July 26, 2018

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
Post Office Box 350
Trenton, New Jersey 08625-0350

Submitted via Rule.Comments@bpu.nj.gov

Re: Docket No. QX18040466: Offshore Wind Solicitation of 1,100 Megawatts

Dear Secretary Camacho-Welch:

Ocean Wind welcomes the opportunity to provide input on the Board of Public Utilities' (BPU or Board) imminent solicitation of 1,100 megawatts of offshore wind capacity. Ocean Wind is New Jersey's most advanced offshore wind project. The Ocean Wind lease area, located over 10 miles due east of Atlantic City, can support over 3,500 megawatts of offshore wind capacity, enough generation to serve over 2 million New Jersey households. Ocean Wind is an Ørsted project, the world's leading developer and operator of offshore windfarms. The company has built and now operates 24 projects around the world and has another 5,000 megawatts of projects under construction.

Ocean Wind is one of the two holders of federal offshore Renewable Energy Leases on the Outer Continental Shelf offshore of New Jersey, having acquired our 160,000-acre lease in 2016. As such, Ocean Wind has a significant interest in ensuring that the state creates a transparent and predictable solicitation structure that will enable the long-term success of the offshore wind industry in New Jersey, supporting the development of a cost-effective, reliable, and environmentally sound energy source for the citizens of New Jersey.

Ocean Wind supports Governor Murphy's Executive Order No. 8 (EO8), which directs state agencies to take all necessary actions to implement OWEDA to realize the development of 3,500 megawatts of offshore wind generation off the coast of New Jersey by 2030. EO8 also directs the BPU to issue a solicitation calling for proposed offshore wind projects for the generation of 1,100 megawatts of electric power, the nation's largest such solicitation to date. As requested by the BPU, Ocean Wind is limiting these comments to the solicitation for 1,100 megawatts and will provide comments to future solicitations and the state's realization of the 3,500 megawatt goal when invited by the BPU.

Ocean Wind believes the BPU should be guided by an effort to provide the lowest cost, highest value, and most reliable projects to the people of New Jersey. To ensure that Qualified offshore wind projects, as defined at N.J. Rev. Stat. § 48:3-51 (and referred to herein as "Projects"), can be built and operated successfully in the long-term, there are several principles we believe should guide the development of New Jersey's solicitations. These principles are:

- Enabling robust competition
- Prioritizing project viability
- Establishing a stable, long-term commitment to offshore wind
- Minimizing uncertainties and risk in the development process because lenders abhor uncertainties, and they will only lead to increased ratepayer costs

State Procurements

1. How should BPU stagger/phase in New Jersey's offshore wind procurements to realize the State's goal of 3,500 megawatts. Should this schedule be announced before any solicitations are released?

2. How should the BPU structure the initial solicitation for 1,100 megawatts of offshore wind capacity as called for under EO8?

The BPU should announce the full schedule of solicitations to achieve 3,500 megawatts before any solicitations are released. Visibility into the state's long-term development plan provides assurances and certainty to the industry that establishing a supply chain and manufacturing in the state will be beneficial in the long-term. This will also establish New Jersey as an offshore wind leader, sending a strong message to industry and the supply chain that New Jersey is committed to achieving its goal of 3,500 megawatts by 2030, attracting long-term jobs and businesses. This commitment would provide significant benefits to the state: a typical 1,000 megawatt Ørsted offshore wind farm generates approximately 1,000 annual direct jobs during construction and projects with high degrees of local content development will likely exceed that figure. In addition, there are thousands of indirect jobs generated by industry development. This Board has recognized the multiplier effect of capital expenditures and resulting job creation and its benefits to New Jersey's economy.

When determining its solicitation schedule, the BPU should consider the procurement schedules of other states with offshore wind procurement targets such as New York and Massachusetts. In order to optimize the development of the U.S. market and facilitate strong supply chain growth, New Jersey should attempt to establish a steady pipeline of projects in coordination with other states along the East Coast, avoiding a boom and bust cycle.

