OREC contract price credits ratepayers the actual market revenue for energy, capacity and RECs. Hence, ratepayers pay the Net OREC Price. Because the project’s revenue from energy sales in the PJM Day-Ahead (DA) and Real-Time (RT) markets are nodal based, LAI used a statistical model to account for the spread between nodal and zonal prices. Predicted nodal prices for each proposed interconnection point are a function of zonal prices and chronological variables.

This statistical model is also explained in Appendix A.

### 2.2.2.3 Capacity Price Forecast

LAI’s forecasted EMAAC capacity prices are also similar to the BPU’s guideline prices. LAI’s forecasted clearing price averaged about \$216/MW-day for the 2020 through 2045. BPU’s guideline prices averaged about \$212/MW-day over the same period.

**Figure 6. BPU and LAI Capacity Price Forecasts**



LAI has found that MAAC and EMAAC prices begin to separate from the PJM-RTO clearing price in the 2030s. Price separation is initially caused by coal retirements in MAAC, where many states include Regional Greenhouse Gas Initiative (RGGI) carbon allowance pricing. This divergence is further

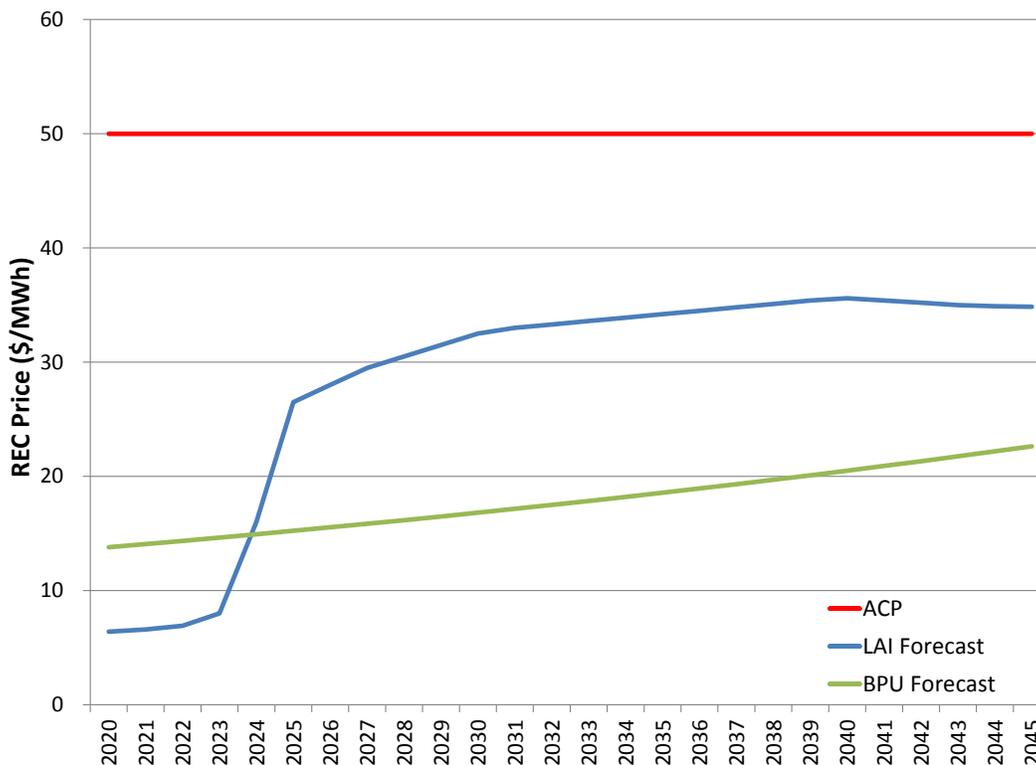
<sup>10</sup> Potential reformation of operating reserves in PJM may sustain upward pressure on wholesale energy prices, but this market and regulatory dynamic has not been included in LAI’s quantification of energy prices over the forecast period.

exacerbated by nuclear retirements at or before Nuclear Regulatory Commission (NRC) license expirations in MAAC and EMAAC.

#### 2.2.2.4 New Jersey Class I REC Price Forecast

LAI’s forecasted REC prices are higher than BPU’s forecasted prices, mainly due to the phase-out of the Federal production tax credit (PTC) and investment tax credit (ITC) reflected in LAI’s fundamentals model that requires full cost recovery for new renewables projects. The primary source for capital and operating cost data is a presentation from Lawrence Berkley National Laboratory.<sup>11</sup> Other key assumptions and method attributes supporting the REC price forecast are explained in Appendix A. Figure 7 shows both BPU and LAI’s REC price forecasts through 2050 and the alternative compliance payment (ACP), which serves as an upper bound to REC prices.

**Figure 7. BPU and LAI NJ Class I REC Price Forecasts**



### 2.3 Transmission points of interconnection

In order to meet the rules at N.J.A.C. 14:8-6.5.(a).14, applicants were required to provide specific information regarding their Interconnection Plan for each project alternative, as follows:

- A plan for interconnection, including designation of the point of interconnection (POI); and
- An estimate of transmission system upgrade costs, including documentation supporting the estimate.

<sup>11</sup> Mark Bolinger, Lawrence Berkley National Laboratory, “Turning a Double Negative Into a Positive: What It Will Take To Stay Competitive In the Face of Rising Interest Rates and the Loss of the PTC,” May 8, 2018 presentation at WINDPOWER 2018, Chicago., [http://s23.a2zinc.net/clients/AWEA/WP18/Custom/Handout/Speaker13276\\_Session2997\\_1.pdf](http://s23.a2zinc.net/clients/AWEA/WP18/Custom/Handout/Speaker13276_Session2997_1.pdf)

Rules at N.J.A.C. 14:8-6.5(a).14.(vi) provided that an estimate of transmission system upgrade costs must be included with the application and Guidelines Subsection 2.4 required this cost be included in the OREC Purchase Price. Guidelines Subsection 2.4 also conveyed a preference for a fixed price offer and at the same time recognized the uncertainty about the future cost of needed transmission system upgrades. Hence, the Board allowed applicants to include OREC Purchase Prices that will be reconciled or “trued-up” with actual transmission system upgrade costs minus the amount the applicant includes within its offer for OREC pricing with cost true-up, when PJM has completed the estimate of transmission system upgrade costs allocable to each offshore wind project. Applicants were permitted to embed from 0% to 100% of the transmission system upgrade costs in their base OREC Purchase Prices. Other project-related transmission costs associated with the offshore and onshore transmission segment to the POI are not subject to reconciliation.

Transmission system upgrade costs can have a significant impact on Net OREC Price. In LAI’s experience in PJM, there are instances where transmission system upgrade costs can be materially higher than initial estimates. The gap between initial expectations and PJM’s final determination can induce a project to withdraw from the interconnection queue or otherwise alter the original injection quantity in order to limit adverse financial exposure. In light of the Guidelines Subsection 2.4, any applicant that submitted a transmission cost estimate that is significantly lower than what may be reasonably expected poses a potential risk to ratepayers if the applicant requested true-up.

LAI evaluated each applicant’s Interconnection Plan as submitted for each project alternative. The primary evaluation criterion is the reasonableness of the estimate of the transmission system upgrade costs. LAI’s review encompassed examination of the applicant’s documentation regarding system upgrade costs, an analysis of the submitted study or studies, responses to CQs, and a review of other information in the public domain from PJM. LAI also relied on Supplemental Information submitted by applicants on May 13, 2019. All POIs are located in the JCP&L and ACE load zones. Hence, a review of prior interconnection studies in JCP&L and ACE was also performed.

LAI reviewed methods the applicant advanced to mitigate cost risk. This included the procurement of Capacity Interconnection Rights (CIRs). CIRs quantify the power that a generating unit is permitted to deliver to PJM at a specified bus enabling the unit to participate in PJM’s BRA as a capacity resource. CIRs are unit specific and granted in a quantity commensurate with the MW installed nameplate identified in a generator’s interconnection request and interconnection service agreement. Under PJM’s Open Access Transmission Tariff, the generator pays for any transmission system upgrades required to ensure deliverability. PJM grants CIRs to the generation developer upon completion of the necessary transmission system upgrades to resolve reliability criteria violations.<sup>12</sup>

For the transmission evaluation criterion, LAI assigns qualitative ratings to the applications at the project level to account for variation across the proposed project alternatives on the following basis:

- Green – Applicant provided a detailed, reasonable, and well documented estimate of transmission system upgrade costs supported by an analysis using a software model that uses a methodology consistent with that used by PJM for each project alternative.
- Yellow – Applicant provided a reasonable estimate of transmission system upgrade costs for each project alternative.

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<sup>12</sup> CIRs can be transferred from one generator to another. If the recipient of CIRs is a generator in the PJM queue, the transferred CIRs have the potential to offset all or part of the transmission system upgrade costs determined by PJM as allocable to the recipient generator for the transmission system upgrades that are required to resolve reliability criteria violations. An applicant’s use of CIRs has the potential to mitigate adverse cost exposure associated with transmission system upgrades to accommodate one or injections.

- Red – Applicant provided an unreasonable estimate of transmission system upgrade costs for each project alternative.

## 2.4 Exposure to adverse transmission system upgrade costs

Under the Board’s transmission system upgrade reconciliation approach, all applicants have the option to pass through the cost of such upgrades PJM determines from the respective System Impact Study. Applicants were encouraged to make good faith estimates of transmission system upgrade costs through technical study and documentation. LAI reviewed each applicant’s documentation in order to assess potential adverse ratepayer impacts ascribable to the pass-through of transmission system upgrade costs in relation to each applicant’s initial estimate.

## 2.5 Calculation of Net OREC cost

Applicants submitted as part of the application form price information for each proposed project alternative by energy year.<sup>13</sup> An All-In OREC Purchase Price schedule was expressed in nominal \$/OREC. Applicants also submitted a transmission component price schedule related to the system upgrade portion of the OREC Cost, also stated in nominal \$/OREC. As discussed in the individual project evaluations, we substituted where appropriate LAI’s estimate of the transmission component related to the system upgrade portion of the OREC cost. The Levelized OREC Purchase Price is stated in nominal \$/MWh and includes the system upgrade portion of the OREC Cost, including LAI’s assumption where appropriate. The LNOC is expressed in nominal \$/MWh, and includes the effect of the revenue credits.

LNOC is calculated for each project alternative submitted with the applications. Derivation of LNOC is based on the proposed OREC Price Schedule and LAI’s estimate of hourly project output, annual project unforced capacity, and market-based energy, capacity, and REC prices. Consistent with the transmission cost method referenced above, it reflects LAI’s estimate of anticipated transmission system upgrade costs allocable to ratepayers in New Jersey under the true-up or reconciliation provision set forth in the Guidelines and N.J.A.C. 14:8:6.5.(a).12. If the proposed OREC Purchase Price includes a portion subject to actual transmission upgrade costs, LAI included these costs in the derivation of the Net OREC cost. The value of ancillary services was not considered per Attachment Seven to Guidelines.<sup>14</sup>

LAI’s Base Case in Aurora reflects the Governor’s stated commitment to a full buildout of 3,500 MW of offshore wind in New Jersey by 2030. We incorporated the set of hourly energy prices for each on-shore delivery point identified by the applicant from January 1, 2024 through December 31, 2045. Related models have been used to forecast capacity prices for relevant Local Deliverability Areas (LDAs) and New Jersey Class I REC prices. The LNOC model applies the proposed OREC prices to estimated OREC quantities, and adjusts for market energy, capacity, and REC revenues on an hourly or monthly basis. The LNOC model accumulates payments and credits over a calendar year. The LNOC model includes financial discounting and levelization over the 20-year contract term in accord with standard industry practice.

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<sup>13</sup> Per the OREC Funding Mechanism at page 3, an “energy year” means the 12-month period from June 1 through May 31 and is to be numbered according to the calendar year in which it ends.

<sup>14</sup> Offshore wind resources would not likely qualify for any ancillary services procured by PJM. The future value of ancillary services is hard to predict and would likely comprise an insignificant portion of any project’s total operating revenue.

