Appendix A – Cost Analysis

1 Overview

The New York State Energy Research and Development Authority (NYSERDA), working in collaboration with the New York Department of Public Service (DPS), led analysis to assess the deployment, cost and benefit of incremental renewable energy resource under Tier 1 of the Renewable Energy Standard (RES) and the Offshore Wind Standard (OSWS) aimed at meeting the 70 by 30 goal and the goal of 9 GW of offshore wind as set out in the Climate Leadership and Community Protection Act (CLCPA). NYSERDA and DPS acknowledge the contribution of Sustainable Energy Advantage, LLC (SEA) for its primary analytical role in the development of the analysis of land-based large-scale Tier 1 resources, and Renewables Consulting Group (RCG) for its primary analytical role in the development of the offshore wind analysis.

1.1 Large-scale Renewables Analysis

The analysis of land-based large-scale Tier 1 resources (LSR analysis) forecasts the cost of newly-constructed and repowered large-scale renewable resources available to meet New York's Tier 1 RES procurement targets as procured through long-term contracts. Projected costs are primarily a function of four key sets of variables: (i) technology cost; (ii) financing cost; (iii) technology performance; and (iv) market (NYISO energy and capacity) prices. In addition, available federal incentives are considered in the project cost assessment as appropriate. Available supply resources are sorted and selected for deployment from least to highest expected levelized premium paid by NYSERDA through its long-term Renewable Energy Credit (REC) contracts. Premiums are calculated as the product of a project's expected generation during the contract period and the difference between a project's as-bid Strike Price (approximately equal to a project's levelized cost of energy (LCOE)) and the projected per-megawatt-hour reference market values of energy and capacity over a project's lifetime, assuming contract payments for 100 percent of a project's expected average annual energy production over a 20-year contract life. LCOEs are a function of technology costs and financing costs, while market value is a function of forecasted market prices. As a simplifying assumption for this White Paper, the scope of the analysis was limited to land-based wind and utility-scale solar PV technologies. Import opportunities were not analyzed.

The analysis assesses "Resource Blocks" representing the resources available to NYSERDA for long-term REC contracting. The analysis represents the diversity of resource block characteristics (e.g. location, cost, production profile, market revenue); however, as a modeling simplification, the supply potential within specific geographic zones with similar characteristics (location, resource intensity, scale, interconnection cost, etc.) is combined into a single Resource Block. The analysis does not explicitly predict the development of a particular site in a particular location, but instead takes a probabilistic approach, assigning "de-rating factors" to account for the proportion of technical potential that is developable due to land use, permitting and other constraints impacting a Resource Block's probability of success.

In addition to constraints, the analysis also applies annual phase-in factors to the resource potential for each technology to reflect that only a limited portion of total resource potential will have reached sufficient development maturity to be available for procurement each year, as a result of factors such as interconnection, permitting, and supply chain constraints.

Resource Blocks are defined by the following inputs:

- The block's location (NYISO zone) within New York;
- The maximum potential developable quantity (MW);
- Production characteristics, including levelized annual net capacity factors (%) and representative hourly production profiles;
- The block's NYISO unforced capacity value (UCAP) (% of nameplate installed capacity);
- Capital expenditures (CAPEX) (excluding network upgrade costs) ($/kW);
- Fixed operations and maintenance expenditures (O&M, or OPEX) ($/kW); and
- An aggregation of financing cost assumptions.

These inputs are used in combination with a forecast of market revenues to calculate the following outputs:

- The LCOE ($/MWh);
- The levelized market value ($/MWh) of energy and capacity over the project's lifetime; and
- The levelized premium ($/MWh), derived as the difference between LCOE and levelized market value.

To determine a project's date of commercial operation, a four-year lag was assumed between the time of contracting and commercial operation for both land-based wind and solar PV resources.

In order to benchmark cost and generation assumptions used by the analysis, actual Fixed REC price bids received by NYSERDA in response to its 2019 solicitation (RESRFP19-1) were compared to modeled premiums that the analysis would project for a similar portfolio of projects at that point in time. Project economics were found to fall within a similar range, providing confidence in the model's underlying technology cost and financing cost assumptions.

1.2 Offshore Wind Analysis

Similar to the LSR Analysis, the analysis of offshore wind resources (OSW Analysis) forecasts the costs of newly-constructed offshore wind resources available to meet New York's procurement targets through long-term contracts by assessing Resource Blocks based on (i) technology costs; (ii) financing costs; (iii) technology performance; and (iv) market (NYISO energy and capacity) prices to determine projected premium cost (assuming contract payments for 100 percent of generation over a 25-year contract life).

Unlike their land-based counterparts, however, offshore wind project sites are regional resources, making NYSERDA's selection of available resources also a function of growing competition among neighboring northeastern states. The OSW Analysis considers both existing offshore wind project sites in the U.S. northeast as well as multiple additional areas in the New York Bight that may be advanced by the federal government for near-term leasing.[1] Unlike the Resource Blocks supporting the LSR Analysis, specific potential offshore wind Resource Blocks are limited in number and well defined given the federal government leasing process. The OSW Analysis therefore includes a comprehensive assessment of each individual Resource Block, defined by the following inputs:

- The block's project and interconnection locations;
- The maximum potential developable quantity (MW);

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1 https://www.boem.gov/sites/default/files/renewable-energy-program/State-Activities/NY/Bennett-and-Feinberg-presentation.pdf (Page 10)

- Production characteristics, including levelized annual net capacity factors (%) and representative hourly production profiles;
- CAPEX (excluding network upgrade costs) ($/kW);
- Fixed OPEX ($/kW); and
- An aggregation of financing cost assumptions.

These inputs are used in combination with a forecast of market revenues to calculate the following outputs:

- The block's NYISO UCAP (% of nameplate installed capacity);
- The LCOE ($/MWh);
- The levelized market value ($/MWh) of energy and capacity over the project's lifetime; and
- The levelized premium ($/MWh), derived as the difference between LCOE and levelized market value.

To determine a project's date of commercial operation, a six-year lag was included between the time of contracting and commercial operation.

In order to benchmark cost and generation assumptions used by the analysis, actual Index OREC price bids received by NYSERDA in response to its 2018 offshore wind solicitation (ORECRFP18-1) were compared to modeled premiums that the analysis would project for similar projects at that point in time. Project economics were found to fall within a similar range, providing confidence in the model's underlying technology cost and financing cost assumptions.

2 Inputs and Methodology

2.1 Land-Based Wind Cost and Quantity

The costs and performance characteristics of land-based wind are site specific. Resource potential is specific to wind speed and land use characteristics, further constrained by permitting limitations that have historically been more challenging for land-based wind than for some other technologies. Cost is strongly tied to such factors as project scale, topography, distance from interconnection, and accessibility to roads. Production is also influenced by technology deployed (influenced by such factors as hub height, blade length, low wind-speed technology). This analysis used a detailed geospatial approach intended to reflect the site-specific nature of land-based wind development with respect to resource potential and project cost.

The geospatial study identified and characterized potential land-based wind sites in New York at three different hub heights (85 meters, 110 meters, and 135 meters). Resource Blocks were derived by interpolating identified sites at the three hub heights to reflect improvement in project characteristics (e.g., site capacity, capacity factors) that can be achieved with taller turbines within the same geographic footprint. De-rates to raw land areas were applied to differentiate the likelihood of successful permitting based on a site-by-site screening of the presence and proximity of potential neighbors as well as land-use conflicts. Cost functions were also developed to represent development cost variations that are associated with both project scale and site characteristics.

While a geospatial approach was used for determining land-based wind resource potential, it is applied as a probabilistic analysis. Resource Blocks do not depict and should not be used to define site locations, deployment timing, and costs for actual individual projects.

Repowering opportunities for existing land-based wind projects are included in the analysis, reflecting current eligibility rules for repowering.

Data sources for the land-based wind cost data included literature review of publicly available resources (including the NREL 2019 ATB[2]), past NYSERDA analyses and interviews with developers active (or planning to be active) in New York.

2.1.1 Capital Expenditures (CAPEX)

The "Base Case" land-based wind CAPEX assumptions are based on an idealized 200 MW project ("base project") located in an idealized (for permitting and installation) central U.S. plains location commencing commercial operation in 2020. A CAPEX value of $1,210/kW (in 2020 dollars) was selected for this base project. Transmission and interconnection costs were developed separately on a site-specific basis, as described further in Section 2.7 of this Appendix.

A series of adjustments to this starting point CAPEX is applied to reflect cost differences between land-based wind development in New York and the idealized central U.S. plains location, as well as cost variations associated with key parameters that characterize land-based wind development cost. These adjustments include locational adjustments (Table 1), project size adjustments (Table 2), and topography adjustments (Table 3).

Locational Adjustments: a "regional factor" is applied as a multiplicative scalar representing the ratio of general CAPEX costs specific to upstate New York and Long Island relative to national average costs. A compounding "siting factor" reflects siting and soft cost difference from the base project.

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2 https://atb.nrel.gov/electricity/2019/

Table 1 - Land-based Wind CAPEX Locational Adjustments

NY Region	NYISO Zones	Regional Factor	Siting Factor	Final Adjustment Factor
Upstate	Rest of state	1.01	1.06	1.07
Long Island	Zone K	1.25	1.10	1.38

Size Adjustment: the size adjustment reflects dis-economy of scale compared to resources in size categories smaller than the 200 MW base project.

Table 2 - Land-based Wind CAPEX Size Adjustment

Technology Size Category	Adjustment Factor
LBW 10-30 MW	1.30
LBW 30-100 MW	1.15
LBW 100-200 MW	1.02
LBW >200 MW	1.00

Topography Adjustment: the base CAPEX is also subject to an adjustment for the site topography to reflect cost differences caused by more challenging site topography (slopes) and access to roads.

Table 3 - Land-based Wind Topography Adjustment

Land Type	Definition: Slope Range (%); Mutual Exclusion of Land Type	Min. Elevation (m)	Adjustment Factor
1. Plain	0 – 5%; Not 3 or 4	N/A	1.00
2. Rolling Hills (Accessible)	>5 – 15%; Not 1,3 or 4	N/A	1.07
3. Rolling Hills (Remote)	8 – 12%; Not 4	300	1.12
4. Mountainous	>10 – 20%	500	1.22

An experience curve was developed to represent technology cost changes over time compared to a 2020 project (commercial operation date of 2020), shown in Figures 1 and 2. The experience curve was derived by converting the 2019 NREL ATB “Low” CAPEX forecast for "techno-resource group (TRG) 6" - which is the most consistent with characteristics of the majority of sites in New York – into an index.

Figure 1 - Land-based Wind CAPEX Trajectory, Nominal $

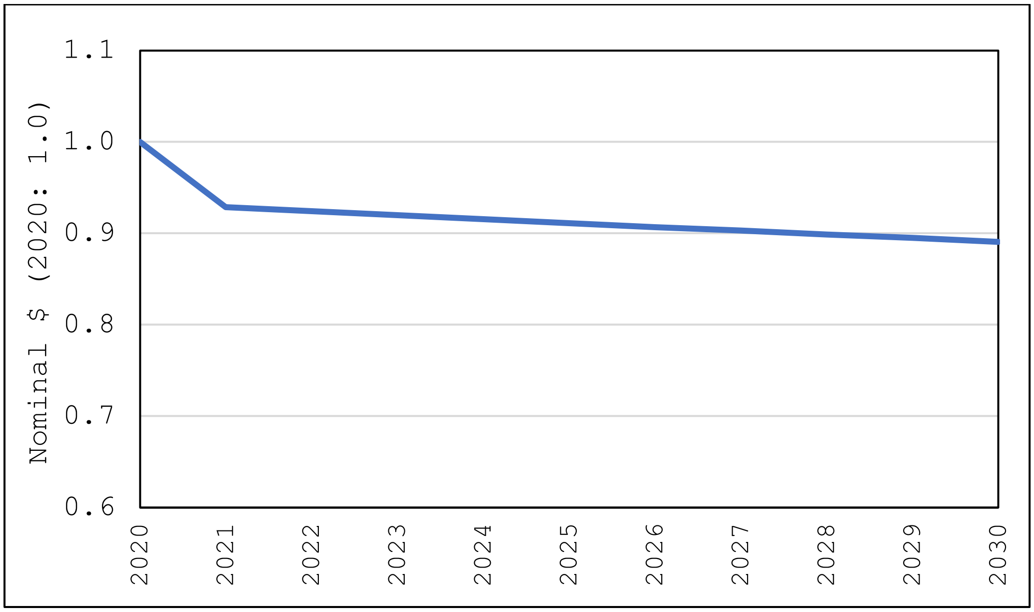
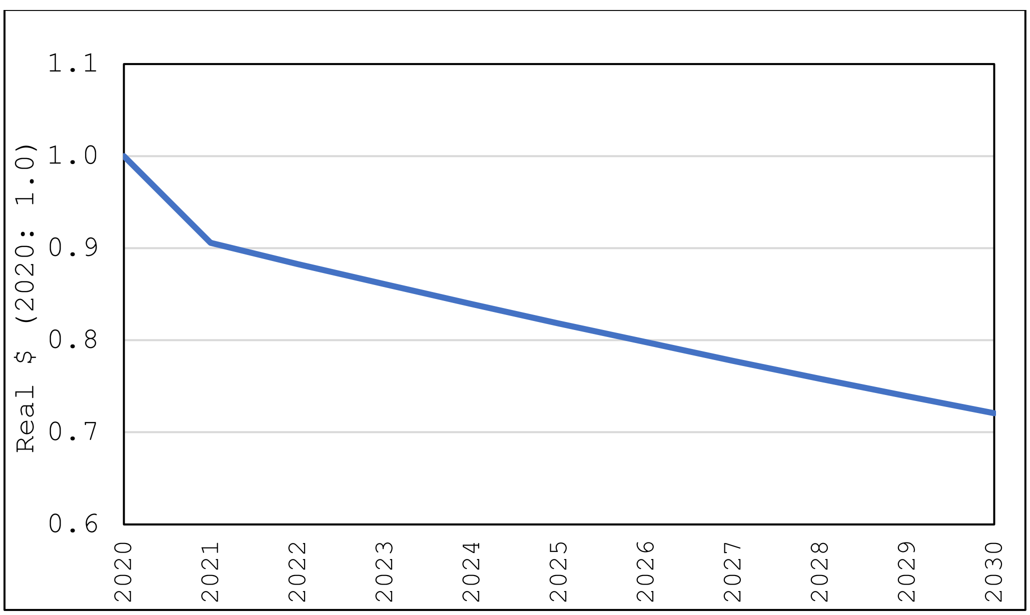


Figure 2 - Land-based Wind CAPEX Trajectory, Real $



2.1.2 Operations & Maintenance Expenditures (OPEX)

A nominal levelized baseline value for fixed OPEX cost was set at $68/kW-yr for a 100-200 MW project commencing commercial operation in 2020 based on literature review and developer interviews. This value reflects the levelized annual expenses required to operate a plant over its 20-year contract life and is assumed to reflect the amortized cost of all equipment repairs and replacements (including provisions for capitalized expenditures); all operations, maintenance, repair and replacement labor; insurance expense; project management and administrative expense; land lease or royalty payments; and property taxes (or payments in lieu thereof).

To represent New York-specific regional labor cost differences, a labor cost adjustment factor of 1.1 was applied to industry average OPEX. After accounting for this regional labor adjustment, the final fixed, nominal levelized OPEX cost was $74.8/kW-yr for a 100-200 MW project commencing commercial operation in 2020.

