May 20, 2022

Ms. Carmen Diaz
Acting Secretary of the Board
New Jersey Board of Public Utilities
44 South Clinton Avenue, 1st Floor
PO Box 350
Trenton, NJ 08625 – 0350

Via email to: Board.Secretary@bpu.nj.gov

Re: Request for Additional Information – In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, Docket No. QO10100630

Dear Acting Secretary Diaz,

On behalf of Rise Light & Power, LLC, and our wholly-owned subsidiary Outerbridge New Jersey, LLC (collectively, "Rise"), I write to provide the New Jersey Board of Public Utilities ("NJBPU" or "Board") with responses to your Request for Additional Information, issued April 27, 2022.

I greatly appreciate this opportunity to share insights. In the following, I endeaveor to offer three unique perspectives. First, obviously, Rise is developing the Outerbridge Renewable Connector ("Outerbridge") project and therefore has the prespective of a transmission developer participating in the SAA solicitation. Second, I offer my personal perspectives as an individual who has been involved in New Jersey's offshore wind program dating back to the first Blue Ribbon Panel. Finally, I offer lessons learned as an offshore wind developer who has lead relevant work on the Block Island, South Fork, Skipjack 1, Revolution, Sunrise and Ocean Wind 1 projects. I respectfully offer these perspectives in hopes of helping the Board to successfully implement its nation-leading offshore wind goals and avoid the factors that have entangled other projects in controversey and delay.

Thank you again for this opportunity to share these insights. Please do not hesitate to reach out to us if we can be of further assistance.

Best regards,

Digitally signed by Clinton Plummer
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Clinton L. Plummer
Chief Executive Officer
Rise Light & Power

REQUEST FOR INFORMATION - OFFSHORE WIND DEVELOPERS

1. What are the most significant risks to completing your OSW generation project(s) on time and within budget if your project relies on one or more SAA transmission projects? How can those risks be best mitigated?

For OSW developers relying on SAA transmission projects, the two most significant project-on-project risks are permitting risk and execution risk (as it relates to delays to the transmission project becoming operational and the OSW project being able to interconnect).

(1) **Permitting Risk** will vary depending on whether the OSW project interconnects with an Option 1B or Option 2 project.

- Option 1B projects pose less permitting risk than Option 2 projects for several reasons, each rooted in the fact that their infrastructure is all onshore.
  - First, Option 1B projects keep the management of all offshore routing and permitting work in the hands of the offshore wind developers, who are best position to align the same with the overall design of the wind farm. By offering fixed landing spot at the shore, Option 1B projects greatly simplify the work of the developer, while allowing them to maintain control over the BOEM and other federal permitting processes.
  - Second, the scope of required federal approvals, if any, is expected to be significantly less, which keeps control of their permitting more fulsomely with the State of New Jersey. Specifically, Option 1B projects that have low impact siting and design may not trigger review under the National Environment Policy Act ("NEPA"), or if they do, are more likely to result in a Finding of No Significant Impact given their limited scope in federal jurisdiction.

- Conversely, the permitting for an Option 2 project has a number of significant risks:
  - The scope of an Option 2 project will almost certainly trigger a full Environmental Impact Statement.
  - Federal legal precedent regarding project segementation, BOEM may be unable to commence the review of an Option 2 project until the specific OSW farm(s) connecting to it have been identified and their associated impacts accounted for.
  - The permitting process will be more complex due to the unprecidented level of coordination required between the transmission developer and wind developer.

(2) **Execution Risk** is also significantly greater for Option 2 projects than for Option 1B projects, and therefore Option 2 projects have a higher liklihood of not being in service on schedule to support the interconnecting offshore wind project commissioning, even if the Option 2 project is selected by the Board in advance of the offshore wind project(s).

- Option 2 projects carry significant risk because such projects put the burden of offshore construction on transmission developers, rather than offshore wind developers.
  - Offshore wind developers are in the best position to manage the construction of offshore transmission infrastructure for several reasons.
    - Offshore wind developers are best positioned to align the construction schedule of the offshore transmission infrastructure with that of the overall wind farm.
    - Offshore wind developers are best positioned to identify synergies among the construction methods for the offshore wind farm and transmission infrastructure
    - Offshore wind developers are best positioned to manage union labor relations for the entirety of the offshore project scope.
  - Further, Offshore wind developers are in a better position to manage the supply chain for offshore transmission infrastructure.

  - Offshore transmission infrastructure sourcing is a core competence of the offshore wind developers because they have to do it in nearly every other global market.
  - Offshore wind developers are best positioned to select the offshore transmission componetns that will best align with the wind farm and overall project schedule. Depending on the type of technology used for the transmission solution, project-on-project risk could further materialize due to the risk of bottlenecks in the supply chain.
  - The supply chain for offshore transmission infrastructure is very consolidated, with only a handful of vendors for key components. Offshore wind developers with a global reach will have much greater ability to exert leverage over that supply chain.
  - Similarly, there are very few vessels capable of installing offshore transmission infrastructure. Offshore wind developers will have much greater ability to exert leverage over vessel suppliers.

