



Offshore Wind Policy Options Paper

Submitted by

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Executive Summary

In this Offshore Wind Policy Options Paper (Options Paper), NYSERDA provides an assessment of alternatives for addressing a wide range of policy issues pertinent to the successful deployment of offshore wind energy within the context of Governor Cuomo's goal of obtaining 50 percent of New York's electricity from renewable sources by 2030 (50 by 30 target). This Options Paper forms part of New York's Offshore Wind Master Plan (Master Plan), published concurrently.¹

Background. NYSERDA's development of the Master Plan was announced by Governor Cuomo in his 2016 State of the State address. In the Master Plan, NYSERDA (i) provides a roadmap for the cost-effective and responsible development of offshore wind projects (ii) includes proposals for the best possible sites for development, (iii) suggests guidelines for developers, and (iv) provides options regarding the purchase of offshore wind energy to ensure lowest costs to ratepayers.

Governor Cuomo issued a further directive in his 2017 State of the State address, announcing a commitment to support the development of up to 2.4 gigawatts (GW) of offshore wind energy. In his 2018 State of the State address, the Governor proposed to procure at least 800 megawatts (MW) of offshore wind generation over the next two years as the initial step towards achieving the 2.4 GW goal.

As the State drives toward the Governor's 2.4 GW goal of offshore wind deployment, it will be necessary to provide clear market direction with respect to: (i) procurement and contracting, including hedging approaches and cost-containment provisions; (ii) coordination with New York's Renewable Energy Standard (RES); (iii) transmission and interconnection (T&I); (iv) responsible identification of new Wind Energy Areas (WEAs); and (v) support of offshore wind related workforce, supply chain, and infrastructure opportunities. In this Options Paper, NYSERDA addresses the first three of these five components. NYSERDA addresses the other components listed above – such as identification of new WEAs, workforce development, supply and infrastructure opportunities, and related issues – in the Master Plan.

Benefits and Costs Associated with Bringing Offshore Wind to New York. Development of offshore wind in New York will provide a range of benefits, including economic growth, job creation, public health improvements and greenhouse gas (GHG) emission reductions. Achieving the State's 2.4 GW offshore wind goal would reduce carbon emissions in New York by more than 5 million short tons of CO₂e by 2030, which would comprise a significant portion of the 50 by 30 target. These GHG-reduction benefits, estimated in this Options Paper at around \$1.9B (net present value), are approximately equal to estimated program costs for the most cost-effective procurement options. This indicates that the carbon reduction benefits alone could justify the costs of the State's commitment to 2.4 GW of offshore wind, even before accounting for other anticipated benefits.

Deployment of a new source of renewable energy in close proximity to load centers in New York City and Long Island provides a host of additional non-carbon benefits, including diversification of our energy supply, and a generation profile that is more closely matched to peak demand than other renewable resources. Offshore wind development will also result in considerable economic development and health benefits for New Yorkers. On the basis of NYSERDA's initial screening analysis carried out for the

¹ See <https://nyserdera.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan>

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Master Plan, the public health benefits of 2.4 GW of installed offshore wind are estimated at approximately \$1.0B (net present value). Additionally, nearly 5,000 new New York jobs could be created from New York and regional offshore wind deployment, from construction, manufacturing and operations jobs to engineers and investors, many of which are in sectors that deliver long-term local economic benefits through the operating life of the wind farms. Such benefits are discussed in the Workforce Opportunity of Offshore Wind in New York report, which is published as part of the Master Plan.

A quickly-declining cost trend of offshore wind is also an essential aspect of the benefit-cost assessment in this Options Paper. In Europe, offshore wind development costs have decreased dramatically in recent years; in many cases offshore wind is cost-competitive with land-based renewables. The cost reductions seen in Europe depended to a material extent on local learning and local infrastructure development resulting from economies of scale. With achievement of the 2.4 GW goal contributing to similar scale economies in the U.S. Northeast, NYSERDA projects that by 2030 the cost to procure offshore wind will be lower than the cost of Tier 1 Renewable Energy Credits (RECs) associated with other large-scale renewable technologies.

Proposal to Develop the 2.4 GW Commitment in Two Phases. In addition to the cost challenge associated with early-stage offshore wind deployment in the U.S., the sector faces several other near-term challenges. Development lead times are longer than those of other types of renewables projects, and the federal government's offshore wind energy area leasing activity has limited the number of developers initially eligible to compete.

Therefore, in this Options Paper NYSERDA proposes that initial policy decisions will be made for a "Phase I" of offshore wind procurement and deployment. In line with the Governor's announcement at his 2018 State of the State address, this would be comprised of two initial annual offshore wind procurement rounds of at least 400 MW each in 2018 and 2019. NYSERDA expects that policy options for future procurements would be reviewed and adjusted as appropriate.

NYSERDA also concludes from the aforementioned offshore wind challenges that New York's offshore wind procurement should proceed on the basis of a competitive procurement mechanism which seeks only offshore wind proposals, with commensurate volumetric load-serving entity (LSE) obligations, ramping up to the goal of 2.4 GW by 2030.

Procurement Options. To aid the Public Service Commission (Commission or PSC) with its decision-making, NYSERDA has assessed a full range of procurement options that can be utilized to deliver the 2.4 GW offshore wind target and kick-start the North American offshore wind industry. NYSERDA's cost analysis carried out in support of this Options Paper demonstrates that the choice of procurement approach for offshore wind deployment has a critical impact on the resulting cost. Key differentiating factors between procurement options are the extent to which hedging benefits are provided against risks of commodity revenue uncertainty, and the level of involvement of NYSERDA and other organizations, such as utilities.

- **Procurement Option 1 – Fixed REC:** NYSERDA's past large-scale renewables (LSR) procurement auctions under the Renewable Portfolio Standard (RPS) Main Tier, and current procurements under Tier 1 of the RES, employ a structure that provides a limited revenue hedge. Under this

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approach, winning LSR projects receive a fixed, as-bid REC price throughout the contract lifetime, but no hedge is provided against changes in commodity electricity (energy and/or capacity) prices, so the risks and rewards of fluctuations in the energy and capacity markets remain with the project developer. This elevated risk to the developer leads to increased cost of capital and thus higher projected program costs than those expected under other procurement options with more far-reaching hedging benefits.

- **Procurement Option 2 – Bundled PPA:** This procurement structure provides a hedge against commodity electricity price risk, and thus could unlock significant reductions in project cost of finance. Under this approach, one or more utilities would competitively procure offshore wind projects and make an all-in, fully-hedged revenue stream for commodity value and RECs available to winning projects.
- **Procurement Option 3 – Utility-Owned Generation (UOG):** Like the Bundled PPA option, this option would involve competitive procurement by one or more utilities. Offshore wind developers would develop, design, build, and potentially operate offshore wind facilities; and once completed, project ownership would be transferred to the utility or utilities. UOG represents an alternative form of hedged procurement that would benefit from the low costs of capital that would be available through rate-basing utility investments.
- **Procurement Option 4 – Split PPA:** This option pairs NYSERDA fixed-price REC procurement (as under Option 1) with fixed-price commodity energy and capacity procurement by a utility. From a developer's perspective, this option would be similar to the Bundled PPA option in its hedging benefit, effectively providing a fully-hedged product consisting of a fixed commodity and a fixed REC-price component. However, from the perspective of the State's ratepayers, the effective cost premium associated with the REC-price component would depend on the level of the fixed commodity value compensation offered by the utility.
- **Procurement Option 5 – Market OREC:** Unlike the Bundled PPA, UOG and Split PPA options, the Market OREC structure would provide commodity hedging benefits without necessitating utility involvement. Under this option, NYSERDA would provide a premium payment to projects based on the net difference, from time to time, between the project's winning bid price (expressed as an all-in revenue amount) and the actual revenue the project was able to achieve from its commodity sales (whether in the regulated wholesale markets or through other transactions). While this would deliver a perfect commodity hedge, jurisdictional concerns may arise regarding the link to the project's actual commodity sales transactions; in addition, this approach could result in a potential disincentive to project operators to maximize their sales revenue.
- **Procurement Option 6 – Index OREC:** Under this option, NYSERDA would provide a premium payment to projects under an offshore wind REC contract based on the net difference, from time to time, between the project's winning bid price (expressed as an all-in revenue amount) and the average commodity market price as expressed in a market index or composite of indices, whether the project sold its commodities into the regulated wholesale markets or not. While this option provides most of the hedging benefits of alternative fully-hedged options discussed above, this structure would address jurisdictional concerns by avoiding a link between

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premium payments and the project's actual commodity sales. This option would also provide the advantage of incentivizing generators to maximize the commodity sales value of offshore wind energy.

- **Procurement Option 7 – Forward OREC:** Like New York's Zero-Emissions Credit (ZEC) program, this option would provide a payment to winning projects that would adjust every two years. Unlike the ZEC structure, however, this approach would allow for both upward and downward adjustment of payments: the offshore wind REC premium level of each two-year period would be calculated prior to the beginning of the tranche according to two-year energy and capacity price forecasts or forward indices, and would remain fixed for the duration of the tranche. This option would aim to provide long-term hedging benefits for the lifetime of projects by leveraging shorter-term (two-year) hedging products to bridge the period between REC premium level adjustments; accordingly, its success in unlocking the cost benefits of a hedged procurement structure depends on funders' confidence in the availability of two-year hedging products in the market for the duration of the asset life.

Procurement Options Assessment. NYSERDA's assessment of the procurement options has compared Options 2-7 to the current Fixed REC procurement method used under the Tier 1 of the RES (Option 1). Options 2-7 all have the potential (subject to certain dependencies for some of the options) to result in significant program cost savings, with estimated Phase I incremental program costs above those of Tier 1 of the RES for these options ranging from no incremental costs to \$0.4B (corresponding with a bill impact of up to 0.26%).

However, a number of these options are subject to significant dependencies and uncertainties. The Bundled PPA, UOG and Split PPA options all depend on utility willingness to adopt a leading role in procurement of offshore wind projects. In addition, under the Split PPA approach, program cost savings compared to Fixed REC procurement depend on the price level which the utility would be prepared to guarantee for the purchase of energy and capacity value over the asset lifetime; a potential price range could include low valuation levels for energy and capacity such that cost savings compared to Fixed REC might not materialize. The Market OREC option is subject to jurisdictional risks. The viability of the Forward OREC option as a low-cost procurement option depends on funder confidence that two-year forward hedging products for energy and capacity would be available in the market through the lifetime of offshore wind assets.

On balance, NYSERDA concludes from the analysis described in this Options Paper that the following options for offshore wind procurement in New York during Phase I do not offer a similar level of benefits as the other five potential approaches:

- Fixed REC, due to the relatively high projected costs; and
- Market OREC, unless jurisdictional uncertainties can be addressed.

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NYSERDA recommends that the Public Service Commission (Commission) should focus attention for its Phase I decision on one or more of the remaining options, and should base its decision on the following considerations:

- The Split PPA option should be carefully evaluated for feasibility, due to the limited scale of deployment, implementation complexities and uncertainties around effective costs to ratepayers.
- Although the Commission has previously declined to advance a UOG option for land-based renewables, there may be a limited role for this structure to reflect the specific early development challenges of the U.S. offshore wind sector.
- The Forward OREC would need validation of feasibility from market participants, due to its novel nature and uncertainty on funders' assessment of this structure and resulting costs of finance.
- Options that depend on utility participation (Bundled PPA, Split PPA and UOG) should only be adopted as the sole procurement option for one or more procurement rounds if and when critical uncertainties would have been resolved either through a Commission Order or through firm commitments from the utility or utilities in question, in particular on the scale of the utility's commitment and, in the case of Split PPA, the level of the fixed long-term energy and capacity prices the utility would be prepared to offer.
- Any of the utility-led options could potentially be included as alternative bid options in a solicitation by utilities, which would allow for direct comparison of benefits and risks associated with each option.
- In the absence of firm utility commitments, these options could still be progressed in parallel with another procurement option, such as Index OREC.

Procurement Schedule, Evaluation and Contract Terms. In this Options Paper, NYSERDA assesses a base case Phase I procurement schedule with 400 MW solicitations in 2018 and 2019. NYSERDA believes this commitment will drive market interest and cost savings but also reflects what can reasonably be delivered within those timeframes given near-term supply chain constraints. Contracts to be entered into with winning bidders would ultimately be structured similarly to RES Tier 1 contracts; NYSERDA recommends the following approach to adapt contracts to the specific circumstances of offshore wind:

- Building on the current approach of a contract tenor of up to 20 years used in the RES Tier 1 program, bidders could be allowed to propose terms up to 25 years, to reflect the expected offshore wind asset life.
- Contracts could require generators to deliver the committed proportion of offshore wind RECs for the lifetime of the project, to ensure that New York ratepayers receive the full benefits over the project's lifetime in return for their investment.

In addition, procurement and evaluation terms and conditions as currently used in RES Tier 1 solicitations would need to be adapted to offshore wind project development schedules and complexities. Evaluation criteria could be customized to offshore wind through the use of both price and

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non-price categories. The Commission may also consider whether additional siting standards would need to be met. NYSERDA and other State agencies, through the execution of the Master Plan, are developing siting standards for offshore wind projects in Federal waters. Standards may include but not be limited to a minimum distance from shore to address potential visibility concerns or the application of best management practices to address environmental or commercial activity concerns.

Cost Containment. To minimize program costs to ratepayers, NYSERDA recommends considering options both to maximize competition between projects, which will drive costs down, and to mitigate the potential impacts of limited competition, which nevertheless will likely remain a feature of Phase I because of limited federal wind energy lease areas. With a view to maximizing competition, NYSERDA assumes that bids from projects offshore regional states will be eligible for New York procurement (subject to the delivery of the energy to New York per an overarching requirement such as under the RES). Cost containment opportunities include setting a maximum bid price, minimum price reduction benchmarks for future solicitations, and/or conducting open-book vetting of bidders' costs against a set rate of return. In each case benchmarks could be informed by offshore wind price projections and actual prices observed in other Northeast states.

Coordination with the RES Tier 1 Procurement Targets. In addressing the coordination between offshore wind procurement and the RES Tier 1 procurement targets, NYSERDA recommends that as regards procurement during Phase I either offshore wind procurement quantities would be set as separately from the RES Tier 1 procurement targets, or that the aggregate of the RES Tier 1 procurement and offshore wind procurement volumes would be increased. The resulting increased total procurement from Tier 1 and offshore wind projects during Phase I could be reflected in the evaluation of subsequent Tier 1 procurement targets during the next review. Such measures would avoid market uncertainty in the land-based renewable electricity sector during years in which offshore wind procurement would exhaust much or all of the Tier 1 procurement targets if counted toward these established targets.

Funding through LSE Obligation. NYSERDA assumes that offshore wind funding would be provided by a compliance obligation placed on LSEs, subject to the Commission's jurisdiction, together with voluntary compliance by the Long Island Power Authority and New York Power Authority, to reach a statewide policy – similar to the approach under the RES Tier 1. The obligation could be structured as a market-type obligation as in the RES Tier 1 or as a more administrative allocation structure as in the ZEC program. At least for Phase I, given the nascent nature of the offshore wind sector, NYSERDA recommends that a standalone obligation similar to the ZEC requirement would be most suitable. Alternatively, the offshore wind compliance obligation could be integrated into the existing RES Tier 1 LSE obligation, potentially in the form of a "REC multiplier" for offshore wind RECs that would account for cost premium differences between offshore wind and other Tier 1 technologies. Such integration, with or without multipliers, however, may expose the ultimate procurement entity to REC payment recovery risk and significant implementation complexities and is therefore less suitable than a standalone obligation.

Transmission and Interconnection (T&I). As a result of the limited number of developers and lease sites in the near-term, NYSERDA limits its assessment of Phase I T&I procurement options to "direct radial" T&I structures. In such structures, T&I is procured to meet the needs of the specific offshore wind project in question. NYSERDA expects that T&I procurement options would be expanded during Phase II

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as the pool of lease sites expands to include evaluation of the feasibility of a T&I “backbone” that could serve additional future projects. NYSERDA has considered the following T&I procurement options:

- **T&I Option 1 – Developer Owned:** A single solicitation process would be used to procure both generation and T&I assets. The winning bidder would own and operate both.
- **T&I Option 2 – Independently Owned:** The offshore wind generation facility and the T&I infrastructure would each be procured separately. The winning bidders of the generation and T&I procurement processes – which could but would not necessarily be the same entity – would own and operate the assets in question.
- **T&I Option 3 – Regulated Asset:** The T&I assets would be owned and operated as regulated assets, with the intention to leverage the potentially lower cost of finance associated with rate-based assets.

NYSERDA believes that T&I Option 1 provides the most easily-implementable and feasible option for Phase I of offshore wind development in New York. While T&I Option 3 (Regulated Asset) could unlock moderate cost benefits through lower cost of finance, those potential benefits must be weighed against significant implementation challenges, including around the scoping of offshore wind T&I projects to ensure eligibility as regulated assets, potentially cumbersome and untested procurement processes and issues related to construction timing risk and energy delivery risk. NYSERDA recognizes that T&I Option 2 (Independently Owned), though untested, could also be suitable for Phase I.

NYSERDA expects Phase I procurement to proceed on the basis of direct radial T&I infrastructure, but notes that under all three options T&I projects could be scoped as network projects to serve multiple offshore wind projects, should this be considered preferable.

Next Steps. Based on NYSERDA’s consultation with Department of Public Service (DPS) Staff, NYSERDA expects that following the filing of this Options Paper, DPS will issue a notice in the New York State Register in accord with the provisions of the State Administrative Procedures Act (SAPA). This notice will commence a public notice and comment rulemaking process by which the Commission may consider certain actions described by NYSERDA in this submission. The notice will, among other things, present a framework for and solicit comments about decisions that the Commission may make to implement any decisions related to Phase I procurement as discussed in this Options Paper. The rulemaking will provide for at least a 60-day public comment period.

NYSERDA also understands that the actions it requests will necessitate the Commission’s consideration of a Generic Environmental Impact Statement (GEIS). A draft GEIS will be presented by DPS Staff to the Commission and once accepted by the Commission will be made available for public comment. The Commission will thereafter consider the public comments to the draft GEIS prior to taking actions described in this Options Paper. The GEIS will address factors relevant to consideration of the associated environmental impacts including project size and the range of potential sites to be developed as well as relevant other considerations related to the contents of the Master Plan and its appended studies. In considering the potential environmental impacts of the development of offshore wind it is important to note that the distinctions among the options presented in this Options Paper are financial and contractual in nature. Such distinctions do not relate to the physical parameters or operating characteristics of the projects that ultimately will be deployed and thus do not imply any differences to

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the carbon benefit or other environmental benefits and impacts resulting from the projects to be deployed under an eventual Order.

NYSERDA looks forward to working with DPS staff and other interested parties as this process progresses.

1 Introduction and Objectives

1.1 Organization of this Options Paper

This Options Paper lays out the full range of potentially viable options for New York’s offshore wind procurement and contracting, and provides analysis of the cost implications of the key structural options. Section 2 describes offshore wind project eligibility consideration for (i) meeting load-serving entity (LSE) offshore wind compliance obligations and (ii) participating in a procurement for offshore wind. Section 3 lays out offshore wind procurement and contracting options. Section 4 discusses funding offshore wind through an LSE compliance obligation. Transmission and interconnection issues and options are presented in Section 5. Finally, Section 6 summarizes the cost analysis of procurement and contracting options, as well as sensitivity analyses exploring variations in project size procured and transmission ownership alternatives.

1.2 Introduction

1.2.1 New York Renewable Energy and Offshore Wind Policy Context

On August 1, 2016, the Commission issued an Order Adopting a Clean Energy Standard (CES) (CES Order), which mandated LSEs’ compliance with the Governor’s 50 percent renewables by 2030 goal.² The Commission structured the RES “Tier 1” component of the CES as an LSE obligation to procure a specified quantity of eligible renewable energy credits (RECs). Under the Order, NYSERDA procures compliance-eligible RECs through competitive solicitations for long-term agreements with eligible generators. NYSERDA’s purchases of eligible RECs both support the financing of renewable energy projects, and also provide it with RECs to resell for ultimate retirement by LSEs.

While offshore wind is an RES-eligible technology, the CES Order did not put in place any specific provisions. Instead, the Commission asked NYSERDA to identify mechanisms for doing so. The Commission stated:

“New York is fortunate to have substantial potential for offshore wind production and with appropriate time, careful planning and deliberate action, the State has the opportunity to exploit its geographic advantage to develop offshore wind and promote the beneficial attendant economic activity associated with this burgeoning industry. In order to maximize the potential for offshore wind, in addition to the actions taken in this Order, the Commission is requesting NYSERDA to identify the appropriate mechanisms the Commission and the State may wish to consider to achieve this objective.”³

² Case 15-E-0302, Proceeding to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting A Clean Energy Standard (issued August 1, 2016).

³ CES Order at p. 18.

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The CES Order indicated that the “appropriate next step (...) is to await NYSERDA’s study and request that NYSERDA include in its analysis recommendations on the best solutions for maximizing the potential for offshore wind in New York.”⁴

Governor Cuomo announced in his 2016 State of the State address the development by NYSERDA of a New York Offshore Wind Master Plan (Master Plan), the purpose of which is to provide a comprehensive State roadmap for advancing development of offshore wind in a cost-effective and responsible manner.⁵

In his 2017 State of the State, Governor Cuomo announced a 2.4 gigawatt (GW) goal of offshore wind power for New York by 2030, which would result in enough power generation for up to 1.2 million homes and the largest commitment in U.S. history.⁶ As part of this commitment, he called on the Long Island Power Authority (LIPA) to approve a contract to purchase the output of the 90 megawatt (MW) Deepwater Wind South Fork project, as New York State’s first offshore wind project.⁷

At the 2018 State of the State address, the Governor proposed to issue solicitations in 2018 and 2019 to develop at least 800 MW of offshore wind projects as an initial step towards delivering the 2.4 GW goal.⁸

The Master Plan is published concurrently with this Offshore Wind Policy Options paper (Options Paper), and this Options Paper forms part of it.⁹

As part of the Master Plan development process, NYSERDA has conducted more than 20 studies and surveys and reached out to residents of Long Island, New York City, and other interested stakeholder groups to provide feedback. The Master Plan study area encompasses a 16,740 square-mile area of the ocean from the south shore of Long Island and New York City to the continental shelf break which was examined for potential future offshore wind development (see Figure 1).

⁴ CES Order at p. 103.

⁵ Cuomo, Andrew M. 2016. *Built to Lead: 2016 State of the State*, New York State, https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2016_State_of_the_State_Book.pdf, at p. 80.

⁶ Cuomo, Andrew M. 2017. “Governor Cuomo Presents 25th Proposal of 2017 State of the State: Nation's Largest Offshore Wind Energy Project Off Long Island Coast and Unprecedented Commitment to Develop up to 2.4 Gigawatts of Offshore Wind Power by 2030.”. <https://www.governor.ny.gov/news/governor-cuomo-presents-25th-proposal-2017-state-state-nations-largest-offshore-wind-energy>

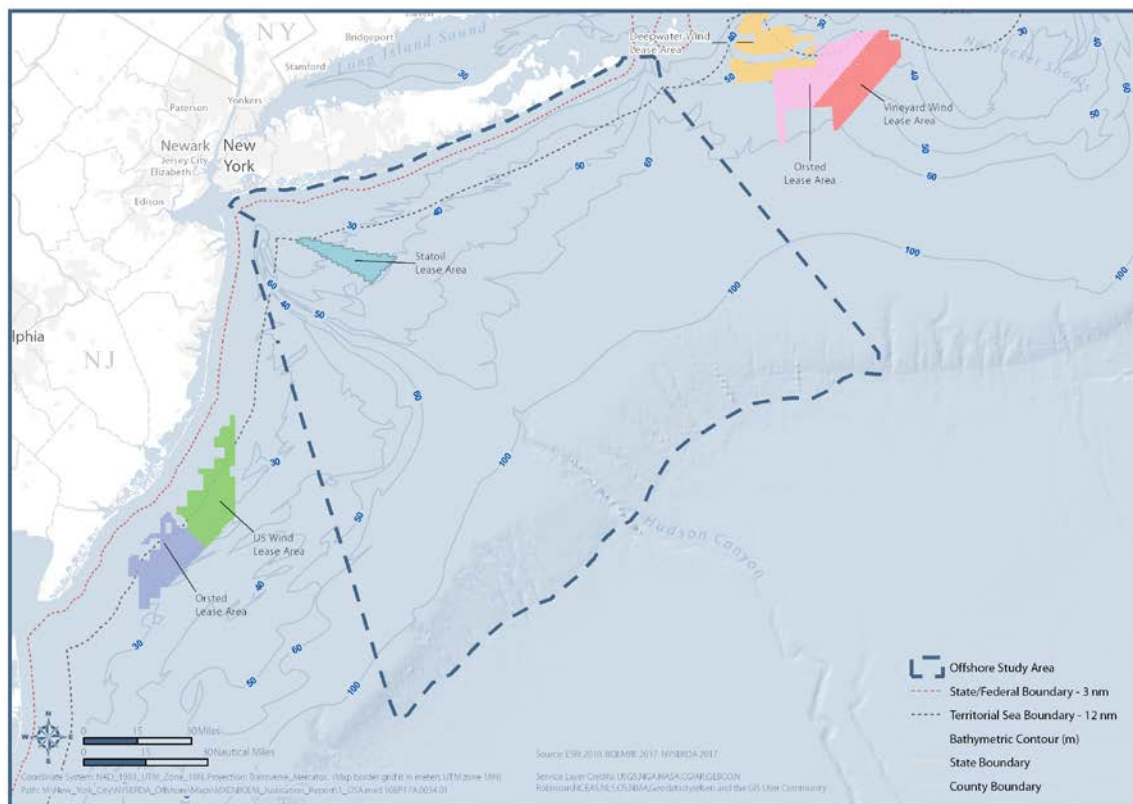
⁷ Cuomo, Andrew M. 2017. *Excelsior - Ever Upward: 2017 State of the State*, New York State, <https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2017StateoftheStateBook.pdf>, at p. 55.

⁸ Cuomo, Andrew M. 2018. *Excelsior - Ever Upward: 2018 State of the State*, New York State, <https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2018-stateofthestatebook.pdf> at p. 218.

⁹ NYSERDA, 2018. New York State Offshore Wind Master Plan, Charting a Course to 2,400 Megawatts of Offshore Wind Energy”, see <https://nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan>

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Figure 1: Master Plan Offshore Study Area and regional existing lease areas



1.2.2 Emerging U.S. Offshore Wind Activity

The United States is developing a robust pipeline of projects to ensure growth in the country's nascent offshore wind market. Near-term activity is concentrated in the North Atlantic, but other projects are in various stages of development across the country, including the Great Lakes, the West Coast, and Hawaii.

Rhode Island's statutory Long-Term Contracting Standard for Renewable Energy led to the completion of the first operating offshore wind project in the United States in 2016, the 30 MW pilot-scaled Block Island Wind Farm in state waters. In addition, the law separately provides an opportunity for a long-term PPA between a developer selected by the state to develop a utility-scale offshore wind farm, and National Grid, of between 100 and 150 MW in Federal waters.¹⁰

In August 2016, Massachusetts enacted An Act to Promote Energy Diversity (H.4568), which requires state electricity providers to issue solicitations for 1,600 MW of offshore wind capacity by 2027 using 15 to 20-year power purchase agreements. As part of this solicitation process, the electricity providers –

¹⁰ In 2010 (as amended in 2012) the Rhode Island General Assembly established under Chapter 26.1 of Title 39 of the Rhode Island General Laws a Long-Term Contracting Standard for Renewable Energy. § 39-26.1-7 was established to "facilitate the construction of a small-scale OSW demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland. § 39-26.1-8 provides for the utility-scale wind farm. This latter option has not yet been pursued.

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Eversource, National Grid and Unitil – in coordination with the Massachusetts Department of Energy Resources (DOER), issued a request for proposals on June 29, 2017. In this Request for Proposals (RFP) they sought bids for 400 MW of offshore wind energy generation, with bidders being invited to also provide optional alternative proposals with a nameplate capacity between 200 MW and 800 MW. Between 400 MW and 800 MW are expected to be awarded, by means of a single bid or a combination of smaller bids from separate bidders.¹¹ On December 20, 2017, Deepwater Wind, Ørsted (and Eversource Energy), and Copenhagen Infrastructure Partners (and Avangrid Renewables) each submitted proposals to DOER for offshore wind projects of the required 400 MW, and each also submitted an alternative proposal ranging from 200 MW to 800 MW of nameplate capacity. Some of the proposals are paired with energy storage, and each bid included the associated transmission proposals (both dedicated individual lead lines and expandable proposals to accommodate future projects).¹²

In January 2017, LIPA and Deepwater Wind reached an agreement on a 20-year power purchase agreement for the 90 MW South Fork project and announced that the site could become operational as early as 2022. This project represents the first 90 MW toward New York's 2.4 GW goal.¹³

In May 2017, Maryland's Public Service Commission awarded offshore renewable energy credits (ORECs) to US Wind's 248 MW project and Deepwater Wind's 120 MW Skipjack project, both for 20 years. As a precondition for receiving the credits, each developer is required to invest in port infrastructure upgrades, local manufacturing, and workforce development.¹⁴

In New Jersey, the legislature passed legislation in 2010 authorizing 1,100 MW of offshore wind supply.¹⁵ The U.S. Bureau of Ocean Management (BOEM) has leased two wind energy areas to Ørsted and US Wind, and the state established a lease to a pilot-scaled Fisherman Energy project.¹⁶ Thus far the state's Board of Public Utilities has not authorized these projects to proceed or issued implementation orders, although New Jersey is widely expected to advance offshore wind discussions further in 2018.

¹¹ Massachusetts Department of Energy Resources, Unitil, National Grid and Eversource Energy. Request For Proposals For Long-Term Contracts For Offshore Wind Energy Projects, Issuance Date: June 29, 2017, <https://macleanenergy.files.wordpress.com/2017/02/section-83c-request-for-proposals-for-long-term-contracts-for-offshore-wind-energy-projects-june-29-2017.pdf>

¹² Massachusetts Department of Energy Resources, Unitil, National Grid and Eversource Energy. Massachusetts Clean Energy: Massachusetts Section 83C Bids. Retrieved from <https://macleanenergy.com/83c/83c-bids/>

¹³ Cuomo, Andrew M. 2017. "Governor Cuomo Announces Approval of Largest Offshore Wind Project in the Nation." Albany, NY: NYSERDA, January 25. <https://www.nyserda.ny.gov/About/Newsroom/2017-Announcements/2017-01-25-Governor-Cuomo-Announces-Approval-of-Largest-Offshore-Wind-Project>

¹⁴ Maryland PSC. Case No. 9431, In the Matter of the Applications of US Wind, Inc. and Skipjack Offshore Energy, LLC for a Proposed Offshore Wind Project(s) Pursuant to the Maryland Offshore Wind Energy Act of 2013, Order No. 88192, issued May 11, 2017. <http://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>

¹⁵ New Jersey PL 2010, Chapter 57: The Offshore Wind Economic Development Act. ftp://www.njleg.state.nj.us/20102011/PL10/57_.PDF. Section 38.d.(4) requires the BPU of Public Utilities (BPU) to establish an offshore wind renewable energy certificate (OREC) program.

¹⁶ BOEM. 2017. "Commercial Wind Leasing Offshore New Jersey." <https://www.boem.gov/Commercial-Wind-Leasing-Offshore-New-Jersey/>

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In addition, some states are taking other initiatives to tap into their offshore wind potential. For instance, Maine created a program to fund small pilot deep-water offshore wind projects,¹⁷ and California and the BOEM established an intergovernmental task force to coordinate in planning future offshore wind development opportunities in federal waters off the coast of California.¹⁸

New York's 2.4 GW offshore wind goal puts the State in a strong position to capitalize on both the expected cost reductions that will come with building a regional U.S. industry of a sufficient scale to replicate declining cost trajectories observed in European offshore wind markets, and the corresponding economic benefits from becoming a "hub" for the emerging domestic offshore wind industry. Such benefits are discussed in the Workforce Opportunity of Offshore Wind in New York report (see Appendix T of the Master Plan).

1.2.3 Offshore Wind Cost Trajectories

The European offshore wind industry started over twenty years ago, and currently has over 12 GW of offshore wind in commercial operation. As depicted in Figure 2, between 2015 and the present, the offshore wind industry has experienced significant declines in the cost of actual projects and bids on projects in the development pipeline in Europe. The decline being experienced in Europe is widely attributed to factors associated with economies of scale, including industrialization of the offshore wind industry, increasing turbine size and rating, and declines being realized in several key cost components. Competition among project developers as a key component of the selection process further helps to reduce cost; for example, in the U.K., the most recent auction results in September 2017 achieved new prices that were (on average) 47% lower than the prior U.K. auction results in 2015.

While it may take several years for the U.S. offshore wind industry to mature sufficiently to realize comparable costs, as shown in Figure 3, recent U.S. studies show that activities to drive market scale, market visibility, scale economies, construction, operating and financing experience, development of local supply chain, and competition are projected to lead to rapidly falling offshore wind prices in the U.S. as well.

¹⁷ In 2013, the Maine Public Utilities Commission issued a request for proposals for long-term contracts for deep-water offshore wind energy pilot projects pursuant to the 2010 Ocean Energy Act. See http://www.maine.gov/mpuc/electricity/rfps/standard_offer/deepwater2010/ and PUBLIC Law, Chapter 615, LD 1810, 124th Maine State Legislature, An Act To Implement the Recommendations of the Governor's Ocean Energy Task Force (Ocean Energy Act). http://www.mainelegislature.org/legis/bills/bills_124th/chappdfs/PUBLIC615.pdf

¹⁸ BOEM. 2016. "Meeting Initiates Planning for Ocean Renewable Energy Opportunities off California." Press Release (issued October 13, 2016). <https://www.boem.gov/press10132016/>

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Figure 2: Recent European outlook on LCOE for offshore wind (€/MWh)¹⁹

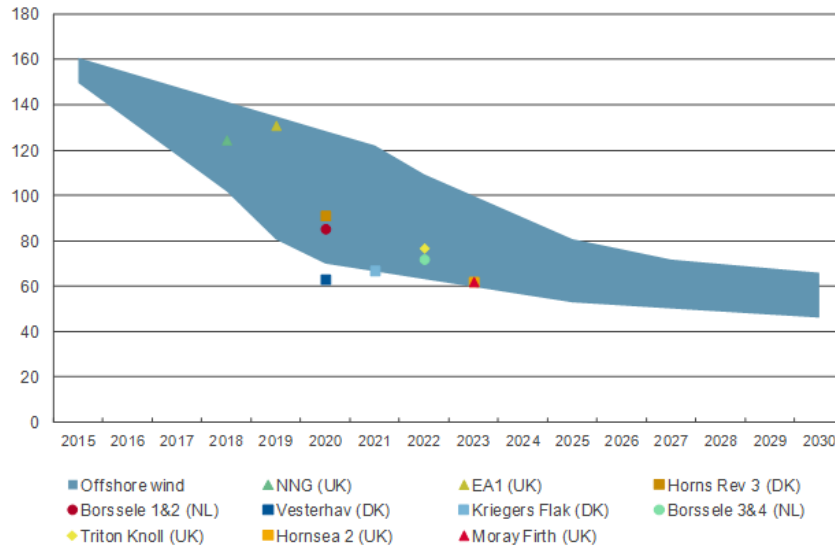
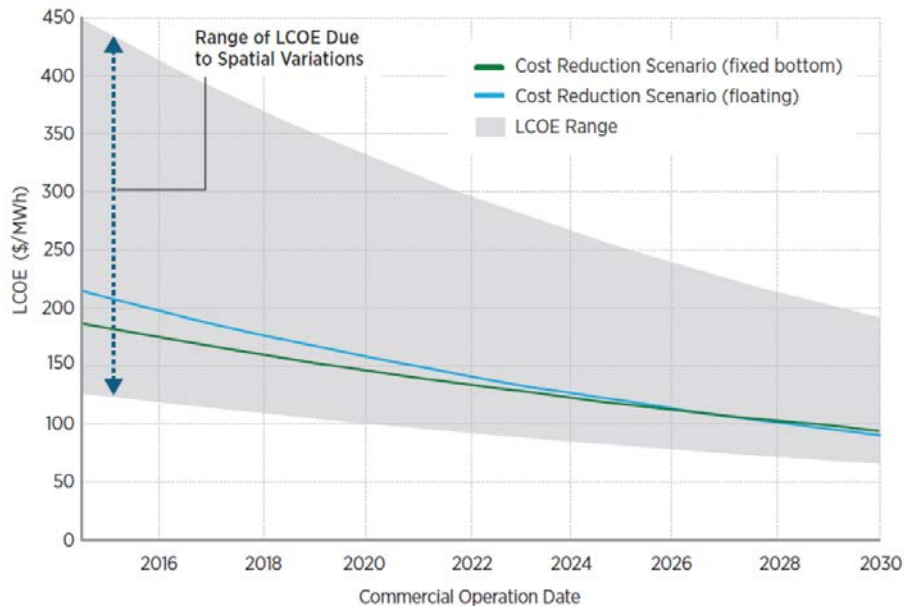


Figure 3: LCOE for potential offshore wind power projects from 2015-2030 (COD) throughout the U.S. technical resource areas²⁰



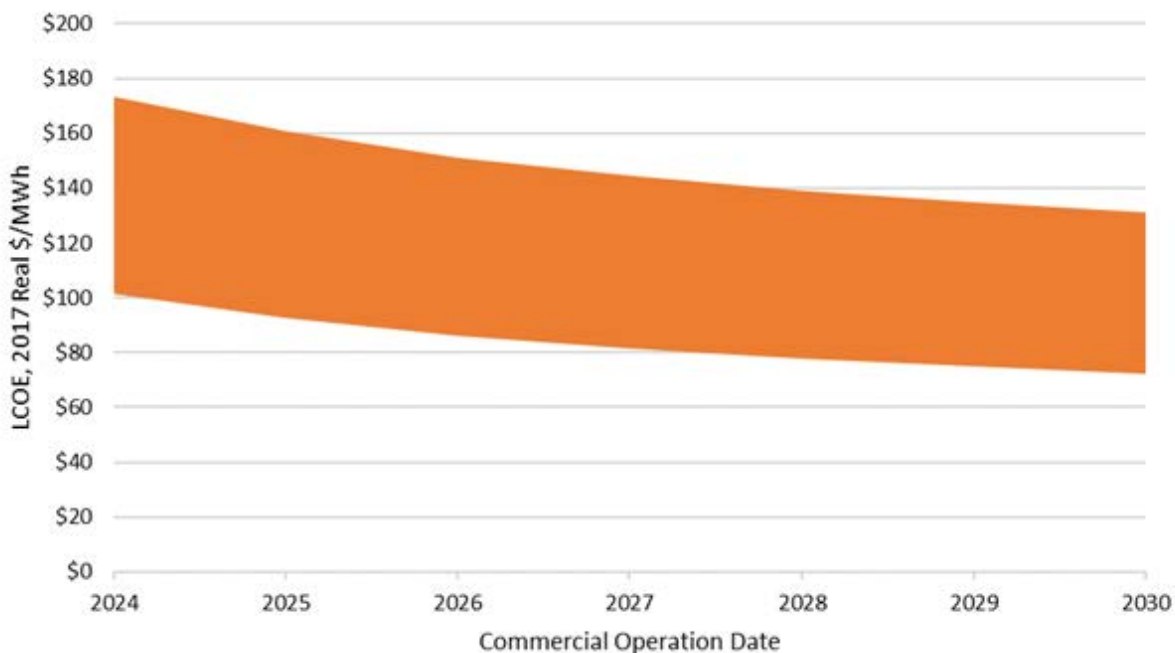
¹⁹ Source: BVG Associates presentation at Franco-British Offshore Wind and Tidal Business Event, Paris, 2 February 2017. Updated by BVG Associates using public sources as of December 2017. All winning bids were converted to LCOE including transmission costs. Calculation assumes that 2016 commodity prices and macroeconomics remain throughout the period, low-cost finance is available, and competition continues in the supply chain and between developers.

