October 28th, 2022

New England States Transmission Initiative,

Anbaric Development Partners, LLC ("Anbaric") develops electric transmission and energy storage projects that strengthen the power grid, integrate regional markets, and bring renewable energy to population centers. Anbaric appreciates the opportunity to submit these comments and recommendations in response to the New England States Regional Transmission Initiative (RTI) Request for Interest (RFI) noticed September 1, 2022) (the "RFI").

Introduction

New England is at an inflection point in the development of new clean energy sources needed to achieve decarbonization requirements. New England states have made important progress toward deploying renewable energy, and several grid-scale projects are expected to come online in the next few years. However, achieving the scale and pace of renewable energy deployment – for all renewable energy sources and particularly for offshore wind – requires planning and competitive procurement of new transmission infrastructure.

Procurement of wind farms paired with project-specific generator lead lines enabled states to quickly procure the first five offshore wind projects. However, the limits of this approach are apparent in mounting grid congestion and interconnection costs, the expected proliferation of export cables across the seabed and shore landings, and lost opportunities to transition to a rational infrastructure development approach that achieves both near-term targets and long-term goals at lowest cost and with least impact on the environment, coastal communities and fisheries.

Moving to a planned approach is a prerequisite to achieving the 30,000 MW of offshore wind needed to achieve 2050 decarbonization goals.[1] Without planning states and ratepayers will pay more than necessary for the renewable energy buildout or will fall short of legal emission reduction requirements.

Fortunately, New England has the information and tools to build a grid centered on renewable energy, and federal funding can reduce the costs of needed investments. ISO-NE has identified points of interconnection that can receive the next round of offshore wind projects with minimal upgrades.[2] Analysis shows that a planned approach can avoid over a billion dollars in transmission costs and reduce marine cabling by almost 50%.[3] New England states have experience procuring terrestrial transmission, New Jersey has piloted an approach for offshore wind transmission, and Germany[4] and the Netherlands[5] have seen their reliance on planned, shared transmission result in subsidy-free offshore wind generation projects delivered in recent auctions. Competitive procurement will drive down the costs of

---

[1] The Massachusetts Energy Pathways to Deep Decarbonization report, All Options scenario finds that the region will need 30,000 MW of offshore wind to achieve 2050 climate targets, see page 113 at: https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download

[2] June 17th, 2020 Presentation to PAC by Al McBride, at slide 5; https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf

[3] Brattle Group's 2020 *Offshore Transmission in New England: The Benefits of a Better-Planned Grid* finds that planned transmission could reduce marine cable miles by 49%. Study available at: https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf

[4] See: https://www.nytimes.com/2017/04/14/business/energy-environment/offshore-wind-subsidy-dong-energy.html

[5] See: https://windeurope.org/newsroom/press-releases/worlds-first-offshore-wind-farm-without-subsidies-to-be-built-in-the-netherlands/

transmission and interconnected wind farms, and funding from the *Infrastructure Investment and Jobs Act* is available to cover a large portion of capital costs.

New England is in a leading position in the United States as a first mover on offshore wind with ambitious climate targets that will drive continuing deployment of offshore wind and other clean energy resources. Instead of a bottleneck, transmission can be the bedrock of a power system that enables this transition. It is therefore critical to pursue the best path forward that can integrate the most renewable energy, most cost effectively, and in the most feasible technical and environmental manner. The modular offshore wind integration plan ("Modular Plan") presents a prudent pathway to procure initial components of a networked ocean grid in 2023 while laying the foundation for continuing development of a regional and interregional grid that facilitates growth of all renewable energy sources. The responses below provide information and recommendations on procedural, commercial and technical considerations to facilitate a practical and implementable no-regrets transmission procurement that will keep New England on track to address the threat of climate change and enable the offshore wind industry to continue growing as a source of domestic clean energy, investment, and well-paying union jobs.

In aggregate, the responses show that New England is ideally positioned to implement the Modular Plan. The comments describe:

- How the Modular Plan positions New England well to access newly available federal funds and reduce the cost of achieving offshore wind and climate goals;
- Proven cost-containment mechanisms the reduce costs of transmission development and insulate states and ratepayers from risks associated with large infrastructure projects;
- Technological considerations, focusing on the advanced capabilities of high voltage direct current (HVDC) transmission systems to minimize onshore upgrades, support grid resilience, strengthen connections to other regions, and facilitate integration of onshore wind and solar energy;
- Environmental justice and workforce development implications related to offshore wind transmission;
- The importance of planning and developing open-access transmission to scale offshore wind at lowest cost;
- Locations to connect offshore wind to the grid and transmission corridors to reach onshore grid connection locations;
- A procurement approach to ensure interoperability and scalability of transmission technology.
- Transmission ownership models and approaches to ensure fair cost allocation among New England states;
- Potential benefits of public-private partnerships, including the ability to enable third parties to purchase offshore wind, and;
- Co-benefits that could be created through competitive transmission procurement.

1. Comment on how individual states, Participating States, or the region can best position themselves to access U.S. DOE funding or other DOE project participation options relating to transmission, including but not limited to funding, financing, technical support, and other opportunities available through the federal Infrastructure and Investment Jobs Act.

The RTI advances multiple goals of the federal funding made available through the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA). Both statutes promote investment in projects that will improve electric system resilience and reliability, expand the availability of zero emissions generation resources, accelerate technological innovation, and create opportunities for communities hosting the projects. The expansion of offshore wind resources to serve the New England states meets each of those objectives, and recent guidance from the U.S. Department of Energy (DOE) offers a roadmap for developing proposals for federal investment in New England's offshore transmission system.

Based on review of the IIJA, IRA, and DOE's statements on the transmission support programs, Anbaric recommends that New England states focus primarily on the Grid Resilience and Innovation Program[6] (GRIP), initially by developing a Concept Paper for DOE centered on the Modular Plan. States should monitor the Transmission Facilitation Program[7] as another potential source of federal support and utilize funds from the IRA to cover costs of implementing the Modular Plan.

a) Focus initial efforts on Section IIJA 40103(b) Grid Innovation Program

The DOE's draft GRIP FOA divides available IIJA grants into three "topic areas" that align with statutory funding authority:

- Grid Resilience Grants: IIJA Section 40101(c) – $2.5 billion for five fiscal years; approximately $1 billion available from initial FOA
- Smart Grid Grants: IIJA Section 40107 – $3 billion for five fiscal years; approximately $1.2 billion available from initial FOA
- Grid Innovation Program: IIJA Section 40103(b) – $5 billion for five fiscal years; approximately $2 billion available from initial FOA

The Grid Resilience and Smart Grid topic areas may be well suited to requests from private entities to support implementation of the Modular Plan, but the Grid Innovation Program appears to be the most promising funding source for individual states, Participating States, or the region to position for accessing DOE funding. In its draft FOA, the DOE identifies as "technical approaches of interest" for the Grid Innovation Program several items that are components of the Modular Plan:

- "Investments and strategies that accelerate interconnection of clean energy generation and/or storage"
- "Interregional or cross-ISO/RTO projects that address key grid reliability, flexibility, and/or resilience concerns"
- "Projects addressing grid access challenges for remote, stranded, or novel low-carbon resources"

---

[6] U.S. DOE, Grid Deployment Office & Office of Clean Energy Demonstrations, *Instructions for Draft Funding Opportunity Announcement, FOA Number: DE-FOA-0002740, titled "Grid Resilience and Innovation Partnerships (GRIP)"* (August 30, 2022) (*Draft GRIP FOA*).

[7] U.S. DOE, Grid Deployment Office, *Notice of Intent and Request for Information regarding establishment of a Transmission Facilitation Program* (May 10, 2022) (*TFP NOI).*

- "Planning, modelling, cost allocation, or other approaches that enable a transition to innovative financial and/or regulatory constructs that accelerate transmission expansion"
- "Underground or underwater HVDC systems in challenging environments"
- "Power flow controllers for AC or HVDC systems"[8]

The proposed Modular Plan offers the opportunity to unlock offshore wind resources, demonstrate innovative and deployment-ready technology, and set up a flexible system that could result in increased inter-regional grid reliability and resilience. The proposal fits squarely into the innovation and resilience mandates of the Grid Innovation Program.

Additionally, Grid Innovation Program funding is reserved for government entities like the New England states. Eligible entities for the program include:

- States
- Combinations of two or more States
- Indian Tribes
- Units of local government
- Public utility commissions

The states participating in the RTI could apply individually, or through their public utility commissions or local governmental units. A multi-state application for Grid Innovation Program support may enable the participating New England states to leverage federal support effectively – attracting a larger share of funding for an agreed regional approach in comparison to a single state application. Moreover, collaboration among governments, system operators, and the private sector is one of the "primary objectives" DOE identifies in its draft FOA for the Grid Innovation Program:

> DOE is proposing to solicit projects that contribute significantly to one or more of the following primary objectives: … Enhancing collaboration between and among eligible entities and private and public sector owners and operators on grid resilience, including in alignment with regional resilience strategies and plans. This includes collaboration across state and other territorial boundaries …[9]

DOE encourages Grid Innovation Program applicants to "assemble diverse and multi-functional project teams" able to address technical, financial, regulatory, and stakeholder outreach, and economic justice challenges. The RTI is an example of just such collaboration: an approach that brings to the table the expertise and local understanding of the participating States, the technical experience of ISO New England, and the knowledge and resources of private sector investors and developers.

b) <u>Develop a Concept Paper supporting implementation of the Modular Plan</u>

In a project as ambitious and innovative as the Modular Plan, public and private stakeholders must reach agreements before determining points of interconnection, equipment standards, or engineering design documents. The Modular Plan framework, informed by responses to the RFI, can serve as an deployment proposal for purposes of seeking federal support and issuing requests for proposals from transmission developers. The federal funding opportunities in the IIJA are focused on moving projects from study and demonstration into deployment. Developing the Modular Plan into a firm conceptual

[8] DOE, *Draft GRIP FOA*, at 27.
[9] DOE, *Draft GRIP FOA*, at 26.

proposal for transmission deployment will fit with the process that DOE will use to review GRIP applications.

DOE's draft FOA states that before reviewing full applications for funding, DOE will "encourage" or "discourage" applicants based on evaluation of a streamlined "Concept Paper."[10] The Concept Papers, as envisioned in the draft FOA, should be less than twenty pages long, and will be evaluated based on the following factors:

- The proposed work, if successfully accomplished, would clearly meet the objectives as stated in the FOA for the specific topic area.
- The proposed work aligns with and supports State, local, Tribal, regional resilience, decarbonization, or other energy strategies and plans.
- The applicant has identified risks and challenges, including possible mitigation strategies, and has shown the impact that DOE funding and the proposed project would have on the relevant field and application.
- The applicant has the qualifications, experience, capabilities and other resources necessary to complete the proposed project.

Development of the Modular Plan as a deployment proposal would be consistent with the decision-making framework: a well-developed Concept Paper does not require every detail be worked out; without DOE buy-in on the overall concept, additional detail work may not increase the likelihood of accessing DOE funding. The first critical path step in positioning for federal funding is to craft a Concept Paper that satisfies the criterion of the Grid Innovation Program.

c) <u>Develop a framework suitable for participation in the Transmission Facilitation Program</u>

The Transmission Facilitation Program (TFP) authorizes DOE to use up to $2.5 Billion in revolving funds to support new or upgraded transmission lines. As part of the TFP, DOE can enter into capacity contracts, loan agreements, or public-private partnerships with transmission developers. In contrast to GRIP funds, including the Grid Innovation Program, the TFP does not offer grant funding – the DOE is to be paid back for TFP facilitation support from either capacity contract revenues or payments structured to recover DOE's financial commitments made through loans or public-private partnerships.

The TFP is an innovative program designed to encourage transmission deployment, and it may be useful in the future for New England OSW development. The DOE has indicated that the first request for TFP proposals (expected later in 2022) will focus on projects that are more advanced in the development process than the Modular Plan. While a final RFP has not yet issued, in its Notice of Intent, DOE suggested its first TFP solicitation would focus on projects seeking capacity contracts only, and that the projects supported should be prepared to be in construction or operation by the end of 2027.[11] DOE has indicated that subsequent TFP RFPs will be open to longer-term projects that seek not only capacity contracts, but also loans or public-private partnerships, and these subsequent RFPs may be best suited to support the Modular Plan.