### 2.5.1 Levelized Net OREC Cost

LNOC can be presented either in levelized nominal dollars or in levelized real (constant date value) dollars. The nominal levelized convention comports with the intended administration of OREC pricing as fixed nominal prices by energy year. The real levelized convention represents a more meaningful and fair comparison of offers with different expected OREC contract start dates or operational capacity schedules over the 20-year OREC term. It is sometimes used by state entities to report in current day dollars the expected price over a long contract term for a project that will not start commercial operation for several years.

In general terms, the LNOC is equal to the applicant's OREC price offer for a specific project alternative, adjusted for the value of capacity, energy, and RECs. The unitized cost of transmission system upgrades is incorporated in the derivation of Net OREC cost.

### 2.5.2 Application to Portfolios of Projects

In this first round solicitation, the Board has initially sought offshore wind projects that will sum to about 1,100 MW. Somewhat more or less than 1,100 MW may be selected. Under certain circumstances, the Board may consider awarding a portfolio of projects that materially exceed 1,100 MW. While the Board may award a single OREC equal to or approximately equal to 1,100 MW, there are other options that meet the Board's procurement target, for example, one 700 MW project coupled with one 400 MW project, or, an 800 MW project coupled with a 300 MW project. Among the array of submissions there are eleven potential project combinations that achieve the stated goal of about 1,100 MW. The set of portfolio combinations expands in the broader context of a procurement cap that exceeds 1,100 MW by more than a few percent. Portfolio evaluation is a central part of LAI's assessment, including New Jersey economic benefits and environmental impacts tradeoffs.

## **2.6 Comparison with public sources of LCOE**

Among the application requirements listed in N.J.A.C. 14:8-6.5.(a).3. v. includes "[a] full cost accounting of the project, including total construction, the feasibility study used to determine the construction costs, and decommissioning costs." To meet this requirement, the applicants provided the capital expenditure (CapEx) for each proposed project alternative in varying levels of detail. None provided a feasibility study used to determine construction cost.

CapEx is the total capital expenditure required to reach commercial operation. CapEx reflects the full set of costs to permanent financing, including all development and soft costs, interconnection costs, labor reserves and financing costs. There were many significant differences in the level of detail submitted by the three applicants, thereby requiring LAI to exercise judgment in the comparison of project capital and operating costs by submission. LAI's review of the relevant CapEx for each proposed project alternative necessarily relied on the applicant's representation of total project cost. LAI also reviewed the relevant operational expenditures (OpEx). OpEx comprises the ongoing costs for all operation and maintenance (O&M) and administrative expenses. Capital replacements and overhauls during the operational life of the project are included in OpEx. OpEx is usually divided into fixed O&M costs stated in \$/kW-year, which are necessarily incurred regardless of annual energy production, and variable O&M.

Examination of CapEx and OpEx for each project submission provides additional assurance to the Board that the OREC Price is based on the actual cost of the project as required under N.J.A.C. 14:8-6 and in Guidelines Subsections 3.3 and 3.12 which ask for the levelized cost of electricity (LCOE) over 20 years. To validate the reasonableness of each applicant's CapEx and OpEx estimates for each project alternative, LAI compared the costs submitted by the applicant to benchmark metrics in the public

domain. The CapEx and OpEx review supports the quantification of the LCOE. Recent information from various public sources provides LCOE benchmarks used to support LAI's reasonableness check.

LAI's evaluation of the relative strength of each applicant's all-in CapEx and OpEx at the project level with the industry benchmarks assigns a qualitative rating on the following basis:

- Green – Applicant submitted CapEx and OpEx that are similar to LCOE benchmarks.
- Yellow – Applicant submitted CapEx and OpEx that substantially diverge from LCOE benchmarks.
- Red – Applicant submitted CapEx and OpEx that substantially diverge from LCOE benchmarks and application lacks useful information, or CapEx and/or OpEx shows significant difference versus rival submissions.

### 3 ECONOMIC IMPACTS

N.J.A.C. 14:8-6.5.(a).11.(i) required the cost-benefit analysis for the project to include a “detailed input-output analysis of the impact of the project on income, employment, wages, indirect business taxes, and output in the State with particular emphasis on in-State manufacturing employment.” The Guidelines described Criterion 2, New Jersey economic impacts, as including, “among other metrics, the number of jobs created by the project, increase in wages, taxes receipts and state gross product for each MW of capacity constructed.”<sup>15</sup> The OREC Application Form requested that the Net Present Value (NPV) of total impacts be reported for state gross product, output, wages, and tax receipts.

N.J.A.C. 14:8-6.5.(a).11.(xiii) required job totals to be reported as “full-time equivalent (FTE) positions assuming 1,820 hours per FTE-year.” The Application Form requested that the average annual number of jobs be reported separately for the construction period and the operation period.

The rules at N.J.A.C. 14:8-6.5.(a).11.(ix) specify that the evaluation will consider the direct, indirect, and induced economic effects broken out by the project construction and operations phases. The Application Form required that nominal monetary impacts be discounted to 2019 at a 7% discount rate.

Neither the N.J.A.C. rules nor the Guidelines provided precise instructions or templates for documenting and reporting inputs and outputs of the applicant’s selected State economy model. The only template for reporting economic impacts was the summary Application Form. Hence, the applicants each provided the more detailed inputs and outputs from their selected State economy input-output model and other related information in a different form and amount of detail.

Evaluation of the economic impacts claimed for each proposed project alternative is largely a qualitative assessment. The quantitative model results were viewed with respect to the credibility of the model data and assumptions for a specific array of New Jersey expenditures on goods and labor services, the firmness and credibility of the commitments, plans, and aspirations that result in the specified direct expenditure and jobs effects. In addition, some proposed projects would have much different New Jersey economic impacts if a third-party manufacturer does not develop a fabrication facility in New Jersey or a new port facility is not developed.

Elements of the New Jersey Economic Development Plan are assigned qualitative ratings at the project level as follows:

#### *Project Activity Locations*

- Green – activity would or is expected to take place in New Jersey
- Yellow – activity may take place in New Jersey
- Red – activity will not take place in New Jersey or no mention provided

#### *Labor and Management*

- Green – definite plan for relationship with organized labor or project management
- Yellow – indefinite plan
- Red – no plan mentioned

#### *Infrastructure Investment (ports, fabrication plants, O&M facilities)*

- Green – definite plan for investment in New Jersey that would also provide support to future projects
- Yellow – vague plan or expectation without much, if any, supporting evidence

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<sup>15</sup> Guidelines, page 17

- Red – no plan or mention

*Development Expenditures for sponsorship programs*

- Green – definite financial commitment to a sponsorship program
- Yellow – anticipate making a financial commitment to a sponsorship program
- Red – no mention of sponsorship

Aspects of New Jersey economic impact guarantees related to investments, expenditures, and jobs are assigned qualitative ratings as follows:

*Investment and/or Operation Expenditure Commitments*

- Green – substantial minimum guaranteed expenditure relative to total capital cost
- Yellow – small to moderate size minimum guaranteed expenditure relative to total capital cost
- Red (or blank) – no commitment mentioned

*Construction and/or Operation Jobs Commitments*

- Green – large minimum guaranteed number of FTE-years relative to total construction phase FTE-years and/or operation phase annual FTEs
- Yellow – small minimum guaranteed number of FTE-years relative to total construction phase FTE-years and/or operation phase annual FTEs
- Red (or blank) – no jobs commitment mentioned

*Total Commitments – minimum guaranteed spend*

- Green –substantial guaranteed spend relative to capital cost
- Yellow – moderate guaranteed spend relative to capital cost
- Red – small guaranteed spend relative to capital cost

### **3.1 Input-output modeling of New Jersey economy**

While the applicants each utilized one of the recommended regional economic input-output models, they differed substantially in the use of the model, including data inputs and reporting of results. LAI scrutinized the data and assumptions in order to make certain adjustments in order to provide a consistent comparison across applicants. The main problem applicants encountered is that N.J.A.C. 14:8-6.5.(a).11 was not clear on which of the metrics listed – “income, employment, wages, indirect business taxes, and output” was to provide the basis for the summation of economic benefits from increased in-State activity from “construction, operations and maintenance, and equipment purchases” was to be included together with ratepayer net costs and environmental net benefits. Two of the applicants correctly used the income measure (also known as “value-added” or “gross domestic product”), while the third applicant apparently tried to include all the listed direct spending effects metrics, which led to double-counting.

### **3.2 Distinction between effects and benefits**

It is important to recognize that economic effects do not have a direct translation into economic benefits. In theory, secondary economic benefits only result from local project-related expenditures when manufacturing, services, and other industries have under-utilized capacity, and the labor force suffers from unemployment and under-employment. Under those depressed conditions, project development uses capital equipment and labor whose opportunity cost is below market prices. At the other extreme, when capital and labor resources are fully employed, the capital and operating

expenditures on a project development merely displace other spending elsewhere in the local or broader economy.

An analysis limitation is that static economic input-output models, such as the IMPLAN and R/ECON models used by the applicants, assume that all capital and labor resources are already fully employed in the local study area (New Jersey, in this instance), so local project spending is “manna from heaven” that has maximal stimulus effects because new housing, schools, and hospitals, among other support services, are needed to serve an expanded population. This is because the existing labor force is assumed already to be fully employed.

An economic effects analysis should account for the net direct effects of a project that increases costs to businesses and households. To the extent that retail electricity bills increase to cover the additional cost of ORECs, firms and households have less money to spend on other goods and services, which has a negative effect on the New Jersey economy. Neither the N.J.A.C. rules nor the Guidelines explicitly requested that the economic impacts analysis be provided as net effects, and none of the applicants provided an analysis of net effects. Hence, the quantitative effects of changes in New Jersey state gross product and wages, for example, must be evaluated against how much of those gross project effects are mitigated by reductions in other economic production activities in the State. This netting aspect is a qualitative issue for the Board to factor into any award decisions.

## 4 RATEPAYER IMPACTS

Ratepayer impacts associated with a proposed project or portfolio are based on the Present Value of Net OREC Cost (PVNOC) and a PV-adjusted total New Jersey EDC retail load. The calculation does not include any adjustments for indirect costs or benefits associated with price effects in the energy, capacity, or REC markets. Likewise, it does not include adjustments for the avoidance of greenhouse gas emissions or for the creation of economic activity benefits. Impacts are presented in total present value, levelized 2019 dollar per kWh retail rate change, 2019 dollar typical residential, commercial, and industrial monthly bill changes, and percentage changes in monthly bills based on current retail rates.

PVNOC is derived from the same elements as those used to calculate LNOG.<sup>16</sup> Annual gross OREC costs are calculated based on proposed OREC pricing and estimated annual production. Annual energy capacity and REC market revenues are estimated from proposed output patterns and, as previously described, LAI's forecasted market prices. In general terms, the annual avoided cost of New Jersey Class I RECs is based on the proposed OSW production and a market forecast for REC prices. Specifically, the present values of the gross OREC costs and the three revenue credit components are calculated at a nominal discount rate of 7%. The Net OREC Cost is calculated as the gross cost less the revenue credits.

The present value of the forecast New Jersey retail load quantity is calculated using the real discount rate to allow for the determination of a real (constant base year dollar) levelized retail rate impact per MWh of retail load.<sup>17</sup> Retail load for each year is based on the EIA forecasts used in LAI's simulation modeling.

### 4.1 Net OREC cost in terms of change in rates by EDC customer class

The Net OREC cost will affect retail rates through two paths. First, the gross OREC cost and the energy and capacity revenue credits will be included as a non-bypassable component of the EDC delivery charges to all classes of customers. LAI assumed that this pass-through will be a similar rate for all customer classes. Second, the credit for avoided Class I REC purchases will be passed through to customers via the supply charge, whether supply is provided directly by the EDCs or through competitive retail supplier.

The levelized retail rate impact in 2019 \$/kWh is calculated as the PVNOC divided by the present value of retail load quantity.<sup>18</sup>

### 4.2 Net OREC cost in terms of change in customer class average bills

EIA data covering the 2018 calendar year was used to estimate average monthly usages and total bills for residential, commercial, and industrial/transportation customers in New Jersey.<sup>19</sup> All four NJ EDCs were aggregated for this purpose.