- Unlike an offshore wind developer, an Option 2 transmission developer will have to select technology independent of the interconnecting wind farm, then manage the sourcing of the same without a global pipeline of projects to leverage, and then endeavor to manage the construction and commissioning of the same in an exetremely challenging offshore environment independent of the wind farm it is intended to serve. Such arrangement invites a host of execution delays.
  - Delays in permitting an Option 2 project will have knock-on effects on project schedule and eat into any "float" between the scheduled operational commencement date of the transmission project and the commissioning of the OSW farm(s).

- Conversely, Option 1B projects are able to execute a much simpler onshore project:
  - Onshore transmission infrastructure benefits from a more robust supply chain with many more competitive options.
  - A number of highly-skilled New Jersey-based contractors are able to execute onshore transmission projects today
  - Union labor jurisdictions for onshore transmission infrastructure is already defined in New Jersey
  - Onshore construction is not subject to the same risks of delay as offshore construction

- Taken together, the above factors make it clear that Option 1B projects are not only likely to be more cost-effective for ratepayers, but also more likely to be available on schedule.

- Given the foregoing, selecting Option 1B projects willa materially decrease the risk of permitting delays and make it more likely that the offshore wind project will be able to deliver its power on schedule.

2. For new Bureau of Ocean Energy Management ("BOEM") leaseholders, are there concerns about obtaining a PJM queue position given that a Board decision on the SAA may constrain the potential points of interconnection ("POIs") for future New Jersey OSW projects? Please describe the considerations related to utilizing SAA POIs and how OSW developers might switch from their queue positions (if already acquired) to the SAA-provided POI.

While the PJM interconnection process is time-consuming, and while the SAA program has the potential for significant risk reduction and cost savings, it is very difficult to say *a priori* that an SAA project will definitely result in such benefits relative to the PJM process.

The state and federal permitting regimes for offshore wind in the US are such that a typical timeline for an offshore wind farm to achieve a final investment decision and to commence construction is approximately four (4) years after the receipt of an offtake agreement or OREC award. Therfore, in the scenario in which offshore wind facilities interconnect via the traditional PJM process, interconnection is not likely to be the critical path to commencing construction.

The management of interconnection processes is a competency that offshore wind developers are expected to have in every other state. Other ISOs have complicated interconnection processes and yet every other state that is pursuing offshore wind projects requires the offshore wind developers to manage the process. Indeed, other PJM states such as Maryland are successfully implementing offshore wind programs without the benefit of an SAA program.

For these reasons, the PJM interconnection process may, in certain circumstances, be advantageous relative to an SAA project. On the other hand, in certain other circumstances, an SAA project may help to reduce uncertainty regarding system upgrades, cable landfall and terrestrial right-of-ways.

Therefore, if the Board elects to proceed with one or more SAA awards, we encourage the Board, at a minimum, to allow wind developers to offer their own interconnection strategies, in addition to those identified through the SAA process.

3. If the Board were to select one or more Option 2 proposals under the SAA—onshore substations to offshore collector platforms (see, the November 18, 2020 Board Order under this same docket for more information on the Options)—please provide additional details and considerations for connecting and coordinating OSW generation projects in terms of the costs, timing and operability of the OSW generation projects.

4. If the Board were to select one or more Option 3 proposals under the SAA—offshore network connecting lease areas and substations to each other—please provide additional details and considerations for connecting and coordinating OSW generation projects in terms of the costs, timing and operability of the OSW generation projects.

5. ***If an SAA Option 2 or Option 3 proposal is selected, is there any situation in which an OSW generation project would not be able to use the SAA Option 2 or Option 3 solution?***

Multiple OSW developers have testified publicly, in New Jersey and elsewhere, to their aversion towards third-party offshore collectors – similar to these proposals submitted to the SAA under Option 2 and Option 3. This risk aversion is driven by the unsuccessful and costly history of third-party offshore collectors, and the fundamental challenges associated with introducing third-party ownership of a vital component of an OSW project.

When Germany attempted to create an offshore grid network for wind developers to connect into, delays in the availability of that third-party offshore collector system cascaded into delays for several OSW developers, including Ørsted, RWE, and EnBW. As a remedy, the German government required ratepayers to subsidize 90% of the developer revenues they would have earned without the delays caused by the offshore collector system[2]. A recent study comparing the German and UK OSW transmission system, found that the German system is twice as expensive as the UK system[3]. The planning, construction, and operation of OSW farms and offshore transmission systems is done by different entities in Germany – which leads to higher coordination effort. In the UK, the OSW wind farm and the offshore transmission system are built by the OSW farm developer. Therefore, the OSW farm developer is also responsible for connecting the wind farm to the grid.

