Dear Massachusetts Energy Market Stakeholder,

The Massachusetts Department of Energy Resources (ñDOERò), the Massachusetts Office of the Attorney General (ñAGO ò), and electric distribution companies that operate in Massachusetts (ñEDCsò) seek your input into the development of a request for proposals (ñRFPò) for the competitive solicitation of bids to enter into cost-effective long-term contracts for Offshore Wind Energy generation pursuant to Section 83C of Chapter 169 of the Acts of 2008, as amended by Chapter 188 of the Acts of 2016, *An Act to Promote Energy Diversity*. This new law requires every EDC to jointly and competitively solicit bids for Offshore Wind Energy Generation equal to approximately 1,600 megawatts (MW) of aggregated nameplate capacity no later than June 30, 2027. It also requires DOER and the EDCs to jointly propose the timetable and method for solicitation of long-term contracts for review and approval by the Department of Public Utilities (ñDPUò) prior to the issuance of the RFP.

With this comment period, the DOER, the EDCs, and the AGO hope to gather stakeholder input on a number of key areas. This letter aims to focus stakeholder comments by providing questions that stakeholders should answer in their written comments.

All interested stakeholders should submit their written comments to marfp83C@gmail.com by 12:00PM on March 13, 2017. Comments will be reviewed and considered in the development of the RFP prior to its submission to the DPU for review and approval.

Thank you for your participation in this important initiative. We look forward to receiving constructive comments to these questions.

Sincerely,

The Massachusetts Department of Energy Resources
The Massachusetts Office of the Attorney General
Fitchburg Gas & Electric Light Company d/b/a Unitil (ñUnitilò)
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid

NSTAR Electric Company and Western Massachusetts Electric Company d/b/a Eversource

Issues for Stakeholder Comment

Please provide concise answers to the following Stakeholder Questions

1. Please provide the following information with your comments:

    a. Name of Organization

    GridAmerica Holdings Inc.

    b. Type of Organization (Public/Industry/Advocacy/Other)

    Industry / Developer

2. Section 83C of Chapter 169 of the Acts of 2008 (ñSection 83Cò), as amended by Chapter 188 of the Acts of 2016, An Act to Promote Energy Diversity, requires a solicitation to be issued by June 30, 2017, including a timetable for the solicitation. Please respond to the following questions regarding the timetable:

    a. How much time do bidders need to develop proposals?

    Bidders should be permitted a six months to respond to each solicitation. This suggested minimum period follows precedent for RFPs in New England. While New England Clean Energy RFP included only a ten-week period to develop proposals, that RFP also included a one-month draft RFP and comment period that preceded the final RFP by more than eight months. Moreover, the New England Clean Energy RFP allowed bidders to propose any size project greater than 20 MW, providing developers the opportunity to decide upon and prepare their project bids well in advance of the RFP. This is in contrast to the 83C solicitation, where developers may need to modify their project size based upon the amount called for in the 2017 solicitation. A six-month period allows time for any such modification, which may include adjustments to various bid inputs such as engineering or financing factors, along with any required internal approvals for such modified bid amount.

    As another example, the Midcontinent ISO (ñMISOò) recently concluded a RFP for a competitive electric transmission project. MISOõs process allows 180 days from the time of the solicitation to the due date for proposals. MISOõs recent process resulted in 11 bids that were extremely detailed arid created significant value for MISOõs customers.

    Equally important is the time the evaluators take to conclude the REP. Knowing how long it will take to evaluate and select a winner allows bidders to solicit firm pricing. If bidders donõt know how long the REP will remain open they may not be able to efficiently price certain aspects of their projects.

        i. What market conditions (technology, vessels, local supply chain, etc.) or ongoing data collection might necessitate a shorter or longer time period for proposal development?

        No comment at this time.

    b. Section 83C allows the use of a staggered procurement schedule and, if applicable, specifies that a subsequent solicitation ñshall occur within 24 months of a previous solicitation.ò

i. How should the timing of future solicitations be staggered in time?

No comment at this time.

ii. What market conditions (technology vessels, local supply chain, etc.) or ongoing data collection should be considered when determining the timeframe of future solicitations?