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<sup>16</sup> See Section 2.5

<sup>17</sup> Formula for present value of retail load quantity:

$$PVERLQ = \sum_{i=2019}^{2045} WLQ_i \times RLF \times EDCF / (1 - RDR)^{(i-2019)}$$

WLQ<sub>i</sub> is the New Jersey Wholesale Load for year i from simulation model (MWh)

RLLF is the Retail Load Loss Factor for New Jersey load

EDCF is the fraction of New Jersey retail load served by EDCs

RDR is the Real Discount Rate = (1 + NDR) / (1 + INF) - 1

INF is the Inflation Rate (2.00%)

<sup>18</sup> An adjustment from MWh to kWh is made.

These findings are tabulated below:

**Table 1. 2018 New Jersey EDC Monthly Bill and Usage**

Rate Type	Residential	Commercial	Industrial & Transportation
Total Energy Load (MWh)	29,459,876	38,574,730	7,380,640
Total Billing (\$000)	\$4,557,477	\$4,708,450	\$742,855
Number of Customers	3,554,679	521,305	11,819
Average Monthly Usage (kWh/mo)	690.6	6,166	52,040
Average Monthly Bill (\$/mo)	\$106.84	\$752.67	\$5,238

The monthly cost impact of an OREC purchase on the typical monthly bill for each rate type is calculated as the product of the levelized retail rate impact (2019 \$/kWh) and the appropriate average monthly usage in kWh. The percentage change in the typical monthly bill is calculated as the ratio of the monthly cost impact divided by the baseline average monthly bill.

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<sup>19</sup> <https://www.eia.gov/electricity/data.php>

## 5 ENVIRONMENTAL IMPACTS

### 5.1 Net reductions of pollutants

The rules at N.J.A.C. 14:8-6.5.(a).11.(xiv).(1) and (3) required applicants to “provide an assessment of the impact of the construction, operation and decommissioning of the project on emissions of carbon dioxide, sulfur dioxide, nitrous oxide, and particulate matter.”

Emissions impacts are of two categories: (1) emissions directly related to operation of equipment (marine vessels, on-road trucks, non-road equipment such as excavators, stationary generators, worker transportation, and other machinery) during construction, operation, and decommissioning of the project, and (2) emissions avoided by operation of the project through the displacement of fossil-fueled generation.

With respect to category 1, proposals are evaluated based on several factors:

- The completeness of the data provided, the level of detail, and the extent of documentation supporting the assumptions used to develop the emissions estimates;
- Applications that specified the use of low-emissions equipment or proposed any other measures to reduce emissions during construction operation, or decommissioning, if any, were rated more favorably than applications that did not make such representations.

LAI also considered the quantity of emissions on a unitized basis, *i.e.*, tons per MW per year during construction, operation, and decommissioning. However, this factor is not deemed to be a reliable differentiator among applications since each applicant used different assumptions and methods for calculating emissions.

Relative to category 2 emissions, category 1 emissions are small. For all projects, the displacement of emissions from fossil generation over the project lifetime more than offsets the incremental emissions produced during construction, operation and decommissioning. LAI also recognizes that the short term category 1 emission impacts may not be fully incremental, that is, vessels, vehicles, and other equipment used for construction of the project could be used otherwise on other construction projects in the region.

The Application Form required each applicant to provide the net reduction in CO<sub>2</sub>, NO<sub>x</sub>, SO<sub>2</sub> and particulate matter (PM) over the lifetime of each project alternative. Because applicants appear to have used different assumptions to model the avoided emissions, it is not possible to rely on the values in the Application Form to directly compare the emissions benefits across projects. Some applicants, for example, appear to have netted the category 1 emissions from the total avoided emissions. Others did not. There are also differences in the extent of the footprint over which the emissions were modeled, and differences in the assumed project lifetime.

Therefore, to facilitate an apples-to-apples comparison, LAI independently modeled the regional electric system and analyzed regional emissions from generation, with and without the proposed offshore wind projects. LAI estimated the emissions avoided by running Aurora for a case with the New Jersey planned buildout of 3,500 MW of OSW capacity by 2030 against a base case of no New Jersey OSW capacity and scaled results for each project. Since CO<sub>2</sub> is a greenhouse gas with global impacts, LAI calculated the monthly differences in CO<sub>2</sub> emissions over the Aurora study region (PJM, NYISO, ISO-NE). LAI calculated the reduction in NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> emissions across all of MAAC. This is a reasonable approach, since reductions in these pollutants in upwind states will contribute to improved air quality and health outcomes in New Jersey. LAI’s Aurora model does not include PM emissions directly. Instead, we recorded the annual changes in generation for MAAC resources that burn natural gas, coal, and oil. EPA

data from the 2014 National Emissions Inventory for direct PM<sub>2.5</sub> emissions for natural gas, coal, and oil generators were divided by EIA generation data for those fuel types in 2014 to calculate average PM<sub>2.5</sub> emission rates by fuel type. Those constant PM<sub>2.5</sub> rates were applied to the MAAC generation differences by fossil fuel type.

With respect to the absolute magnitude of the avoided emissions, the primary differentiator among projects is the proposed capacity – larger projects displace more fossil generation. However, for this criterion, the applicable metric is the emissions reductions per MW of capacity or per MWh of energy production. While small differences in net emissions may arise from differences in the injection point, and from differences in the expected capacity factor, on a unitized basis, we do not expect that the avoided emissions are a significant differentiator. For a target portfolio of a given total capacity, the net avoided emissions benefit is comparable, whether the portfolio consists of a single project or multiple projects.

Applicants are assigned qualitative ratings at the application level, as follows:

- Green – Application provided detailed and complete information on the assumptions and methods used to compute the category 1 and 2 emissions, and based the evaluation on project-specific conditions.
- Yellow – Application lacked sufficient information on the assumptions and methods used to compute category 1 and 2 emissions, and/or used generic rather than site-specific information.
- Red – Application provided no backup information or documentation.

Color-coding is raised one level (*i.e.*, Yellow to Green) for projects that proposed a feasible method for mitigating emissions during construction, operation, or decommissioning.

## **5.2 Feasibility and strength of plan to minimize environmental impacts**

Environmental Protection Plans (EPPs) were evaluated to assess the completeness and level of detail contained in each applicant's identification of potential environmental impacts and proposed mitigation associated with the project alternatives, including the installation of the export cable, and construction of the on-shore cable and substation. EPPs were reviewed for completeness against the requirements in the Guidelines Subsection 3.15 and N.J.A.C. 14:8-6.5.(a).10 and 11. Identification and description of anticipated stressors, receptors, effects, and mitigation during construction, operations, and decommissioning of the proposed project were evaluated and compared to current peer-reviewed research. Sources cited in the EPP were checked to ensure they are current, relevant, and reputable.

LAI engaged a subcontractor, EA Engineering, Science, and Technology, Inc., PBC (EA), to conduct a detailed evaluation of the EPPs. LAI incorporated EA's analysis of receptors and other environmental stressors in our qualitative review based on the following criteria:

- Green – Characterization of biological receptors includes detailed descriptions of species, geographic range, general habitat, temporal changes, listed species, mortality, and source data are assigned Green within the summary tables. Non-biological receptors covered with detailed existing conditions descriptions and high-quality source data. Discussion of effects includes quantified specific direct physical impacts, indirect physical impacts, and behavioral impacts as they relate to the temporal and spatial scale of potential stressors. EPP outlined modification of project equipment and methods to minimize stressors, structure siting to avoid receptors, and mitigation implementation to minimize effects during all phases of the project.
- Yellow – Application lacks some information, does not include current high-quality sources, and/or relies primarily on desk-top studies.

- Red – Data are significantly lacking, no additional studies are planned, and/or they are not addressed at all.

The New Jersey Department of Environmental Protection (NJDEP) also reviewed the EPPs and other relevant application components provided by BPU in the context of the solicitation requirements stipulated in the Guidelines Subsection 3.15 and N.J.A.C. 14:8:6.5.(a).10 and 11. Specifically, the NJDEP evaluated the feasibility and strength of the EPPs in mitigating environmental impacts associated with the project and the feasibility and strength of the Interconnection Plan relative to environmental impacts. NJDEP also identified gaps in information provided. The NJDEP did not evaluate air emissions impacts associated with the projects, including the net reductions of CO<sub>2</sub> and other pollutants for each MWh generated. The evaluation of emissions impacts was conducted solely by LAI.

The overall rating for each applicant's EPP consolidated NJDEP's review and LAI's scoring of the individual components, and applied the same criteria as described above for the individual components.

## **6 STRENGTH OF GUARANTEES FOR ECONOMIC IMPACTS**

Per Guidelines Section 4 Criterion 5, applications will be evaluated by the strength of their guarantees for economic impacts. Specifically, “[t]his includes all measures proposed to assure that claimed benefits will materialize as well as plans for maximizing revenue from the sales of energy, capacity and ancillary services.”<sup>20</sup> A complication is that one applicant expressed its spending and jobs guarantees conditioned on external decisions. For those contingent guarantees, LAI evaluated both the larger maximum guarantee conditioned on a positive event occurring, and the backstop smaller minimum guarantee for the alternative outcome of the conditional event not occurring.

### **6.1 Claimed investments and expenditures in New Jersey**

The Guidelines requested that the Economic Development Plan section of the application is to “propose consequences if claimed benefits do not materialize.”<sup>21</sup> LAI evaluated the proposals based on their claims of expected New Jersey expenditures and jobs and their penalty formulas for falling short of their own claims. A complication is that one applicant expressed its minimum spending and jobs guarantees conditioned on an external decision. For those contingent guarantees, LAI evaluated both the larger minimum guarantees conditioned on a positive event occurring, and the backstop smaller minimum guarantee for the alternative outcome of the conditional event not occurring.

### **6.2 Plans to ensure that revenues will be maximized**

N.J.A.C. 14:8-6.5.(a).12.(ix) required that each applicant is required to refund to ratepayers revenues associated with the sale of energy, capacity, ancillary services, environmental attributes, and any other revenues, including (but not limited to) tax credits, subsidies, grants, or other funding not identified in the application and not included in the OREC price submitted, over the 20-year term of OREC. All revenues are to be credited to ratepayers except for any sales in excess of the Annual OREC cap for energy. The project may elect to retain up to 25% of the incremental energy revenues for sales above the Annual OREC cap.

N.J.A.C 14:8-6.5.(a).6 required that the Project Revenue Plan and Strategy section of the application include identification of strategies for realizing all expected revenues from energy, capacity, ancillary services, and any other sources.<sup>22</sup> The Guidelines, Subsection 3.6, add that the Revenue Plan should “identify strategies for maximizing those revenues.” The Guidelines permit the project to make BPU-acceptable bilateral sales as an alternative to systematic reliance on the PJM DA or RT markets.

LAI reviewed each applicant’s marketing strategy, which may include strategic alliances with marketers or traders doing business in New Jersey. LAI reviewed the general structure of a hedge program or strategy that can reduce monthly volatility relative to sale of all energy in PJM’s DA or RT markets. Of particular concern are market and regulatory uncertainties associated with PJM’s Minimum Offer Price Rule (MOPR) that has the potential to hinder or preclude the realization of capacity revenue for State-sponsored resources that have an underlying cost structure that does not comport with PJM’s Independent Market Monitor’s criterion for inclusion of such capacity as an eligible capacity resource in the BRA. While wind resources have limited potential for selling ancillary services, the prospect for ancillary service sales as well as the sale of environmental attributes has been considered in the context of the applicant’s explanation of how it would ensure revenue maximization.