Size adjustments, consistent with relative scale of the land-based wind CAPEX size adjustments, were applied to reflect economy of scale compared to resources in other size categories (see Table 4).

Table 4 - Land-Based Wind Fixed O&M Size Adjustments

Technology Size Category	**Adjustment Factor**
LBW 10-30 MW	1.27
LBW 30-100 MW	1.13
LBW 100-200 MW	1.00
LBW >200 MW	0.98

OPEX costs were held constant in real dollar terms, i.e. increasing with inflation over time in nominal dollar terms.

2.1.3 Resource Potential

A geospatial approach was used to determine technical resource potential and performance for land-based wind in New York at three hub heights (85 meters, 110 meters, and 135 meters). The following land exclusions, corresponding with constraints on feasible wind power development, were applied to remove land areas from the developable resource potential.

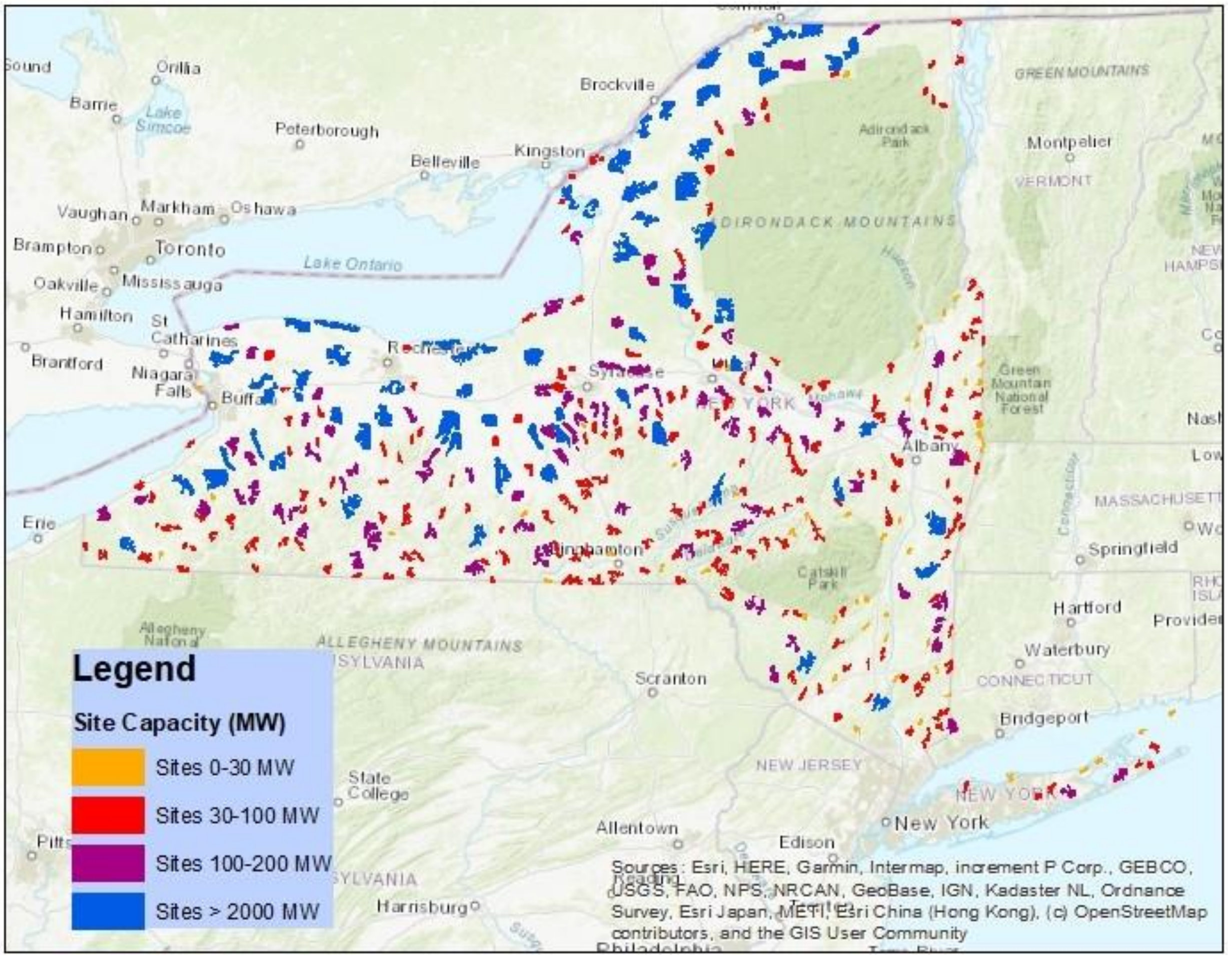
Table 5 - Land-Based Wind Primary Constraints

Constraints - Excluded Areas	**Buffer (meters)**
Adirondack and Catskill Parks	155
National Historic Preserves / Sites / Parks	155
Wildlife Management Areas	155
State Unique Area	155
State and Local Parks	155
National Monuments	155
National Wildlife Refuges	155
National Park Service Land	155
Fish and Wildlife Service Lands	155
American Indian Lands	155
GAP Status 1 & 2 Lands (Protected Lands)	155
Urban Areas (Class 22)	200
Urban Areas (Class 23) & (24)	500
Wetlands & Waterbodies	30
Large Airports	6,000
Small / Medium Airports	3,000
Proposed Wind Farms	3,000
Existing Wind Farms	3,000
Slopes > 20%	N/A
Appalachian Trail	3,000

Any continuous area (after the exclusion of constraint areas) capable of hosting a wind project of at least 20 MW in size was defined as a potential project site.

Figure 3 depicts the land-based wind sites included in the analysis. As noted above, this is the result of probabilistic geospatial analysis and should not be interpreted as defining actual project sites.

Figure 3 - Land-based Wind Potential Sites by Size Categories (at 110m Hub Height)



A further constraint was applied to reflect the presence and density of dwellings within or proximate to each site footprint and resulting permitting constraints. Sites with "substantial" housing density were excluded from the analysis. For the remaining sites, a probabilistic factor was applied to determine the available capacity at each site, as shown in Table 6 (e.g., for a site with "High" housing density, only 5% of the footprint was considered available).

Table 6 - Land-Based Wind Probability of Permitting by Housing Density

Housing Density Level	Probability
High	5%
Medium	25%
Low	70%
None	95%

2.1.4 Capacity Factors

For analysis at each hub height, capacity factors based on current technology were estimated for each identified site. To calculate capacity factors, a scalable wind turbine power curve (representing the composite of several leading turbine models) was first developed by SEA’s subcontractor UL, LLC to represent current, commercially-available technology.

Wind speed and air density data from each site were applied to the composite power curve to determine the gross hourly energy production at the selected hub height for a typical year. The resulting net annual energy production, after accounting for typical loss factors (other than curtailment by the system operator) was divided by the maximum possible energy output (i.e., operating at nameplate capacity in all hours) to produce a typical annual net capacity factor for each site at each hub height, applicable in the first year of the analysis. Resulting 20-year levelized resource potential-weighted average capacity factors for each NYISO zone are shown in Table 7.

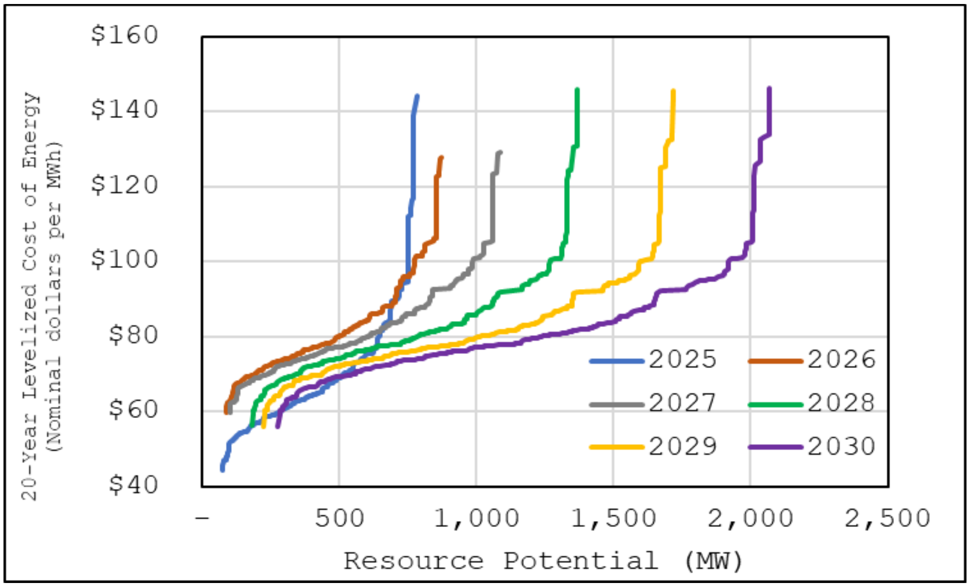
Table 7 – Weighted Average Land-Based Wind Capacity Factors

Zone	2025	2026	2027	2028	2029	2030
A	37%	37%	37%	37%	37%	37%
B	38%	38%	38%	37%	38%	38%
C	35%	35%	35%	35%	36%	36%
D	39%	39%	38%	38%	38%	38%
E	38%	38%	38%	38%	38%	38%
F	n/a	n/a	n/a	36%	37%	37%
G	n/a	n/a	n/a	37%	37%	37%
H	n/a	n/a	n/a	35%	35%	35%
I	n/a	n/a	n/a	n/a	n/a	n/a
J	n/a	n/a	n/a	n/a	n/a	n/a
K	n/a	n/a	n/a	43%	43%	43%

2.1.5 Land-Based Wind Supply Curves

Based on the input assumptions as described above, Figure 4 below shows the resulting projected available resource quantity and LCOEs by year for land-based wind Resource Blocks. These supply curves reflect gradual phase-in of available resource potential over time, as a result of factors such as supply chain capacity to develop only a limited number of sites at any one time, interconnection queue issues, etc. The resource available in each year is also shown net of resource potential that was adopted (in the base case projection) in previous years.

Figure 4 - Land-based Wind LCOE Supply Curve



Notes:

- LCOE shows a significant increase between 2025 and 2026 due to phase-out of the federal Production Tax Credit (PTC).
- LCOE declines over time despite more cost-competitive "low-hanging fruit" resources getting deployed, driven by a CAPEX decline and technological advancement (including hub height evolution).
- Each supply curve shows a steep cost increase at the tail of the supply curve, reflecting less-competitive sites (due to interconnection cost, lower wind speed, diminished economy of scale, topography, and accessibility).

2.2 Utility-Scale Solar PV Cost and Quantity

Compared to land-based wind, solar PV resource potential characteristics, all else equal, are relatively uniform across a large geographic footprint, with only modest insolation variations relating to cloud cover and snow accumulation impacts. Some land-use types are constrained by permitting limitations, but, typically, solar permitting is less challenging than wind. Cost is primarily a function of project scale, distance from interconnection, and accessibility to roads.

Cost and performance characteristics are also determined by the technology deployed (fixed-tilt versus single-axis tracking, and mono-facial versus bifacial technology). The past three NYSERDA RES Tier 1 solicitations (RESRFP17-1, RESRFP18-1, and RESRFP19-1) have accepted proposals to deploy all possible combinations of these technologies. Project-specific technology selection is often a function of site characteristics and developer preference.

A geospatial analysis was conducted to estimate the total developable area for solar PV resources after considering certain land-use types and constraints. Because the potentially-available gross land area far exceeds the amount of solar PV that could reasonably be deployed, the analysis was limited to sites near existing interconnection opportunities and roads, variables which are likely to lead to lower project costs.

Data sources for the solar PV cost data included literature review of publicly-available resources (including the NREL 2019 ATB and a Wood Mackenzie Power & Renewables PV System Pricing report commissioned circa August 2019) and interviews with developers active (or planning to be active in this scale) in New York.

2.2.1 CAPEX

The “Base Case” solar PV CAPEX assumptions are based on 10-25 MW projects using each of four technology combinations (standard fixed-tilt, standard single-axis tracker, bifacial fixed-tilt, and bifacial single-axis tracker) at an average U.S. site.

Table 8 below shows the baseline CAPEX values for these four technology combinations.

Table 8 - Utility-Scale Solar PV CAPEX Baseline for Project Commencing Commercial Operation in 2020

2020 $/kW$_{DC}$	**Mono-facial**	**Bifacial**
Fixed Tilt	$950	$997
Single-Axis	$1,074	$1,127

Transmission and interconnection costs were developed separately on a site-specific basis, as described further in Section 2.7.

A series of adjustments was applied to reflect regional cost differences in solar PV development among New York regions (Siting Factor) and solar siting and permitting cost differences between different New York regions and the national average (EIA Regional Factor), as well as cost variations associated with key parameters that characterize utility-scale solar development cost. These adjustments included locational adjustments (Table 9) and project size adjustments (Table 10).

Locational Adjustments: a "regional factor" is applied as a multiplicative scalar representing the ratio of general CAPEX costs specific to regions within New York State to national average costs. A compounding "siting factor" reflects siting and soft cost difference from the idealized national site.

Table 9 - Utility-Scale Solar PV CAPEX Locational Adjustments

NY Region	**NYISO Zones**	**EIA Regional Factor**	**Siting Factor**	**Final Adjustment Factor**
Upstate	Rest of state	0.98	1.00	0.98
New York City	Zone J	1.25	1.02	1.28
Long Island	Zone K	1.45	1.02	1.48

Size Adjustment: the size adjustment reflects the relative economy of scale compared to resources in size categories larger than the 10-25 MW baseline.

Table 10 - Utility-Scale Solar PV CAPEX Size Adjustments

Technology Size Category	Adjustment Factor
>200 MW	0.77
100-200 MW	0.82
75-100 MW	0.90
25-75 MW	0.90
10-25 MW	1.00

An experience curve was developed to represent technology cost declines on a $/kW basis over the period of the analysis compared to a 2020 project (commercial operation date of 2020), see Figures 5 and 6.