No comment at this time.

3. Section 83C requires that the initial procurement be issued by June 30, 2017, and any individual solicitation ñshall seek proposals for no less than 400MW of aggregate nameplate capacity of offshore wind energy generation resources.ò In each of your responses, please include an explanation of how your suggested approach would lead to a more cost-effective result for ratepayers.

a. What is the maximum megawatts of aggregate nameplate capacity that should be sought in the initial solicitation under Section 83C? Should the initial solicitation request minimum megawatts of aggregate nameplate capacity greater than the statutory requirement of 400MW? If so, why?

The initial solicitation should seek the full 1,600 MW called for in Section 83C. Most importantly, completing the full solicitation in a single procurement process will allow the project to be constructed in the most coordinated and cost-effective manner. Some of these efficiencies can be gained by smaller solicitations by constructing project components common to each solicitation at once ï such as a single platform for a switching station at which each developer would connect ï but any staged procurement process would require multiple construction deployments, which would increase customer costs.

b. What considerations should be taken into account in deciding the size of this initial solicitations and, if applicable, the size of future solicitations?

No comment at this time.

c. Based on your response to the previous question (3b), what minimum and/or maximum megawatts of aggregate nameplate capacity of offshore wind energy generation (ñOSWò) resources should be sought in future solicitations?

No comment at this time.

d. Recognizing that Section 83C calls for proposals no less than 400MW of aggregate nameplate capacity of OSW resources, what are the pros and cons including impacts to the market and to the cost to ratepayers of selecting multiple bids with individual project sizes less than 400 MW.

No comment at this time.

e. What potential future changes in the market should be considered in determining the size of aggregate nameplate capacity of OSW resources sought in future solicitations?

4. Section 83C requires the evaluation team to carefully review of any transmission costs associated with a bid. Please respond to the following questions regarding the evaluation of related transmission costs:

   a. What documentation and information should bidders provide in order to demonstrate the reasonableness of their transmission costs estimates included in their bid?

      It is important that bidders provide a strong basis on which the transmission cost element of each bid is formed so that the evaluation team can ascribe value to this component of the bid. Bidders should be required to document this basis by providing the following information:

      A description of the process used to determine transmission costs;

      If transmission costs were determined by vendor bids, the amount and the vendor providing the cost bid for each major transmission component;

      The extent to which actual on-water route survey information was factored into vendor bids;

      The primary terms and conditions under which the cost of each major transmission component was proposed to be procured by the bidder; and

      A statement of the experience of the principal vendors and the bidder (including its affiliates) in procuring and installing subsea transmission facilities.

   b. Please describe, in detail, how transmission cost risks should be analyzed in the quantitative portion of the bid evaluation.

      Evaluators should recognize that transmission cost risk is inherent in the types of projects being solicited. Cost caps or other provisions included in bids to shield customers from this risk by shifting it to developers necessarily come at a cost, which developers will necessarily reflect in their bids. In section 83(c), the Legislature expressed a strong preference for cost containment provisions, which the evaluators must implement.

      This means that evaluators will have to analyze the firmness of cost caps or other cost containment provisions by assessing the risks presented by any carve-out or cost-sharing features included in the bid to the Legislatureөs cost-sharing objective. Such features should be accepted only if they provide bid reductions that outweigh the risks that customers will be responsible for additional transmission costs.

   c. What type of cost containment features might a bidder use to ensure that transmission cost overruns, if any, are not borne by ratepayers as required by the statute?

      No comment at this time.

5. Please respond to the following interconnection-related questions:

   a. How should the procurement be structured to allow reasonable evaluation of bids that have not completed the ISO-NE I.3.9 process?

      The two issues arising from interconnection that should be evaluated are viability and cost. Completion of the ISO-NE 1.3.9 process is not necessary to adequately evaluate these two issues. Viability with respect to schedule for permitting and construction of interconnection facilities and system upgrades can be assessed by examining the current status of interconnection and studying the proposed interconnection. Cost of interconnection should be incorporated into the bid. Firm price bids should receive more weight in the evaluation.