²⁰ Unsubsidized LCOE. Source: NREL Spatial-Economic Cost Reduction Pathway Analysis for U.S. Offshore Wind (Sept. 2016), see: <http://www.nrel.gov/docs/fy16osti/66579.pdf>, p. xiii

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As part of this Options Paper, NYSERDA has conducted a study of expected offshore wind technology cost developments between 2024, when NYSERDA projects the first project being deployed, and 2030, when the State seeks to achieve its goal of 2.4 GW of installed offshore wind projects. The results are summarized in Figure 4 and are in line with those for wider U.S. projections shown in Figure 3.

Figure 4: New York State projected LCOE trend²¹



1.3 Objective

This Options Paper responds to the Commission’s request to assess mechanisms for the development of New York’s offshore wind energy resources, as discussed in Section 1.2. Such mechanisms include the procurement and offtake contracting mechanisms needed to put New York on the path to meet the 2.4 GW offshore wind goal established by Governor Cuomo.

The appropriate approach should balance the scale, pace and design of procurements needed to rapidly drive down offshore wind cost in the long run, while seeking to minimize the cost to ratepayers of achieving these objectives. In assessing the range of offshore wind procurement policy options, this Options Paper is reflective, to the maximum extent possible, of program design principles previously identified by the Commission, including:²²

- 1) Utilizing a phased approach to implementation;

²¹ Unsubsidized LCOE. The spread of LCOE projections shown reflects the progression from the lowest-cost site modeled with the most cost-effective procurement structure to the highest-cost site included in the analysis modeled with the least cost-effective procurement structure. Further details on cost projections are set out in Section 6 and in the appendices.

²² CES Order at pp. 11, 26, 32, 103, and 152-3.

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- 2) Funding the cost of offshore wind procurement via an LSE obligation, primarily via supply charges to the maximum extent possible;
- 3) Utilizing the central procurement approach, at least in the near-term, comprised of competition among suppliers for contracts for up to 25 years;
- 4) Using co-incentives to support resource types desired for policy purposes that might not be stimulated by head-to-head procurement alone; and
- 5) Limiting the use of “carveouts” (i.e., volumetric set-asides) to the extent possible.

1.4 Opportunities and Challenges

The opportunities presented by offshore wind deployment at scale are significant and wide-ranging.

First, offshore wind comprises a major portion of the renewable generation needed for New York to meet its renewable energy goals; and, as discussed in Section 1.2.3, the rapidly falling costs of offshore wind and the expectation that such lower costs can be realized in U.S. waters can make that opportunity cost-effective. In the CES, the Commission requires that by 2030, 50 percent of all electricity used in New York State be renewable. This furthers the State’s objective of reducing greenhouse gas emissions by 40 percent by 2030, with the new renewables projects needed to achieve the 50 percent target avoiding approximately 15 million short tons of CO₂e emissions. The Governor’s goal of 2.4 GW of offshore wind would be expected to deliver around a third of these carbon emission reductions - more than 5 million short tons of CO₂e by 2030.

In its analysis supporting this Options Paper, NYSERDA estimates that the GHG emissions reduction benefits of delivering 2.4 GW of offshore wind energy will amount to approximately \$1.9B (net present value).²³ This benefit is approximately equal to the estimated program costs for the range of most cost-effective procurement options identified in this Options Paper (see Section 3). This indicates that the carbon reduction benefits alone could justify the costs of the State’s commitment to 2.4 GW of offshore wind, even before accounting for other anticipated benefits.

Second, offshore wind development at scale will provide considerable economic development opportunities to New Yorkers. This will be true regardless of the location of the offshore wind lease area within which a winning bidder in a New York procurement may construct its facility, as it is technically feasible to support offshore wind deployment from New York to any of the existing east coast federal wind energy areas. Economic development is therefore likely to be driven by commitments to purchase energy or environmental attributes of the projects, rather than simple geographic proximity. The offshore wind industry will create a wide array of jobs, ranging from construction, supply chain and operations jobs to engineers and investors. Given New York’s diverse and experienced workforce, the 2.4 GW goal and additional regional deployment could result in nearly 5,000 jobs for New Yorkers. Many of these positions are in the operation, maintenance and service sector, which deliver long-term local economic benefits through the operating life of the wind farms. Such benefits are discussed in the Workforce Opportunity of Offshore Wind in New York report (see Appendix T of the Master Plan).

²³ Using U.S. Social Cost of Carbon. See EPA’s Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015). See Appendices C and E.

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Third, offshore wind presents a significant public health opportunity. By offsetting electricity generation from fossil-fuel generators, which produce air pollutants that adversely affect air quality, and due to the high population density of New York City and the surrounding region, the monetized health benefits are expected to be significant even for small improvements in air quality. A screening analysis carried out in support of the Master Plan estimates that the total health benefits of 2.4 GW of offshore wind could amount to approximately \$1.0B (net present value) and approximately 100 fewer premature deaths.²⁴

As with deployment of any first-of-a-kind, major energy infrastructure technology in the United States, significant challenges also face the successful development of offshore wind.

Perhaps the foremost challenge to offshore wind development is cost; at the same, achieving long-term cost reductions to enable cost-effective future deployment of offshore wind energy represents an important opportunity. NYSERDA's assessment balances early-stage development costs and expected longer-term cost reductions.

While the relative cost of the first offshore wind projects in the U.S. is still projected to be higher than that of typical land-based projects, the offshore wind sector has experienced dramatic cost reductions over the past few years in Europe -- to the point where in many cases the technology is cost-competitive with land-based renewables projects.²⁵ Cost reductions are thus a key aspect of the successful development of offshore wind energy in New York. The cost reductions seen in Europe have depended to a material extent on local learning and local infrastructure, including supply chain scale economies; in order to unlock such cost reductions for New York, deployment at scale in the region is a prerequisite. Pursuit of the 2.4 GW deployment goal is thus not only important as a direct contribution towards New York's 2030 renewable energy and climate change mitigation goals, but also as an investment that will enable New York and the region to exploit offshore wind resources cost-effectively over the longer-term. The analysis in this Options Paper projects that delivery of the 2.4 GW goal by 2030 could be expected to achieve this objective, with projected costs to procure offshore wind in 2030 lower than the cost of Tier 1 RECs associated with other large-scale renewable technologies.

A number of further challenges shape the initial options available to New York for offshore wind procurement:

- Competition in the nearer term is limited to the federal Wind Energy Areas (WEAs) approved and leased off New York, New Jersey, Rhode Island and Massachusetts. At present, the sole New York lease area designated and leased by BOEM is capable of hosting approximately 1,000 MW and is leased entirely to a single developer (Statoil Wind US LLC). However, up to five other leased areas within existing Wind Energy Areas (the Rhode Island and Massachusetts Wind Energy Area, the two Wind Energy Area offshore of Massachusetts, and the two Wind Energy Areas offshore of New Jersey) are sufficiently proximate to New York to conceivably deliver to New York under delivery requirements that would follow those used in RES Tier 1 solicitations, and therefore could participate in a New York offshore wind competitive procurement. In future

²⁴ See Appendix E.2.

²⁵ CarbonBrief 2017. "Analysis: UK auction reveals offshore wind cheaper than new gas."

<https://www.carbonbrief.org/analysis-uk-auction-offshore-wind-cheaper-than-new-gas>. 14 December 2017.

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years it is expected that BOEM will have identified additional WEAs, including additional areas off the coast of New York.²⁶

- The current construct of RES Tier 1 procurements via NYSERDA central procurement using fixed-price REC contracts limits a generator's ability to hedge its commodity electricity revenues. The resulting level of exposure would be difficult to manage for a new industry such as offshore wind. Multiple NYSERDA studies including cost analysis conducted for this Options Paper indicate that reliance on fixed-price offshore wind renewable energy credit contracts implies higher expected costs to ratepayers than alternative approaches offering more fully-hedged revenues.²⁷
- Offshore wind development lead times include lengthy federal permitting processes that extend beyond NYSERDA's current RES procurement timelines.
- States that advance tangible offshore wind targets and procurements will be more likely to drive the early U.S. supply chain investment and job creation opportunities that will anchor the new U.S. offshore wind industry in certain locations. As discussed above, New York is one of several states that is competing for developer and supply chain interest; advancing offshore wind procurements will help to bring this investment to New York.
- A technical feasibility study, released earlier this year, was conducted by the New York Independent System Operator, Inc. (NYISO) on behalf of NYSERDA and the New York State Department of Public Service, to determine whether 2.4 GW of offshore wind can be injected into Zones J (New York City) and K (Long Island) without thermal overloads.²⁸ The analysis indicated that it is feasible to inject 2.4 GW of offshore wind into Zones J and K without thermal violations under both peak and light load scenarios, under scenarios that included as few as seven substations. While the assessment did not identify any bulk transmission upgrades necessary to inject 2.4 GW of offshore wind without thermal overloads, additional analyses will need to be conducted to meet the NYISO's interconnection requirements for specific projects.

²⁶ On October 2, 2017, New York State submitted an identified Area for Consideration to the federal government's Bureau of Ocean Energy Management (BOEM). New York State requested that within this Area of Consideration, BOEM expeditiously identify and lease at least four new Wind Energy Areas, each capable of supporting at least 800 megawatts. <https://www.nyserdera.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan/Area-for-Consideration> BOEM's designation and leasing of additional WEAs is likely to require up to two years to execute, likely too late for participation in a Phase I offshore wind procurement but presenting opportunities for new approaches in Phase II. Through this process, NYSERDA will also explore with BOEM the potential for NYSERDA to bundle competitive offtake opportunities with the lease bids in new WEAs.

²⁷ NYSERDA. 2015. "Large-Scale Renewable Energy Development in New York: Options and Assessment" NYSERDA Report 15-12. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={26BD68A2-48DA-4FE2-87B1-687BEC1C629D}>; DPS. 2016. "Clean Energy Standard White Paper – Cost Study"

²⁸ NYISO. 2017. "Offshore Wind Injection Assessment" http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2017-12-01/OSW.pdf

This Options Paper identifies options for taking advantage of the opportunities and addressing the challenges for the initial phase of New York offshore wind projects.

2 Offshore Wind Eligibility

2.1 LSE Compliance Obligation Eligibility

Consistent with the principles reiterated in Section 1.2, NYSEDA assumes in this Options Paper that offshore wind deployment will be funded by means of a purchase obligation placed on LSEs, as discussed in more detail in Section 4. Based on this approach – regardless of the specific LSE obligation option adopted – offshore wind projects would need to meet eligibility requirements similar to the RES Tier 1 eligibility requirements, as follows:

- **Location:** Eligible offshore wind projects would need to be located on the Outer Continental Shelf of the United States in areas that BOEM has leased;²⁹ they would need to be able to interconnect either directly to the NYISO transmission system or into the transmission system of a control area adjacent to the NYISO; and they would need to be able to contractually deliver energy into the New York market similar to the deliverability requirements applicable under the RES Tier 1 delivery requirements. This eligibility approach would allow the supply of resources from waters offshore neighboring states such as Massachusetts, Rhode Island, and New Jersey to compete in the New York procurements.
- **Vintage and Commercial Operation Date (COD):** Eligibility would be subject to a first date of commercial operation on or after January 1, 2015.³⁰

2.2 Procurement Eligibility and Evaluation Criteria

NYSEDA also assumes that offshore wind procurement in New York will be conducted through separate offshore wind solicitations, using a similar competitive process as that used for large-scale renewables under RES Tier 1 procurements. Based on this assumption, offshore wind procurement eligibility requirements – as distinct from the criteria that determine whether projects are eligible towards an LSE compliance obligation as discussed in Section 2.1 – could be similar to those applied in past large-scale renewables auctions under the Renewable Portfolio Standard (RPS) and RES Tier 1, regardless of the offshore wind procurement structure to be employed (as discussed further in Section 3 below). Eligibility criteria are expected include the following requirements, in addition to the requirements set out in Section 2.1 above:

- The project COD would need to be later than the date of the applicable solicitation.

²⁹ It would also be possible to consider offshore wind that meet comparable standards for site control located either in the Great Lakes or in the waters off of adjacent Canadian provinces for eligibility.

³⁰ Depending on the ultimate structure, LIPA's contract with the 90 MW South Fork Offshore Wind project could count towards LIPA's share of a statewide offshore wind strategy, but would not be directly relevant to procurement of offshore wind associated with Public Service Commission jurisdictional load.

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- Solicitation requirements and standard contract milestones would also need to recognize that a longer lead time is required for offshore wind development than is currently reflected in NYSERDA's RES Tier 1 solicitations.
- The project would need to be located in a BOEM lease area.
- In order to minimize speculative bidding and the risk of selecting projects unable to reach commercial operation within the time allowed under a standard contract, it is envisioned that the procurement, like the RESRFP17-1 solicitation for RES Tier-1-eligible supply, would establish threshold criteria for a minimum level of project maturity.

Evaluation criteria are expected to resemble those used in the RES Tier 1 solicitations,³¹ but could be customized to offshore wind.

- The procuring entity(ies) could evaluate offshore wind proposals through the use of both price and non-price categories. Examples of non-price categories include the project's expected economic benefits to New York, the overall viability of the project, the use of New York labor in project construction and operation, impacts to New York from a grid integration perspective, associated ratepayer impacts, etc.
- The Commission may also consider whether additional siting standards would need to be met. NYSERDA and other State agencies, through the execution of the Master Plan, are developing siting standards for offshore wind projects in Federal waters. Standards may include but not be limited to a minimum distance from shore to address potential visibility concerns, the application of best management practices to address environmental or commercial activity concerns, or the inclusion of test sites to support research and development activities. If such standards applied to a New York State procurement, they would ultimately be subject to approval by the Commission and would only apply to WEAs competing in the relevant New York procurement.

3 Procurement and Contracting

This section includes discussion of the range of available options for offshore wind procurement structures and contracts. NYSERDA addresses the following components:

- A phased approach to offshore wind procurement and contracting needed to achieve the 2030 2.4 GW offshore wind target;
- Procurement structure options;
- The procurement schedule and procurement targets for the size of offshore wind projects to be procured;
- Cost containment options;
- Finance and co-incentives; and

³¹ NYSERDA used four evaluation components for RESRFP17-1: Bid Price (70 points), Incremental Economic Benefits (10 points), Project Viability (10 points), and Operational Flexibility and Peak Coincidence (10 points). See Renewable Energy Standard Purchase of New York Tier 1 Eligible Renewable Energy Credits Request for Proposals (RFP) No. RESRFP17-1, June 2017;

<https://portal.nyseda.ny.gov/servlet/servlet.FileDownload?file=00Pt0000002yD26EAE>

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- Options for contracting features including premium payment structure, contract duration and key terms and conditions.

Interaction between procurement of generation and procurement of transmission and interconnection (T&I) is discussed further below in Section 5.

3.1 Phased Approach

As discussed in Section 1, certain of the challenges and constraints facing offshore wind development for New York may be more prevalent in the immediate future than after deployment of New York's first few offshore wind farms. NYSERDA concludes that an initial, transitional approach (Phase I) is necessary until offshore wind is ready to be mainstreamed into the CES procurements or alternate approaches to support the development of offshore wind emerge. As the offshore wind industry gains experience and comfort with market visibility, costs fall, lead times shrink, more WEAs are created, a more robust development pipeline assures competition, and the supply chain matures, additional approaches more fully aligned with the CES principles will become more viable.

As a result of the specific offshore wind challenges referred to above, NYSERDA concludes that Phase I procurement should be conducted by means of competitive solicitations specifically for offshore wind projects, and thus separate from RES Tier 1 solicitations. Eligible proposals would be for any projects – whether in WEAs currently leased offshore New York, New Jersey, Rhode Island, Massachusetts, or elsewhere – that can demonstrate contractual delivery into the New York Control Area. As discussed in Section 3.4 below, it is proposed that Phase I should be comprised of procurements in both 2018 and 2019, each at least for 400 MW or a total of 800 MW.³²

Several procurement and contracting options are available within these bounds, laid out in Section 3.2.

3.2 Phase I Procurement and Contracting Structure Options

A key feature that differentiates possible procurement and contracting options from both an investor's and a ratepayer impact point of view is the extent to which such structures provide projects with a partially or fully-hedged revenue stream – a factor particularly important for a nascent U.S. industry such as offshore wind. A second important factor that distinguishes options is the level of potential involvement from NYSERDA and utilities as contracting parties.

This section discusses a range of structures – presented as seven options – that differ either in terms of their approach to hedging aspects or the organizations involved in implementing them. Each option includes estimated program costs (expressed as a net present value of the incremental cost – if any – above the value of energy, capacity and Tier 1 RECs) for a Phase I base case rollout of 800 MW as discussed above. Cost projections are subject to a range of uncertainty factors; further detail on the analysis, including scenario and sensitivity analysis, is provided in Section 6 below and Appendix D.

³² Cuomo, Andrew M. 2018. *Excelsior - Ever Upward: 2018 State of the State*, New York State, <https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2018-stateofthestatebook.pdf> at p. 218.

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NYSERDA evaluates each option against the following criteria:

- **Feasibility.** This criterion considers the extent to which an option is subject to issues that may affect implementation either in time for the planned first solicitation in 2018, or at the scale needed for the 2.4 GW goal, or more generally. This includes the relative ease of implementation and administration, dependencies on third parties such as utilities, or any legal risks.
- **Scale of Application.** NYSERDA assesses whether procurement options meet developers' needs – an important consideration where multiple states compete for limited development resources. Consideration is also given to how options could help ensure that winning project proposals successfully complete construction and maximize the operational lifespan of the assets.
- **Cost Effectiveness.** This examines the extent to which options help to minimize ratepayer cost, including by reducing project developer financing and revenue requirements. A key factor is the level of revenue risk protection (hedging) offered by each procurement option.
- **Compatibility and Acceptability.** NYSERDA considers each option's compatibility with competitive wholesale markets and, in particular, whether an option provides the proper incentives regarding locational decisions that recognize price signals and transmission constraints. This criterion also reflects the level of cost uncertainty and risk to which ratepayers may be exposed.

3.2.1 Procurement Option 1: Fixed REC

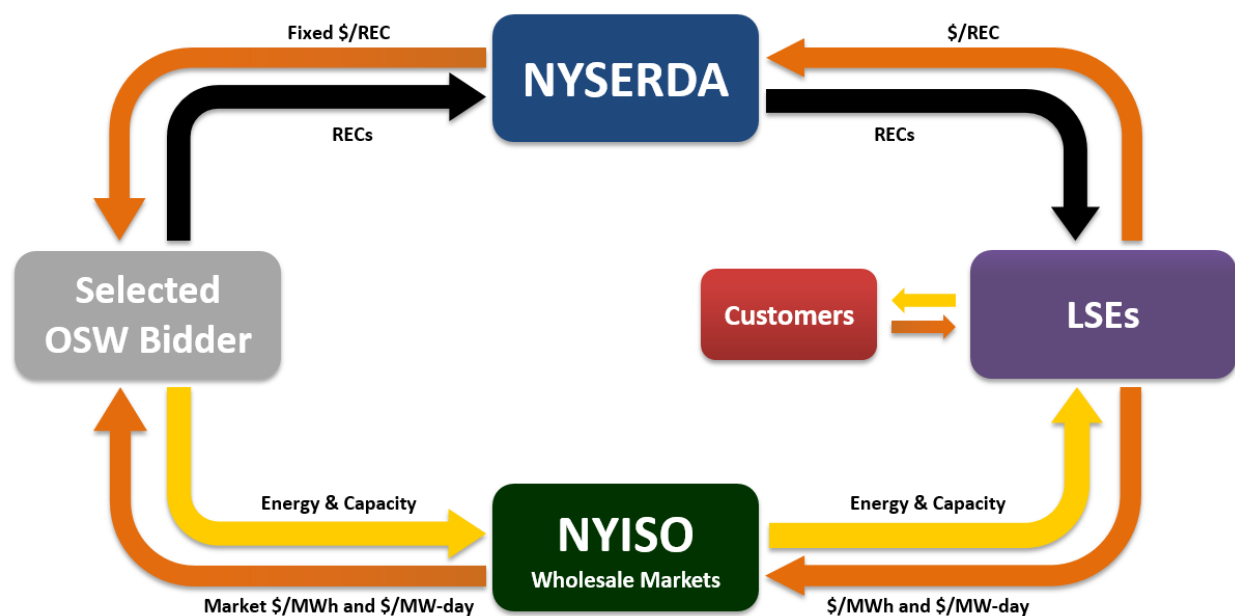
Under this approach, NYSERDA would procure RECs using a process similar to the RES Tier 1 fixed-price REC procurements in which NYSERDA has a role of central procurement entity.

Procurement would proceed as follows: NYSERDA would issue an RFP to procure (RECs from) offshore wind projects of a certain volume or size under long-term contracts. Qualified offshore wind projects would offer competitive bids at a fixed \$/megawatt-hour (MWh) price to NYSERDA. NYSERDA would then evaluate and potentially select one or more bids for award using criteria similar to those in the RES Tier 1 solicitations, but customized to offshore wind procurement and with the inclusion of offshore-wind specific criteria. NYSERDA and the selected bidder(s) would enter into a standard offshore wind REC contract.

Pursuant to the contract, the offshore wind project would deliver an agreed-upon percentage of the offshore wind RECs it generates, subject to any contractually-required maximum quantities, to NYSERDA for a fixed \$/REC price. NYSERDA would then resell the offshore wind RECs to the State's LSEs (or potentially other entities) for compliance with the LSE obligation (see Section 4). Energy and capacity would be sold by the offshore wind project as it sees fit (subject to any delivery requirements under the contract), either into NYISO wholesale markets or, alternatively, through bilateral sales. The procurement structure does not provide a long-term commodity electricity price hedge, though developers may seek any hedges available from market counterparties. The contracting and cash flow under this approach are shown in Figure 5.

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Figure 5: Procurement Option 1: Fixed REC: contracting and cash flow



One or more of New York’s utilities could elect to participate jointly with NYISDA in a procurement for offshore wind. In this case, the RFP would be issued jointly, and winning bids would be selected jointly by NYISDA and the utilities. Offshore wind RECs and the cost of payments made for them would be allocated between NYISDA and the utilities according to predetermined proportions. The assumption would be that the project would sell energy and capacity into the wholesale markets or to other bilateral parties – if agreement on sale of energy and capacity with a utility participating in the procurement was reached, this would effectively result in a Bundled PPA structure as discussed in Procurement Option 2 below. Instead of joining during the procurement stage, utilities could alternatively, upon conclusion of bid selection by NYISDA, be offered the opportunity to negotiate contracts with any projects not selected by NYISDA.

Option Assessment

The Fixed REC structure is relatively simple to implement; the process and associated solicitation and contract documents are well-established. This structure has not been subject to legal challenge in New York and has survived challenges elsewhere.

Continued use of the Fixed REC contract as the contracting vehicle for offshore wind, however, poses considerable risks for New York’s ability to meet its objectives. The primary limitation of this option is that it leaves commodity price risk with the offshore wind project, with the elevated risk to the developer leading to increased cost of capital for offshore wind projects and resultant higher offshore wind REC prices than alternatives which hedge commodity revenues. As a result, the cost analysis as discussed in more detail in Section 6 below estimates a significant incremental program cost of \$1.2B associated with Phase I offshore wind deployment under base case assumptions.

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Moreover, this type and duration of contract may not incent developers to develop and build offshore wind for New York, especially given more attractive alternatives available in other regions, such as longer-term utility contracts for bundled energy and RECs.³³ Similarly, the likelihood that obtaining a contract will result in successful financing and construction of a project is materially lower compared to options which offer full hedges.

In terms of the wholesale power market, the fixed price REC contract does not significantly reduce the incentives of renewable generators to locate in less transmission constrained parts of the grid. The charges paid by ratepayers, once offshore wind REC fixed price contracts have been executed, do not vary with the wholesale market price of energy as the energy market price risk is borne by the renewable generators.

3.2.2 Procurement Option 2: Bundled PPA

NYSERDA's analysis in support of this Options Paper (see Section 6) confirms previous conclusions that significant reductions in project cost of finance, and thus premium payment and ratepayer impact, could be unlocked where the procurement structure provides a hedge against commodity electricity price risk.³⁴ In past NYS analyses, this type of approach has most prominently been assessed in the form of a structure referred to as bundled power purchase agreements (PPA).³⁵ This structure would provide projects with an all-in, fully-hedged revenue stream for commodity value and RECs that would remove project exposure to commodity price risk – referred to as a “perfect hedge”.³⁶

Under this option, participating utilities would (under the Commission's oversight) issue an RFP (jointly in the case of multiple participating utilities) to procure bids from qualified offshore wind project developers. Participating utilities would seek predetermined sized projects capable of providing a predetermined volume of energy, capacity and/or offshore wind RECs. Contrary to fixed-price REC premium bids such as those under the RES Tier 1, bids under this approach would be submitted as the all-in revenue amount per MWh required by the project (Strike Price). The participating utilities would then evaluate and potentially select one or more bids for award using criteria similar to those in the RES Tier 1 solicitations, but customized to offshore wind procurement and with the inclusion of offshore-wind specific criteria.

³³ For example, Massachusetts requires state electricity providers to issue solicitations for 1,600 MW of offshore wind capacity by 2027 using 15 to 20-year bundled power purchase agreements (Act to Promote Energy Diversity (H.4568))

³⁴ NYSERDA. 2015. “Large-Scale Renewable Energy Development in New York: Options and Assessment” NYSERDA Report 15-12. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={26BD68A2-48DA-4FE2-87B1-687BEC1C629D}>; DPS. 2016. “Clean Energy Standard White Paper – Cost Study.”

³⁵ Ibid

³⁶ A variant of this structure, as included by the New York Power Authority (NYPA) in its recent renewables solicitation (Request for Quotation 6000171779, “Large-Scale Renewable Projects”, March 21, 2017), could see a utility paying upfront for a proportion of the energy, capacity and/or REC output. Such payment would be financed by the utility and paid off over time using the project's commodity (and/or REC) revenues. The upfront payment would cover a proportion of the project's capital cost. In this case the project developer would need to finance the remainder and would still retain ownership of the full project.

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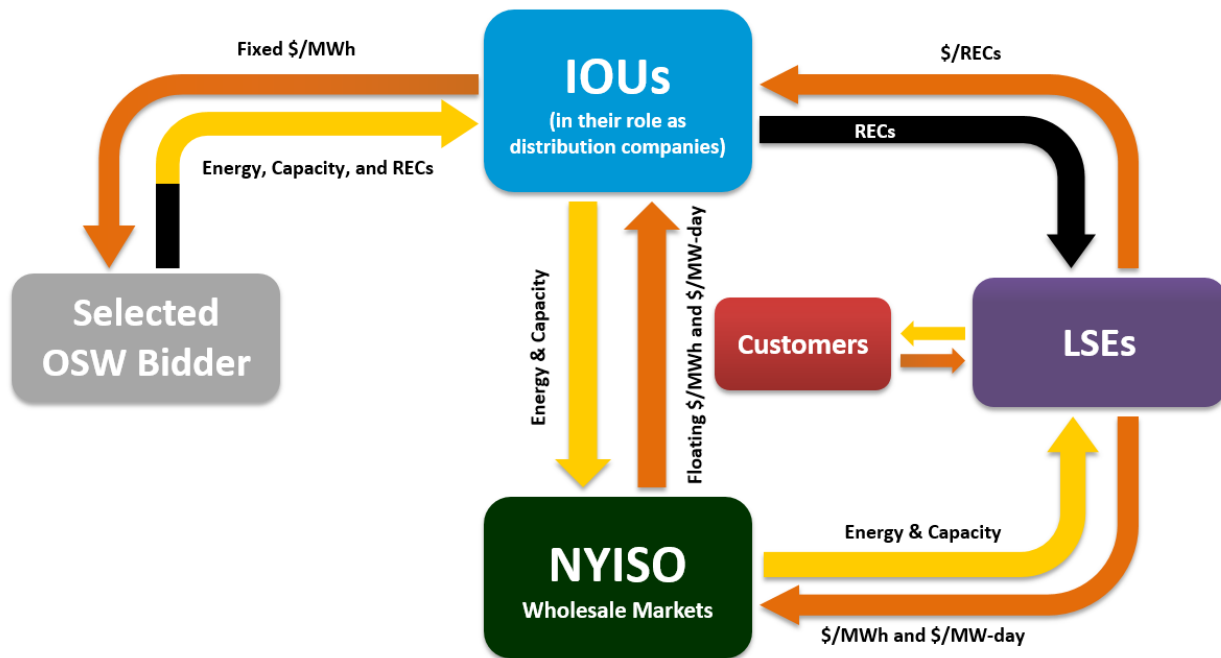
The utilities would either resell the offshore wind project’s energy and capacity to their customers or sell the offshore wind project’s energy and capacity into NYISO wholesale markets, while retaining the project’s offshore wind RECs for compliance purposes and/or selling them to the State’s LSEs (see Section 4).

Figure 6 shows the contracting and cash flow under this approach.

This model is utilized in some other states; for instance, Massachusetts, Connecticut, and Rhode Island have required their investor-owned utilities (IOUs) to issue solicitations and enter into long-term bundled PPAs.³⁷

As NYSERDA is not an electric market participant in the business of buying and selling electricity, utilities would likely need to be required or incentivized to adopt a leading role in realizing a bundled PPA approach in New York. It is possible that NYSERDA could conduct the solicitation on behalf of the utilities, similar to the process utilized in Connecticut, and NYSERDA encourages the Commission to explore both options. Under either process, NYSERDA recommends that the final decision to execute a contract in response to bids submitted would be made by the utilities, in consultation with NYSERDA. Following conclusion of the bid evaluation process, the utilities would then file either a request for approval of the contract with the Commission, or present a filing indicating their reasons for not executing a contract.

Figure 6: Procurement Option 2: Bundled PPA: contracting and cash flow



³⁷ In Connecticut, the Department of Energy and Environmental Protection (DEEP) conducts the solicitation, but the electric distribution companies enter into the PPAs.

Option Assessment

Similar to the approach in other states, use of long-term PPAs for offshore wind would likely require Commission action to ensure procurements at sufficient scale are initiated by utilities. This practice would be novel for New York and would differentiate the treatment of offshore wind from other renewables under the prior CES Order, but would be consistent with practices in other states (as noted above) and present potentially significant cost savings.

If the IOUs were responsible for signing long-term contracts, issues regarding potential impacts on their credit rating or with respect to the financial accounting treatment of the transactions may arise. To the extent the economic risk of non-recovery is substantial, it could affect an IOU's cost of capital, which, indirectly and over time could result in an increase in customer rates. Another IOU concern may be how the contracts, or portions of them, are treated for purposes of financial accounting. To the extent the accounting treatment communicates to investors that there is more economic risk, IOUs may seek to either modify the transaction to offset the adverse accounting treatment or resist conducting the transaction altogether. In other jurisdictions, IOUs entering into long term bundled contracts for renewables have been compensated for these potential issues through the provision of remuneration. In Massachusetts and Rhode Island, in return for taking on the financial obligation for entering into PPAs, the states' EDCs are entitled to remuneration of 2.75% of annual payments under the PPAs.³⁸ The current level of compensation in Massachusetts and Rhode Island has been included for illustrative purposes in NYSERDA's analysis of the associated costs of this option.

A bundled PPA with an IOU would provide a project with a strong energy hedge with a creditworthy party, thus providing an optimal means of facilitating financing of new renewable generation and increasing the likelihood that contracted projects would be built. A bundled PPA with creditworthy IOUs would also reduce developer risk premiums and would likely minimize ratepayer costs relative to other alternatives. As a result of these hedging benefits, the analysis discussed in more detail in Section 6 estimates an incremental program cost for Phase I offshore wind deployment of \$0.3B (net present value), considerably less than the \$1.2B forecast under Option 1.

The need to coordinate among multiple purchasing entities would create challenges to this option's implementation. It could take the IOUs considerable time to execute on processes to administer a solicitation for energy and offshore wind RECs under long-term PPAs. Where IOUs are responsible for procurement, regulatory approval processes are often associated with RFP issuance and approval of PPAs, an additional step not required under the current approach. In addition to additional effort and cost to participants in the process, regulatory approval would likely create considerable lag in implementation of a solicitation process.

The issues associated with compatibility with wholesale energy markets and with retail choice associated with this approach have in recent years manifested themselves through provisions which address negative locational based marginal price (LBMP) issues in PPAs. Also, if the IOU's are responsible

³⁸ Massachusetts Section 83C of An Act to Promote Energy Diversity (2016). <https://malegislature.gov/Laws/SessionLaws/Acts/2016/Chapter188>; Rhode Island General Laws § 39-26.1-4 and Power Purchase Agreement between National Grid and the Block Island Wind Farm, June 2010. [http://www.ripuc.org/eventsactions/docket/4185-Amended%20PPA%20\(PUC%206-30-10\).pdf](http://www.ripuc.org/eventsactions/docket/4185-Amended%20PPA%20(PUC%206-30-10).pdf)

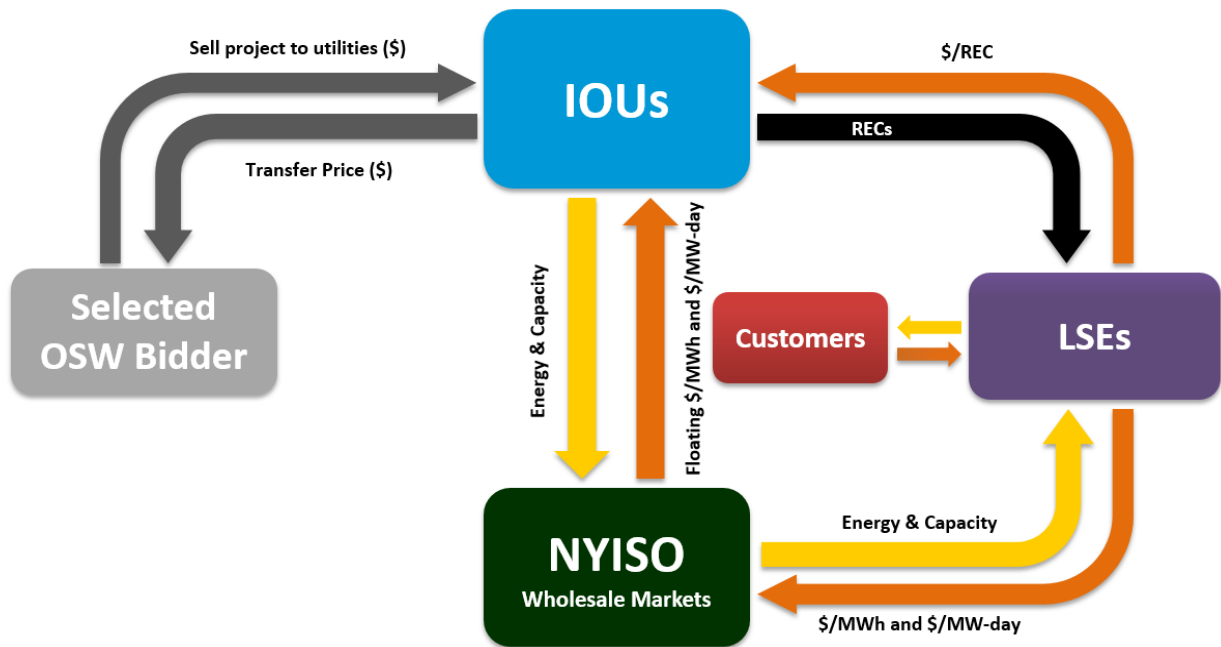
for procurement, an allocation mechanism may be required to spread the purchases and/or costs fairly across the utilities. In addition, for bundled procurements, the IOUs would need to effectuate the resale of the non-REC commodities purchased (energy and perhaps capacity) to reveal the net cost of offshore wind RECs procured, and to charge or credit customers for the difference between costs and revenues.

3.2.3 Procurement Option 3: Utility-Owned Generation (UOG)

Under this option, the process to solicit and assess bids would follow that described under Option 2 (Bundled PPA), but offshore wind project developers would offer distinct all-in price bids for the transfer of ownership of an offshore wind project from the developer to one or more utilities upon achieving a pre-determined, agreed upon development milestone (e.g., upon contract execution or upon achieving commercial operation).

The utilities would either resell the offshore wind project’s energy and capacity to their customers or sell the offshore wind project’s energy and capacity into NYISO wholesale markets, while retaining the project’s offshore wind RECs for compliance purposes and/or selling them to the State’s LSEs (see Section 4). The contracting and cash flow under this alternative are shown in Figure 7.

Figure 7: Procurement Option 3: Utility-Owned Generation: contracting and cash flow



Option Assessment

Unlike the other procurement options, in this scenario the cost of finance would not be determined by market rate cost of finance, but rather by the cost of rate-based utility projects. This approach could unlock a lower cost of capital (and thus reduced ratepayer impacts) if this procurement model were

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pursued in a manner to ensure that utility costs were contained.³⁹ NYSERDA's cost analysis performed for this Options Paper estimates the Phase I incremental program cost under the UOG option at a \$0.2B benefit (net present value).

While advocates of this approach have stated that UOGs would provide a range of benefits including lower cost than PPAs,⁴⁰ the Commission determined that "utility-owned generation also has the potential to inhibit entry by other market participants, which can result in less competition and higher costs in the long-run."⁴¹ Although the Commission accordingly declined to advance a UOG option for land-based renewables, there may be a limited role for this structure to reflect the specific early development challenges of the U.S. offshore wind sector.

This option's success depends upon interest from and participation by utilities. The need to coordinate among multiple purchasing entities could create challenges to implementation, which would make implementation in time for a 2018 solicitation unlikely. Moreover, successful application of this option would depend on the willingness of project developers to secure offshore wind leases and develop projects on the basis of transferring them to a third party rather than maintaining project ownership and operation (and making an investment return over the project lifetime).

Regarding risk allocation, in this option ratepayers bear the risk of offshore wind production estimation uncertainty and would be responsible for compensating the utility regardless of the performance of the asset; in all other options discussed above this risk is borne by the project developer.

3.2.4 Procurement Option 4: Split PPA

Under this approach, a utility would participate jointly with NYSERDA in a solicitation to procure offshore wind projects of a certain production volume or installed capacity under long-term contracts.

Before each procurement, NYSERDA would negotiate with the utility the fixed price at which the utility would be prepared to purchase energy and capacity from the project for the contract lifetime (Reference Price), which would be stated in the tender documentation. Based on this Reference Price, bidders under the split PPA approach would submit their bids as fixed-price REC bids, and the process to solicit and assess such bids would follow that set out under Option 1 above.

Pursuant to the contract, the offshore wind project would deliver an agreed-upon percentage of the offshore wind RECs it generates, subject to any contractually-required maximum quantities, to NYSERDA (and/or the utility if the utility wishes to acquire RECs) for a fixed \$/REC price. The generator would have a one-off option (but not the obligation) to enter into an agreement with the utility in question to sell energy and capacity to the utility at the Reference Price for the contract lifetime; the combination of a

³⁹ NYSERDA. 2015. "Large-Scale Renewable Energy Development in New York: Options and Assessment," NYSERDA Report 15-12. <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={26BD68A2-48DA-4FE2-87B1-687BEC1C629D}>. See also Appendix B.

⁴⁰ CES Order at p. 43. Case 15-E-0302, Proceeding to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Comments of Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, and Orange and Rockland Utilities, Inc.

⁴¹ Ibid at p. 100

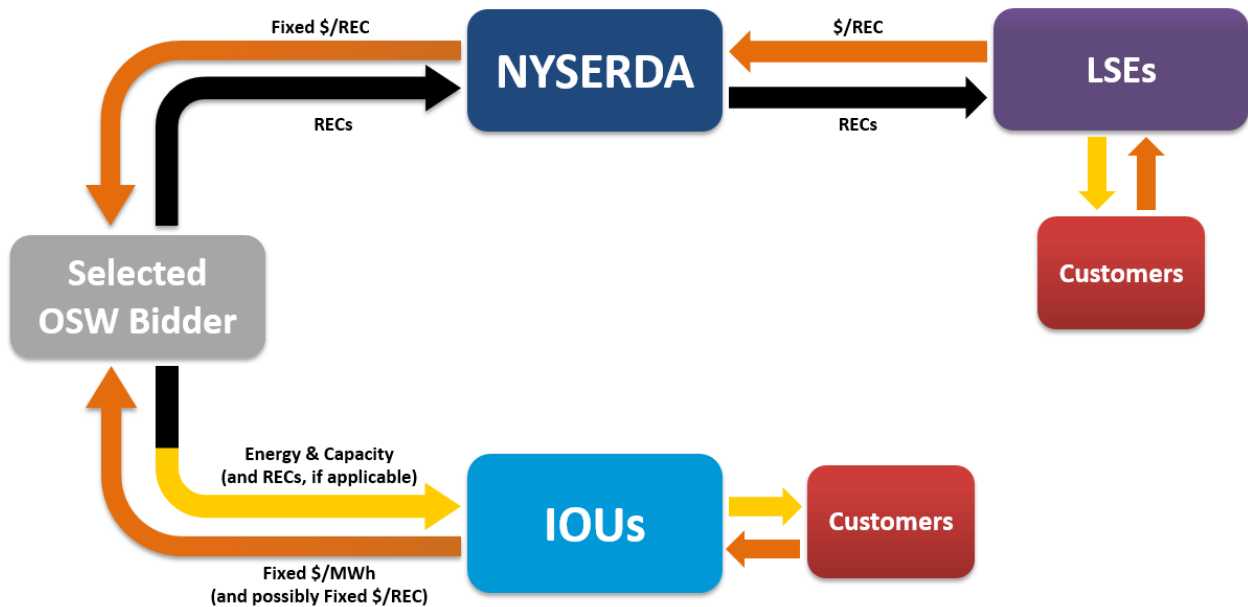
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fixed REC price and a fixed price for energy and capacity would effectively provide the generator with a perfectly-hedged product similar to Option 2.

NYSERDA would resell its offshore wind RECs to the State's LSEs (or potentially other entities) for compliance with the LSE obligation (see Section 4). The utilities would resell any energy and capacity they purchase to their customers.

The contracting and cash flow under this alternative are shown in Figure 8.

Figure 8: Procurement Option 4: Split PPA: contracting and cash flow



Option Assessment

Procurement Option 4 allows a fully-hedged product to be offered to the project developer, thus removing the cost of exposure to commodity price risk, and allowing the project to access the low cost of finance associated with a fully-hedged structure.

However, the extent to which this would translate to reduced REC costs to statewide ratepayers would depend on the pricing that participating utilities would offer as the fixed Reference Price referred to above. Such pricing would have to be negotiated with the utility or utilities. Ahead of such negotiations, the cost analysis presented in this Options Paper includes the Split PPA option with the Bundled PPA option, since both involve similarly-hedged utility-led procurement structures. However, the potential price range that a utility might wish to offer could include low valuation levels for energy and capacity such that from the perspective of the State's ratepayers, cost savings compared to the Fixed REC structure of Option 1 might not materialize.

The feasibility of this option depends on sufficient interest from and participation by utilities, who may represent a level of interest in offshore wind procurements less than either the 800 MW proposed for Phase I or the 2.4 GW goal. Some utilities may also have preferences with regard to the location of the

project. The specific needs of those utilities may substantially limit project selection options including interconnection locations.

This option also requires coordination among multiple purchasing entities. The interests of the REC and commodity purchasers may not be aligned, which may create challenges to arriving at an agreeable project selection and in terms of allocating costs between counterparties. The presence of multiple counterparties to the contract would also introduce increased risk over a traditional PPA from a developer's perspective.

3.2.5 Procurement Option 5: Market OREC

Under the "Market OREC" approach, which would build on the offshore wind REC policy adopted in Maryland,⁴² NYSERDA would procure a certain quantity of offshore wind RECs from qualified projects using a competitive procurement mechanism similar to the REC-only RES procurements referred to in Option 1. Contrary to fixed-price REC premium bids such as those under the RES Tier 1, bids under this approach would be submitted as the all-in revenue amount per MWh required by the project (Strike Price). NYSERDA would then evaluate and potentially select one or more bids for award using criteria similar to those in the RES Tier 1 solicitations, but customized to offshore wind procurement and with the inclusion of offshore-wind specific criteria. The final Strike Prices for winning projects would be set by NYSERDA based on the results of the RFP.

Pursuant to the contract, the offshore wind project would deliver an agreed-upon percentage of the offshore wind RECs it generates, subject to any contractually-required maximum quantities, to NYSERDA. Energy and capacity would be sold by the offshore wind project as it sees fit (subject to any delivery requirements); this could be either into NYISO wholesale markets or, alternatively, through bilateral sales. Offshore wind generators would be required to report to NYSERDA their actual revenues received from selling energy and capacity. To determine the net amount paid to the generator, NYSERDA would deduct from the Strike Price the actual revenues received by the offshore wind generator from selling energy and capacity.

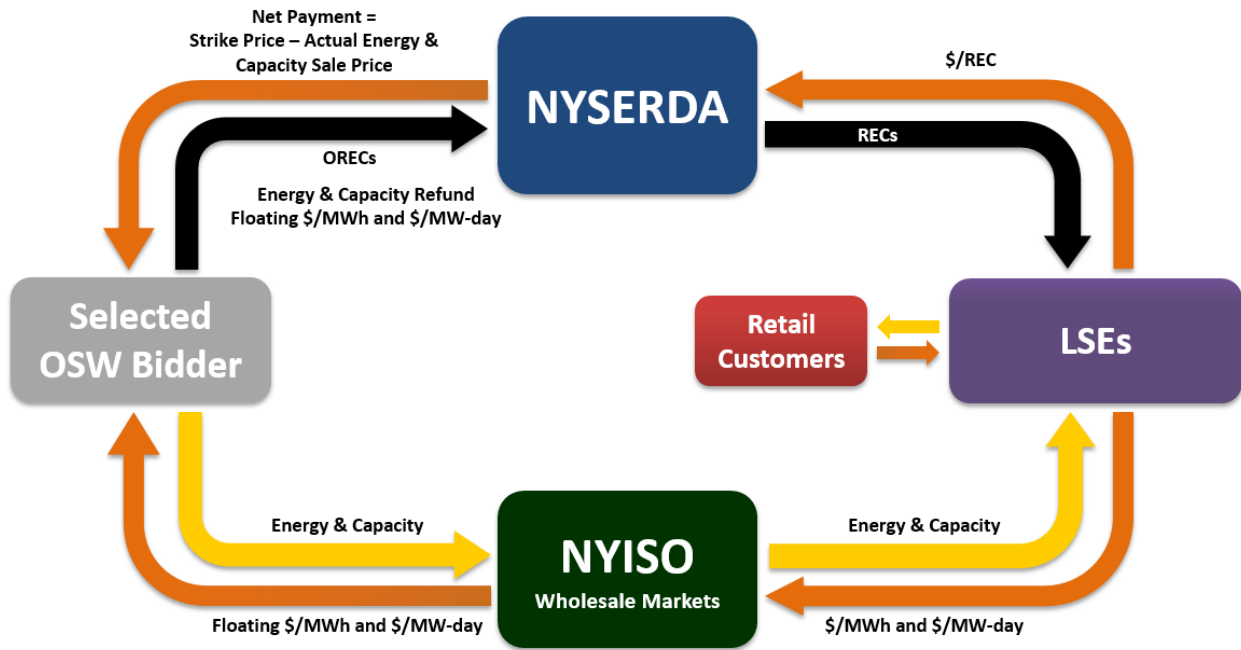
NYSERDA would resell the offshore wind RECs to the State's LSEs (or potentially other entities) for compliance with the LSE obligation (see Section 4). The contracting and cash flow under Procurement Option 5 are shown in Figure 9.

As under Procurement Option 1, one or more of New York's utilities could elect to participate jointly with NYSERDA in a procurement for offshore wind under the Market OREC option. In this case, the RFP would be issued jointly, and winning bids would be selected jointly by NYSERDA and the utilities. Offshore wind RECs would be allocated between NYSERDA and the utilities according to predetermined

⁴² The Maryland Offshore Wind Act of 2013 established an offshore wind carve-out within the state's Tier 1 RPS. Pursuant to the statute, the Maryland Public Service Commission (MDPSC) is required to set the carve-out, which cannot exceed 2.5 percent of the state's total load. The MDPSC is also authorized to direct the state's retail electricity suppliers to purchase offshore wind RECs from qualified offshore wind projects to satisfy their obligations under the offshore wind carve-out. Unlike conventional RECs, the gross price of an offshore wind REC reflects the value of energy capacity, ancillary services and environmental attributes. (Maryland Offshore Wind Energy Act of 2013, http://mgaleg.maryland.gov/2013RS/chapters_noln/Ch_3_hb0226E.pdf). This approach contrasts with the approach to long-term PPAs in Massachusetts where the utilities are required to undertake the procurement process as a matter of state law.

proportions. The assumption would be that the project would sell energy and capacity into the wholesale markets or to other bilateral parties – if agreement on sale of energy and capacity with a utility participating in the procurement was reached, this would effectively result in a Bundled PPA structure as discussed in Option 2. Instead of joining during the procurement stage, utilities could alternatively, upon conclusion of bid selection by NYSERDA, be offered the opportunity to negotiate contracts with any projects not selected by NYSERDA.

Figure 9: Procurement Option 5: Market OREC: contracting and cash flow



Option Assessment

Under the Market OREC approach, structuring and implementing a competitive bidding process as well as administering the associated contracts is more complex administratively than implementing a program with only fixed-price offshore wind REC contracts. However, unlike Options 2 (Bundled PPA) and 3 (UOG), this option would not be reliant on utility participation which would increase the feasibility of its near-term implementation. While the direct link between the project’s actual energy and capacity sales and the amount of premium per offshore wind REC paid may create a jurisdictional question related to the Federal Power Act, the fact that the payment is not conditioned upon the project’s participation in federally regulated markets may at the same time reduce legal risk.

A Market OREC could make a strong contribution toward maximizing renewable generation and achieving New York’s goals by incentivizing developers to enter the New York market, and facilitating financing of offshore wind generation. By “locking in” the value of energy as well as offshore wind RECs

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for the contract term, this option should also reduce the risk that a contracted project would not be able to obtain financing due to a reduction in market energy prices following a contract award.

Ratepayer costs are likely to be lower when energy price risk is hedged than when energy price risk is unhedged or only partially hedged. As a general matter, the more “perfect” the hedge, the lower the risk premiums generators will need to charge, and the lower the cost of financing. Accordingly, the cost analysis conducted for this Options Paper estimates an incremental program cost of \$0.2B associated with Phase I offshore wind deployment, significantly lower than the \$1.2B estimated for Option 1.

An important consideration is the compatibility of a Market OREC structure with operation of competitive wholesale markets and with retail choice and acceptability among stakeholders. Specifically of note is the impact a Market OREC might have on renewable generator decisions to locate in less transmission constrained parts of the grid; and the impact a Market OREC structure might have on decisions to operate or curtail production, particularly when LBMPs are negative. Providing a hedge based on the generator’s actual commodity sales receipts raises the concern that the generator may have little incentive to maximize the energy and capacity sales value and thus minimize ratepayer cost.

From a ratepayer perspective, incremental program costs would increase when wholesale energy market prices decrease, and would fall when wholesale energy market prices increase. While there will not be precise correlation between spot wholesale energy prices and retail rates, a Market OREC would thus provide a form of energy price hedge to retail customers as well as to generators.⁴³

3.2.6 Procurement Option 6: Index OREC

Option 6, the “Index OREC” approach, draws on the renewables procurement structure introduced in the United Kingdom (U.K.) and the U.K.’s experience as the world’s leading nation in terms of offshore wind deployment.⁴⁴

NYSERDA would procure a certain quantity of offshore wind RECs from qualified projects using a competitive procurement mechanism like the REC-only RES procurements described in Option 1. Bids under the Index OREC approach would reflect the project’s required all-in revenue amount per MWh (Strike Price). NYSERDA would then evaluate and potentially select one or more bids for award using criteria similar to those in the RES Tier 1 solicitations, but customized to offshore wind procurement and with the inclusion of offshore-wind specific criteria. The final Strike Prices for winning projects would be set by NYSERDA based on the results of the RFP.

Pursuant to the contract, the offshore wind project would deliver an agreed-upon percentage of the offshore wind RECs it generates to NYSERDA, subject to any contractually-required maximum quantities. Energy and capacity would be sold by the offshore wind project as it sees fit, subject to any delivery requirements, either into the wholesale market or otherwise through bilateral contracts.

⁴³ See also Appendix D.2.1 for a quantitative discussion of this effect.

⁴⁴ The current U.K. procurement structure was introduced in 2013 and is used for procurement in respect of a range of technologies including offshore wind. A first procurement round under this structure was conducted in 2014, and a second round concluded recently in 2017, see www.gov.uk/government/publications/contracts-for-difference/contract-for-difference.

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NYSERDA would pay the offshore wind generator a price for each REC created in the New York Generation Attribute Tracking System (NYGATS) and conveyed to NYSERDA, calculated as the Strike Price minus the Reference Price. The Reference Price would be derived from an index or composite index price comprised of average energy and capacity values for a period of time, such as a month, reflective of the time of generation but not the actual prices received by the offshore wind generator (which may be impacted by time-of-day and other factors).

A number of specific design issues would have to be addressed when determining the Reference Price.

- **Wholesale energy value.** the energy component of the hourly day-ahead LBMP prices (excluding the losses and congestion components of the LBMP), as published by the NYISO, could be used as the basis for the energy value component of the Reference Price. Prices could be at the zonal level, or averaged at a statewide level, or at a more localized level. A further issue for consideration involves the settlement or averaging period for the purpose of the Reference Price calculation. Options could include establishing a production-weighted Reference Price for each hour based on the metered amount of generation and the average day-ahead or real-time LBMP price index for that period, or using the total monthly metered generation and the monthly average of the hourly LBMPs.
- **Capacity value.** System capacity revenue for a generator is a function of a quantity of capacity (in MW) available for sale, and the price available in the capacity market per MW sold. The NYISO determines the initial capacity quantity, or unforced capacity (UCAP), to be applied during initial operation of the project – 38 percent in the case of offshore wind.⁴⁵ Once an offshore wind generator has sufficient historical production, the NYISO updates the UCAP value based on the unit's average production during the previous year's capability period during a pre-defined set of peak hours. For the purpose of offshore wind procurement under an Index OREC Option, it could be preferable to maintain the NYISO's initial UCAP value for the duration of the contract, in order to avoid discouraging value maximization by the generator; on the other hand, where the initial UCAP may be at a conservative level, this approach could provide excess upside to the generator. The capacity value accounted for in the Reference Price would likely be pro-rated to reflect the percentage of its production that the project has committed to NYSERDA.

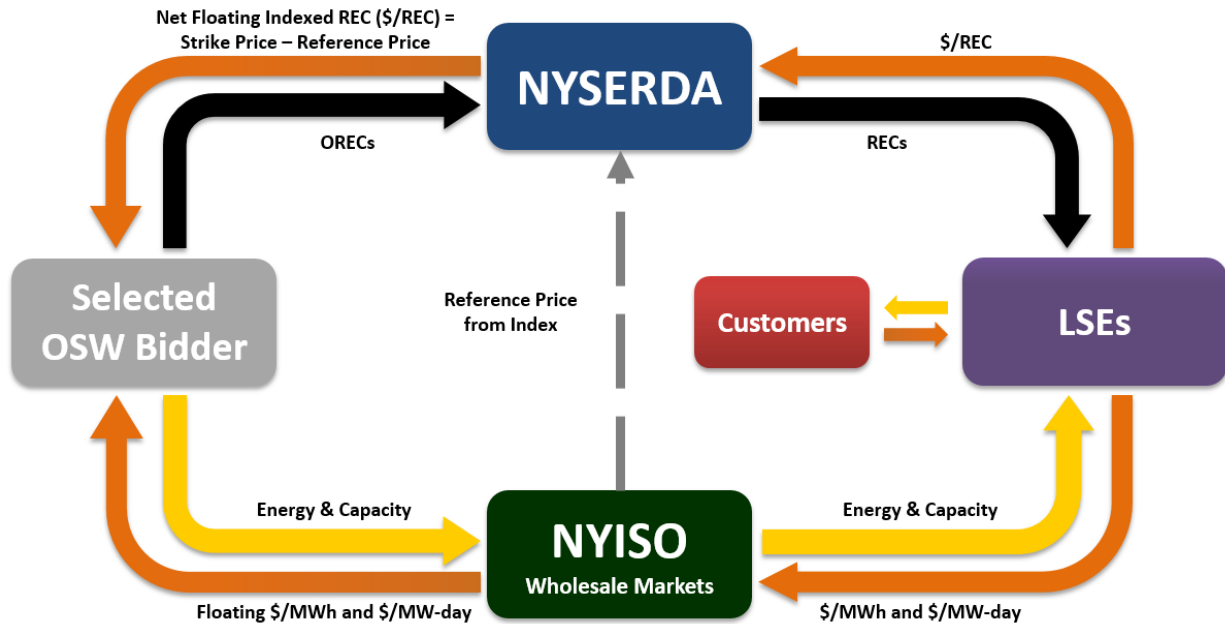
NYSERDA would resell its offshore wind RECs to the State's LSEs (or potentially other entities) for compliance with the LSE obligation (see Section 4). The contracting and cash flow are shown in Figure 10.

One or more of New York's utilities could elect to participate jointly with NYSERDA in a procurement for offshore wind. In this case, the RFP would be issued jointly, and winning bids would be selected jointly by NYSERDA and the utilities. Offshore wind RECs and the cost of payments made for them would be allocated between NYSERDA and the utilities according to predetermined proportions. The assumption would be that the project would sell energy and capacity into the wholesale markets or to other bilateral parties (which could include the utility participating in the procurement). Instead of joining

⁴⁵ NYISO. 2017. NYISO Installed Capacity Manual, Version 6.37 (08/25/2017), Section 4.5. http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

during the procurement stage, utilities could alternatively, upon conclusion of bid selection by NYSERDA, be offered the opportunity to negotiate contracts with any projects not selected by NYSERDA.

Figure 10: Procurement Option 6: Index OREC: contracting and cash flow



Option Assessment

By combining NYSERDA’s established REC procurement approach and elements from the successful use of hedging structures in other jurisdictions, this option provides reduced risk, lower cost of capital, and reduced ratepayer costs relative to Procurement Option 1. Many of the implementation needs would be similar to Option 5, with no major impediments to launching a near-term offshore wind procurement, although further specifics would have to be developed regarding the formula for the Reference Price.

Unlike the Market OREC model (Procurement Option 5), this approach hedges commodity revenue risk by reference to a market price index (or composite of indices) rather than the generator’s actual commodity revenue. This is simpler than the Market OREC structure in that the commodity revenue information on which it relies can be derived from an index or composite of indices, and does not require the generator to furnish actual sales revenue data. It also reduces legal risk exposure by avoiding a link between the procurement structure and the generator’s actual wholesale market interactions, and it creates an incentive for the generator to maximize actual commodity sale revenue.

This approach would provide the generator with a good but imperfect hedge. It would be up to the generator to manage any risk of discrepancy between the commodity price reflected in the market index, and the commodity sale value achieved by the generator from time to time.

Accordingly, the cost analysis conducted for this Options Paper estimates an incremental program cost of \$0.3B associated with Phase I offshore wind deployment, significantly lower than the \$1.2B estimated for Option 1 and only marginally higher than the \$0.2B associated with Option 5.

3.2.7 Procurement Option 7: Forward OREC

Option 7, the “Forward OREC” approach, is a variation on the Index OREC model of Option 6. It draws upon the ZEC structure used in the CES, adapted to the offshore wind context, as well as the Fixed REC procurement approach of Option 1.

This option would provide a payment to winning projects that would, similar to New York’s ZEC program, adjust every two years. Unlike the ZEC structure, this approach would allow for both upward and downward adjustment of payments: the REC price of each tranche would be calculated prior to the beginning of the tranche according to two-year energy and capacity price forecasts or forward indices and remain fixed for the duration of the two-year period, and then be recalculated every two years thereafter in the same manner. This option would aim to effectively provide long-term hedging benefits for the lifetime of projects by leveraging shorter-term (two-year) hedging products available in the market to bridge the period between offshore wind REC price adjustments.

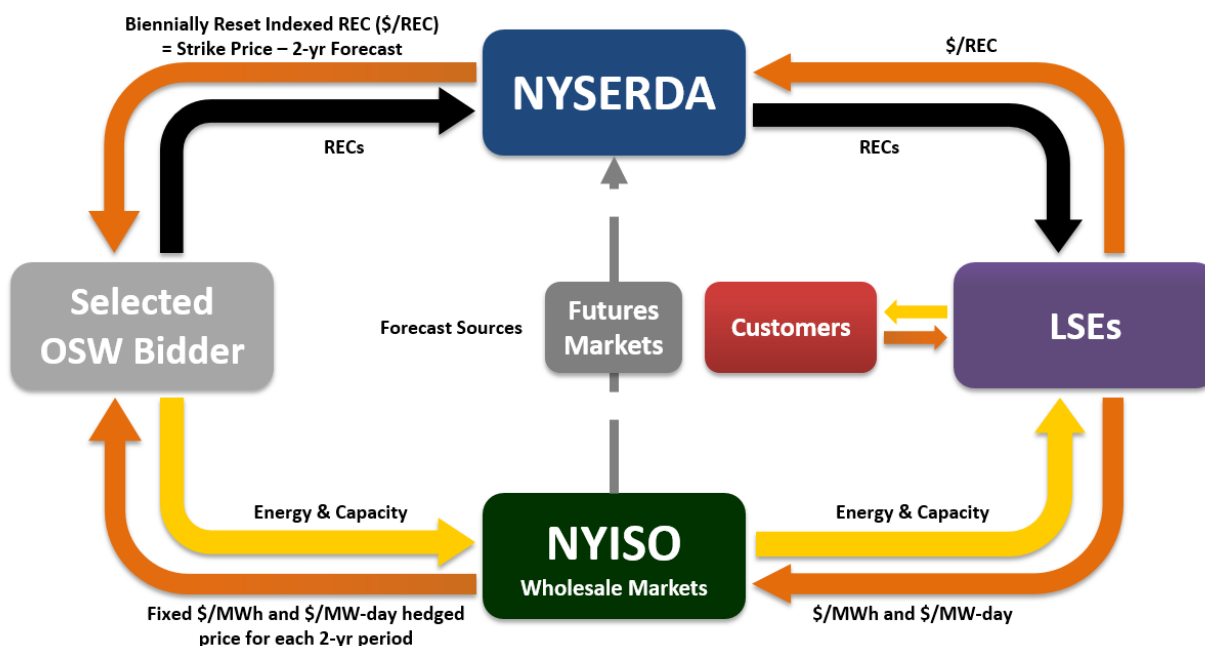
NYSERDA would procure a certain quantity of offshore wind RECs from qualified projects using a competitive procurement mechanism similar to the REC-only RES procurements described in Option 1. As in the Index OREC option, bids under the Forward OREC approach would reflect the all-in revenue amount per MWh (Strike Price). NYSERDA would then evaluate and potentially select one or more bids for award using criteria similar to those in the RES Tier 1 solicitations, but customized to offshore wind procurement and with the inclusion of offshore-wind specific criteria. The final Strike Prices for winning projects would be set by NYSERDA based on the results of the RFP.

Pursuant to the contract, the offshore wind project would deliver an agreed-upon percentage of the offshore wind RECs it generates to NYSERDA, subject to any contractually-required maximum quantities. Energy and capacity would be sold by the offshore wind project as it sees fit, subject to any delivery requirements, either into the wholesale market or otherwise through bilateral contracts. Payments by NYSERDA to the generator would be made for each offshore wind REC created in NYGATS and conveyed to NYSERDA.

The difference between the Index OREC option (Option 6) and the Forward OREC option would be that in the former, the net payment per MWh from NYSERDA to the generator would be the difference between the Strike Price and the index (Reference Price) from time to time; under the Forward OREC option it would be the difference between the Strike Price and a commodity value index that is fixed and set at the beginning of each two-year tranche as the two-year forward price at that time. The generator is assumed to have access to market hedge opportunities to cover commodity fluctuation risk during each of the two-year tranches throughout the project life.

NYSERDA would resell its offshore wind RECs to the State’s LSEs (or potentially other entities) for compliance with the LSE obligation (see Section 4). The contracting and cash flow under Procurement Option 7 are shown in Figure 11.

Figure 11: Procurement Option 7: Forward OREC: contracting and cash flow



One or more of New York’s utilities could elect to participate jointly with NYISDA in a procurement for offshore wind. In this case, the RFP would be issued jointly, and winning bids would be selected jointly by NYISDA and the utilities. Offshore wind RECs and the cost of payments made for them would be allocated between NYISDA and the utilities according to predetermined proportions. The assumption would be that the project would sell energy and capacity into the wholesale markets or to other bilateral parties (which could include the utility participating in the procurement) using two-year hedging arrangements. Instead of joining during the procurement stage, utilities could alternatively, upon conclusion of bid selection by NYISDA, be offered the opportunity to negotiate contracts with any projects not selected by NYISDA.

Option Assessment

As under the Index OREC option, this option aims to design net premium payments to projects such that they fluctuate as a function of commodity value over time. The main advantage of the Forward OREC Option is that it builds on NYISDA’s established REC procurement mechanism and the ZEC pricing structure, and thus leverages familiarity with these approaches which would increase the feasibility of implementing this approach in time for a 2018 solicitation.

The primary limitation of this structure is that it is uncertain whether two-year commodity hedging products such as those available in the market today will continue to be available throughout the lifetime of the offshore wind projects (well into the 2050s). More specifically, funder confidence in the availability of such hedging products will determine whether the low cost of finance associated with (near) perfect hedging can be realized.

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Questions would also arise whether reliance on market hedging products by 2.4 GW of offshore wind projects would distort the market – including the price levels at which hedging products are offered – in unforeseen ways. If a large volume of offshore wind energy seeking to buy two-year hedges were to have a downward effect on the commodity value offered in such hedging products, this could lead to a higher effective premium payments and ratepayer costs.

In order to reflect current uncertainty in particular on how funders will assess the aspects mentioned above, the cost analysis presented in this Options Paper provides two cost estimates for this option: if the finance community is prepared to underwrite this approach effectively as a highly-hedged structure similar to Procurement Option 6, the Phase I incremental program costs are aggressively estimated at \$0.4B and thus not too dissimilar from those of Option 6. If not, this option would turn out to be more similar to Option 1 (Fixed REC) with Phase I incremental program costs more conservatively estimated at \$1.0B.

3.3 Procurement Options Assessment

Estimated program costs were calculated for each option for a Phase I base case rollout of 800 MW (400 MW procured in 2018 and 2019, with commercial operation dates in 2024 and 2025). Program costs are expressed as a net present value of the incremental program cost – if any – above the value of energy, capacity and Tier 1 RECs, as well as incremental energy bill impacts. Projections are subject to a range of uncertainty factors; further detail on the analysis, including scenario and sensitivity analysis, is provided in Section 6 below and Appendix D.

Table 1: Phase I incremental program cost and bill impact by procurement option

Cost Indicator	1. Fixed REC	2./4. Bundled/ Split PPA ⁴⁶	3. Utility- Owned Generation	5. Market OREC	6. Index OREC	7a. Forward OREC, Conservative	7b. Forward OREC, Aggressive
Phase I Incremental Program Cost	\$1.2B cost	\$0.3B cost	\$0.2B benefit	\$0.2B cost	\$0.3B cost	\$1.0B cost	\$0.4B cost
Phase I Incremental Bill Impact	0.76%	0.19%	-0.16%	0.14%	0.18%	0.60%	0.26%

These procurement sensitivities present a wide range of incremental program costs. Those structures that offer perfect or near-perfect hedges show substantially lower program costs than approaches that offer a more limited hedge, in particular the Fixed REC option. The low-cost options include Bundled PPA, Index OREC and Utility-Owned Generation.

A number of options are subject to significant dependencies and uncertainties. The Bundled PPA, UOG and Split PPA options all depend on utilities adopting a leading role in procurement of offshore wind projects. In addition, under the Split PPA approach, cost savings compared to Fixed REC procurement depend on the price level which the utility would be prepared to guarantee for the purchase of energy

⁴⁶ As discussed in Section 3.2.4, under the Split PPA option, the effective cost to ratepayers may be significantly higher than the figure stated here, depending on the fixed long-term price a utility may be prepared to offer for energy and capacity.

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and capacity value over the asset lifetime; a potential price range could include low valuation levels for energy and capacity such that cost savings compared to the Fixed REC option might not materialize. The Market OREC option is subject to jurisdictional risks. The viability of the Forward OREC option as a low-cost procurement option depends on funder confidence that two-year forward hedging products for energy and capacity would be available in the market through the lifetime of offshore wind assets.

The overall assessment of each option versus the evaluation criteria is summarized below in Table 2.