Figure 5 - Utility-Scale Solar PV CAPEX Trajectories (Nominal $)

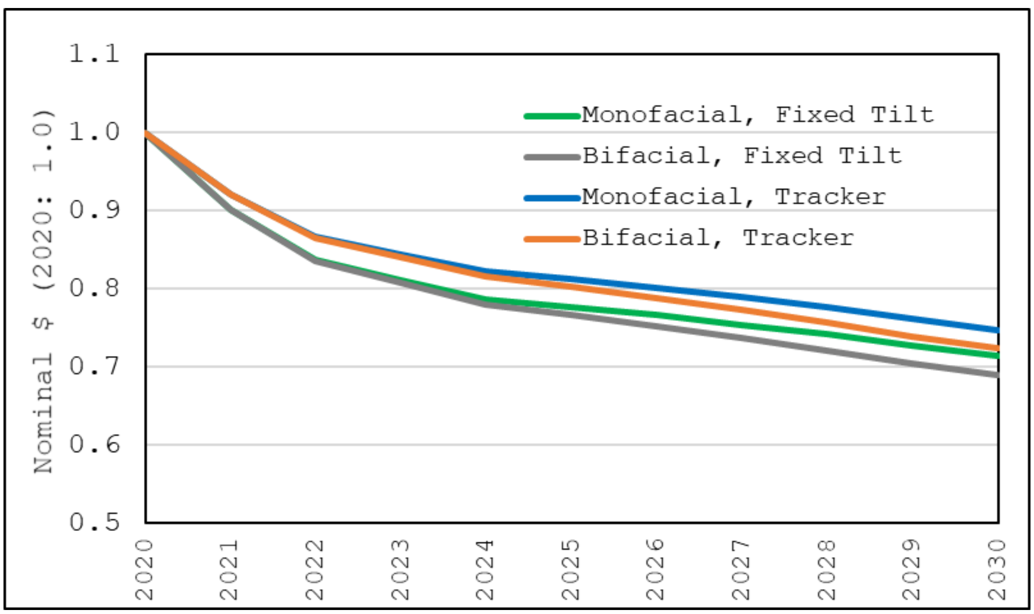
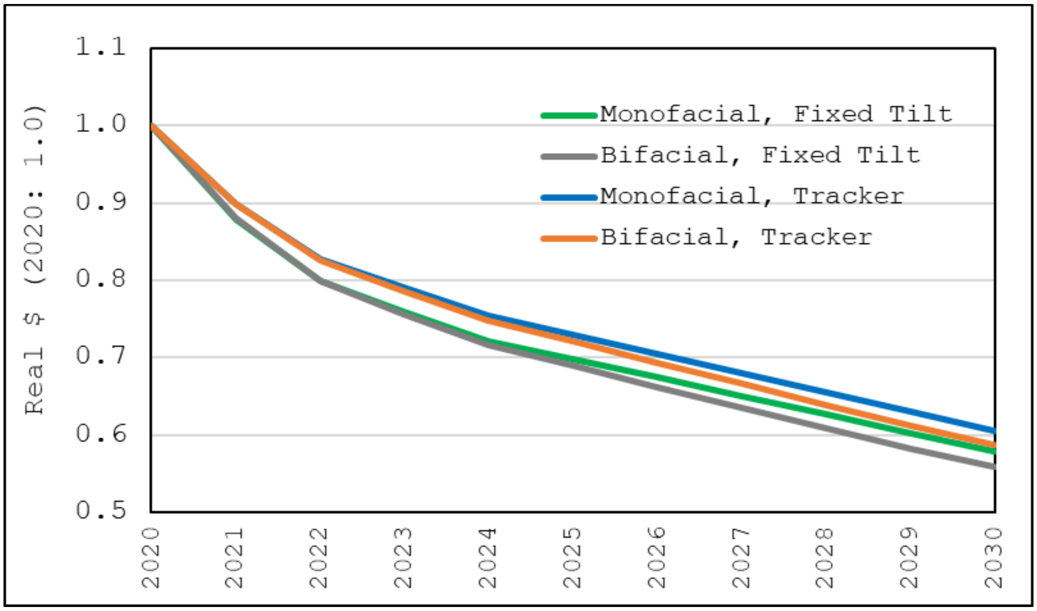


Figure 6 - Utility-Scale Solar PV CAPEX Trajectories (Real $)



2.2.2 OPEX

Fixed OPEX baselines were developed for fixed-tilt and single-axis tracker projects. After determining the baselines, a labor cost adjustment factor of 1.1 was applied as a proxy of regional labor cost differences between New York and the national average. The resulting O&M costs are shown in Table 11.

Levelized OPEX costs were held constant in real dollar terms, increasing with inflation over time in nominal dollar terms.

Table 11 - Utility-Scale Solar PV Fixed O&M

Technology	**Fixed O&M ($/kW-yr DC)**
Fixed Tilt	$24.87
Single-Axis	$27.39

2.2.3 Technology Deployed

Both fixed-tilt and single-axis tracker solar projects could be developed on the same sites identified in the utility-scale solar resource potential analysis described above. Fixed-tilt and single-axis tracker solar facilities have different cost and production characteristics, with single-axis trackers producing more energy but at higher rates of CAPEX and OPEX.[3] To determine which technology option would be cost optimal to deploy at a specific location in a given year under the study assumptions, it was assumed that developers would install whichever technology option would have a lower levelized revenue requirement at that site at the time of solicitation.[4]

Similarly, both mono-facial and bifacial solar projects, which have different cost and production characteristics, could be developed on the same sites. Bifacial solar projects currently have higher CAPEX and OPEX than mono-facial solar projects, but responses to NYSERDA’s RESRFP19-1 procurement included a diverse mix of mono-facial and bifacial PV technology. However, based on the market research carried out for this analysis, the benefit of the higher energy production of bifacial solar project is expected to outweigh its cost premium in the near future. Based on this assumption, bifacial solar is modeled as the default technology for this assessment.

2.2.4 Resource Potential

A geospatial analysis for determining solar PV resource potential was developed using a geographic information system (GIS)

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[3] While fixed-tilt and single-axis tracking configurations have different MW per unit of land area density due to room required for moving panels and avoidance of shading, the MW of capacity was not varied, as a modeling simplification.

[4] This assumption is a modeling simplification and may generally hold true in the long run; however, it is noted that deployment of solar PV with trackers in locations with harsh winter weather conditions is immature, and NYSERDA’s RESRFP19-1 saw a diverse mix of solar PV technology.

based site screening approach based on a review of publicly available solar and renewable energy technical potential studies. Two simplifying assumptions were made in this analysis:

- A utility-scale solar PV project would connect at either 23-46 kV, 69 kV or 115 kV (voltages for which data was readily available in a GIS data layer);
- Given the ample land available and economic considerations, developers would choose to site utility-scale solar PV projects near existing substations (within a three-mile radius) or very near existing transmission lines (within a one-mile radius).

Similar to the resource potential assessment for land-based wind, all primary constraint land areas (see Table 12) were first excluded in the analysis. A secondary-level constraint was applied to exclude all areas beyond three miles of any existing substations (at 23-46 kV, 69 kV and 115 kV) and beyond one mile of existing transmission lines (only 115 kV lines were considered due to data constraints).

The remaining contiguous areas were considered as potential project sites. A power density of 7.5 acres/MW was used to calculate the resource potential (in MW) at each site. Only sites with a capacity of 10 MW or higher were considered in this analysis.

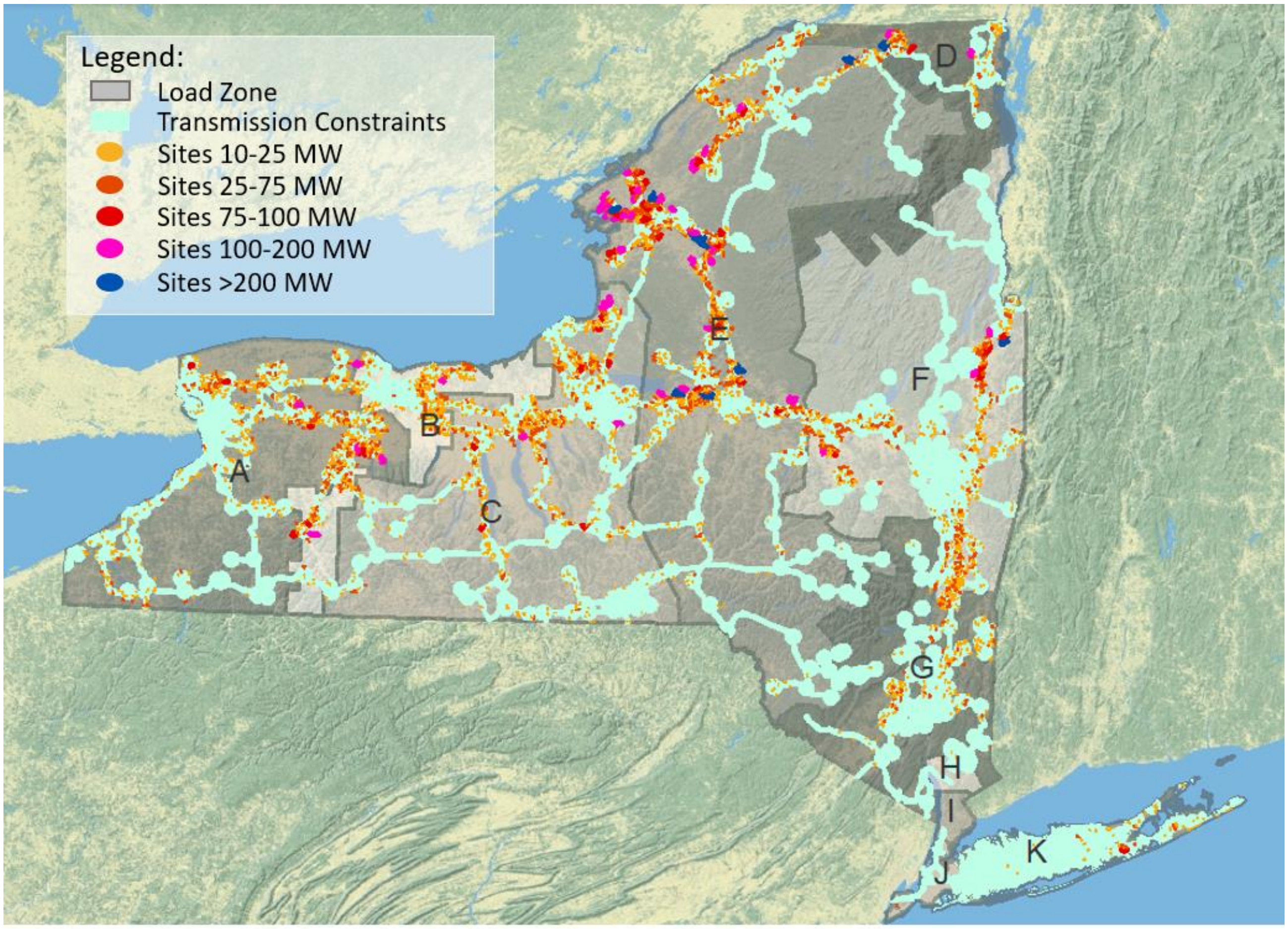
Table 12 - Utility-Scale Solar PV Primary Constraints

Primary Constraints - Excluded Areas	**Additional Buffer Beyond Excluded Area**
Adirondack and Catskill Parks	100 ft.
National Historic Preserves/Sites/Parks	100 ft.
Wildlife Management Areas	100 ft.
State Unique Area	100 ft.
State and Local Parks	100 ft.
National Monuments	100 ft.
National Wildlife Refuges	100 ft.
National Park Service Land	100 ft.
Fish and Wildlife Service Lands	100 ft.
American Indian Lands	100 ft.
GAP Status 1 & 2 Lands (Protected Lands)	100 ft.
Urban Areas	25 ft.
Forests	0 ft.
Cultivated Crops	0 ft.
Wetlands & Waterbodies	100 ft.
Existing Roads and Highways	25 ft.
Airports	25 ft.
Slopes ≥ 5%	N/A

Potential sites shown in Figure 7 below are the result of probabilistic geospatial analysis and should not be interpreted as defining actual project sites.

The identified sites were spatially correlated with land cover types (Barren Land, Shrub/Scrub, Grassland/Herbaceous, Pasture/Hay) and a probability de-rate to 25% of available land area was applied to the Pasture/Hay area within a site to reflect a lower probability of permitting success.

Figure 7 - Utility-Scale Solar PV Potential Sites by Size Categories



2.2.5 Capacity Factors

Capacity factors for mono-facial and bifacial solar PV (fixed-tilt and single-axis tracker) were derived for a representative location in each NYISO zone using 8,760 hourly production data from PV Watts® Calculator and NREL's System Advisor Model (SAM), respectively, at representative locations for each NYISO zone. Resulting Year-1 capacity factors for each NYISO zone are shown in Table 13.

Table 13 - Utility-Scale Solar PV DC Capacity Factors (before Degradation)

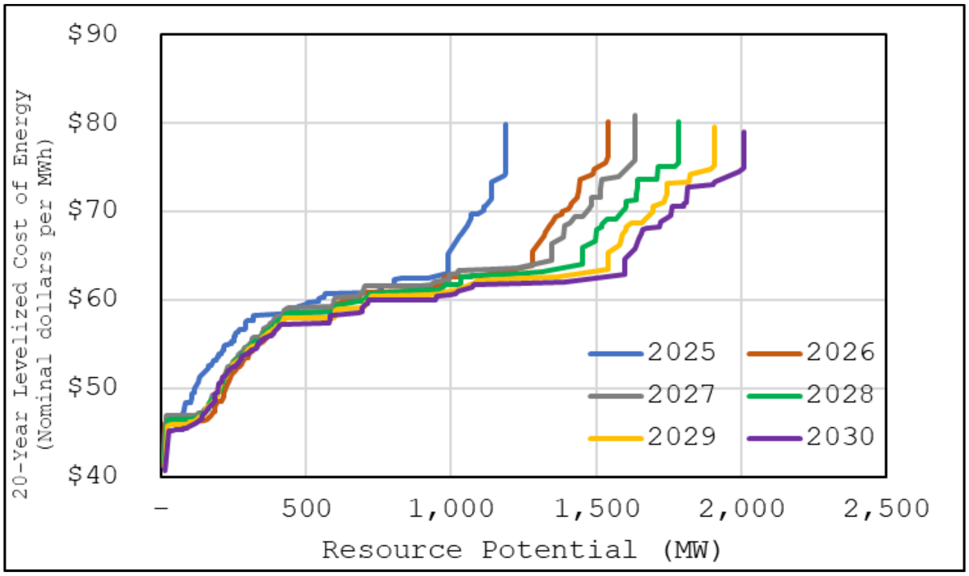
Zone	Selected Location	Mono-facial		Bifacial	
		Fixed	1-Axis	Fixed	1-Axis
A	Buffalo	14.5%	17.7%	15.3%	18.3%
B	Rochester	14.5%	17.5%	15.2%	18.2%
C	Syracuse	14.7%	17.9%	15.5%	18.6%
D	Plattsburgh	14.8%	18.0%	15.6%	18.7%
E	Utica	14.6%	17.9%	15.4%	18.6%
F	Albany	15.3%	18.7%	16.1%	19.4%
G	Poughkeepsie	15.4%	18.9%	16.2%	19.6%
H	Millwood	15.5%	19.1%	16.4%	19.9%
I	Yonkers	15.9%	19.3%	16.7%	20.1%
J	New York City	16.1%	19.6%	17.0%	20.4%
K	Long Island	16.2%	19.9%	17.1%	20.6%

To account for an assumed annual production degradation of 0.5%, the annual production accounting for degradation was levelized to produce a single, fixed capacity factor for each system.

2.2.6 Utility-Scale Solar PV Supply Curves

Based on the input assumptions as described above, Figure 8 below shows the resulting projected available resource quantity and LCOEs for utility-scale solar PV Resource Blocks. These supply curves reflect gradual phase-in of available resource potential over time, as a result of factors such as supply chain capacity to develop only a limited number of sites at any one time, interconnection queue issues, etc. The resource available in each year is also shown net of resource potential that was adopted (in the base case projection) in previous years.

Figure 8 - Utility-Scale Solar PV LCOE Supply Curve



Notes:

- LCOE declines over time despite more cost-competitive "low-hanging fruit" resources getting deployed and phase-down of federal Investment Tax Credits (ITC), driven by CAPEX decline.
- Each supply curve shows a steep cost increase at the tail of the supply curve, reflecting less-competitive sites (due to interconnection cost, economy of scale, topography, and accessibility).

2.3 Offshore Wind Cost and Quantity

Offshore wind is a unique renewable resource in that, to maximize economies of scale and minimize soft costs, individual generation projects are generally much larger than their land-based counterparts. Offshore wind costs are primarily a function of project scale, a site's distance from shore, the available wind resource, the site’s water depth, and, given the resource’s novelty in the United States, the expected commercial operation date of the project.