The BPU should issue the first solicitation of 1,100 megawatts this year to take advantage of federal tax incentives that phase out at the end of 2019. One such tax incentive is the investment tax credit (ITC), which sunsets after 2019. In order for projects to secure the benefits of the ITC, they must receive notification of an award from the Board by mid- 2019. The first solicitation should be timed such that selected projects can make this deadline.

To facilitate a solicitation this year, the BPU should conduct the first procurement within the existing regulatory framework established in and pursuant to OWEDA. See generally N.J.S.A. 48:3-87.1; N.J.A.C. 14.8-6.3, and 14:8-6.5 (2018). That existing framework provides for a thorough evaluation of individual projects' net benefits and other project information, and the BPU could readily add a competitive-bidding overlay to it in furtherance of EO8 and the BPU's competitiveness goals. Adding such a competitive overlay would not require revising either OWEDA or its implementing regulations;[1] as such revision would be time-consuming and therefore counterproductive to enabling New Jersey ratepayers to benefit from cost reductions in the first solicitation created by the ITC and putting New Jersey in the lead position in the United States in offshore wind development. Future solicitations may be able to benefit from lessons learned from early solicitations and the state may find it beneficial to refine the current regulatory structure at a later date. However, to prevent costly delays, the state should proceed with the first solicitation according to the current statutory and regulatory framework.

Ocean Wind recommends the BPU issue a solicitation in Q3 of this year and provide at least two months of lead-time before opening an OREC window. Such a timeframe will afford developers adequate lead-time to adjust project development plans to the extent needed to address the priorities and requirements articulated in the solicitation.

[1] For example, OWEDA and its implementing regulations establish minimum criteria that a Project must satisfy in order for the BPU to be able to approve an OREC application, but nevertheless afford the BPU discretion in determining whether to approve, conditionally approve, or deny an application. See N.J.S.A. 43:3-87.1.c–d; N.J.A.C. 14:8-6.5(b). The determination could presumably be based at least in part on a comparison against other Projects for which OREC applications have been submitted.

To allow the agency to compare projects, the BPU should open a short OREC window of a few weeks to allow projects to proceed along the review process in tandem. The two-month lead time will provide developers time to prepare OREC applications, so a longer OREC window is not necessary. If the OREC window is too long, the process may threaten the attainment of the realization of the ITC.

According to OWEDA, developers are required to meet with the BPU at least 30 days prior to an OREC application submission. If there are additional requirements established for developers in the solicitation, the BPU should set a period after issuance but before the proposal deadline when developers can request clarification or seek exceptions for problematic solicitation requirements. The solicitation should provide a procedure for requesting and prompt action upon requests for exceptions.

To continually improve proposals and leverage lessons learned from solicitations, the BPU should offer an opportunity for debriefing after projects are awarded. The BPU could use a similar process to federal government contracts, where bidders are allowed at least three days to request a debriefing after the announcement of an award. This would allow both winning and losing applicants to understand the evaluation process and the strengths and weaknesses of their applications from the perspective of the agency.

Following its solicitation of 1,100 megawatts this year, the BPU should establish two rounds of 1,200 megawatt procurements. One of the most important considerations in establishing and expanding a local offshore wind industry in New Jersey is the ability to establish business foundations that are stable, predictable, and scalable. To these ends, it is imperative that the BPU establish a solicitation schedule in which each successive solicitation commences not later than 24 months after the prior solicitation and includes opportunities for utility-scale project development. Ocean Wind does not expect the market conditions to change so materially between solicitation cycles as to warrant any significant departures from this 24-month cycle. A time-certain solicitation schedule of utility-scale procurements will reinforce expectations of market size and timing and, in conjunction with what other states in the region (such as New York) may be contemplating, further encourage regional investment in necessary supply chain industries.

Confidentiality

OREC applications will of necessity contain trade secret and other confidential information. The BPU should include language in the solicitation making it clear that portions of proposals submitted during the OREC window are confidential and not subject to public disclosure, including under the Open Access to Public Records Act. Applicants should be able to designate those portions of the application which should receive confidential treatment, and know that they will be treated confidentially.