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[2] EWEA. “Is German Offshore Wind under Thread?” 10 APR 2013. Online. Available: http://www.ewea.org/blog/2013/04/is-german-offshore-wind-under-threat/

[3] https://www.offshorewind.biz/2019/04/11/german-offshore-grid-costly-and-inefficient-study/

If New Jersey were to require connections into Option 2 or Option 3 projects, OSW developers will likely require a similar guarantee from the State. The balance sheet of a third-party offshore collector is significantly less than that of an interconnecting OSW project, and it would be impossible for the transmission entity to backstop such an obligation. Thus, New Jersey's ratepayers would bear the risk of paying for energy that could not be dispatched onto the PJM system due to delays in offshore transmission. If the State is unable to provide the guarantee, the OSW developer may have no choice but to pursue its own transmission solution in order to deliver the project, and avoid the risks with a failed OSW development project.

To avoid the risk that OSW developers do not use projects awarded under the SAA, we encourage the Board, at a minimum, to allow wind developers to offer their own interconnection strategies, in addition to those identified through the SAA process. More practically, we recommend that the Board refine the SAA process to provisionally award a portfolio of projects under the SAA, and require OSW developers to submit two bids in the state's OREC procurement: one that includes a project under the SAA, and one that utilizes a generator radial-line approach. This provides OSW developers with the most flexibility to identify the transmission solution that gets the OSW project completed, while ensuring New Jersey's ratepayers get the lowest cost solution.

6. How should the Board consider the optimal locations for Option 2 substations? Should such determinations occur at the time of the Board's SAA decision or following the Board's OSW generation solicitations? If the location is determined *after* the generation solicitations, what type of coordination between generation and transmission developers would be required?

7. ***Describe if and how the primary transmission line technology used for the Option 2 proposal, HVAC or HVDC, affects the development – timing, sizing, locational considerations and costs – of new OSW projects.***

The choice of technology has a material impact on each of the factors referenced. Based on our understanding of the SAA proposals, it is also a key differentiator between the Options under consideration. We understand that all Option 2 proposals utilize HVDC technology, whereas all Option 1B proposals utilize HVAC to connect to the OSW farms.

The location of OSW lease areas that may participate in future NJ OREC solicitations vary widely. Some are farther to the North, where they could connect to onshore waterfront interconnection facilities, such as Outerbridge, using HVAC cables, and avoiding the cost, complexity and risk of delay associated with building offshore HVDC converter stations. Other lease areas are located farther south, where offshore HVDC might be the only viable means of connecting to New Jersey's grid. Given this diversity in locations, developers would benefit from having flexibility in the path to interconnect to the grid. A "one-size-fits-all" approach is not in the interest of ratepayers, as it would preclude the owners of the northern lease areas from offering more cost-effective HVAC configurations.

The final configuration of OSW lease areas varies not only in location, but also in size and shape. The potential installed capacities of these lease areas do not neatly align with either the Option 2 HVDC systems offered in the SAA solicitation are in five discrete size increments[4] – none of which align with the potential capacities of the lease areas. This means that, in order for an OSW developer to make a competitive offer into New Jersey's future OREC solicitations using one of these options, a portion of their lease area will be unutilized. In contrast, offshore HVAC cables provide capacity in 300 to 400 MW increments – which can better match the capacity of the lease areas and allow OSW developers to better align the maximum potential capacity of their lease areas with the potential injection (and OREC offer) into New Jersey.

[4] From PJM's Competitive Planner tool: 1,148 MW, 1,200 MW, 1,400 MW, 1,500 MW and 1,510 MW

Option 1B proposals, like Outerbridge, give OSW developers the ability to maximize the potential delivered capacity of their leases by aligning the design of the OSW project with the offshore transmission system. This also gives the OSW developer full control of the scope of the offshore transmission – mitigating risks that arise from permitting and project-on-project risks (relative to Option 2 proposals) as discussed above.

8. ***For an Option 2 or Option 3 scenario, do you believe that the selection of HVAC or HVDC will affect the ability to receive federal funding that may prioritize "innovative" technologies? Please address availability of federal funding for transmission and/or federally-backed loans/loan guarantees.***

Assuming that the issue of "innovative technologies" is in the context of Department of Energy's Loan Program Office ("LPO") through its Title 17 Innovative Energy Loan Guarantee Program, we do not believe that the selection of HVAC or HVDC is an issue. Firstly, both HVAC and HVDC technology are already in use across several projects in the US. An innovative technology will likely cover a project that attempts to interconnect various OSW farms via a mesh network – which would be "new" to the US. Additionally, the innovative technology could be one that significantly increases the energy capacity that each cable can transmit compared to what is operational today.

LPO eligibility requirements stipulate that the Project must employ "New or Significantly Improved Technology" as compared to Commercial Technology in service in the United States. This "innovation" must constitute one or more meaningful and important improvements in productivity or value and NOT be "Commercial Technology." Commercial Technology is defined as technology that has been installed in and is being used in three or more commercial projects in the United States in the same general application as in the proposed project[5].

9. ***Describe how risks of cable outages are managed with HVAC versus HVDC technology, particularly where using large single HVDC lines for any offshore segment.***

HVAC cables provide capacity in 300 to 400 MW increments. By contrast, the optimal capacity for HVDC cables is in the range of approximately 1,200 MW – equivalent to the size of a single OSW project (that matches the anticipated OREC solicitation).