Also, and again unlike land-based technologies, offshore wind project sites are not located within New York State, but are instead in federal waters managed by the Bureau of Ocean Energy Management (BOEM). Sites are therefore limited in number, allowing project costs to be analyzed with enhanced site-by-site specificity.

A geospatial analysis was conducted to identify and characterize the projects sites expected to be available to deliver to New York State, including all existing lease areas reaching to the southern coast of New Jersey and the eastern coast of Massachusetts, as well as expected future lease areas in the New York Bight.

2.3.1 CAPEX

The “Base Case” offshore wind CAPEX assumptions are based on a proprietary model developed by RCG that contains cost data and forward-looking cost assessments through 2040. CAPEX assumptions are broken down into the following components and are modeled for both HVAC and HVDC transmission systems:

- Project development;
- Turbine supply;
- Foundation supply;
- Installation of turbines and foundations;
- Supply & installation of array cables;
- Supply & installation of substations and export cables; and
- Other, comprised of port fees, environmental, logistics, commissioning, contingency, and other miscellaneous project costs.

HVAC and HVDC systems differ, from a CAPEX perspective, because an HVDC system requires an HVDC offshore converter, an HVDC cable, and an HVDC onshore converter, whereas an HVAC system simply requires only an HVAC cable (with reactive compensation, if required). HVDC systems are, generally, economically preferable for sites with longer transmission distances.

For a typical 800 MW project in the New York Bight with a commercial operation date (COD) in 2025, Base Case CAPEX values are as follows:

Table 14 – Base Case CAPEX Assumptions for a 2025 COD 800 MW Project

2020 $k/MW	**HVAC System**	**HVDC System**
Project Development	$269	$269
Turbine Supply	$1,197	$1,197
Foundation Supply	$423	$423
Installation of Turbines and Foundations	$261	$261
Supply and Installation of Array Cables	$108	$108
Supply and Installation of Substations	$307	$696
Supply and Installation of Export Cables	$286	$205
Other	$368	$398
Total	$3,218	$3,551

A series of adjustments to these Base Case CAPEX figures were then made for projects with different site characteristics and technology selections, including the below variables:

- Wind resource (capacity factor);
- Water depth;
- Distance to port;
- Offshore transmission distance;
- Land-based transmission distance;
- Installation vessel strategy;

- Project size;
- Turbine size; and
- Foundation type.

2.3.2 OPEX

Fixed OPEX assumptions were broken down between Generation OPEX and Transmission OPEX and were developed based on data from recently completed offshore wind projects in Europe. Offshore wind Generation OPEX is broken down between three distinct periods over the project life:

- The first five years of operation, when the wind turbines are under warranty;
- Years six through 15, when operations and maintenance is assumed to be run by either the turbine supplier or under an operations management agreement; and
- From year 16 onward, when no warranties are in place and operations and maintenance is assumed to be run by the project owners.

Transmission OPEX was similarly modeled temporally but was also comprised of three primary functions: offshore substation maintenance, export cable maintenance, and onshore maintenance. Table 15 below shows OPEX values for a typical 800 MW project in the New York Bight with a COD in 2025.

Table 15 – Base Case OPEX Assumptions for a 2025 COD 800 MW Project

2020 $k/MW/yr	HVAC or HVDC System
Generation OPEX, years 1-5	$54
Generation OPEX, years 6-15	$60
Generation OPEX, years 16+	$44
Transmission OPEX, years 1-5	$3
Transmission OPEX, years 6-15	$4
Transmission OPEX, years 16+	$4

2.3.3 Technology Deployed

The primary driver of technology cost reductions over time is the nameplate capacity of turbines, a variable which is strongly linked with a project’s COD. The analysis assumes a trajectory of turbine nameplate capacity over time as shown below in Table 16. For CODs between those listed explicitly below, turbine nameplate capacities were linearly interpolated to the nearest 0.5 MW.

Table 16 – Offshore Wind Turbine Nameplate Capacity by Year

Commercial Operation Date	Turbine Nameplate Capacity
2020	9.5
2025	12
2030	18
2035	22

Other technology drivers of offshore wind project cost include installation vessel strategy, foundation type, and transmission system (HVAC or HVDC). Assumptions across these categories were as follows:

- Installation vessel strategy: for installations prior to 2027, projects were assumed to use a feeder barge solution with a European installation vessel; for installations in 2027 or beyond, projects were assumed to be able to access a U.S.-flagged installation vessel.

- Foundation type: jackets and piles were assumed the default foundation type for all installations, as this is a proven market solution with abundant market cost data. Other technology options, such as monopiles and gravity-based systems, are commercially-viable alternatives.
- Transmission system: all installations were modeled using both HVAC and HVDC systems. The economics of both options were then compared head-to-head on a project-by-project basis, and the solution supporting the lowest LCOE was selected for each project.

2.3.4 Resource Potential

Fifteen project sites were considered, as shown below in Figure 9 and listed in Table 17. However, these project sites are regional resources, meaning each is also available for delivery to a neighboring state. This assessment therefore removed available resources over time, reflecting other regional procurements.

Figure 9 – Offshore Wind Project Sites

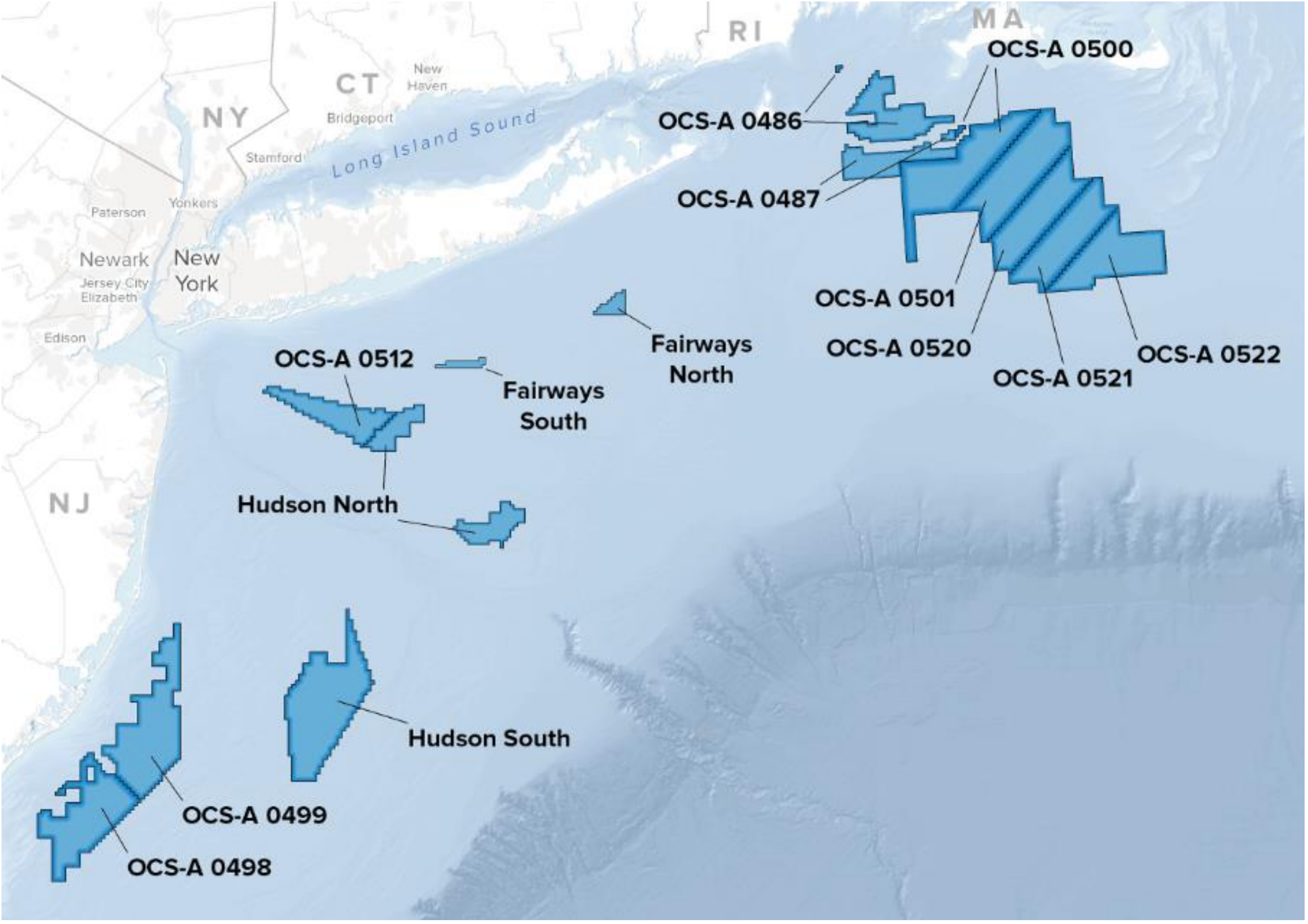


Table 17 – Offshore Wind Project Sites

Project Site Name	**Status**
OCS-A 0486	Leased to developer
OCS-A 0487	Leased to developer
OCS-A 0498	Leased to developer
OCS-A 0499	Leased to developer
OCS-A 0500	Leased to developer
OCS-A 0501	Leased to developer
OCS-A 0512	Leased to developer
OCS-A 0520	Leased to developer
OCS-A 0521	Leased to developer
OCS-A 0522	Leased to developer
Fairways North	BOEM Draft Wind Energy Area
Fairways South	BOEM Draft Wind Energy Area
Hudson North 1	BOEM Draft Wind Energy Area
Hudson North 2	BOEM Draft Wind Energy Area
Hudson South	BOEM Draft Wind Energy Area

2.3.5 Capacity Factors

Data obtained from the NREL Wind Integration National Dataset Toolkit and other publicly available sources (MERRA2, ERA5), along with an accompanying power curve supplied by RCG, were used to generation average annual generation profiles for each project site. Bespoke generation profiles were created for 9.5 MW, 12 MW, and 18 MW turbines, allowing for interpolation between these nameplate capacities for other technology solutions. Generation assumptions also included high-level assumptions regarding wake loss and technical loss estimates. Net capacity factors, for three select turbine nameplate capacities, are shown in Table 18 below.

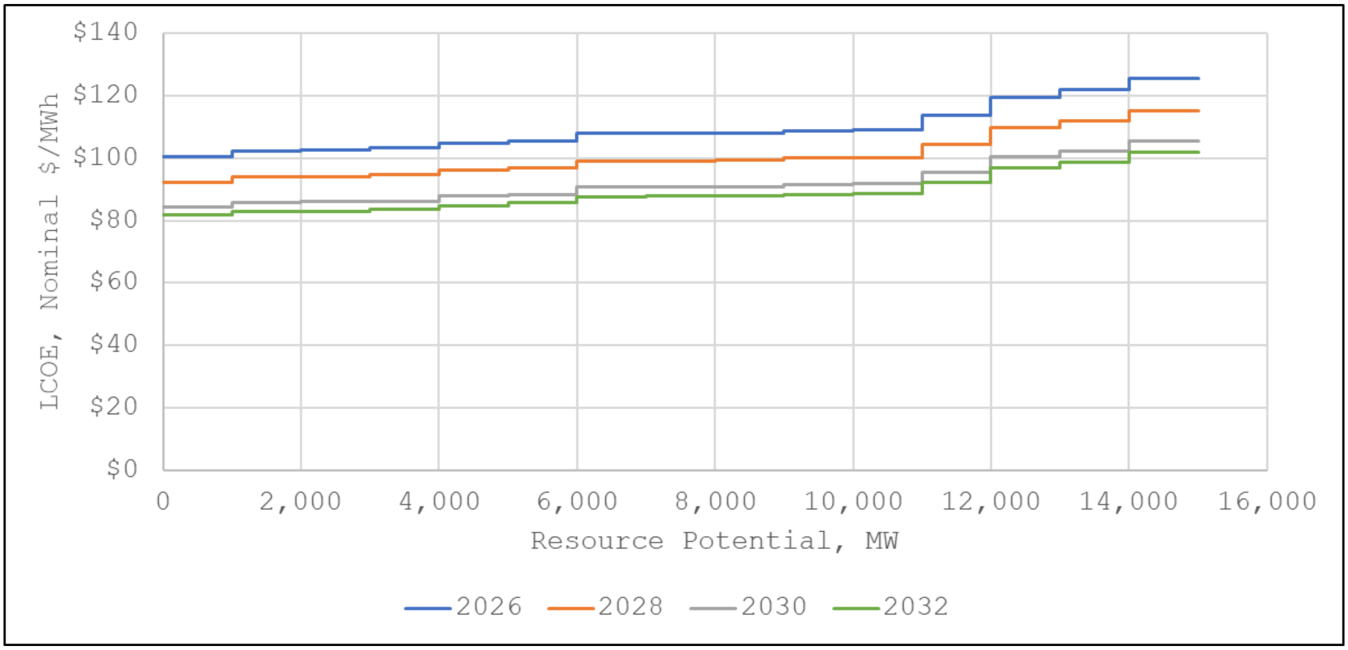
Table 18 – Offshore Wind Capacity Factors

Project Site Name	**9.5 MW Capacity Factor**	**12 MW Capacity Factor**	**18 MW Capacity Factor**
OCS-A 0486	46%	53%	54%
OCS-A 0487	46%	53%	54%
OCS-A 0498	41%	48%	49%
OCS-A 0499	41%	48%	49%
OCS-A 0500	46%	53%	54%
OCS-A 0501	46%	53%	54%
OCS-A 0512	42%	49%	50%
OCS-A 0520	46%	53%	54%
OCS-A 0521	46%	53%	54%
OCS-A 0522	47%	53%	54%
Fairways North	44%	51%	52%
Fairways South	42%	49%	51%
Hudson North 1	42%	49%	51%
Hudson North 2	44%	51%	52%
Hudson South	43%	50%	51%

2.3.6 Offshore Wind Supply Curves

Based on the input assumptions as described above, Figure 10 below shows the resulting projected resource quantity and LCOEs for all modeled offshore wind project sites, assuming 800 MW deployments, for installations between 2026 and 2032.

Figure 10 – Offshore Wind LCOE Supply Curve



Notes:

- LCOE declines over time driven by CAPEX and OPEX declines.
- Cost increases less dramatically at the tail of the supply curve than for the land-based wind and solar PV supply curves shown further above, since the range of available offshore wind lease areas does not include any cost-prohibitive sites.

2.4 Energy and Capacity Market Value

The commodity market value of renewable resources analyzed in this assessment represents the revenue paid to a generation project from the NYISO wholesale energy and capacity markets for its products (energy and capacity; it is assumed that these resources produce no ancillary services of material market value).

The commodity market value of each Resource Block is comprised of:

- The production-weighted zonal energy market price ($/MWh), which is based on a typical year hourly production profile. This is calculated by taking the ratio of the total energy revenues the project would have earned at zonal locational-based marginal prices (LBMPs) over the last three years (average of Day-Ahead and Real-Time), divided by the all-hours unweighted average LBMPs over the same period.
- The zonal capacity price ($/kW), adjusted by the capacity value (the season-weighted average unforced capacity as a percentage of nameplate capacity).

2.4.1 Wholesale Energy Price Forecast

For this analysis, the 2019 NYISO CARIS I energy price forecast[5] was used as the "Base Case" energy price forecast through 2028. Thereafter, the energy price is assumed to stay constant in real dollar terms at the 2028 level (i.e., continuing to increase with inflation annually in nominal dollar terms).

An alternative energy market price forecast was developed to test the sensitivity of program costs to energy market values. This "Low Energy Pricing" scenario applies a gradually increasing discount to Base Case energy pricing such that long-term pricing is 25 percent lower than Base Case values.