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<sup>20</sup> Guidelines, page 10

<sup>21</sup> Ibid, page 15

<sup>22</sup> Guidelines, page 9

## 7 LIKELIHOOD OF SUCCESSFUL COMMERCIAL OPERATION

### 7.1 Project design

#### 7.1.1 OSW project components

N.J.A.C. 14:8-6.5.(a).2.(i).(2) required a demonstration by applicants that “that the wind technology is viable, cost competitive, and suitable for use in New Jersey's offshore environment under varying and expected meteorological and climate conditions...” In support of this requirement, applicants were to provide a “[d]escription of major types of equipment that have been selected to be installed, including specifications, warranties, commercial operating history and the ability of the equipment to work in New Jersey's offshore and near shore climates.”

Major types of equipment include wind turbine generators (WTGs), foundations, offshore substations, and inter-array and export cables. Each of these components is evaluated separately following the guidelines established by the application requirements and Board Guidelines, utilizing the specific criteria listed below.

##### 7.1.1.1 *Wind Turbine Generators*

Applicants are evaluated on their WTGs based on the following three subcategories: certification, specifications and warranties, and operating history. Applicants are assigned qualitative ratings at the application level based on the following criteria:

#### **Certification**

- Green – The WTGs have been certified, or if they are not certified, applicant provided a detailed certification plan that is underwritten by a certifying body.
- Yellow – Applicant provided a certification plan which does not satisfy the requirements to achieve a Green rating.
- Red – No certification plan provided.

#### **Specifications and Warranties**

- Green – Specifications and warranties were provided, and they demonstrate that the WTGs are suitable for use in New Jersey's offshore climate.
- Yellow – Specifications and warranties were provided, but there is some question about the suitability of the WTGs for use in New Jersey's offshore climate or specification and warranties were not provided, but the manufacturer of the proposed WTGs has previously supplied WTGs used successfully in a similar climate.
- Red – Specification and warranties indicate that the proposed WTG is unsuitable for use in New Jersey's offshore climate and/or manufacturer has not previously supplied WTGs used successfully in a similar climate.

#### **Operating History**

- Green – The proposed WTG is commercially available and has been successfully put into service in one or more areas substantially similar to New Jersey's offshore climate.
- Yellow – The proposed WTG is not commercially available and has not previously been put into service in any areas substantially similar to New Jersey's offshore climate, but the proposed WTG manufacturer has previously supplied similar WTGs that are commercially available and have been put into such service.
- Red – The proposed WTG manufacturer has not previously supplied similar WTGs.

#### 7.1.1.2 Foundations

Applicants are evaluated on the suitability of the foundations identified in the application.

- Green – The proposed foundation has an established history of use in locations substantially similar to the offshore waters of New Jersey.
- Yellow – The applicant has provided specifications, warranties and/or characteristics for the proposed foundation that indicate its ability to work successfully in New Jersey’s offshore climate.
- Red – The applicant has not met the requirements above for a Green or Yellow rating.

#### 7.1.1.3 Inter-array and Export Cables

Applicants are evaluated on the suitability of the Inter-array and export cables identified in the application.

- Green – The proposed undersea cables have an established history of use in locations substantially similar to the offshore waters of New Jersey.
- Yellow – The applicant has provided specifications, warranties and/or characteristics for the proposed undersea cables that indicate their ability to work successfully in New Jersey’s offshore climate.
- Red – The applicant has not met the requirements above for a Green or Yellow rating.

#### 7.1.1.4 Offshore Substations

Applicants are evaluated on the suitability of proposed substations.

- Green – The proposed equipment has an established history of use in locations substantially similar to the offshore waters of New Jersey.
- Yellow – The applicant has provided specifications, warranties and/or characteristics for the proposed equipment that indicate its ability to work successfully in New Jersey’s offshore climate.
- Red – The applicant has not met the requirements above for a Green or Yellow rating.

#### 7.1.1.5 O&M Facilities and Vessels

Applicants are evaluated on the reasonableness and completeness of the information provided in the application.

- Green – The applicant provided more than the basic information requested concerning the O&M facilities and vessels to be utilized during the operating period, and all the information was reasonable.
- Yellow – The applicant provided no more than the basic information requested concerning the O&M facilities and vessels to be utilized during the operating period, and all the information was reasonable.
- Red – The applicant did not provide the basic information requested concerning the O&M facilities and vessels to be utilized during the operating period and/or some of the information was not reasonable.

#### 7.1.2 Transmission points of interconnection and system upgrades

All applicants were required to submit a proposed project schedule and milestones. The schedule includes the expected time for transmission interconnection studies and approvals. The schedule for

transmission interconnection studies is influenced by the transmission POI and the required transmission system upgrades.

Based on LAI's experience with the PJM interconnection process, the likelihood of a project's successful commercial operation depends to a large extent on the PJM interconnection process, in particular, the required transmission system upgrades. Because the applicants, for the most part, have opted for transmission cost reconciliation, the cost of higher than anticipated transmission system upgrade costs is a risk borne by ratepayers, not the applicant. Therefore project default risk attributable to the potential exposure to higher than anticipated system upgrade costs is of limited relevance for purposes of the Board's first round procurement. Nonetheless, the amount and level of uncertainty surrounding transmission system upgrade costs depends on the POI.

PJM has specific milestones for the interconnection studies process. These include:

- The submission of an interconnection request and the execution of a Feasibility Study Agreement
- Holding a scoping meeting with the developer
  - Within 45 days of receipt of Interconnection Request
- Conducting the Feasibility Study
  - 120 days (30 day modelling period + 90 days study period)
- Execution of a System Impact Study Agreement
  - Within 30 days of receipt of Feasibility Study
- Conducting the System Impact Study
  - 180 days (60 days modelling period plus 120 days study period)
- Execution of a Facilities Study Agreement
  - Within 30 days of receipt of System Impact Study
- Conducting the Facilities Study
  - 180 days
- Execution of an Interconnection Service Agreement (ISA)
  - Within 60 days of receipt of Facilities Study

Within 45 days of receipt of an executed ISA, PJM provides the interconnection customer with a Construction Service Agreement (CSA). This is the contract the customer must execute within 90 days. Per Attachment A of PJM Manual 14 A (New Services Request Process)<sup>23</sup> the PJM interconnection process can take between 26 and 30 months. An applicant's project schedule shows the applicant's ability to meet these PJM milestones. Execution of the CSA bodes well for a project's likelihood of success.

LAI notes that a significant amount of required transmission system upgrades will require a longer construction time which can delay the project's schedule. An applicant's timeline for the construction of the required transmission upgrades can impact a project's likelihood of timely commercial operation. Higher than anticipated transmission system upgrades may hinder timely commercial operation, but is not likely to create an insurmountable commercial barrier, particularly since applicants have opted for true-up.

LAI's review of the Interconnection Plan is centered on one evaluation criterion per N.J.A.C. 14:8-6.5.(a).14 et seq.: a review of the project's PJM interconnection request, study schedule and the schedule for construction of the required transmission system upgrades. LAI's review of the status of

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<sup>23</sup> See <https://www.pjm.com/-/media/documents/manuals/m14a.ashx>

the interconnection request and the POI has included a review of whether the applicant had submitted a valid interconnection request. LAI reviewed any PJM interconnection milestones the project has met.

Applicants are assigned qualitative ratings at the project level as follows:

- Green – The proposed project schedules were detailed, complete, and included feasible timelines and an understanding of the PJM interconnection process, thereby providing a high degree of assurance that the project will meet the proposed in-service date.
- Yellow – The proposed project schedules included sufficient detail to demonstrate the feasibility of achieving the proposed in-service date.
- Red – The proposed project schedules lacked detail, or indicated significant risk of delay.

### 7.1.3 Port and other infrastructure development needs

LAI identified three areas of activities and plans related to port and related infrastructure development of relevance in gauging each applicant's prospects for timely commercial success as well as New Jersey's potential realization of economic benefits through port restoration, development and staging for construction. First, port and infrastructure development during the construction phase were examined. Second, LAI examined the availability of O&M facilities and related logistics during the operational phase. And, third, land acquisition needs were reviewed. Underlying each rating are considerations about the depth of the plan, including the level of effort expended by the applicant to address port and infrastructure development. LAI considered what steps have already been taken or accomplished toward achievement.

Applicants are assigned qualitative ratings for port and related infrastructure development at the project level as follows:

- Green – Applicant demonstrated that it has thoroughly contemplated the plans, has accomplished certain initial milestones, for example, signed an memorandum of understanding (MOU), and conveyed potential economic benefits to New Jersey.
- Yellow – Applicant submitted a plan that has not been thoroughly documented, includes some facilities in New Jersey, but otherwise is deemed sensible in terms of supporting successful project development in accord with the proposed milestone schedule.
- Red – Applicant did not provide enough information to conclude that the plan is either Green or Yellow.

## 7.2 **Experience**

### 7.2.1 OSW projects

Corporate offshore wind experience is based on the number and size of offshore wind projects for a company, as well as the roles for which the company has been responsible. While the number and size of the project developer's projects are relatively easy to confirm, the roles for which the company has been responsible is not easy to confirm. Relevant offshore experience with oil and natural gas exploration and production (E&P) is a secondary positive factor in light of the strong similarities in environmental permitting, design, engineering, construction techniques, and operating environment.

Applicants are assigned qualitative ratings for offshore wind experience as follows:

- Green – Applicant has significant offshore wind experience.
- Yellow – Applicant has limited offshore wind experience but significant offshore oil & gas experience.
- Red – Applicant has limited offshore experience of any kind.

### 7.2.2 Key personnel

Per the rules at N.J.A.C. 14:8-6.5.(a).1, applicants were required to submit information on key personnel, specifically regarding OSW project development experience. Personnel offshore wind experience is based on an individual's experience in the offshore wind industry, supplemented by onshore wind and offshore oil and gas experience. In relation to offshore wind development, offshore oil and gas E&P experience is relevant, but has been assigned less weight. Having a complete and logical organizational chart is also a secondary positive factor.

Applicants are assigned qualitative ratings for key personnel offshore wind experience as follows:

- Green – Project team has significant offshore wind experience.
- Yellow – Project team has limited offshore wind experience but significant offshore oil & gas experience.
- Red – Project team has limited to no offshore experience of any kind.

### 7.3 **Supplier arrangements**

For these criteria, applications are evaluated to determine whether they included a reasonable plan to procure the primary equipment and components in a timeframe necessary to meet the targeted schedule. Each applicant was required to provide the following documentation as part of its application:

- A letter of intent or MOU from the WTG manufacturer/supplier to supply the selected WTGs;<sup>24</sup>
- A declaration from the foundation manufacturer/supplier that states their ability to manufacture and deliver all foundation components within the targeted schedule; and
- A declaration from the undersea cable manufacturer/supplier that states their ability to manufacture and deliver all undersea cable components within the targeted schedule.

For each of the three project components, a qualitative rating is assigned on the following basis:

- Green – Letter of intent, MOU or declaration from the manufacturer/supplier states their ability to manufacture and deliver all components within the targeted schedule.
- Yellow – Letter of intent or similar statement from a manufacturer/supplier with an established history of providing the components to similar projects was submitted but does not include specific reference to the scope of supply or targeted schedule;
- Red – The applicant did not meet the requirements above for a Green or Yellow rating.

### 7.4 **Site control**

Land Acquisition Plans are evaluated to assess the applicant's ability to comply with project's ability to secure all property and rights of way to construct the land-based interconnection facilities.

Applicants are assigned qualitative ratings for site control as follows:

- Green – Applicant (a) fully identified all properties and rights of way needed for the on-shore substations and land-based portions of cable rights of way, (b) obtained site control through ownership rights, lease, or irrevocable option to purchase or lease for substation locations and for rights of way through non-public roadways or thoroughfares, and (c) fully delineated the route for rights of way through public roadways or thoroughfares.

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<sup>24</sup> N.J.A.C. 14:8-6.5.(a).2.(iii)

- Yellow – Applicant identified the general locations of properties and rights of way needed for the on-shore substations and land-based portions of rights of way, but did not identify specific properties or final rights of way.
- Red – Applicant did not identify properties needed for on-shore substations and/or land-based portions of rights of way, or if there are known obstacles to securing those sites.