Failure on a single HVAC cable would not jeopardize energy production of an entire OSW farm as the balance of energy can still be delivered by the unaffected HVAC cables. In addition, the actual loss of energy production will likely be less as the transmission capacity of remaining functional HVAC cables may exceed the design specifications for short periods.

In contrast, failure of an HVDC cable will likely jeopardize the energy production of an entire OSW farm as the technology is designed to accommodate ~1,200 MW in capacity. This means that the associated OSW farm will likely be offline until the cable failure is resolved as there would be no means to transmit electricity to the POI. Without a mesh network, there is no redundancy for HVDC systems as having a spare transmission line on "standby" for a single OSW farm would be cost prohibitive.

10. For an Option 2 or Option 3 scenario, please address whether an HVAC or HVDC would better integrate into a multi-state or multi-regional offshore wind transmission grid? Should coordination or future computability opportunities affect the Board's evaluation of proposals?

11. ***How does the selection of an Option 2 transmission solution affect the permitting risk for OSW generation projects? What about an Option 1b?***

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[5] Source: https://www.energy.gov/sites/default/files/2021-09/LPO_Technical_Eligibility_Handout_Title17-REEE_Sept2021.pdf

As detailed in our response to Question #1 above, selection of an Option 2 transmission solution will significantly impact the permitting risk for an offshore wind project for several reasons. First, an Option 2 project will almost certainly trigger a full Environmental Impact Statement, requiring a great deal of analysis by BEOM. Second, based on Federal legal precedent regarding project segementation, BOEM may be unable to commence the review of an Option 2 project until the specific OSW farm(s) connecting to it have been identified and their associated impacts accounted for. For these reasons, the permitting process for an Option 2 project will be much more complex due to the unprecidented level of coordination required between the transmission developer and wind developer.

Conversely, Option 1B projects pose significantly less permitting risk than Option 2 projects for several reasons, each rooted in the fact that their infrastructure is all onshore. First, Option 1B projects keep the management of all offshore routing and permitting work in the hands of the offshore wind developers, who are best position to align the same with the overall design of the wind farm. By offering fixed landing spot at the shore, Option 1B projects greatly simplify the work of the developer, while allowing them to maintain control over the BOEM and other federal permitting processes. Second, the scope of required federal approvals, if any, is expected to be significantly less, which keeps control of their permitting more fulsomely with the State of New Jersey. Specifically, Option 1B projects that have low impact siting and design may not trigger review under the National Environment Policy Act ("NEPA"), or if they do, are more likely to result in a Finding of No Significant Impact given their limited scope in federal jurisdiction.

As such, Option 1B projects have a lower risk of not being in service in advance of the OSW project(s) procured by the Board in their next solicitation – in time to support the commissioning of the OSW projects awarded in that solicitation. On the other hand, Option 2 projects have a higher risk of not being in-service before the OSW farm(s) – potentially delaying the commissioning process of the OSW farm, and delaying the State's ability to reduce carbon emissions[6].

12. Please share any other important risks associated with an Option 2 solution that can impact project development.

Please see our responses to Question #1 and Question #11, above. As detailed therein, Option 2 solutions amplify several risks that will ultimately harm the State and its ratepayers, including project-on-project risks related to permitting and execution.

The risk to New Jersey and its ratepayers has two dimensions: (i) The risk that OSW developers refuse to utilize BPU's SAA Transmission Project(s), irrespective of type[7] and instead insist on an alternative path to interconnect to the Bulk Transmission System – resulting in stranded costs; and (ii) The project-on-project risk that one of the BPU's SAA Transmission Project(s) is behind schedule, whether due to permitting or execution issues, and results in adverse knock-on effects to an Interconnecting OSW project(s).

- Should New Jersey require connections into an offshore collector system (i.e., similar to Option 2 or Option 3 projects under the SAA), OSW developers will likely require a guarantee from the State to cover losses in the event of delays in completing the offshore transmission system. The balance sheet of a third-party offshore transmission provider is relatively small compared to that of an interconnecting OSW project, and will be unable to provide a backstop that would be satisfactory to an OSW developer. If the State is unable to provide the guarantee, the OSW developer may have no choice but to pursue its own transmission solution in order to deliver the project. Doing so could result in prolonging the OSW development processes, and restarting efforts on permitting – all adding costs to the project.

[6] By displacing energy supply from carbon emitting sources
[7] Whether an Option 1b, Option 2 or Option 3 project

- To mitigate the project-on-project risk of delays in offshore transmission causing OSW projects to be late, we recommend that the Board makes it clear early on in the process that it will measure energy delivered to the POI for the calculation of ORECs – irrespective of the transmission solution selected. Doing so will align the interests of the OSW farms and transmission systems. The interdependency between the two parties will influence the structuring of commercial arrangements that will lower the risk of delays. For example, OSW farms would seek performance guarantees (and contractual damages) from transmission developers to ensure projects are on-time – which helps lower costs and risks to ratepayers. In addition, OSW farms may ask for step-in rights to complete construction if the transmission project fails to meet certain agreed upon milestones.