Post-20 Year OREC Life

The solicitation should address the treatment of projects after the duration of twenty years of OREC pricing; specifically, it should recognize that, following that term, a Project should be treated as a merchant generator. This approach is called for by existing law, and a clear statement of it is needed to provide certainty to lenders and investors, which will enhance New Jersey's aspiration to be the leading offshore wind state in the country. Without specificity, lender uncertainty will drive up costs to the detriment of ratepayers. Notably, eventual merchant status for Projects will also benefit the New Jersey ratepayers, including because any merchant income from the post-OREC term will work to lower the OREC prices offered by developers in a competitive process as envisaged for the OREC window.

Having a Project shift to merchant status following its twenty-year OREC term is called for by OWEDA, in which the legislature imposed a mandate for an offshore wind carveout in New Jersey's renewable energy portfolio standard, but specified that it must be based on a twenty-year operating term for each Project. See N.J.S.A. 48:3-87.d(4). Consistent with the temporal scope of that mandate, the statute requires OREC applications to provide a financial analysis for a twenty-year term. N.J.S.A. 48:3-87.1.a(2). Absent further legislative action, it is therefore appropriate for Projects to shift to merchant status following their twenty-year term of entitlement to OREC pricing. This is confirmed by OWEDA's acknowledgment that operations beyond that twenty-year term may require a renewal of the Project's offshore wind lease. See N.J.S.A. 48:3-87.1.a(6). The U.S. Bureau of Ocean Energy Management's regulations provide for such renewals—though they contemplate that renewals will be requested toward the end of the initial operations term (i.e., well into the OREC term). See 30 C.F.R. §§ 585.422–585.429 (2017). While Ocean Wind is confident in its ability to obtain such renewals as needed, it acknowledges that, in OWEDA, the legislature may reasonably have sought to avoid a scenario in which the obligation to purchase ORECs from a Project extends until a time when the Project's operating status is—theoretically—uncertain. Instead, it is preferable for the Project to have merchant status at that time. As further discussed below, there is also another source of uncertainty at present: ongoing debate concerning participation of renewable energy generators in the PJM-administered interstate markets; merchant status would provide flexibility for Projects to navigate that evolving regulatory landscape, and thereby reduce risk to ratepayers.

The Board may, of course, consider a Project's future merchant revenues when evaluating an OREC application, consistent with the statutory requirement for an OREC application to address "the projected electrical output and anticipated market prices over the anticipated life of the project, including a forecast of electricity revenues from the sale of energy derived from the project and capacity." N.J.S.A. 48:3-87.1.a(5). As noted above, Ocean Wind believes that the prospect of future merchant revenues will enable Projects to offer lower OREC prices. Furthermore, Projects operating as merchants following the twenty-year OREC term will continue to reduce New Jersey electric rates through several well-established benefits, as recognized by the BPU: merit order benefits (by which the energy from the project will reduce market clearing prices) and reducing the need for other class 1 renewables to be paid for by New Jersey ratepayers. These benefits will accrue both during and after the twenty-year OREC period, as will other benefits related to enhanced economic activity and environmental benefits.

BPU Solicitation Size

2. How should the BPU structure the initial solicitation for 1,100 megawatts of offshore wind capacity as called for under EO8?

3. Should the BPU request proposals scaled at 1,100 megawatts, or should the BPU request proposals in smaller blocks of capacity (i.e. 400 megawatts)?

The BPU should allow developers to propose projects of any size in the OREC window up to the full 1,100 megawatt size. The agency should allow developers to supply multiple mutually exclusive proposals and the BPU should select the project or projects for a total of 1,100 megawatts that provide the highest score under the evaluation criteria. This provides flexibility to developers to optimize project size based on their respective business models while providing a basis to compare projects across a spectrum of planned capacity.

Allowing developers to bid in utility-scale projects up to the full 1,100 megawatts enables them to select and submit the most economical and efficient project sizes. Small projects will typically come at a significantly higher cost than larger projects, because the activities required for permitting, development, procurement, construction and operation will be paid for on a multiple basis, eroding the economies of scale enjoyed by a larger project. Preserving bidder flexibility to propose larger scale projects will enable the BPU to evaluate these benefits as compared to smaller projects and opt to secure these significant cost savings for the benefit of ratepayers.