## 7.5 Permitting

Permitting Plans are evaluated to assess the applicant's ability to comply with all regulatory requirements and associated permitting within the proposed development milestones. Plans were reviewed to evaluate the completeness, proposed strategy, and anticipated timeline of all relevant federal, state, and local agency approvals, permits, or authorizations. Copies of any submitted applications or issued approvals were reviewed. Proposed turbine arrays, export cable routes and landfall locations, on-land rights of way and substation locations were reviewed to analyze whether the applicant would be likely to encounter significant obstacles in obtaining certain permits, potentially jeopardizing development milestones, and/or causing additional mitigation/compliance costs. LAI coordinated this effort with NJDEP.

Applicants are assigned qualitative ratings by LAI for each of the anticipated permits and authorizations as follows:

- Green – Applicant provided a complete and detailed strategy and timeline for each specific permit required, and identified the specific activity requiring the permit or authorization.
- Yellow – Applicant provided a plan missing either a timeline or strategy, or provided an overly optimistic milestone schedule, or did not identify the specific activity requiring the permit or authorization.
- Red – Applicant provided a plan that lacked in both strategy and timeline, or the item was not addressed at all, or if there is a significant probability that the Applicant will encounter obstacles in obtaining certain permits.

LAI coordinated the Permitting Plan review effort with the NJDEP. NJDEP verified all state agency regulatory approvals or permits listed in the application, noted those omitted, and identified potential permitting challenges.

Based on the ratings for the individual permits and authorizations, and input from NJDEP, LAI assigns an overall rating for each project alternative as follows:

- Green – Applicant demonstrated a strong understanding of all required permits and authorizations, permit milestones appear feasible and consistent with the overall development schedule, and there do not appear to be any significant permitting challenges or proposed project elements that are inconsistent with regulatory requirements.
- Yellow – Applicant demonstrated a good understanding of most required permits, authorizations, and timelines but has omitted one or more key permits or has underestimated the timeframe for one or more permits.
- Red – Applicant appears to have an incomplete understanding of all required permits and authorizations, or permit timeline appears inconsistent with the overall project development schedule, or proposed project has one or more elements that may encounter significant permitting challenges.

## 7.6 Financing

### 7.6.1 Ownership

Ownership defines the projects' ultimate owners, accounting for 100% ownership interest in the project entity. Color-coding is based on the owner's commitment to pursue project development and construction under the Board's commercial structure whereby the project receives payment only for generation delivered to the POI. This take-if-tendered structure leaves all production and transmission delivery risk with seller, thereby requiring the project's owners to commit capital and expertise to address development, construction, and operational risk.

Applicants are assigned qualitative ratings for ownership as follows:

- Green – Project sponsors have made significant corporate commitments to their particular project.
- Yellow – Project sponsors have made restricted corporate commitments.
- Red – Project sponsors have made weak commitments.

### 7.6.2 Financial strength

Financial strength reflects the financial capability of the project owners to raise all required funds for the project without subjecting the owner(s) to financial stress. Thus it is a function of the parent company size (revenues and assets), profitability (net income), funding capability (cash, cash equivalents, and market valuation), and ability to raise debt (debt-to-capitalization and credit rating). The financial strength of the applicant is assessed in the broader context of the parent company's debt to equity ratio, long term credit rating, and market valuation, among other leading financial metrics of relevance.

Applicants are assigned qualitative ratings for financial strength as follows:

- Green – Project sponsors are profitable and have large and strong balance sheets.
- Yellow – Project sponsors have financial challenges and limited balance sheet strength.
- Red – Project sponsors have serious financial weaknesses.

### 7.6.3 Financing plan

Applicant's financing plans required by rules at N.J.A.C. 14:8-6.5.(a).4.(iv) are judged based on the reasonableness and completeness of each plan proposed by the project owners. Offshore wind projects can and have been financed on-balance sheet, *i.e.*, with project debt and equity funding provided by the parent, or by utilizing third-party construction debt, tax equity, and permanent operating period debt (also referred to as back-leverage). In either case, LAI confirmed that the applicant fully considered the potential availability of a 12% ITC for projects that meet Internal Revenue Service qualification requirements to offset federal income taxes or to facilitate a tax equity investment.

Applicants are assigned qualitative ratings for their financing plan as follows:

- Green – Realistic financing plan clearly specifies the source of equity / debt funds and addresses the potential of qualifying for a 12% ITC.
- Yellow – Financing plan fails to fully specify funding sources or address qualifying for ITC.
- Red – Financing plan is incomplete.

## 8 COST-BENEFIT ANALYSIS

N.J.A.C. 14:8-6.5.(a).11 required the applicant to provide a cost-benefit analysis (CBA) that contains three components: net OREC costs, State economic benefits, and environmental benefits. In order to quantify and aggregate the three disparate components into a net benefits measure, the economic benefits and environmental benefits must be monetized.

The project costs include OREC purchases over the 20-year contract term, and are netted against revenues received by the project from the sale of energy, capacity, and any ancillary services, and the avoided cost of New Jersey Class I RECs over the same contract period. While the BPU provided a set of standard forecasts of energy, capacity, and REC prices to applicants for the purpose of initial evaluation, LAI used its own forecasts for these three electricity commodities in its evaluation.

While N.J.A.C. 14:8-6.5.(a).11 indicated that several economic effects criteria are to be modeled and reported by the applicant, including income, wages, output, indirect business taxes, and jobs, for the purpose of practical aggregation and monetization, the income or gross domestic product measure was selected because it represents the net value-added in-State. In contrast, the output measure represents sales, so it is a much less useful summary metric for State economic effects since it includes the value of purchases of goods and services from outside the State, in addition to the value-added in-State. Wages and indirect business taxes are paid out of value-added, so inclusion of either of those two metrics with gross domestic product would double-count those effects in the overall economic benefits measure.

Reputable project evaluations of economic benefits often discount the indirect and induced effects reported by a regional input-output model due to its static equilibrium behavioral assumptions and data limitations. For example, the analyst may include only, say, 50% of the indirect effects and perhaps even less for the induced effects in recognition of model structure and data limitations to accurately predict these secondary effects of direct local expenditures.

Even more sophisticated model results evaluation will further discount all (direct, indirect, and induced) effects by recognizing that some or most of the supply chain firms and workers that would be affected by project spending would have other avenues for utilization of their services, so not all of the gross effects reported by the input-output model represent net benefits. A local economy experiencing high unemployment and under-employment will experience more economic development for the same local project spending injection than at a different time or different place with fewer slack or idle physical and human resources. For example, a \$1 billion injection at the beginning of the Great Recession in 2009 would result in more economic value when many construction and manufacturing firms and workers were suffering than in 2019, due to a greater opportunity cost when reallocating those resources to higher value-added production activities.

In accordance with N.J.A.C. 14:8-6.5.(a).11.(xiv), applicants provided analyses of the anticipated environmental benefits and impacts associated with the proposed projects. Applicants were required to submit information regarding project-related emissions of CO<sub>2</sub>, NO<sub>x</sub>, SO<sub>2</sub>, and direct PM<sub>2.5</sub> and to monetize the net emissions benefits, that is, the emissions displaced from fossil-fired generation by OSW, less the incremental emissions associated with construction, operation, and decommissioning of the project. As noted in Section 5.1, applicants each used different methods and assumptions to forecast the avoided emissions from fossil generation. Therefore LAI conducted an independent analysis using a single set of assumptions of the emissions-related environmental benefits associated with each proposed project to use in our cost benefit analysis. LAI did not independently model each project's anticipated incremental emissions from vessels, vehicles, and other equipment, but relied on each applicant's estimates. These values are a small offset to the total emissions benefit.

Monetary values associated with the emission of CO<sub>2</sub>, and other pollutants were included in the analysis. For CO<sub>2</sub>, LAI, as well as each of the applicants, relied on the social cost of carbon (SCC) from the US Government’s Interagency Working Group, which monetizes damages associated with an incremental increase in carbon emissions in a given year.<sup>25</sup> Health effects associated with direct PM<sub>2.5</sub> emissions and for NO<sub>x</sub> and SO<sub>2</sub> as precursors to PM<sub>2.5</sub> were estimated from EPA’s Technical Support Document (TSD) *Estimating the Benefit per Ton of Reducing PM<sub>2.5</sub> Precursors from 17 Sectors* for NO<sub>x</sub>, SO<sub>2</sub>, and direct PM<sub>2.5</sub>.<sup>26</sup> From the SCC study, the average case estimated using a 3 percent discount rate was selected and converted to dollars per short ton. The TSD presented dollar values in terms of mortality and morbidity per short ton of avoided NO<sub>x</sub>, SO<sub>2</sub>, and direct PM<sub>2.5</sub> for the years 2016, 2020, 2025, and 2030; LAI adopted the values cited in the TSD and escalated them beyond 2030 for this analysis. The annual nominal social costs for CO<sub>2</sub>, NO<sub>x</sub>, and SO<sub>2</sub> were netted against the generation-weighted average market emissions allowance costs used in the Aurora simulations to calculate the net externality annual values per ton to apply against the change in emissions.

**Table 2. 2020-2050 Average Social Cost of Emissions**  
(nominal \$/ton)

CO <sub>2</sub>	NO <sub>x</sub>	SO <sub>2</sub>	Direct PM <sub>2.5</sub>
\$87	\$11,598	\$80,228	\$303,677

Net benefits in the cost-benefit analysis were then calculated as the NPV, with a 7% nominal discount rate, of net OREC costs over the 20-year contract period using LAI’s market price forecasts, plus economic benefits and emissions benefits over a 30-year OSW project operation period. This approach standardizes the cost-benefit analysis across all three applicants, which used their own assumptions for inclusion of economic benefits, their own models of changes in air emissions and of the externality costs of the four emission types, and their own time horizon for summing the discounted economic and environmental benefits.

<sup>25</sup> “Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 Interagency Working Group on Social Cost of Greenhouse Gases, United States Government” August 2016. <https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon-technical-documentation>

<sup>26</sup> U.S. EPA, “Technical Support Document Estimating the Benefit per Ton of Reducing PM<sub>2.5</sub> Precursors from 17 Sectors” February 2018. [https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd\\_2018.pdf](https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf)

## **9 SUMMARY SWOT ANALYSIS ACROSS THE SIX CRITERIA**

N.J.A.C. 14:8-6.5 and the six criteria from Section 4 of the Guidelines form the basis of LAI's evaluation of the three applicants' project options for OREC contract award. The Board's decision to award one or more OREC contracts can be taken only after all critical elements of each individual project submission have been evaluated. These elements include the financial strength and credibility of the applicant, experience, technology, price, environmental attributes and permissibility, transmission viability, economic benefits, and ratepayer impacts. The eligible projects have also demonstrated positive net benefits in the cost-benefit analysis.

To facilitate the Board's basis for decision, LAI has summarized the competitive elements of each applicant's submission in the project specific evaluation, focusing on project-specific strengths, weaknesses, opportunities and threats (SWOT). The SWOT framework is a simple 2 by 2 matrix where each category is represented in one of four boxes.

- Strengths represent the positive features pertaining to the applicant's experience and likelihood of commercial success. Strengths represent features over which the applicant exhibits a high degree of control.
- Weaknesses represent negative economic and environmental attributes that hinder the applicant's prospects of commercial success in the context of the Board's first-round procurement target. Weaknesses represent features over which the applicant exhibits a moderate or low degree of control.
- Opportunities represent positive features regarding technology, environmental mitigation and economic growth that are representative of offshore wind industry growth in New Jersey. Opportunities represent potential upside benefits to New Jersey that are controllable in part or in full by the applicant.
- Threats represent hazards that can block or delay the Board's realization of the procurement goal. Therefore strategic considerations associated with the selection of one or more projects that have the potential to weaken the Board's prospects for success are categorized as threats. Threats are of largely outside the control of the applicant.