Option 2 (and Option 3) projects have a greater risk of not being in service on schedule to support the OSW project commissioning, even if the transmission project is selected by the Board well in advance of he OSW farm(s) under the OREC solicitation, for all the reasons described in our responses to Questions #1 and #11 above.

13. Through what mechanisms should the risk of Option 2 or Option 3 cable failures be allocated? Does the potential risk for failure impact the preference for HVAC versus HVDC cables?

14. If an Option 2 or Option 3 proposal is selected, please detail the potential reliability and economic benefits.

15. For the build out of transmission facilities under the current generator radial lines approach, please provide additional details and considerations on the costs, feasibility, timing and operability of requiring OSW developers of future projects to utilize certain specified technology types, including potentially identifying common Original Equipment Manufacturers, requiring mesh- ready[8] offshore substations, or other future-proofing specifications. Further, please detail the anticipated coordination that would be required to eventually interconnect between mesh-ready substations, including any anticipated unavailability of OSW generation or other foreseeable risks.

Whether executed under a generator radial-line approach, or in connection with an Option 1B proposal, a carefully-planned mesh-ready requirement in the OREC RFP would allow the State to achieve the benefits of an Option 3 project, without the risks of the same. As demonstrated by New York's approach, a mesh-ready network can be an RFP requirement.

Developing an offshore mesh-ready network will require significant guidance from the BPU and may need to be coordinated with PJM. Specifically, the technical and commercial considerations that would need to be addressed at the time of an OREC RFP would include:

- Size of the connections from/to neighboring OSW farms to standardize offshore substations
- Responsibility for executing the mesh network; i.e., what aspects of the network OSW developers are responsible to engineer, procure and install to enabled sufficient flexibility in the design
- Design specifications on platform topsides and foundations
- Who will own the mesh network? Segments of the mesh network will be built at different times by different developers, and each connecting OSW farm will need to accede into the terms of and conditions of a pre-defined ownership structure. What is the process of connecting OSW farms into the mesh network?
- Who is responsible for operating the mesh network? What dispatch/scheduling

[8] Offshore wind collector substations are "mesh-ready" when sized and designed to be able to eventually interconnect to other mesh-ready offshore wind collector substations.

methods will be used? What happens in the event of an operator, and how are losses allocated?

- How will the energy flows through the mesh network be metered, accounted, and paid? Energy will flow across the mesh network from different OSW farms. How will revenues and losses be accounted? How will payments be made?
- What will be the contractual POI? Large Generator Interconnect Agreements (LGIA) name a Point of Interconnect (POI) for each wind farm developer.
- How would responsibility for mesh expansion planning and operation be addressed? Initially, the mesh network might be a ring buss. Given offshore assets are buried subsea cables and fixed offshore platform decks that are difficult and expensive to expanded, new developers entering the market would likely become radial branches at existing platforms. The MESH would likely evolve into a hybrid ring-radial network over time.
- Will PJM capacity market rules apply to the mesh network? Current rules for bidding into the capacity market under a propsective mesh operation may be either unenforceable or require significant re-tooling.
- How will reactive power be managed between OSW farms? OSW farms will be non-firm distributed generators within the mesh network, with increased capacitive load as the mesh network grows.
- What is the mesh network design standard? Will the standard allow for the safe maintenance and operation of the off shore equipment with a focus on how to fully isolate mesh connections to compensate for outages by individual OSW farms.

Binding developers to specific Original Equipment Manufacturers may reduce vendor diversity resulting in higher cost and longer duration construction. Ongoing supply chain constraints could delay implementation of New Jersey's offshore wind goals if supplier diversity is hindered.

16. For an Option 2 and Option 3 proposal, please provide additional details and considerations on the costs, feasibility, timing and operability of requiring OSW developers of future projects to utilize certain specified technology types, including potentially identifying common Original Equipment Manufacturers, requiring mesh-ready[9] offshore substations, or other future-proofing specifications. Further, please detail the anticipated coordination that would be required to eventually interconnect between mesh-ready substations, including any anticipated unavailability of OSW generation or other foreseeable risks.

Same response to question #15 above.

[9] Id.

REQUEST FOR INFORMATION – NEW JERSEY DIVISION OF RATE COUNSEL

1. If an SAA solution is selected by the Board, should those costs be assigned and allocated among New Jersey ratepayers on a load-ratio share? Is there an existing load-ratio share methodology that the Board could adopt? If you recommend a methodology other than load-ratio share, please describe that methodology and its comparative advantages/disadvantages.

2. ***How should the Board evaluate Option 2 transmission solutions that have less impact on the public (i.e. avoid beach crossings), but inherently entail greater costs?***

We recommend that the Board take a holistic view of the SAA proposals relative to the full set of options for delivering power from the available offshore wind leases to shore. Specifically, we recommend that the Board evaluate all SAA proposals – whether Option 1B or Option 2; whether HVAC vs HVDC – using the same transparent scoring system. We recommend a phased approach, detailed below, that will allow evaluating the full cost of delivered ORECS, considering OREC proposals and SAA proposals. Doing so will help maintain public support for the State's offshore wind program by re-assuring the public that the selected projects are in the State's best interest. This approach would required several steps.

