Supreme Judicial Court for the Commonwealth Full Court: SJC-12886 Filed: 3/19/2020 10:58 AM

COMMONWEALTH OF MASSACHUSETTS

SUPREME JUDICIAL COURT

No. SJC-12886

NEXTERA ENERGY RESOURCES, LLC,
Petitioner-Appellant,

v.

DEPARTMENT OF PUBLIC UTILITIES,
Respondent-Appellee.

APPEAL OF AN ORDER OF THE DEPARTMENT OF PUBLIC UTILITIES PURSUANT TO G.L. C. 25, § 5

BRIEF OF NEW ENGLAND POWER GENERATORS ASSOCIATION, INC., AMICUS CURIAE IN SUPPORT OF PETITIONER-APPELLANT NEXTERA ENERGY RESOURCES, LLC AND REVERSAL

Mark C. Kalpin (BBO #635836)
Brett D. Carroll (BBO #640569)
Christopher M. Iaquinto (BBO #685718)
HOLLAND & KNIGHT LLP
10 St. James Avenue
Boston, MA 02116
Tel: 617-523-2700
mark.kalpin@hklaw.com
brett.carroll@hklaw.com
christopher.iaquinto@hklaw.com

SJC RULE 1:21 CORPORATE DISCLOSURE STATEMENT

Amicus curiae New England Power Generators Association, Inc. ("NEPGA") states, pursuant to Mass. R. App. P. 17(c)(1), that it is a 26 U.S.C. § 501(c)(3) nonprofit organization. There is no publicly held corporation that owns 10% of NEPGA's stock, as NEPGA does not issue stock or any other form of securities and does not have any parent corporation.

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Page(s)

Cases

Statutes

Regulations

Other Authorities

I. STATEMENT OF ISSUE TO BE CONSIDERED

This Court solicited amicus briefs[1] on the question of "[w]hether three power purchase agreements [('PPAs')] between [the three] Massachusetts electric distribution companies [('Companies')] and HQ Energy Services (U.S.) Inc. [('HQUS')], complied with section 83D of an Act Relative to Green Communities, St. 2008, c. 169, [as amended by St. 2016, c. 188, § 12,] and 220 Code Mass. Regs. 24, et seq. [('Section 83D')]." In response to the Court's question, amicus submits that the answer must be "no." Amicus respectfully urges this Court to reverse the Massachusetts Department of Public Utilities' (the "Department") June 25, 2019 final decision (the "Order") to approve the PPAs (as well as the corresponding transmission services agreement ("TSA")) between the Companies and HQUS because the PPAs fail to comply with the statutory and regulatory requirements applicable to the procurement process

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[1] This brief is filed pursuant to Mass. R. App. P. and the Court's solicitation of amicus filings (Docket Entry #7).

articulated in Section 83D, as they fail to ensure incrementality and guaranteed winter power delivery.

II. INTEREST OF AMICI CURIAE

The New England Power Generators Association, Inc. ("NEPGA") is a private, not-for-profit trade association representing competitive (non-utility) electric power generators in New England. Its member companies are responsible for generating and supplying electric power for sale within the New England wholesale power system and play a significant role as active participants in New England's competitive wholesale electric markets. In Massachusetts, NEPGA represents nearly 85% (or roughly 9,740 MW) of generation capacity located in 25 cities and towns and across a diverse portfolio of fuels and technologies. Its member companies employ over 1,000 workers in the Commonwealth and contribute tens of millions of dollars in annual state taxes.

NEPGA supports the public interests in this Commonwealth as its mission is to support competitive wholesale electricity markets in New England. Sustainable, competitive markets, as envisioned by the Massachusetts Legislature and guided by stable public policies, are the best means to provide long-term reliable and affordable supplies of electricity for consumers in this Commonwealth.