## **10 APPROACH TO ADDITIONAL EVALUATION OF PORTFOLIOS**

LAI evaluated individual bids of 300 MW to 1,100 MW as well as multiple bids in combination to meet a minimum of approximately 1,100 MW of installed capacity. Larger projects tend to be the most price competitive and confer the strongest supply chain benefits. Selection of two small to midsize projects to meet the 1,100 MW cap would result in a substantial price premium and may also result in lower supply chain benefits. To the extent the procurement target can be substantially increased, then a diverse portfolio of two projects would likely confer significant benefits to New Jersey, foster robust competition in subsequent procurements, while strengthening New Jersey's ability to become a regional powerhouse for offshore wind development along the Atlantic seaboard from Virginia to New England. LAI thus evaluated a range of portfolios around 1,100 MW to approximately 1,600 MW in order to address the range of achievable benefits. If the 1,100 MW target is deemed inviolate, the Board will need to weigh the additional cost borne by New Jersey ratepayers for the sake of portfolio diversity.

LNOG restates the PVNOG on a levelized nominal \$/MWh or \$/OREG basis. LNOG is the primary measure for assessing the economic merit of projects of different sizes, and is most useful in ranking projects or portfolios that vary in the total amount of OREGs for selection. If the projects under evaluation for this 1,100 MW procurement target were significantly smaller, the idealized portfolio would consist of the projects stacked in order of increasing LNOG until the capacity limit was (roughly) achieved. However, in this procurement economy of scale dictates that projects must be large in order to minimize unit cost. A portfolio is by definition at least one project. Based strictly on price, a sensible portfolio is likely to consist of one or two projects, not three. There is a limited set of possible portfolios which have a total capacity that approximates the 1,100 MW target procurement objective.

Consideration of portfolios consisting of more than one project involves evaluation considerations beyond the simple quantification of the aggregated qualitative and quantitative benefits and costs based on the six criteria. Hence, LAI's evaluation also reflects three additional considerations for comparative evaluation. The three other considerations are briefly discussed below in the following sections.

### **10.1 Diversification of developer, design, interconnection, and infrastructure risks**

Risk exposure can be project specific. Despite best efforts to screen out projects that have one or more components of substantial risk affecting project viability, it is possible that one or more developers will encounter other risks that have not been identified in this Final Evaluation Report. In addition, a low probability risk event may occur, thereby hindering timely commercial development. The Board may therefore want to hedge its bets by awarding two projects in a portfolio that meets the approximate 1,100 MW procurement target. To the extent the Board is willing to award two or more projects that amount to a material increase above 1,100 MW, risk reduction and economic price objectives are well served through project diversity.

A portfolio approach would be more likely to promote lower cost outcomes in subsequent procurement rounds. This results from enhancing competition and progression along the "learning-by-doing" curve, especially for developers with different supply chain and logistics strategies.

### **10.2 Conflicting and complementary aspects of infrastructure development**

To the extent that two or more selected applicants rely on the same ports, vessels, or fabrication facilities, there may be competition for scarce existing physical and human resources, thus hindering timely development of the conflicting project plans and schedules. Resolution of such conflicts may entail sequencing development of one project sufficiently later than the other so as to eliminate scarce infrastructure or third-party supplier capacity constraints. Conflicting and complementary aspects of

offshore wind development in New Jersey may be exacerbated by simultaneous development at adjacent BOEM lease sites to serve New York, and, to a lesser extent, New England or Virginia.

There may also be complementary aspects of two or more offers if one project plan would spur development of infrastructure, such as a port facility or a fabrication facility, which could also be used by other projects.

### **10.3 Implications for future procurements to fulfill 3,500 MW plan**

Multiple projects developed in two or more BOEM lease areas in the first phase of development may increase the likelihood of achieving Governor Murphy's 3,500 MW goal by enabling each selected applicant's BOEM area, port facilities, vessels, offshore cable routes, and supply chain arrangements to be reused in subsequent phases. By physically tying initial development from multiple BOEM locations to New Jersey, it would tend to increase the chances that the remaining undeveloped BOEM lease areas would remain available for development by New Jersey.

To the extent that this first procurement phase is coupled with optional infrastructure developments, there would be potential dividends to New Jersey for years to come. Such dividends materialize in two ways: first, by helping to reduce the cost of construction of future projects designed to fulfill Governor Murphy's procurement goal; and, second, by positioning New Jersey as a major regional hub from Virginia to New England.

## **APPENDIX A: LAI COMMODITY PRICE FORECASTING MODELS AND KEY ASSUMPTIONS AND DATA**

### **Input Assumptions**

LAI utilizes Aurora, a chronological dispatch simulation model licensed from Energy Exemplar, to forecast power market outcomes, including energy prices, capacity prices, power plant emissions, and natural gas demand for electric generation. LAI uses the default database provided by Energy Exemplar as a foundation. This triannually updated database is augmented with extensive customization based on public data sources, proprietary calculations, and LAI's professional judgment based on experience in PJM and neighboring RTOs.

According to the Guidelines, selected OSW projects will be funded through the OREC mechanism for 20 years. We assumed that project(s) selected in this first procurement round would have an in-service date no later than the start of 2026. To cover the 20-year contract term LAI ran Aurora from 2020 through 2045.

LAI prepared two Aurora simulation projections in support of BPU's economic and environmental goals:

- The base scenario included the full 3,500 MW of New Jersey's OSW goal, constructed in three tranches (1,100 MW, 1,200 MW, and 1,200 MW). This forecast was used to estimate net OREC cost and ratepayer impacts under expected (baseline) market conditions by providing prices for energy and capacity products to compare against bid prices. REC prices were forecasted using the output of the AURORA model together with LAI's proprietary model of the all-in cost of land-based wind energy located in the RTO portion of PJM.
- In order to estimate the avoided emissions in New Jersey, a "but-for" case was configured as an excursion of the base scenario. The excursion assumption was that no OSW is built in New Jersey. The purpose of this case was solely to estimate the CO<sub>2</sub>, NO<sub>x</sub>, and SO<sub>2</sub> emissions avoided within New Jersey by the procurement of OSW. No replacement energy was procured to meet New Jersey RPS in the No OSW case. We compared the New Jersey plant emissions (CO<sub>2</sub>, SO<sub>2</sub>, NO<sub>x</sub>) from the 3,500 MW OSW case to the no OSW case to determine the tons of avoided emissions in New Jersey for each year of the study period.

### **Study Region**

Aurora was utilized in a zonal configuration with the study region modeled to include PJM, NYISO, and ISO-NE. Therefore, nodal price differentials in ACE and JCP&L were estimated for purposes of net OREC cost and ratepayer impacts. Nodal price differentials required a separate analysis of zonal-to-nodal spreads. Boundary flows to other regions (including MISO, TVA, IESO, and Quebec) were modeled based on an average weekly profile for each month using three years of historical flow data (168 hours by 12 months, 2016-2018). Imports into New York from Ontario were throttled down to reflect the impending refurbishment schedule of IESO's nuclear units.

The three ISOs were further divided into zones to capture the key transmission constraints within each. LAI modeled all of the load zones within MAAC and elected to aggregate the western portion of the PJM footprint into a "Rest of RTO" zone. NYISO was divided into seven load zones (A through K, with some aggregation upstate). ISO-NE was divided into the 13 sub-areas identified in the Regional System Plan (RSP).

### **Transfer Limits**

Inter-zonal transmission transfer limits were defined using several publicly available data sources:

- PJM BRA Planning Parameters
- NYSRC Installed Capacity Requirement (ICR) Report
- NYISO ESPWG / TPAS meeting materials
- ISO-NE RSP
- ISO-NE Forward Capacity Market (FCM) Tie Benefits Study
- ISO-NE Cost of New Entry (CONE) and ORTP Analysis

In cases where data were not available or data sources conflict, the analysis relied on the default settings provided by Energy Exemplar, as well as professional judgment, to determine appropriate limits. Energy Exemplar performs a nodal power flow simulation that informs the zonal transmission limits in the default database.

### Demand Forecast

LAI relies on RTO planning documents such as PJM’s Load Forecast Report, NYISO’s Gold Book, and ISO-NE’s CELT Report as the basis for peak and annual energy forecasts. RTO forecasts that include EE/PDR are utilized. Behind the meter (BTM) solar, which is also forecasted in planning documents, is defined as a supply-side resource in order to reflect the changes to hourly shape of net load that solar creates, as solar generation does not track demand.

RTO sources generally do not forecast beyond 10 or 20 years. Therefore, LAI made assumptions to extrapolate the load forecasts. LAI assumed that gross load will follow an exponential growth curve based on the last year’s forecast annual growth rate. The forecast assumed that BTM solar and energy efficiency resource capacity will follow a constant growth rate per the last RTO source forecast year’s expansion rate.

**Figure A1. Forecasted Net Energy for Load**

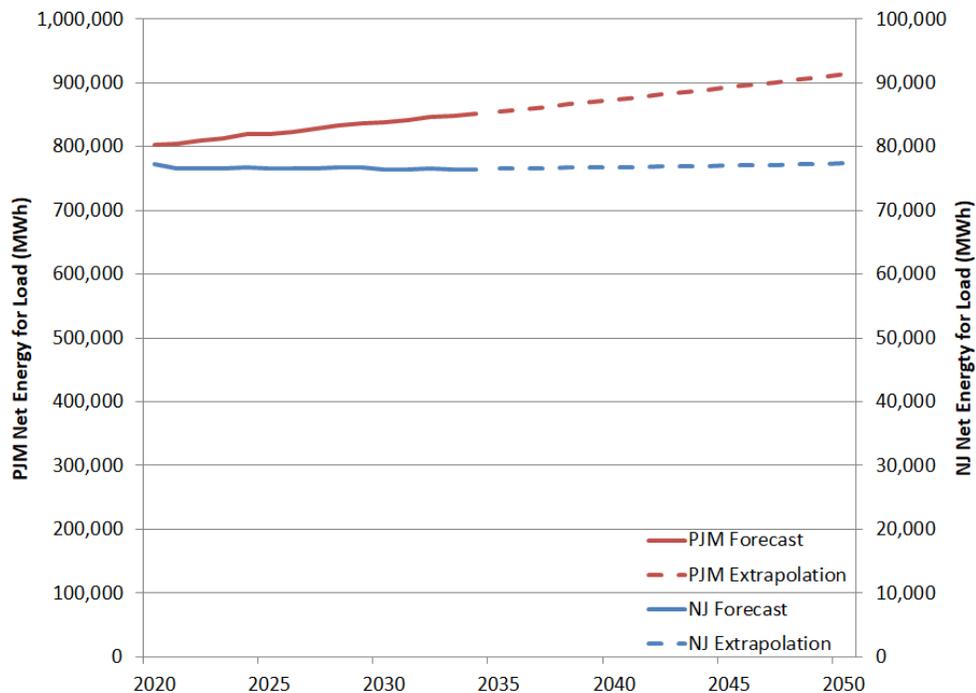
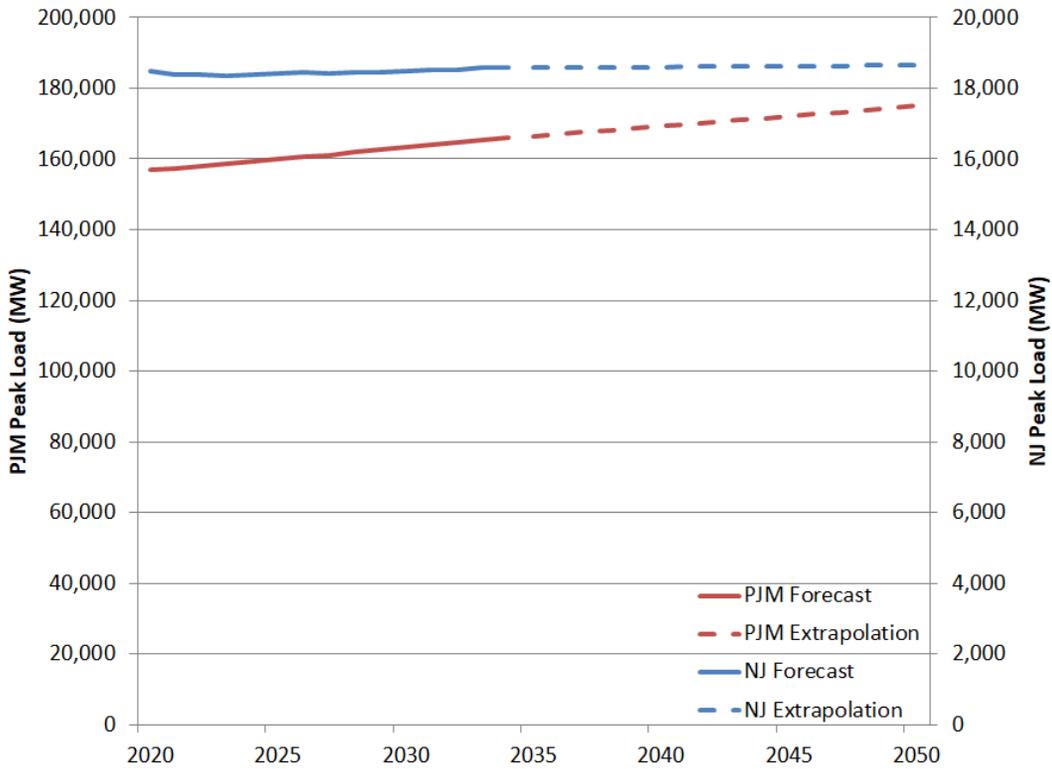