Figures 11 and 12 below show both the long-term Base Case and sensitivity energy price forecasts for NYISO zones C and J, which are shown here as illustrative zones for land-based and offshore wind resources, respectively, in New York State.

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5 https://www.nyiso.com/documents/20142/8263756/06%202019_CARIS_1_Base.pdf/503ecc6d-06cb-296c-62da-3efb12fd0515

Figure 11 – Annual Zonal Average Energy Price Forecast: Base Case Scenario and Low Energy Price Scenario (Nominal $)

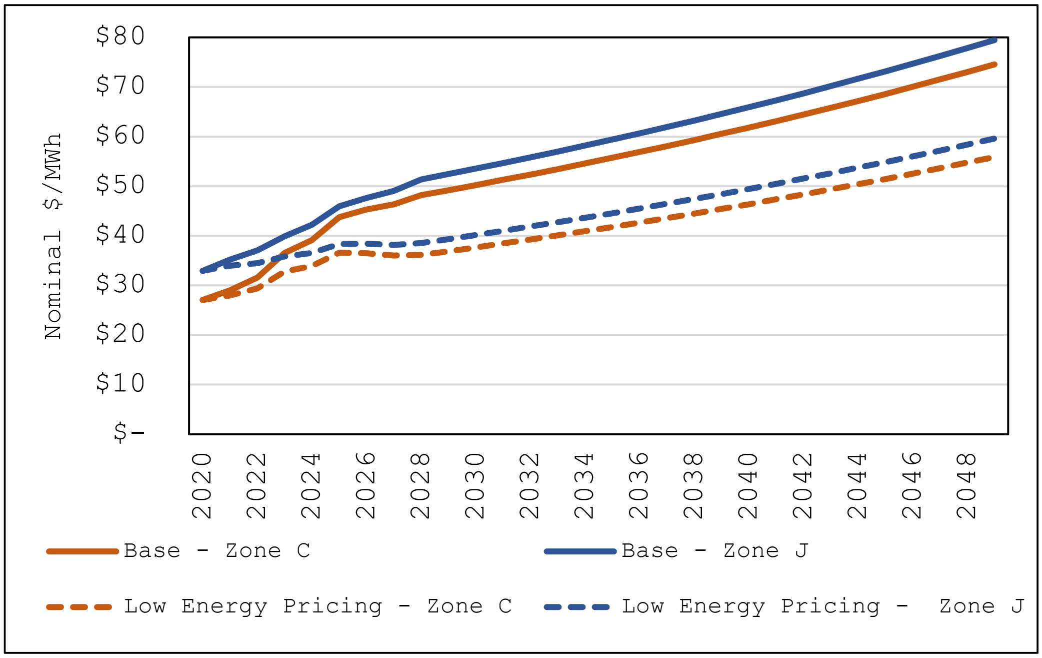
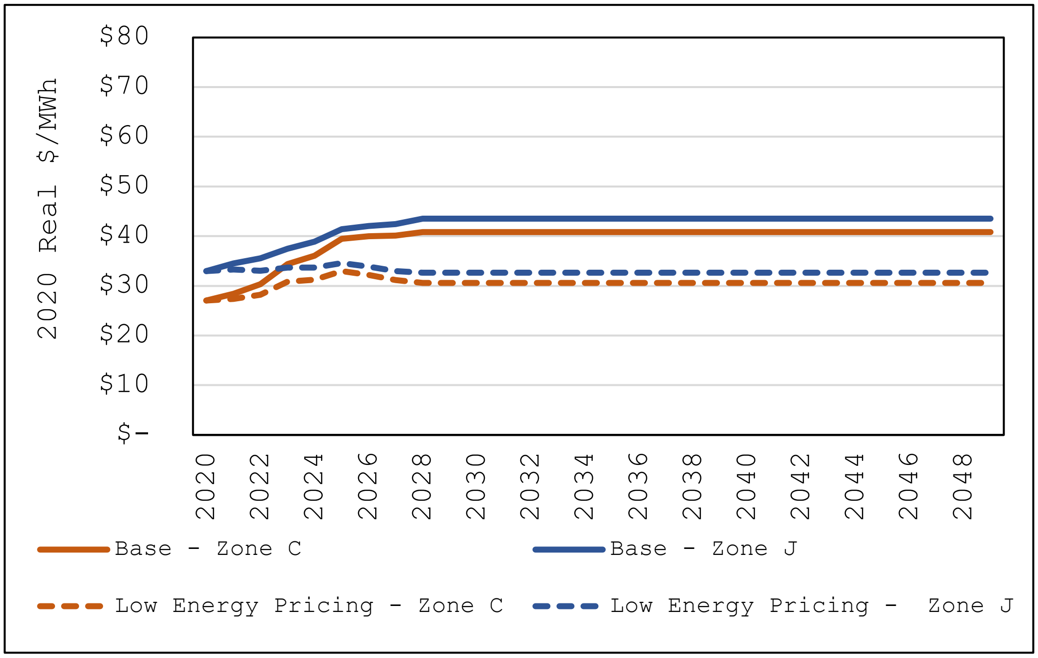


Figure 12 – Annual Zonal Average Energy Price Forecast: Base Case Scenario and Low Energy Price Scenario (Real $)



2.4.2 Capacity Price Forecast

Zonal Summer and Winter Installed Capacity Market (ICAP) generator prices from 2020 to 2038 as per the BCA Order (Order Establishing the Benefit Cost Analysis Framework, Case 14-M-0101, January 21, 2016) were translated to zonal average annual UCAP prices using the average of the zonal Summer 2018 and Winter 2018/17 translation factors. In 2039 and thereafter, the capacity prices were held constant at the 2039 level in real dollar terms (increasing with inflation in nominal dollar terms).

Figure 13 - Zonal Annual UCAP Price Forecasts (Nominal $)

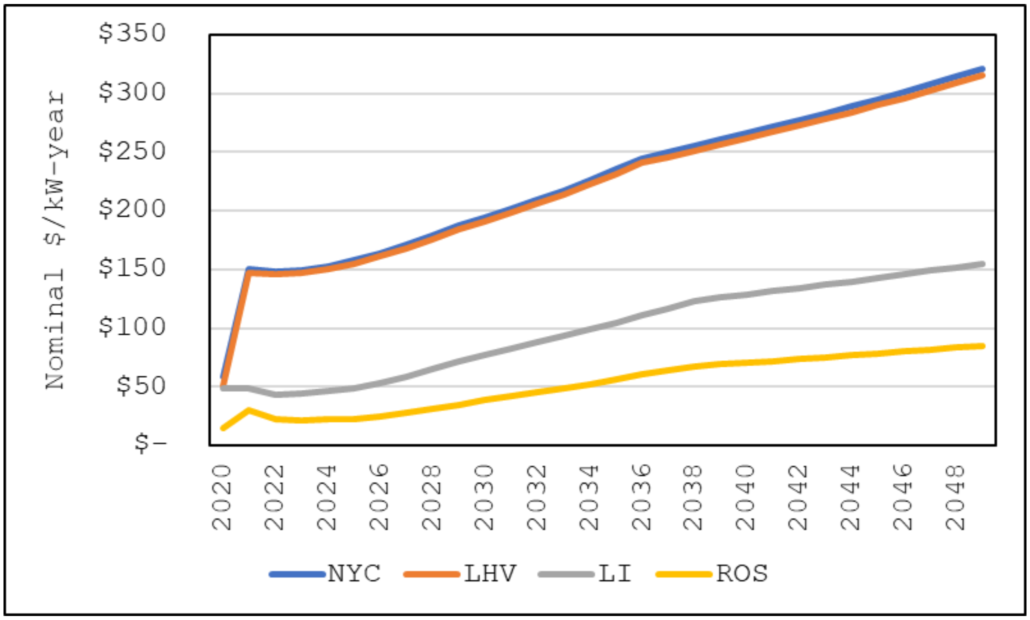
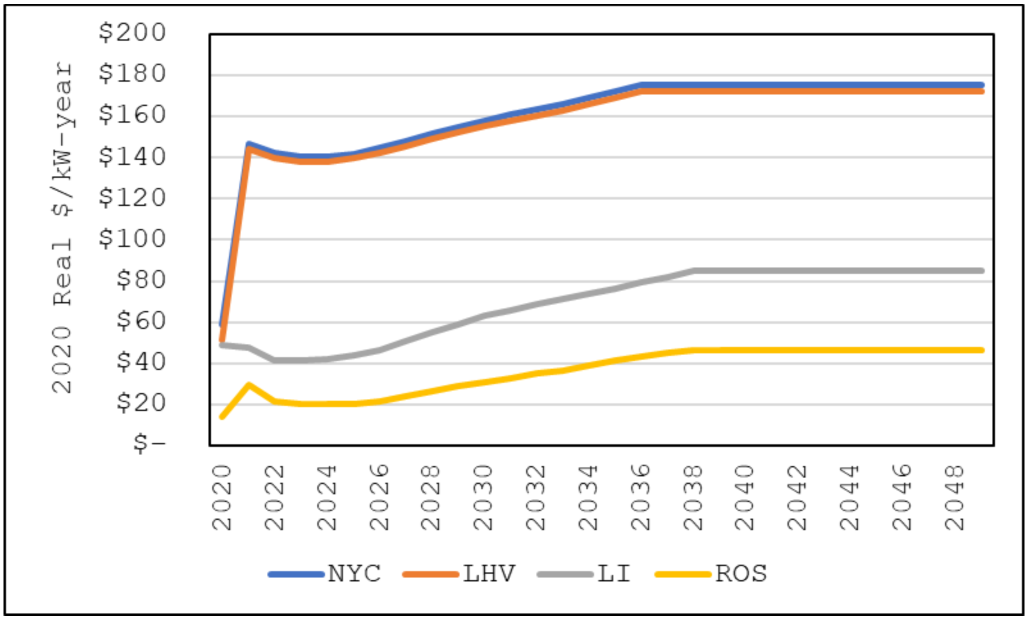


Figure 14 - Zonal Annual UCAP Price Forecasts (Real $)



For the calculation of each resource block's commodity market value, the $/kW-yr capacity price was converted to its $/MWh equivalent by multiplying by its unforced capacity percentage and dividing by the product of (capacity factor * 8,760 hours). Each Resource Block's unforced capacity percentage was projected based on an average of the summer and winter unforced capacity percentages provided in the NYISO Installed Capacity manual.[6]

An alternative scenario was developed to test the sensitivity of program costs to the unforced capacity percentages of all studied technologies. Unforced capacity percentages are determined on a project-by-project basis in accordance with NYISO procedures, which may be subject to change based on future NYISO proceedings. This "Low UCAP" scenario applies a uniform 50 percent haircut to Base Case unforced capacity percentages.

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6 http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

2.4.3 Production-Weighting Adjustment of Energy Market Values

The hourly energy market values credited to intermittent generation projects vary by time of production. Technologies that produce a greater proportion of their output during peak hours are worth more than those with a greater proportion of off-peak production. To reflect the seasonal and temporal variations while using an annual energy market price forecast, a production-time weighting adjustment approach was applied for this analysis.

2.5 Federal Incentives

Federal renewable energy tax incentive programs, including the Production Tax Credit (PTC) and the Investment Tax Credit (ITC), reduce a Resource Block's LCOE by reducing the revenue required to meet investor rates of return. The PTC represents a 10-year production incentive realized as a tax credit for each MWh of production, while the ITC represents a tax credit which is calculated as a percentage of eligible investment.

The eligibility requirements for PTC and ITC in this analysis were modeled based on the current legislation, as follows:

- For wind resources, the PTC is set to 60 percent for projects commencing construction in 2020 and is phased-out to zero percent thereafter. Wind resources are also eligible for an "ITC in lieu of PTC" option, at the project owner's discretion, which starts at the full 30% and follows the same phase-out schedule.
- For solar PV, the ITC is set at 22 percent for projects commencing construction in 2021. Thereafter, the ITC reverts to a stationary 10 percent.

The eligibility for PTC/ITC incentives is determined based on the assumed "begin construction" date of a resource block, meaning that only a fraction of the Resource Blocks studied in this analysis are eligible for these federal incentives. A project that meets the IRS requirements to "commence construction" in a particular year may earn the value of the incentives noted above for that year so long as it comes online within the timeframe allowed by law.

2.6 Financing Assumptions

A simple project finance structure, which represents a reasonable blend of alternative available renewable energy financing structures, was selected for this analysis. Additionally, while both the Fixed (O)REC and Index (O)REC structures remain available in NYSERDA's ongoing solicitations, this analysis assumed all future contracts would be awarded under an Index (O)REC procurement structure.

A federal tax rate of 21% and a state tax rate of 7.1% were applied to all technologies.

Financing costs were calculated for a "with federal tax credit" case and a "without federal tax credit" case.[7] An interpolation of the financing costs with and without (or reduced) federal incentives was performed to derive the finance cost values for years when tax credit values are phasing down.

Table 19 shows financing costs assumed in the analysis.

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[7] For solar PV, the "without federal tax credit" case reflects an Investment Tax Credit level of 10%.

Table 19 - Technology Financing Assumptions

Technology	Contract Life	Debt Term	With Federal Tax Credit			Without Federal Tax Credit		
			% Equity	Total Cost of Debt	Total Cost of Equity	% Equity	Total Cost of Debt	Total Cost of Equity
Land-based wind, 10-30 MW	20	20	45%	5%	11%	55%	6%	9%
Land-based wind, >30 MW	20	20	55%	5%	10%	65%	6%	9%
Offshore wind	25	20	50%	6%	11%	60%	6%	10%
Utility-scale solar PV	20	20	50%	6%	10%	60%	6%	8%

A number of uncertainties may impact the accuracy of the finance costs used in this analysis, including: different finance structures than the project finance approach modeled here; the accounting of any post-contract revenue; tax credit monetization; forecasts of unhedged market revenues, etc. For all resource technologies, a benchmarking and calibration exercise was used to develop multiplicative scalars to modestly adjust the financing assumptions such that weighted average modeling results align with recent NYSERDA procurement results from RESRFP19-1 and ORECRFP18-1.

2.7 Transmission and Interconnection

The cost of interconnection borne by new land-based generators is considered as part of the total CAPEX and is modeled as the sum to two components:

- Generator Lead. The first component can be thought of as the cost of the “extension cord” to plug into the existing transmission system, and all associated non-line direct costs such as building or modifying a substation. These are commonly referred to as the generator lead cost.

- Network Upgrades. The second component is the upstream non-reimbursed network upgrade costs that are determined by the NYISO (or interconnecting utility, if interconnecting to the distribution system or within a neighboring control area) and are charged to the generator through the interconnection process.

Socialized grid integration and network upgrade costs are not examined in this analysis. For new offshore wind generators, standard transmission interconnection cost assumptions are included in each project's CAPEX as discussed in Section 2.3.1.

2.7.1 Generator Lead Cost

The generator lead cost is modeled as consisting of the sum of two components: the cost of building new generator lead lines and the "non-line" cost of interconnecting that line to either an existing transmission line (via a new substation or a "line tap") or to an existing substation. A number of planned, typically smaller, utility-scale solar projects currently in the NYISO interconnection queue have proposed to use a line tap configuration, where a generator lead line would interconnect to an existing transmission line without requiring a new substation. While some larger projects have proposed a line tap, the cost impact of this lower cost solution is much more impactful for smaller projects. Therefore, as a simplification, this analysis assumed all solar PV projects smaller than 25 MW would use a line tap configuration to interconnect to a 115-150 kV line.

Assessment of generator lead costs considered five interconnection voltage ranges: 23-46 kV; 69 kV; 115-150 kV; 230 kV and 345 kV. Data sources included (i) the Black & Veatch 2014 Capital Costs for Transmission and Substations study, and (ii) the Eastern Interconnection Planning Collaborative 2012 draft report on

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios. Consultation with an interconnection engineering expert and a review of recent NYISO system impact and feasibility studies for land-based wind and solar PV projects currently in the interconnection queue were used to refine and update these national and regional data sources by aligning the data with actual experience in New York. The resulting baseline generator lead cost assumptions are shown below in Table 20.

Table 20 - Generator Lead Cost Assumptions

Voltage (kV)	Compatible Project Capacity Range (MW)	Transmission Line Cost($M/Mile)	"Non-Line" Cost ($M)		
			Interconnecting to New Substation	Interconnecting to Existing Substation	Line-Tap
23 – 46	10 – 20	$0.55	$1.28	$0.83	N/A
69	15 – 60	$0.72	$3.32	$1.33	N/A
115 – 150	20 – 150[8]	$1.59	$9.19	$2.00	$1.53
230	100 – 230	$1.73	$10.72	$3.11	N/A
345	100 – 500	$3.96	$20.93	$4.66	N/A

2.7.2 Network Upgrades

Projects can connect to the NYISO grid via either an Energy Resource Interconnection Service (ERIS) agreement, or, to access capacity market revenues, a Capacity Resource Interconnection Service (CRIS) agreement. Network upgrades may be required under each option, but in constrained areas of the grid, where additional upstream network investments are required to assure capacity deliverability, CRIS upgrades may be materially costlier.

In either case, the costs of network upgrades are site specific, not transparent, non-linear, and therefore difficult to estimate with precision. Conducting the necessary transmission studies to determine project-specific network upgrade costs is beyond the scope of this analysis.

[8] 20 – 500 for solar PV.

Project 11 from the September 2015 DPS "Comparative Evaluation of Alternating Current Transmission Upgrade Alternatives" report[9] was chosen as a proxy for developing an appropriate indicative network upgrade cost assumption for this analysis. The project was a $1.2 billion upgrade project that was estimated to bring an additional 1,000 MW of capacity to the UPNY/SENY interface. Based on this data point, a $30/kW-yr value representing a transmission upgrade with a similar cost was selected as a proxy network upgrade cost adder.

This adder was divided into two categories: a $10/kW-yr ERIS adder that was applicable to all resources; and a $20/kW-yr CRIS adder that was applied to resources interconnecting via CRIS, except resources in NYIZO zones H, I, J and K, which were assumed not to be subject to network upgrade costs. Further, the analysis assumed that network upgrade costs would not be allocated evenly to all technologies. The applicability of this CRIS adder to each technology subcategory is shown in Table 21 below.

Table 21 - Applicability of CRIS Adder

Resource Category	% of CRIS Adder Applied
Land-Based Wind < 20 MW	50%
Land-Based Wind ≥ 20 MW	100%
Utility-Scale Solar	10%

2.8 Carbon Value

Figures 15 and 16 below show the social cost of carbon (SCC) used in this study taken from EPA's Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised August 2016). This forecast is consistent

[9] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B0D8D7B2B-D671-41B8-8CCB-D8D1B9FA0A17%7D

with the PSC's January 21, 2016 Order, "Order Establishing the Benefit Cost Analysis Framework". The specific values used reflect a slight modification due to a revision from EPA. The avoided CO2 emission rate underlying the carbon value was assumed as an average marginal rate of 1,103 pounds per MWh.

The pecuniary value reflects the portion of the carbon value currently monetized in the electricity price through the Regional Greenhouse Gas Initiative (RGGI). When calculating the carbon value of deployment scenarios in this analysis, such RGGI value is excluded to avoid double counting. The RGGI value was taken from the 2019 NYISO CARIS I forecast of RGGI allowance prices (held constant in real terms after 2028).

Figure 15 - Carbon Value per MWh (Nominal $)

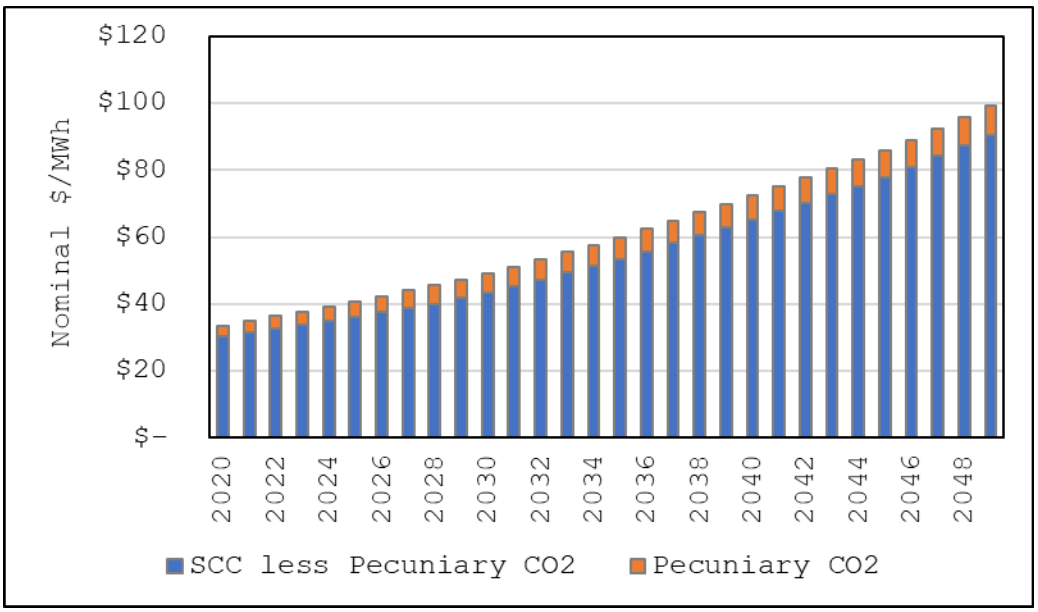
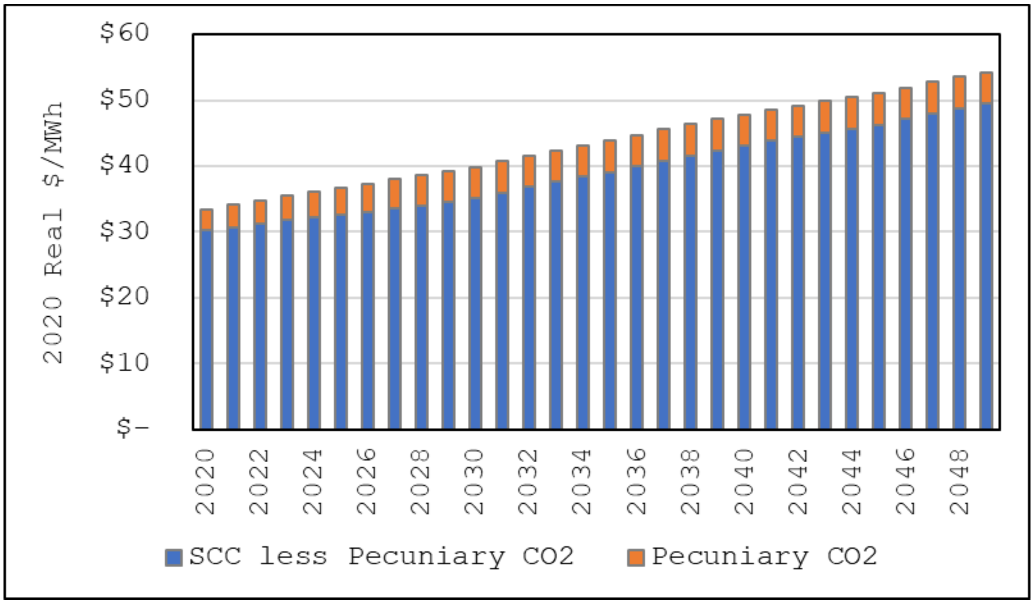


Figure 16 - Carbon Value per MWh (Real $)



3 Scenario Results

The LSR and OSW Analysis as discussed above was used to project costs and benefits of the Tier 1 and offshore wind procurement proposals set out in this White Paper.

As discussed in Section II.b of the White Paper, NYSERDA and Staff propose to use a 2030 load projection of 151,678 GWh as the basis for estimating the incremental resources to be procured in order to reach the 70 by 30 Target. Reaching the 70 by 30 Target therefore requires 106,174 GWh of annual generation from renewable energy, a volume which is supported by operational, contracted, and to-be-contracted resources as shown below in Table 22. 42,858 GWh of generation is estimated to be required to be procured under the Tier 1 and offshore wind programs incremental to baseline renewables and already-contracted projects. Analysis of cost and benefit focuses on the incremental renewable energy procurements proposed in this White Paper, namely Tier 1 and offshore wind procurements from 2021. Forthcoming procurements in 2020 (RESRFP20-1 and ORECRFP20-1) have already been considered and approved by the Commission and are therefore not reflected in this assessment.

Table 22 - Estimated 70 by 30 Target Contributions

	GWh/ year	% of 2030 Load
Baseline renewable generation	39,013	25.7%
Tier 1, constructed and contracted	8,952	5.9%
Contracted offshore wind	7,985	5.3%
NY-Sun 6 GW target by 2025	7,366	4.9%
New offshore wind procurements	17,868	11.8%
Remaining RES procurements	24,990	16.5%
Total	**106,174**	**70%**

In addition to projections of capacity and generation deployed each year to meet the above required quantities, the analysis provides the following main cost and benefit indicators:

- Program costs reflect the estimated additional payments (resource cost minus the energy and capacity value) to be made under the Tier 1 and offshore wind programs to the portfolio of deployed projects in order for such projects to be commercially viable.
- In addition, net societal benefits are presented, which are defined as the societal value of the avoided CO2 emissions (in excess of the carbon value already included in the electricity price as a result of the Regional Greenhouse Gas Initiative (RGGI)) minus the program costs. See Section 2.8 for further detail on the assumed carbon value.

Program cost and societal benefit are provided as the lifetime net present value, reflecting the program cost and value over the period until all installations have reached the end of their program payment entitlement, discounted to net present value in 2020 at a nominal 6.14% discount rate.

In addition, the ratepayer perspective is provided by examining the levelized percentage electricity bill impact of program costs. This is calculated as the net present value program cost divided by the net present value total statewide electricity bill spend over the lifetime of the projects.

Finally, the analysis provides projections of the premium amounts per MWh.

Throughout this analysis, statewide estimates are shown. The jurisdictional load-serving entities (LSEs) are expected to be responsible for approximately 73% of the total costs (commensurate with their share of statewide load).

Administrative and transactional costs both for government and market participants are not assessed in this analysis.

While the focus of this analysis is on avoided greenhouse gas emissions, which drive climate change and ocean acidification, it should be noted that the avoidance of burning traditional fuels (e.g., oil, natural gas, and coal) has additional benefits for human health, wildlife, and habitats. Burning of fossil fuels results in air pollutants that are responsible for adverse environmental and economic impacts including the degradation of lakes, streams, and forests from acid deposition; elevated levels of mercury in fish and other wildlife; and human morbidity and mortality from poor air quality related to ozone and particulate matter. These benefits are not quantified in this analysis.

Reducing emissions is particularly important for the New York City metropolitan area, which has a high population and high density of emissions sources. Concentrations of fine particulate matter (PM2.5) and ozone — two pollutants with public health impacts that include respiratory and cardiovascular disease — are higher in the New York City metropolitan area than in the rest of the State. Each year in New York City, PM2.5 at levels higher than background are estimated to be associated with more than 2,000 premature deaths, 4,800 emergency department visits for asthma, and 1,500 hospitalizations for respiratory and cardiovascular disease.[10] Reducing pollution by even modest amounts in such a highly-populated area would have significant benefits.

3.1 Tier 1 Analysis

This Section details economic and technology forecasts for Tier 1 RES resources procured through RES solicitations from 2021 through a range of five scenarios in addition to the Base Case. These five scenarios are analyzed as specific modifications of the Base Case.

- High Load Scenario: assumes approximately 9.6 TWh of incremental statewide load in 2030 relative to the Base Case, requiring close to 6.7 TWh of additional Tier 1 generation to meet the 70 by 30 Target;
- Low Energy Pricing Scenario: assumes a gradually increasing discount to the Base Case energy pricing forecast such that projected long-term prices are reduced by 25%;

10 https://archive.epa.gov/epa/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

- Low UCAP Scenario: assumes a gradually increasing discount to Base Case UCAP values for all Tier 1 resources such that long-term UCAP values are reduced by 50%;
- Low Resource Cost Scenario: assumes a gradually increasing discount to Base Case capital and operational expenses for all Tier 1 resources such that long-term LCOEs are discounted by approximately 10%; and
- High Resource Cost Scenario: assumes a gradually increasing premium to Base Case capital and operational expenses for all Tier 1 resources such that long-term LCOEs are increased by approximately 10%.

3.1.1 Summary of Tier 1 RES Key Findings

The following high-level observations are presented from the results of the LSR Analysis:

1. Across a wide range of scenarios, future Tier 1 RES procurements present a significant net benefit, with the value of energy, capacity, and avoided greenhouse gas emissions far outweighing the resource cost. In the Tier 1 Base Case Scenario, a projected program cost of approximately $1.3 billion, equating to a levelized ratepayer bill impact of 0.43%, delivers a net societal benefit after accounting for the value of avoided carbon of over $7.7 billion.
2. Uncertainty in technology cost and load forecast have less impact on projected program costs than uncertainty in energy pricing: variations in resource costs and load forecast are estimated to reduce or raise program costs by less than 40%. The Low Energy Pricing Scenario shows a more significant impact on program cost. In a scenario where

future commodity prices would be lower than assumed in the Base Case there could a more than doubling of program cost. However, even in this downside scenario, lifetime bill impacts remain at just over one percent. In addition, the impact of any increased program costs as a result of lower energy prices would be counterbalanced by the benefit ratepayers would experience from lower commodity prices in the form of lower electricity bills.

3. The scenario projections indicate that the expected levelized premium payment for each procurement year reduces over time, to the point where some projects are expected to reach the point of market parity by 2030.

3.1.2 Base Case

As noted in Table 22, the Base Case assumes that 24,990 GWh of generation from incremental Tier 1 RES procurements will be required to reach the 70 by 30 target from procurements starting in 2020. Assuming all future RES procurements are equally sized, each procurement would need to deliver 3,570 annual GWh of statewide new generation. Table 23 below shows the projected annual generation of clearing resources by technology for the procurements from 2021 assessed in this analysis.

Table 23 - Base Case, Annual Generation of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	1,734	1,181	1,036	821	627	474
New Utility-Scale Solar Generation, GWh/yr	1,836	2,389	2,534	2,749	2,943	3,096
Cumulative Tier 1 Generation, GWh/yr[11]	3,570	7,140	10,710	14,280	17,850	21,420

Table 24 below shows the projected installed capacity of each procurement's clearing resources by technology.

