Wind Energy Lease Holder Pre-ARFI Engagement Q&A
Emailed Questions received by 12/31/24.

Notes:

The following constitutes a partial set of responses. Remaining questions (Q&A #8 and #18), as noted below, will be addressed expeditiously in the coming days.

The questions provided have been modified to preserve confidentiality. Recommendations and other editorial comments regarding the ARFI structure have been received with thanks from the Duke Energy Team.

Q&A #1 **Considering that both the Carolina Long Bay projects and the Kitty Hawk South project will provide proposals assuming HVDC offshore transmission solutions, we respectfully recommend that the ARFI Team allow proposals delivering up to 1,200 to 1,400 MW by 2034, which is generally considered the minimum economical size for projects using HVDC, as it will facilitate optimized proposals, reducing costs per megawatt-hour (MWh).**

The Settlement calls for 800-1,100 megawatts (MW) of offshore wind by 2034 and up to a total of 2,200 to 2,400 MW by 2035. The utilities will require the respondents to use a value no greater than the maximum of 1,100 by 2034 and 2,400 MW by 2035. If the respondent feels they can provide additional capacity by 2034 or 2035, inclusive of necessary transmission capacity additions and timelines at a lower average installed cost per MW, they would be permitted to submit a response based on this higher capacity value. However, capacity above the maximums stated above could require acceleration of network upgrades that may be impossible or impractical to implement in order to support such additional capacity.

Q&A #2 **In order to provide the most accurate explanation of project schedule to COD, thereby justifying COD estimates, it will be important to understand when developers could expect a signed contract to be in place (and/or other key milestones, as used in other RFP-like processes – start of negotiations, contract execution, etc.). This will allow critical-path development activities to progress (assuming this process proceeds from an ARFI to an RFP). This information would also inform the proposed scheduling of progress payments, should this option be submitted as part of the ARFI response. Can these indicative milestones be estimated in the ARFI or, if indicative milestones cannot be provided at the time of ARFI issuance, could clarity be provided on when the ARFI team can commit to making this estimated information available?**

The utilities expect the respondents to provide a schedule and key milestones including contract dates in their response necessary to achieve COD based on procurement of between 800 and 1,100 MW for commercial operation by 2034, and up to 2,200 to 2,400 MW by 2035 for DEP and DEC customers.

Q&A #3 **Can the ARFI Team advise on what timing assumptions developers should make about the duration of the interconnection study and transmission upgrade process as part of the program?**

An executed interconnection agreement is achieved approximately 2 years after the interconnection request is submitted into the annual DISIS cluster study process. Once an interconnection agreement is executed, transmission network upgrade projects will be initiated. Timelines for transmission network upgrades identified in the DISIS study results will determine the estimated schedule for onshore networked transmission projects being placed into service.

Q&A #4 **Proposals will be much more cost-effective and timelier if Duke commits to provisions ensuring Duke's collaboration and cooperation in activities related to cable landfall, interconnection, and transmission upgrades (and related tasks, including onshore development, state and local permits, and stakeholder relations).**

The utilities intend to provide commercially reasonable assistance and cooperation to all participating developers commensurate with proposals. At this time, the developer (as the interconnection customer) is responsible for bringing the project to the POI with additional details to be provided in the ARFI. Duke Energy anticipates collaboration and support of the project's successful permitting, consistent with efforts employed in prior experiences with alternative solicited resources.

Q&A #5 **Are developers allowed to submit multiple alternative proposals that differ based on physical aspects (e.g., size, POI, etc.), and/or schedule, and/or pricing, or are leaseholders limited to one?**

The developers are permitted to submit multiple alternative proposals; however, the minimum required proposal must also be provided.