Through its passage of the Electric Restructuring Act in 1997 (St. 1997, c. 164) the Massachusetts Legislature determined that a competitive wholesale electric generation market, in which independent generators (instead of Massachusetts residents) take the risks associated with developing and operating multi-million dollar generation assets, will best ensure that the cost of electric energy for Massachusetts residents will be minimized. NEPGA's members have embraced that challenge – access to the most efficient generating resources in the region has been maximized, and system reliability has increased. This increased competition has reduced wholesale electricity supply prices and yielded near-20% price reductions for Commonwealth residents. At the same time, massive reductions in carbon dioxide emissions – amounting to approximately 60% since 1990 – have been realized. These results have been accomplished without any long-term contractual or financial risk to Massachusetts ratepayers.

NEPGA's members have achieved those significant savings, in part, because Massachusetts (and other New England states) support the operation of the ISO-New England ("ISO-NE") administered competitive wholesale market. Procurements that are inconsistent with the Legislature-enacted statutory exceptions to the competitive wholesale market (such as Section 83D) have the potential to distort the price signals created by the competitive market, and to negatively impact the continued viability of the competitive market that is tasked with providing economic and reliable daily supplies of electricity to Massachusetts residents.

NEPGA thus has a vital interest in the issue for which this Court specifically solicited amicus briefs. Any improper application of Section 83D will have significant and deleterious consequences on Massachusetts residents and businesses because there will be no guarantee of delivery of additional supplies of electric power during critical winter months to minimize the potential for extreme price spikes, as required under Section 83D. Accordingly, and particularly in light of this Court's solicitation of amicus briefs concerning the compliance of the PPAs with Section 83D, NEPGA believes that its proposed amicus brief will assist the Court in deciding the issue presented.

III. RULE 17(c)(5) Declaration

No affirmative declaration pursuant to the conditions set forth in Mass. R. App. 17(c)(5) is warranted by the preparation and financing of this brief. In an abundance of caution, NEPGA declares that the Appellant, NextEra, is one of NEPGA's member companies, and in connection with its membership has paid an annual membership fee to NEPGA. However, that fee is unrelated to the preparation and submission of this brief. NextEra did not contribute to the funding of nor participate in the development of this brief.

IV. SUMMARY OF ARGUMENT

The Massachusetts Attorney General's Office, the Sierra Club, and NEPGA – entities whose interests span the spectrum of energy generation and transmission policies in the

Commonwealth, and as such are in frequent disagreement – all agree that the PPAs approved by the Department's Order fail to satisfy the very purpose, and explicit terms, of Section 83D. The following hypothetical explains this consensus.

Assume there exists a marketplace in the Commonwealth for widgets. Widgets are a necessity. The purchasers in the market are Massachusetts citizens and businesses. The average demand is 100 widgets per year, which is provided by the competitive market. At certain times of the year (winter), but not every year and not in similar amounts, the demand for widgets spikes. To ensure an adequate supply exists, the Massachusetts Legislature enacts a statute (*i.e.*, Section 83D) enabling entities authorized by the Commonwealth (*i.e.*, the Companies) to purchase via guaranteed long-term contracts additional widgets "outside" of those already produced in the competitive market. Pursuant to the statute, the Commonwealth (through the Department) authorizes the purchase of 9 additional widgets every year for 20 years, and requires that the seller guarantee the delivery of a portion of these widgets during the winter months of each year when they are needed most.

Requests for proposals are issued and a competitive bidding process is conducted to purchase the 9 widgets. The eventual winner is a competitive market participant that already is producing, on average, fifteen widgets per year within the competitive market. Instead of requiring that the winner produce its 9 widgets in addition to the 15 it already is producing on average (*that is, requiring the winner to produce a total of 24 widgets*), the final contract (*i.e.*, the PPAs) effectively guarantees delivery of, at most, a total of 18 widgets and, at worst, a total of 12 widgets. Worse yet, if the seller cannot deliver the additional widgets in one year, the seller can instead deliver those same widgets in the following year without penalty. In essence, the seller (a) has a reduced obligation to continue to sell its widgets into the competitive market, (b) can use the widgets it currently sells into that market to satisfy its obligation under the contract, and (c) has no guaranteed obligation to deliver any of those widgets during the critical winter months.