Table 24 - Base Case, Installed Capacity of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	543	365	316	244	183	134
New Utility-Scale Solar Capacity, MW	1,186	1,541	1,634	1,773	1,897	1,994
Cumulative Tier 1 Capacity, MW	1,729	3,635	5,585	7,602	9,681	11,809

3.1.3 High Load Scenario

The High Load Scenario assumes a 2030 statewide load of 161,324 GWh, reflective of the NYISO's 2019 Baseline forecast for 2030 with load served by behind-the-meter resource included.[12] This would represent an increase of 9,646 GWh from the Base Case, which results in demand for an incremental 6,752 GWh from future RES procurements to reach the 70 by 30 Target. Assuming all future RES procurements are equally sized, each procurement would need to deliver 4,535 annual GWh of new generation. Table 25 below shows the projected

11 Incremental to procurements before 2021.

12 https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/9ff426ab-e325-28bc-97cf-106d792593a1?t=1588251915775

annual generation of each procurement's clearing resources by technology.

Table 25 - High Load Scenario, Annual Generation of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	2,210	1,532	1,367	1,289	1,268	1,298
New Utility-Scale Solar Generation, GWh/yr	2,325	3,003	3,168	3,245	3,267	3,237
Cumulative Tier 1 Generation, GWh/yr	4,535	9,069	13,604	18,139	22,673	27,208

Table 26 below shows the projected installed capacity of each procurement's clearing resources by technology.

Table 26 - High Load Scenario, Installed Capacity of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	691	470	416	384	374	379
New Utility-Scale Solar Capacity, MW	1,503	1,938	2,044	2,093	2,105	2,084
Cumulative Tier 1 Capacity, MW	2,194	4,603	7,062	9,539	12,017	14,480

3.1.4 Low Energy Pricing Scenario

In this scenario, the Base Case energy pricing forecast (discussed in Section 2.4 of this Appendix) is gradually discounted over time such that long-term prices are discounted by 25% by the year 2028 and subsequently. Table 27 below shows the projected annual generation of each procurement's clearing resources by technology.

Table 27 - Low Energy Pricing Scenario, Annual Generation of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	1,734	1,192	1,035	821	627	539
New Utility-Scale Solar Generation, GWh/yr	1,836	2,378	2,535	2,749	2,943	3,031
Cumulative Tier 1 Generation, GWh/yr	3,570	7,140	10,710	14,280	17,850	21,420

Table 28 below shows the projected installed capacity of each procurement's clearing resources by technology.

Table 28 - Low Energy Pricing Scenario, Installed Capacity of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	542	372	314	243	182	153
New Utility-Scale Solar Capacity, MW	1,186	1,534	1,635	1,773	1,897	1,952
Cumulative Tier 1 Capacity, MW	1,728	3,634	5,583	7,598	9,677	11,782

3.1.5 Low UCAP Scenario

In this scenario, the Base Case UCAP values for all Tier 1 RES resources (see Section 2.4.2 of this Appendix) are gradually discounted over time such that long-term UCAP values are reduced by 50%. Table 29 below shows the projected annual generation of each procurement's clearing resources by technology.

Table 29 - Low UCAP Scenario, Annual Generation of Clearing Resources

Procurement Year	2021	2022	2023	2024	2025	2026
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	1,732	1,189	1,045	817	733	701
New Utility-Scale Solar Generation, GWh/yr	1,838	2,381	2,525	2,753	2,837	2,869
Cumulative Tier 1 Generation, GWh/yr	3,570	7,140	10,710	14,280	17,850	21,420

Table 30 below shows the projected installed capacity of each procurement’s clearing resources by technology.

Table 30 - Low UCAP Scenario, Installed Capacity of Clearing Resources

Procurement Year	2021	2022	2023	2024	2025	2026
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	541	360	319	243	214	201
New Utility-Scale Solar Capacity, MW	1,188	1,536	1,628	1,775	1,828	1,848
Cumulative Tier 1 Capacity, MW	1,729	3,625	5,572	7,590	9,632	11,681

3.1.6 Low Resource Cost Scenario

In this scenario, the Base Case resource cost projections for all Tier 1 RES resources are gradually discounted over time such that long-term LCOEs are discounted by approximately 10%. Table 31 below shows the projected annual generation of each procurement’s clearing resources by technology.

Table 31 - Low Resource Cost Scenario, Annual Generation of Clearing Resources

Procurement Year	2021	2022	2023	2024	2025	2026
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	1,734	1,181	1,036	821	627	474
New Utility-Scale Solar Generation, GWh/yr	1,836	2,389	2,534	2,749	2,943	3,096
Cumulative Tier 1 Generation, GWh/yr	3,570	7,140	10,710	14,280	17,850	21,420

Table 32 below shows the projected installed capacity of each procurement's clearing resources by technology.

Table 32 - Low Resource Cost Scenario, Installed Capacity of Clearing Resources

Procurement Year	2021	2022	2023	2024	2025	2026
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	543	364	316	244	183	135
New Utility-Scale Solar Capacity, MW	1,186	1,541	1,634	1,773	1,897	1,994
Cumulative Tier 1 Capacity, MW	1,729	3,634	5,584	7,600	9,680	11,809

3.1.7 High Resource Cost Scenario

In this scenario, the Base Case resource cost projections for all Tier 1 RES resources are gradually increased over time such that long-term LCOEs are at a premium of approximately 10%. Table 33 below shows the projected annual generation of each procurement's clearing resources by technology.

Table 33 - High Resource Cost Scenario, Annual Generation of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Generation, GWh/yr	1,734	1,181	1,036	821	627	587
New Utility-Scale Solar Generation, GWh/yr	1,836	2,389	2,534	2,749	4,943	2,983
Cumulative Tier 1 Generation, GWh/yr	3,570	7,140	10,710	14,280	17,850	21,420

Table 34 below shows the projected installed capacity of each procurement's clearing resources by technology.

Table 34 - High Resource Cost Scenario, Installed Capacity of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
New Land-Based Wind Capacity, MW	542	364	316	244	182	167
New Utility-Scale Solar Capacity, MW	1,186	1,541	1,634	1,773	1,897	1,921
Cumulative Tier 1 Capacity, MW	1,728	3,633	5,583	7,599	9,678	11,766

3.1.8 Cost and Benefit Scenario Results

As discussed above, cost and benefit metrics for the range of scenarios include program cost, carbon value, net societal benefit and levelized bill impact. Table 35 shows these output metrics for the scenarios examined in this analysis.

Table 35 - Lifetime Tier 1 RES Portfolio Cost and Benefit Metrics (Real 2020$)

	Lifetime Program Cost, 2020 NPV	Lifetime Avoided Carbon Value, 2020 NPV	Avoided Carbon Volume in 2030, Short Tons	Lifetime Net Societal Benefit, 2020 NPV	Lifetime Levelized Bill Impact, %
Base Case	$1.3 billion cost	$9.0 billion benefit	11.8 million	$7.7 billion benefit	0.43%
High Load Scenario	$1.9 billion cost	$11.5 billion benefit	15.0 million	$9.6 billion benefit	0.60%
Low Energy Pricing Scenario	$3.3 billion cost	$9.0 billion benefit	11.8 million	$5.7 billion benefit	1.07%
Low UCAP Scenario	$1.8 billion cost	$9.0 billion benefit	11.8 million	$7.3 billion benefit	0.57%
Low Resource Cost Scenario	$0.9 billion cost	$9.0 billion benefit	11.8 million	$8.2 billion benefit	0.27%
High Resource Cost Scenario	$1.8 billion cost	$9.0 billion benefit	11.8 million	$7.2 billion benefit	0.59%

Figures 17-19 show the annual volume and value of avoided carbon for all installations from procurements proposed in this White Paper in the Base Case and High Load Scenarios. Avoided carbon volumes and values are identical between the Base Case, Low Energy Pricing, Low UCAP, Low Resource Cost, and High Resource Cost Scenarios.

Figure 17 – Tier 1 RES Annual Avoided Carbon Volume

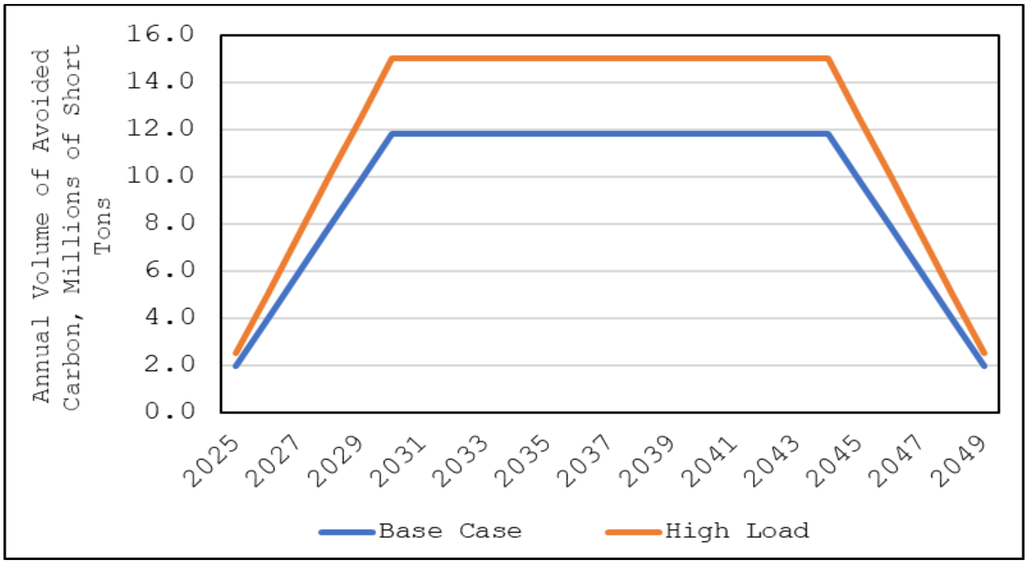


Figure 18 – Tier 1 RES Annual Avoided Carbon Value (Nominal $)

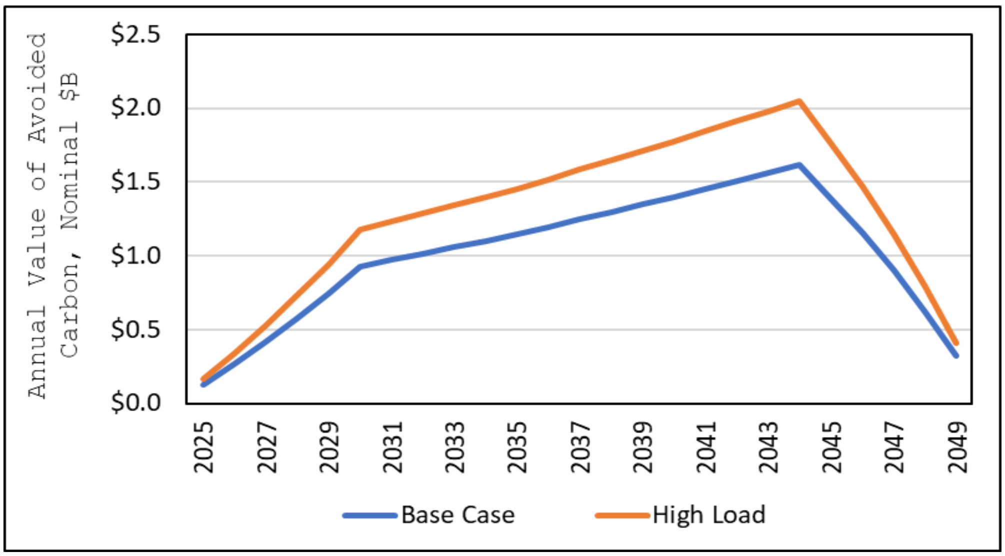
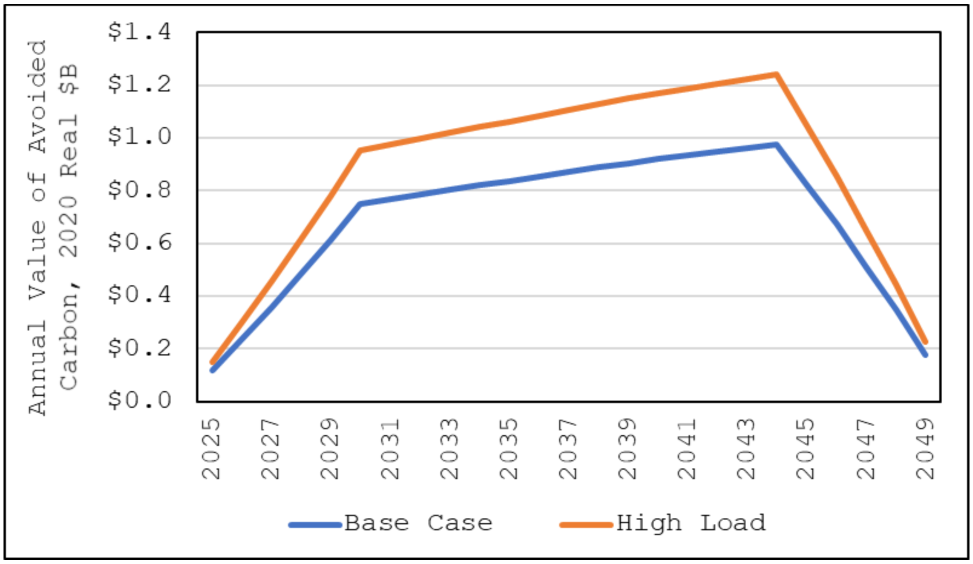


Figure 19 – Tier 1 RES Annual Avoided Carbon Value (Real $)



Additionally, procurement-specific metrics are provided to demonstrate projected changes in costs over time. Table 36 below shows the projected weighted average LCOE for each procurement's clearing resources across all scenarios. As noted in Section 2 of this Appendix, all procurements assume the Index REC procurement structure.

Table 36 - Weighted Average LCOEs of Clearing Resources (Nominal $/MWh)

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Base Case	$62.85	$67.12	$67.46	$66.67	$66.18	$65.77
High Load Scenario	$62.68	$67.63	$67.49	$66.97	$66.64	$66.29
Low Energy Pricing Scenario	$63.18	$68.29	$67.33	$66.50	$65.99	$65.36
Low UCAP Scenario	$62.80	$67.31	$67.45	$66.64	$65.83	$65.01
Low Resource Cost Scenario	$61.65	$65.22	$64.03	$62.18	$60.66	$59.31
High Resource Cost Scenario	$63.91	$69.18	$70.73	$71.01	$71.57	$71.83

Table 37 below shows the projected weighted average lifetime (20-year) REC prices for each procurement's clearing resources across all scenarios.

Table 37 - Weighted Average Lifetime REC prices of Clearing Resources (Nominal $/MWh)

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Base Case	$13.46	$13.26	$12.52	$9.94	$6.15	$2.93
High Load Scenario	$13.82	$14.33	$13.02	$9.85	$7.24	$5.04
Low Energy Pricing Scenario	$24.23	$24.57	$24.28	$23.61	$20.35	$17.27
Low UCAP Scenario	$13.92	$15.79	$15.08	$12.72	$9.25	$6.44
Low Resource Cost Scenario	$12.85	$12.17	$10.13	$5.77	$0.90	($3.51)
High Resource Cost Scenario	$14.02	$14.39	$15.53	$13.98	$11.27	$9.11

Table 38 below shows the projected weighted average year-1 REC prices for each procurement's clearing resources across all scenarios. The differences in REC premiums between tables 37 and 38 are reflective of the Index REC procurement structure and commodity price forecasts as shown in Section 2.4, with expected REC premium payments declining over the lifetime of installations as their energy and capacity revenue is projected to increase.