Additionally, large projects promote the establishment of the supply chain in New Jersey, supporting full-time, long-term jobs in the offshore wind industry. Small projects will not produce the scale necessary to attract suppliers, which will typically require a minimum contract size, as well as a visible future "pipeline" of projects, to meet the necessary thresholds for establishing capital-intensive manufacturing or assembly facilities. Furthermore, large-scale procurements allow New Jersey to leap frog other states that have developed pilot projects or smaller scale projects to demonstrate the viability of offshore wind along the East Coast. Other states procuring offshore wind such as Massachusetts and New York are opting for utility-scale procurements with solicitations for 800 megawatts or more. New Jersey should take advantage of the lessons learned from these earlier actions and implement them in the development of larger-scale and more economical projects. Ultimately, allowing multiple and large-scale bids will provide the BPU the opportunity to determine the optimal projects or projects for the state and for ratepayers.

Promoting a Competitive Process

4. How may a solicitation be structured to ensure strong competition from multiple OSW developers?
5. What conditions should be included to ensure maximum competition in terms of OREC Price?

The BPU should establish a "pay as you bid" structure where developers must bid their best and final prices into the auction and are awarded projects based on those prices. This process would allow a clear comparison between projects and avoid a renegotiation following initial bidding. Renegotiation with the BPU following initial bidding could encourage developer "gaming," where developers are motivated to submit a higher price initially with the understanding they will be required to renegotiate the price in a subsequent round. A bilateral negotiation process between the BPU and the winning developer does not promote the same competitive pressure as a full competitive process between all developers. It also provides fodder for future court challenges claiming collusion. Additionally, if a developer does not add enough to its initial bid and must then renegotiate that price, there is the potential for a break off of the negotiation, ultimately putting development at risk. Instead, the BPU should inform developers of the "pay as you bid" structure in advance, making it clear there is one opportunity to put in a best and final offer, and developers will bid accordingly. In short, "pay as bid" promotes "price discovery" of the lowest price a proposer can offer since having "one bite at the apple" incentivizes proposers to put their best offer forward in its proposal, with no "holding back" or gaming.

To further promote competition, the BPU should open a short OREC window of a few weeks to allow projects to proceed along the review process in tandem. If the OREC window is too long, developers could submit projects months apart, allowing for less comparison between projects during the evaluation or delaying earlier projects' review periods. A longer period is unnecessary and will slow the development process.

Optimizing Project Revenues

6. OWEDA requires the OREC Price to be an all-in price that includes the full cost of the construction, operation and decommissioning of the project with all revenues being refunded to ratepayers. What measures can be included in project proposals to optimize all revenues over the life of the project?

The BPU should structure its solicitation and regulatory approach to reflect the following factors:

1. We propose to sell the power into the applicable PJM power market. For both energy and capacity, all net PJM revenues would be credited to ratepayers. As power prices rise over the years, increasing (and all) revenues would be credited to ratepayers. This approach will enable projects to avoid bearing power market risk so that ratepayers: (1) avoid the risk premium that projects will include in their OREC prices if the project were to absorb market price risk and (2) capture all energy and capacity benefits realized by a project during the OREC term.

2. While the “default approach” to market power would be as described above, alternatively the BPU could direct other approaches including:
    a. directing the project to sell bilaterally to other off takers at fixed or other prices, with all revenues returned to ratepayers with no additional risk to the project;
    b. directing that the rights to the energy and/or capacity be auctioned off by the project with all revenues assigned to ratepayers with no additional risk to the project. There are many wholesale power participants who may have interest in buying the rights to the power. This market test could provide assurance to the BPU that ratepayers were receiving the best value.

3. The BPU should not require projects to demonstrate that the resource optimized its participation in the wholesale markets in a way that provided the maximum possible return to ratepayers. This will impose regulatory risk that Projects cannot foresee or hedge (for example, the possibility of BPU ordering after-the-fact disallowances when a power marketing strategy does not yield benefits) and that will increase risk premiums in OREC Prices. While Ocean Wind supports the Board’s goal of maximizing Projects’ revenues that are passed on to New Jersey ratepayers, it believes that Projects must be afforded ample discretion in how to further that goal, for at least two additional reasons.
    a. First, Projects should not be required—either by an order awarding ORECs or by the rules of a solicitation—to participate in the PJM-administered interstate energy and capacity markets. As the Board has explained, “[t]he OREC program is ‘untethered to a generator’s wholesale market participation.’” Protest of the N.J. BPU 18 n.101, *PJM Interconnection, L.L.C.*, FERC Docket Nos. ER18-1314-000 & ER18-1314-001 (May 7, 2018) (citing *Hughes v. Talen Energy Marketing*, 136 S. Ct. 1288, 1299 (2016)). But adding a PJM market-participation requirement could be seen as undermining that untethered status, thereby potentially creating a jurisdictional question and attendant legal risk.
    b. Second, Projects should not be put at risk of penalization in the event they are excluded from the PJM-administered capacity market. The Federal Energy Regulatory Commission (FERC) recently rejected PJM’s proposed revisions to its Tariff’s Minimum Offer Price Rule (MOPR), and in so doing suggested that generators participating in state programs that incentivize renewable energy may be unable to participate in the PJM-administered capacity market in the future. *See PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,236, at PP 157–63 (2018). The Board should accordingly craft any revenue-maximization goal so as not to penalize Projects should this regulatory eventuality come to pass—or should PJM’s MOPR otherwise be revised to the detriment of offshore wind.

4. N.J.A.C. 14:8-6.5(a)12.ix states: “To the extent that the project produces energy revenues exceeding those associated with the sale of ORECs, the applicant may propose that it retain up to 25 percent of the incremental energy revenues, but not any other environmental attributes or other benefits, with the remainder to be returned to ratepayers.” In order to reasonably implement this rule, projects should be allowed to set the volume of production they expect to meet annually and capture any natural volatility in that production through the banking system. Consistent with the regulation, this would allow projects to retain up to 25 percent of any incremental revenues, since such sharing would only come into effect if the production estimate were incorrectly estimated by the developer. However, if the BPU sets the production cap and there is a limit on banking, then it is unreasonable for developers to carry the risk of these restrictions and developers should be allowed to retain 100 percent of the incremental revenues.

5. Any determination about revenue is highly dependent on the Federal Energy Regulatory Commission (FERC) decision expected in late 2018 around capacity markets and subsidy issues—including but not limited to the issues referred to in point 3 above—not to mention possible appeals of such action. The

Board should maintain some flexibility in this regard. Developers should be given flexibility under the OREC solicitation rules to do whatever is required of them by the FERC and PJM in terms of revenue. E.g., action taken by either FERC or PJM to impair offshore wind resources' opportunity to access certain wholesale revenues should not undermine their entitlement to ORECs.

<u>Evaluating Net Economic Benefits</u>

7. OWEDA requires that offshore wind developers demonstrate a net economic benefit for the State. How should the BPU ensure net economic benefits in order to be able to compare applications?

According to OWEDA, offshore wind projects must demonstrate a net economic benefit to the state. To ensure this, we recommend that the BPU rely on both price and non-price factors to evaluate projects. We also recommend transparent evaluation criteria and clarity on their relative weighting, particularly between and among price and non-price factors. In its evaluation, we recommend the BPU include criteria that indicate the likelihood of success in the project's development and delivery of benefits, including:

- Economic criteria: (1) OREC price; (2) Net economic benefits
- Non-Price Criteria: (1) The financial strength of the developer and whether its financing sources are firm; (2) A demonstrated ability to complete the project in a timely manner; (3) Technical capability and experience; (4) Job and economic activity creation; (5) Environmental impacts

Ocean Wind also recommends for the solicitation several key elements listed below that will support the success of New Jersey's first procurement of offshore wind.