Figure A2. Forecasted Peak Load



### Fuel Price Forecast

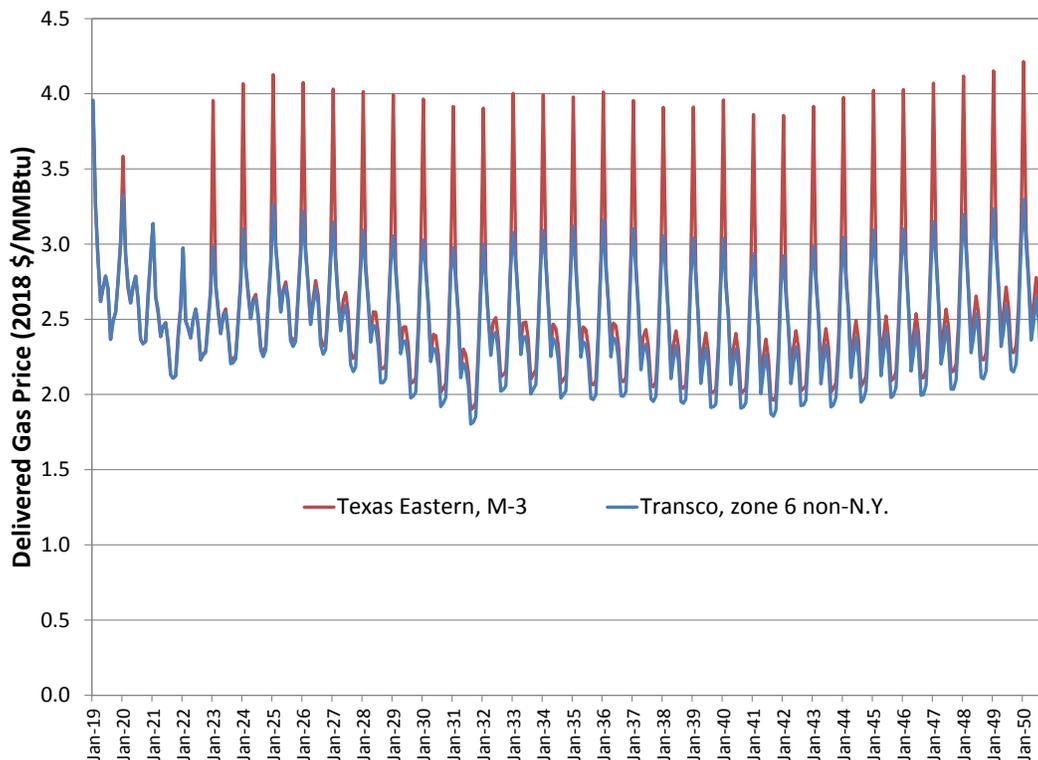
Fuel prices, as delivered to generators, were forecasted for natural gas, oil products, and coal. Nuclear generators are price takers and do not have much dispatch flexibility. Therefore we ignore nuclear fuel prices and assume that nuclear plants run fully-loaded, except for periodic refueling outages.

### Natural Gas Price Forecast

The forecast of delivered natural gas prices starts with a Henry Hub commodity price projection from EIA’s 2019 AEO. Historically, the AEO Reference Case has typically overestimated the trajectory of natural gas prices. LAI therefore utilized a simple average of the AEO Reference Case and the AEO High Oil and Gas Resource and Technology Case. Based on the average monthly profile of historic Henry Hub prices observed over the last ten years, monthly shaping of natural gas prices into-the-pipe in Louisiana will be applied to the annual prices over the study period.

To reflect the value of gas delivered across the study region, basis adjustments for pricing points of relevance were made to the cost of natural gas into-the-pipe at the Henry Hub. To calculate basis, LAI uses GPCM, a leading gas price simulation model covering North America. Delivered gas prices to New Jersey, including Transco Z6 Non-New York and Texas Eastern M3, are shown in Figure A3. Other pricing points of relevance across the study region include Dominion South Point, Transco Zone 6 New York, Algonquin Citygates, Tennessee Zone 5 and Zone 6, and Iroquois Gas Transmission System Zones 1 and 2. These other pricing points have been incorporated in the simulation model but are not illustrated below.

**Figure A3. Monthly Delivered Gas Prices in New Jersey**



Other Fuel Price Forecasts

Delivered oil products prices were forecasted based on the 2019 AEO, consistent with the Henry Hub forecast.

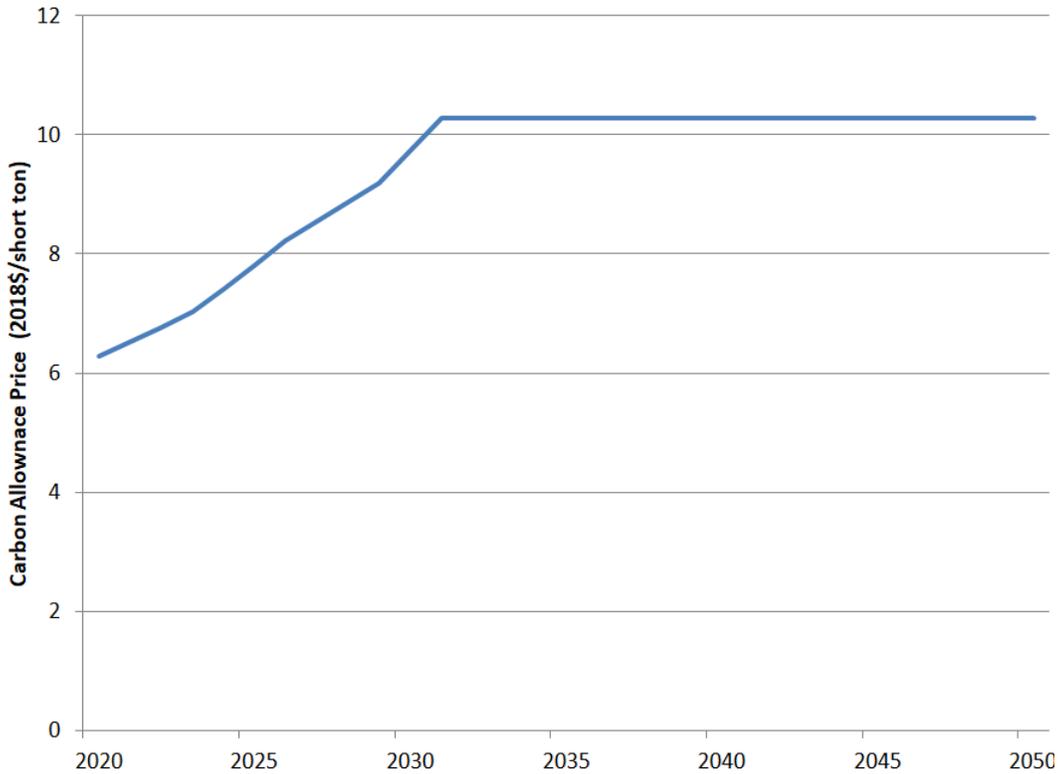
Coal prices were forecasted using the 2019 AEO prices for delivered coal to electric generators as a commodity price. These prices were then adjusted on a unit and state level to reflect local price adders based on basin sourcing and transportation costs. These adders are developed by Energy Exemplar and are primarily based on a review of EIA-923 fuel receipts data.

**Carbon Allowance Price**

For CO<sub>2</sub> allowance prices, the Base carbon allowance price case relied on final RGGI Model Rule Policy Scenario forecast prices that were prepared on behalf of the 2017 RGGI Program Review conducted by the RGGI Stakeholder Group. LAI assumed that New Jersey will rejoin RGGI at the start of 2020, consistent with Governor Murphy’s Executive Order 7.<sup>27</sup> The forecast assumed that Virginia will join RGGI by 2020. LAI assumes that following the end of the current program period, the RGGI real price stays constant. LAI assumes carbon emissions prices of 0 \$/ton for resources located outside of the RGGI states

<sup>27</sup> The RGGI Model Rule forecast did not include New Jersey or Virginia. LAI assumes that the inclusion of New Jersey and Virginia will increase the cap accordingly, and therefore will have no direct impact on the allowance prices. However, there will be an effect on modeled energy prices from more fossil fuel resources facing higher effective fuel costs.

**Figure A4. RGGI Allowance Price Forecast**



### **Firm Resource Additions**

LAI assumed that any resource cleared in a capacity auction such as the PJM BRA or ISO-NE FCM will be built and will therefore be a scheduled addition in Aurora.

In NYISO there is no three-year forward capacity auction. After reviewing construction milestones, LAI determined that the CPV Valley and Cricket Valley combined cycle projects should be added as scheduled additions in Aurora. Both combined cycle projects are sited for Zone G (Hudson Valley). CPV Valley (680 MW) has reached commercial operation. Cricket Valley (1,100 MW) is expected to be in service by 2020, with site work and transmission upgrades well underway.

### **Scheduled Renewable and Clean Energy Resource Additions**

For renewable resources, we assumed that projects with signed Interconnection Service Agreements in PJM or ISO-NE or accepted interconnection cost allocations in NYISO will be built.<sup>28</sup>

The scenarios also include all renewable and clean energy projects, including OSW, that have approved contracts and/or which have been selected for long-term contract under a state-mandated procurement:

- US Wind and Skipjack OSW projects, with a combined 368 MW of capacity, will deliver into EMAAC (DPL). Anticipated in-service dates are in 2020 and 2023, respectively. These contracts have been approved by the Maryland PSC.

<sup>28</sup> Despite its having an executed ISA, the IRP excludes Cape Wind since its contracts with Eversource and NGrid have been terminated.

- The 130 MW Deepwater Wind’s South Fork OSW project will deliver into NY Zone K, with an anticipated in-service date of 2022. The Long Island Power Authority approved the Power Purchase Agreement (PPA).
- The Vineyard Wind 800 MW OSW project is assumed to have a phased in-service date of January 2022 for the first 400 MW and June 2022 for the remainder of total project nameplate. Vineyard Wind will deliver into SEMA (Barnstable, MA).
- Deepwater’s 700 MW Revolution Wind project was selected by NGrid Rhode Island (400 MW), the CT Clean Energy RFP (200 MW), and the CT Zero Carbon RFP (100 MW). Revolution Wind will deliver into the Rhode Island Zone and is expected to be placed in service in 2023.
- The 1,200 MW New England Clean Energy Connect project, selected by the Massachusetts EDCs under the 83D procurement and submitted to the MA DPU for PPA approval. LAI assumed a 2023 in-service date, with scheduled annual energy delivery profile similar to that of HQ imports on the Phase II HVDC tie.