Anbaric suggests continued dialogue with DOE concerning public-private partnership or capacity contract arrangements. Because the TFP authorizes a transmission support vehicle that has not been

[10] DOE Draft FOA, at 43.
[11] DOE, *TFP NOI*, at 9.

utilized before, it is important to work with DOE to devise a framework that will meet the TFP's standards for managing its revolving fund.

d) Monitor IRA opportunities that support implementation efforts

Programs in the IRA are less defined than IIJA programs and include less direct transmission deployment funding, but IRA programs may support funding for implementation of the Modular Plan. Since the IRA passed more recently than the IIJA, the DOE has not yet issued guidance on IRA provisions similar to the IIJA draft FOA and TFP NOI. There are, however, three important provisions of the IRA that could fund states' efforts to plan and implement transmission procurement and support stakeholder engagement and permitting:

i. Grants totaling $760 million to transmission siting authorities (i.e., State, Local, or Tribal governmental entities) to assist in studying proposed project or alternative siting corridors, hosting negotiations regarding siting, participating in federal, state, or ISO/RTO regulatory proceedings, and promoting economic development in affected communities (Section 50152). This funding may be useful in facilitating stakeholder siting discussions related to offshore transmission corridors, onshore landing points, and terrestrial transmission routes. Funding could additionally contribute to costs of securing any necessary FERC or ISO approvals and working with affected communities to spur economic development initiatives.

ii. A $100 million appropriation to the DOE Secretary "to pay expenses associated with convening stakeholders" and "to conduct planning, modeling, and analysis" regarding development of interregional and offshore wind transmission (Section 50153). The statute specifically references offshore wind transmission and could defray certain state costs associated with transmission deployment (particularly elements the Modular Plan that enable future interregional offshore connections).

iii. $2 Billion for direct loans for construction or modification of transmission in federally designated National Interest Electric Transmission Corridors (NIETC) (IRA Section 50151). To date, there have been no proposals to designate transmission pathways in New England or in federal waters as NIETCs. The NIETC concept is important both to development of TFP public-private partnerships and in relation to this additional IRA loan money, and its contours will likely be developed more fully as DOE scopes those programs.

These IRA provisions have not yet been further elucidated by guidance documents and early engagement with DOE can help New England states inform design of the programs.

2. Comment on ways to minimize adverse impacts to ratepayers including, but not limited to, risk sharing, ownership and/or contracting structures including cost caps, modular designs, cost sharing, etc.

The primary means of minimizing ratepayer impacts is through competition. The Brattle Group has estimated that competitive transmission development processes have produced cost savings of 20% to 30% compared to traditional incumbent utility developed projects.[12] Others have noted that

[12] Pfeifenberger, Chang, Sheilendranath, Hagerty, Levin, and Jiang, Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value, April 2019, p. 43

"winning bids of competitive transmission projects have been priced on average 40% below initial project cost estimates and have been accompanied with cost caps or other cost-control mechanisms."[13]

Within competitive transmission procurements adverse ratepayer impacts can further be mitigated through a range of risk reduction strategies, many of which are employed by non-incumbent developers in competitive transmission processes. These risk mitigation strategies include alternative ownership models; alternative cost recovery frameworks; and alternative contracting structures. Each is further discussed below.

Alternative Ownership Models

Alternative ownership models focus on non-utility ownership where independent transmission owners accept and manage risks not typically borne by utilities. Independent transmission developers utilize best practices based on domestic and international experience that can lower costs and reduce project risks. Furthermore, the capabilities needed for anticipated transmission investments, particularly those offshore, require specific skill sets and expertise that is not typically possessed by incumbent electric utilities. Affiliates of incumbent utilities have been active in transmission procurements – typically outside of the service territory of incumbent affiliates – offering capabilities that may not be offered by the incumbent utility where the transmission is being procured, further justifying the benefits of enabling alternative ownership models. These alternative ownership models are further discussed in our response to Question 14.

Alternative Cost Recovery Frameworks

Alternative cost recovery frameworks include contract structures that employ the following cost and revenue containment measures: (a) cost caps that specify limits on project construction and operations and maintenance costs; (b) limits on equity returns; (c) debt/equity ratios that reduce the average weighted cost of capital; and (d) caps on revenue requirements. For example, in addition to offering the lowest bid ROE (8.5%) and pledging to not seek any traditional FERC incentive adders, Anbaric's proposals to New Jersey's State Agreement Approach (SAA) offered a suite of cost mitigation measures designed to protect the state's ratepayers from cost overruns. If Anbaric's realized costs exceed the bid amount, the excess would earn a reduced ROE, up to a cap, above which there would be no cost recovery at all for Anbaric. Further, Anbaric proposed a capped equity structure (45%), and a reduced ROE if the project is not delivered on time.[14]

These risk mitigation strategies are based a range of technical, contractual, and commercial innovations utilized by independent transmission developers. The cost caps are typically enabled by the substantial investment made by transmission developers in preparing their proposals prior to submission in the competitive process. This investment includes pre-construction surveys and review of the regulatory and permitting frameworks as well as early consultations with regulatory authorities so that project permitting risks can be properly assessed and permitting strategies developed.

---

https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

[13] LS Power, FERC Conference on Cost Caps, November 2018)

[14] Additional information on cost containment mechanisms proposed by Anbaric and other bidders in the SAA are provided in PJM's NJOSW Financial Analysis Report posted October 25th, 2022 and available at: https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468

Alternative Contracting Structures

Alternative contracting structures also help mitigate risk for large transmission projects. These alternative structures include:

a) Contracts with EPC firms and equipment vendors that require greater overall cost responsibility and stronger incentives for cost containment than are reflected in contracting structures typically employed for utility transmission construction; and

b) Contracts between the independent transmission developer and the entity (e.g., a state) contracting for transmission service. These contracts provide for the close coordination with respect to the development and construction of the transmission facilities to ensure that they are available when needed; provide financial penalties for project delays to ensure that schedules are aligned; and provide incentives for ensuring a high availability for the transmission facilities. A critical element of these contracts is ensuring efficient risk allocation. Project-on-project risk is oft-mentioned by generation developers, but efficient contract structures can help mitigate or eliminate this risk.

3. **Identify the advantages and disadvantages of utilizing different types of transmission lines, like alternating current (AC) and direct current (DC) options for transmission lines and transmission solutions. Should 1200MW/525kV HVDC lines be a preferred standard in any potential procurement involving offshore transmission lines?**

Direct current transmission technology provides the greatest flexibility, optionality and ability to transmit power long distances and thus avoid constraints on the terrestrial grid. State-of-the-art high voltage direct current (HVDC) transmission systems can direct power where it is needed when it is needed, enhance resiliency by interconnecting offshore transmission into a controllable network, and send power over the long distances needed to reach load centers from the offshore wind lease areas. Establishing a 1,200 MW/525kV HVDC preferred standard for offshore wind transmission would capitalize on economies of scale, position for evolution of the onshore grid to accept larger injections of onshore wind, and make optimal use of limited cable routes and onshore points of interconnection (POIs).

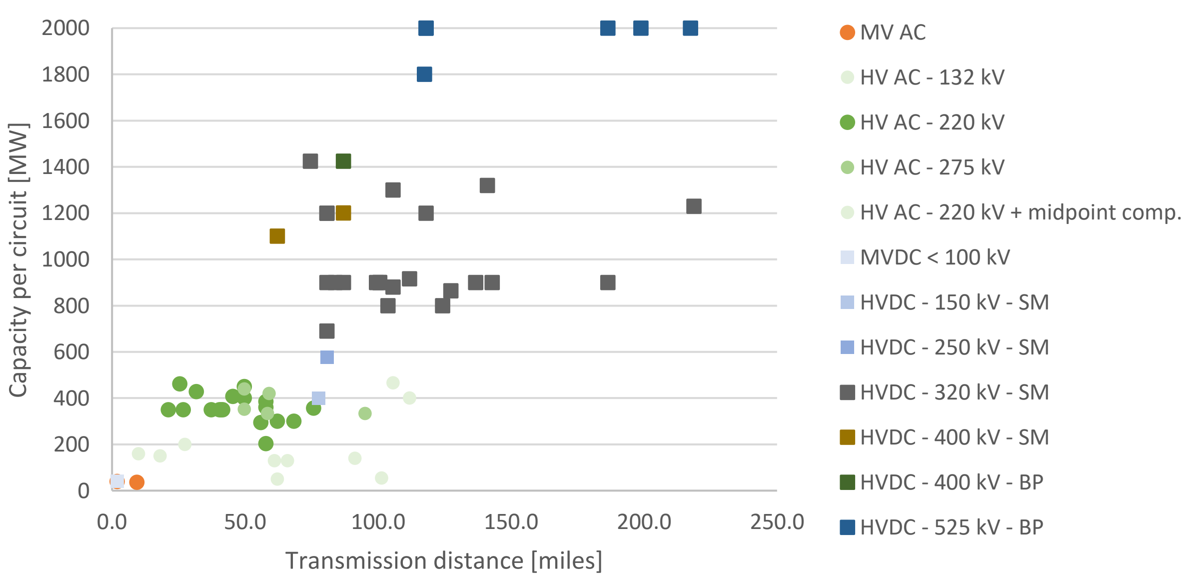
Modular development of HVDC transmission systems provides the greatest economic, environmental and scalability advantages for New England. Initial offshore wind projects have utilized near-shore points of interconnection (POIs) in Southeast New England and integrating the next round of projects will require longer distance transmission best suited for HVDC technology. HVDC systems can be interconnected offshore to create a networked ocean grid that will enhance reliability, controllability, and economic benefits of offshore wind. Use of scalable, state-of-the-art HVDC transmission will achieve current offshore wind targets and enable expansion to integrate additional offshore wind in the future by adding additional interlinking transmission modules to the system. A fully networked ocean grid will provide redundant pathways for offshore wind to reach shore in the event of cable failure. Networked HVDC transmission will enable power to be directed to specific POIs based on energy pricing and local system needs, and will provide new pathways between onshore POIs, thus strengthening the onshore grid and enabling efficient utilization of power sources across New England.

Multiple types of transmission can be used to interconnect offshore wind, with technologies and deployment models maturing to reflect local conditions and global market trends. The rationale supporting initial development of modular HVDC transmission systems with capabilities to support a fully networked ocean grid is clear from an examination of the key building blocks of offshore grid systems.

AC versus DC technology choice based on suitability for purpose: AC solutions are economic for shorter transmission distances (under 60 miles) and lower capacities (below 500 MW per circuit). The distances needed to transport power from the MA/RI lease areas will, in almost all instances, exceed 100 miles (most notably for cable runs terminating at POIs in the Boston area, Southwest Connecticut, and even Southeast Connecticut). While the reach of AC technology can be extended by adding reactive compensation and filtering devices, HVDC provides better technical capabilities and lower overall cost of ownership for higher capacities and longer distances.

This is reflected in the choices of transmission technology made by offshore wind farms in development or operation in various global markets. Each of the circles in Figure 1 below represents an offshore wind transmission project that chose AC solutions; the DC solutions are designated by squares. The types of projects are also distinguished by the kV level and, for the HVDC projects, by whether the projects chose "Symmetrical Monopole" (SM) configurations or "Bipole" (BP) configurations.[15]

Figure 1: Offshore Wind Transmission Technology by Distance and Capacity



As is clear from the choices made by these project developers, DC solutions predominate for the longer distance, higher capacity projects needed to integrate the next round of offshore wind projects efficiently with the New England grid.