- First, we recommend that the Board issue guidance that it will provisionally award a portfolio of projects under the SAA prior to the OREC solicitation, and require offshore wind developers to submit two bids in the state's OREC procurement: one that includes a provisionally-selected SAA project, and one that utilizes a generator radial-line approach.
    - This guidance should include evaluation criteria. For the same, we recommend the Board include factors including, but not limited to, cost and risk to ratepayers, deliverability, environmental impact, public opposition, economic impact, and ability to meet State policy objectives.
    - Other jurisdictions have assess the releative benefirst or risks of intangible or non-quantifiable factors (e.g., environmental impact, public opposition, etc.) by establishing a relative scoring system (e.g., score of "1" for high risk, and "5" for low risk), and assign a weighting for each factor. This converts the qualitative assessment into a numerical score that provides the Board with a methodical and consistent approach to prioritize projects in a manner that reflects the Board's priorities.
- Second, in establishing the short list of provisionally-awarded SAA projects, we recommend that the Board employ a two-stage screening:
    - As step one, we recommend that the Board segment proposals geographically, based on their ability to deliver energy cost-effectively from clusters of offshore wind leases. Given the diversity of lease locations, proposals can be segmented based on the cluster of offshore wind leases they can serve cost-effectively (e.g., Northern vs Southern, other otherwise).
    - As step two, we recommend that the Board select the most favorable individual SAA proposal, or clusters of SAA proposals in each segment – which could include Option 1B or Option 2 proposals or both – based on the published scoring criteria.
- Finally, the Board upon receiving OREC bids, the Board should select the combination of OREC proposals and SAA proposals that results in the most favorable scoring, based on the published scoring.

In the event the Board elects to not employ this approach, we recommend selecting SAA projects based on the same two-step approach contemplated above for selecting provisional awardees.

3.	***How should the Board weigh Option 1b transmission solutions against each other that have less impact on the environment (i.e. wetlands), but may inherently entail greater costs?*** See our response to Question #2, above.
4.	***How should the Board evaluate the cost differences of HVAC versus HVDC transmission solutions?*** See our response to Question #2, above.
5.	***How should the Board evaluate the risk of failure and associated economic implications of HVAC versus HVDC transmission solutions?*** As detailed in our response to Question #2, above, we recommend that the BPU establish a transparent scoring system that will allow for consideration of both quantitative and qualitative factors, such as failure risks. For context, HVAC solutions are proven in the OSW industry, given their long operating history in Europe. As such, global supply chains are well established for HVAC solutions – reducing project-on-project risk from deliverability of key components. In contrast, there is limited operating history of HVDC for OSW farms. Accordingly, the supply chain is not as robust compared to equipment for HVAC. In addition, a major risk on HVDC comes with having to place converter stations offshore. For scale, the converter stations approximate the size of a football stadium, and finding real estate that is both appropoiately-sized and properly zoned for converter stations is challenging, particulary in densely populated areas like Northern New Jersey and the Jersey Shore. Additionally, based on our discussions with equipment vendors, there is a shortage of vessels that can deliver the equipment in the US. Moreover, the manufacturing capacity of the offshore converter station is also limited. For these reasons, the risk of failure (and deliverability) of HVDC solution from the OSW facility to shore is greater compared to that of HVAC. HVAC cables provide capacity in 300 to 400 MW increments – which can better match the capacity of the lease areas, and allow the OSW developers to better align the maximum potential capacity of their lease areas with the potential injection (and OREC offer) into New Jersey. By contrast, Option 2 HVDC systems offered in the SAA solicitation range from 1,148 MW to 1,510 MW increments. Not only would HVDC systems limit the OSW developer's ability to maximize the energy generation capacity from the lease area, but it increases the risk of energy loss from transmission system failures. Failure on a single HVAC cable would not jeopardize energy production of an entire OSW farm. In contrast, failure of an HVDC cable would jeopardize the energy production of an entire OSW farm, as there would be no route to the POI.
6.	***How should the Board evaluate the costs of the SAA versus the baseline scenario (radial export cables) and how should the Board consider non-price benefits?*** We agree that an analysis should be performed to determine whether ratepayers would benefit from the anticipated lower cost of procuring offshore wind energy through the SAA, or whether an OSW developer can deliver a lower cost solution by providing the entire solution on its own. See our response to Question #2, above, for our recommended apporach.
7.	***How should the Board weigh intangible or other economic benefits (parks, recreation opportunities, and economic development) against proposal costs?***

See our response to Question #2, above.