In addition, the scenarios include generic OSW projects to fulfill policy goals in other states of the study region:

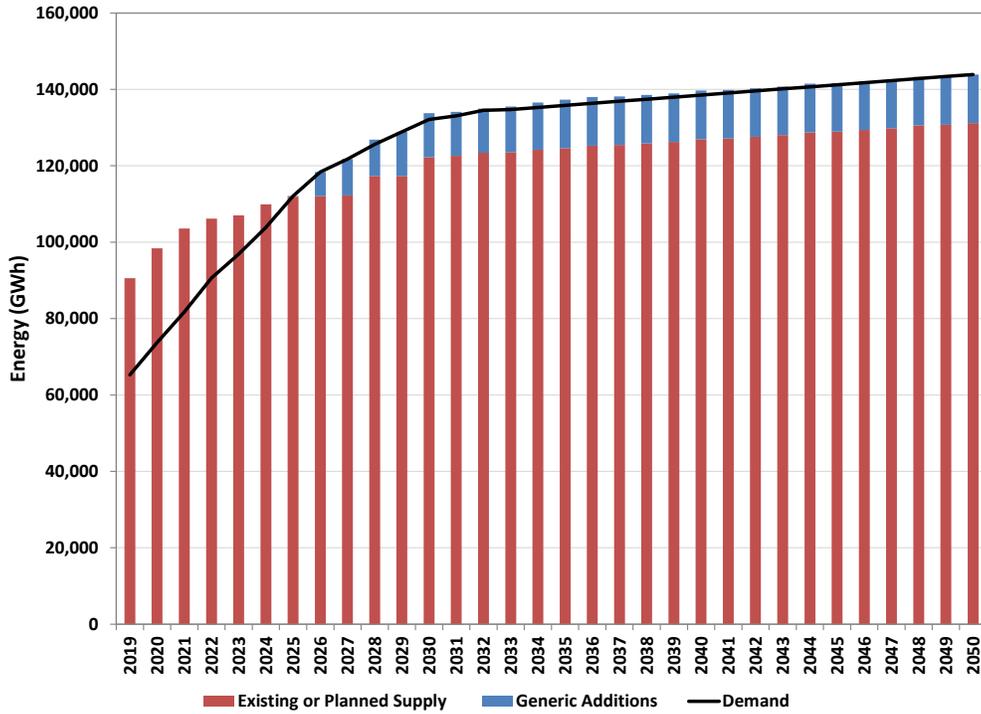
- New York State, through contracts with the New York State Research and Development Authority (NYSERDA), will develop 2,400 MW of OSW into New York City and/or Long Island by 2030 in response to NYSERDA’s anticipated procurement milestones.
- Massachusetts will develop an additional 800 MW of offshore wind to fulfill the rest of the Massachusetts 83C 1,600 MW goal by 2023 in order to receive the soon-to-expire federal investment tax credit. We also included an additional 1,600 MW of OSW capacity now contemplated but not yet announced by Massachusetts.

Generic renewable capacity was added to make up the Class I energy deficits in PJM and NYISO (ISO-NE did not require generic additions). The solar-to-wind ratio used for PJM was calculated based on projected solar and wind capacity found in the July 26, 2018 Integrating Renewables in PJM Presentation. Utility-scale solar and onshore wind additions in PJM were distributed to zones in proportion to zonal queued capacity. New Jersey’s solar goals are met by in-state solar resources only. We made the simplifying assumption that RECs are fungible in PJM. The projected energy from generators with the potential of producing Class I RECs<sup>29</sup> in any PJM state was included as Class I existing or planned supply. The addition of Class I generic solar and onshore wind resources in PJM starts in 2025 and ends in 2035. From 2035 to 2050, the growing REC production of existing or planned Class I resources modeled keeps up with the growing Class I REC demand. Hence, no generic Class I additions are needed in this period to meet Class I requirements in PJM. For the 0 MW OSW but-for cases, we assumed that generic Class I additions make up for the 3,500 MW of OSW displaced. The PJM Class I supply and demand after generic additions from 2019 to 2050 with and without NJ OSW are shown below in Figure A5 and Figure A6.

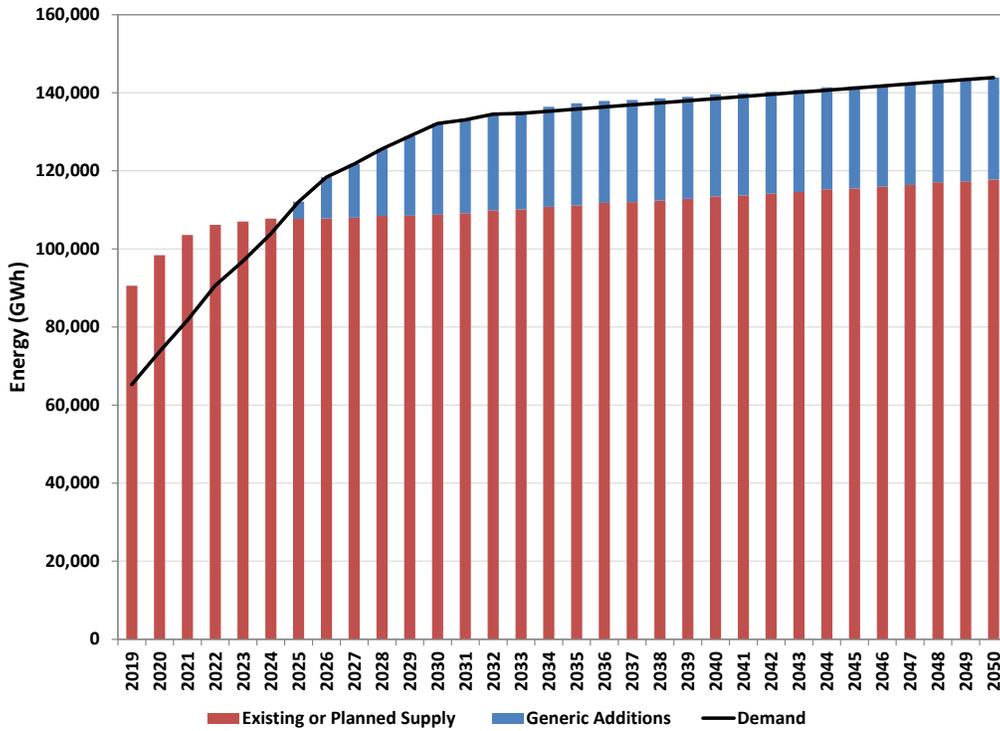
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<sup>29</sup> The GATS database lists all renewable generators and where they are registered as Class I.

**Figure A5. PJM Class I Supply and Demand 2019 – 2050, with NJ OSW**



**Figure A6. PJM Class I Supply and Demand 2019 – 2050, without NJ OSW**



The solar-to-onshore wind ratio used for New York was calculated using year 2030 values from Table C.1 Cumulative, in NYSERDA's *Clean Energy Standard White Paper Cost Study Report*. LAI's OSW buildout assumption is based on Governor Cuomo's Green New Deal January 2019 announcement that includes a

target for developing 9 GW of offshore wind capacity by 2035. LAI has made the simplifying assumption that Governor Cuomo’s 9 GW OSW target for downstate New York will be implemented. We did not adjust downstate transfer capability to accommodate large new injections through 2035, however. Utility-scale solar and onshore wind additions in NY were distributed to zones in proportion to zonal queued capacity. Offshore wind additions were distributed evenly in New York City (Zone J) and Long Island (Zone K). Only offshore wind capacity was added to make up the Class I deficit in ISO-NE.

### **Firm (Scheduled) Retirements**

The scenarios include retirements documented by the ISOs in planning documents and notices. PJM deactivations lists are reflected in the resource mix. NYISO retirement notices and ISO-NE permanent de-list bids through Forward Capacity Auction (FCA) 13 and non-price retirements are also integrated into the retirement assumptions.

LAI did not retire the PSEG nuclear fleet (Hope Creek, Salem) until their respective NRC licenses expired. LAI also assumed that Ohio will provide some subsidy to the FirstEnergy units that have requested deactivations (Perry, Davis-Besse), and therefore those units will operate until their licenses expire. Per New York State’s mandate, Indian Point units 2 and 3 retire in 2020 and 2021, respectively. Other nuclear units in the study region are retired according to their license expirations, which generally bring them to 60 in-service years. The remaining coal units in New York are assumed to retire by 2020 per Governor Cuomo’s mandate. LAI also assumes significant attrition of downstate New York peaking resources resulting from expected more restrictive NO<sub>x</sub> regulation, on the order of about 3,000 MW.

### **Capacity Expansion Modeling**

The capacity forecast utilizes Aurora’s Long Term Capacity Expansion functionality to determine an equilibrium path of annual resource additions and retirements beyond scheduled additions and retirements. Under this functionality, Aurora calculates the present value of all existing resources and determines which generators are candidates for retirement based on lowest present value over the forecast period. Expected capacity prices are a direct driver of new build decisions under the simulation logic. The model iterates to an equilibrium solution given potential candidate new resource options and retirements. In each iteration, an updated set of candidate new resource options and retirements is placed into the system and the model performs its chronological commitment and dispatch logic for those resources. The model tracks the economic performance of all new resource options and resources available for retirement based on market prices developed in the iteration. At the end of each iteration the long-term logic decides how to adjust the current set of new builds and retirements, or it determines that the model has converged on an optimal solution. This capacity expansion technique relies on each ISO’s capacity demand curve in order to balance supply and demand and determine capacity prices.

### **Capacity Demand Curve Forecast**

LAI implemented its projection of the PJM demand curve, the Variable Resource Requirement (VRR), in the Aurora model to forecast PJM capacity prices. PJM’s BRA planning parameters for the 2021/2022 Delivery Year served as the foundation of the VRR forecast.<sup>30</sup> Parameters were adjusted to reflect updates to Net CONE, expected energy efficiency levels, and to incorporate the 2019 PJM Load Forecast Report.<sup>31</sup> Adjustments to the points on the VRR curve will be made for the ISO and each LDA based on a

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<sup>30</sup> <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-bra-planning-period-parameters.ashx?la=en>

<sup>31</sup> <https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-forecast-report.ashx?la=en>

ratio of the forecasted peak demand net BTM solar to the reported BRA peak for the 2021/2022 Delivery Year. LDA-level prices were determined for EMAAC, MAAC, and RTO using data available on CETL and CETO in the area.

LAI monitored the two proposed capacity market changes before the Federal Energy Regulatory Commission (*i.e.*, Fixed Resource Requirement alternative and changes to apply MOPR to new and existing resources). However, modeling reflected capacity market rules. Given that PJM undergoes quadrennial adjustments to the CONE calculations, VRR curve shape, and other factors which influence clearing prices, long-term forecasts of capacity prices are very uncertain.

### **Addition/Attrition Forecasting**

#### Candidate Additions

LAI creates candidate resources which Aurora considers for new additions. Plant specifications from each RTOs' CONE study are used to define the candidate resources; combined cycle and combustion turbines are both included as candidates regardless of which technology has been selected as the basis for the capacity demand curve.

#### Candidate Retirements

LAI restricted the candidates for retirement to coal and oil-fired steam and combustion turbines.

### **New Jersey Class I REC Prices**

LAI forecasted annual New Jersey Class I REC prices using LAI's proprietary model developed in house. The model uses onshore wind firm capital and operating costs, financial parameters, and zonal hourly energy prices and annual capacity prices from the Aurora model. The primary source for capital and operating cost data is the Department of Energy 2017 Wind Technologies report.<sup>32</sup> The model simultaneously solves for a consistent and smooth time-series of REC prices for multiple vintages of wind farms as a mathematical programming model that minimizes deviations from a target rate-of-return for each vintage. By using multiple vintages of wind farms in the model, capital cost and wind energy performance changes over time may be modeled. Capital and operating costs are projected to decrease over time as a result of technical cost productivity improvements, while the phase-out of the ITC and PTC in the early 2020s will result in an increase in project cost borne by developers and duly reflected in REC prices. Side constraints prevent annual REC prices from exceeding the \$50 per megawatt hour ACP rates set by the New Jersey RPS.

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<sup>32</sup> [https://www.energy.gov/sites/prod/files/2018/08/f54/2017\\_wind\\_technologies\\_market\\_report\\_8.15.18.v2.pdf](https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf)