May 18, 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

Re: Docket No. QX18040466 – In the Matter of Offshore Wind Renewable Energy Certificate (OREC) Funding Mechanism

Dear Secretary Camacho-Welch:

Ørsted welcomes the opportunity to provide input on the Offshore Wind Renewable Energy Certificate (OREC) Funding Mechanism Straw Proposal (Straw Proposal) issued by Board of Public Utilities ("Board" or "BPU") Staff on April 27, 2018. Ørsted is the world's leading developer and operator of offshore windfarms. The company operates 23 projects comprising over 4,000 MW with another 5,000 MW under construction. Ørsted 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.

Ørsted's Ocean Wind Project lies 10 miles due east of Atlantic City and can support over 3,000 MW of wind generation – enough generation to serve over 1.5 million New Jersey households and almost enough generation to meet Governor Murphy's goal of realizing 3,000 MW of offshore wind energy generation by 2030. As such, the company has a significant interest in ensuring that New Jersey establishes an efficient and secure funding mechanism that will enable the industry to develop offshore wind farms in New Jersey safely, efficiently, and cost-effectively.

The BPU Staff's Straw Proposal provides an initial framework for an OREC funding mechanism as a basis for further discussion and development. We understand that the Straw Proposal is not intended to provide a fully developed funding approach. Rather, it is intended to lay the framework for future discussion. Based on that understanding, we believe that the Straw Proposal provides a sound conceptual basis for further development.

Ørsted greatly appreciates the time and effort of BPU Staff to undertake this process and believes these recommendations offer a practical and innovative solution to achieve the offshore wind goals set forth in Governor Murphy's Executive Order No. 8 and to fully implement the Offshore Wind Economic Development Act (OWEDA).

Ørsted 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.A.C.* 14:8-6.1 (and referred to herein as "Projects"), can be built and operated successfully for the next twenty-plus years, there are several principles we believe should guide the development of New Jersey's OREC funding mechanism. These include reducing credit risk, enhancing revenue certainty, and ensuring secure and independent revenue oversight and collection. Structuring the OREC funding mechanism to take these principles into account will reduce "risk premiums" and allow developers to offer the lowest reasonable cost for their Projects. Reducing structural risk inherent in the payment mechanism will reduce the payment "risk premium" embedded in OREC prices, ultimately resulting in lower costs to ratepayers.

Unless Projects investors assess New Jersey's OREC funding program and conclude that it will provide OREC revenue certainty over the twenty-year duration of an OREC Pricing Plan, investors will either move away from investing in New Jersey or impose additional "risk premiums" into the OREC Price, driving up the cost of the program to customers.

These comments are intended to help the BPU Staff refine its approach and avoid these ratepayer impacts.

1. General Structure

Ørsted believes the role of the electric distribution companies (EDCs) outlined in the Straw Proposal – to collect funds from their customers through a tariff surcharge (like many other surcharges currently provided for in EDC tariffs) and to make payments (through an OREC Administrator who pools all funds collected from the four EDCs) – presents a sound foundation for OREC funding. It will simplify the OREC process relative to other approaches previously considered by the Board, all which rely on collecting these funds from dozens of third party and BGS Suppliers.

It is recommended that the following mechanism be included in the rule so that the surcharge is clearly defined to cover projected OREC costs:

a) The BPU rule should specifically require EDCs to establish a tariff rider that contains a non-bypassable rate surcharge on a per kwh basis to be charged to all customers receiving EDC service. This surcharge (OREC Surcharge) will be equal to the forecast revenue requirement for all OREC purchases divided by the total of estimated sales for all four EDCs, plus administrative costs, grossed up by sales tax and all other "gross ups" typically applicable to EDC rates. It would be set annually, effective on June 1 of each year for a twelve-month period, consistent with the Energy Year convention used for BGS contracts, the RPS, and PJM.
b) It is possible that more than one Project would be approved by the Board. The Board should set the OREC Surcharge based on all BPU-approved Projects, based on their anticipated in-service date, OREC pricing, and production. If there is more than one approved Project, the OREC Surcharge would be based on the sum of the OREC Price of each Project multiplied by the anticipated OREC Production of each Project, divided by the total of the forecasted load of EDCs grossed up by administrative costs and applicable taxes.
c) As discussed more fully below, the OREC Administrator would support the Board in setting these charges.

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2. Payment certainty

Ørsted recommends that the BPU rule address issues related to the financeability of the funding plan. Specifically, the rule should address and mitigate certain risks related to certainty of revenue flow to Projects and to the participation of the EDCs which, if not addressed in the rule, would be taken on by Project owners and ratepayers. Financing companies evaluate every risk carefully when making decisions about the availability and return requirements for their funds. While the risk of non-payment by EDCs is generally low, it should be addressed since such non-payment for ORECs by EDCs would have a significant impact to Projects, and its severe impact would be reflected in OREC Prices unless clearly addressed (due to a higher cost of financing projects) and mitigated by the BPU rule. It is also possible that financing companies would choose to invest in states other than New Jersey.

Accordingly, the BPU rule should provide for:

a) Creation of a separate bankruptcy remote fund, independent from the EDCs, which would be maintained by an independent OREC Administrator, as trustee. This would prevent the OREC funds from being commingled with general EDC funds and being used for other EDC (or bankruptcy court) purposes. This separate fund is an option in the Straw Proposal; it should be a requirement. EDCs have maintained separate funds (in trust, escrow, or similar funds) for such cost items as nuclear decommissioning, environmental clean-up, and bond securitization.

b) Transfer of funds from the EDCs to the OREC Administrator for customer surcharge payments should be made no less frequently than every five days to an escrow account managed and maintained by the OREC Administrator. Late payments would be subject to a late payment charge. Funds would flow from customers to the EDCs, and then be transferred to the separate fund, from which the OREC Administrator would pay for ORECs from Projects. The separate fund will not only provide visibility and accountability into OREC collections and payments but will also reduce the possibility of an EDC or bankruptcy court drawing on funds not yet paid to offshore wind projects. This separate account would be created by the OREC Administrator, with strict procedures allowing for withdrawals only to be processed by the OREC Administrator for OREC payments, or to pay for costs approved by the Board for administration.

c) Allowance for a reserve amount to be held in the separate fund, overseen by the OREC Administrator, for the following purposes: i) to assure for timely OREC payment during periods of collection lag due to seasonality of production, variation in EDC load, variations in funding levels from the source of the reserve (energy revenue, capacity revenue, and other) and other factors; and, ii) to address issues such as potential EDC failure to collect or bankruptcy direction to pay debt holders (as described below). The amount of the reserve should reflect both of these factors and could also include consideration of the "early warning system" described below to allow for reserve levels to be set based upon the financial standing of the EDCs.

d) While Board Staff has contemplated funding a reserve strictly from PJM revenues, other permissible sources for reserve funding, in addition to PJM revenues, should include: i) an OREC price premium on the OREC Surcharge (as described in section 1 above) utilized by EDCs to collect OREC funding, which will collect an extra margin above the OREC price to fund the reserve; or ii) allowance for EDCs to begin collecting OREC funding at the beginning of an energy year, prior to an offshore wind project achieving commercial operation. For example, if the OREC rate were to be effective in the EDC's rates on June 1 but the Project went into operation on October 1, four months of funds would be collected without OREC payments made to the project. In this way, funds would be collected from ratepayers ahead of commercial operation, and these revenues could help fund the reserve. It should be noted that offshore wind projects would only be paid for actual production and would not be paid prior to achieving commercial operation – the early collections would be used simply to fund a reserve balance. The Straw Proposal included a provision that the reserve could contain up to three months of PJM revenues. Based on the need to provide adequate payment assurance to Projects, the BPU rule should permit a reserve greater than this amount to be proposed by the Project, based on its financial metrics.