Power Capacity of Cables: AC cables suffer from several phenomena that limit their effectiveness at delivering real power, especially as distance increases. For example, AC cables produce reactive power

[15] A monopole configuration has a single conductor of negative polarity and uses the earth, sea, or a metallic line for the return path of current. In the monopole arrangement, two converters are placed at the end of each pole. The symmetrical monopole arrangement uses two high-voltage conductors, each operating at half of the transmission voltage. A bipole link has two conductors (one is positive, and one is negative), and includes converter stations at each end. The most significant advantage of the bipolar configuration is that if any of the links stop operating, the bipolar link can be converted into monopole mode and half of the system can supply power.

that reduces the cable's real power rating, and the amount of reactive power (and associated reduction in power capacity) increases with distance. The reactive power is not present when using DC cable; because the currents and voltage are not alternating, only purely resistive effects are present. Thus, DC technology optimally utilizes every cable by maximizing power rating and effectively eliminating limits on transmission distance. This makes DC a more economical and environmentally friendly choice for longer offshore wind transmission distances.

HVDC Converters: To use HVDC transmission to link offshore wind to an onshore POI, power must be converted from AC to DC (at the offshore converter station) and DC back to AC (at the onshore converter station). Over time, various HVDC converter technologies, such as current-sourced converters (CSC) have emerged and been supplanted by superior technology.

The emergence of voltage-sourced converters (VSC) has allowed HVDC systems, especially for offshore applications, to increase system controllability, reduce the development footprint of transmission, and increase reliability. VSC-HVDC can act as an offshore voltage source and create the voltage reference needed by the offshore wind turbines to generate power. VSC based HVDC converters can independently control real and reactive power output and can deliver voltage support services to the onshore AC grid so that no additional reactive power compensation equipment is necessary.

The VSC category includes various types of technologies, but Modular Multi-level Converters (MMC) are the state of the art in converter technology. MMC offer excellent control capabilities, low losses, small footprint, high reliability, good scalability, and low harmonic distortion. For these reasons, MMC are considered the converter technology of choice for offshore wind connections. The technology comes in several versions. Each version could be utilized in the New England context, and each comes with cost and functionality trade-offs described below.

- Full-bridge (FB-MMC) **–** A key distinguishing factor among MMC technologies is the type and number of power semi-conductors they use (to control factors including turn-on/turn-off capability). FB-MMCs use four Insulated Gate Bipolar Transistors (IGBT) per submodule, enabling operation at low or reversed DC voltages, and the ability to block DC short-circuit currents and HVDC fault clearing. FB-MMC are thus able to support full functionality of a networked HVDC ocean grid and conform with requirements of the onshore grid that limit tolerable loss of generation in the case of faults (elaborated below). This functionality comes at increased cost associated with the relatively large number of IGBT involved. FB-MMC provide benefits in multi-terminal HVDC grids, particularly in grids utilizing overhead lines subject to faults such as lightning strikes. Full-bridge converters can also operate at reversed polarity, which enables integration with older pre-MMC converters. FB-MCC systems have been deployed in China and are in construction in Europe. [16]

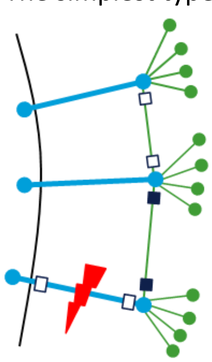
[16] Several VSC based multi-terminal HVDC projects have been successfully put into operation in China, demonstrating the technical viability. In Europe, which has a more comparable transmission development approach to the United States, several multi-terminal HVDC grid projects are ongoing. The German ULTRAnet three-terminal 380 kV bipole full-bridge VSC based 2 GW system will be operational from 2023 onwards and will transport offshore wind energy from the north of Germany to the south. In Scotland, the three-terminal radial Caithness-Moray-Shetland system is nearing completion. Between Greece and Crete, both the EuroAsia and Ariadne links are being prepared as multi-terminal ready links. In the Netherlands and Germany, the 2 GW 525 kV design standard is being developed to be multi-terminal ready, enabling future extensions to form multi-purpose multi-terminal systems such as the WindConnector between the Netherlands and the UK, and the Nautilus link between Belgium and the UK. *See,* CIGRE, *German HVDC Corridors as Starting Points for a Pan-European HVDC Overlay Grid*, at 5 (2022).

- Half-bridge (HB-MMC) – These converters use only two IGBT per submodule, which results in lowest cost, highest efficiency, and high reliability. This comes at the cost of reduced functionality. HB-MMCs are not capable of operating at reduced DC voltage or blocking DC short-circuit currents. For radial offshore wind connections this is no concern, so HB-MMC is the technology of choice. When HB-MMCs are connected in a multi-terminal configuration in which the combined generation capacity exceeds the frequency reserves limits of the onshore grid, direct current circuit breakers (DCCBs) will be necessary to selectively clear DC grid faults and ensure the resulting loss of infeed is compliant with the onshore grid limits. HB-MMC would thus need to be supplemented with DCCBs to enable full networked ocean grid functionality and conform with tolerable loss of generation in the case of faults. HB-MMC are being utilized by two projects connecting from the MA/RI lease areas to New York.[17]
- Hybrid MMCs – Hybrid MMCs use a mix of HB and FB submodules to achieve some of the additional functionality such as reduced voltage operation, or fault blocking, without the full cost of a 100 percent FB converter.

Direct Current Circuit Breakers: DCCBs are currently in use in Chinese HVDC projects and continue to progress in development for use in Europe. A European research and development project has established DCCB testing standards for three different full-scale technologies, and DCCB are included as part of an "energy hub" project now under development in Denmark.[18]

Offshore Platform Interlinks: Compatible and expandable offshore platforms (OSPs) can be interlinked in an ocean grid system to achieve three different types of functionality and benefits for offshore wind production and delivery: auxiliary power, redundant transmission capacity, and backbone functionality.

The simplest type of interlink is used to supply an OSP with auxiliary power from an adjacent OSP when the OSP's own export link to shore experiences an outage. As depicted in the diagram at left, three OSPs are connected by interlinks that enable them to serve one another based on lines constructed at sea between the platforms. This type of interlink allows the operator to supply auxiliary power to the affected OSP (or the larger wind farm) without running a diesel generator during the export link outage.

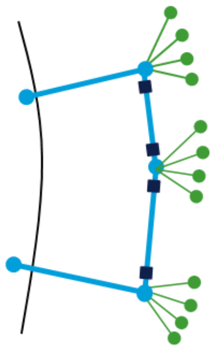


A higher capacity interlink can provide redundant transmission capacity for a wind farm if the export link serving the wind farm experiences an outage. The amount of redundant transmission capacity depends on the adjacent export link and the interlink sizing. Typically, these types of interlinks are rated for several hundred megawatts. Redundant transmission capacity can be realized using either several HVAC cables or a single HVDC interlink cable circuit. The interlink is normally not in service (switches on either end of the interlink are "normally open"). The interlink is only placed in service if one of the OSPs export cables is out of service.

Interlinks can also be used to connect multiple OSPs to form a transmission backbone. As depicted in the diagram below, three wind farms are connected together by interlinks in a manner that enables power transmission over only two export links to the shore. Interlinks can also be used to transmit

[17] The Sunrise Wind and Beacon Wind projects connecting wind farms in the MA/RI lease areas to New York are utilizing HB-MMC transmission.
[18] The North Sea Wind Power Hub includes a feasibility study for the realization of a pilot HVDC circuit breaker on the Bornholm Island in the Baltic Sea which is now under development as one of the two Danish energy hubs. *See* NSWPH Validation Technical Requirements | North Sea Wind Power Hub

power from one POI to another POI by using the interconnected offshore transmission network as a parallel backbone path to the onshore transmission network, thereby relieving onshore congestion. The amount of backbone capacity depends on sizing of the export links and interlink. Typically, these types of interlinks are rated from several hundred megawatts to one or two gigawatts.



Backbone transmission capacity can be realized using either several HVAC cables or a single HVDC interlink cable circuit. The interlink is normally in service (switches on either end of the interlink are "normally closed"). If one of the export links experiences an outage, the remaining healthy link(s) can still be used to provide redundant transmission capacity and redundant supply of auxiliary power. If the capacity of offshore wind generation connected to the backbone grid exceeds the maximum loss of infeed of the onshore transmission grid, then a protection strategy which limits the maximum loss of infeed to acceptable levels must be installed.

For HVAC interlinks, protection can be achieved by following conventional transmission development approach of placing AC circuit breakers at each cable's end. In case of HVDC interlinks, HVDC system protection must be applied by installing equipment which is capable of interrupting DC fault currents (DCCBs or full-bridge converters) and disconnecting the smallest possible part of the DC grid which contains a fault to limit both the immediate and long-term impact of DC grid faults on the onshore AC grid.

Notably, HVDC interlinks could be created between different BOEM lease regions and adding such interlinks could facilitate new interregional transmission capacity. Since the distances between BOEM lease sections are longer than 60 miles, such lengthy interlinks would need to rely on HVDC cables.

The key technologies discussed above that facilitate HVDC system development are at or above the demonstration phase, and several – including MMC-VSC HVDC converters and 400 kV and 525 kV cables – are included in projects coming online in 2023. Moreover, international adoption can speed the technical readiness and commercial availability of selected technologies. For example, European utility TenneT is currently procuring multiple 2,000 MW HVDC circuits. According to TenneT's July 2022 press release, TenneT has developed a new 2,000 MW, 525 kV standard that it will use for at least 6 standardized offshore wind connections to support the German and Dutch governments with an additional of 20 GW of offshore wind by 2030 (on top of their existing targets).[19]

Standardization

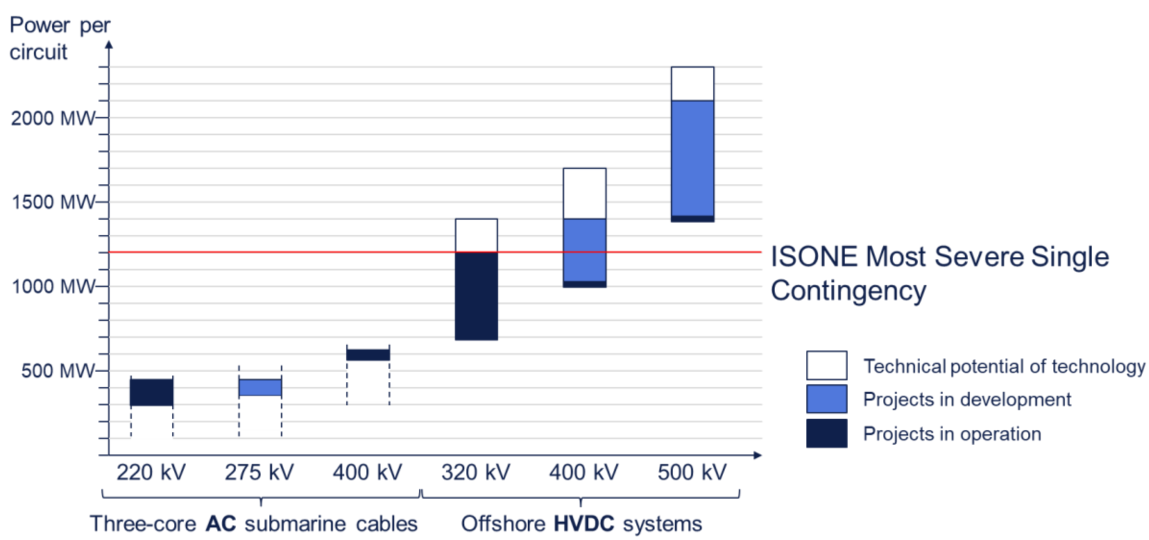
Establishing a preferred standard for HVDC transmission lines will facilitate interoperability and scalability by building on technologies that are already moving toward full acceptance in other markets. This will create a "least-regrets" approach for a modular buildout of transmission for offshore wind, which must scale to reach decarbonization goals. Taking a least-regrets approach entails planning for future expandability and making needed anticipatory investments that will enable expansion. Due to the challenging construction environment offshore, it is far cheaper to make anticipatory investments during fabrication and onshore assembly of offshore transmission infrastructure than retrofitting offshore where weather conditions, logistics, and construction risks increase costs significantly. Taking a

[19] See: https://www.tennet.eu/news/tennet-has-opened-2gw-program-tender-525-kv-dc-offshore-cable-manufacturing-and-installation

least regrets approach to implementing the Modular Plan would consist of utilizing standardized high capacity (i.e., 525kV) cables from the outset, and designing offshore platforms with the ability to accommodate advanced HVDC control technologies that will enable greater sea-to-shore transmission capacity and interconnection of offshore platforms as the ocean grid is built out and expanded over the coming decades.