1. Economic Criteria: Accountability
    a. According to OWEDA, projects must pass a net benefit test that ensures projects provide more benefits to New Jersey ratepayers than they do costs. One key element of this approach is ensuring that developers deliver the promised long-term benefits and are held liable for any benefits that do not materialize. One way to ensure that ratepayers are protected is to provide security in the form of cash, bonds or letters of credit against their proposed economic benefits. Projects would develop an independent report to verify the project's job creation and local economic benefit targets were met and once validated by the BPU, the money would be returned to the project, or the security relinquished.
    b. To protect ratepayers, the BPU should require the selected project to post material security (i.e., $1,000,000 or more). This would be in addition to any payments made by a developer to the BPU for the BPU's cost of review of its application, pursuant to BPU's regulations. A security requirement of this size would limit unrealistic bidding because the security would be at risk if the project were not delivered within the defined timeframe or with the required qualifications and benefits. Fractions of this security would be lost upon failure to deliver in accordance with the milestones. The developer would forfeit any remaining amount for non-delivery of an "end-milestone" or failure to achieve benefits.
    c. The BPU should also set the OREC payments for the commissioning date of the project specified in the application and valid for twenty years. If projects are unable to meet their deadlines, they miss the equivalent time on the OREC payments. However, there should be a degree of flexibility for developers as a "no buffer" requirement for deadlines may lead to added contingencies in the developer business case. To avoid these contingencies, the BPU should allow a short buffer of 12 months, similar to what has been established in other offshore wind markets. If a project exceeded the 12-month buffer, the developer would be required to forfeit half the security deposit and at that point could elect to preserve the OREC award for another 12 months. If a developer failed to meet a 24-month deadline they would fully forfeit the security deposit absent a force majeure event.

2. Net Economic Benefit Threshold
    a. The net economic benefit threshold should be a floor for qualification and any project with a negative result should be rejected. Using the net economic benefit test, projects should be ranked according to the highest cost-benefit ratio or the greatest present value of net economic benefits over the life of the project.

3. Transparent Evaluation Criteria and Relative Weighting
    a. The solicitation should also be transparent on the evaluation criteria and their relative weighting, particularly between and among price and non-price factors. The BPU should select the project or projects for a total of 1,100 megawatts that provide the highest score under the evaluation criteria. Non-price factors should be specific, quantifiable to the extent possible and limited. Five critical non-price factors that should form the basis for the evaluation are:
        - the financial strength of the developer and whether its financing sources are firm,
        - a demonstrated ability to complete the project in a timely manner,
        - technical capability and experience,
        - job and economic activity creation,
        - and environmental impacts.

       Each of these non-price factors should be based on firm evidence and not conjecture. The solicitation should describe in detail the criteria, scoring weights and scoring methods used to evaluate the factors in the evaluation.

4. Facilitating a Clear Comparison
    a. To promote a fair competitive process, when evaluating project proposals of different sizes, the BPU should unitize the project OREC Prices to ratepayers to allow for comparison of project direct costs. This would prevent a smaller project with higher OREC prices to be viewed and evaluated by the BPU as more attractive than a larger project with lower OREC prices because its calculated revenue requirement is lower.
    b. To allow for comparison of proposals of different size and with different price escalators, the Board should specify in the solicitation what discount rate it will use to present value OREC Price proposals. This would allow Proposers to offer pricing that reflects this evaluation factor and the BPU to more clearly compare the prices of projects.

<u>Technologies under the Solicitation</u>

8. What other elements should BPU consider including in the 1,100 megawatt offshore wind solicitation called for under EO8 (e.g. storage, other adjunct technologies)?

The BPU should not include adjunct technologies in its solicitation. Instead, if the BPU elects to attach other technologies to a project, the state should issue a separate solicitation to increase the number of companies that are able to bid into the process. Including adjunct technologies in this solicitation would further complicate the evaluation process, add uncertainty and may restrict companies with adjunct technologies from being able to offer a proposal, as they would have to be attached to one of the offshore wind developers to do so.

<u>Transmission</u>

9. Should the BPU request bids for expandable, nondiscriminatory, open-access offshore transmission facilities for the efficient delivery of power to the onshore transmission system?

OWEDA requires that a Qualified Offshore Wind Project be a fully integrated generation and transmission project. Pursuant to N.J.S.A. 48:3-51 a Qualified Offshore Wind Project is defined as a “wind turbine electricity generation facility in the Atlantic Ocean and connected to the electric transmission system in this State, ***and includes the associated transmission-related interconnection facilities and equipment***, and approved by the Board pursuant to [N.J.S.A. 48:3-87.1]" [Emphasis added].