3. OREC Administrator

The Board should direct the EDCs to enter into a joint contract for an OREC Administrator. The function of the OREC Administrator should be fully provided for in the BPU rules.

Reasonably incurred cost to retain and manage the OREC Administrator should be recoverable in the OREC Surcharge. These costs could include both the cost of the OREC Administrator and the cost of related EDC activity to fund and manage its OREC responsibilities. These costs should be determined annually by the Board and included in the OREC Surcharge calculation. The OREC Administrator should establish escrow accounts and designate a trustee.

In addition to managing and receiving funds from EDCs and making timely payments to Projects, the Administrator should also be responsible for:

a) Paying Projects for ORECs, within four business days of invoice from Projects, who will invoice for ORECs on a weekly basis. This invoice and payment timing is consistent with PJM's timing for energy payments. Late payments should be subject to a late payment charge;
b) Monitoring and verifying that OREC payments are correct;
c) Providing information to Suppliers as to their level of OREC purchase obligations;
d) Administering a PJM GATS account for each Project so that ORECs are transferred from Projects to the Administrator's GATS account upon payment to Project for their ORECs; and transferring ORECs from its GATS account to Suppliers, in accord with the RPS obligation of Suppliers. Instead of having Projects transfer their ORECs directly to the Suppliers (as stated in the Straw Proposal paragraph 9), the OREC Administrator will aggregate ORECs from all Projects and transfer them to suppliers. This greatly simplifies the transfer process;
e) Obtaining necessary contact and sales information for each Supplier from the EDCs so it can carry out its responsibilities;
f) Assuring payments from EDCs on a timely basis, and providing notice to the BPU and Projects when i) EDC payments are delayed; ii) reserves are forecasted to fall below proscribed levels in the next six months; or, iii) reserves fall below proscribed levels;

g) Establishing the OREC surcharge, described in Section 1, on an annual basis based on forecasts of EDC sales, OREC production, and OREC Prices and provide such information to the Board for it to approve the rate to be effective June 1 of each year;
h) Maintaining and administering separate subaccounts for each Project, so that OREC funds for each Project are separately held, maintained, and administered. This prevents financial and operational issues with one Project from impacting other Projects.

4. Counterparty Credit

Ørsted fully supports the BPU Staff's proposal for EDCs to collect OREC related revenues through a surcharge as a simpler, lower-risk structure than one based on collecting funds from dozens of suppliers. While payment risk from EDC participation is unlikely, it should be addressed since the inability of payment for ORECs by EDCs would have a significant impact to Projects.

While EDC bankruptcy is unusual, it is an outcome that should be understood and planned for in the design and implementation of the OREC funding mechanism. If this issue is not addressed, then such implied bankruptcy risk will be embedded in project rates of return and OREC pricing.

To address this issue, Ørsted suggests the inclusion of the following protections in the Board's rule:

a) Implementation of an "early warning system" to alert Projects and the BPU of approaching financial issues with EDCs. Such a structure is already provided for in the BPU's BGS structure. In this process, the BPU and the BGS Suppliers (who are relying on EDCs for payment of their supply contracts) can monitor EDC financial and credit standing, and certain actions occur if credit standing declines to certain levels. Similarly, the OREC Funding rule should have provisions which define the procedure to be used to monitor EDC credit standing, including increasing the reserve.
b) In the event of an EDC default, the rule should provide that OREC payments would be first made from the reserve. Responsibility for OREC Payments should be reassigned immediately (through operation of the rule) upon default by an EDC to the entity which replaces the defaulting EDC. The associated OREC Surcharge would also be collected by this replacement entity.
c) Requiring the posting of margin or other security measures in the event of a credit downgrade or other credit issue at the EDC level which would be recoverable in the OREC Surcharge.