Table 38 - Weighted Average Year-1 REC prices of Clearing Resources (Nominal $/MWh)

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Deployment Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Base Case	$22.80	$23.89	$23.35	$20.36	$16.76	$13.71
High Load Scenario	$23.10	$24.95	$23.80	$20.08	$17.54	$15.39
Low Energy Pricing Scenario	$28.73	$31.24	$32.09	$32.23	$29.13	$26.13
Low UCAP Scenario	$21.57	$24.43	$23.90	$21.12	$17.90	$15.39
Low Resource Cost Scenario	$22.21	$22.82	$20.97	$16.19	$11.52	$7.29
High Resource Cost Scenario	$23.33	$25.02	$26.36	$24.39	$21.87	$19.77

3.2 OSW Analysis

This Section details economic and technology forecasts for offshore wind resources procured through offshore wind solicitations from 2021 through a range of scenarios in addition to the Base Case, all of which meet the requirement to develop 9 GW of offshore wind by 2035. Scenarios are analyzed as specific modifications of the Base Case.

- Low Energy Pricing Scenario: assumes a gradually increasing discount to the Base Case energy pricing forecast such that projected long-term prices are reduced by 25%;
- Low UCAP Scenario: assumes a gradually increasing discount to Base Case UCAP values such that long-term UCAP values are reduced by 50%;

- Low Resource Cost Scenario: assumes a gradually increasing discount to Base Case capital and operational expenses such that long-term LCOEs are discounted by approximately 10%; and
- High Resource Cost Scenario: assumes a gradually increasing premium to Base Case capital and operational expenses such that long-term LCOEs are increased by approximately 10%.

For each scenario, projections of the annual generation and corresponding installed capacity of procured resources as well as estimates of portfolio cost and benefits are provided.

3.2.1 Summary of OSW Key Findings

The following high-level observations are presented from the results of the LSR Analysis:

1. While offshore wind costs remain higher than those of Tier 1 resources, the value of energy, capacity, and avoided greenhouse gas emissions still significantly outweighs the resource cost across all scenarios.
    a. In the OSW Base Case Scenario, the incremental program cost to reach the 2035 9 GW goal is estimated to be close to $3.5 billion, equating to a levelized ratepayer bill impact of 1.07% and delivering a net societal benefit after accounting for the value of avoided carbon of almost $9.6 billion.
    b. The program cost of the incremental contribution of offshore wind deployments towards the 70 by 30 Target is projected as $2.7 billion or a bill impact of

0.88%, delivering a net societal benefit after accounting for the value of carbon of $4.0 billion.

2. The program cost projections indicate expected reductions of offshore wind resource cost over time in response to strong policy signals that scale the market, confirming the long-term benefits to ratepayers from market-scaling investments.
3. Uncertainty in technology cost has less impact on projected program costs than uncertainty in energy pricing: variations in resource costs and load forecast are estimated to reduce or raise program costs by less than 40%. The Low Energy Pricing Scenario shows a more significant impact on program cost. In a scenario where future commodity prices would be lower than assumed in the Base Case this could increase program cost by around 80%. However, even in this downside scenario, lifetime bill impacts remain at just over 2.1%. In addition, the impact of any increased program costs as a result of lower energy prices would be counterbalanced by the benefit ratepayers would experience from lower commodity prices in the form of lower electricity bills.
4. The scenario projections indicate that the expected levelized premium payment for each procurement year reduces over time, to the point where projects approach the point of market parity in the mid-2030s.

3.2.2 Capacity and Generation

As noted in Table 22, the analysis assumes a contribution of 17,868 GWh of generation from incremental OSWS procurements towards the 70 by 30 target. Procurements are assumed to target at least around 1,000 MW each to reflect the likely scale of offshore wind projects. Accordingly, roughly equal annual procurements delivering over 4,500 GWh each are assumed in the analysis, with a single one-year procurement pause (assumed in 2024) to emphasize the distinction between offshore wind procurements expected to contribute to the 70 by 30 target (those occurring prior to 2024) and subsequent procurements needed to deliver the 2035 9 GW target. The resulting capacity and generation are shown in Tables 39 and 40 below. Annual generation figures differ slightly between procurements reflecting the specific characteristics of each offshore wind site. The generation and capacity projections shown below apply across each of the offshore wind scenarios.

Table 39 - Base Case, Annual Generation of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Deployment Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Offshore Wind Generation, GWh/yr	4,661	4,273	4,561	-	4,717	4,732	4,747
Cumulative Offshore Wind Generation, GWh/yr[13]	4,661	8,934	13,495	13,495	18,212	22,945	27,692

Table 40 - Base Case, Installed Capacity of Clearing Resources

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Deployment Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
New Offshore Wind Capacity, MW	1,000	1,000	1,000	-	1,058	1,058	1,058
Cumulative Offshore Wind Capacity, MW[14]	1,000	2,000	3,000	3,000	4,058	5,116	6,174

13 Incremental to procurements before 2021.

14 Incremental to procurements before 2021.

3.2.3 Cost and Benefit Results

As discussed above, cost and benefit metrics for the range of scenarios include program cost, carbon value, net societal benefit and levelized bill impact. Table 41 below details these portfolio cost and benefit metrics across all scenarios for project installations through 2030 (thus showing resources that are eligible to support the 70 by 30 Target), while Table 42 extends the projection to cover project installations through 2035.

Table 41 - Lifetime Offshore Wind Portfolio Cost and Benefit Metrics for Installations through 2030 (Real 2020$)

	Lifetime Program Cost, 2020 NPV	Lifetime Avoided Carbon Value, 2020 NPV	Avoided Carbon Volume in 2030, Short Tons	Lifetime Net Societal Benefit, 2020 NPV	Lifetime Levelized Bill Impact, %
Base Case	$2.7 billion cost	$6.7 billion benefit	7.4 million	$4.0 billion benefit	0.88%
Low Energy Pricing Scenario	$4.5 billion cost	$6.7 billion benefit	7.4 million	$2.2 billion benefit	1.48%
Low UCAP Scenario	$3.0 billion cost	$6.7 billion benefit	7.4 million	$3.7 billion benefit	1.00%
Low Resource Cost Scenario	$2.0 billion cost	$6.7 billion benefit	7.4 million	$4.7 billion benefit	0.66%
High Resource Cost Scenario	$3.3 billion cost	$6.7 billion benefit	7.4 million	$3.4 billion benefit	1.10%

Table 42 - Lifetime Offshore Wind Portfolio Cost and Benefit Metrics for Installations through 2035 (Real 2020$)

	Lifetime Program Cost, 2020 NPV	Lifetime Avoided Carbon Value, 2020 NPV	Avoided Carbon Volume in 2035, Short Tons	Lifetime Net Societal Benefit, 2020 NPV	Lifetime Levelized Bill Impact, %
Base Case	$3.5 billion cost	$13.1 billion benefit	15.3 million	$9.6 billion benefit	1.07%
Low Energy Pricing Scenario	$6.9 billion cost	$13.1 billion benefit	15.3 million	$6.2 billion benefit	2.12%
Low UCAP Scenario	$4.4 billion cost	$13.1 billion benefit	15.3 million	$8.7 billion benefit	1.35%
Low Resource Cost Scenario	$2.0 billion cost	$13.1 billion benefit	15.3 million	$11.1 billion benefit	0.61%
High Resource Cost Scenario	$5.0 billion cost	$13.1 billion benefit	15.3 million	$8.1 billion benefit	1.53%

Figures 20-22 show the annual volume and value of avoided carbon for all installations from procurements proposed in this White Paper deployed through 2035. Avoided carbon volumes and values are identical across the range of scenarios.

Figure 20 – Offshore Wind Annual Avoided Carbon Volume

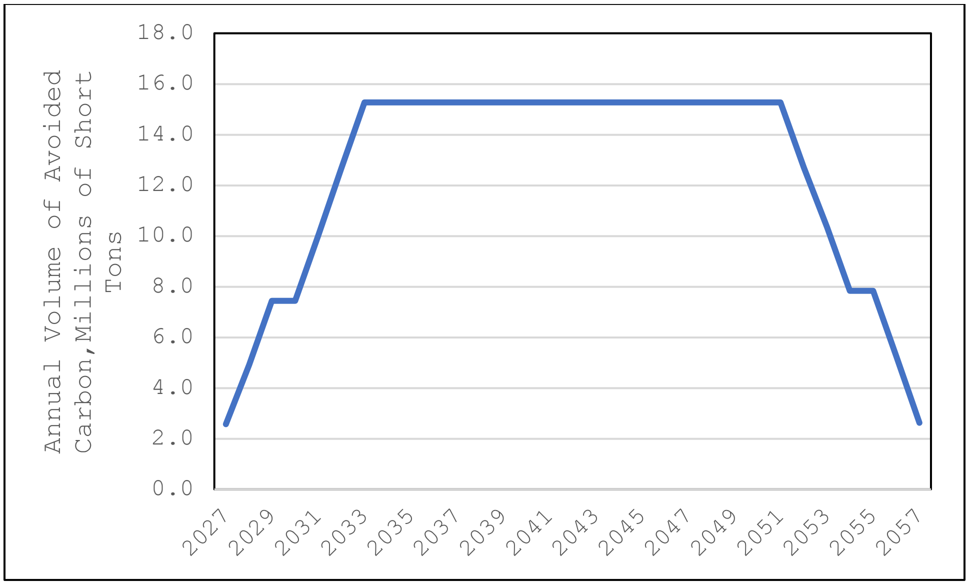


Figure 21 – Offshore Wind Annual Avoided Carbon Value (Nominal $)

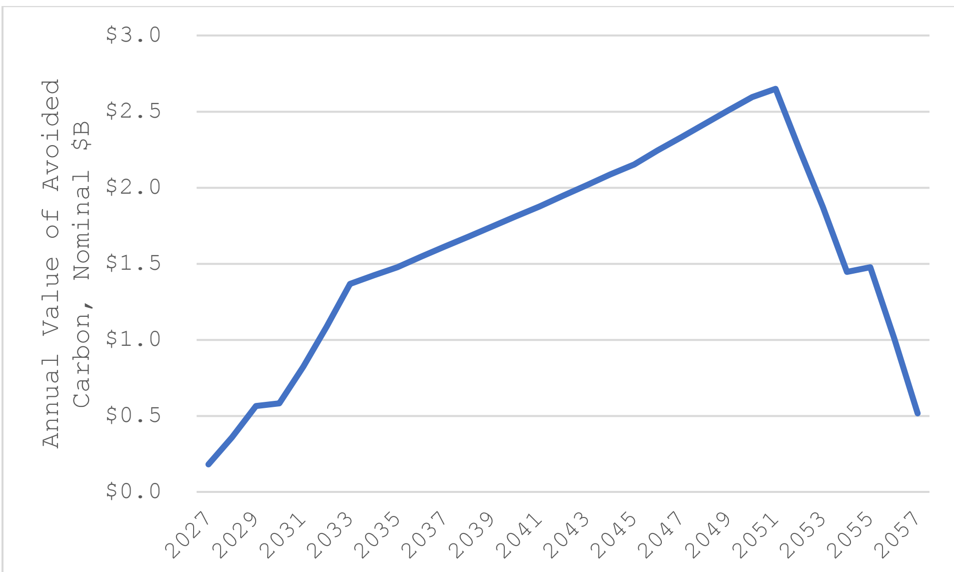
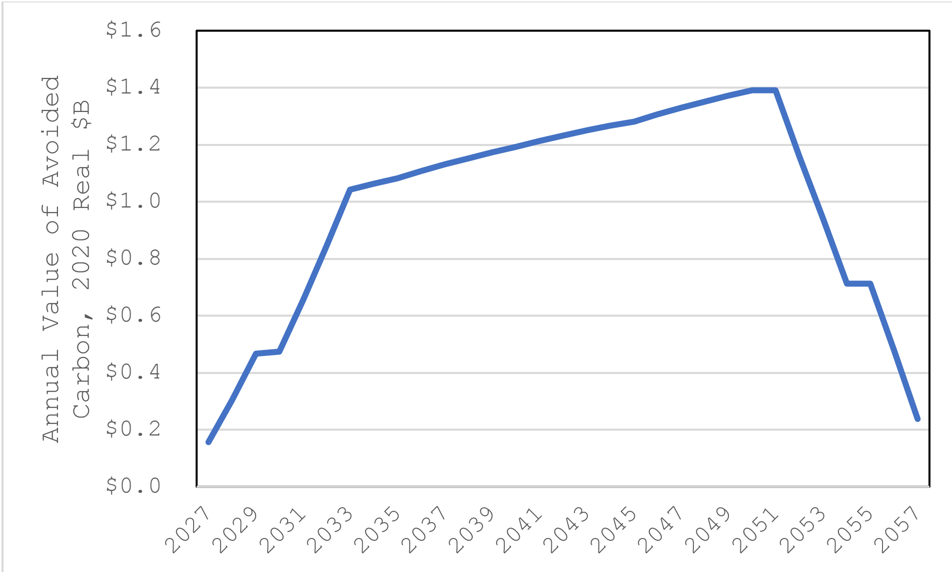


Figure 22 – Offshore Wind Annual Avoided Carbon Value (Real $)



Additionally, procurement-specific metrics are provided to demonstrate projected declining costs over time. Table 43 below shows the projected weighted average LCOE for each procurement's clearing resources across all scenarios.

Table 43 - Weighted Average LCOEs of Clearing Resources (Nominal $/MWh)

Procurement Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Deployment Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Base Case	$97.50	$103.44	$89.23	-	$90.19	$89.29	$89.72
Low Energy Pricing Scenario	$97.50	$103.44	$89.23	-	$90.19	$89.29	$89.72
Low UCAP Scenario	$97.50	$103.44	$89.23	-	$90.19	$89.29	$89.72
Low Resource Cost Scenario	$93.04	$96.71	$82.44	-	$81.38	$80.36	$80.75
High Resource Cost Scenario	$101.96	$110.16	$96.02	-	$99.01	$98.21	$98.70

Table 44 below shows the projected weighted average lifetime (25-year) OREC prices for each procurement's clearing resources across all scenarios.

Table 44 - Weighted Average Lifetime OREC prices of Clearing Resources (Nominal $/MWh)

Procurement Year	2021	2022	2023	2024	2025	2026	2027
Deployment Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Base Case	$28.70	$27.48	$17.06	-	$14.90	$7.37	$6.13
Low Energy Pricing Scenario	$44.25	$42.92	$33.45	-	$32.02	$24.21	$23.33
Low UCAP Scenario	$30.32	$32.71	$20.01	-	$18.31	$14.67	$13.54
Low Resource Cost Scenario	$24.24	$20.75	$10.27	-	$6.08	($1.56)	($2.84)
High Resource Cost Scenario	$33.17	$34.20	$23.85	-	$23.72	$16.30	$15.10

Table 45 below shows the projected weighted average year-1 OREC prices for each procurement's clearing resources across all scenarios and sensitivities. The differences in REC premiums between tables 37 and 38 are reflective of the Index OREC procurement structure and commodity price forecasts as shown in Section 2.4, with expected OREC premium payments declining over the lifetime of installations as their energy and capacity revenue is projected to increase.

Table 45 - Weighted Average Year-1 OREC prices of Clearing Resources (Nominal $)

Procurement Year	2021	2022	2023	2024	2025	2026	2027
Deployment Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Base Case	$42.49	$39.87	$29.93	-	$28.19	$20.90	$20.00
Low Energy Pricing Scenario	$53.82	$52.72	$43.55	-	$42.39	$34.86	$34.25
Low UCAP Scenario	$43.58	$44.37	$32.08	-	$30.79	$27.18	$26.36
Low Resource Cost Scenario	$38.03	$33.15	$23.14	-	$19.37	$11.97	$11.03
High Resource Cost Scenario	$46.96	$46.60	$36.72	-	$37.01	$29.83	$28.97