Q&A #6 **Will there be a limitation on the number of alternative proposals submitted? We would recommend that allowing for any of these types of modifications would support the identification of optimal solutions for modeling.**

No; however, the utilities expect that the developer's alternative proposals should be reasonably different and appropriately characterized to ensure variances from the minimum required proposal are readily discernible and comparable.

a. **Is the "Minimum requirement" applicable to <u>all</u> proposals?**

   No; from the standpoint that alternative proposal may alter some aspect of the "minimum requirement" including capacity, timing, scope of additional services and risk sharing. However, all proposals must at least transfer ownership no earlier than mechanical completion but before the asset is placed in service.

b. **Are "alternative proposals" like asset purchase agreements eligible (is this what is meant by transfer prior to mechanical completion)?**

   No; generally, Asset Transfers would place development and construction responsibility on the ultimate owner of the facility early in the project development lifecycle sometime after acquisition of site control and during the development phase before ordering of equipment and construction activities. It is generally understood that the WEA leaseholders and their partners have a strong track record related to these development and construction activities.

Q&A #9 **Over the last two years, the use of indexation formulae and inflation adjustment mechanisms has become standard practice in offshore wind and other energy procurements, from New Jersey to Massachusetts. These types of pricing adjustment mechanisms allow for a bidirectional adjustment to pricing based on changing and, to some extent, unpredictable macroeconomic circumstances during the long-lead development period. Given the long time period between potential contract execution and COD of any long-lead resource project, not to mention the added time and uncertainty between ARFI proposal submission and contract execution, developers may be incentivized to post an artificially high price to capture unexpected risk (or to submit a lower price now during the ARFI stage, that will only go up at the contract execution stage), unless there is a mechanism to protect both developers and ratepayers from changes in supply chain, changes in law, and other difficult to predict variables which a developer cannot control. Would the ARFI Team be open to a bidirectional indexation formula to account for such risks?**

The purpose of the ARFI is to determine next steps in offshore wind development and seeks commercially accurate and reasonable information on cost and risk sharing approaches and mechanisms. The utilities are open and amenable to evaluating approaches offered by developers to manage costs and risks, and developers should provide their assumptions and reasoning in managing costs and risks as part of their ARFI responses. Duke will take this suggestion under advisement and provide, as part of the "minimum requirement", an adjustment index formulation. Alternative responses can either use this proposed formulation or utilize another at the respondents choosing.

Q&A #11 **How does the ARFI Team anticipate adjusting the process if there is a change in law that impacts tax credits, or that imposes tariffs on key components that are used for offshore wind?**

The utilities do not anticipate an adjustment to the ARFI process itself in the event there is change in law impacting tax credits, etc.; However, the utilities do expect that, if any of these hypothetical scenarios came to fruition, it could result in an overall impact to the LCOE and ultimate cost to customers for the resource.

a. **The presence or absence of tax credits, and imposition of tariffs could theoretically be part of the indexation formula.**
   For tax credits, this would not be applicable for a BOT as those are credits claimed by the utilities and not incorporated into the BOT pricing offered by the developers. Tariffs would impact the BOT pricing.

Q&A #12 **Will the Utility assume the same network upgrade-related costs at New Bern that it assumed in the past CPIRPs, and will these all be attributed to offshore wind, and will it be focused on supporting 2.4 GW of offshore wind or less/more? Will Power Advisory and/or DNV have visibility into how the network upgrades-related costs for a New Bern interconnection will be estimated and incorporated into the reference price development and the modeling to evaluate the inclusion of proposed offshore wind projects?**

For all large generators requesting interconnection to the DEP system, the utility must follow the FERC approved cluster study process prescribed in the Joint OATT. This process requires each large generator to enroll in an annual cluster study and the resources will be studied for the requested interconnection service within that cluster of resources requesting interconnection. For an offshore wind resource requesting interconnection at the New Bern POI at a specified MW level, the transmission network upgrades for the requested interconnection service will be determined through the annual cluster study and the costs of the identified upgrades will be allocated to the resources, in addition to the offshore wind resource, shown to have a given threshold impact on the identified transmission network upgrades. Estimates for network upgrade proxies for wind resources are updated for each CPIRP cycle. Power Advisory and DNV will be conducting a general review of reference price development, however, are not involved in detailed development of network upgrade estimates.