This definition makes clear that a Qualified Offshore Wind Project must include both the turbine electricity generation facility in the Atlantic Ocean ***and*** must also include transmission-related interconnection facilities and equipment. The Statute does not permit the BPU to separately approve a generation project and separately approve a transmission project. Ocean Wind fully supports a full scope approach to the offshore wind farm, which provides an "all-in" price, including the wind farm and interconnection, as mandated by OWEDA. This approach creates greater value to New Jersey ratepayers by delivering lower cost offshore wind energy and minimizing construction risks. This is because transmission assets are an inherent part of the overall offshore wind farm, required for delivering power to shore, and splitting them off creates complexity and increases uncertainty on timelines and delivery by introducing hard to manage interfaces, which all result in substantially higher costs and risks for ratepayers.

Moreover, pursuant to N.J.S.A. 48:3-87.1 an application for approval by the BPU as a Qualified Offshore Wind Project must include, *inter alia*: "…the projected electrical output and anticipated market prices over the anticipated life of the project, including a forecast of electricity revenues from the sale of energy derived from the project and capacity, as well as revenues anticipated by the sale of any ORECs, RECs, air emission credits or offsets, or any tradeable environmental attributes created by the project". N.J.S.A. 48:3-87.1a.(5).

It must also include, *inter alia*, the anticipated carbon dioxide emissions of the project. N.J.S.A. 48:3-87.1a.(7).

These provisions could only be applicable to a fully integrated project that includes generation and transmission. They could not apply to a stand-alone transmission project. Thus, the statute requires that a Qualified Offshore Wind Project be a fully integrated generation and transmission project.

Transmission companies who wish to be part of an offshore wind project are not excluded from doing so, as some have claimed. They are free to make proposals to provide such transmission service to offshore wind developers, who are incented under OWEDA to put together the most beneficial proposal to the BPU. As with other equipment suppliers who will be integrated into an offshore wind project, the transmission developers should make their proposals to offshore wind developers and should not (and cannot under the law) be a separate proposer in the OWEDA offshore wind development process.

Ocean Wind supports this approach following extensive experience by Ørsted in markets that employ both approaches. Ørsted has built close to 4 gigawatts of offshore transmission systems, more than any other offshore developer. Ørsted has developed expertise in the development of offshore transmission, including the offshore substation, the export cables and the onshore substation, ensuring that transmission is optimized for the offshore wind generation build out and designed and constructed according to the same project schedule, ensuring on time delivery and coordination between assets. This full scope approach has reduced costs and risks associated with offshore wind development.

The UK, which employs a fully integrated approach, has become the world's largest offshore wind market and has been able to save ratepayers millions of dollars while growing this industry. A large independent study commissioned by Ofgem, the UK's electricity markets regulator, found that the full scope approach helped create savings of up to $400 million between 2009-2012 when the UK procured approximately 2 gigawatts of offshore wind generation. For the offshore wind capacity installed in that period, that is equivalent to a universal levelized cost of electricity (LCOE) reduction of $6 per megawatt-hour (MWh).

In contrast, in Germany, often cited as an example of a system where a segmented approach has been implemented, transmission infrastructure has been plagued by delays and cost overruns, thereby delaying generation project in service dates. The first eight German offshore wind farms experienced delays of 6 to 24 months and cost overruns of up to 93 percent. The cost of compensating the affected offshore wind farm developers, who were left with approximately 1.8 gigawatts of stranded assets, ran to almost $1.3 billion which was paid for through an extra levy charged to German rate payers.

Given the scale of New Jersey's offshore wind target, similar delays would result in added costs of over $2.5 billion, and unfortunately, there is nothing to suggest that U.S. third party transmission providers would be any better placed to manage the interface issues, sub-optimal risk allocation, or added complexity that the segmented approach inadvertently introduces. Indeed, we are now seeing some of Europe's oldest offshore wind markets move away from the segmented approach and towards full scope systems. Denmark, the original architect of the segmented transmission system, has just announced that it will move to a fully integrated approach due to the system's optimal economic incentives and efficiency. We are also seeing other U.S. offshore wind markets reject the segmented approach to offshore wind development. For example, the New York Public Service Commission rejected the segmented approach for Phase I of its program to procure at least 800 megawatts of offshore wind by 2019, concluding that "holding the generator responsible for transmission is the most easily-implementable and feasible option for jump-starting offshore wind development in New York." Case 18-E-0071, In the Matter of Offshore Wind Energy, issued at adopted July 1, 2018 at 56.