Per the ISO-NE tariff, interconnection facilities and systems upgrades identified by the bidderôs System Impact Study are deemed sufficient to remedy all significant adverse impacts on affected Transmission Ownersôtransmission facilities. It is not the policy of ISO-NE to permit special ñre dispatch agreementsò (i.e. re-dispatch or curtailment outside the normal Security-Constrained Economic Dispatch of the ISO-NE region) between Interconnection Customer and ISO-NE in lieu of the construction of interconnection facilities and system upgrades to avoid anticipated significant adverse impacts on the transmission system nor is re-dispatch permitted to solve limiting constraints on the sub-transmission system (see ISO-NE Planning Procedure No5-6). Therefore no such bilateral ñre-dispatch agreementsò curtailing operations of bid resources should be anticipated in the evaluation process.

Bids should provide the status of any interconnection studies already underway with ISO-NE. If an interconnection agreement has not been executed, the bid should provide the steps that need to be completed before an interconnection can be executed with its associated timeline. Any completed ISO-NE studies or study model data at the time of submitting the proposal should be provided and further submitted as soon as it becomes available.

Not allowing evaluation of offers from resources that have not completed the ISO-NE 1.3.9 process would unnecessarily limit the field of bidders competing for selection in the REP to the detriment of customers. Prohibiting the evaluation of resource options that are highly cost effective and executable on the basis of its interconnection request status is not in the public interest and may in fact leave customers with a handful of projects that are relatively costly and face intense community opposition but remain in the procurement process merely due to its interconnection status.

b. For bids that have not completed the ISO-NE I.3.9 process, what information, such as technical reports or system impact studies that closely approximate the ISO-NE interconnection process, should the procurement require from bidders to allow a complete evaluation of bids and associated risks, costs, and benefits?

All resources are ñviableò with regard to their ability to seek and receive Interconnection Service ð that is, the right to interconnect to the ISO-NE PTF. The interconnection process determines the interconnection facilities and system upgrades required to achieve such Service in a manner that avoids significant adverse impact on the affected Transmission Ownersôtransmission system. While such system upgrades may or may not entail substantial cost, under a fixed or capped price arrangement such costs would not be at risk to customers. As discussed above, viability with respect to schedule for permitting and construction of interconnection facilities and system upgrades may be assessed through a review of the interconnection request status and the nature of such facilities.

The issue of resource viability with respect to its value to customers is not best assessed in the interconnection process but through studies measuring the energy and capacity deliverability of the bid resource. As Interconnection Service does not guarantee energy and capacity deliverability, it is important that the evaluation process assesses the ability of bid resources to economically compete with local resources and be dispatched in a constrained network under a range of load scenarios. A firm physical right over a defined path is one manner in which to secure deliverability and ensure that Massachusettsô policy goals are met cost-effectively and with reduced risk to customers. Deliverability may further be incentivized through assessment of substantial financial penalties for non-delivery of energy and environmental attributes over the term of the procurement contract.

Deliverability should also consider energy market basis risk to Massachusetts customers (likely at NEMA or Mass Hub) associated with the delivery point of the bid resource. Bidders should provide to evaluators any final studies they have undertaken measuring such basis risk over the term of procurement. Evaluators should reflect basis risk in the relative monetary and risk comparison across all bid resources.

c. What documentation should the procurement require bidders to provide that demonstrates the reasonableness of their estimates for interconnection costs and deliverability costs (costs of network upgrades including reactive compensation, and voltage control to compensate for cable charging)?

Documentation supporting interconnection cost estimates may include studies showing the viability of the chosen technology (AC/HVDC interconnection), along with studies of related interconnection costs, offshore switching platform costs, or other studies providing evidence of viability and cost for the proposed interconnection.

d. What other cost containment information should the solicitation require bidders to provide to allow for a complete evaluation of bids and associated risks, costs, and benefits?

No comment at this time.

e. What potential impact, if any, does the cluster interconnection analysis being developed by ISO-NE have on developing transmission costs and/or transmission planning for OSW?

No comment at this time.

6. Section 83C requires that projects must be ñcost effective to electric ratepayers in the Commonwealth over the term of the contract.ò What could bidders include in their proposals to ensure that the long-term contracts for OSW will be the most cost effective to ratepayers?