Table 2: Procurement options summary evaluation

Procurement Options	Evaluation Criteria			
	Feasibility	Scale of Application	Cost Effectiveness	Compatibility & Acceptability
1: Fixed REC	++	-	--	+
	Familiar and few implementation issues	Less attractive to developers than hedged options available in other states	High cost of finance due to limited hedge	Few concerns but ratepayers would not benefit from lower program cost if commodity prices rise
2: Bundled PPA	-	++	++	-
	Dependent on utility interest; various IOU implementation and administration issues would take time to resolve	Strong hedging benefit with creditworthy counterparty	Low cost of finance due to perfect hedge	Reduced incentive to maximize locational value due to perfect hedge
3: UOG	-	-	++	-
	Would require change in PSC policy; various implementation issues would take time to resolve	Development without ownership may be less attractive to developers	Low cost of finance as rate-based asset	Reduced beneficial effects of market forces and competition
4: Split PPA	-	+	-	-
	Dependent on utility interest and other implementation issues	Strong hedging benefit but contractual complexities due to split in counterparties	High uncertainty on effective cost to ratepayers until commodity price is agreed by utility	Reduced incentive to maximize locational value due to perfect hedge
5: Market OREC	-	++	++	-
	Jurisdictional questions may present considerable legal risk	Strong hedging benefit with creditworthy counterparty	Low cost of finance due to perfect hedge	Reduced incentive to maximize locational value due to link with actual commodity sales
6: Index OREC	+	+	+	++
	Limited implementation challenges	Significant hedging benefit with creditworthy counterparty	Low cost of finance due to near-perfect hedge	Maintains locational value incentive; increases in commodity prices would reduce ratepayer cost
7: Forward OREC	+	-	-	+
	Limited implementation challenges	Funders may not be confident of continued availability of two-year commodity hedge products	Few cost benefits unless funders assume continued availability of two-year hedging products in the market	Maintains locational value incentive, but large volume of offshore wind may distort the market for hedging products

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On balance, NYSERDA concludes from the analysis described in this Options Paper that the following options for offshore wind procurement in New York during Phase I do not offer a similar level of benefits as the other five potential approaches:

- Fixed REC, due to the relatively high projected costs; and
- Market OREC, unless jurisdictional uncertainties can be addressed.

NYSERDA recommends that the Commission should focus attention for its Phase I decision in respect of offshore wind procurement on one or more of the remaining options, and should base its decision on the following considerations:

- The Split PPA option should be carefully evaluated for feasibility due to the limited scale of deployment implementation complexities, and uncertainties around effective costs to ratepayers.
- Although in its CES Order, the Commission has previously declined to advance the UOG option for land-based renewables, there may be a limited role for this structure to reflect the specific early development challenges of the offshore wind sector.
- The Forward OREC would need validation of feasibility from market participants, due to its novel nature and uncertainty on funders' assessment of this structure and resulting costs of finance.
- Options that depend on utility participation (Bundled PPA, Split PPA and UOG) should only be adopted as the sole procurement option for one or more procurement rounds if and when critical uncertainties would have been resolved either through a Commission Order or through firm commitments from the utility or utilities in question, in particular on the scale of the utility's commitment and, in the case of Split PPA, the level of the fixed long-term energy and capacity prices the utility would be prepared to offer.
- Any of the utility-led options could potentially be included as alternative bid options in a joint solicitation by utilities, which would allow for direct comparison of benefits and risks associated with each option.
- In the absence of firm utility commitments, Bundled PPA, Split PPA and/or UOG could still be progressed in parallel with another procurement option, such as Index OREC.

3.4 Procurement Schedule and Targets

Offshore wind industry participants repeatedly cite a procurement approach that creates market predictability and visibility with respect to the timing and scale of demand as a key to driving down cost. Such an approach helps the private sector plan and invest in efforts associated with development and supply chain development, thereby benefitting the State as well.⁴⁷ Market visibility could be provided by

⁴⁷ NYSERDA. 2015. "New York Offshore Wind Cost Reduction Study," prepared by Stephanie McClellan, Deniz Ozkan, Willet Kempton, Andrew Levitt and Heather Thomson (University of Delaware, Newark, DE). <https://www.nysERDA.ny.gov/-/media/Files/EERP/Renewables/New-York-Offshore-Wind-Cost-Reduction-Study-2014.pdf> and IEA RETD TCP. 2017. "Comparative Analysis of International Offshore Wind Energy Development," prepared by IEA Renewable Energy Technology Collaboration Programme (IEA RETD TCP, Utrecht, Netherlands). <http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf>

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establishing volumetric quantity targets over time for offshore wind procurement and LSE demand, ramping up to the goal of 2.4 GW in operation by 2030. The following specifics would further provide market visibility:

- A regular solicitation schedule with associated targets, either annual or biennial, set well in advance would aid in market timing and scale visibility, thereby supporting the long-term investments needed to drive down the cost of offshore wind.
- Commitments to a solicitation schedule with minimum procurement targets (subject to cost containment as discussed in Section 3.5) will help to create market certainty, but at the same time the State should allow for upward flexibility in procurement volumes when scale economies would yield lower offshore wind bids, to help New York reach its 2.4 GW offshore wind goal at least cost.⁴⁸
- Offshore wind procurement targets, particularly the actual volume procured if different from the stated minimum procurement target, should be tightly linked to a dedicated offshore wind LSE compliance obligation, and should be set to allow LSEs to accommodate the substantial offshore wind procurement volume in their retail contracts.
- Setting targets in units of energy (gigawatt-hours or GWh) per year rather than capacity (MW), would account for different project capacity factors while tying directly into LSE obligations specified as a percentage of energy sales.

The main procurement volume options with respect to achievement of the target volume of 2.4 GW by 2030 include:

- Soliciting an average of around 400 MW – or the equivalent expressed in GWh – of offshore wind per year, which, when starting with a first phase of procurement in 2018 and 2019 and assuming a six-year period between solicitation and commencement of operation, would leave a “reserve” of one year, which could either allow for a one-year hiatus in solicitations or a one-year margin for construction delays; or
- Starting with smaller procurements, ramping up to larger annual procurements closer to the end of the target period.

The cost analysis supporting this Options Paper (as discussed in more detail in Section 6) assesses options of 100 MW, 200 MW or 400 MW for a first solicitation, assumed to be issued in 2018 as part of Phase I. 400 MW was assessed to be a realistic procurement volume for the first year of offshore wind deployment given near-term supply chain constraints. The cost assessment concludes that significant diseconomies of scale would occur for volumes smaller than 400 MW, resulting in program costs that are similar in absolute terms for 100 MW, 200 MW and 400 MW procurements despite the size differences. This analysis is considered in more detail in Section 6.4. Accordingly, and as announced in

⁴⁸ For example, Massachusetts, in its current Section 83C offshore wind procurement, is attempting to strike a balance between market visibility and a steady buildup towards its goals (which support development of supply chain), and the flexibility to take advantage of scale economies. Massachusetts has sought bids for 400 MW, but has allowed bids of up to 800 MW, allowing bidders to make the case for the economic advantage of scale.

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Governor Cuomo’s 2018 State of the State address, it is proposed to proceed with procurement volumes of at least 400 MW each during Phase I solicitations in 2018 and 2019.⁴⁹

3.4.1 Impact on RES Tier 1 Procurement Targets

Procurement of an average of around 400 MW of offshore wind projects per year could fulfill a large portion, and potentially in some years all or nearly all, of the procurement targets established in the CES Order for the RES Tier 1.⁵⁰ This could create doubt as to the market for RES Tier 1 supply and thereby risk maintaining robust development pipelines of onshore RES Tier 1-eligible supply, in particular if Tier 1 procurement targets that have already been set were to be adjusted downwards.

To mitigate this risk, NYSERDA recommends in respect of procurement during Phase I (2018 and 2019) to either set the offshore wind procurement volumes as separate from and in addition to the RES Tier 1 procurement targets, or to increase the aggregate procurement of RES Tier 1 and offshore wind procurement targets. The resulting increased total procurement from Tier 1 and offshore wind projects during Phase I could be reflected in the evaluation of subsequent Tier 1 procurement targets during the next review.

See also Section 4 which further discusses the interaction between offshore wind deployment and the RES LSE compliance targets.

3.5 Cost Containment

3.5.1 Phase I Options

Competition between market participants is an effective and important way to reduce costs. However, during Phase I offshore wind lease sites and leaseholders may be limited in number.⁵¹ The eligibility of projects located in sites offshore nearby states (subject to deliverability requirements) will help to broaden competitive pressure. Nevertheless, NYSERDA recommends that the Commission consider the following options to further ensure cost efficiency:

- Establishing “reasonable price” benchmarks, either for each procurement or by reference to a certain level of reduction in the level of maximum bid price that would be accepted compared to the preceding round.⁵²

⁴⁹ Cuomo, Andrew M. 2018. *Excelsior - Ever Upward: 2018 State of the State*, New York State, <https://www.governor.ny.gov/sites/governor.ny.gov/files/atoms/files/2018-stateofthestatebook.pdf> at p. 218.

⁵⁰ CES Order at p. 14.

⁵¹ See Figure 1 in Section 1 for a depiction of the existing lease areas off New York, Massachusetts, New Jersey and Rhode Island whose leaseholders would be the likely participants in a 2018 or 2019 NYSERDA solicitation until additional New York WEAs are made available for leasing from BOEM.

⁵² This is a requirement of the Massachusetts offshore wind procurement under Section 83C of An Act to Promote Energy Diversity (2016).

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- Requiring an “open book,” cost-based determination of the winning bidder’s actual costs subject to a maximum realized internal rate of return (IRR), and IRR price adjustments for projects whose bids fall above one of the benchmarks.⁵³

Price benchmarks could be based on either: (i) a number of published factors (as with the New York ZEC program’s use of the social cost of carbon⁵⁴); (ii) other offshore wind competitive benchmarks (such as Massachusetts Section 83C bids, LIPA contract price for the South Fork Wind Farm⁵⁵ scaled to a larger project, Maryland offshore wind REC prices, any offshore wind awards resulting from NYPA’s RFQ Q17-6164MH⁵⁶ or a combination thereof); or (iii) cost modeling (this approach is used to establish ceiling prices in Rhode Island’s REGrowth program).⁵⁷ For New York, cost modeling is available in the form of NYSEDA’s cost decline forecast carried out in support of this Options Paper (see Figure 4 in Section 1.2 as well as Appendix A).

A reasonable price benchmark could be utilized in several ways throughout the procurement process.

- It could be published as part of the solicitation process, acting as a proactive driver for bid prices (similar to the concept of pre-determined support level reduction for instance used in the NY Sun program, and mirroring price reduction “degression” structures widely used in many European renewables policies).
- It could be a threshold or evaluation criterion employed confidentially in the evaluation process, similar to the current assessment process in RES Tier 1 procurements.
- In addition, a reasonable price benchmark could be employed as an administratively-determined maximum bid price above which the procuring entity would refuse to contract. If (based on a reasonable price benchmark), the procuring entity were to choose to set its offered contract price to a bidder below the price offered by that bidder, a bidder could choose to accept the price and execute the agreement, or decline and receive a refund of its bid deposit.

3.5.2 Competitive Tendering of De-Risked Sites

While the cost containment measures described above can be deployed as needed in Phase I, in Phase II the Commission may consider further options to optimize competitive dynamics in the bid process. In particular, stimulating competition among developers to develop a single de-risked site as opposed to each developer proposing projects in separately leased WEAs has been shown in Europe and by independent studies to lower costs. This approach assures access, minimizes the risk of significant expenditures by bidders before they receive an offtake contract, reduces the time to develop, creates

⁵³ This approach was employed in the Power Purchase Agreement between National Grid and the Block Island Wind Farm. See [http://www.ripuc.org/eventsactions/docket/4185-Amended%20PPA%20\(PUC%206-30-10\).pdf](http://www.ripuc.org/eventsactions/docket/4185-Amended%20PPA%20(PUC%206-30-10).pdf)

⁵⁴ CES Order, at p. 131.

⁵⁵ Cuomo. 2017. “Governor Cuomo Announces Approval of Largest Offshore Wind Project in the Nation.”

⁵⁶ NYPA. 2017. “Large Scale Renewables Request for Proposals,” New York Power Authority, Q17-6164MH. <https://wwwapps.nypa.gov/procurement/downloadrfq.aspx?RFQNumber=Q17-6164MH&rfq=4077&CatID=36&wage=0>

⁵⁷ National Grid, Rhode Island Renewable Energy Growth Program, https://www9.nationalgridus.com/narragansett/business/energyeff/4_dist_gen.asp

increased knowledge about the site (thereby reducing development costs), and generally reduces the remaining development risk born by generators.

This approach has proven successful in the Netherlands. The Netherlands Offshore Wind Roadmap consisted of phased offshore wind deployment over a 5-year period, driven by a National Energy Agreement to install 4.45 GW by 2023. In particular, the Roadmap centered on the government identifying five 700 MW sites which would be de-risked and competitively tendered annually from 2015 to 2019.⁵⁸ The first two tenders were held in 2015 and 2016. Each successive tender includes a decreasing price cap; in the two solicitations held thus far, bid prices were significantly below the price cap.⁵⁹

3.5.3 Coordination with Other States

As noted in Section 1, offshore wind deployment at scale within a framework providing long-term market certainty is critical to mirroring the significant cost reductions achieved to date mainly in Europe as well as driving continued further cost declines by enabling local supply chain and learning effects. As other states up and down the eastern seaboard pursue their own efforts to deploy offshore wind⁶⁰ – and despite the competitive dynamics between these states in trying to capture the commensurate economic benefits – the resulting greater scale of deployment across the Northeast will help to amplify cost reduction successes that any state could achieve in isolation. Coordination in turn will be key to leveraging these collective efforts into maximum cost reduction. Some potential manifestations of the coordination include:

- To the degree that the states can collaborate in making their collective targets and the timing thereof visible, they can provide developers and their manufacturing, installation and operations supply chain with the maximum degree of visibility to support and potentially accelerate their investment decisions, as well as ensure limited and high-value supply chain assets such as turbine installation barges are used as efficiently as possible.
- The timing of individual states' procurements, as well as the associated commercial operation date milestone requirements, has the potential to either align and support orderly development activities, or complicate them. When uncoordinated, procurements without clarity on selection and commitment timing and risk interactions can be seen by developers as competing opportunities, complicating their bidding efforts, and can also confound the evaluation of the procurement entities. If states are able to coordinate to a degree by staggering procurement timing, aligning commercial operation date milestones, or explicitly addressing requirements for offers to be considered firm (where withdrawing would result in financial jeopardy with respect

⁵⁸ Netherlands Enterprise Agency. 2017. "Offshore wind in the Netherlands: The roadmap from 1,000 to 4,500 MW offshore wind capacity." Retrieved from

<https://www.rvo.nl/sites/default/files/2015/03/Offshore%20wind%20energy%20in%20the%20Netherlands.pdf>

⁵⁹ IEA RETD TCP. 2017. "Comparative Analysis of International Offshore Wind Energy Development."

⁶⁰ See <https://www.boem.gov/Renewable-Energy-State-Activities/> for an overview of efforts of each state.

to bid security), they can mitigate these complications and create a more orderly and additive market dynamic.⁶¹

- Finally, achieving the scale economy and reliability benefits of the development and buildout of offshore wind transmission and interconnection facilities capable of supporting multiple offshore wind projects delivering to multiple states may be leveraged through intra-state coordination of planning and procurement with respect to project physical configuration and size.

3.6 Co-incentives

As noted in the CES Order, “Co-incentives may also be used to target specific technologies within a tier, either because they have a specific public policy value or to improve the competitive balance within the tier.”⁶²

Co-incentives may take the form of grants or similar upfront funding injections awarded to a winning bidder. Grants could be used to reduce a project’s remaining need for financial support, which in combination with any of the procurement options considered in Section 3.2 would lead to a lower REC price or Strike Price.

Co-incentives may be assessed in future including as to the following aspects:

- whether the use of grants as a co-incentive would further decrease the overall cost of the program;
- whether the option of replacing part of the REC-based financial support by a grant would be at NYSERDA’s or the bidder’s discretion;
- what conversion factor would be used to compare bids with or without a grant element when ranking bids to identify winning projects;
- at what time during the project development process a grant would be made available;
- potential tax implications of grants, which might limit their efficiency; and
- the specific terms and conditions of any grant program, including milestones, termination rights, and whether and how grant payments could be recouped if a project does not perform.

3.7 Finance

Many of the offshore wind procurement structures, as discussed above, can provide an effective means of reducing offshore wind project risk. In addition, the offshore wind finance supply chain is robust, and is poised to directly deploy capital for U.S. generation projects utilizing well understood project revenue and economic models. While NYSERDA recognizes that costs associated with the pre-solicitation project development stage may be subject to financing challenges for independent or smaller project

⁶¹ For example, NYSERDA and NYPA sought supply simultaneously in 2017 large-scale renewables procurements, while providing coordinated timelines and notifications to bidders to help them mitigate the risk of participating in both procurements.

⁶² CES Order, at p. 32.

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developers, this is not expected to be a concern for the project developers with access to Phase I sites. It is therefore expected that adequate sources of finance will be available to enable construction of Phase I offshore wind projects, particularly if New York offshore wind projects are substantially similar to precedent transactions previously financed in the global marketplace.

There may be roles for the New York Green Bank (NYGB). Examples of roles NYGB can consider, subject to its investment criteria, due diligence and financial analysis, include acting as a lender or as a credit enhancement (guarantees, reserves, etc.) provider. Possible impetuses for NYGB capital could include: (i) the significant scale and high volume of capital needed for large-scale offshore wind; (ii) procurement models that may result in power purchase agreements that are not fully contracted at a fixed rate for the life of the project; (iii) risk mitigation related to equitable allocation of transmission operational risks between transmission owners and project owners; and (iv) certain development expenditures where the development risk can be substantially mitigated.

Another option for consideration – likely during Phase II – is a “tariff bond” structure, where a bond structure with low cost of capital would be leveraged to provide a project with investment grade financing. The bond financing would be issued by a special purpose vehicle and ultimately be supported by rate mechanisms to allow greater security for the underlying debt. Implementation of this structure would require action by the PSC and would require a range of implementation issues to be considered in more depth, such as: allocation of various project risks, clarification of the utilities’ role, use of rate case approval mechanisms, and legislation enabling the bond structure to achieve the highest possible credit rating.

3.8 Contracting

The terms and conditions of contracts resulting from any of the proposed offshore wind offtake structures will need to be designed and approved by the Commission to meet the particular circumstances of offshore wind project development and operation. In particular, the Commission may consider the duration, milestones, security, performance standards and guarantees, rights and consents to reflect differences in lead-time and risks applicable to the offshore wind industry.

With respect to the duration or “tenor” of the contracts, NYSERDA recommends the following approach:

- To allow bidders the flexibility to propose a contracted premium payment period of up to 25 years, which would reflect the longer expected lifetime of offshore wind projects compared to land-based renewables.
- To require a minimum premium payment duration of 20 years, which would incentivize the developer to ensure the project’s successful operation for at least that period.
- To require generators to deliver the committed proportion of RECs for the lifetime of the project (irrespective of the premium payment period), to ensure that where New York ratepayers provide the necessary level of support to make an offshore wind project commercially viable they also receive the full benefits over the project’s lifetime.

Furthermore, the period of time between contracting and the commercial operation milestone date would likely need to be longer than that which is included in the RES Tier 1 contracts for land-based

renewables, to reflect both project lead times and the timing risks associated with T&I development; this extension would mitigate an offshore wind project's risk exposure to T&I delays.

4 Funding through LSE Obligations

Achievement of the 2.4 GW offshore wind goal contributes to New York's wider goal of 50 percent renewable electricity by 2030. Offshore wind is already an eligible technology under the RES Tier 1, and under the current RES LSE obligation, REC funding would thus be available for offshore wind projects. The RES includes a funding mechanism by means of the LSE obligation for compliance with the RES pursuant to the CES Order.⁶³ With regard to Tier 1 projects procured by NYSERDA through its large-scale renewables solicitations, this mechanism enables NYSERDA to resell the RECs it obtains from procured projects to LSEs, thus recovering its costs. However, since offshore wind projects are expected to require a premium above the cost of other Tier 1 resources, at least in the near-term (see also Section 6 for offshore wind Phase I program cost projections), this value would be insufficient to recover the premium payments made to the offshore wind projects.

Section 4.1 discusses options for funding the offshore wind procurement costs. Section 4.2 discusses setting offshore wind LSE compliance obligations and their coordination with RES Tier 1 LSE compliance targets.

4.1 Offshore Wind Obligation Structure

NYSERDA assumes that offshore wind funding would be provided by a compliance obligation placed on LSEs, subject to the Commission's jurisdiction, together with voluntary compliance by the Long Island Power Authority and New York Power Authority, to reach a statewide policy – similar to the approach under the RES Tier 1.

Options for implementing an LSE compliance obligation to deliver suitable funding levels for offshore wind procurement include:

- Mainstreaming offshore wind within the RES Tier 1;
- Applying a Tier 1 REC multiplier; or
- Establishing a separate offshore wind LSE compliance obligation.

NYSERDA has identified two variations within the third alternative: a “market option” in which – like the RES Tier 1 obligation – LSEs have the option to buy from NYSERDA, but can also purchase RECs from other eligible sources at market prices or pay an Alternative Compliance Payment (ACP); and an “allocation option” under which – like in New York's ZEC program – LSEs are required to buy their pro-rata share of offshore wind RECs procured at an established price from NYSERDA, a utility procuring offshore wind generation, or via bilateral agreements with offshore wind generators.

⁶³ CES Order at p. 93-95. The obligation is supported by all LSEs, both “jurisdictional” (NYSERDA-procured offshore wind RECs resold to RES Tier 1 obligated entities) and “non-jurisdictional”/voluntary compliance (NYP&LIPA, who have elected to voluntarily comply with the CES and REC obligation through supply charges to retail and potentially wholesale customers). Funding is derived from all ratepayers primarily through the generation supply charge. The RES Maintenance Tier will be funded through distribution service rates in a manner similar to recovery under the prior Renewable Portfolio Standard.

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The discussion of obligation options in this Options Paper is most pertinent to the expected Phase I market dynamics. Future developments may allow for consideration of alternative structures in Phase II, as is the case with respect to procurement contract options.

4.1.1 Mainstream RES Tier 1

RECs from offshore wind projects are currently eligible towards compliance by LSEs with their RES Tier 1 obligation. If NYSERDA was to procure offshore wind projects (through any of the procurement options described in Section 3), it could resell them to LSEs as Tier 1 RECs together with the RECs procured through regular NYSERDA Tier 1 auctions, at a blended (weighted average) price.⁶⁴

At least for Phase I, under almost all procurement methods, NYSERDA expects offshore wind RECs to be more expensive than those sourced from other Tier 1 eligible projects (see Sections 3 and 6). To the extent this premium would not be addressed through co-incentives (see Section 3.6), NYSERDA's blended REC resale price would increase – likely significantly – compared to its REC resale price without offshore wind. This would create an increased risk to NYSERDA that the blended REC disbursement price would exceed that which LSEs could obtain from other sources. NYSERDA might not be able to sell its RECs and recover its costs, increasing its reliance on the utility “backstop” funding obligation under the CES.⁶⁵ If the offshore wind procuring entity was a utility, in this scenario such utility (and its customers) might end up bearing a disproportionate amount of the incremental costs of offshore wind projects.

If the Commission were to adopt one of the procurement options that provide offshore wind projects with a commodity price hedge (such as the Bundled PPA or Index OREC structure), this risk may be exacerbated if commodity prices fall, which would lead to a higher net offshore wind REC premium. In such an event, the risk that NYSERDA's blended REC disbursement price (or, in the case of a procuring utility, the disbursement price at which the utility would want to sell to recover its costs) would rise above that which LSEs could obtain from other sources would increase, particularly if such disbursement faced competition from either less costly Tier 1 RECs from other market sources or if REC surpluses (and correspondingly low REC prices) prevailed in neighboring markets.

The resale risk as described above would be reduced once offshore wind costs will have decreased to levels similar to those of onshore large renewables technologies. For Phase II, the mainstreaming option described here may thus be more attractive.

⁶⁴ As is currently the case in RES Tier 1, the price calculation, both in this option and the other options considered in this Section 4, would include an adder to cover administrative costs.

⁶⁵ Case 15-E-0302, Proceeding to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Approving Administrative Cost Recovery, Standardized Agreements and Backstop Principles (November 17, 2016).

4.1.2 REC Compliance Multiplier

The CES White Paper⁶⁶ described the use of RECs within the RES:

One REC will be created for each CES-eligible MWh generated; this is the universal unit of measure in states with REC markets. The REC feature is essential for New York's market-based CES obligation to have compatibility across systems, policies (i.e., Environmental Disclosure Label Program) and markets. Generation owners will be able to certify projects for eligibility in multiple states to facilitate their access to the highest value markets.

However, REC or RPS compliance “multipliers” have been used by the states of Washington, Oregon, Nevada, Colorado, New Mexico, Texas, Michigan, and Delaware⁶⁷ (most of which have vertically-integrated utility markets) in those states’ Renewable Portfolio Standards to favor targeted renewables. Through REC multipliers, sometimes referred to as “bonus RECs,” these states grant extra credit by purchasing more than one REC per MWh from eligible generators or technologies. In most cases multipliers are used to encourage distributed generation such as from rooftop solar photovoltaics (PV). While the U.S. has little experience deploying multipliers in competitive markets with LSE obligations such as New York’s RES Tier 1, the United Kingdom successfully encouraged most of its early offshore wind deployment in the period from 2009 by offering the equivalent of two RECs per MWh of offshore wind electricity.⁶⁸

The advantage to New York of using a multiplier for offshore wind support would be that such a structure could to a large extent address the REC resale challenges identified in the “mainstreaming” option above within the current RES Tier 1 LSE obligation structure. This approach would work by defining that offshore wind RECs would be credited towards LSE compliance obligations at more than one RES Tier 1 REC (for example, 2X), as opposed to creating multiple RECs/MWh, which would conflict with the use of NYGATS to support the Environmental Disclosure Program, and make NYGATS incompatible with certificate tracking systems in neighboring markets.⁶⁹

However, the challenges to implementation of a REC multiplier strategy to support offshore wind within the RES Tier 1 would include at least the following:

- Since each offshore wind REC would be credited as more than one MWh towards LSE compliance targets, the RES Tier 1 targets would need to be adjusted to reflect the expected mix between offshore wind and other technologies such that the 50 percent renewable electricity

⁶⁶ DPS. 2016. “Staff White Paper on Clean Energy Standard,” at p. 13, <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={930CE8E2-F2D8-404C-9E36-71A72123A89D}>

⁶⁷ Barbose, Galen. 2016. “U.S. Renewables Portfolio Standards 2016 Annual Status Report,” Lawrence Berkeley National Laboratory. <https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf>. DSIRE Database. <http://www.dsireusa.org/>

⁶⁸ U.K. Department of Energy and Climate Change. 2009. “Government Response to the 2009 Consultation on the Renewables Obligation”, URN 09D/847, p.16.

⁶⁹ One REC will be created for each CES-eligible MWh generated. This feature is essential for New York’s market-based CES obligation to have compatibility across systems, policies (i.e. Environmental Disclosure Label Program) and markets, as required in the CES Order.

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target would still be met. Such target adjustments would need to be reset periodically if the mix between offshore wind and other technologies deviates from expectations.

- Offshore wind RECs associated with each offshore wind procurement tranche would have a distinct cost that may differ either from the market value of a RES Tier 1 REC from time to time or that of other offshore wind procurement tranches. It would not be possible to establish a single stable multiplier that would perfectly reflect such price differences over time, and, compared to the mainstreaming option discussed above, this option would thus reduce but not eliminate the disbursement risk discussed in Section 4.1.1.
- Although offshore wind RECs would technically be part of the Tier 1 obligation, in practice the multiplier might not allow for fully-blended resale of traditional Tier 1 RECs and offshore wind RECs.

4.1.3 Separate Offshore Wind LSE Compliance Obligation

The Commission could establish a new LSE compliance obligation specifically for offshore wind. This separate target would increase over time towards the 2.4 GW offshore wind goal. Eligibility for RECs from offshore wind projects to count towards the new compliance obligation would be as discussed in Section 2.

The advantages of a distinct LSE compliance obligation for offshore wind include that its implementation would be relatively straightforward (in particular, it would avoid multiple market prices for Tier 1 RECs), it would avoid the implementation complexities associated with a REC multiplier, it would provide the necessary funding for offshore wind cost premiums that could not be readily supported under mainstreaming offshore wind in the RES, and that LSEs could plan for targets.

The primary limitation of this approach is that – at least initially – the liquidity of offshore wind RECs eligible towards this obligation would be limited. During that period there might be only one source of offshore wind RECs (namely the procuring entity as per the procurement options discussed in Section 3). This may not be a significant concern since, at least during Phase I, it is unlikely that market-based REC trading would be a viable driver of offshore wind deployment, and it is expected that the LSE compliance obligation would be a funding mechanism only.

Market Option

A dedicated offshore wind compliance obligation using a market approach would mirror the RES Tier 1 approach. LSEs could purchase from the procuring entity or other eligible offshore wind projects, or comply via payment of an ACP, which would be distinct from (and higher than) the RES Tier 1 ACP.

The primary advantages of such an approach are its familiarity as a parallel structure to the RES Tier 1, the benefits of allowing markets to create price signals and liquidity, and the potential for LSEs to have access to the least-cost options.

A potential disadvantage of this approach, which may arise in particular in the later years of the program, is the risk of the contractual counterparty being unable to sell its offshore wind RECs at a price that covers its costs. This issue may arise at a time when offshore wind REC prices will have benefited

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from rapidly-declining offshore wind costs, undercutting the cost of procuring RECs from early-stage Phase I offshore wind projects.

Another potential disadvantage of this structure would be the potential mismatch between obligation and availability of eligible offshore wind RECs, which could result from the delay or failure of a project coming on line, or a major outage from an export cable failure (as discussed further in Section 5). Such mismatch could expose LSEs to REC price fluctuation.

Allocation Option

Under an allocation option, The Commission would set LSE compliance obligation levels to match actual production from procured volumes. Only offshore wind projects awarded through the selected procurement process (as per Section 3) would be eligible to meet the LSE obligation, akin to the ZEC program. Like the New York ZECs, offshore wind RECs would be non-tradable and would be allocated to all LSEs in proportion to load. LSEs would pay the price established by NYSERDA or the PSC. There would be no alternative option to pay an ACP instead of obtaining the required amount of offshore wind RECs, although, as in the ZEC program, LSEs would have the option to procure offshore wind RECs through bilateral agreements with eligible offshore wind generators. In the case of one or more utilities as the procuring offshore wind entities (see Section 3.2), the Commission would need to determine the quantities and price at which such procuring utility would allocate offshore wind RECs to obligated LSEs.

The advantages of this approach are that it eliminates the disbursement risk as discussed above and the potential reliance on the utility backstop. NYSERDA (or, as appropriate, the procuring utility) would – by design – be able to sell all procured offshore wind RECs at a sufficient price. From the LSE perspective, there would be no risk of exposure to ACP payments in the event of mismatch between REC supply and obligation levels. This option would also avoid most of the implementation challenges noted for other options.

The disadvantages of this approach are that it would not allow formation of spot price market signals. However, this would likely not be a significant drawback -- the offshore wind market is expected to have limited capability to respond to spot price signals in the foreseeable future due to the projects' risk profile. In addition, under this approach LSEs would not know the exact quantity of their offshore wind REC obligation in advance. While LSEs prefer the ability to forecast precisely, the per MWh cost would be more predictable than under a market option approach, which would be helpful for pricing such retail offerings.

4.1.4 Option Comparison

On balance, NYSERDA recommends creating a distinct offshore wind LSE compliance target for Phase I, using an allocation structure similar to that utilized in the ZEC program for disbursement of offshore wind RECs. This option avoids the significant cost recovery risk that NYSERDA (or procuring utilities) would face under an approach where offshore wind would remain within the current RES Tier 1 LSE compliance obligation. An alternative option whereby offshore wind would remain in the RES Tier 1 obligation but would receive a REC multiplier could reduce (but not eliminate) the disbursement risk, but would at the same time introduce a range of implementation challenges, which would not occur under the option of a separate offshore wind compliance obligation. Within the option of a separate

offshore wind tier, the ZEC-like disbursement approach would be more suitable to the specific early-stage nature of the offshore wind market than disbursement through a REC trading approach.

4.2 LSE Compliance Obligation Targets

Two issues would need to be addressed regarding LSE compliance obligation target levels: (i) setting the level of the offshore wind obligation (unless the mainstream or multiplier options are pursued); and (ii) possible adjustments of the non-offshore wind Tier 1 LSE compliance targets in response to offshore wind procurement and generation.

4.2.1 Offshore Wind Compliance Obligation Targets

If the Commission adopts a dedicated offshore wind LSE compliance obligation under the market approach, it could set target levels as either:

- Intended to match the expected procurement volume and timing of offshore wind production;
- In excess of expected procurement volume and timing (allowing headroom for surplus offshore wind RECs from NYISO or in neighboring markets to supply); or,
- Below expected initial procurement volume and timing (allowing LSE banking towards increasing annual compliance target, but risking NYSERDA cash flow).

Under either of these approaches, as discussed above, the binary nature of an offshore wind obligation filled through a very small number of large projects would result in a significant risk of mismatch between targets and available offshore wind REC quantities.

By contrast, under the allocation structure, the design of the dedicated offshore wind obligation could be set to achieve a much greater match between REC supply and target. Perfect alignment between REC supply and target could be achieved by setting the target for each period upon conclusion of the period to match exactly the available offshore wind REC volume.

4.2.2 Impact on RES Tier 1 LSE Compliance Targets

Section 3.4 notes that the procurement volume of offshore wind projects could fulfil much or even all of the current Tier 1 procurement targets in certain years; a similar issue arises for Tier 1 LSE compliance targets if the offshore wind compliance target were mainstreamed into the RES Tier 1. This could create market uncertainty and risk for LSEs in their planning for compliance with Tier 1 targets.

This issue would not arise immediately if the Commission were to adopt the option of separate offshore wind compliance targets – distinct from Tier 1. However, as part of the Commission’s regular review of Tier 1 LSE compliance targets, it may adjust such targets over the period to 2030 both to reflect the contribution of offshore wind towards the 50 percent renewable electricity target and to ensure that the Tier 1 and offshore wind target trajectories together would reach the 50 percent target.

5 Transmission and Interconnection

Transmission and interconnection (T&I) strategies can have significant impacts on offshore wind cost, feasibility, scalability, timing/sequencing, sizing, and risk exposure:

- T&I is a major cost item, comprising as much as 30 percent of the total wind farm plus connection system cost;
- T&I strategy drives reliability and availability of offshore wind generation, both of which have a large impact on the cost of energy; and
- T&I strategy influences how the risks of delay or failure are managed and allocated, impacting the average cost of capital and in turn, the cost of energy.

Analysis of T&I infrastructure in this Options Paper is limited to the “wet transmission”, which includes the onshore substation, offshore substation, and export cable.⁷⁰

5.1 Phased Approach

Whether facilities are developed, sized and constructed to support a single, initial offshore wind facility (“direct radial” T&I), or instead are either expandable or sized to accommodate both initial and subsequently built facilities (a “backbone” network) is an important question when considering offshore wind T&I alternatives. Under some circumstances, the latter option offers the upside of improved scale economies and reduced barriers to entry; however, this approach can also lead to the risk of overbuilding facilities that may not end up getting used, potentially resulting in stranded asset costs.

Presently, the WEAs available to compete for a New York offshore wind procurement during Phase I are limited, dispersed, and not readily expandable. The sole New York lease area designated and leased by BOEM is capable of hosting approximately 1,000 MW and is leased to a single developer (Statoil Wind US LLC). Offshore wind projects in other leased areas within existing WEAs off of Rhode Island, Massachusetts, and New Jersey could conceivably interconnect directly to New York or interconnect within an adjacent control area with energy delivered to NYISO, which would make them eligible for procurement under the CES and under the options discussed in this paper.

New York has requested of BOEM the lease of additional New York WEAs,⁷¹ which could be designated and leased within two years, but this will likely be too late for participation in Phase I offshore wind procurement during 2018 and 2019. NYSERDA focuses its discussion of T&I options in this Options Paper on Phase I and assumes that during Phase I T&I will be procured to meet the needs of the project in question, resulting in direct radial structures for each project.

By Phase II, it is expected that BOEM will have leased additional areas where eligible projects could be built, which will allow consideration of additional options. An example of such a consideration can be

⁷⁰ Array cables are considered part of the generating assets for the purpose of this analysis.

⁷¹ On October 2, 2017, New York State submitted an identified Area for Consideration to BOEM, requesting that within this Area of Consideration, BOEM expeditiously identify and lease at least four new Wind Energy Areas, each capable of supporting at least 800 megawatts. <https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan/Area-for-Consideration>

found in Massachusetts. In June of 2017, Massachusetts utilities issued a request for proposals (RFP)⁷² to commence a competitive procurement for offshore wind. In a context markedly different from New York, Massachusetts has access to two BOEM-designated leases (which comprise part of larger WEAs containing unleased area further from shore), as well as the lease of a joint Rhode Island and Massachusetts WEA. In this RFP, Massachusetts gave bidders the opportunity to include proposals for T&I options that would allow the T&I infrastructure to be used by multiple future projects, and some bids did so.⁷³

5.2 Phase I Transmission & Interconnection Options

Even with the constraints that are expected to limit Phase I T&I infrastructure to direct project radials, there are many factors to consider when developing an offshore wind T&I strategy. These include timing mismatch risk between the construction of generation and transmission systems, delivery responsibility (liability in case of inability to deliver offshore wind generation due to constraints or failures in the T&I infrastructure), cost of financing, the cost recovery mechanism (through transmission or supply charges) and policy implementation practicalities. These factors are primarily impacted by the choice of T&I procurement structure. There are three primary options available for procurement of T&I, and within each option the entity that develops and owns the T&I assets is different.