In Denmark, where the segmented approach is practiced for far-from-shore offshore wind projects, authorities seek to avoid costly delays by building the transmission assets a long time in advance. However, this structure incurs considerable costs and is not possible at this stage of the New Jersey process given the long lead time required for transmission development. As one example, the Horns Rev 3 offshore wind farm is expected to be commissioned in 2019 in the Danish North Sea. The Danish transmission system operator began development work on the transmission assets in April 2012, seven years in advance, and completed construction in fall 2016, three years in advance.

Even if it were possible, this approach still has significant drawbacks that would make it costly for New Jersey ratepayers. It is only possible in Denmark because authorities determine the size of the wind farm, meaning that developers are unable to optimize the wind farm to the site or the transmission solution. This limit on flexibility removes an important cost-reduction lever, thereby increasing the cost of the project. This approach also creates large opportunity costs, because transmission assets stand idle for years; these costs would be borne by electricity customers.

In New Jersey, this approach raises many additional challenges. The first relates to uncertainty over the Federal Energy Regulatory Commission (FERC) regulations governing a separately owned transmission network. Any transmission service arrangements under this approach would need separate FERC authorization, which would likely add substantive complexity. Such complexity would be exacerbated in a scenario where the transmission asset for which cost-recovery is sought is super-sized to accommodate future development. Under FERC regulations, costs begin to be billed to customers as soon as construction is complete. This means customers could begin paying costs associated with wind farms that do not yet exist, and may not exist for many years. Cost recovery of a separately owned transmission asset is extremely complex and time-coming under the PJM tariff, would add substantial issues to the OSW development pathway and frustrate the realization of the Governor's Offshore wind goals.

There are also technical challenges that arise from segmenting transmission and generation. One approach that has been suggested includes building a single transmission asset that could accommodate entire state procurements of offshore wind. Only high-voltage direct current (HVDC) technology supports a transmission asset of that size. The main problem with this approach is that the required HVDC technology is largely untested offshore and highly complex. Offshore wind farms in Germany used simpler point-to-point HVDC technology and still faced technical challenges and delays. Similar lengthy delays would be likely with a single HVDC transmission asset and given the novelty of the technology (a shared offshore HVDC grid with several offshore wind farms connecting to a single offshore substation has never been built), the risk might be un-insurable, meaning it would have to be borne by the transmission developer. All of this creates the risk of significant and costly delays (paid for either through direct compensation or through the developer's high risk premiums). A single HVDC transmission asset would carry an up-front price of several billion dollars. Indeed, given the high-risk nature of the asset, it would likely be un-financeable by third party debt providers, leading to very expensive cost-of-capital for the transmission developer and further increasing costs. Moreover, given that the offshore wind farms connecting to it would be built gradually, a large share of the capacity of the transmission asset would stand idle for years. Depending on the size and location of the wind farms ultimately built, a share of the transmission asset might never be used. Even with roughly 12,000 megawatts of offshore wind in the North Sea, a shared HVDC grid has been rejected given the unclear benefits and substantial risks. Finally, connecting all of the state's offshore wind to the onshore grid through a single HVDC export cable carries a large risk in case of a cable outage. It would run contrary to the regulatory support this Board has given to redundancy of energy facilities.

In sum, based on Ørsted's experience in these markets and its understanding of New Jersey's goal to safely, efficiently, and cost-effectively deliver 3,500 megawatts of offshore wind to the state by 2030, Ocean Wind believes OWEDA appropriately defines the OREC structure by including generation and transmission.

Ocean Wind thanks the BPU for the opportunity to submit comments to help to achieve New Jersey's clean energy goals and support the long-term development of the offshore wind industry in New Jersey. If you have any questions on these comments, please feel free to contact me at (857) 284-1430. We look forward to continued dialogue in furtherance of clear and robust offshore wind regulations.

Sincerely,

Elisabeth Treseder
Senior Policy Advisor
Ørsted North America