No comment at this time.

7. Section 83C requires one or more procurements of OSW and requires that long-term contracts be ñcost effective to Massachusetts electric ratepayersò and ñavoid line losses and mitigate transmission costs to the extent possibleò and ensure that transmission cost overruns, if any, are not borne by ratepayers.ò The transmission needed to deliver OSW generation resources to shore could have a significant impact on customer costs, benefits, and risks. Please address the following questions:

    a. What potential approaches related to the transmission portion of the RFP(s) should be considered when designing the RFP to achieve the total OSW procurement goals of Section 83C? For example, potential approaches might include requiring each generation bidder to fulfill its own transmission needs (either with other bidders, with partners, or by themselves) or might include delivery to a common off shore delivery point. Full descriptions of each potential approach would be helpful.

Approach 1 ï Coordinated Model: A bidder would develop and install transmission cables running from a single point of interconnection at the shore to an offshore switching station. Generation developers would then independently install transmission cables running from each developerôs collection platform(s) to the offshore switching station, where they would be aggregated.

The offshore switching station would take the place of a collection platform under the Gen-Tie Model, thereby retaining the same number of platforms under that Model. The transmission cables would be installed only as required by the pace of procurement through the serial RFPs.

The switching station and offshore power electronics can be constructed in stages to match the pace of the serial RFPs: The jacket would be installed with pin piles or similar method, and the first section of topsides would be installed by float-over. The first section of topsides will house the equipment required for the initial phase. Later phases will be designed and fabricated in modularized containers that would be capable of being installed with vessels available at that time.

Approach 2 ï Gen-Tie Model: Bidders would independently develop transmission facilities to serve their own generation facilities. Given the geographic dispersion of the leases, it is expected that the developers would utilize more than one point of on-shore interconnection.

b. Identify the pros and cons of each with particular focus on consumer costs, benefits, and risks.

	Pros	**Cons**
Coordinated Model	Cost ï aggregation allows for fewer cables between the aggregation platform and the shore interconnection, generating cost savings. The single point of interconnect means a single permitting regime and single permitting period. Environmental and safety ï Fewer cables and fewer construction periods means fewer disturbances of the benthic environment and a safer construction protocol.	Risk - The developer of the aggregated system must absorb the capital cost of the pre-built jacket structure for the offshore switching station until such time that capacity is procured sufficient to fully utilize that structure. There is also risk that the EDCs will not ever procure capacity sufficient to offset the cost of the pre-built jacket structure. This risk could be mitigated by a commitment from the State to complete the full 1600 MW procurement, or by customer, EDC, State or Regional ownership of these common facilities. The risk of pre-building the common facilities would likely need to be absorbed by the EDCs, State or Region, until the OSW facilities come on line, perhaps along the lines of the ñtrunklineò approach that the FERC has approved.
Gen-Tie Model	Development and construction is conducted only as required through the serial RFPs, matching the timing of	Multiple points of interconnection means multiple permitting regimes and multiple periods of construction activity

	contracted revenue with capital expenditures and avoiding overbuild risk. Allowing each developer to design transmission that best fits its own lease promotes developer equity and fairness in the process.	at the onshore substations. More cables means more cost and more disturbance of the benthic environment.

c. What elements of each option might increase or reduce customer benefits to the greatest extent? What elements might increase or reduce customer risks? Please explain your answers.

For the Coordinated Model, the element that most greatly increases customer benefits is the reduction in cost due to the reduction in the required number of cables and the reduction in the required permitting and construction activity afforded by the single point of interconnection with the shore. The element that most greatly increases customer risk is the likely need for the customer, EDCs, State or Region to absorb the risk of pre-building the jacket structure for the aggregating platform.

d. How might these approaches be affected by the size and timing of Section 83C solicitations?

The Coordinated Model would benefit greatly from a single commitment to the full 1600 MW in the first solicitation. This would eliminate the risk of a mis-match between the time of constructing the jacket structure for the switching platform and the time these facilities are being fully utilized. This Model would still benefit from relatively large solicitations in earlier years as this would reduce the amount of time that the jacket structure would be not fully utilized.