Establishing a preferred standard for high-capacity HVDC transmission will maintain consistency with current transmission system operations while enabling future expansion to realize economies of scale. HVDC transmission using VSC MMC converters and cables with capacities of 400kV and 525kV is being deployed in Europe and can transmit 2,000 MW or more of capacity. As depicted below, HVDC systems can drive much more power per circuit than systems relying on AC cables.

Figure 2: Power Capabilities by Technology and Voltage



Standardizing use of high-capacity cables will enable optimal utilization of limited cable routes and accessible points of interconnection, and will minimize overall marine cabling requirements (additional information on environmental benefits of HVDC transmission is provided in response to question 12, below).

As noted in the chart, operating parameters on the ISO-NE grid and neighboring grids limit the ability to utilize higher capacity transmission lines at present. However, integration of offshore wind through a networked HVDC ocean grid and application of established operational practices for existing projects over 1,200 MW of capacity could facilitate the use of 1,200+ MW HVDC transmission going forward. ISO-NE's Planning Procedure No. 5 (PP-5) currently limits new resources to a maximum 1,200 MW injection on the bulk power grid. This standard was established to minimize the impact of losing a large new power source, and includes special operating parameters for larger injections that exceed the 1,200 MW limit in PP-5.[20]

[20] The facilities that exceed the 1,200 MW limit in PP-5 are the 450kV Phase II line supplying up to 2,000 MW of hydroelectricity from Quebec to New England, the single 1,244 MW reactor at the Seabrook Nuclear Power Plant, and the 1,237 MW Millstone Unit 3. These facilities are allowed to operate up to their maximum rated capacities except for periods when loss of the

Utilizing networked HVDC transmission with advanced HVDC controls would reduce the likelihood of losing the full generation capacity associated with a single transmission link to shore. HVDC circuit breakers and full bridge converter technology described above can reroute power instantaneously in the event of a fault, enabling offshore wind power to be redirected to other networked HVDC transmission lines in the event of cable failure. When a cable to shore is lost, the HVDC network is reconfigured instantaneously to redirect power in a matter of milliseconds, sending power to shore at other injection points and minimizing loss of power that had been carried by the failed cable. Due to the variable nature of offshore wind generation, most of the time the remaining networked cables would be capable of picking up the majority of the offshore wind previously carried by the failed cable. For example, in windy conditions with a 75% capacity factor for offshore wind, three 2,000 MW networked HVDC transmission systems would each be injecting 1,500 MW onto the grid. If one of the systems is lost, the 1,500 MW carried by the failed system would be re-routed instantaneously to utilize 1,000 MW of available capacity on the remaining two systems, which would then each deliver 2,000 MW to the grid. The loss of one HVDC system carrying 1,500 MW would thus result in an instantaneous loss of only 500 MWs to the grid – well under 1,200 MW even in this higher capacity factor example. As more modular HVDC systems are deployed and networked offshore, the ability of the ocean grid to accommodate a failure will be increased. During the limited hours when all wind farms served by the ocean grid are operating at 100% output, single injections could be dispatched down to single source loss limits, as is currently done for single sources with greater than 1,200 MW of capacity. Energy storage systems could also be utilized to support large offshore wind injections.[21]

Thus, HVDC systems with capacities in excess of 1,200 MW could be utilized in conjunction with networked HVDC interlinks and converter stations with FB-MMC capabilities or HB-MMC converter stations and DCCBs. Until PP-5 is updated to implement this approach and offshore HVDC interlinks are built, higher capacity cables to shore could be limited to carrying 1,200 MW. Once PP-5 is updated and offshore HVDC interlinks are installed, the additional capacity of higher voltage HVDC cables to shore could be utilized. Market development of switchgear technology is currently focused on 525kV HVDC cables, and thus setting a standard for 1,200 MW/525kV HVDC transmission systems would enable New England to create a no-regrets, future-proof foundation for development of a networked ocean grid while remaining within current operational parameters.

With a basis in the overall 1,200MW/525kV standard, procurements should include common parameters such as:

- Common rated voltage and basic insulation level
- System grounding philosophy
- Protection philosophy
- Defined grid functional behavior to enable multi-terminal and multi-vendor readiness
- Requirements for offshore wind platform expandability and associated spare switchgear bay(s) and J-tube(s) on the platform

---

resource's full capacity would threaten transmission system stability. During such periods the resources are limited to injecting 1,200 MW into the transmission system. A similar approach could be applied to offshore wind injections above 1,200 MW.

[21] Energy storage systems located onshore could also be used to facilitate large offshore wind injections. Energy storage systems co-located with offshore wind injections could be used during periods of high offshore wind production to store offshore wind power that exceeds injection limits. During periods of lower offshore wind production, stored offshore wind energy could be released to the grid.

Including standard design elements will enable modular export transmission links to be networked together offshore, improving performance, availability, and benefits to the onshore grid. Setting standards would also establish clear expectations for developers to make investments geared toward future growth of the offshore transmission system. This standardization is the first step toward a fully modular network, enabling "plug and play" additions to the ocean grid over time. Additional information related to interoperability and future development of interlinks between offshore converters is provided in response to Question 13, below.

4. **Comment on whether certain projects should be prioritized and why. For example, should a HVDC offshore project that eliminates the need for major land- based upgrades be prioritized over another HVDC offshore project that does not eliminate such upgrades**

In recognition of challenges related to building onshore transmission in New England, projects that minimize onshore upgrades and thus lower ratepayer costs should be prioritized. Analysis by the Brattle Group found that a planned approach centered on routing around onshore grid constraints and delivering power to load centers could avoid over $1.1 billion in onshore grid upgrades and significantly reduce the risk associated with major onshore transmission projects.[22] These risks of major onshore upgrades include cost overruns averaging 79% on major onshore transmission projects in New England since 2002, and average project durations of 5 years, with some projects taking up to 9 years to complete.[23] The risk of backing into major onshore upgrades is evident in ISO-NE's Second Cape Cod Resource Integration Study,[24] which would establish new 345kV transmission in a new right-of-way from Cape Cod to the Boston area as the default solution – a project that could cost up to $1.4 billion.[25] While some onshore upgrades will undoubtedly be needed – and may be beneficial to support the Modular Plan – HVDC projects routing around onshore grid congestion should be prioritized in order to minimize risk of permitting delays and cost overruns.

5. **Identify any regional or interregional benefits or challenges presented by the possibility of using HVDC lines to assist in transmission system restoration following a load shedding or other emergency event and particularly from using the black start capabilities of HVDC lines in the event of a blackout.**

HVDC transmission systems can provide regional and interregional benefits in assisting system restoration following load shedding or other emergency events. HVDC systems connecting offshore wind can be configured to provide ancillary and emergency response services, including black start. In a

[22] Brattle Group's 2020 *Offshore Transmission in New England: The Benefits of a Better-Planned Grid* builds on ISO-NE's Economic Studies to calculate costs and evaluate risks associated with two scenarios: 1) the current offshore transmission approach of connecting generator lead lines to nearshore locations, and 2) a planned approach utilizing HVDC to route offshore wind to load centers and robust grid connections. For the next 3,600MW of capacity the planned approach costs 10% less overall, avoided $1.1 billion in onshore grid upgrades, and significantly reduced risk of cost overruns and delays experienced by recent onshore transmission projects in New England. Study available at: https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf.

[23] New Hampshire Transmission, Greater Boston Cost Comparison NHT Analysis using New England Comparables, https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf

[24] See: https://www.iso-ne.com/static-assets/documents/2021/05/a4_initiation_of_second_cape_cod_resource_integration_study_presentation.pdf

[25] CHA Consultants found that new 345kV transmission from West Barnstable to K Street in Boston would cost $1.4 billion. See slide 82 at: https://newengland.anbaric.com/wp-content/uploads/2020/07/Brattle_Group_Offshore_Tranmission_in_New-England_5.13.20-FULL-REPORT.pdf

blackout or other emergency an offshore HVDC network provides capabilities that would not otherwise be available to onshore grid operators. While HVDC lines are not generation sources, they can provide infeed to a grid in blackout that provides services similar to a black start generator and can offer such services in a controllable manner that is important to a black start recovery.

Black start restoration is an essential part of electric system security. When a system experiences a blackout, the re-start process involves a complex and gradual re-establishment of the networked components necessary to serve loads within the region. Black start restoration starts with a power source that can self-start without grid support, then builds to the addition of loads that, in turn, enables re-energizing transformers and transmission lines that ultimately re-synchronize the region experiencing the blackout. The power sources at the front end of the restoration process are critical to successful recovery of the system.

While black start generating units have traditionally been power generators (who commit to maintain necessary fuel and capabilities to start up without external electrical power), HVDC systems for offshore wind could serve a similar purpose. HVDC converters can be configured to have back-up power available at the onshore converter in order to feed the offshore wind into the system to power the restoration. The HVDC link can behave much like a generator: it can be controlled to deliver the appropriate amount of power to the AC system needed to support the early steps in "island" creation that initiates a successful restoration. In the delicate circumstances that may exist as a system is in the process of being restored, controllability is critical – too much power can overwhelm the load/generation balance being meticulously created. HVDC operators can work with onshore grid operators to provide inputs to island creation that suit what is needed at different points in the process.

HVDC links that are connected to other regions' systems enable support for the connected region's emergency or black start conditions. On an interregional basis, interconnected HVDC links can provide the interregional imports like those that ISO/RTO regions rely on to address emergency shortages in their areas. For example, the FERC/NERC report on the 2021 Winter Storm noted that MISO and SPP received over 13,000 MW of support from the rest of the Eastern Interconnection system during the parts of the storm when critical amounts of generation was on outage.[26] When storms or other emergency conditions are affecting a large portion of the onshore grid, offshore wind farms may not be affected in the same way, and could be capable of offering power not available from onshore resources due to storms or other emergency conditions.

HVDC connections also can serve as "firewalls" between offshore wind farms and the onshore AC grid, to ensure that offshore wind turbine generators (WTGs) are relatively unaffected by onshore grid disturbances. In AC systems, any disturbance in the onshore grid can propagate through to the offshore wind farms and impede the operation of the WTGs. Moreover, if power delivery to certain load centers in the ISO-NE region is constrained due to emergency conditions, offshore HVDC systems could be available to provide an alternative route to move the power around the troubled sections of the grid.

If the States and ISO-NE seek to utilize the HVDC system as a black start resource, certain technical and regulatory considerations would need to be addressed:[27]

---

[26] FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States*, November 2021, at 146.

[27] For more in-depth consideration of these factors and the use of HVDC for black start services generally, *see*, The National HVDC Centre, *Maximizing HVDC Support for [Great Britain] Black Start and System Restoration* (April 12, 2019).

- Review and updating, as necessary, black start procurement and testing practices to incorporate HVDC lines as black start resources.
- Develop the control capability of the offshore wind farms and the HVDC links to energize the associated AC transmission, undertake block loading, and provide stable power island operation during restoration. The wind farm and its associated HVDC converters controls need to be developed to operate in a weak grid. For example, conventional wind farms are normally synchronized to a strong onshore grid with rotating inertia. To enable offshore wind farm black start services, the offshore wind farm converters need to be controlled to emulate traditional synchronous machines and operate in grid-forming mode instead of grid-following mode.
- Develop a clear understanding of the strength of the AC system at the landing point where the HVDC line interconnects with the AC system. The strength of the AC system at the point it receives power from a black start resource (whether provided by conventional generators or HVDC lines) strongly influences the likelihood of success of rebuilding the system from a particular point in the electrical system.
- Incorporate potential black start restoration scenarios into the planning and modelling tools that assess offshore wind availability and variability. Understanding the capability of the wind resource to support the steady power needed to support black start restoration in various conditions is an important element in setting expectations of what the HVDC lines could offer during emergency conditions.
- Determine the availability and size of auxiliary local generators (e.g., energy storage, diesel generators, or uninterruptible power supply) for self-start and emergency braking of the wind turbines. Additional auxiliary supplies may be required to energize the wind farm inter-array cables and offshore and onshore HVDC converters.