- T&I may be procured together with the generation facility, with the winning developer constructing both;
- T&I may be procured through separate bids for T&I and generation assets (either in the same or separate procurement processes), such that different developers might construct the T&I and generation portions of the project; or
- T&I may be procured as a regulated asset in order to leverage the potentially lower cost of finance available for rate-based assets.

NYSERDA's assessment of these three options is informed by existing U.S. and European strategies and experiences.

5.2.1 T&I Option 1 – Developer Owned

The typical approach for large new U.S. wind development to date – primarily onshore⁷⁴ – is that the developer is responsible for the T&I infrastructure in the form of project-specific radials, and continues to maintain ownership post-construction. Within the offshore wind procurement context, this would mean that both generation and T&I would be procured as part of the same solicitation. Procurement bids would need to reflect the cost of both generation and T&I assets. Any above-market premium needed to finance the combined cost would be borne through the LSE compliance obligation and

⁷² MA DOER, et al. Request for Proposals For Long-Term Contracts For Offshore Wind Energy Projects (2017).

⁷³ See <https://macleanenergy.com/83c/83c-bids/>

⁷⁴ As there has been little U.S. offshore wind experience, the experience described is that of most U.S. land-based wind. For the one operating U.S. offshore wind farm, Block Island Wind Farm, developer Deepwater Wind owns the connection between the generator and a National Grid substation on Block Island; due to the unique configuration of that facility, which involved also interconnecting Block Island to the mainland power grid, Deepwater Wind also commenced development of the cable between BIWF and the mainland, which was transferred to National Grid who completed construction and owns that facility.

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ultimately supply charges as discussed in Section 4. During operation, the developer would need to manage any delivery risk (the risk that offshore wind energy could not be delivered onshore due to T&I cable failure or outage). Options could be explored to mitigate such risk, such as underwriting a portion of the risk through a New York Green Bank dedicated reserve fund.

Option Assessment

- The advantages of this option are:
 - Construction timing risk would be a reduced concern, since the same developer would be responsible for construction of both T&I and the generating facility.
 - Since the developer of the generating assets also owns and operates the T&I infrastructure, the developer would be in control of any delivery risk and could thus manage this risk better than if the T&I owner is separate.
 - In practical terms, including T&I procurement in the solicitation process for offshore wind projects would minimize the administrative and contractual complexities.
- The disadvantages of this approach are:
 - Developer-owned T&I infrastructure would be expected to be subject to somewhat higher costs of finance under most of the procurement options discussed in Section 3 (see Section 6 for a more detailed discussion of T&I cost projections under various procurement options) compared to T&I development as a regulated asset.
 - The scope of the T&I infrastructure would likely be tailored to the generation project in question, and a “backbone” approach as may be considered for Phase II may be more difficult to implement. However, given the assumption of radial T&I development as discussed above during Phase I, this would likely not be a concern for procurement in the near term; in addition, the experience of the Massachusetts RFP described above indicates that it would still be possible to scope network-type T&I approaches under the developer-owned T&I approach.

5.2.2 T&I Option 2 – Independently Owned

Instead of procuring offshore wind projects as joint bids for generating assets and T&I infrastructure, T&I could be procured either through a separate solicitation, or a single solicitation could allow separate bids and separate selection of winners for the respective two project components. The same developer could be the winner in both auctions, but this would not necessarily be so.

During Phase I, T&I projects would be expected to be scoped and sized to match the requirements of the offshore wind generation project in question, though it would be possible to invite network-type bids. Bids would likely be invited on a \$/MW-year basis.

It would be necessary to determine how delivery risk would be allocated between the generation and T&I asset owners, both in the contracts with the developer of the generating assets and the developer of the T&I assets. Options for the allocation of delivery risk include requiring a certain level of delivery availability commitment (e.g. in the form of a minimum service level commitment) from the T&I owner and specifying the calculation of liability if the T&I owner fails to meet the delivery standard.

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Payments under the T&I contract could be made either directly from the procuring entity to the T&I owner, or on a pass-through basis to the owner of the generating assets. The latter approach could be more attractive since it would create a contractual relationship between the owners of the generating and T&I assets, which would facilitate, for instance, the implementation of delivery performance standards.

The Commission would need to establish how the costs of the winning T&I bid would be funded given that the T&I developer would not be in a position to produce RECs. To the extent that NYSERDA (or a utility) would procure both the generating and T&I assets, a likely option would be to use a funding approach based on the offshore wind LSE compliance obligation (as discussed in Section 4) for both projects. The procuring entity would blend premium payments made for both projects into the price at which offshore wind RECs would be disbursed to LSEs. Other funding options either through ratepayers' supply or distribution charges could be considered.

A variant for consideration could be a structure whereby procurement and construction of the T&I assets is included in the procurement of the generating assets (as per T&I Option 1) but ownership of the T&I infrastructure is divested to a third party offshore transmission owner after commissioning.

Option Assessment

- The advantages of this option are:
 - It offers the potential benefit relative to the T&I Option 1 of allowing more easily for scaled economies with backbone and oversized structures.
 - Conducting a separate procurement process for the T&I infrastructure may maximize competitive benefits and put further downward pressure on T&I project costs.
- The disadvantages are:
 - This structure is untested, and could be subject to implementation complexities in the interaction of the procurement and contracting processes between the generating and T&I assets.
 - There could be increased construction timing mismatch risk under this structure if the procurement results in different owners of the generation and T&I facilities.

5.2.3 T&I Option 3 - Regulated Asset

Multiple European countries, including Germany, France, the Netherlands and Denmark, have pursued a structure where a regulated entity – the onshore transmission system operator (TSO) or an offshore transmission owner (OFTO) – is responsible for extending the transmission system offshore to connect with the offshore substation and operating it for the lifetime of the asset. In New York, procurement of T&I assets using a similar structure could be carried out as utility-owned, rate-based assets (similar to the UOG option discussed in Section 3 for procurement of generating assets) or through the Public Policy Transmission Planning Process (PPTPP, see Box 1).

Procurement of the offshore wind generating facility would be carried out without procurement of T&I infrastructure, and bid prices would reflect the cost of the generating asset only. The cost of T&I would be borne by ratepayers through transmission charges.

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A number of jurisdictional, policy and project scoping issues would need to be resolved to determine whether offshore wind T&I would be eligible for development as a rate-based asset, in particular in the case of point-to-point connections such as a direct radial connection between the onshore substation and the offshore wind turbines. As noted in Section 3, current Commission policy does not allow for utility ownership of generating assets, and this position may extend to (direct radial) T&I assets. Under either utility rate cases or the PPTPP, questions around the PSC's jurisdiction in offshore waters would arise. T&I utility ownership would also depend on utility appetite to proceed based on this approach.

It would be necessary to determine how delivery risk would be allocated between the generation and T&I asset owners. For instance, in Germany the T&I owner is subject to delivery service level commitments, such that the generation owner would be compensated in certain circumstances if offshore wind energy cannot be delivered due to issues related to the T&I infrastructure. However, there is little precedence for such arrangements in respect of regulated assets in the U.S.

A variant for consideration could be a structure whereby procurement and construction of the T&I assets is included in the procurement of the generating assets (as per Option 1) but ownership of the T&I infrastructure is divested to a utility under its rate case after commissioning.

Box 1 – The NYISO Public Policy Transmission Planning Process (PPTPP)⁷⁵

The NYISO PPTPP is one of four components of the NYISO's Comprehensive System Planning Process (CSPP). It is the result of FERC Order 1000 requiring public transmission providers to consider public policy in transmission planning. According to the NYISO Public Policy Transmission Planning Process Manual, "A Public Policy Requirement is defined in the tariff as a federal or state law or regulation, including a Commission rulemaking order adopted after public notice and comment under state law, that drives the need for transmission." Steps in the PPTPP include:

1. Identification Step: the NYISO solicits proposals for transmission needs driven by Public Policy Requirements. The Commission then considers proposals and determines for which ones the NYISO should solicit proposals.
2. Proposal Step: the NYISO solicits proposals for needs identified in Step 1.
3. Evaluation Step: the NYISO evaluates viability and sufficiency of proposals to satisfy Public Policy Transmission Need.
4. Selection Step: the NYISO evaluates and selects the most efficient and/or cost-effective solution. "The NYISO develops the Public Policy Transmission Planning Report that sets forth its findings regarding the proposed solutions."

Evaluation metrics include "capital costs, cost per MW ratio, expandability, operability and performance of the solution, availability of property rights, schedule for project completion, and criteria specified by the NYPSC." The PPTPP occurs once every two years. NYISO last solicited proposals (Step 1) in August 2016; 12 proposals were submitted in October 2016.

⁷⁵ www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/M-36_Public%20Policy%20Manual_v1_0_Final.pdf

Option Assessment

- The main advantages of this option are:
 - As discussed in more detail in Section 6, T&I assets developed as regulated assets are expected to benefit from somewhat lower costs of finance compared to market-rate procurement options.
 - This option also allows more easily for scale economies through the development of a “backbone” network or shared radial structure where the transmission is able to facilitate the interconnection of multiple projects, though, as noted, this may be a more relevant consideration during Phase II.
- The disadvantages are:
 - A number of implementation issues and hurdles would need to be addressed. The regulated asset approach is generally applied to network-type assets rather than direct radial connections, and the Commission’s position whether this option could be pursued for radial T&I infrastructure during Phase I would need to be clarified. The Commission’s jurisdiction in offshore waters would need to be confirmed.
 - Construction timing risk could be more of an issue than under T&I Option 1, which presents the possibility of either the generation facility or transmission infrastructure not earning revenue for some period.
 - Planning and construction through the PPTPP is a cumbersome and untested process that would likely take significantly more time than the other options considered.
 - The Commission would need to determine to what extent the owner of a regulated offshore wind T&I asset would be subjected to liability for failure to deliver the energy; unless service level standards in this respect could be applied to the owner of the T&I infrastructure, the generation owner would be fully exposed to delivery risk but would have no means of controlling it. This could increase overall project risk and cost compared to Option 1 where this risk is within the generation owner’s control.

5.2.4 T&I Option Comparison

T&I Option 1 (Developer Owned) is the most familiar approach and would face few implementation challenges. Key potential risks – construction timing mismatch risk and energy delivery risk – would be controlled by the entity best placed to manage them: the offshore wind project developer. Depending on the generation asset procurement structure to be pursued (see Section 3), this option may be subject to somewhat higher costs than T&I Option 3 (Regulated Asset), but the cost difference is estimated to be relatively small.

An advantage of either T&I Option 3 or Option 2 (Independently Owned) would be that they would more easily enable development of network or backbone T&I projects. However, given the expected radial connection approach to Phase I projects, this factor is unlikely to be of significance until Phase II projects are considered, and procurement under Phase I under any of the options could still include aspects of network T&I infrastructure if so desired.

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A disadvantage of T&I Option 2 (Independently Owned) is that this structure is untested and would involve more implementation complexities than Option 1, but NYSERDA recognizes that this option could be suitable for Phase I.

6 Cost Analysis

NYSERDA has conducted an offshore wind cost analysis in support of the policy assessment in this Options Paper. This analysis complements the CES Cost Study, which was published on April 8, 2016.⁷⁶ NYSERDA acknowledges the contributions of Sustainable Energy Advantage, LLC (SEA) and SEA's subcontracting consultants BVG Associates (BVG) and Climate Policy Initiative (CPI) for their primary analytical role in the development of this analysis.

This section describes the cost analysis carried out for Phase I, reflecting deployments of up to 800 MW of capacity procured in 2018 and 2019 and deployed in 2024 and 2025. Longer-term costs associated with deployment of 2.4 GW of offshore wind by 2030 are considered in Appendix D.

Program costs depend on a number of key factors, some of which can be influenced directly by New York State ("endogenous" factors), such as procurement structure, transmission ownership strategy and siting decisions. Other factors, are largely outside of New York's control ("exogenous" factors), such as wholesale energy prices (which are driven by natural gas prices) and financing costs. This section analyzes the cost impacts associated with variations in the endogenous factors, while the exogenous factors are considered in Appendix D.

Appendix C provides details in respect of the key input assumptions and methodology applied to the cost and benefit analysis in this Options Paper.

Cost projections for Phase I projects are provided in this section in the form of the following cost indicators:

1. **Incremental program costs** are calculated as the incremental revenue, on top of energy, capacity and Tier 1 REC premiums, that would allow offshore wind generators to reach their cost of capital. These costs are provided as a net present value of incremental performance-based incentive (PBI) payments over time on top of the projected value of Tier 1 RECs.
2. **Electricity bill impact** is expressed as the incremental program costs in 2025, the last year of Phase I deployment, in real dollars, divided by the most recently reported (2016) total statewide electricity bill spend.

⁷⁶ DPS. 2016. "Clean Energy Standard White Paper – Cost Study."

6.1 Key Findings

Key findings of the analysis include:

1. Consistent with the findings of the CES Cost Study, procurement structures result in significant differences in projected costs. As shown in Section 6.3, a structure providing a hedged revenue stream such as a “Bundled PPA” delivers substantially lower project and program costs than structures that provided only a limited hedge against commodity price risk, such as the existing “Fixed REC” structure.
2. Small initial projects are not likely to deliver cost savings. Due to diseconomies of scale, the costs per unit of energy for projects of 100 MW and 200 MW in size are significantly higher than those for 400 MW projects. As a result, the total Phase I program costs for such smaller projects would be comparable to those of a 400 MW project despite their smaller size and energy output. This is discussed in Section 6.4.
3. Long-term ownership of the “wet transmission” infrastructure, which includes the onshore substation, offshore substation and export cable, is a modest driver of projected costs. T&I Option 3, under which the T&I infrastructure would be owned as a regulated asset, could offer modest cost benefits to a structure where the developer is retained as the long-term owner, as shown in Section 6.5.
4. While future long-term trends in wholesale energy prices are uncertain, they are expected to be an important driver of offshore wind program costs over the period to the 2030 goal. However, variances in program costs as a result of energy price swings would be outweighed by opposite effects on ratepayers’ overall electricity bills. For example, lower-than-expected energy prices could increase offshore wind program costs, but this would be more than offset by a reduction in energy bills from lower wholesale energy prices. See Appendix D.2.1.
5. The largest driver of potential variations in financing costs is the choice of procurement structure. In addition, the analysis examined the impact of finance cost data uncertainty. While less impactful, sensitivity analysis in this respect as set out in Appendix D.2.2 suggests that Phase I cost projections presented throughout this Options Paper are subject to an uncertainty range of plus or minus \$0.2B due to such data uncertainty.

6.2 Base Case Assumptions

Section 1.2 discusses the range of in-state and out-of-state sites available for Phase I deployment; for the purposes of the cost analysis presented in this section, deployment was assumed to take place in the area referred to as the Statoil Lease Area (see Figure 12). This site has the potential to support more than 1,000 MW.⁷⁷ The analysis for Phase I deployment in this Options Paper examines a base case scenario of 400 MW of offshore wind deployed in both 2024 and 2025, in line with the recommendation set out in Section 3.4. Alternative Phase I project sizes for the 2024 deployment are considered in Section 6.4, which examines whether small initial project sizes can deliver cost savings. NYSERDA also assumes that the Phase I projects interconnect to Long Island, which offers a shorter distance than a

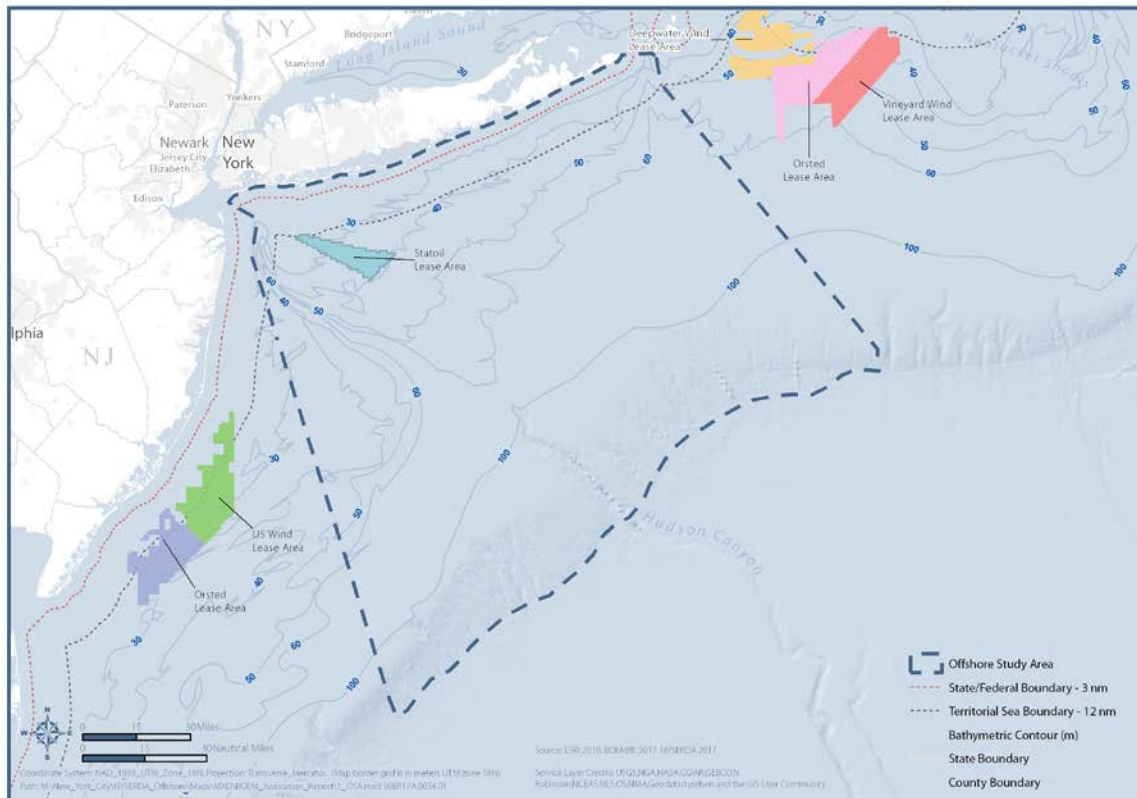
⁷⁷ Statoil presentation to New York task force meeting, “Statoil New York WEA – status and way forward”, October 3, 2017.

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New York City connection. Transmission constraints and energy demand may determine if a different interconnection strategy is required. These sensitivities are considered in the Master Plan.

As discussed in Section 5, the base assumption in this study is a “developer-owned” transmission strategy, reflective of T&I Option 1. Under this option, the wet T&I, defined as the onshore substation, offshore substation and export cable, is developed, constructed and owned by the generation project developer.

Figure 12: Offshore wind areas are expected to be eligible for Phase I procurements (not inclusive of the sites that may deliver offshore wind to New York during Phase II)



6.3 Procurement Structure Scenarios

As discussed in Section 3, NYSDORA has identified multiple procurement structures for consideration. Detailed descriptions of these options can be found in Section 3.2. Table 3 below notes the estimated Phase I incremental program costs associated with each of these options, under base case assumptions as described in Section 6.2 above.

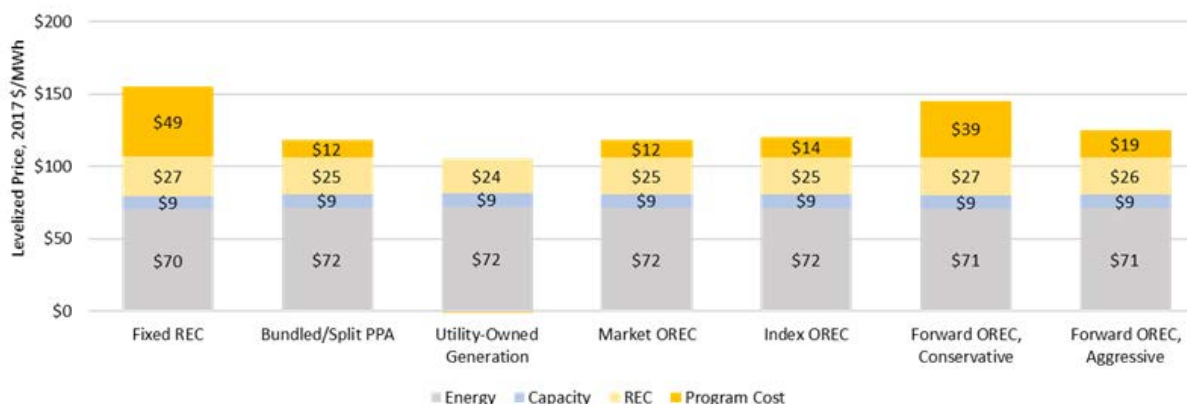
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Table 3: Phase I incremental program cost and bill impact by procurement option

Cost Indicator	1. Fixed REC	2./4. Bundled/ Split PPA ⁷⁸	3. Utility- Owned Generation	5. Market OREC	6. Index OREC	7a. Forward OREC, Conservative	7b. Forward OREC, Aggressive
Phase I Incremental Program Cost	\$1.2B cost	\$0.3B cost	\$0.2B benefit	\$0.2B cost	\$0.3B cost	\$1.0B cost	\$0.4B cost
Phase I Incremental Bill Impact	0.76%	0.19%	-0.16%	0.14%	0.18%	0.60%	0.26%

Figure 13 illustrates the breakdown of the levelized cost of energy (LCOE)⁷⁹ for each procurement option in a 2024 400 MW deployment, shown as its constituent components of energy, capacity, REC and program cost revenue.

Figure 13: LCOE broken down by energy, capacity, REC and program cost for 2024 400 MW deployments of varying procurement structure



These procurement sensitivities present a wide range of incremental program costs. Those structures that offer perfect or near-perfect hedges show significantly lower program costs than approaches that offer a more limited hedge, in particular the Fixed REC option. The low-cost options include Bundled PPA, Index OREC and UOG. The Forward OREC model presents significantly different program cost outlooks between the conservative and aggressive scenarios. As discussed in Section 3.2.7 there is uncertainty in the likelihood of conservative or aggressive outcomes for the Forward OREC model. Similarly, the Market OREC, Bundled PPA, UOG and Split PPA options are all subject to significant qualitative dependencies and uncertainties, discussed in Section 3.2.

Both the Bundled PPA and Market OREC structures offer a perfect hedge to the project developer, therefore resulting in identical LCOEs. These structures differ in incremental program costs, however, because the Bundled PPA option includes a 2.75% assumed premium paid to the contracting utility that

⁷⁸ As discussed in Section 3.2.4, under the Split PPA option, the effective cost to ratepayers may be significantly higher than the figure stated here, depending on the fixed long-term price a utility may be prepared to offer for energy and capacity.

⁷⁹ LCOE represents the levelized volumetric pricing per unit of energy required by a project over its projected useful life to achieve the investor's target rate of return.

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is captured in the program cost calculation but not reflected in the LCOE. The Split PPA option, which also offers a perfect hedge, is equal in LCOE to the Bundled PPA and Market OREC options but may be comprised of varying levels of energy, capacity and program cost revenues. This is because the contracting utility in the Split PPA structure may value energy and capacity at a discount relative to projected wholesale prices, in which case the cost to statewide ratepayers (REC and program cost) would comprise a greater proportion of LCOE than shown in Figure 13.

6.4 Project Size Scenarios

This section examines the impact of procuring various levels of generating capacity in the first procurement (in 2018), which is expected to be operational in 2024. Three scenarios are considered: 400 MW (the base case scenario), 100 MW and 200 MW.

To provide a sense of the cost impacts across the range of procurement options studied in Section 3.2, this section utilizes two representative structures, the Bundled PPA and Fixed REC. As only a single deployment year is analyzed, the cost results shown in Table 4 do not reflect the full Phase I, but only the first procurement in 2024.

Table 4: 2024 incremental program cost and bill impact by project size

Cost Indicator	Fixed REC			Bundled PPA		
	400 MW	100 MW	200 MW	400 MW	100 MW	200 MW
2024 Incremental Program Cost	\$0.7B cost	\$0.5B cost	\$0.6B cost	\$0.2B cost	\$0.4B Cost	\$0.3B cost
2024 Incremental Bill Impact	0.41%	0.28%	0.33%	0.11%	0.20%	0.19%

Figure 14: LCOE broken down by energy, capacity, REC and program cost for 2024 deployments of varying size and procurement structure

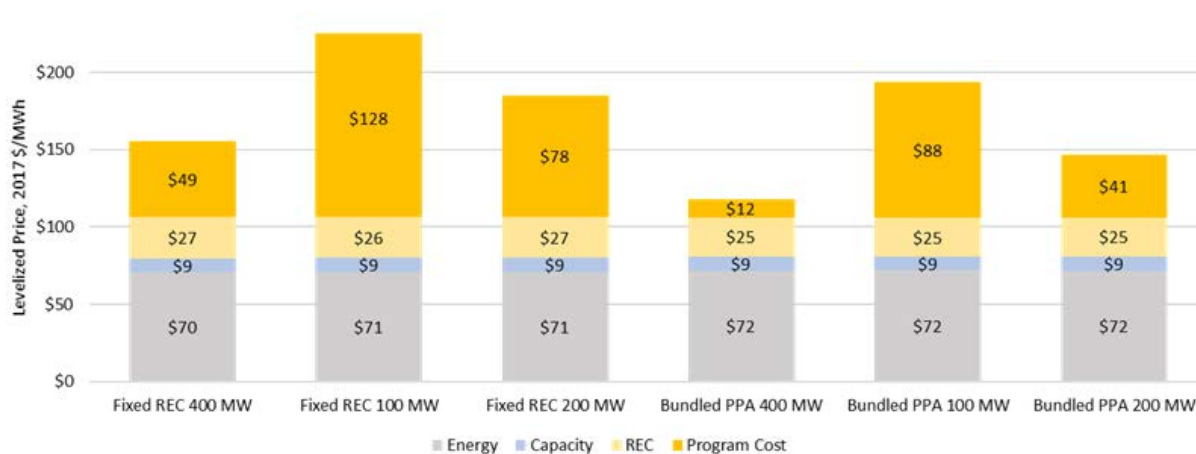


Figure 14 shows the significant diseconomies of scale that occur when comparing 100 MW or 200 MW projects to a 400 MW project. As can also be observed in Figure 14, these effects are magnified in the

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incremental program cost, because the other elements of the revenue stack – energy, capacity and RECs – are not affected by varying project size. For instance, under the Bundled PPA procurement model, a 400 MW project offers a 39% reduction in LCOE versus a 100 MW project and a 20% reduction versus a 200 MW project. However, when considering incremental volumetric (\$/MWh) program costs, the 400 MW project offers a reduction of 86% and 70% versus the 100 MW and 200 MW projects, respectively. As a result of these diseconomies of scale, estimated total incremental program cost for the 2024 deployment is similar across the three sizes (as shown in Table 4), and in some cases the smaller projects are even projected to cost more than the 400 MW project.

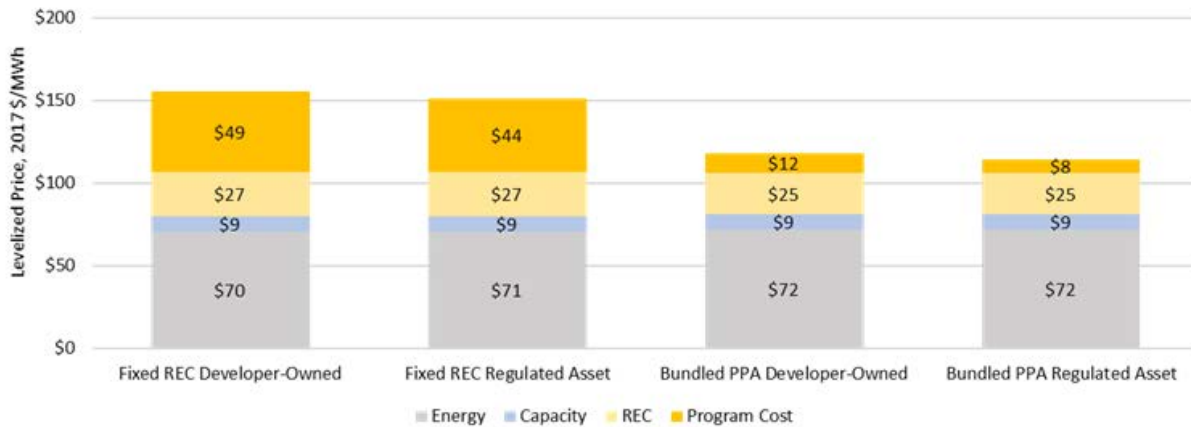
6.5 Transmission Ownership Scenarios

As discussed in Section 5.2, there are several possible options for offshore wind T&I strategy, particularly in regard to the procurement structure. The base assumption in this study is “developer-owned”, where procurement of the onshore substation, offshore substation and export cable occurs together with the generation assets, reflective of T&I Option 1. An alternative option, T&I Option 3, is for the wet transmission to be procured, developed and owned as a “regulated asset”.

The “developer-owned” and “regulated asset” scenarios were analyzed for Phase I deployments in the context of two representative procurement structures, the Fixed REC and Bundled PPA.

Table 5 and Figure 15 show that there is only a modest difference in program cost or LCOE between developer-owned and regulated asset scenarios. This cost difference is a function of the lower cost of capital that is expected for regulated assets, and is of an order of magnitude lower than the range of cost differences seen between different procurement structures

Figure 15: LCOE broken down by energy, capacity, REC and program cost for Phase I deployments of varying transmission ownership and procurement structure



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Table 5: Phase I incremental program cost and bill impact by transmission ownership strategy

Cost Indicator	Fixed REC		Bundled PPA	
	Developer-Owned	Regulated Asset	Developer-Owned	Regulated Asset
Phase I Incremental Program Cost	\$1.2B cost	\$1.1B cost	\$0.3B cost	\$0.2B Cost
Phase I Incremental Bill Impact	0.76%	0.69%	0.14%	0.08%

Appendices

Appendix A. Technology Methodology

This appendix describes the analysis used to estimate the expected capital expenditures (capex), operational expenditures (opex) and capacity factors for offshore wind projects deployed in Atlantic waters off New York during the period to 2030. The forecasted values are used, along with separately derived financing assumptions detailed in Appendix B, to derive levelized cost of energy (LCOE) estimates for offshore wind, which is in turn used to estimate program costs for the various scenarios and sensitivities assessed in this Options Paper (see Appendix C).

This analysis discussed in this appendix was developed by BVG Associates (BVGA), with contributions from Sustainable Energy Advantage and AWS Truepower, a UL company.

A.1 Site Characteristics and Deployment Assumptions

The analysis studies capex, opex, and capacity factors as a function of four primary variables:

- Site characteristics (average water depth, distance to grid, distance to staging port and average wind speed);
- Project vintage: commercial operation dates (CODs) are considered for any year between 2022 and 2030;
- Individual offshore wind project size: 100 MW, 200 MW, 400 MW or 800 MW; and
- Overall deployment profile in New York, the region and globally (as costs are dependent on economies of scale across the wider market).

Technology choices, including turbine rated capacity, foundation type and transmission system (alternative current (AC) or direct current (DC)), are only varied indirectly through the site characteristics and project vintage:

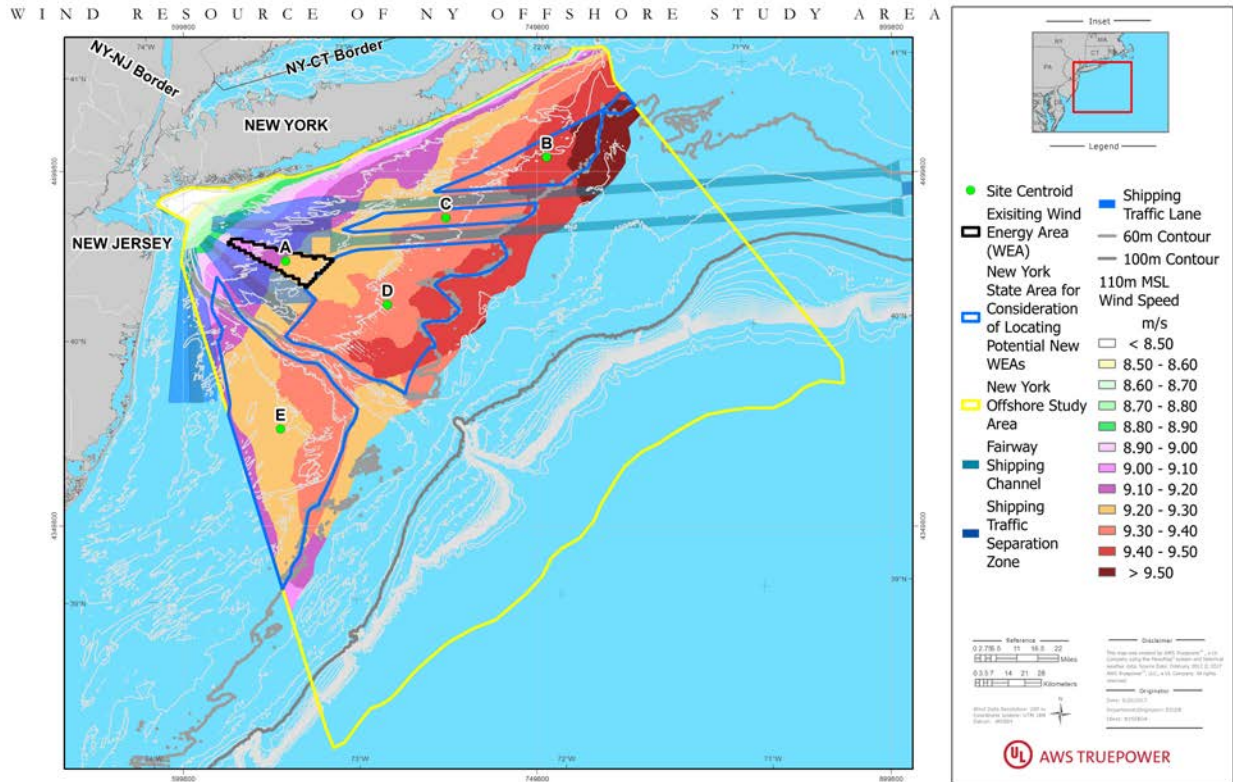
- Turbine capacity is a function of each project's vintage (and accordingly, cost reductions as a result of increasing turbine size over time are addressed through the learning rates described in Section A.7). Turbine size assumptions reflect the projected standard commercially viable technology over time;
- Foundation type is dictated by water depth, but all sites have water depths where jacket foundations are expected to be the lowest cost option;
- The specifics of the transmission system are determined by the project rating and the distance to grid (both offshore and onshore), with large projects more than 160 km offshore generally preferring DC transmission.

As New York is a new market for offshore wind, it is assumed that the turbines used in the first projects will not be the largest, state of the art size, but rather commercially proven turbines that are capable of being installed by vessels available in the eastern U.S. waters. This analysis assumes an 9.5 MW turbine capacity for COD 2024 projects. By COD 2030, this is assumed to have increased to 13 MW. Incremental increases in turbine size, which can be seen in Table 7, are assumed for vintages between 2024 and 2030.

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To derive resource costs that are representative of potential offshore wind projects in New York and consistent with current and likely future Wind Energy Areas to be leased by BOEM, the analysis considers five zones, shown as A through E in Figure 16.

Figure 16: Location and wind resource of zones A through E



For illustrative purposes, Table 6 shows the site characteristics for the centroids of each zone, which are also identified in Figure 16.

Table 6: Site characteristic for the centroids of each site

Zone	Mean water depth (m)	Distance to Long Island grid (km)	Distance to New York City grid (km)	Minimum distance to port (km)	Wind speed at 108m above MSL (m/s)
A	35	51	105	81	9.2
B	50	117	211	126	9.4
C	46	79	165	142	9.3
D	52	81	155	132	9.3
E	36	123	157	134	9.3

Due to the shape of the continental shelf in the study area, the water depth is similar between the zones, suggesting the likely use of similar foundation technology between sites. Wind speeds are also relatively consistent across zones, meaning distances to interconnection and port facilities expected to be the primary drivers of cost differentiation between zones.