The Gen-Tie model is less affected by the size and timing of the solicitations. However, there would still be an advantage to fewer, larger solicitations as this would increase the efficiency of procuring labor and equipment while reducing cost by decreasing the number of construction deployments.

Capital costs for offshore wind are expected to decline over time as technologies improve and construction capacity is developed in North America. These cost declines will partly but not entirely offset the benefit of earlier, larger solicitations in each Model.

e. The RFP could require an additional bid that assumes the bidderõs OSW facilities interconnect at a pre-defined transmission point constructed at an off-shore location by a Transmission Developer. If included in the RFP, the bid would be in addition to the requirement for each bidder to provide a proposal in which its OSW facilities would interconnect to the existing on-shore transmission network. On the assumption that the RFP includes such an off-shore proposal, please address the following questions:

i. What elements of this approach might increase ratepayer benefits to the greatest extent? What elements might reduce ratepayer benefits? Please explain your answers.

This ñUtility Coordinated Modelò is largely described above in the ñCoordinated Modelò description. The added ñUtilityò portion infers that this model would include cost recovery by customers, the State or Region for all facilities that would transmit power from the offshore location to the ISO-NE PTF. This cost recovery aspect would completely mitigate the risk to the transmission developers of pre-building the common facilities as identified in the Coordinated Model, above, while retaining all other benefits as described in that Model.

ii. What minimum level of technical information regarding such a pre-defined off shore location will bidders need in order to allow them to provide accurate and complete bids based on this scenario? Please explain.

Bidders will need to know the specific location of the pre-defined offshore transmission point.

iii. What additional (i.e., non-technical) information will bidders need in order to allow them to provide accurate and complete bids based on this scenario? Please explain.

Bidders will also need a financial commitment that delivery from the offshore transmission point to the ISO-NE PTF is ready on time and that it performs as specified. This commitment would likely require the provision of liquidated damages protection.

iv. What such approach will allow the most efficient and cost-effective result? What circumstances or approaches could potentially diminish the efficiency or cost-effectiveness of such a network expansion? Please explain your answers.

No comment at this time.

f. Describe what other mechanisms or requirements should be considered for reducing the short-term and long-term costs of transmission interconnecting OSW facilities. For example, are there steps that could be required for transmission associated with the first OSW project that could reduce overall costs to ratepayers when subsequent OSW project(s) and their associated transmission are built?

As described above, if transmission for the first solicitation follows the ñCoordinated Modelò or the ñUtility Coordinated Model,ò then the onshore substation, the cables from the shore to the offshore platform, the jacket structure for the offshore platform, and portions of the offshore platform would be prepared in advance to accommodate later solicitations. This advance work would greatly increase efficiency by consolidating the permitting process and reducing the number of construction deployments.

8. Section 83C requires that projects ñadequately demonstrate project viability in a commercially reasonable timeframe.ò How should the solicitation address this requirement? Please address the following questions:

a. The RFP may require all proposals to meet an in-service date for generation, what is the earliest that date should be??

For the first solicitation, the RFP should not require an in-service date any earlier than December 31, 2022 for projects 800 MW or less, and no earlier than December 31, 2023 for larger projects. Bidders should be free to offer earlier online dates.

b. Should proposals that commit to an earlier commercial operation date be favored over projects with later commercial operation dates? Please provide reasoning to support your response.

For the 2017 solicitation, all projects with proposed CODõs before 2025 should be evaluated on an equal basis for that feature. This window allows for projects of different sizes to be completed within a reasonable window. This flexibility provides the developers the time to complete projects on a reasonable schedule without exposing customers to undue costs that may result from more compressed timing. Giving credit to earlier proposed commercial operation dates runs the risk of favoring projects that would be suboptimal if overly aggressive in-service dates are not achieved. Importantly, the 83C legislation does not express any requirement or preference for the timing of project completion other than the commercial reasonableness standard cited above.

c. In a construction plan what documentation should bidders be required to provide to reasonably inform the evaluation team about the projectõs viability?

No comment at this time.

d. How should logistical constraints be addressed in the solicitations relative to such things as port constraints, availability of vessels, etc.?