An HVDC system can provide emergency response benefits that would not be available from an AC-based system, though utilization of HVDC transmission for black start and other emergency support requires careful evaluation and coordination.

6. Identify the benefits and/or challenges presented by using land based HVDC lines or other infrastructure to increase the integration of renewable energy (other than offshore wind) in New England to balance injections of offshore wind.

Land based HVDC lines are well suited to integrate onshore wind, solar and other forms of renewable energy by routing to load centers or avoiding local grid congestion. Onshore wind in Northern Maine has long been limited by constraints on the Maine transmission system, and HVDC transmission from Northern Maine to Southern New England could bypass constraints on the AC grid and deliver power directly to load centers.

Similar benefits could be provided by a networked HVDC ocean grid. A networked HVDC ocean grid could alleviate overloads on the terrestrial grid and increase integration of renewable energy other than offshore wind. When a networked HVDC ocean grid is connecting to locations subject to onshore transmission constraints – such as Northern Maine – the offshore grid could provide an alternate route for new or existing renewable energy resources to reach load during the frequent periods when offshore wind is generating at less than 100% capacity. Such a case is particularly salient for solar and onshore wind in Northern Maine, which have high summer capacity factors. The capacity factor for offshore wind is projected to be lowest during summer months, and as such onshore wind and solar could utilize available capacity on the networked HVDC ocean grid to route around onshore transmission constraints and reach load centers in Southern New England.

ISO-NE's 2050 Transmission Study identified overloads in each of the studied years for North-South transfers during Summer Peak Load conditions. If 2,000MW of transmission for floating offshore wind is connecting to Maine, 2,000MW of transmission for floating offshore wind is connecting to Massachusetts, and the offshore platforms are connected via 2,000 MW HVDC transmission then there would be a 2,000MW inter-zone path from Maine to Massachusetts. Under the 5% availability of offshore wind during summer peak assumed in ISO-NE's analysis, 200MW of this 2,000MW of transfer inter-zone transfer capacity would be utilized by 200MW of offshore wind (5% of the 4,000MW that the two 2,000MW transmission systems are designed to serve at full offshore wind output). Thus, 1,800MW of remaining transfer capacity would be available from North to South. This 1,800MW of transfer capacity could be utilized to route 1,800MW of renewable energy generation from Maine to Massachusetts, thus alleviating the need for onshore transfer capacity and related upgrades. This transmission path would offer variable availability but would be provided at no additional marginal cost and could offer ratepayer benefit in reducing curtailment of renewable energy.

7. **Comment on the region's ability to use offshore HVDC transmission lines to facilitate interregional transmission in the future.**

Development of a modular HVDC-based system like the Modular Plan can facilitate interregional transmission between the New England States and neighboring regions due to four key strengths of HVDC transmission.

First, HVDC transmission lines are superior to HVAC lines technically and economically for transporting power the distances required to support interregional offshore connections. Offshore wind farms are connected to the onshore transmission grid using submarine cables. As describe in detail response to Question 3, the primary cable transmission technologies are HVAC (with various forms of reactive power compensation) and HVDC. The choice of HVAC or HVDC is predominantly determined by the length of the cable route to the onshore POI. In general, AC solutions are more economic for short transmission distances (less than 60 miles) and low capacities (below 500 MW per circuit). Anbaric estimates that the distances needed to transport power from New England offshore wind leases will, in almost all instances, exceed 100 miles (most notably for cable runs terminating at POIs in the Boston area, Southwest Connecticut, and even Southeast Connecticut). In addition, to meet the states' clean energy goals, larger capacities will be needed to deliver OSW resources to shore. The ability of HVDC to transmit power long distances with minimal losses makes it a superior transmission solution for moving large amounts of OSW, as part of a networked ocean grid spanning multiple regions.

Second, HVDC systems are less subject to disturbances from the onshore grid where they are interconnected. This characteristic increases the likelihood that HVDC-based systems will be available when needed for service across regions. Any disturbances coming from the onshore AC grid can propagate through an offshore AC system and affect the operation of the wind turbine generators. This becomes particularly problematic when the wind farm is connected to a "weak" AC grid. The rate of active power recovery after an AC grid fault is determined by the relatively slow offshore wind farm controller. The slow wind generation output recovery can lead to a period of energy deficit in the overall transmission system following a fault, which in turn can lead to voltage induced frequency instability in weak grids. By contrast, HVDC connections can act like a "firewall" between the offshore wind farms and the onshore AC grid and ensure that the wind turbine generators are relatively unaffected by onshore grid disturbances. DC dynamic breaking resistance supports the quick active power recovery after an onshore AC grid fault, and the offshore wind farm generation is not affected.

Third, HVDC systems have a smaller physical footprint – particularly HVDC cables – than AC-based counterparts. If new connections are required for interregional functionality, whether additional interlinks between offshore service platforms, or incorporation into a gathering system, the more streamlined footprint and lower environmental impact of constructing HVDC offers advantages, particularly if the interconnecting region is constrained in its options for linking the systems.

Finally, where there is uncertainty about the timing or extent of offshore transmission system expansion to serve interregional (or other) needs, HVDC systems offer the flexibility to serve present needs effectively without compromising future requirements for growth. With the appropriate planning and levels of anticipatory investment, HVDC systems can grow to serve new needs more efficiently than comparable AC-based systems.

8. **Comment on any just-transition, environmental justice, equity, and workforce development considerations or opportunities presented by the transmission system buildout and how these policy priorities are centered in decisions to develop future infrastructure.**

All energy and climate policies must account for the burdens of energy infrastructure placed on environmental justice communities. As states take a more deliberate approach to transmission planning, supporting environmental justice and spreading economic opportunity broadly must be core objectives. In practice, transmission placed within any community should be sited and constructed to minimize adverse impacts by placing transmission lines underground and carefully locating onshore transmission infrastructure to minimize community impacts.

Transmission development can also be an important source of direct and indirect economic development and jobs. A report by the New Hampshire Departments of Energy, Environmental Services, and Business and Economic Affairs found that $20 million invested in interconnecting offshore generation to the onshore grid would create $87 million in economic activity and 600 construction jobs.[28] More broadly, planned transmission will provide a clear pathway for offshore wind and related investment to grow in New England. With a clear path to tens of gigawatts of additional offshore wind deployment, supply chain companies will have confidence to locate in New England, utilizing local ports, skilled labor, and creating well-paying union jobs. In the absence of planned transmission, offshore wind projects could stall, and the region could back into unplanned onshore upgrades taking up to a decade to complete, dissuading the supply chain from establishing a presence in New England and losing private sector investment and well-paying, union-based jobs.

[28] Report on Greenhouse Gas Emissions, and Infrastructure and Supply Chain Opportunities as it Relates to the Deployment of Offshore wind in the Gulf of Maine, 2022, available at: https://www.des.nh.gov/sites/g/files/ehbemt341/files/documents/offshore-wind-deployment-report.pdf

9. **Comment on how to develop transmission solutions that maximize the reliability and economic benefits of regional clean energy resources.**

To maximize the benefits from New England's clean energy resources, the states can ensure the necessary flexibility and readiness for optimal technological and economic solutions by following two fundamental principles that have long governed terrestrial transmission planning processes.

- Open Access to Offshore Transmission – The "open access" principle has guided U.S. transmission policy for over twenty years. Open access separates transmission resources from connected generators. It gives all generators access to an efficient transmission system on a non-discriminatory basis and at a non-discriminatory price. In relation to offshore wind, open access will lead to development of infrastructure that, rather than being controlled by individual generator locations, provides the opportunity for an optimal infrastructure – featuring offshore collector stations constructed near or within Wind Energy Areas (WEAs), allowing generators to connect where it is most efficient for the overall system. Establishing an open access framework facilitates modular and networked transmission emerging as the best practice for offshore transmission development.
- Planned Transmission Systems – In transmission policy, open access goes hand-in-hand with transmission planning. Planning avoids one-off transmission lines that may serve a single project effectively but hinder interconnection of subsequent projects. In the offshore wind context, planning will ensure efficient utilization of scare cable routes and POIs accessible from the water. Planning depends on prioritizing interconnection locations and establishing standards for voltage levels and technology choices.

Utilizing open access, planned transmission to integrate offshore wind yields the following benefits:

- Cost savings – Planned, open access transmission can advance the public interest by harnessing the power of competition to secure the best projects at the lowest cost, while, at the same time, sharing transmission costs across multiple offshore wind generation projects. Transmission costs typically range between 15 to 25 percent of an offshore wind project's total capex and can be as high as 30 percent.[29] Based on reports from European offshore development, sharing transmission results in cutting transmission's portion of project costs by up to 40 percent. Additionally, the cost of transmission can be financed separately from generation and paid off over a much longer period — with corresponding lower monthly payments.
- Accelerated permitting, construction and grid connection – Efficient integration of wind energy is critical to achieving New England states' climate goals. Planned transmission systems can be designed, permitted, and built in advance of wind farms and are scalable as multiple WEAs are developed and ready for commercial operation. Transmission developers familiar with the interconnection process, engineering challenges, large-scale project management, permitting processes and public engagement requirements could accelerate the pace of transmission permitting, construction, and ultimately connection of offshore wind power to the grid.
- Reduced footprint and conflict – Requiring each offshore wind generation developer to build its own transmission to the onshore grid for 30,000 MW of offshore wind could yield dozens of

[29] The New York Public Service Commission found that "[t]ransmission is a large cost component of an offshore wind project," which "may comprise 30% of total costs of an offshore wind development." Phase 1 Procurement Order, at 54.

generator lead lines in the ocean. The proliferation of seabed transmission cables is inconsistent with avoiding and mitigating impacts on environmental resources and potential conflicts with other uses, especially commercial fishing.

The impacts of multiple generator lead lines apply onshore as well. Activities involved in laying and connecting dozens of generator lead lines to inland interconnection substations would require digging up roads and rights-of-way in a multitude of communities along the routes. An unplanned approach could require repeated disruptions from onshore construction if multiple projects cross the same communities at different times. This raises significant onshore engineering challenges in limited rights-of-way, increases conflicts, complicates the ability to avoid sensitive shoreline cable landings, and increases likelihood of community opposition to multiple projects.

- Efficient access to limited interconnection points – Planned open access offshore wind transmission optimizes usage of scarce and high-value interconnection points, cable routes, and sea-to-shore transition points. These benefits are especially important in New England, which has limited points of interconnection that can integrate significant quantities of offshore wind without major and expensive upgrades. Additionally, it will be challenging and cost-prohibitive to lay additional cables in an already used route, to expand a substation multiple times, or to permit multiple lines in an environmentally sensitive area.

The Modular Plan is consistent with these principles, and an open access approach to moving an ocean grid forward will best advance optimal use of New England's significant offshore wind resources.

10. Identify potential Points of Interconnection (POIs) in the ISO-NE control area for renewable energy resources, including offshore wind. What are the benefits and weaknesses associated with each identified POI? To the extent your comments rely on any published ISO-NE study, please cite accordingly.

Routing power to POIs in the Boston area and Connecticut will minimize onshore upgrades and consumer costs. Delivering power to the Boston area and Southwest Connecticut load centers will bring renewable energy directly to where it needed most to power a future low carbon grid. Coastal Connecticut and the Massachusetts Bay host robust coastal substations that can accept offshore wind injections at lower cost than connecting to Southeast New England and upgrading the onshore grid.

Locations for interconnections of offshore wind (and other resources) are important drivers of system performance and upgrades. Routing offshore wind to demand centers has the potential to improve system performance and minimize upgrades, as noted in ISO-NE's 2019 Economic Study for NESCOE, which found that "offshore wind could be connected while avoiding significant onshore transmission upgrades by using High Voltage Direct Current (HVDC) connections from the offshore wind farms to load center substations".[30] The 2019 Economic Study used Mystic and K Street substations in the Boston area as examples, and noted that "other load center substations, such as in Southwest Connecticut could be considered."