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Table 7: Base deployment profile for New York. Zones are defined by their original naming convention, shown in Figure 16, as well as the modified naming convention used for the BOEM proposal, shown in Figure 17

Value \ COD	2024	2025	2026	2027	2028	2029	2030
Zone	A (Statoil)	A (Statoil)	n/a	D (East)	E (West)	E (West)	D (East)
Farm Size (MW)	400	400	n/a	400	400	400	400
Transmission Interconnection	Long Island	Long Island	n/a	Long Island	NYC	NYC	NYC
Turbine Capacity (MW)	9.5	9.5	n/a	11.0	13.0	13.0	13.0
Foundation Type	Jacket	Jacket	n/a	Jacket	Jacket	Jacket	Jacket
Transmission Type	AC	AC	n/a	AC	AC	AC	AC

Table 7 shows the deployment profile assumed for the cost analysis. Building on the Phase I deployment assumptions discussed in Section 6.2, the analysis assumes that:

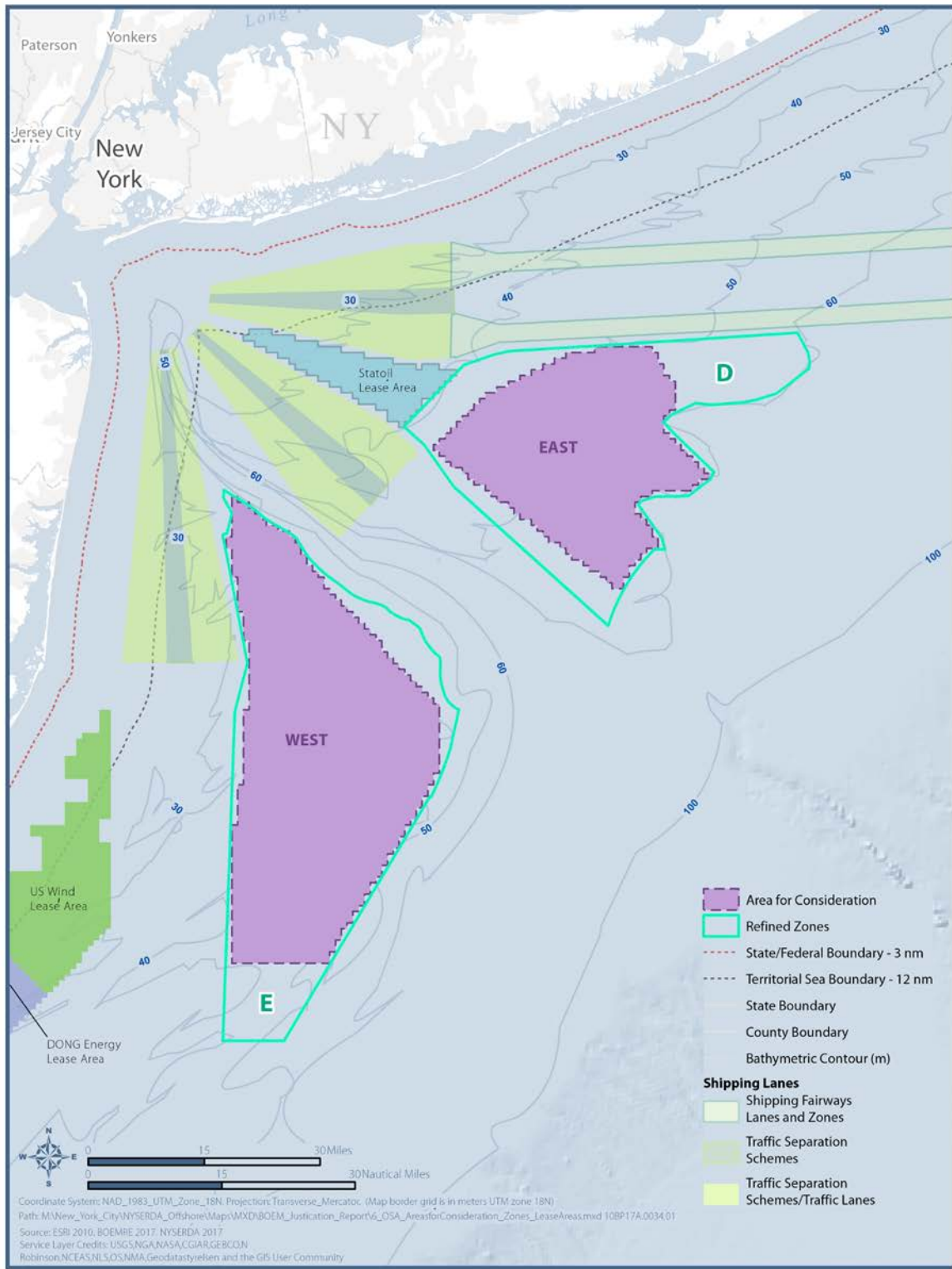
- No more than 400 MW will be installed in a single year to reduce supply chain and installation risk;
- A hiatus of one year between Phase I and Phase II solicitations would lead to a one-year deployment gap in 2026;
- 1,200 MW of offshore wind is connected to Long Island and 1,200 MW is connected to New York City (transmission constraints and energy demand may determine a different interconnection strategy is required); and
- Development would take place in the most economical locations within each zone, optimizing variables such as distance to shore and water depth.

Zone A was considered because it is an existing WEA, and zones D and E are representative of the areas for consideration proposed to BOEM, which are shown below in Figure 17.⁸⁰

⁸⁰ NYSERDA. 2017. New York State Area for Consideration for the Potential Locating of Offshore Wind Energy Areas. <https://www.nyseda.ny.gov/-/media/Files/Programs/offshore-wind/Potential-Locating-OSW-AreaConsideration.pdf>

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Figure 17: The areas for consideration identified by NYSERDA in its recommendation to BOEM. These areas are not inclusive of the sites that may deliver offshore wind to New York. Also pictured are the current leases held by Statoil, US Wind and DONG Energy. The Statoil, East, and West sites are utilized for the cost analysis of New York's 2.4 GW goal.



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A number of more detailed assumptions on site characteristics and deployment are set out in Box 2 below.

Box 2 – Detailed site and deployment assumptions

- Projects are assumed to have an operational life of 25 years, consistent with current industry standards.
- The analysis assumes turbines are spaced at nine rotor diameters (downwind) and six rotor diameters (cross-wind) in a rectangle, with the lowest point of the rotor sweep at least 22 meters above mean high water. A tidal range of 2 meters is assumed, and no storm surge is considered.
- A multi-contract approach is assumed for construction, meaning that fully-wrapped engineering, procurement and construction contracts are not available.
- The turbines are assumed to be certified to Class IA to international offshore wind turbine design standard IEC 61400-3.
- The 2022 baseline turbines are assumed to have low-ratio gearboxes and mid speed, mid-voltage AC generators, with a 164-meter diameter rotor and a capacity of 8 MW (modifications related to turbine size over time are addressed in Section A.7).
- Ground conditions are assumed to have some locations with lower bearing pressure, the presence of boulders, or significant gradients, but to have enough locations with 10 meters of dense sand on 15 meters of stiff clay, which would be suitable for a wind farm.
- Installation is assumed to occur sequentially: the foundation first, followed by the array cable and then the pre-assembled tower and turbine.
- At the end of the project life, the decommissioning process is assumed to take one year, as it fully reverses the assembly process. Piles are cut off at a depth below the sea bed, which is unlikely to lead to uncovering, and cables are pulled out. Environmental monitoring is conducted after all equipment has been removed. The residual value and cost of scrapping is ignored.

A.2 Cost Methodology

To derive offshore wind capex and opex projections, this analysis forecasts the cost of components and services involved in the development, construction, operation, and decommissioning of generation assets and their associated transmission. Transmission costs include the supply, installation, operation, and decommissioning of the offshore substation and cables, as well as upgrades of an onshore substation.

Cost data from the European offshore wind market was used to develop detailed baseline cost assumptions assuming a COD of 2022. These assumptions were then modified to produce values appropriate to New York. Adjusting European data for the New York context involved modifications for logistics, materials, labor and financing costs, as well as modifications for differences in supply chain resourcing and component sourcing.

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For projects with a COD in 2022, it is assumed that most of the components and installation services would be procured from a global, rather than U.S., supply chain. In particular, turbine supply from Europe and use of a European installation vessel are assumed. Some development work is assumed to be performed by organizations in New York and other U.S. states. In the operational phase, the first few years of activity are assumed to be delivered by technicians from companies in the global supply chain. It was assumed that no ports would be able to accommodate a large jack-up vessel for major component exchange in 2022. Throughout the period to 2030, however, a U.S. supply chain is assumed to develop, and ports, vessels and personnel are assumed to be increasingly available locally. The approach to estimating technology cost reductions over the period to 2030 (including as a result of transitioning to a local supply chain) is detailed in Section A.7 below.

A.2.1 Data Sources

With the lack of data for project development in the U.S., capex and opex are derived based on a detailed assessment of offshore wind in the European market modified to reflect the New York case.

The most recent sources of information available related to European capex and opex are:

- Technology Innovation Needs Assessment (TINA): Offshore Wind Power Summary Report, Low Carbon Innovation Coordination Group, 2016;⁸¹
- A Spatial-Economic Cost-Reduction Pathway Analysis for U.S. Offshore Wind Energy Development from 2015–2030, NREL, 2016;⁸²
- Innovation Outlook: Offshore Wind Technology, IRENA, 2016;⁸³ and
- Future renewable energy costs: offshore wind, InnoEnergy, 2016.⁸⁴

The source data contained within these reports is combined with industry announcements and direct academic or industrial enquiry to give up-to-date European offshore wind costs.

The New York offshore wind costs are developed from these by applying New York-specific inflators and deflators to the typical contributions for labor, materials, equipment and facilities costs. The following cost modifiers are used.

- Any transport and import tariffs;
- Installation and major operations via Jones Act-compliant working are assumed; and
- Any other cost modifiers relevant for the U.S. situation, including labor and materials.

⁸¹ <http://www.lowcarboninnovation.co.uk/document.php?o=46>

⁸² <https://www.nrel.gov/docs/fy16osti/66579.pdf>

⁸³ <http://www.irena.org/->

/media/Files/IRENA/Agency/Publication/2016/IRENA_Innovation_Outlook_Offshore_Wind_2016.pdf

⁸⁴ http://www.innoenergy.com/wp-content/uploads/2016/09/KIC-InnoEnergy-Offshore-Wind-anticipated-innovations-impact-2016_A4.pdf

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The following sources are used to inform the derivation of U.S. modifiers:

- Oil and Gas Global Salary Guide, Hays, 2015 – data from this source is used as a proxy for offshore work;⁸⁵ and
- U.S. Wind Energy Manufacturing and Supply Chain: A Competitiveness Analysis, prepared for: U.S. Department of Energy by GLWN, Global Wind Network, June 15, 2014⁸⁶ – In comparison to onshore wind described in this source, it is assumed that offshore wind manufacturing is sourced more in the U.S. Northeast, rather than the Midwest or South.
- May 2016 State Occupational Employment and Wage Estimates, New York, Bureau of Labor Statistics.⁸⁷

Exchange rates and commodity pricing (steel, copper, etc.) are assumed to be fixed at average 2016 levels.

As costs were calibrated based on European research, costs were first developed for an 800 MW farm reflective of typical European project sizes expected for COD from 2022 to 2030. Table 8 below shows the baseline costs such a 2022 COD 800 MW project after modification of the data with U.S. modifiers as discussed above. Siting assumptions include interconnection to Long Island, a water depth of 45 meters, a wind speed of 9.2 meters per second, a distance to port of 105 kilometers and a distance to grid of 95 kilometers.

Table 8: Baseline capex, opex and capacity factor for a 800 MW, 2022 COD project interconnected to Long Island

Site Characteristic	Value
Generation CAPEX (\$000/MW)	4,041
Generation OPEX (\$000/MW/yr)	109
Transmission CAPEX (\$000/MW)	1,349
Transmission OPEX (\$000/MW/yr)	27
Net Capacity Factor	42.3%

A.2.2 Project Size and Location

Scale factors are used to adjust element values from those of the 800 MW site to the 400 MW base case site assumed in New York as well as the smaller sizes of 100 MW and 200 MW assessed in sensitivities. These scale factors are consistent with available data, and have been validated via industry engagement

⁸⁵ <https://www.hays.de/documents/10192/1770028/hays-oil-gas-salary-guide-2016.pdf>

⁸⁶ https://energy.gov/sites/prod/files/2014/09/f18/U.S.%20Wind%20Energy%20Manufacturing%20and%20Supply%20Chain%20Competitiveness%20Analysis_0.pdf

⁸⁷ https://www.bls.gov/oes/current/oes_ny.htm

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over the past two years, including major suppliers and developers of projects in Europe and with interests in projects in the U.S. For the 100 MW sites, however, the range of scale factors that could fit the data is large, so the accuracy of the estimate on any individual element is lower for the modelled 100 MW project size than that for the larger farms.

These scale factors are date-dependent functions for each project element. Larger differences in cost between site sizes are seen for the later vintages, where large sites are likely to have become more standard.

The projected costs are also adjusted for the physical siting characteristics of each zone as discussed in Section A.1 and shown in Figure 16: average water depth, distance to grid, distance to staging port and average wind speed. Table 9 below shows the baseline costs for 2022 COD 400 MW projects in each of the five zones.

Table 9: Baseline capex, opex and capacity factor for 400 MW, 2022 COD projects in each of the five zones

Site Characteristic	Zone A	Zone B	Zone C	Zone D	Zone E
Farm Size (MW)	400	400	400	400	400
Generation CAPEX (\$000/MW)	3,889	5,061	4,451	4,525	4,057
Generation OPEX (\$000/MW/yr)	115	128	121	120	117
Transmission CAPEX (\$000/MW)	1,151	1,427	1,136	1,233	1,405
Transmission OPEX (\$000/MW/yr)	21	25	20	22	25
Net Capacity Factor	42.2%	43.0%	42.5%	42.7%	42.0%

A.2.3 Transmission

Transmission costs are calculated for connection from the project site to an “average” substation. For projects of 400 MW or greater, this would require interconnection at 138 kV at least. No assessment is made of specific substation upgrades. Transmission cabling is assumed to be routed via either New York City or Long Island.

Modelled costs include the development of the transmission system and the supply of onshore and offshore substations and export cables. Data sources for the cost of equipment and installation of New York City transmission and interconnection are as noted in Section A.2.1 above – the European data for equipment and installation is assumed to be applicable for interconnection to New York City, as siting characteristics are similar. Costs of labor and materials are modified to be appropriate for New York; however, no additional cost has been assigned for the acquisition of land rights.

For transmission connecting to the grid through Long Island, there are barrier islands to navigate and a shallow lagoon to cross, as well as the usual landfall civil engineering work. Additional modelling was developed to assess these costs. To gather detailed insight about the additional costs associated with

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installing export cables across the barrier islands, input was received from Global Marine Systems, Fugro Subsea, DeepOcean, Van Oord, Jan de Nul, Transmission Excellence and TNEI. To cross the barrier islands, a standard joint box and ducted cable solution is assumed, although directional drilling for the whole of the island crossing could prove to be less disruptive. A barge suitable for shallow waters is assumed to be used to lay cable across the lagoon. In offshore waters, a specialist cable-lay vessel is assumed to be used.

Transmission cables work at high voltage to minimize energy losses over long distances. The analysis applies an HVAC or HVDC transmission system, depending which is more cost-effective based on the parameters of the installation in question. Over longer distances, HVAC is less efficient than HVDC. HVDC systems are currently very expensive, especially the required offshore substation. For mid-distances, it can be cheaper to use a HVAC system with reactive compensation stations. In the case of an HVAC system, up to two offshore substations are required depending on the project size. The rest of the transmission system is comprised of a single reactive compensation substation, two 3-core submarine export cables and a single onshore substation assumed to be feeding existing 230kV 60Hz circuits. In the case of an HVDC system, the transmission system is assumed to be comprised of a single offshore substation connected to an onshore substation via three 1-core export cables.

In all cases, this analysis assumes project-specific transmission systems that are direct radials to shore, and does not consider any shared export cable facilities.

A.3 Capex

The following components are included in the analysis of capex.

Development

Development costs cover a wide array of activities, including environmental and wildlife surveys, met mast installation and data collection, engineering and planning studies, and environmental monitoring. Also included are project management and other administrative and professional expenses, such as accounting and legal consultation. Apart from reservation payments to equipment suppliers, no construction or equipment costs are considered during development.

Turbine

Turbine components include the tower, nacelle, blades, and hub, as well as any required sub-systems and electrical systems to the point of connection to the array cables. Cost are also included for transportation and delivery to a port facility, turbine commissioning, and equipment warranties.

Foundation

Foundation components include any piles, transition pieces, secondary steel, or other components required for the foundation structure. Costs are also included for transportation and delivery to a port facility, and equipment warranties.

Array cables

Array cable costs include the supply of the cables, delivery to a port facility, and equipment warranties.

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Generation contingency

Contingency for the generation assets include potential cost overruns for both the supply and installation of the turbine, foundation, and array cabling.

Installation of the generation asset

The installation of the generation assets includes activities such as transportation of all components from the port facilities, any pre-assembly work at the staging port, and the installation of all array cables, foundations, and turbines. Commissioning work is also included for the array cables and foundations, while turbine commissioning is performed through the turbine supply agreement. Additional costs are also considered for scour protection for the foundations and array cables, subsea cable protection (such as mats), and construction insurance. Insurance is expected to cover all construction and third-party risks from the start of construction through commissioning.

Decommissioning

Beyond the removal of the turbines, foundations, and array cables, decommissioning costs also include planning work and the design of any additional required equipment. Costs are also considered for additional environmental work and monitoring that may be legally required.

T&I Assets

The T&I infrastructure includes the offshore substation, onshore substation, and the export cable that connects the two. Costs considered include the equipment supply, installation, and contingency for both the supply and installation costs.

A.4 Opex

All site access for opex purposes is assumed to be provided by a service operation vessel. The following components are included in the modelling of the opex.

Planned maintenance

Planned maintenance includes the scheduled maintenance of turbines based on suppliers' recommendations or the owner's experience. Such maintenance includes condition-based rather than time-based maintenance programs, as well as planned health and safety inspections.

Unplanned service

Unscheduled interventions in response to events or failures are the primary drivers of unplanned service costs. Interventions may be proactive (before failure occurs, by responding to condition monitoring inspections) or reactive (after failure has occurred). Also included is contingency for major components failing before the full turbine design life.

T&I Assets

Opex costs of the T&I infrastructure includes maintenance of the substation and export cable, including planned maintenance and unscheduled response to events or failures. Also considered are potential costs related to the operation of the onshore grid.

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Other Opex

Other opex covers fixed cost elements that are unaffected by technology innovations, including contributions to community funds, and monitoring of the local environmental impact of the wind farm.

A.5 Development & Construction Financing

The costs of development and construction are assumed to be funded by the project developer through construction financing. Construction financing is assumed to be taken out prior to any significant development or construction spend, and its costs are rolled into the final installed capex figures in this analysis. Development and construction phase financing assumptions (weighted average cost of capital, or WACCs) are applied to the installed capex projections to derive the final installed total capex.

To calculate the costs of development and construction phase financing, a capex spending profile in years prior to COD that is representative of typical develop and construction-phase expenditures in Europe is used as shown in Table 10.

Table 11 shows the real project financing rates applied to projects installed in each year of the analysis. As deployment increases within the U.S. and New York, construction financing rates are expected to fall due to an improved supply chain, reduced development risk, and less regulatory risk. Financing costs are assumed to be identical for generation and transmission costs.

Table 10: Capex spend profile

Years prior to COD	5	4	3	2	1	0
Generation CAPEX	9%	1%	5%	21%	39%	24%
Transmission CAPEX	0%	13%	37%	44%	6%	0%

Table 11: Cost of financing for the development and construction phases, by vintage

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Construction phase WACC	9.5%	8.5%	7.6%	7.2%	6.9%	6.6%	6.3%	6.1%	5.9%

A.6 Capacity Factors

The projection of capacity factors considers levels of turbine performance and energy generation for each location modelled, and losses due to wake effect, availability, array and export transmission, and environmental factors. Several assumptions were made when determining capacity factors:

- A wind shear exponent of 0.12;
- Rayleigh wind speed distribution; and
- A mean annual average temperature of 10°C.

A.6.1 Energy Production Data Sources

Section A.1 discusses the turbine capacity assumptions used in this analysis. A power curve based on a blend of Siemens, MVOW and GE’s turbines was developed, calibrated for a COD 2022 project, as shown in Figure 18.

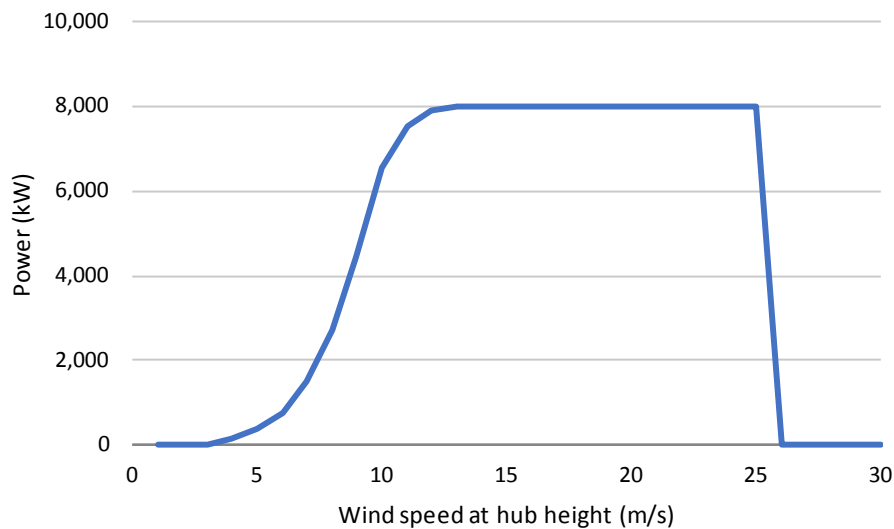
A.6.2 Net Capacity Factor

For the purpose of calculating energy production, this analysis uses the annual P50 net capacity factor value (the ratio of annual energy production expected to be exceeded 50 percent of the time, to the maximum energy production of a resource of equivalent scale that produced at its maximum capacity in all hours) after accounting for typical categories of losses. Losses considered include:

- Site air density adjustments from the standard turbine power curve, due to temperature and altitude;
- Aerodynamic array losses;
- Electrical array losses;
- Losses due to unavailability of the wind turbines, structure and array cables; and
- Losses from cut-in/cut-out hysteresis, power curve degradation, and power performance loss.

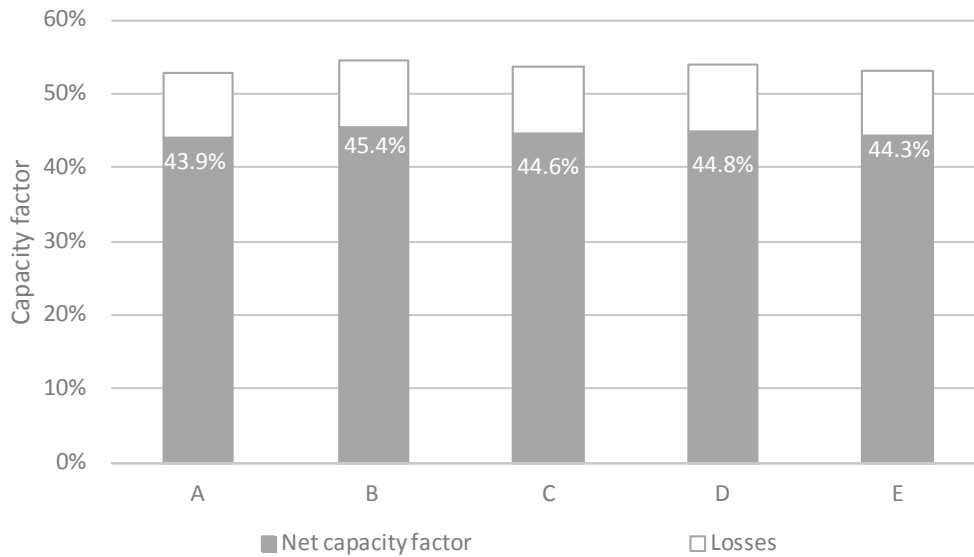
For example, Figure 19 shows the average net capacity factors for the centroids of each zone, after accounting for losses, for a 400 MW project with COD 2024. Net capacity factors are also projected to increase over time with incremental turbine technology.

Figure 18: Power curve for an 8 MW turbine, also illustrative of power curves for larger turbine sizes



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Figure 19: Average net capacity factors for the centroids of each zone for 2024 COD projects



A.7 Learning

Cumulative offshore wind deployment, particularly in the waters off New York and the broader Northeastern U.S., is assumed to affect scale economies, supply chain buildout and other factors driving the offshore wind capex and opex outlook. Three relevant markets are considered to affect learning and resulting cost reductions in New York deployments: New York, the U.S. market (Rest of U.S.), and the wider global market (Rest of World). Each trajectory impacts the projected costs of offshore wind in New York. The assumed New York deployment profile is described in Section A.1. Deployment assumptions for the Rest of U.S. were developed using BVGA’s proprietary forecast model consistent with current state level plans and policies. Lastly, deployment for the rest of the world is developed using BVGA’s 2017 report for Wind Europe, “Unleashing Europe’s offshore wind potential.”⁸⁸

Table 12 shows the assumed cumulative deployments over the period to 2030 used in this analysis.

Table 12: Cumulative deployment assumptions by region (GW)

Region \ COD	2024	2025	2026	2027	2028	2029	2030
New York	0.4	0.8	0.8	1.2	1.6	2.0	2.4
Rest of U.S.	2.4	3.6	5.0	6.4	7.7	9.1	10.5
Rest of World	36.7	40.7	44.9	49.0	52.8	56.8	60.7

A learning rate methodology is used to enable the adaptation of the model to different levels of deployment to reflect changes in cost over time as a result of supply chain and industry buildout. A learning rate for a particular market represents the amount of cost decline (in real terms) resulting from a doubling of that market’s volume.

⁸⁸ <https://windeurope.org/wp-content/uploads/files/about-wind/reports/Unleashing-Europes-offshore-wind-potential.pdf>

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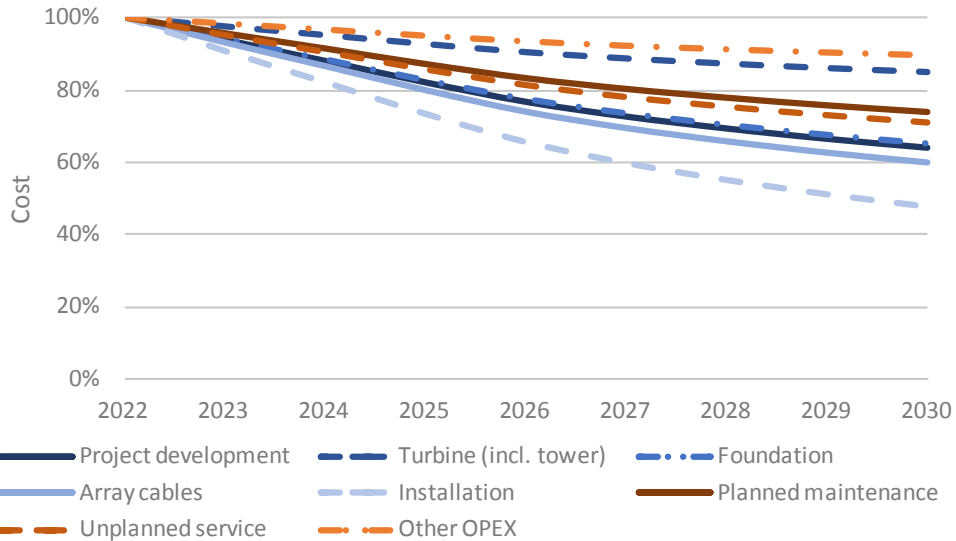
The learning rates are calibrated to BVGA’s proprietary modelling of innovation, learning and supply chain development using the deployment assumptions aligned with each scenario for the U.S. East Coast market and the global market. Resulting learning rates are shown in Table 13. Greater than projected growth of the market volume (increased deployment), would result in accelerated learning in New York, while less than projected deployment would result in slower New York learning.

Table 13: Learning rates by element and scenario as real percent reduction for each doubling of volume in the applicable market

Element	New York/US Learning Rate	Rest of World Learning Rate
Project development	9.8%	8.6%
Turbine (incl. tower)	3.9%	3.4%
Foundation	10.6%	9.0%
Array cables	11.0%	9.7%
Installation	17.2%	14.6%
Planned maintenance	7.0%	6.2%
Unplanned service	7.8%	6.9%
Other OPEX	2.7%	2.4%

Figure 20 shows the effect of the learning rates, under the assumed deployment profiles, on each cost component. Costs are shown as a real percentage of baseline COD 2022 project costs.

Figure 20: Combined effect of learning rates on cost components over time



Tables 14 and 15 show the capex, opex and capacity factor results over time for two illustrative sites in zone A and zone B. The deployments in zones A and B are reflective of low- and high-LCOE scenarios, respectively, due to each zone’s physical site conditions.

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Table 14: Capex, opex, and capacity factor results for 400 MW sites in zone A with interconnection to Long Island

Site Characteristic	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation CAPEX (\$000/MW)	3,889	3,597	3,226	2,965	2,796	2,647	2,528	2,429	2,343
Generation OPEX (\$000/MW/yr)	115	110	102	96	92	89	86	83	81
Transmission CAPEX (\$000/MW)	1,151	1,054	942	877	832	797	770	746	725
Transmission OPEX (\$000/MW/yr)	21	20	19	19	18	18	17	17	17
Net Capacity Factor	42.2%	42.9%	43.9%	44.8%	45.4%	45.9%	46.4%	46.7%	47.1%

Table 15: Capex, opex, and capacity factor results for 400 MW sites in zone B with interconnection to Long Island.

Site Characteristic	2022	2023	2024	2025	2026	2027	2028	2029	2030
Generation CAPEX (\$000/MW)	5,061	4,650	4,115	3,727	3,481	3,259	3,085	2,939	2,814
Generation OPEX (\$000/MW/yr)	128	122	113	107	102	98	95	92	89
Transmission CAPEX (\$000/MW)	1,427	1,309	1,173	1,094	1,039	997	964	935	910
Transmission OPEX (\$000/MW/yr)	25	24	23	23	22	22	21	21	20
Net Capacity Factor	43.0%	43.7%	44.8%	45.6%	46.2%	46.8%	47.2%	47.6%	48.0%

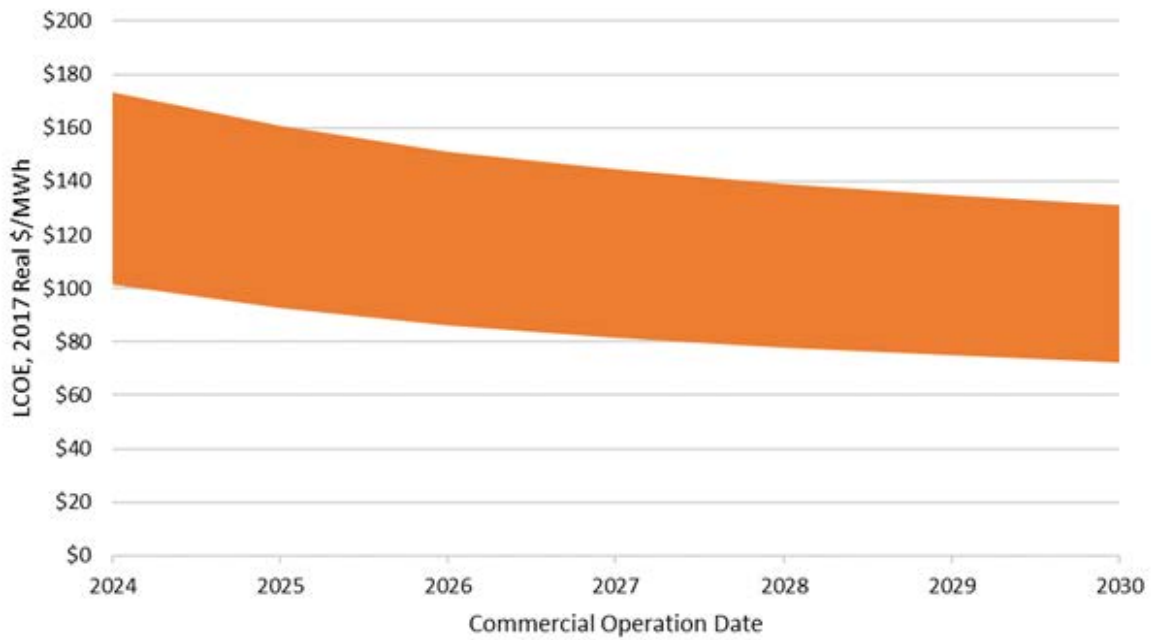
Table 16 and Figure 21 show the resulting LCOEs for these two illustrative sites over time. The high-LCOE scenario assumes deployment under the (high finance cost) Fixed REC procurement option in zone B, whereas the low-LCOE scenario assumes the (low finance cost) UOG procurement option in zone A. See Appendix D for more detail on the LCOE methodology. Figure 21 shows these two LCOE trajectories as bounding scenarios, with the LCOEs of deployments in other geographies and under different procurement models falling between these bounds.

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Table 16: Long-term LCOEs for a high- and low-LCOE deployment profile

COD	Zone B, Fixed REC	Zone A, UOG
2024	\$173	\$101
2025	\$161	\$93
2026	\$151	\$86
2027	\$145	\$82
2028	\$139	\$78
2029	\$135	\$75
2030	\$131	\$72

Figure 21: LCOE trend over time for New York deployments



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A.8 Results

The resulting capex, opex and capacity factors are shown in the tables below for the base deployment case (Table 17) and the project size scenarios discussed in Section 6.4 (Table 18).

Table 17: Capex, opex, and capacity factor results for the base deployment case

Value \ COD	2024	2025	2026	2027	2028	2029	2030
Farm Size (MW)	400	400	-	400	400	400	400
Generation CAPEX (\$000/MW)	3,226	3,070	-	2,986	2,610	2,504	2,607
Generation OPEX (\$000/MW/yr)	102	97	-	92	87	84	84
Transmission Interconnection	Long Island	Long Island	-	Long Island	NYC	NYC	NYC
Transmission CAPEX (\$000/MW)	942	859	-	857	1,028	1,001	1,113
Transmission OPEX (\$000/MW/yr)	19	18	-	19	24	23	25
Net Capacity Factor	43.9%	44.8%	-	46.4%	46.1%	46.5%	47.6%

Table 18: Capex, opex, and capacity factor results for the alternative project sizes considered for 2024 deployments

Project Size (MW)	100	200
Generation CAPEX (\$000/MW)	4,529	3,690
Generation OPEX (\$000/MW/year)	155	120
Transmission Interconnection	Long Island	Long Island
Transmission CAPEX (\$000/MW)	2,859	1,697
Transmission OPEX (\$000/MW/year)	19	19
Net Capacity Factor	44.3%	44.0%

Project cost and generation values are not expected to vary by the other scenario and sensitivity drivers explored in this analysis – procurement structure, transmission ownership strategy, commodity forecast or operational cost of capital. This data reflects different sites throughout the deployment period (see Table 7) and thus does not correspond directly with the values shown for selected illustrative sites over time in Section A.7. All values are real 2017 dollars.

Appendix B. Finance Cost Methodology

In conjunction with the analysis described in Appendix A aimed at assessing capex and opex, a separate analysis was carried out to project the operational cost of finance for offshore wind projects in a range of scenarios. This analysis was developed by Climate Policy Initiative (CPI).

The analysis approached the topic from a range of angles, including use of financial theory, a review of historic trends in Europe, the principal global offshore wind market to date, interviews with a range of participants in the New York energy market and potential offshore wind developers, and financial analysis.

- Assumptions were made for context parameters including risks impacting the cost of finance.
- Key quantitative finance inputs were researched, including the cost and term of debt and the cost of equity.
- Some components of the overall cost of finance, including the debt/equity ratio (i.e. gearing), are sensitive to scenario assumptions, and accordingly such finance components were projected dynamically for the full range of scenarios examined in this Options Paper.
- For each scenario, the results provided a full set of finance indicators, such as debt and equity investment values and the resulting weighted average cost of capital (WACC).

This Appendix discusses operational finance. Development and construction financing costs are discussed in Appendix A.

B.1 General Assumptions

B.1.1 Operational Risk Allocation

The study made certain simplifying assumptions about many risks, which have proved material for finance providers in the principal offshore wind markets to-date (the U.K., Germany, Denmark and the Netherlands). These assumptions are necessary because of the relatively early stage of offshore wind policy development in New York. Underpinning the analysis were the following assumptions regarding risk allocation during a project's operating phase:

- Projects in New York will be using established turbine and foundation technologies that have been tested and financed in Europe.
- Projects would be exposed to the risk of lost revenue in the event of offshore grid connection failure (the assumed impact of such losses is addressed through modeling of capacity factors as discussed in Appendix A.6).
- The offshore wind generator would not be exposed to curtailment risk due to onshore transmission congestion or because of negative locational marginal prices.
- Regulatory support in New York would be "grandfathered" if changes to the regime and/or market were made in future (e.g. projects would not be exposed to any substantial "change in law" risk).