No comment at this time.

e. What information should the solicitation require regarding site control for proposed transmission routes, points of interconnection to the grid, and port locations for staging?

No comment at this time.

9. Section 83C stipulates that DPU shall not approve a contract from a subsequent solicitation ñif the levelized price per MWh, plus associated transmission costs, is greater than the levelized price per MWh plus transmission costs that resulted from the previous procurement.ò Please address the following question:

a. What information should the solicitation require, that is different from information that would already be provided on bid parameters and pricing for a specific bid category, to enable an accurate and transparent estimate of the levelized price of energy?

No comment at this time.

10. Section 83C requires that the clean energy resources to be used by a developer under the proposal to contribute to reducing winter electricity price spikes. How would bidders demonstrate that proposed long-term OSW contracts can meet this requirement? How should the evaluation process consider bids that cannot demonstrate an ability to meet this requirement?

No comment at this time.

11. Given that Section 83C allows ñoffshore wind energy generation resources to be paired with energy storage systemsò, please respond to the following questions regarding the evaluation of the potential benefits associated with storage being paired with an OSW project:

a. Should the Section 83C bid evaluation process quantitatively evaluate the potential benefits associated with storage paired with OSW resources potential qualification and participation in other ISO-NE markets, (e.g., ancillary services market)? If so, what methodology should the evaluation team utilize to ensure all the benefits are captured?

No comment at this time.

b. Where would energy storage systems potentially be located, and what options should be allowed for ownership and/or operation?

No comment at this time.

c. Should the operation of storage be completely associated with the OSW project or be allowed to sell services into the ISO-NE markets outside of operation of the OSW project?

No comment at this time.

12. Section 83C states that where possible, proposals should mitigate any environmental impacts. Please address the following regarding this provision:

a. Identify and describe the environmental impacts associated with the installation of underwater transmission cables in state waters. Describe recommended mitigation strategies and explain what commitments and information a bidder should provide to demonstrate that it will mitigate the identified environmental impacts.

Installing a submarine cable may affect the marine environment in state waters, however an applicant can minimize these impacts with upfront planning, a variety of environmental surveys (geophysical & geotechnical, benthic, etc.), the use of publicly available marine data, agency and stakeholder consultation, and the use of best management and engineering practices and mitigation measures.

Companies with extensive experience and expertise in designing, constructing, and operating overhead, underground and submarine electric cables should be weighed with more merit than those without this expertise. Companies having met the financial qualifications and having an established Environmental Management Systems can demonstrate that, with established techniques, environmental impacts will be minimized to the maximum extent possible. A proven willingness to develop such a project in the spirit of marine stewardship with deep consideration for both the habitat and all other maritime stakeholders is a qualification that should be paramount to evaluators.

Impacts associated with submarine cable installations are most often temporary and can be direct or indirect in nature. Though this may not be an exhaustive list, resources that may be affected and some avoidance and mitigation strategies are described below:

Resource	**Potential Impact**	**Avoidance and Mitigation**
Geologic and Physiological Resources	Although there is little to no probability to alter ocean processes, physical attributes and tidal currents should be considered. Bed rock and certain sediment type could cause challenges during a cable	Project siting should avoid hard bottom to the best extent possible. Installation techniques should be chosen to minimize disturbance yet maximize cable protection