[30] June 17th, 2020 Presentation to PAC by Al McBride, at slide 5; https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf

ISO-NE's Second Cape Cod Resource Integration Study[31] carried out in 2022 further validates the logic of routing offshore wind directly to load centers. ISO-NE evaluated three potential transmission solutions to enable additional offshore wind interconnection on Cape Cod: overland HVAC from Cape Cod toward Boston; submarine HVDC from Cape Cod to Boston, and HVDC transmission from the offshore wind lease areas to Boston. Overland HVAC from Cape Cod to Boston would require new transmission rights of way, upgrades to a large number of circuits, and overall system dynamic performance would worsen as remote inverter-based generation replaces local synchronous generation. Submarine HVDC from Cape Cod to Boston avoided the need for new overland rights of way and upgrades to onshore circuits but would also contribute to degradation of system dynamic performance. In contrast, HVDC transmission from offshore wind lease areas to Boston "does not exhibit any of the performance issues that were identified for the other alternatives".

It should be noted that HVDC connections to load centers in Southwest Connecticut would be expected to provide similar benefits. Additionally, other robust POIs outside of the Boston area and Southwest Connecticut could be capable of receiving HVDC injections without exhibiting drawbacks of connecting additional offshore wind on Cape Cod.

As New England states move to procure transmission elements under the Modular Plan, preferred POIs or load zone could be identified, yet bidders should be allowed to propose alternate POIs supported by analytical justification.

11. Similarly, comment on whether there are benefits to integrating offshore wind deeper into the region's transmission system rather than simply interconnecting at the nearest landfall (e.g., using rivers to run HVDC lines further into the interior of New England). If there are enough benefits to make this approach feasible, please comment on any obstacles, barriers, or issues that Participating States should be aware of regarding such an approach.

Integrating offshore wind deep into the region's transmission system could provide benefits, but such benefits must be weighed against the cost and complexity of accessing POIs farther from the coast. Owing to the density of communities along the cost and resistance to new overhead transmission, accessing locations farther from the coast would likely require routing underground or in bodies of water. In the last major expansion of the high voltage power system, the cost of underground 345kV transmission averaged $19.5 million per mile, with projects taking 5 to 7 years to complete.[32]

Anbaric has evaluated routing HVDC cables in river segments to avoid construction related impacts on land uses, wetlands, cultural resources, transportation facilities and other water, sewer, and electric utilities. Anbaric has been involved in advancing an HVDC cables route in the Sakonnet River in Rhode Island to support integrating offshore wind as well as the Hudson River in New York to provide transmission capacity between New Jersey and New York.

The Connecticut River provides an opportunity to route offshore wind to Points-of-Interconnection to the interior of New England, though ecological considerations would have to be considered. The

[31] See: https://www.iso-ne.com/static-assets/documents/2022/09/a03_second_cape_cod_resource_integration_study_status_update.pdf

[32] New Hampshire Transmission, Greater Boston Cost Comparison NHT Analysis using New England Comparables, average cost of underground 345kV projects completed from 2002 to 2013, and project duration of underground 345kV projects ranged from 5 years for Stoughton Cables, and 6.9 years for Middletown to Norwalk project. Report available at: https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf

bathymetry in the Connecticut River consists of a continuous navigable channel up to the Middletown Kleen Energy System Power Plant. Obstructions such as bridges and other infrastructure are limited. Between the mouth of the river and Middletown, CT, there are three bridges: Amtrack-Bascule Bridge; the I-95/US 1 Hwy Bridge; and the East Haddam Swing Bridge. There are six submarine cables within proximity of the listed bridges that run perpendicular to the Connecticut River.

The Connecticut River supports one of the highest fish diversities in New England, with 78 species including two finfish that are listed as Endangered at the federal level: Atlantic sturgeon and shortnose Sturgeon, and five species of finfish are listed as Endangered at the state level.[33] Routing the cable to avoid gravel and course sediment shoals and banks (habitats that serve as vital spawning and feeding habitats) and time-of-year restrictions during construction would minimize impacts on habitats. Most of these habitats could be avoided through careful routing and micro-siting of the cable system to avoid, as much as feasible, the sensitive habitats utilized by the listed Federal and State Endangered Species.

12. **Identify likely offshore corridor options for transmission lines. Please comment on the potential for such corridor options, include size of the corridor footprint and potential number of cables that can be accommodated, to minimize the number of lines and associated siting and environmental disturbance needed to integrate offshore wind resource. For any offshore corridor identified, please indicate how the corridor avoids or minimizes disturbances to marine resources identified in the applicable plan, including the Connecticut Blue Plan and the Massachusetts Ocean Management Plan.**

In November of 2019 Anbaric submitted an application to the Bureau of Ocean Energy Management for a Right-of-Way Grant application for the Southern New England OceanGrid Project. [34] This application identifies offshore corridor options for transmission lines. Each of the aliquots (squares) identified in Figure 3 below measures three miles by three miles, and as such can accommodate multiple transmission lines from multiple developers.

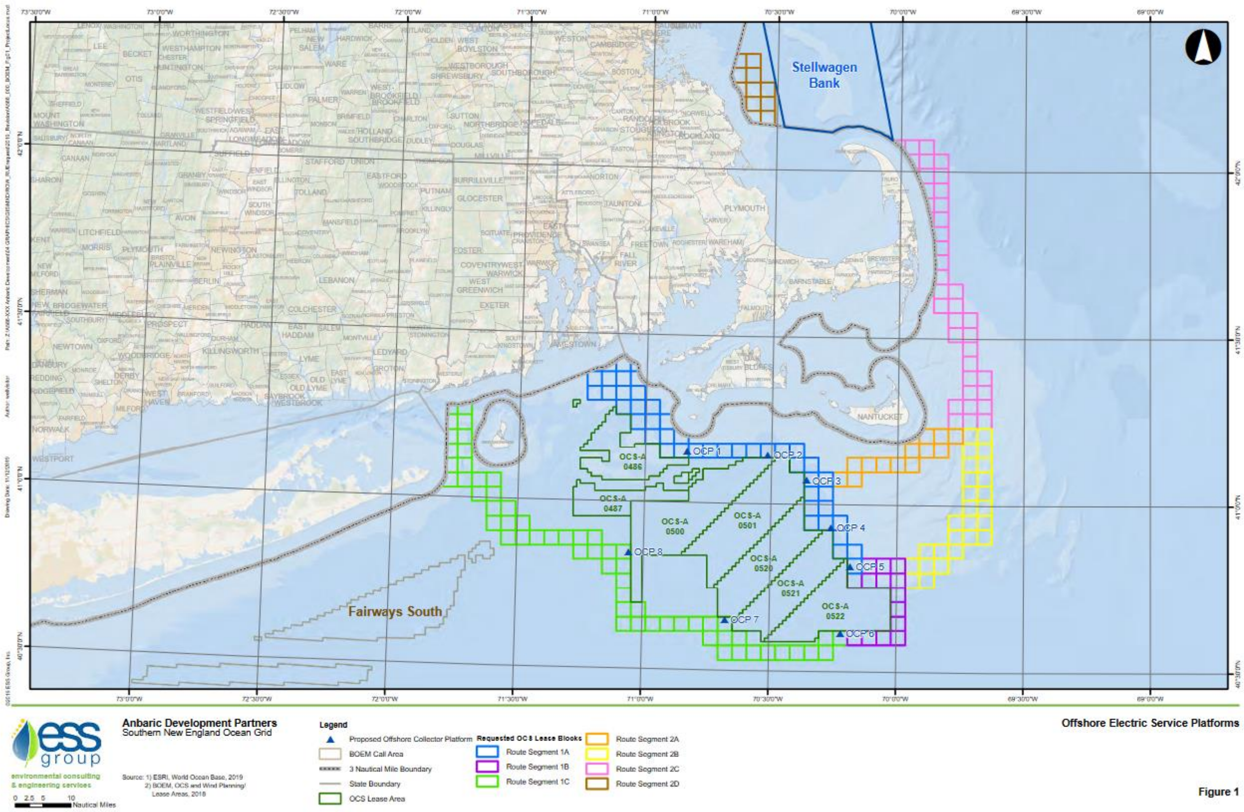
Anbaric has additionally identified cable routes in state waters corresponding with the transmission corridors in federal waters starting 3 miles from shore. The routing assessments are being advanced to identify specific offshore cable alignments that reduced impacts to marine resources and minimize use conflicts. The selected offshore corridor will avoid and/or minimize disturbances to protected ocean resources and uses identified in the 2021 Massachusetts Ocean Management Plan (dated January 3, 2022) as well as Ecologically Significant Areas and Significant Human Use Areas as identified in the inventory provided in the Long Island Sound Blue Plan (approved May 14, 2021).

---

[33] See: https://nativefishcoalition.org/connecticut

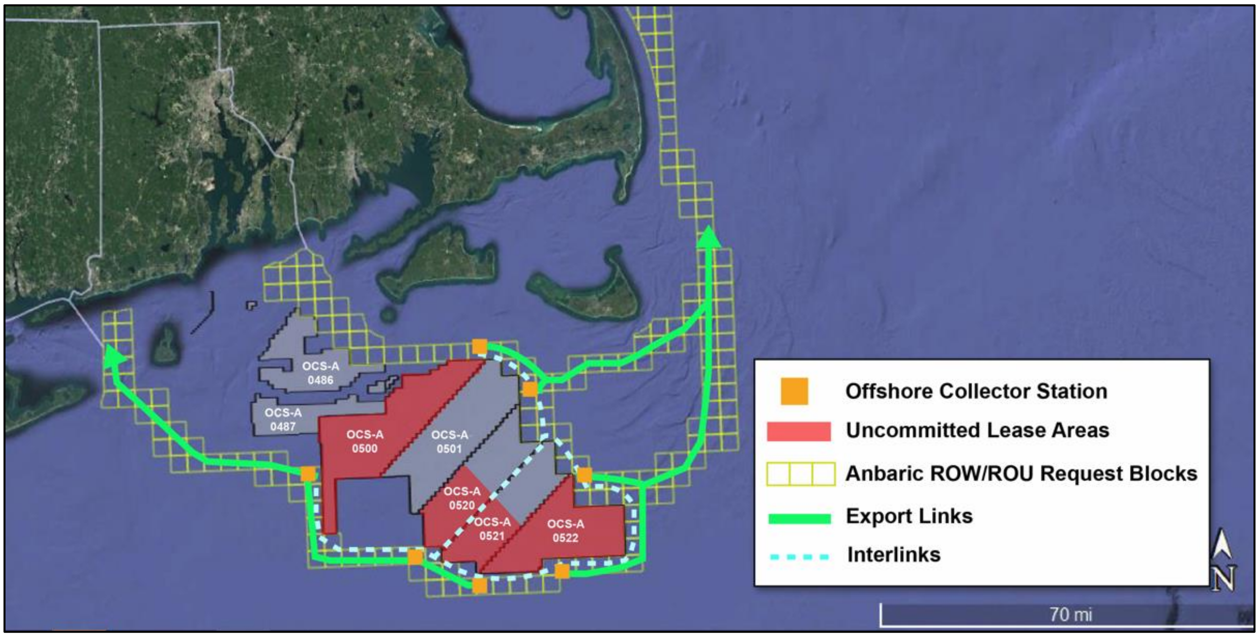
[34] Anbaric has submitted two applications for Right-of-Way/Right-of-Use and Easement ("ROW/RUE") Grants under 30 C.F.R. § 585.300. Anbaric's proposed New York/New Jersey OceanGrid project was submitted in April 2018 and Anbaric's proposed Southern New England OceanGrid project was submitted in November of 2019. Both proposals are under review by BOEM, and are available at: https://www.boem.gov/renewable-energy/state-activities/regional-proposals

Figure 3: Anbaric Southern New England Right-of-Way/Right-of-Use and Easement Grant Application



When considering the potential configuration of transmission lines in a modular ocean grid, the locations and layout of the uncommitted lease areas and proximity/accessibility to available POIs must be considered. As shown in the image below, the remaining lease areas are OCS-A 0500 to the northwest, OCS-A 0522 to the southeast and the southwest portions of OCS-A 0520 and OCS-A 0521.