8. How should the Board consider the varying cost-cap proposals?

See our response to Question #2, above for our detailed recommendations on evaluations. We recommend that cost cap proposals be assessed as part of both price and project viability criteria, within the relevant geographic segmentation. In addition to the quantitative analysis, we recommend that the Board consider the commercial feasibility of the cost-cap to ensure an adequate risk-sharing mechanism between developer and ratepayers. A cost-cap mechanism that places all the risk to the developer may end up being most costly to the ratepayers in the long run as shortcuts could be taken over the contract period (e.g., cutting on maintence) in order to make up for cost overruns during construction. Conversely, shifting an outsized amount of risk to ratepayers would not be attractive as it removes the mechanisms in plance to ensure the transmission developer performs its obligation under the proposal. There is precedent on evaluating cost-caps based on experience from projects completed under FERC Order 1000.

- Cost: Capping the cost of the proposed key equipment is commercially feasible, and should be expected as developers have spent months preparing for the bid submission. Including the cost to be incurred by an incumbent utility is a bit aggressive as costs will not be known until a later date – putting greater risk to the transmission developer.
- Regulated Rate of Return: Fixing the rate of return over a certain period is reasonable and makes projects more competitive. However, doing so over the life of the project is not commercially feasible and is more for optics. First, the FERC will rule on what appropriate rate of return can be realized on projects. Second, we cannot predict what rates will be over the long-term. Hence, a fixed rate could either be too high (i.e., excessive returns being earned by developer), or too low – which shifts risks to ratepayers as discussed above.
- Equity Percentage: The equity component assumed by developers on projects is approximately 50% of the regulated capital. It is expected that all projects will be at around this level as this is what the markets expect. Otherwise, financing will be a challenge.

9. If the Board selects one or more Option 2 or 3 solutions, where should the measurement of energy delivered to the distribution system, for calculation of ORECs, take place?

We recommend that the Board measure energy delivered to the onshore POI for the calculation of ORECs – irrespective of the transmission solution selected. This way, it aligns the interests of both OSW farms and transmission systems, and helps ensure that ratepayers only pay for what is actually delivered – which is no different from how traditional OSW projects are developed[10].

Measuring at the POI will require maximum equipment reliability of both the OSW farm and transmission system. OSW farms would seek performance guarantees (and contractual damages) from transmission developers to ensure projects are on-time – which helps lower costs and risks to ratepayers. In addition, this will help improve the financeability of OSW farms as lenders will see that interests are aligned.

Any other alternative measuring point will be ineffective in aligning interests, and require ratepayers to shoulder unnecessary costs. Measuring ORECs at the interconnection point between the OSW farm and transmission project is not fair to ratepayers as they would have to pay for ORECs even in scenarios where the transmission system is down (and fails to deliver the energy to the POI). Measuring ORECs at the offshore substation is also unfair to ratepayers as it fails to account for the actual delivery of OSW energy to the designated POI.

[10] OSW developer responsible of entire scope from OSW farm to POI on-shore

REQUEST FOR INFORMATION – TRANSMISSION DEVELOPERS

1. How should the Board ensure that projects are completed on schedule given upcoming OSW generation projects' timelines? Please explain how changes in a future OSW generation project schedule may affect a selected SAA project, if at all.

Most fundamentally, the Board can ensure SAA projects are available on time by selecting the right projects. For the reasons detailed above Option 1B projects are much more likely to be delivered on schedule than Option 2 projects.

Beyond selecting the right projecst, there are three additional means of ensuring SAA projects are completed on schedule to coincide with the requirement by OSW farms. It is important that SAA projects become operational prior to the OSW farms, as the grid connection is required to commission the turbines.

- First, we recommend that the BPU set out a realistic timeline that provides clear operational commencement date ("OCD") requirements for both transmission and OSW farm projects. For example, if an OSW farm is required to have an OCD by year X, the associated transmission project would then have an OCD of X minus 12 months. With the OCD set, developers can work back to establish their project schedule and key milestones for Final Investment Decision, Financial Close, and Notice to Proceed. The OCD would make its way into the commercial agreements and project financing documents, and it is expected to result in penalties to vendors (and developers) for failing to meet the OCD.

- Second, the BPU can consider structuring the payment to transmission projects that penalizes developers for failure to meet an agreed OCD. NJ ratepayers will bear the cost of transmission projects, and no payments are expected to developers on a project that isn't operational. In addition, transmission developers could be required to bear additional costs incurred by ratepayers for the delayed OCD. For example, if the State had to procure more expensive energy supply to compensate for the loss in energy supply from the delayed delivery of OSW farms, this incremental cost could be passed on to transmission developers.

- Third, the transmission developer is expected to enter into an interconnection agreement with the OSW farm. As part of this agreement, the OSW farm will want to negotiate penalties for delays in the transmission project being operational as the OSW farm will not be able to deliver energy to the transmission grid (assuming OREC is calculated based on energy supply injected into the POI). The financial penalties will drive schedules for transmission developers to ensure they deliver the project on-time.

2. Please outline any anticipated changes in tax policy and any federal sources of money transmissions developers might seek for a selected SAA project —or that New Jersey could seek.

In January 2022, the Biden Administration announced $20B in financing tools to support enhancements to the US electric grid through the Building a Better Grid Initiative. The program is designed to support both new and existing invesments in transmission infrastructure. If applicable, and in consultation with the BPU, transmission developers may engage in consultations with the Department of Energy to explore financial enhancements (via loan guarantees, grants, etc.) that will lower the project costs.