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If, contrary to the assumptions described here, projects would need to bear at least partial exposure to risks that were excluded from consideration, this analysis could potentially understate the actual financing costs.

B.1.2 Financing Strategies

The analysis assumes that the dominant financing structure for the first offshore wind projects will be project finance. This assumption has a number of secondary implications. First, equity investors in early New York projects are assumed to prioritize returns on investment by maximizing the proportion of a project funded by debt.⁸⁹ It is important to note that some investors may not do so. An equity investor is assumed to set a target internal rate of return (or “hurdle” rate) not based on an assessment of individual project risks, but rather by reference to other similar energy/infrastructure investment opportunities and the level of return promised to its shareholders.

Under this financing approach, the target equity hurdle rate for the financial investor will be unlikely to vary with different project risk profiles or as the offshore wind market matures in New York and globally. However, with the passage of time and increased local deployment, offshore wind technology could start to attract different groups of investors with different priorities, different approaches to assessing risk and lower hurdle rates. Examples of other investors include regulated utilities, YieldCos, and pension funds. These alternative approaches were not considered in this analysis.

B.1.3 Tax

Renewables projects in the U.S. have in recent years been the recipient of a variety of federal and state tax incentives. These include including the Federal production tax credit (PTC), investment tax credit (ITC) and bonus depreciation. This analysis assumes that most of these incentives will be phased out by the time offshore wind projects move forward and thus are not available. There are two principal implications of this: (i) the analysis assumes tax equity would not be a feature of the financing structure; and (ii) it is assumed that project finance debt can be secured directly on the offshore wind asset, rather than, as is currently the case, “back leverage” of equity cash flows. Greater control over the asset means lower risk for lenders and a lower cost of debt, all else being equal.

The study does assume that accelerated depreciation (MACRS) is available in a form similar to that available to land-based wind projects. Further, it assumes that the equity investor has sufficient tax liabilities to monetize any tax benefits that arise as a result of net operating losses resulting from accelerated depreciation in any year by offsetting them against other tax liabilities that arise in the same year.

Corporate tax is assumed to continue at the current Federal (35%) and New York State (7.1%) tax rates⁹⁰ with no changes to current tax law (5- and 15-year MACRS remain in place for wind generation and transmission respectively, but there is no extension of bonus depreciation or any renewable tax credits for offshore wind).

⁸⁹ Leverage was maximized to the extent that the project would still maintain an “investment grade” risk profile.

⁹⁰ Changes to federal tax law effective 2018 will revise the Federal corporation tax rate to 21%. This change is not reflected in the analysis conducted for this Options Paper but is not expected to affect the analysis to a material extent.

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B.1.4 Regulatory and Counterparty Risk

Other than risks associated with changes in law (which are assumed to be neutral), the most material operational regulatory risk is the credit risk profile of principal revenue counterparties (i.e. the risk that the entities that have contracted to pay the generator either cannot or will not make those payments). The analysis assumes an investment grade counterparty for all procurement structures.

B.2 Inputs

B.2.1 Project Operational Inputs

Finance costs were calculated individually for each site deployed under each of the scenarios and sensitivities assessed in the analysis for this Options Paper, using the project-specific capex to establish the amount of finance required, and a range of other inputs (including project capacity, opex, and decommissioning costs) to calculate the cash flow available for debt service. These inputs are discussed in Appendix A.

B.2.2 Energy Market Risk

Equity and debt investors in New York offshore wind projects will have different appetites for bearing energy market risk, which will affect financing costs in different ways.

Equity investors are likely to take energy market risk into account by cutting their estimation of unhedged energy and capacity revenues from a project (a “haircut”) rather than adjusting their target hurdle rate, similar to the way such investors approach renewable resource risk. As a result, projects with greater revenue certainty will require lower expected revenues to meet the equity investors’ target hurdle rate. The analysis assumes that equity investors reflect market risk by employing a haircut of five percent to the base energy and capacity market price projections (discussed in Appendix C) to the extent such revenue is unhedged, whereas no haircut is applied to the extent the procurement structure (see Section 3.2) provides a hedge for commodity revenue.

Debt investors may account for energy market risk in four principal ways (or a combination thereof):

1. Increase debt pricing;
2. Increase the minimum debt service coverage ratio;
3. Haircut the expected revenues; or
4. Discount revenues which cannot be hedged using market instruments (such as derivatives).

Debt investors reflect market risk by including in their base case only those revenues that can be hedged through fixed-price power offtake contracts, minimum or “floor” price guarantees, or derivatives.

A review of the hedging products available in the NYISO market and private discussions with market participants found that in the absence of long-term, fixed-price power purchase agreements or any debt guarantees, offshore projects will be able to hedge market energy and capacity revenues out to at most five years using derivatives. As a result, the analysis assumes that, to the extent a hedge for commodity revenue is not provided by the procurement structure, debt investors will value market revenues for the first five years of the project based on the same market price used by equity investors (i.e. with a five

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percent discount on the forecast used in this analysis) and then discount to zero all subsequent market revenues. Any cost of purchasing hedging products in the market is not considered in the analysis.

B.2.3 Basis Risk

While some of the hedged procurement structures discussed in Section 3.2 provide a perfect hedge, the Indexed OREC structure calculates the premium payment as the difference between a market price for energy and capacity and the project's volumetric gross price bid or Strike Price. Depending on how the "market price" is set (usually a reference to a specific exchange or index), there is a risk ("basis risk") that the asset cannot capture precisely the same price as implied by that reference. This could mean that the amount of revenue earned per unit of generation is sometimes lower, or higher, than the Strike Price in the contract or regulatory agreement.

For procurement structures which place such basis risk on the generator, this analysis quantifies this risk by analyzing the variation in historic market pricing between different price points within the NYISO system (i.e. the node, representative of a project's injection point, and the hub, which could be the settlement point of a market price index). Both equity and debt investors are assumed to consider basis risk in their valuation.

B.2.4 Cost of Equity

The analysis treats the cost of equity (disclosed on a post-tax, nominal basis) as an input rather than an output to the calculation of the WACC. The following four sources are used in assessing the cost of equity for offshore wind projects:

- The Capital Asset Pricing Model (CAPM) is a widely-used tool by economic consultants to assess cost of capital and was one of the techniques used in the most in-depth study of offshore wind finance costs to-date.⁹¹
- A review of target returns for U.S.-focused private equity infrastructure funds and yieldcos.
- Comparables from the European context: observed or disclosed transaction data from European offshore wind transactions with an adjustment for the U.S. context.
- Comparables from the U.S. context: observed or disclosed transaction data from U.S. land-based wind transactions with an adjustment for the offshore context.

The basic concept of CAPM is that investors should be compensated for:

- The time value of money (the "risk-free rate", see below); and
- Risks that cannot be diversified away, i.e. systematic "beta" risks, which are correlated with the market (diversifiable risks are not compensated – many project-specific risks typically fall into this category).

⁹¹ NERA. 2013. Changes in Hurdle Rates for Low Carbon Generation Technologies due to the Shift from the UK Renewables Obligation to a Contracts for Difference Regime. http://www.nera.com/content/dam/nera/publications/archive2/20131209_NERA_Report_Assessment_of_Change_in_Hurdle_Rates.pdf

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Using CAPM, the cost of equity is usually calculated as follows:

$$\text{Cost of Equity} = \text{Risk-free rate} + (\text{Equity beta} \times \text{Total Market Return})$$

The analysis estimated the above components of the cost of equity as follows:

- The risk-free rate is assumed as reflective of the yield-to-maturity of the 20-year U.S. Treasury security. This was projected to future years using forward market pricing as shown in Table 19 below. Changes in the risk-free rate will impact the cost of debt for investment decisions taken at different times.

Table 19: Forecasted yields to maturity of 20-year U.S. treasury securities

COD Date	2024	2025	2026	2027	2028	2029	2030
Maturity of relevant treasury	2044	2025	2046	2047	2048	2049	2050
Yield to maturity	2.88%	2.93%	2.96%	2.99%	3.01%	3.05%	3.08%

- The total market return is the expected return on equity across the market. This is typically estimated using long-run historical returns for a given country. This analysis used S&P 500 data from 1928 to 2016.
- The equity beta measures the correlation of the return on the investment in question to overall market equity returns. Typically, an unlevered asset beta is derived from comparison with similar investments and then adjusted to an equity beta to take account of the gearing of the investment.

$$\text{Equity beta} = \text{Asset Beta} \times (1 + ((1 - \text{tax rate}) \times (\text{debt} / \text{equity})))$$

The analysis then reviewed various public companies with similar characteristics to renewable energy developers to make a judgement on the appropriate beta. The review resulted in an asset beta between 0.6 and 0.7. When combined with an assumed market-average gearing of approximately 70 percent, the analysis derived a cost of equity range of 12.4 percent to 14.1 percent with a central point estimate of 13.25 percent.

CAPM is not often used by itself to determine the cost of equity for individual projects because it does not account for asymmetric risks and real options. However, for the current analysis this was considered a robust approach since most asymmetric risks (e.g. construction overrun risk) and real options occur before wind projects are operational. In addition, the estimated cost of equity was sense-checked as follows:

- Recently raised new private equity infrastructure funds – potential investors in these assets – are targeting 13 to 15 percent internal rate of return net of fees. This corresponds to the high bound of potential offshore wind cost of equity.

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- Recent estimates for private listed utility offshore wind hurdle rates in Europe are around “double digits” in the U.K. or high single digits in Germany and the Netherlands. Because these rates correspond to the potential offshore wind cost of equity in mature markets, the analysis concludes that it will be higher in the young New York market. Information from interviews with market participants suggests costs towards the upper end of this range as well.

B.2.5 Cost of Debt

The analysis treats cost of debt (disclosed on a post-tax, nominal basis) as an input rather than an output. This approach is driven by the observation that project finance lenders in both the European and the U.S. markets will reflect risk differentials between projects by adjusting the amount they are willing to lend to a project, rather than the cost of debt. Pricing differentials also tend to reflect broader competitive trends within capital markets.

Debt pricing is typically determined by adding a spread to a reference: either the funding and capital cost (in the case of a bank) or risk-free rate reference security (in the case of a bond). The analysis concluded, following a review of investment grade project bonds and renewables bank debt in Europe and the U.S., that an appropriate cost of debt for the first project is currently around a 2.5 percent spread over the 20-year U.S. Treasury security.

B.2.6 Debt Sizing

The analysis uses the same techniques used by project finance lenders to assess the amount of debt that would likely be used in financing a New York offshore wind farm in different procurement models.

Lenders will derive a base case projection of project cash flows, most likely taking into account a conservative forecast of generation. This analysis uses a P90 projection, i.e. an amount of generation that statistically would be expected to be exceeded in 90 percent of cases. As discussed above in Sections B.3.2 and B.3.3, lenders will also forecast unhedged exposure to market and basis risk in a conservative fashion.

Considering these cash flows, lenders will project an amount of “cash flow available for debt service” (CFADS). At the same time, lenders will also specify an average or minimum debt service coverage ratio (DSCR), which is the minimum amount of excess cash flows over contracted debt service payments that a lender will accept in return for lending to a given asset. For recent operational offshore wind transactions in Europe (e.g. the WindMW project bond in Germany), this has been between 1.3x and 1.4x. The analysis assumes a base value of 1.4x.

Using the projected CFADS and the target DSCR, lenders will calculate how much they are willing to lend as a proportion of the total investment (i.e. the gearing).

B.2.7 Changes with Time and Deployment

The analytical framework includes mechanics to adjust base finance parameters for different COD dates and different global and local deployment patterns:

- Over time, with no offshore wind deployment globally or locally, only macroeconomic parameters, such as U.S. Treasury yields and inflation, are dynamic.

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- With incremental local offshore wind deployment, debt spreads are reduced as set out in Table 20 below. The analysis included a series of private discussions with market participants in Europe with an interest in the U.S. There was agreement that debt costs in the early phase of the New York market would not be as high as was the case early in the European market as technology and operations and maintenance techniques are more reliable/better developed.

Table 20: Forecasted changes in debt spreads as a function of New York offshore wind deployment

Existing New York Deployment (MW)	400	800	1,200	1,600	2,000
Debt Spread (bps)	250	225	225	200	175

As the regional industry matures, the cost of equity will evolve as changing perceptions of technology and regulatory risk allow the entry of low-cost investors (e.g. YieldCos). This has taken place in European markets but is not estimated in the analysis, reflecting a conservative outlook.

In addition, capital costs (including reductions in development and construction financing costs), operating costs and capacity factors will also change either over time or as a function of deployment. The relationship between time/deployment and these factors is discussed in Appendix A.

Changes in these costs can also affect the calculation of financing costs as follows: changes in revenue and operating costs will result in changes in the cash flow available for debt service (CFADS). Even if the target DSCR has not changed, higher or lower CFADS could support higher or lower amounts of debt and therefore a lower or higher WACC, respectively.

B.3 Analytical Method

Based on the inputs and assumptions set out above, the analysis determined financing costs for each of the scenarios and sensitivities. The primary cost of capital metric output is the internal rate of return from cashflows to all investors from the project, a proxy for the pre-tax WACC that accounts for the more complex capital structure of a project financing.

The following approach was taken to calculate the project finance outputs:

- For each scenario, net project cash flows for both the equity and debt investors were calculated assuming only market energy and capacity revenue (i.e. no revenue premium from policy mechanisms such as Fixed REC, Bundled PPA, etc.).
- Using the fixed input minimum DSCR and assuming a sculpted amortization achieving that minimum DSCR in each period, the lender cash flows were used to size the debt.
- Having established the debt size, the remainder of the project capex was assumed to be equity. Using the debt amortization schedule, the residual cash flow to equity was calculated.
- If such cash flow for equity was insufficient to meet the equity hurdle rate, additional cashflow in the form of the premium payment from the procurement structure in question was added and the calculation repeated (including re-calculation of the cash flow for debt service and thus the debt size) in an iterative manner until the after-tax equity hurdle rate was achieved.

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- In cases of transmission ownership as a regulated asset, the revenue required to meet the utility’s rate of return was also calculated, and this revenue was blended with the generation revenue to develop a cost of capital for the complete project.

This iterative process determines the size of the debt and equity investments, as well as the total project cash requirements to satisfy the costs of capital of both investors. The IRR of the resulting pre-tax cash flows to all investors, including debt and equity for both the generation and transmission, was output as a proxy for the project WACC. This figure serves as an input for the LCOE analysis discussed in Appendix C.

B.4 Results

The resulting cost of capital figures, or WACC proxies, and gearing levels are shown in the tables below for the various scenarios considered in this Options Paper. The procurement scenarios are shown first (Tables 21 and 22), followed by the other policy scenarios (Tables 23 and 24) and sensitivities (Table 25). Gearing is not shown for the commodity pricing and financing cost sensitivities because these sensitivities are not applied as inputs to this finance cost analysis. Details of the procurement and policy scenarios are included in Section 6, while the sensitivities are discussed in Section D.2.

Table 21: Cost of capital assumptions for each procurement structure, by project vintage

	2024	2025	2026	2027	2028	2029	2030
Fixed REC	12.4%	12.8%	n/a	13.0%	13.2%	13.4%	13.2%
Bundled/Split PPA	7.9%	8.0%	n/a	7.9%	8.0%	8.0%	7.9%
Utility-Owned Generation	5.5%	5.5%	n/a	5.4%	5.7%	5.7%	5.5%
Market OREC	7.9%	8.0%	n/a	7.9%	8.0%	8.0%	7.9%
Index OREC	8.2%	8.3%	n/a	8.2%	8.4%	8.3%	8.2%
Forward OREC, Conservative	11.2%	11.5%	n/a	11.7%	11.9%	12.0%	11.9%
Forward OREC, Aggressive	8.8%	8.9%	n/a	8.9%	9.1%	9.0%	8.9%

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Table 22: Gearing assumptions for each procurement structure, by project vintage

	2024	2025	2026	2027	2028	2029	2030
Fixed REC	50%	49%	n/a	48%	48%	47%	48%
Bundled/Split PPA	65%	65%	n/a	65%	66%	66%	67%
Utility-Owned Generation	50%	50%	n/a	50%	50%	50%	50%
Market OREC	65%	65%	n/a	65%	66%	66%	67%
Index OREC	63%	62%	n/a	63%	62%	63%	63%
Forward OREC, Conservative	50%	49%	n/a	48%	48%	48%	49%
Forward OREC, Aggressive	61%	61%	n/a	61%	61%	62%	62%

Table 23: Cost of capital assumptions for each project size and transmission ownership scenario, by project vintage⁹²

	2024	2025	2026	2027	2028	2029	2030
100 MW, Fixed REC	10.5%	n/a	n/a	n/a	n/a	n/a	n/a
200 MW, Fixed REC	11.4%	n/a	n/a	n/a	n/a	n/a	n/a
Regulated Asset Transmission, Fixed REC	11.9%	12.3%	n/a	12.6%	12.6%	12.8%	12.6%
100 MW, Bundled PPA	7.6%	n/a	n/a	n/a	n/a	n/a	n/a
200 MW, Bundled PPA	7.8%	n/a	n/a	n/a	n/a	n/a	n/a
Regulated Asset Transmission, Bundled PPA	7.4%	7.5%	n/a	7.4%	7.4%	7.4%	7.3%

⁹² 100 MW and 200 MW sites were only assessed for a 2024 vintage.

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Table 24: Gearing assumptions for each project size and transmission ownership scenario, by project vintage⁹³

	2024	2025	2026	2027	2028	2029	2030
100 MW, Fixed REC	59%	n/a	n/a	n/a	n/a	n/a	n/a
200 MW, Fixed REC	55%	n/a	n/a	n/a	n/a	n/a	n/a
Regulated Asset Transmission, Fixed REC	43%	41%	n/a	40%	37%	35%	36%
100 MW, Bundled PPA	68%	n/a	n/a	n/a	n/a	n/a	n/a
200 MW, Bundled PPA	67%	n/a	n/a	n/a	n/a	n/a	n/a
Regulated Asset Transmission, Bundled PPA	62%	62%	n/a	63%	62%	62%	63%

Table 25: Cost of capital assumptions for each commodity pricing and financing cost sensitivity, by project vintage

	2024	2025	2026	2027	2028	2029	2030
Low Commodity, Fixed REC	12.4%	12.8%	n/a	13.0%	13.2%	13.4%	13.2%
Low Financing, Fixed REC	11.6%	12.0%	n/a	12.3%	12.5%	12.6%	12.5%
High Financing, Fixed REC	13.1%	13.5%	n/a	13.8%	14.0%	14.1%	14.0%
Low Commodity, Bundled PPA	7.9%	8.0%	n/a	7.9%	8.0%	8.0%	7.9%
Low Financing, Bundled PPA	7.2%	7.2%	n/a	7.1%	7.3%	7.2%	7.1%
High Financing, Bundled PPA	8.7%	8.7%	n/a	8.6%	8.8%	8.7%	8.6%

⁹³ 100 MW and 200 MW sites were only assessed for a 2024 vintage.

Appendix C. Cost and Benefit Methodology

Using the results discussed in Appendix A and Appendix B, program costs are calculated as discussed in this appendix.

Each offshore wind project's LCOE is calculated using that project's specific capex, opex, generation, and cost of capital projections. This provides a levelized amount of revenue per unit of energy that is required for the project to be developed. The LCOE is then compared to the levelized amount of revenue per unit of energy the generator could expect to receive in the wholesale market, comprised of energy and capacity payments, as well as Tier 1 RECs. To the extent the LCOE exceeds levelized market revenues, this is assessed to be the projected incremental program cost.

To obtain gross program costs, incremental program costs are added to the projected levelized Tier 1 REC revenue. This figure represents the total premium, above wholesale energy and capacity revenue, that the project requires. Net program costs are calculated by comparing gross program costs to the value of avoided carbon. Such carbon benefits are quantified using the "social cost of carbon" as published by the Environmental Protection Agency. The cost of carbon is limited to the value in excess of the carbon value already included in the wholesale electricity price as a result of the Regional Greenhouse Gas Initiative (RGGI).

As discussed in Section 6, incremental program cost is the primary cost indicator for analysis of the Phase I deployments. Gross and net program cost are provided as cost indicators for the full 2.4 GW target. The indicators are defined as follows:

Phase I (800 MW) Cost Indicators

1. **Incremental program costs** are calculated as the incremental revenue, on top of energy, capacity and Tier 1 REC premiums, that would allow offshore wind generators to reach their cost of capital. The costs are provided as a net present value (NPV) of incremental PBI payments over time on top of the projected value of Tier 1 RECs.
2. **Electricity bill impact** is expressed as the incremental program costs in 2025, the last year of Phase I deployment, in real dollars, divided by the most recently reported (2016) total statewide electricity bill spend.

Long-Term (2.4 GW) Cost Indicators

3. **Gross program costs** are calculated as the incremental revenue, on top of energy and capacity, that allows projects to reach their target return. The costs are presented as an NPV of incremental PBI payments, inclusive of Tier 1 REC payments.
4. **Net program costs** are defined as the gross program costs minus the NPV of the carbon value associated with the offshore wind deployment. Carbon value is calculated as the societal value of avoided CO_{2e} emissions in excess of the value already included in the electricity price through RGGI.

Each project is assumed to have a 25-year useful life, consistent with offshore wind technology expectations. The analysis time horizon spans commencement of commercial operation years from 2024 to 2030, and project economics are assessed from 2024 to 2054, when the last facility retires.

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C.1 Levelized Cost of Energy

The LCOE is a metric that quantifies the revenue per unit of energy that a project requires in order to pay back the capital and operating costs at the investor's rate of return. For each offshore wind deployment, the calculation takes the capex as of COD, as well as forecasted opex, and uses a standard financial levelization to determine a nominal annual revenue requirement for the project's lifetime. This amount is then divided by the project's projected annual generation to arrive at an LCOE.

Capex, opex, and generation amounts are provided for each deployment using the analysis discussed in Appendix A, while Appendix B details the analysis that calculates the investor rate of return.

LCOE is calculated on a 25-year basis, meaning that energy, capacity, and REC revenues are levelized over 25 years to calculate the required program costs, which are also originally generated as a 25-year levelized value. When considering PBI program costs, each project is assumed to be contracted for a duration of 20 years, consistent with the current CES Tier 1 procurement structure. LCOE over the 25-year life is re-calculated into 20-year levelized premium payments by discounting the 25-year levelized premium at the project's WACC (which produces an upfront program cost) and then levelizing again at the project's WACC over a 20-year period.

Residual control of RECs beyond the 20-year contract may be accomplished through contractual provisions, for example, but these issues fall outside of the model framework, and possible costs associated with such provisions are not included in this analysis.

The analysis assumes that revenue requirements are reflective of projected project costs, and therefore ignores any price speculation that could occur depending on market conditions and procurement strategies.

C.2 Levelized Market Revenue

This analysis considers market revenue to be comprised of commodity revenue and Tier 1 REC revenue. Commodity revenue is the amount paid to a generation project from the NYISO wholesale energy and capacity markets for its products (energy and capacity), or the equivalent value that it would be paid for these products in the spot market, if used to self-supply. Commodity revenue is comprised of:

- The zonal energy market price (\$/MWh); and
- The zonal capacity price (\$/kW-year), adjusted by the capacity value (the season-weighted average UCAP as a percentage of nameplate capacity). This analysis assumes a season-weighted average UCAP value of 38 percent⁹⁴ for all offshore wind generation facilities.

The pricing of Tier 1 RECs is based on the CES Cost Study, which calculated the incremental payments (above energy and capacity revenue) that large-scale renewable projects would require to be commercially viable. Multiple procurement structures were considered in the CES Cost Study, and consistent with current Tier 1 procurements, the Fixed-REC Tier 1 forecast was used for the analysis in this Options Paper.

⁹⁴ NYISO Installed Capacity Manual, Manual 4, August 2017

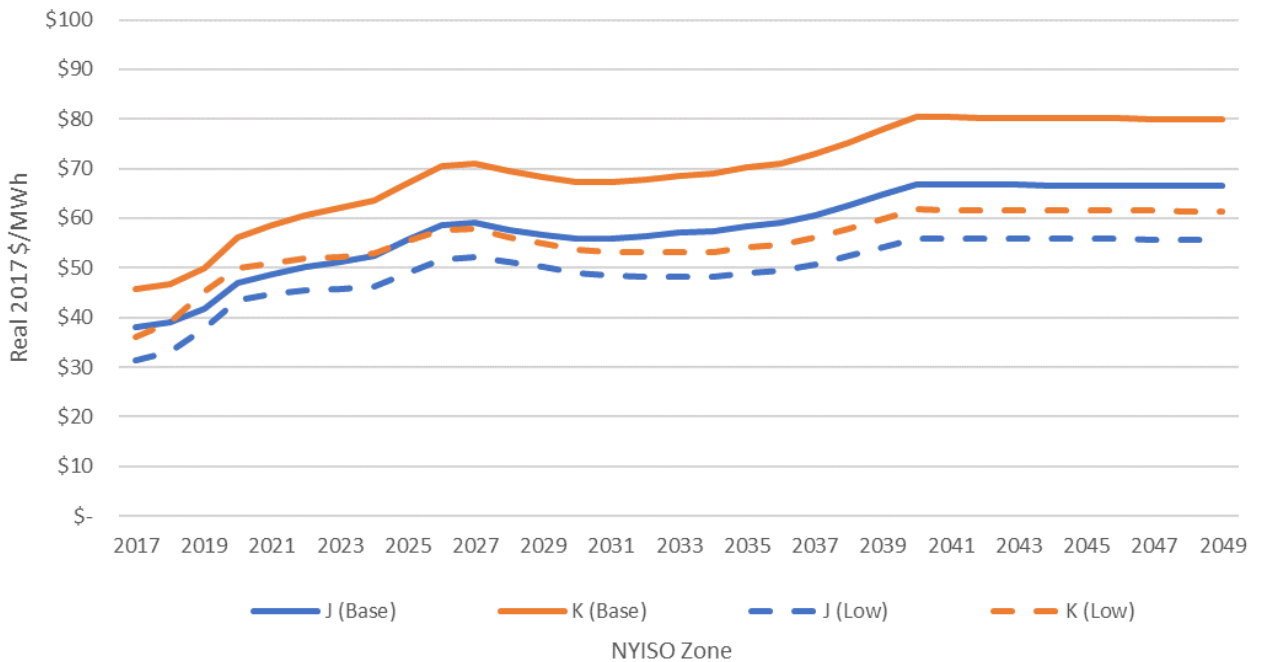
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The energy forecast used in the CES Cost Study was updated as set out below, producing an updated Tier 1 REC pricing forecast. This modified Tier 1 REC pricing is used in the calculation of the total levelized market revenue.

C.3 Commodity Prices

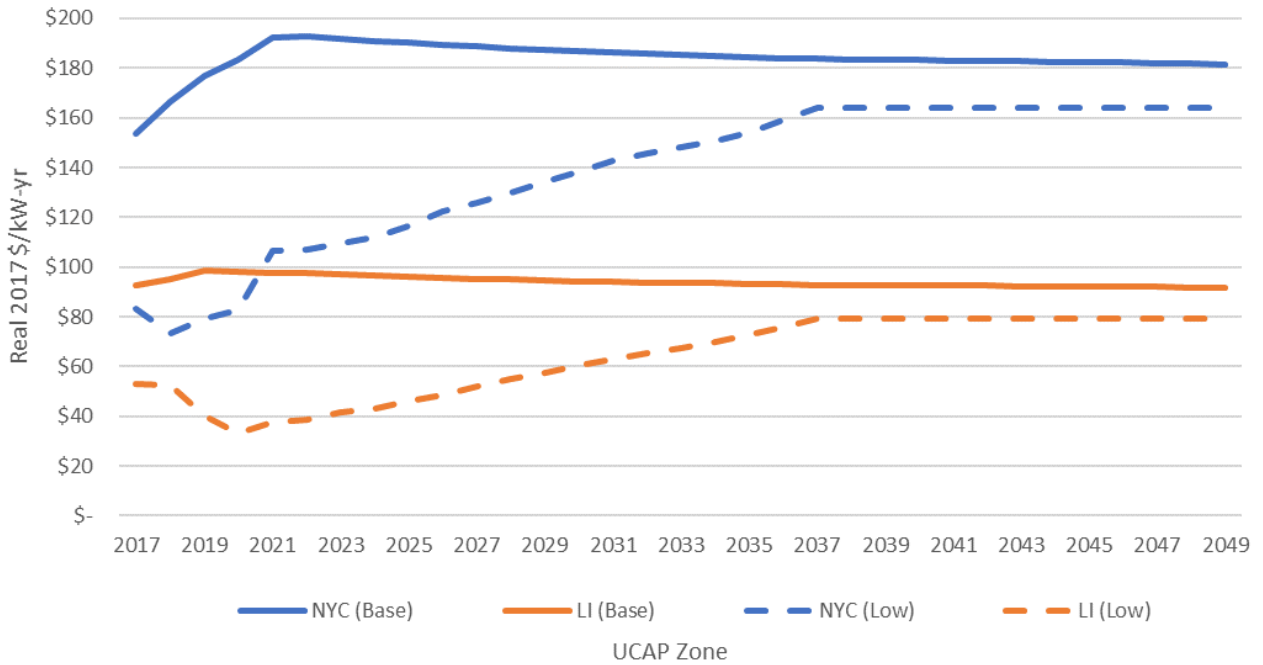
The base commodity forecast used in this analysis is based on an adjusted version of the NYISO Congestion Assessment and Resource Integration Study (CARIS) forecast through 2024. After 2024, it reflects a mix of expected inflation and natural gas price increases. In addition, a low commodity forecast was established as an adjusted version of the base forecast, using scalars to modify the forecast to reflect different assumptions involving natural gas pricing, the New York generation mix, and inflation. Both the base and low energy and capacity forecasts are shown below in Figures 22 and 23 for NYISO zones J and K.

Figure 22: Zonal annual energy price forecasts for the base and low cases



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Figure 23: Zonal annual UCAP price forecasts for the base and low cases



C.4 Carbon Benefits

Figure 24 shows the social cost of carbon used in this analysis (\$/MWh of generation).⁹⁵ This social cost of carbon forecast is consistent with the PSC’s January 21, 2016 Order, “Order Establishing the Benefit Cost Analysis Framework”. Note, however, that the specific values used reflect a slight modification due to a revision from the EPA.

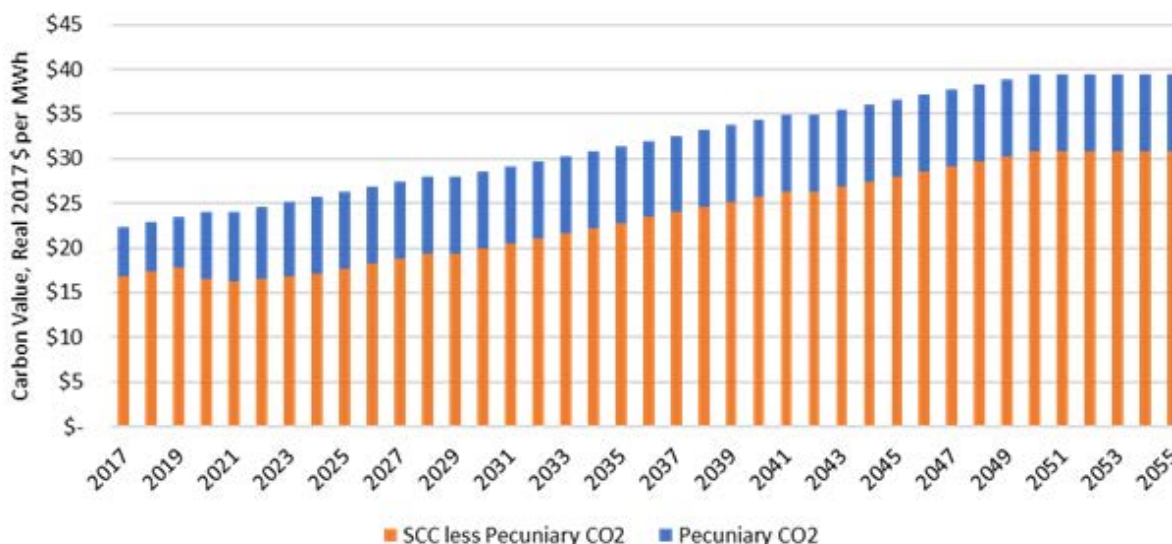
The avoided CO₂e emission rate underlying the carbon value was assumed as an average marginal rate of approximately 0.538 short tons per MWh, consistent with the CES Cost Study.

Carbon benefits are reflected in gross program costs to the extent they are internalized in the electricity price. Figure 24 notes this pecuniary value of CO₂, which was taken from the 2015 NYISO CARIS 1 forecast of RGGI allowance prices (held constant in real terms after 2024). Net program costs are the gross program costs minus the non-pecuniary portion of the social cost of carbon.

⁹⁵ EPA’s Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015).

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Figure 24: The social cost of carbon



C.5 Air Quality and Health Benefits

Modeling was conducted to analyze the potential impact the addition of 2.4 GW of offshore wind capacity interconnected to New York City and Long Island may have on emissions from power generators in New York and surrounding regions. Electricity sector modeling was conducted to produce county level NO_x, SO₂ and PM_{2.5} emissions data for use in a subsequent health impacts screening modeling. The health impacts modeling estimated how the inclusion of offshore wind in the renewable energy mix to fulfill the Clean Energy Standard might improve ambient air quality and reduce adverse health impacts throughout the region.

The Integrated Planning Model (IPM), PROMOD and Co-Benefits Risk Assessment (COBRA) electric sector modeling tools were used to perform this analysis. IPM is a zonal capacity expansion model, while PROMOD forecasts hourly dispatch and pricing projections on a nodal level. IPM was used to determine capacity expansion and retirement of conventional resources for use in PROMOD, as well as calculation of RGGI allowance prices. PROMOD was used to determine the emissions impacts from the addition of the offshore wind generating capacity. County level NO_x, SO₂ and PM_{2.5} emissions data from PROMOD was used as an input in the COBRA air quality modeling. Additional information about these models and key modeling assumptions are provided below.

1. Integrated Planning Model

IPM develops projections for the North American power system, broken into 120 zones covering the lower-48 U.S. states and Canadian provinces. This broad geographic scope allows IPM to capture interactions among neighboring power systems, as well as regional and national markets for fuel and emissions programs, where applicable. For this analysis, the New York Control Area was represented by the 11 load zones (A through K). The New England and PJM systems were also represented in configurations very similar to each system's load zones. The remainder of the lower-48 U.S. was represented by 66 zones and Canada was represented by nine provinces, including Ontario and Quebec, the two provinces that border New York.

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Each zone within IPM is assigned its own load and peak and reserve requirements that it must meet over time with a combination of existing generation sources, new capacity, and transmission resources. Individual transmission lines connecting zones are aggregated into zonal transmission links that can move energy and/or capacity, depending on the zones.

IPM generates least cost dispatch projections for each year-season-segment combination to ensure that demand is met in each segment. It may rely on capacity expansion to contribute to that necessary dispatch. In addition to meeting load requirements each year, zones in IPM must meet peak demand and reserve margin requirements, such as the Installed Reserve Margin (IRM) requirement for the New York Control Area. Within a broader planning region, IPM will also satisfy local capacity requirements (LCRs). This analysis included the LCRs for New York City (Zone J), Long Island (K), and Lower Hudson Valley (G-J) zones.

2. PROMOD

ASEA Brown Boveri's (ABB) PROMOD IV is a highly detailed, fundamental electric market simulation model that chronologically computes hour-by-hour dispatch, prices and production costs while recognizing the constraints on the dispatch of generating units imposed by the transmission system. PROMOD IV uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved alternating current (AC) load flow, to calculate the real power flows for each generation dispatch.

For this analysis, PROMOD was populated with projections of capacity expansion and retirement and allowance prices from IPM.

Case Descriptions for Electricity System Modeling

Two cases/scenarios were examined:

1. CES target fulfillment without offshore wind
2. CES target fulfillment with 2.4 GW of offshore wind

Both cases had identical underlying assumptions for energy and peak demand, gas prices, firmly planned capacity expansion and retirement in New York and neighboring states, reliability-related dispatch proxy, and emissions limits. Both cases also include the new program elements that RGGI participating states agreed to during the 2016 Program Review process.⁹⁶ The two scenarios differ in their forecasted renewable capacity and generation levels by zone used to meet the CES, as well as forecasted RGGI allowance prices. RGGI allowance prices are an output of IPM and an input to the PROMOD model, while capacity and generation assumptions are inputs in both. Select assumptions are discussed in greater detail below.