Figure 4: Illustrative Modular Ocean Grid



The location of these available lease areas and routes to Boston and Connecticut suggest that Export Links could run:

1) Along the South and West of the lease areas to Connecticut
2) From the North and East of the lease areas to the Boston area

(Note that in the Figure 4 the lines for Export Links and Interlinks are illustrative, and represent the routes for multiple, parallel export links located in proximity to minimize environmental impacts.)

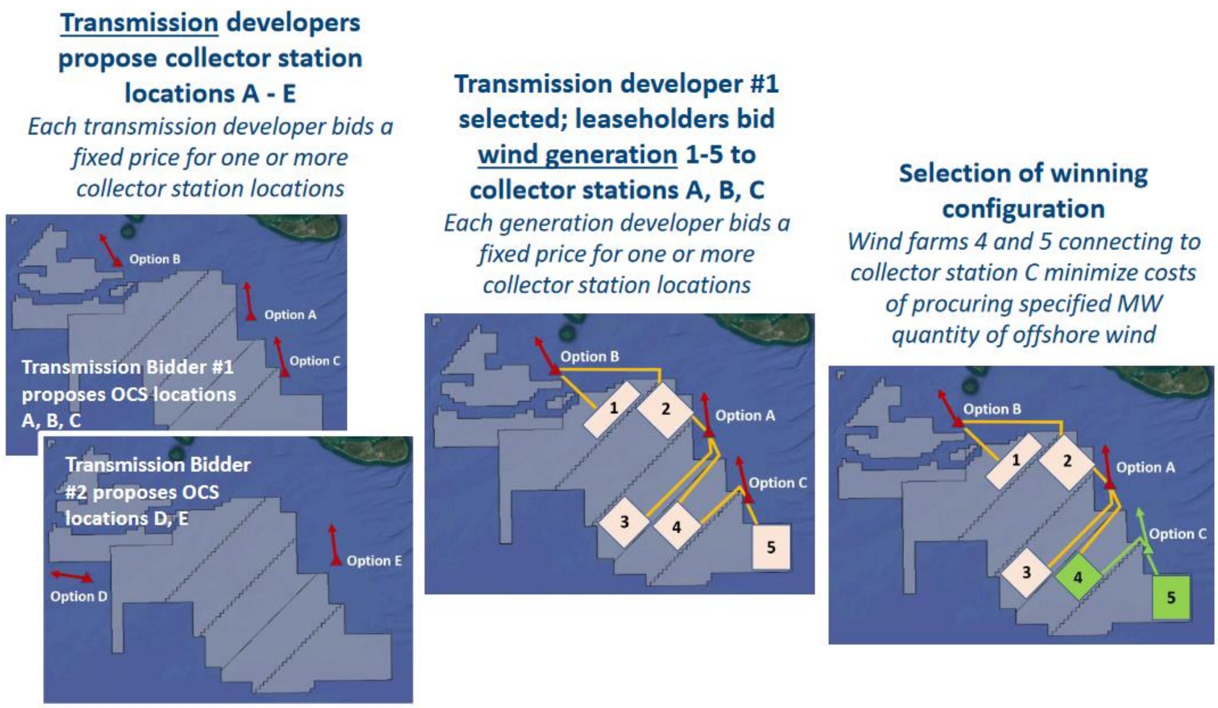
Interlinks between transmission to Boston and transmission to Connecticut could be routed around or along the boundary of lease areas.[35]

Wind farm developers would either run inter-array cables directly to Offshore Collector Stations or build their own project-specific collector stations and run export cables to Offshore Collector Stations on the Ocean Grid. Optimal locations for collector stations would be determined to minimize distances to remaining lease area and enable direct connection of inter-array cables, thus providing the ability to avoid the cost of project-specific collector stations for individual wind farms.

[35] Locating interlinks on the boundaries of lease areas could reduce marine cabling requirements significantly while avoiding interference with activities within the lease area. This approach could produce significant cost savings and minimize impacts on the seabed and marine environment. Section 2(a) of BOEM's standard offshore wind lease grants the lessee the exclusive right to: (1) submit a site assessment plan (SAP) and construction and operations plan (COP) and (2) conduct activities identified in Addenda A and D to the lease. Additionally, Section 3(d) of BOEM's standard lease, states that BOEM "reserves the right to authorize other uses within the leased area and project easements(s) that will not unreasonably interfere with activities described in an approved SAP and/or COP, pursuant to this lease." (30 CFR Part 585).

In an RFP to implement the Modular Plan, transmission bidders could propose to locate Offshore Collector Stations at a number of optimal locations, subject to subsequent matching with offshore wind farms. An illustrative transmission and generation procurement process is depicted in Figure 5 below.[36]

Figure 5: Offshore Wind Transmission and Generation Bidding Process



[36] Brattle Group, 2020, Offshore Wind Transmission in New England: The Benefits of a Better Planned Grid, available at: https://www.brattle.com/wp-content/uploads/2021/05/18939_offshore_transmission_in_new_england_-the_benefits_of_a_better-planned_grid_brattle.pdf

13. Identify strategies to optimize for future interconnection between offshore converters, either AC or DC, to permit power flow between converters to facilitate the transmission of power from offshore to multiple POIs as needed. Similarly, comment on the ability of offshore converters from competing manufacturers to communicate with one another in this future case.

An effective strategy leading to the optimized interconnection between offshore converters and multiple POIs should be guided by several interrelated principles. These principles are rooted in industry experience and intended to enable near-term deployment of no-regrets transmission to achieve near-term targets and long-term goals.

- Procurement processes should encourage standardization of HVDC converter packages. In today's market, there is insufficient interoperability among converter manufacturers' equipment. Work on communications protocols and other standards is underway but will not be complete for a first procurement in 2023 that would meet New England's deployment needs and best position New England to access newly available federal funding. Establishment of a standard type of converter technology in the first procurement would foster the development of scalable, interoperable HVDC transmission in line with the Modular Plan.

- To ensure interoperability of HVDC converter systems, procurement of transmission links (based on a standard such as the 1,200MW/525kV proposed in the RFI) should proceed on a separate and parallel track with procurement of converter stations from a single vendor. Separate procurement of converter stations will ensure interoperability until the industry has defined standards that allow converter stations from different manufacturers to function seamlessly as part of a unified transmission system.

- Expandability should be built into parameters for procurement of offshore platforms associated with transmission links. Offshore platforms can be built to meet only current needs or equipped to accommodate future interlinks to other offshore platforms or additional export links to shore. The future expandability of an offshore substation depends on the degree to which provisions necessary to enable a future expansion (e.g., equipment, system and structure ratings, dimensions, SCADA integration) are addressed. In most cases, anticipatory investment that makes the platform ready for growth during original construction is less expensive than offshore retrofitting. If growth is part of the plan, so should the early investment that will ultimately make growth most economical.

- Optimization of offshore wind networks will ultimately require grid code and equipment standards that have not yet been established. As the initial parts of the system are designed and built, it is imperative that all stakeholders encourage and participate in standards-setting efforts at NERC, NPCC, and state-level agencies responsible for reliable grid operations. As the industry learned from the deployment of large amounts of terrestrial inverter-based resources, new technologies can be added to the system and adjustments made, but long-term reliable operations and maximum integration of new resources require well-understood standards applicable to all market participants. Those standards will also encourage the interoperability of technology and equipment that will facilitate continuing development of the scalable, interoperable system envisioned by the Modular Plan.

- An overall framework for the first round of HVDC transmission deployment should create specific opportunities for application of federal GRIP or TFP support. A procurement plan that sets standards, demonstrates an innovative approach, and puts offshore deployment on a scheduled path forward could provide the basis for the "Concept Paper" requested by DOE to support applications for federal funding or public-private partnerships as described in response to Question 1.

In alignment with these principles, Anbaric recommends the following framework in developing the first round of HVDC system procurements to implement the Modular Plan.

- States procure bids for up to seven HVDC Export Links meeting the 1,200MW/525kV standard suggested in the RFI. States would stipulate other high-level power system parameters (e.g., system grounding and protection strategies, or defined grid functional behavior to enable multi-terminal or multi-vendor readiness). Anbaric suggests that ISO-NE assist in the procurement as appropriate, including the determination of whether additional standard features should be included in the procurement.

  The procurement for Export Links would exclude onshore and offshore HVDC converter station equipment, which would be procured in parallel. Project costs for the Export Links would be bid competitively, and cost-containment mechanisms would be requested to insulate ratepayers from risk. These cost containment mechanisms could include ROE limits, cost caps, fixed pricing, or other cost containment mechanisms described in response to Question 2.

- In parallel, States run a procurement for one to seven onshore and offshore HVDC converter station packages to be integrated with the selected Export Links and owned and operated by the winning Export Link bidders. States would determine whether certain technological parameters would be required of the HVDC converter bidders (e.g., half-bridge or full-bridge modular multi-level functionality). Anbaric suggests that ISO-NE also assist in the development of the solicitation and evaluation of the HVDC converter station procurement.

  Anbaric recommends that project costs for the converter stations be included as a cost-of-service item recovered as part of the overall cost of the Export Link plus converter stations project. Bidding would be competitive, and a single vendor would be selected for all onshore and offshore converter stations to ensure interoperability.

- States select the winning bids for both Export Links and converter stations, and the costs of the converter stations would be added to the winning bid(s) for Export Links to determine the overall cost of the initial buildout of the modular offshore transmission network. The winning Export Link developer(s) would work with the converter station vendor on detailed design, as would be the case if a transmission bidder had run its own solicitation for an HVDC converter vendor. The winning Export Link developer(s) would be responsible for installing, owning, and operating the HVDC converter station(s) as part of its Export Link(s).

- States would then solicit bids for generation connecting to the Export Link(s), as described in response to Question 12. If parallel generation procurements are already underway, or if generation projects are conditionally selected under procurements that legally require generation bidders to make use of shared transmission,[37] winning generation bidders would be

---

[37] Rhode Island's RFP for 600 MW to 1,000 MW of offshore wind generation issued October 14th, 2022 includes a Commitment Agreement which requires bidders to "negotiate in good faith and use commercially reasonable efforts to execute a transmission service agreement pursuant to the Open Access Transmission Tariff for a Regionalized Offshore Transmission Network." See: https://ricleanenergyrfp.com/2022-offshore-wind-rfp/2022-offshore-wind-rfp-documents/

required to undertake commercially reasonable efforts to utilize modular offshore transmission systems.

- Procurement of Interlinks to bring the offshore platforms and Export Links into a networked system would be subject to a subsequent solicitation. The initial procurement for offshore platforms should encourage sufficient anticipatory investment to support addition of planned future interlinks.

This stepwise approach has several advantages. First, it reduces risk for all parties related to interoperability of competing HVDC converter vendors. By selecting a single vendor for the first round of converter packages, States ensure the system has the necessary standardization in place to operate effectively through the first large deployment of offshore grid resources. As grid code develops and the offshore wind industry requires more HVDC converters, interoperability will improve. While that work is underway, the proposed approach enables New England to adopt an advanced design that can be utilized now and be ready for advances in standards and technology.

Second, a direct procurement for HVDC converters offers commercial advantages over requiring transmission developers to include HVDC converter packages in their bids. Under the proposed approach, the HVDC converter vendors would be bidding directly in a separate procurement, rather than being part of a transmission developer bid that may or may not succeed. For that reason, the HVDC converter vendors are more likely to provide most favorable pricing, as the separate HVDC converter procurement would be more likely to result in selection of one of the bidding converter vendors. The direct bidding approach is likely to provide the states better pricing, and the selection of a single vendor would enable States to benefit from economies of scale.

Third, the transmission developers' Export Link bids would be de-risked by removing uncertainties regarding converter interoperability. The Export Link procurement would clarify what is required from transmission bidders in a way that encourages most competitive pricing for services that are within transmission bidders' expertise and control.