In addition, if applicable, transmission developers may also seek to engage in consultations the Department of Energy's Loan Program Office ("LPO") through its Title 17 Innovative Energy Loan Guarantee Program. LPO eligibility requirements stipulate that the Project must employ "New or Significantly Improved Technology" as compared to Commercial Technology *in service in the United States. This "innovation" must constitute one or more meaningful and important improvements in productivity or value and NOT be "Commercial Technology"[11].*

Congress passed legislation in December 2020 to expand the Investment Tax Credit ("ITC") to cover offshore wind projects – which allows for a 30% credit on projects that begin construction before 2026. The ITC covers "property owned by the taxpayer necessary to condition electricity for use on the grid such as subsea cables and voltage transformers" – meaning the OSW farm and the associated offshore transmission system.

3. ***Other than an act of Congress amending the current Federal Investment Tax Credit ("ITC"), might there be an innovative way (such as in collaboration with OSW generation developers) for Option 1b, Option 2, or Option 3 projects that support OSW to qualify for the ITC?***

   Under the current Federal ITC regulations, Qualified offshore wind facilities are qualified wind facilities (within the meaning of the section 45 renewable electricity production credit, without regard to any sunset date) that are located in the inland navigable waters of the United States or in the coastal waters of the United States, and include property owned by the taxpayer necessary to condition electricity for use on the grid such as subsea cables and voltage transformers. This means that 30% of the eligible costs for an OSW developer connecting to an Option 1B project would qualify – essentially all the equipment that is offshore. In contrast, the same OSW developer would have a lower amount of eligible costs that would qualify for ITS under Option 2 or Option 3 projects as ITC is not available to transmission system owners – who would also own the offshore transmission system.

4. ***How might transmission developers explore the availability of federal funding opportunities that may be available to support transmission projects? How would receipt of such funding be incorporated into bids or financing arrangements? How might the Board coordinate on applying for such opportunities?***

   Subject to being selected under the SAA, and negotiation of definitive terms between the developer and the Board, an Order of the Board could be constructed to ensure that a material portion of the benefit that the project receives from federal funding opportunities will be a pass through to the ratepayers.

5. How might transmission developers explore the availability of federally-backed loans for loan guarantees that may be available to support transmission projects? How should developers and the Board coordinate on applying for such opportunities? How would receipt of such loans or loan guarantees be incorporated into bids or financing arrangements?

   Duplicate – same as #4 above.

6. ***How might a selected SAA project manage and mitigate material and equipment supply chain risks and any associated costs, particularly as they might related to HVDC?***

   Most fundamentally, the Board can mitigate these risks by selecting the right projects. For the reasons detailed above, Option 1B projects are much less risky than Option 2 projects.

   - Option 2 projects carry significant risk because such projects put the burden of offshore construction on transmission developers, rather than offshore wind developers.
     - Offshore wind developers are in the best position to manage the construction of offshore transmission infrastructure for several reasons.

[11] Commercial Technology is defined as technology that has been installed in and is being used in three or more commercial projects in the United States in the same general application as in the proposed project .

- Offshore wind developers are best positioned to align the construction schedule of the offshore transmission infrastructure with that of the overall wind farm.
- Offshore wind developers are best positioned to identify synergies among the construction methods for the offshore wind farm and transmission infrastructure
- Offshore wind developers are best positioned to manage union labor relations for the entirety of the offshore project scope.

- Further, Offshore wind developers are in a better position to manage the supply chain for offshore transmission infrastructure.
  - Offshore transmission infrastructure sourcing is a core competence of the offshore wind developers because they have to do it in nearly every other global market.
  - Offshore wind developers are best positioned to select the offshore transmission componetns that will best align with the wind farm and overall project schedule. Depending on the type of technology used for the transmission solution, project-on-project risk could further materialize due to the risk of bottlenecks in the supply chain.
  - The supply chain for offshore transmission infrastructure is very consolidated, with only a handful of vendors for key components. Offshore wind developers with a global reach will have much greater ability to exert leverage over that supply chain.
  - Similarly, there are very few vessels capable of installing offshore transmission infrastructure. Offshore wind developers will have much greater ability to exert leverage over vessel suppliers.

- Unlike an offshore wind developer, an Option 2 transmission developer will have to select technology independent of the interconnecting wind farm, then manage the sourcing of the same without a global pipeline of projects to leverage, and then endeavor to manage the construction and commissioning of the same in an exetremely challenging offshore environment independent of the wind farm it is intended to serve. Such arrangement invites a host of execution delays.
  - Delays in permitting an Option 2 project will have knock-on effects on project schedule and eat into any “float” between the scheduled operational commencement date of the transmission project and the commissioning of the OSW farm(s).

7. How might a selected SAA project manage financial risk, including, but not limited to, market and interest rate dynamics, labor costs, raw material and supply chain costs, land procurement costs, and insurance?

See our response to Question #6, above.

8. If an Option 2 or Option 3 proposal is selected, please detail the potential reliability and economic benefits.