5. Setting the OREC Carve-out for Suppliers

As discussed in the Straw Proposal in paragraphs 6, 7, 8, and 9, the BPU rule should establish the process for establishing the OREC purchase requirement for each Supplier. Since the BGS process sets contracts on a three year forward basis, the Board should also set the OREC purchase requirements for each supplier on a three year forward Energy Year basis to reduce supplier risk. Relying on analysis provided by the OREC Administrator, the Board should set the OREC requirement as a percentage of load for each energy year based on i) the sum of the forecasted OREC production of each Project divided by ii) the sum of the load forecasts of each EDC. Each Project will transfer its ORECs to the GATS account of the OREC Administrator; and the OREC Administrator will transfer ORECs to each Supplier based on sales data for each Supplier provided by the EDCs, multiplied by the percentage defined in the previous sentence.

The following provisions would provide for a stable purchase and transfer of ORECs, allowing for risk premiums to be mitigated for both Projects and Suppliers.

a) All generation from a project would be paid for its ORECs. This provides for symmetry as Projects are also taking on the risk of reduced production from their Projects, since if OREC production is reduced, so are the level of OREC payments. In the case of over-supply in a given energy year (i.e. the production of ORECs exceeded the OREC set-aside RPS), then the quantity of over-supplied ORECs would be used for compliance in the next Energy Year (pursuant to OWEDA, ORECs are eligible in the Energy Year they are produced and the following two Energy Years). As an additional backup mechanism to absorb oversupply of ORECs, the OREC RPS requirement could be increased after the three-year period to absorb these ORECs. In the event of under-supply (i.e., the amount of ORECs produced is less than the OREC set-aside RPS), the RPS requirement could be met from, first, oversupply from previous years, or, if needed, class 1 RECs.
b) As discussed in the other sections of the Straw Proposal and this submission, Suppliers would not pay directly for ORECs. Instead, the EDCs would pay for ORECs on behalf of Suppliers.
c) Projects would produce ORECs for a twenty-year period consistent with OWEDA. After that time, a Project would produce Class 1 RECs which would be sold in the Class 1 market in the same manner as other Class 1 resources.

6. Transmission

The Straw Proposal states that the OREC for each approved Project will reflect the “all-in” price including the wind farm and interconnection. This accurately (and necessarily) reflects the mandate of OWEDA, which defines a qualified offshore wind project for the purposes of ORECs 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.” *N.J.S.A.* 48:3-51. Ørsted fully endorses the structure outlined in the Straw Proposal that applies a full scope approach to the offshore wind farm, consistent with OWEDA. The full scope approach creates greater value to society by delivering overall lower cost offshore wind energy and minimizing construction risks. This is because transmission assets are an inherent part of the overall offshore wind farm and splitting them off creates unnecessary complexity, introduces hard to manage interfaces and allocates risk poorly, which all result in substantially higher costs and risks for ratepayers.

Ørsted has extensive experience in markets that employ a full scope approach such as the UK, which is the world’s largest offshore wind market. In a large independent study commissioned by Ofgem, the UK’s electricity markets regulator, it was found that the full scope approach helped create savings of up to $400 million between 2009-2012 when the UK procured approximately 2 GW of offshore wind generation. For the offshore wind capacity installed in that period, that is equivalent to a universal 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. The first 8 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 GW 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.

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 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 MW 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 MW of offshore wind to the state by 2030, we believe OWEDA appropriately defines the OREC structure by including generation and transmission, and that the Straw Proposal's "all-in" approach correctly adheres to OWEDA's definition.

Ørsted commends BPU Staff for the time, effort, and ingenuity in putting together the Straw Proposal and appreciates the opportunity to submit comments to help to achieve New Jersey's OSW goals. If you have any questions on these comments, please feel free to contact Elisabeth Treseder at (857) 284-1430. We look forward to continued dialogue in furtherance of clear, consistent and efficient regulations.

Sincerely,

Fred Zalcman
Head of Government Affairs
Ørsted North America