Q&A #13 **During the Stakeholder Group Call, the ARFI Team stated that the Public Staff have some ideas of companies who can support the development of the reference price, but that it is not yet determined if there will be third party support. Will the third party be considered an offshore wind expert, or a modeling expert?**

The utilities, in consultation with Public Staff, will develop the reference price and at this time do not anticipate third party support. Power Advisory and DNV will conduct a general review of reference price development.

Q&A #14 **The presentation stated that offers must support procurement of between 800-1,100 MW for commercial operation by 2034 and 2,200-2,2400 MW by 2035 for DEP and DEC customers. Given that neither Carolina Long Bay lease area alone allows for the larger capacity request will responses be accepted if they meet the 2034 timeline at a minimum?**

The purpose of the ARFI is to determine next steps in the utilities' development of offshore wind and to seek commercially accurate and reasonable information on cost and risk sharing approaches and mechanisms. The utilities are amenable and open to proposals that provide benefits at the lowest cost and risk profile to customers, provided they meet the minimum requirements specified in the ARFI once issued.

Q&A #15 **Please explain how Duke envisions running a fair analysis of all wind lease areas and a competitive RFP given the differences between the wind lease areas such as size, current development status, etc.**

The purpose of the ARFI is to determine next steps in the utilities' development of offshore and is not an RFP process. Per NCUC order and the allowance for a fair and unbiased analysis, the utilities have engaged an Independent Evaluator, Power Advisory, as part of the ARFI process. Ensuring the fairness of the evaluation process is a primary focus of the Independent Evaluator. Power Advisory will seek to ensure a fair process by ensuring that the evaluation process properly reflects the underlying value of each of the wind lease areas as a site for offshore wind development from the perspective of the value derived by the utilities' customers. The utilities have also retained DNV as a technical advisor to provide in-depth technical expertise and continuity from the previous offshore wind RFI.

Q&A #16 **How will Duke Energy allocate onshore transmission costs to the projects providing alternative points of interconnection (POIs) in addition to the New Bern minimum POI requirement?**

Refer to Q&A #10 as provided in the 01/03/2025 Q&A response set.

Q&A #17 **How will the IE and Duke ensure fairness in comparing responses that include alternative POIs to those that use the POI in New Bern, which has been studied much more thoroughly than possible alternative POIs?**

The New Bern POI represents the minimum proposal requirement, determined by the utilities to be optimal on several bases, including execution risk and bulk system reliability and acknowledging the extensive public study that is available at the time of the ARFI issuance for this POI. As public studies will not be available for alternate POI's in the timeframe of the ARFI (a study of Sutton as a POI is included in a CTPC Multi-Value Strategic Transmission analysis later in 2025), existing cost proxy estimates, along with execution (timing and risk) and reliability considerations, as well as appropriate project management contingency considerations using engineering experience and judgement, will be used in evaluating other POI proposals.

Q&A #18 **Would Duke consider alternatives to 100% ownership that comply with the law?**

Response forthcoming as noted above.

Q&A #19 **If a developer does not submit any proposals to the ARFI, will it still be allowed to participate in the RFP to ensure a competitive process?**

If there is more than one project that comes in under the reference price and the utilities recommend proceeding to an RFP, the utilities intend to seek clarity from the Commission as to whether projects that did not come in under the reference price or developers who did not participate in the ARFI should be allowed to proceed and/or participate in the RFP. The appropriate time to seek that clarity we believe is post bid submission as developers should be incentivized to submit competitive bids. From the utilities' perspective, a non-response could be viewed as a developer having reservations regarding their ability to develop the lease area in a cost-effective manner within the desired timeframe under current market and policy conditions.