Resource	**Potential Impact**	**Avoidance and Mitigation**
	installation and are also often considered sensitive, special or unique habitats. Tidal areas and beach erosion may impact the marine/land transition points causing risk to the cable once operational. Also these locations, if dynamic enough, could cause cable exposure. The cable route should be reviewed for the need to cross existing cables.	via cable burial. This will likely minimize the need for subsequent, intrusive repairs. Marine/terrestrial transition techniques should be chosen to maintain long term protection of the cable (HDD or trenching to protective depths within substrate). Project siting should minimize multiple crossings of existing cables and/or utilize BMP for crossing existing cables. The guidelines published by the International Cable Protection Committee are a useful reference (as the U.S. has not ratified UNCLOS).
Aquatic Resources (Benthic, Finfish, Essential Fish Habitat (EFH), Marine Mammals and Sea Turtles, Submerged Aquatic Vegetation (SAV))	Temporary and localized disturbance is likely to occur in areas where these resources are present. Mobile species may be temporarily displaced during installation activity due to avoidance behaviors. Loss of habitat, especially EFH, should be evaluated. Depending on the installation/survey methodologies, acoustic impacts may warrant consideration.	The applicant should utilize cable installation techniques that will minimize or avoid sediment disturbance in areas of known benthic EFH and SAV. Should these areas be disturbed during construction, a post installation survey and mitigation strategy should be developed. Impacts to Finfish and Marine Mammals and Sea Turtles should be avoided or minimized by following BMPs outlined by NOAA-NMFS (such as the use of Protected Species Observers).
Rare, Threatened, and Endangered Species	As these species are already jeopardized, further exposure to harm during construction should be assessed.	Project siting should avoid these species to the maximum extent practicable. Consultation with NOAA-NMFS would be recommended to avoid and minimize impacts.
Marine Archaeological and Cultural Resources	Installation and associated bottom disturbing activities can permanently impact submerged cultural resources.	Site specific survey marine survey may be required in order to identify potential submerged cultural resources along a proposed route. Consultation with State Historic Preservation Offices and representatives of Native American Tribes should be required as a means to minimize and avoid disturbance to submerged historic resources and other areas of concern.

Resource	Potential Impact	Avoidance and Mitigation
Water Quality	Cable installation may temporarily mobilize/suspend sediment and soils during construction. Contaminated sediment can be mobilized/suspended into the water column, which can lead to water quality impacts.	Installation techniques should be chosen to minimize sediment suspension to the maximum extent practicable. Project Siting should comply with state regulatory requirements when dealing with contaminated and/or hazardous materials and avoid these areas to the maximum extent practicable.
Marine Use (navigation, transport, commercial/recreational fishing)	Cable installation may cause temporary impacts to marine use in the immediate location of the cable route corridor.	Consultation with various stakeholders should occur well in advance of construction. Installation methods should be used to avoid potential damage to existing cables, fishing gear, or any other submerged assets. A USCG Notice to Mariners should be published for any/all offshore activities and should provide a schedule of pending activities. A fisheries liaison officer should be utilized to communicate project details to commercial and recreational fishing communities.
Public Safety	Cable installation often requires several offshore vessels including large shipboard equipment and staged, shore side equipment. Maneuverability of this equipment may be limited both offshore and on. The release of hazardous material, such as an oil spill on a vessel, may cause localized public safety concerns.	Installation methods should be used to avoid potential public safety issues. Radio communication and other means of marine communication should be utilized. A USCG Notice to Mariners should be published for any/all offshore activities and should provide a schedule of pending activities. All vessels should be equipped with a hazardous materials management plan as well as a spill kit to minimize the spread of any hazardous material.

b. Recognizing that the U.S. Bureau of Ocean Energy Management requires developers (as part of their Construction & Operations) to submit a decommissioning plan and post a bond to address decommissioning that is held by BOEM during life of the project, are there additional considerations that a developer should provide in their proposal toward mitigation of decommissioning cost responsibility for ratepayers?

No comment at this time.

c. Describe any other environmental impacts that should be considered in evaluating the proposals and the documentation needed to demonstrate mitigation of impacts.

No comment at this time.

13. Section 83 states that, where feasible, a project should ñcreate and foster employment and economic development in the Commonwealthò. Please address the following:

a. Describe employment and economic development in the Commonwealth that an offshore wind development might foster.

No comment at this time.

b. Describe what steps might be taken by a developer to foster such employment and economic development in the Commonwealth.

No comment at this time.

c. What information should be required to demonstrate the local economic development benefits of a project?

No comment at this time.

d. Should a supply chain plan be required? Please provide reasoning to support your response, including any information that could be required in the supply chain plan?

No comment at this time.

14. Section 83C requires the DOER to give preference to ñproposals that demonstrate a benefit to low-income ratepayers in the Commonwealth without adding cost to the project.ò Please describe the minimum requirements a bidder should demonstrate to meet this standard.

No comment at this time.