Natural Gas Prices

Henry Hub gas price projections are assumed to be the average of the EIA's Annual Energy Outlook 2017 Reference Case and High Gas Resource Case. The Henry Hub price is \$2.83/MMBtu in 2017 and rises to \$4.23/MMBtu by 2030, expressed in real 2015 dollars.

⁹⁶ http://www.rggi.org/docs/ProgramReview/2017/09-25-17/Program_Elements_Overview_09_25_17.pdf

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Energy and Peak Demand

New York Independent System Operator (NYISO) energy and peak demand assumptions are based on the information in the CES White Paper with energy efficiency, electric vehicle and heat pump assumptions included. NYISO energy demand decreases roughly seven percent from 2017 to 2030. Demand for neighboring regions is taken from ISO forecasts.

Clean Energy Standard

Two CES scenarios were analyzed under this study. Both cases are intended to achieve the State Energy Plan target of having 50 percent of New York's electricity come from renewable energy sources by 2030. The cumulative renewable capacity and generation additions by 2030 are shown in Table 26 below.

Table 26: New York CES capacity and energy additions by 2030

	CES Fulfillment w/o OSW		CES Fulfillment w/ OSW	
	2030 Capacity, MW	2030 Generation, GWh	2030 Capacity, MW	2030 Generation, GWh
Onshore wind	4,744	16,243	2,937	10,200
Grid solar	5,099	6,030	2,478	2,958
Hydro	581	2,668	534	2,474
Offshore wind	0	0	2,400	10,242
Bioenergy	233	1,585	139	937
Imports	549	2,088	457	1,782
Total	11,205	28,613	8,947	28,613

Case 2 has 2,400 MW of offshore wind added by 2030 in Zones J and K as part of the renewable additions specified to attain the CES renewable generation target, while Case 1 did not include offshore wind. For Case 2, PROMOD assumes offshore wind is injected across Zones J (New York City) and K (Long Island).

Capacity Changes

Planned capacity additions and retirements in the New York Control Area were updated to be consistent with assumptions for NYISO's 2017 CARIS process,⁹⁷ with the exception of the Indian Point nuclear facility, which was added as a firm retirement in this analysis, consistent with Entergy's agreement with the State. The key build assumptions are presented below in Table 27.

Planned fossil additions are the same across both Cases 1 and 2 at 2,038 MW. There are no incremental fossil additions between the two cases, as determined on an economic basis by IPM. Total capacity retirements are also the same across Cases 1 and 2. By 2030, NYISO has 4,596 MW of planned fossil and nuclear retirements, as well as 1,686 MW of incremental fossil retirements determined by IPM. Indian

⁹⁷ See slide 10 of NYISO's "2017 CARIS 1 Follow-up" at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_espwg/meeting_materials/2017-08-28/CARIS%20Presentation.pdf

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Point units 2 and 3 are assumed to retire in 2020 and 2021, respectively, and all coal capacity in NYISO is assumed to retire by the end of 2020.

Table 27: NYISO planned build assumptions

	Online Year	Capacity, MW
CPV Valley Energy Center	2018	751
Cricket Valley Energy Center II	2019	1,020
Ogdensburg	2017	89
Bethlehem Energy Center	2018	72
Greenridge Generation	2018	106

Reliability-related dispatch proxy

Select Zone J and K combustion turbines and oil/gas steam units were assigned minimum run generation requirements imposed across the time horizon of the analysis. These requirements were provided by the NYISO and are based on historical performance and were intended to capture transmission or other system limitations that may not otherwise be captured in the modeling. The Zone J requirements sum to 9.0 TWh, while the Zone K requirements total 5.9 TWh. These historical-based requirements may not be reflective of a future system given potential changes in capacity, technology, or transmission resources. If the resulting requirements were to be less than assumed for this analysis, it is likely the addition of offshore wind in Case 2 would have displaced more emissions in Zones J and K.

RGGI Allowance Prices

RGGI allowance prices are inputs to PROMOD based on projections from the corresponding IPM runs. Case 2 allowance prices are roughly seven percent lower than Case 1 prices, reflecting shifts in generation due to the assumed change in the CES generation mix. This difference does not have a meaningful impact on PROMOD's unit dispatch.

Emissions Management

Checks were performed to ensure that CO₂, NO_x and SO₂ emissions were in-line with their respective regulations.

3. COBRA

COBRA is a screening tool developed by the U.S. Environmental Protection Agency that helps state and local governments evaluate the public health benefits of changes in emissions of criteria pollutants. COBRA provides preliminary estimates of the effects of air pollutant emission changes (e.g., NO_x, SO₂ and PM_{2.5}) on ambient air concentrations of PM_{2.5} using a reduced-form air quality model called the Phase II Source-Receptor Matrix. COBRA then translates the estimated changes in ambient PM_{2.5} concentrations into the number of avoided adverse health effects, such as premature mortality, non-fatal heart attacks, asthma exacerbations, and work loss days, using concentration-response functions from the published epidemiological literature. Finally, COBRA estimates the monetary value of the avoided health effects using published values from the literature.

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COBRA uses two different methods to estimate the impacts of emission reductions on premature mortality and non-fatal heart attacks based on separate epidemiological studies of the impacts of air quality on public health. For this reason, COBRA reports the estimated public health benefits as a range. Most of the public health benefits from emission reductions modeled by COBRA are assumed to take place in during the year of the analysis (in this case 2030). An exception is premature mortality. The calculation of the premature mortality benefits assumes that breathing air pollution during the analysis year leads to an increased risk of premature mortality over a 20-year period. The benefits of avoiding deaths in future years are discounted to the present, using discount rates of three percent and seven percent, in accordance with guidelines from the Office of Management and Budget. The three percent discount rate is consistent with assumptions used for carbon accounting. The assumptions used in COBRA are consistent with those used in U.S. EPA analyses of air pollution regulations. This analysis used COBRA v3.0, which was released in October 2017.⁹⁸

⁹⁸ More information COBRA v3.0 is available at www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool

Appendix D. Scenarios and Sensitivities

Supplementing Section 6, this appendix details NYSERDA’s cost analysis of deployment of 2.4 GW of offshore wind by 2030. As in Section 6, scenarios are assessed reflecting endogenous policy options on procurement structure and transmission ownership strategy. In addition, sensitivities are provided to examine two exogenous factors – commodity price forecasts and financing costs.

Cost projections for the full 2.4 GW are provided in the form of the following cost indicators:

1. **Gross program costs** are calculated as the incremental revenue, on top of energy and capacity, that allows projects to reach their target return. The costs are presented as an NPV of incremental PBI payments, inclusive of Tier 1 REC payments.
5. **Net program costs** are defined as the gross program costs minus the NPV of the carbon value associated with the offshore wind deployment. Carbon value is calculated as the societal value of avoided CO₂e emissions in excess of the value already included in the electricity price through RGGI.

The assessment in this appendix reflects an assumed deployment profile as shown in Table 28. Section A.1 details the site selection and interconnection assumptions for both Phase I and Phase II deployments.

Table 28: Base deployment assumptions for installed capacity of offshore wind in New York

	2024	2025	2026	2027	2028	2029	2030
Installed Capacity, MW	400	400	-	400	400	400	400
Incremental Generation, GWh	1,500	1,600	-	1,600	1,600	1,600	1,700
Cumulative Generation, GWh	1,500	3,100	3,100	4,700	6,300	7,900	9,600

D.1 Scenarios

D.1.1 Procurement Structure

Tables 29 and 30 show the long-term costs, carbon benefits, and LCOEs associated with each of the procurement options under the base case assumptions as described in Section 6.2 and above.

Table 29: Long-term cost indicators (2.4 GW deployment) by procurement option

Cost Indicator	1. Fixed REC	2./4. Bundled/ Split PPA	3. Utility- Owned Generation	5. Market OREC	6. Index OREC	7a. Forward OREC, Conservative	7b. Forward OREC, Aggressive
Gross Program Cost	\$4.6B cost	\$1.9B cost	\$0.7B cost	\$1.9B cost	\$2.1B cost	\$3.9B cost	\$2.5B cost
Carbon Benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit
Net Program Cost	\$2.7B cost	\$0.1B cost	\$1.1B benefit	\$0.1B cost	\$0.2B cost	\$2.0B cost	\$0.6B cost

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Table 30: Long-term LCOEs by procurement option

COD	1. Fixed REC	2./4. Bundled/ Split PPA	3. Utility- Owned Generation	5. Market OREC	6. Index OREC	7a. Forward OREC, Conservative	7b. Forward OREC, Aggressive
2024	\$155	\$118	\$101	\$118	\$120	\$145	\$125
2025	\$147	\$110	\$94	\$110	\$112	\$137	\$117
2026	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2027	\$141	\$103	\$88	\$103	\$105	\$130	\$110
2028	\$136	\$100	\$86	\$100	\$102	\$127	\$107
2029	\$132	\$95	\$83	\$95	\$97	\$122	\$102
2030	\$135	\$98	\$84	\$98	\$100	\$125	\$104

D.1.2 Transmission Ownership

Tables 31 and 32 below show the long-term costs, carbon benefits, and LCOEs associated with the transmission ownership strategies identified in Section 6.5 (“Developer-Owned” and “Regulated Asset”). These were analyzed in the context of two representative procurement structures, the Fixed REC and Bundled PPA.

Table 31: Long-term cost indicators (2.4 GW deployment) by transmission ownership strategy

Cost Indicator	Fixed REC		Bundled PPA	
	Developer-Owned	Regulated Asset	Developer-Owned	Regulated Asset
Gross Program Cost	\$4.6B cost	\$4.3B cost	\$1.9B cost	\$1.7B cost
Carbon Benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit
Net Program Cost	\$2.7B cost	\$2.4B cost	\$0.1B cost	\$0.2B benefit

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Table 32: Long-term LCOEs by transmission ownership strategy

COD	Fixed REC		Bundled PPA	
	Developer-Owned	Regulated Asset	Developer-Owned	Regulated Asset
2024	\$155	\$151	\$118	\$114
2025	\$147	\$143	\$110	\$107
2026	n/a	n/a	n/a	n/a
2027	\$141	\$137	\$103	\$100
2028	\$136	\$132	\$100	\$96
2029	\$132	\$128	\$95	\$92
2029	\$135	\$130	\$98	\$94

D.2 Sensitivities

Sensitivity analysis is provided to examine the impact of a range of commodity price and financing assumptions. Results are provided separately for Phase I and a 2.4 GW rollout by 2030. Phase I cost indicators are given as incremental program costs and electricity bill impacts (see Section 6).

D.2.1 Commodity Pricing

This analysis considers two commodity price forecasts, a Base and a Low sensitivity (as discussed in Appendix C.4). Table 33 shows the long-term costs and carbon benefits associated with each commodity pricing sensitivity under base case assumptions (described in Section 6.2).

Table 33: Long-term cost indicators (2.4 GW deployment) by commodity sensitivity

Cost Indicator	Fixed REC		Bundled PPA	
	Base Commodity	Low Commodity	Base Commodity	Low Commodity
Gross Program Cost	\$4.6B cost	\$5.7B cost	\$1.9B cost	\$3.2B cost
Carbon Benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit
Net Program Cost	\$2.7B cost	\$3.8B cost	\$0.1B cost	\$1.3B cost

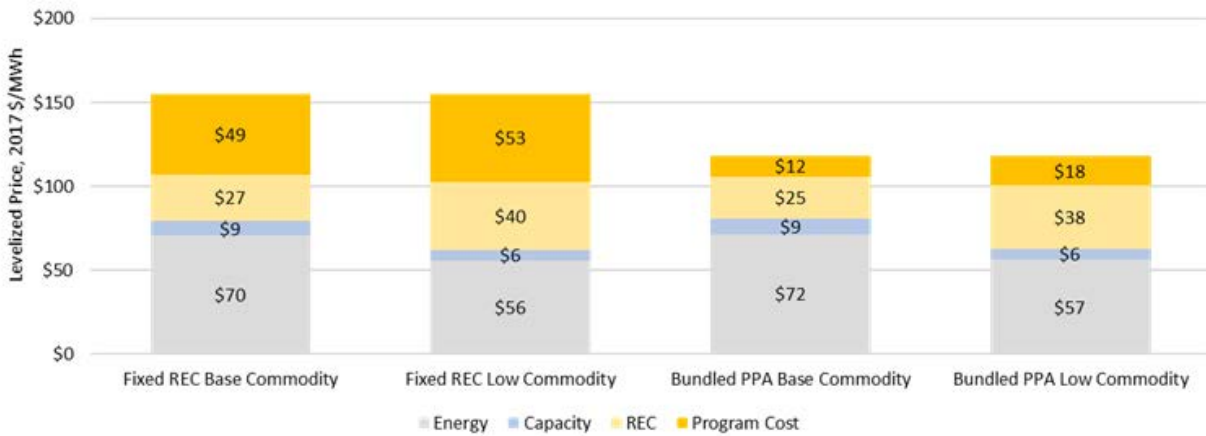
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Commodity pricing sensitivities were also examined only for Phase I deployments, with results shown in Table 34 and Figure 25.

Table 34: Phase I cost indicators by commodity sensitivity

Cost Indicator	Fixed REC		Bundled PPA	
	Base Commodity	Low Commodity	Base Commodity	Low Commodity
Phase I Incremental Program Cost	\$1.2B cost	\$1.3B cost	\$0.2B cost	\$0.4B Cost
Phase I Incremental Bill Impact	0.76%	0.83%	0.14%	0.25%

Figure 25: LCOE broken down by energy, capacity, REC and program cost for 2024 deployments, by commodity sensitivity



While offshore wind program costs would be higher under low energy prices, this would be outweighed by customers' savings on their overall energy bills due to lower energy prices. Figures 26 and 27 show projected statewide spend on wholesale electricity, compared to historic spend levels. Projections are shown with and without estimated offshore wind costs, in each case both under Base and Low commodity price forecasts.

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Figure 26: Fixed REC program costs (2.4 GW deployment) relative to historic and projected statewide wholesale electricity spend

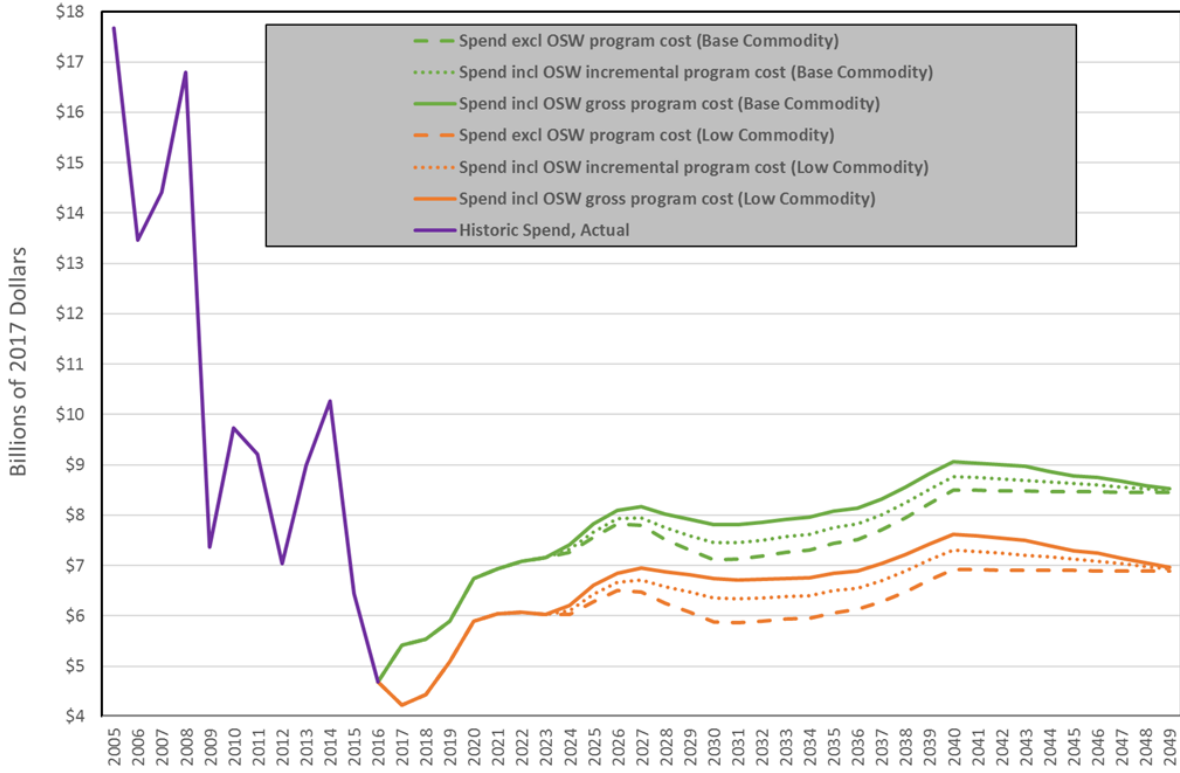
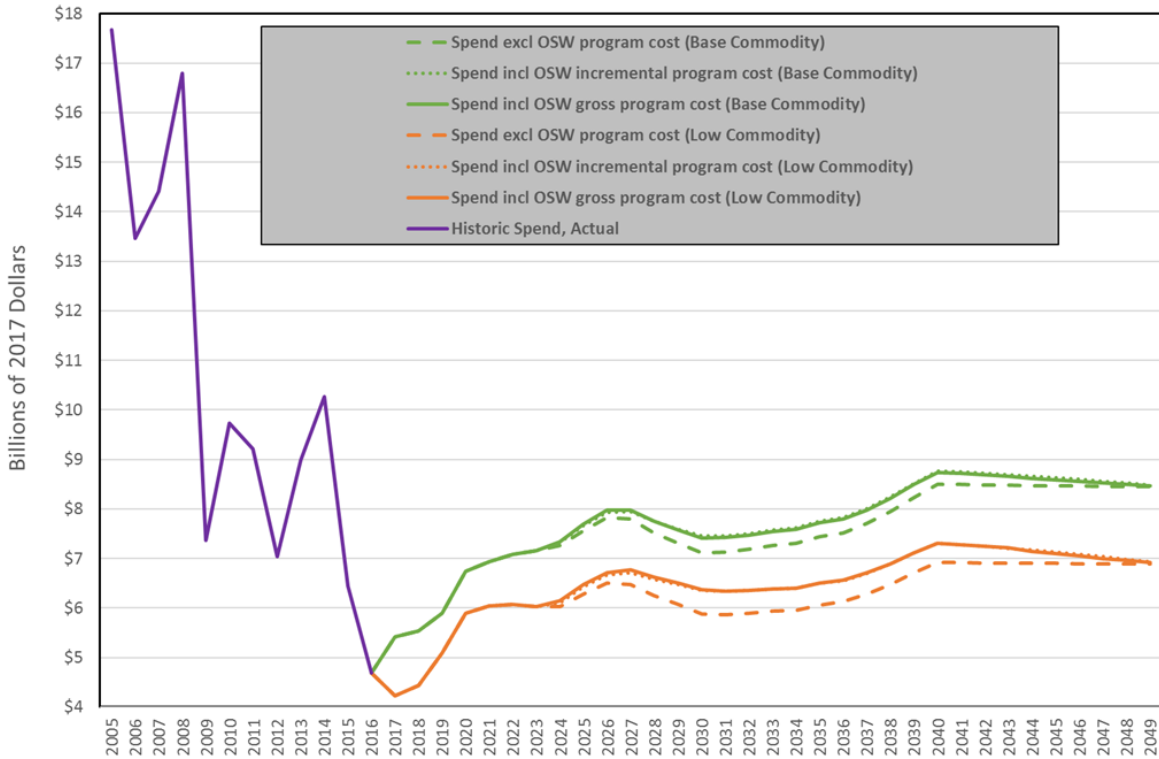


Figure 27: Bundled PPA program costs (2.4 GW deployment) relative to historic and projected statewide wholesale electricity spend



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D.2.2 Financing Cost

This sensitivity illustrates the possible cost impact resulting from both a high and low financing cost sensitivity. These sensitivities are distinct from the impact of alternative procurement structures as discussed in Sections 6 and D.1.1. Procurement structures impact finance costs materially; the sensitivities explored in this section examine the impact of current and future data uncertainty on financing costs. They are analyzed as high and low deviations from the base finance costs assumed for each procurement model, which are calculated according to the methodology outlined in Appendix B:

1. A “Low Financing” scenario, a 0.75 percent decrease in project WACC was applied, relative to the base case.
2. A “High Financing” scenario, a 0.75 percent increase in project WACC was applied, relative to the base case.

See Appendix B for further details on financing assumptions.

Tables 35 and 36 show the long-term costs, carbon benefits, and LCOEs for the financing cost sensitivities under the base case assumptions described in Section 6.2.

Table 35: Long-term cost indicators by financing cost sensitivity

Cost Indicator	Fixed REC		Bundled PPA	
	Low Financing	High Financing	Low Financing	High Financing
Gross Program Cost	\$4.2B cost	\$5.0B cost	\$1.6B cost	\$2.3B cost
Carbon Benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit	\$1.9B benefit
Net Program Cost	\$2.3B cost	\$3.1B cost	\$0.3B benefit	\$0.5B cost

Table 36: Long-term LCOEs by financing cost sensitivity

COD	Fixed REC		Bundled PPA	
	Low Financing	High Financing	Low Financing	High Financing
2024	\$149	\$162	\$112	\$124
2025	\$141	\$154	\$105	\$115
2026	n/a	n/a	n/a	n/a
2027	\$135	\$147	\$98	\$108
2028	\$131	\$142	\$95	\$105
2029	\$127	\$138	\$91	\$100
2029	\$129	\$140	\$93	\$102

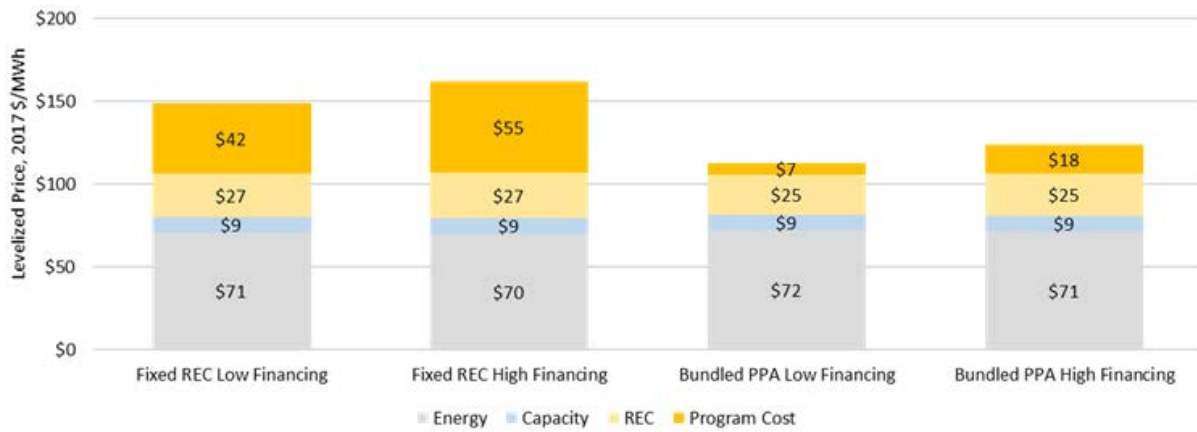
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Financing cost sensitivities were also considered in the context of Phase I deployments, with results shown below in Table 37 and Figure 28.

Table 37: Phase I cost indicators by financing cost sensitivity

Cost Indicator	Fixed REC		Bundled PPA	
	Low Financing	High Financing	Low Financing	High Financing
Phase I Incremental Program Cost	\$1.0B cost	\$1.4B cost	\$0.1B cost	\$0.4B cost
Phase I Incremental Bill Impact	0.65%	0.86%	0.05%	0.24%

Figure 28: LCOE broken down by energy, capacity, REC and program cost for 2024 deployments, by financing cost sensitivity



Appendix E. Benefits

E.1 Carbon Benefits

The value of avoided carbon under the CES was calculated in the CES Cost Study. The avoided carbon attributed to offshore wind in this study is not incremental to the carbon values noted in the CES Cost Study, but is instead a component of the total CES carbon value. The value of avoided carbon is considered a monetized benefit in the calculation of net program costs.

Figure 29 shows the volume of carbon avoided by offshore wind deployment as a component of Tier 1 of the CES, and Figure 30 shows its associated value. Supporting methodology is included in Section C.5.

Figure 29: Volume of avoided carbon from offshore wind relative to total avoided carbon from Tier 1 of the CES

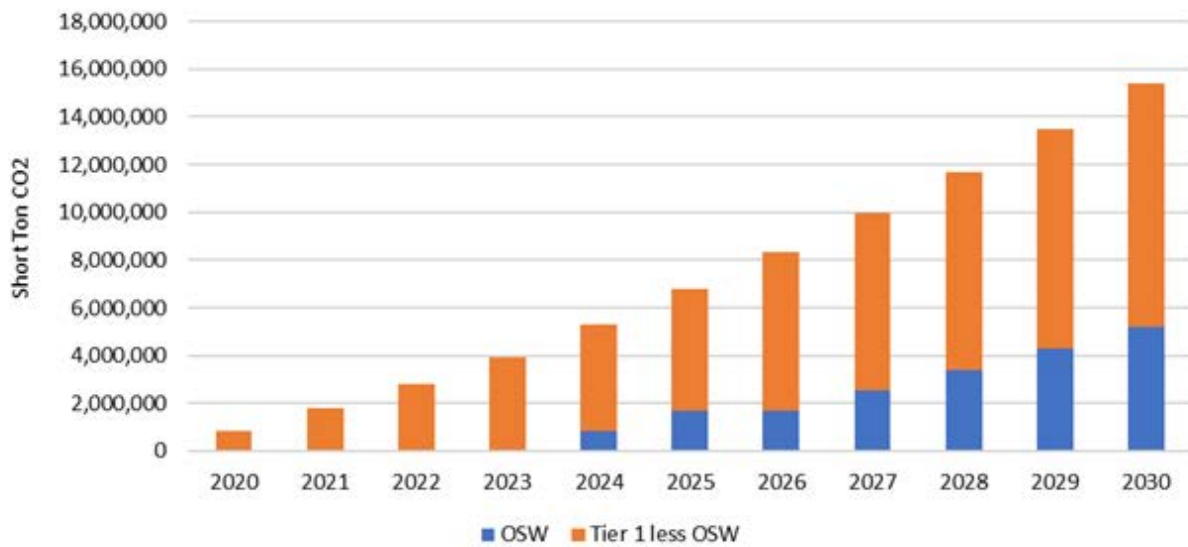
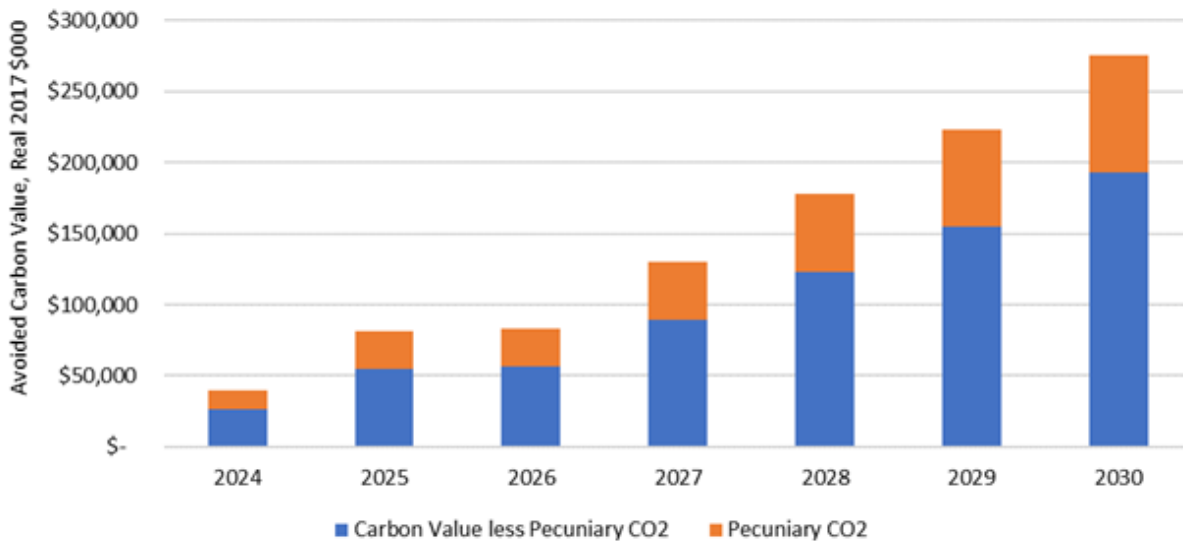


Figure 30: Value of avoided carbon from offshore wind deployment



E.2 Public Health Benefits

Significant improvements have been made to air quality in New York over time due to regulations of high-emitting sources in upwind regions, regulations on the amount of sulfur in heating and transportation fuels, and displacement of high-emitting sources with cleaner lower-cost fuels such as natural gas in the power sector. Increased energy efficiency and increasing installation of zero emissions renewables such as solar photovoltaics and wind will continue to drive the trend of decreasing emissions. This is especially important for the NYC-metropolitan area with its high population and density of emissions sources from many sectors such as power, transportation and heating. All areas of the State are currently designated as attaining the U.S. EPA National Ambient Air Quality Standards for fine particles (PM 2.5). However, concentrations of PM 2.5 are still at health-relevant levels and higher than in the rest of the State. Ozone has not decreased substantially over time and New York State Department of Conservation has recommended to the U.S. EPA that the New York City metropolitan area - consisting of the Counties of Bronx, Kings, Nassau, New York, Queens, Richmond, Rockland, Suffolk, and Westchester - be designated nonattainment for the 2015 ozone NAAQS of 70 ppb. Continued efforts will be needed to reduce these pollutants further.

The public health impacts from PM 2.5 and ozone include respiratory and cardiovascular disease. In New York City, PM 2.5 at levels higher than background is associated with over 2,000 premature deaths, 4,800 emergency department visits for asthma and 1,500 hospitalizations for respiratory and cardiovascular disease each year (NYC Health, 2013). Reducing pollution by even modest amounts in such a highly populated area can have significant benefits.

See Appendix C.6 for methodology details in respect of a screening-level analysis of the air quality benefits for 2030 if 2,400 MW of offshore wind is feeding lower New York that was conducted to support this Options Paper.

This analysis showed that in the 2,400 MW offshore wind scenario, dramatically less harmful air pollution would be present; specifically, more than 1,800 tons of NO_x, 780 tons of SO₂, and 180 tons of PM 2.5 would be avoided in 2030 as compared to a CES scenario without offshore wind.

The State then used EPA's Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool to estimate how those emission reductions would affect ambient air quality and adverse health impacts throughout the region. This tool estimates how changes in ambient air quality affect public health outcomes, and then estimates the monetary value of the public health impacts. This screening-level analysis found that the offshore wind scenario would result in 8 to 18 fewer premature deaths annually and would avoid multiple adverse health outcomes in 2030 across the northeast United States. The total health benefits of the 2030 offshore wind scenario are valued between \$73M and \$165M. However, these benefits should continue well beyond 2030, and an NPV analysis estimates that total health benefits from the 2.4 GW offshore wind deployment would be on the order of \$1B.

E.3 Workforce Benefits

A progressive energy employment landscape already exists in New York State, as evidenced by the approximately 22,000 New Yorkers who are working in the renewable energy industry (including solar,

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land-based wind, and hydropower) across the State.⁹⁹ The State's vision to create a clean, resilient, and affordable energy system has resulted in policy standards that have triggered job growth across a range of technologies. Offshore wind is the next addition to the State's fast-growing clean energy industry and is expected to be a key driver in the increasing demand for renewable energy workers in New York.

An analysis was performed to project the number of workers needed and the nature of jobs created from the development, construction and operation of 2.4 GW of New York offshore wind and deployment in other regional states (see Appendix T of the Master Plan). The analysis found that:

- New York can realize nearly 5,000 new jobs in manufacturing, installation and operation of offshore wind facilities, with a regional commitment to scale development of the resource. Nearly 3,500 of these jobs are expected to support New York wind farms, with the remaining supporting regional projects.
- Nearly 2,000 of these jobs are in operations and maintenance (O&M), providing sustained career opportunities for New Yorkers as the average offshore wind facility life span is at least 25 years.
- Many New Yorkers already possess most of the skills necessary to attract offshore wind manufacturers and developers; skill development support from New York State will assure new workers will have the skills needed to participate in this industry.

The analysis found that New York's workforce is expected to primarily benefit from the long-term O&M sector, which is estimated to support as many as 1,830 jobs. O&M workers must be able to respond quickly to any on-site requests, making their proximity to the wind farms critical. New York can therefore see nearly all of these as baseline jobs, confident they will be sourced locally. Project management and development, as well as installation and commissioning, are expected to create up to 580 additional baseline jobs.

Incremental to baseline jobs, the manufacturing and installation and commissioning sectors could support up to 2,250 and 220 jobs, respectively. The demand for these positions will be during the development and construction phases of the project life cycle.

The analysis was designed along two regional build scenarios, both of which assume execution of New York's 2.4 GW goal:

- **High market** scenario where 8 GW is deployed regionally by 2030.
- **Low market** scenario where 4 GW is deployed regionally by 2030.

The outcomes of these scenarios were also tested by two sensitivities based on the level of New York State market support:

- **High local content:** significant actions are made by the State to support workforce readiness, supply chain development, and infrastructural improvements.
- **Base local content:** limited additional intervention is taken to attract new industry.

⁹⁹ 2017 New York Clean Energy Industry Report, NYSERDA 2017. The broader clean energy industry, including energy efficiency, clean transportation and advanced grid technologies employs over 146,000 workers today.

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The demand for New York workers under each scenario and sensitivity is shown in Table 38. Manufacturing, project management and development, and installation and commissioning averages are calculated from 2024 to 2028. O&M averages represent long-term employment from 2030 onwards.

Table 38: Average demand for New York workers from New York and regional projects

Scenario		Project management and development workers	O&M workers	Installation and commissioning workers	Manufacturing workers
High market	High local content	350	1,830	470	2,250
	Base local content	330	1,820	200	90
Low market	High local content	340	1,790	420	1,310
	Base local content	330	1,780	250	50

E.4 Wholesale Price Impacts

As noted in the Order Establishing the Benefit Cost Analysis Framework,¹⁰⁰ wholesale price impacts are not resource or societal benefits, but transfers from one subset of society to another. Further, they are difficult to estimate accurately. Thus, any market price reductions caused by pursuing the 2.4 GW offshore wind goal should not be considered a societal “benefit” produced by the policy.

However, as also noted, such market price impacts will certainly have at least a temporary impact on ratepayers’ bills. Therefore, when bill impacts are estimated, it is appropriate to acknowledge that such price reductions will temporarily reduce or eliminate these impacts.

The size and duration of such price impacts will depend on many factors. The most important of these are: (i) the quantitative impact the offshore wind projects have on capacity and generation market supply and demand; (ii) the time period over which these impacts occur; (iii) the extent to which the policy change is clearly described in advance, and considered likely to materialize by market participants; and (iv) whether the offshore wind projects will have any long-run effect on the cost of the long run marginal resource that is added when the system is in need of new market-based capacity.

¹⁰⁰ Case 14-M-0101 January 21, 2016

Appendix F. Acronyms

ACP	Alternative Compliance Payment
BOEM	Bureau of Ocean Energy Management
CAPEX	Capital Expenditure
CARIS	Capacity and Resource Integration Study
CES	Clean Energy Standard
CO ₂ e	Carbon dioxide equivalent
COD	Commercial Operation Date
EDC	Electric Distribution Company
IOU	Investor-Owned Utility
IRR	Internal Rate of Return
GHG	Greenhouse Gas
GW	Gigawatt
LBMP	Locational Based Marginal Price
LCOE	Levelized Cost of Energy
LIPA	Long Island Power Authority
LSE	Load-Serving Entity
LSR	Large-Scale Renewables
MWh	Megawatt Hour
NPV	Net Present Value
NYGATS	New York Generation Attribute Tracking System
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYS	New York State
NYSERDA	New York State Energy Research and Development Authority
OPEX	Operating Expenditure
OREC	Offshore Wind REC
PBI	Performance-Based Incentive
PPA	Power Purchase Agreement
PPTPP	Public Policy Transmission Planning Process
PSC	Public Service Commission
REC	Renewable Energy Certificate
RES	Renewable Energy Standard
RFP	Request for Proposals

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RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SCC	Social Cost of Carbon
SEP	State Energy Plan
T&I	Transmission and Interconnection
UCAP	Unforced Capacity
UOG	Utility-Owned Generation
U.S.	United States
WACC	Weighted Average Cost of Capital
WEA	Wind Energy Area
ZEC	Zero-Emissions Credit