Fourth, each procurement would be more straightforward to administer than a single procurement seeking to ensure interoperability of converters from multiple bidders and vendors. Each procurement would be focused and would call upon specific types of subject matter expertise. States and ISO-NE would be involved in both procurements, and their analytical tasks in each procurement would be targeted to a technology and equipment type. The simplicity would reduce the time needed to complete the procurements. Certain key standards would be known at the outset (e.g., the 1,200MW/525kV standard), and a round of scoping comments could provide States the information necessary to determine the extent of other standards needed to make the procurement meaningful and consistent with objectives of the Modular Plan.

14. Comment on the benefits and/or weaknesses of different ownership structures, such as a consortia of developers with transmission owners or use of U.S. DOE participation as an anchor tenant through its authorizations in the federal Infrastructure and Investment Jobs Act, for new offshore transmission lines.

There are a range of different ownership structures that can be used for the types of transmission facilities that are envisioned by the RFI. The most basic alternatives are ownership by: (1) an independent transmission owner without a commercial interest in offshore wind facilities or onshore transmission assets in ISO-New England; (2) various ISO-New England transmission owners, (i.e., incumbent electric utilities); (3) offshore wind project developers that hold BOEM leases and are seeking transmission access to the onshore grid; or (4) various consortia of offshore wind developers and transmission owners (i.e., both independent and local). Some of the key benefits and weaknesses of these alternative ownership structures are outlined below.

Independent Transmission Developers

Independent transmission owners offer specialized expertise required to develop and construct subsea transmission, contract for HVDC transmission and offshore substations, and related equipment and services. In addition, with an active development portfolio of offshore transmission projects, independent transmission developers offer strong relationships with equipment vendors and other contractors (e.g., EPC firms) that can help secure equipment queue positions and more favorable commercial terms for equipment and services. As discussed above in response to Question 2, independent transmission owners offer extensive experience designing and implementing cost recovery frameworks that mitigate the project cost risks borne by customers and performance risks borne by offshore wind project developers and owners.

Incumbent Transmission Owners/Developers

ISO-New England transmission owners offer the benefit of detailed understanding and knowledge of the onshore transmission network and with respect to the development of on-shore transmission facilities. However, incumbent transmission projects in New England have a record of exceeding proposed project budgets, with cost overruns averaging 79% for recent large onshore projects.[38] Furthermore, with a history of developing transmission on a cost-of-service basis, incumbent transmission owners lack experience with the full range of cost control mechanisms that independent transmission owners have pioneered and contracting structures that allow transmission to be constructed with greater cost controls. Incumbent transmission owners may also privilege on-shore upgrades within their franchise territories that are less subject to competition and thus undervalue the benefit of offshore transmission with state-of-art functionality.

Offshore Wind Developers

An important concern associated with offshore wind developers having a role in the development of offshore transmission facilities is the natural potential for decisions regarding the location of critical facilities to favor the offshore wind developer and to disadvantage its competitors. For example, the location of offshore substations will impact the lengths of the cables to connect to the offshore substation and hence the costs of these facilities. The cost of these facilities will be directly borne by offshore wind developers and will be embedded into the contract pricing that they offer. Therefore, any cost savings for these facilities will strengthen the competitive position of the offshore wind developer. As a result, there would be incentive for the offshore wind developer to locate the offshore substation to minimize the required distance of the transmission cables for which it has direct cost responsibility.

Consortia of Generation & Transmission Developers

Finally, having a consortium of offshore generation and transmission developers could facilitate coordination and may assist with optimizing the respective offshore wind generation and

[38] New Hampshire Transmission, Greater Boston Cost Comparison NHT Analysis using New England Comparables, https://www.iso-ne.com/static-assets/documents/2015/02/a2_nht_greater_boston_cost_analysis_public.pdf

transmission construction schedules. Ensuring proper alignment of construction schedules can be achieved through contractual provisions that specify notice requirements. However, this structure suffers from the same potential bias favoring one generation developer's interests as noted above.

U.S. DOE Participation as Anchor Tennant

As described in response to Question 1, the *Infrastructure Investment and Jobs Act* (IIJA) specified that one form of financial support that the DOE can offer transmission projects is capacity contracts where DOE purchases the right to use the transmission facilities. Specifically, DOE may purchase the right to use up to 50 percent of the total proposed transmission capacity of a transmission line for up to 40 years. This financing tool will "provide certainty to developers, operators, and marketers that customer revenue will be sufficient to justify the construction of a transmission line that meets current and future needs." Such a financial commitment from DOE is likely to significantly reduce the revenue requirements for the subject transmission facilities. States could contract for up to the remaining 50 percent of the transmission capacity (e.g. Rhode Island could contract for 600 MW to 1,000 MW of capacity of a 1,200 MW modular system, with DOE contracting for the remainder).

Offshore transmission capacity subscribed by DOE could serve as a platform for third-party purchases of offshore wind through power purchase agreements (PPAs), enabling financing and deployment of offshore wind without relying on state-led procurements. In Texas, strategic investments in transmission through the Competitive Renewable Energy Zone (CREZ) program have enabled significant onshore wind deployment through corporate PPAs.[39] In the Netherlands independent transmission has enabled corporate PPAs for offshore wind.[40] Up-front investment in transmission capacity by DOE through the TFP could similarly enable market-driven offshore wind deployment by large corporate and non-profit entities in the Northeast seeking local renewables to meet sustainability commitments.

For offshore wind in particular it is worth noting that independent, planned transmission is a necessary platform to enable small and mid-sized procurements pursued by third-party buyers. High voltage alternating current (HVAC) transmission systems for offshore wind are most economical in the 300 MW to 500 MW range, and high voltage direct current (HVDC) systems are most economical in the 1,000 MW to 1,400 MW range (and beyond), both of which are far larger than most third-party buyers can support. However, by making transmission available to serve as a platform for procurement, states can enable third-party purchases and unlock a large source of demand.

One mechanism to create a platform for third party purchases of offshore wind could be to utilize a mechanism similar to the multi-state Regional Greenhouse Gas Initiative (RGGI) to market and subscribe transmission capacity for offshore wind.

---

[39] See: https://windsolaralliance.org/wp-content/uploads/2018/10/Corporates-Renewable-Procurement-and-Transmission-Report-FINAL.pdf

[40] See: https://cleantechnica.com/2019/05/28/microsoft-announces-new-offshore-wind-energy-agreement-in-the-netherlands/

15. Comment on cost allocation mechanisms that would prevent cost-shifting between the states based on their policy goals and ensure that local and regional benefits remain quantifiably distinct. How should any future potential procurement identify and distinguish local, regional, and state-specific benefits (e.g., reliability) such that ratepayers only pay for services that they benefit from?

Viable mechanisms exist to allocate costs fairly, prevent cost-shifting among the New England states, recognize differences in state policy goals, and distinguish between local and regional benefits. The starting point for such a cost allocation framework is Cost Allocation Principle 1 in FERC's Order No. 1000, which states: "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."[41]

However, before allocating costs based on the beneficiary pays principle, it is appropriate to assess whether the subject transmission facilities would enable various transmission upgrades or the replacement of aging transmission facilities to be avoided. If so, appropriate credit should be given for these avoided costs, with the portion of the costs represented by these avoided facilities allocated in the same manner as the costs that were avoided.

In addition to avoided upgrade costs there are numerous benefits to strategic transmission development, and numerous methods to determine such benefits. In the interest of avoiding extended and potentially contentious detailed analyses of benefits, utilizing a straightforward and implementable approach to allocating costs is needed. Such an approach is described in the Transmission Blueprint from RENEW Northeast,[42] summarized in the excerpt below:

> *The recommended approach allocates the remaining costs to each State in proportion to the capability requested and received from the transmission procurement. In addition, should other States or third parties subscribe to any excess transmission capability, they would be assigned a similar per-megawatt cost responsibility as that of the participating States. As a result, the costs for participating States will decrease as they will be fully compensated for pre-funding the initially unsubscribed capability. States that choose not to participate would not be expected to bear any additional cost responsibility. Cost allocations to non-participating States would be limited to only avoided reliability or asset replacement costs, which would be assigned in any event. Aligning cost responsibilities with requested transmission capability facilitates the process of identifying, preserving, and assigning created transmission capability.*

Federal funding can additionally facilitate cost allocation by reducing the overall cost of transmission projects.

16. Comment on the benefits and/or weaknesses of using a public-private partnership that might include one or more states or U.S. DOE as part owners with private developers or other sources; and

Public-private partnerships have been demonstrated to be effective for developing, financing, constructing and operating major infrastructure investments. A key element of their effectiveness is the marriage of the ability of private capital to assess, price and manage critical project risks with low-

---

[41] Para 622.

[42] Available at: https://renewne.org/wp-content/uploads/2022/05/RENEW-Northeast-Transmission-Blueprint-2022-05-23.pdf

cost public funding.

The *Infrastructure Investment and Jobs Act* (*IIJA*) outlined public-private partnerships as one alternative for securing financial support from the Department of Energy (DOE). The *IIJA* established the Transmission Facilitation Program described in response to Question 1 to facilitate the construction of electric transmission facilities. Under the *IIJA*, federal financial support from the DOE can be in various forms, including capacity contracts where DOE purchases the right to use the transmission facilities, loans, and public-private partnerships.[43] In the broadest terms, any form of federal support can be viewed as a public-private partnership and this federal support reduces ratepayers' financial exposure. Under the public-private partnerships envisioned by the *IIJA*, DOE partners with a transmission developer in "designing, developing, constructing, operating, maintaining, or owning" a transmission project.

Another risk reduction benefit offered by public-private partnerships is the ability to facilitate the permitting process by reducing the permitting requirements for coordinated transmission facilities, recognizing that such facilities will likely limit the number of required landfalls and reduce environmental impacts.[44] Additionally, BOEM has suggested that it has the ability to condition its approval of Construction and Operations Plans (COPs) on the applicant utilizing coordinated offshore transmission facilities.[45]

17. **Comment on the co-benefits of landfalling offshore transmission lines, such as improvements to reliability and/or resilience (*i.e.*, through the use of HVDC converters or otherwise), economic development (*e.g.*, port development, hydrogen production, *etc.*) and any local system benefits. Identify ways to measure and maximize these co-benefits when evaluating transmission buildout.**

Landfalling HVDC transmission for offshore wind can increase reliability and resiliency of the onshore grid, and can provide economic development benefits, including positioning for additional development of clean energy infrastructure. In addition to the black start and system resilience benefits described in response to Question 5, HDVC converter stations can provide voltage support to the local grid. Strategically located projects could additionally fit within broader grid resilience upgrades by repurposing property in the vicinity of at-risk infrastructure and communities. New large-scale supplies of offshore wind could be paired with energy storage systems and/or support local hydrogen production, particularly in ports with adequate space and necessary infrastructure.

In the procurement of transmission Export Links described in response to Question 13 bidders could be encouraged to maximize co-benefits by basing awards in part on direct benefits and optionality of bids (e.g., to pair with energy storage or hydrogen production). Establishing clear objectives in addition to

[43] The IIJA stipulates that one of the criteria for a public-private partnership is that the eligible project must be necessary to accommodate an actual or projected increase in demand for electric transmission capacity across more than one State or transmission planning region.

[44] While not likely an option for offshore transmission development, one independent transmission developer, TransElect, benefitted from a streamlined permitting process as a result of a public-private partnership with Western Area Power Association (WAPA) that allowed TransElect to secure rights of way at lower cost than under traditional utility ownership.

[45] In the New York Bight Final Sales Notice, BOEM noted it "is continuing a planned approach to transmission and is evaluating options including the use of cable corridors, regional transmission systems, meshed systems, and other mechanisms. Therefore, BOEM may condition COP approval on the incorporation of such methods where appropriate." (Atlantic Wind Lease Sale 8 for Commercial Leasing for Wind Power on the Outer Continental Shelf (OCS) in the New York (NY) Bight - Final Sale Notice, p. 15.)

price could be beneficial more broadly in a transmission procurement, as the cheapest projects may not be consistent with a strategic buildout of transmission to achieve long-term efficiency and deliver desired outcomes to participating states.