That is what happened here. In addition to achieving environmental goals, the Legislature enacted Section 83D to respond, in part, to the challenges posed by extreme weather events and corresponding critical energy needs of the residents and businesses of this Commonwealth. Thus, a critical statutory purpose is to provide additional supplies of electricity generated by renewable energy resources on a firm, or guaranteed, basis during critical winter months.

However, the PPAs ignore this critical requirement, which is intended to protect residents and business in the Commonwealth. Ironically, the Companies' Requests for Proposed Power Purchase Agreements (the "RFPs") that were first approved by the Department *actually complied* with the terms and intent of Section 83D. *See* D.P.U. 17-32 (Addendum at 55) (the "17-32 Order"). The Order approving the RFPs stated that "[b]ecause Section 83D was designed to facilitate the financing of Clean Energy Generation resources," "there must be a 'net increase from incremental new generating capacity'" pursuant to Section 83B's definition of "'New Class I renewable portfolio standard eligible resources.'"[2] Addendum at 93 (quoting Section 83B and Section 83D). *After* the RFPs were issued and the proposed PPAs were submitted to the Department, these crucial requirements of Section 83D were ignored.

As the Attorney General argued during the Department's proceedings in this matter below, the Order should be reversed because it fails to satisfy Section 83D's requirement of providing necessary protections to Massachusetts residents and businesses in the face of extreme winter weather events, such as the polar vortex of 2014.

The Legislature addressed this serious and dangerous winter event through Section 83D's use of a twofold approach. The Legislature (and subsequently the Department) directed the Companies to enter into contracts that would provide additional supplies of electricity (*i.e.*, 9.55 TWh/year of "incremental" electricity) from certain designated generation sources (*i.e.*,

[2] Section 83B provides the definitions for Section 83D.

hydropower). Further, both the Legislature (and subsequently the Department) required those contracts to guarantee that this "incremental" supply of electricity would be delivered when it is needed most (that is, during the winter months when extreme weather events such as a polar vortex are likely to occur).

Under even the most favorable reading to the Department, the PPAs simply do not require the generation and delivery of "incremental"[3] energy to residents or businesses in the Commonwealth. The record before the Department on this issue confirms that the three-year historic average for the sale of electricity by HQUS into New England is 14.8 TWh/year, and that on an annual basis the actual sales by HQUS can vary

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[3] The RFP defined "Incremental Hydroelectric Generation" as:

> Firm Service Hydroelectric Generation that represents a net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the 3 year historical average and/or otherwise expected delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England Control Area.

Addendum at 90 (internal quotations omitted).

between 9.45 TWh/year to 18 TWh/year. RAVII/494, 516. The Attorney General and others argued to the Department that the "incremental" mandate in Section 83D and the RFPs requires the Companies to ensure that any energy purchased from HQUS under the PPAs is *in addition* to the 14.8 TWh/year three-year average. AGO Initial Brief, at 19-20.[4] Stated differently, to comply with Section 83D, each Company should have entered into a PPA that required delivery of a Company's proportionate share of 9.55 TWh/year of electricity,[5] *and* imposed a penalty on HQUS if its total sales of electricity into the competitive ISO-NE market (outside of the PPAs) were less than 14.8 TWh/year.

Notwithstanding these unrefuted facts, the PPAs guarantee the delivery of only minimal "baseline" amounts of

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[4] This citation is to the Certified Record on Appeal transmitted on January 16, 2020 by the DPU to this Court in SJ-2019-0296 (the prior iteration of this appeal before the Single Justice, before referral to the full Court). The location of the document within the folder structure of the Certified Record (which is not Bates stamped) is provided here: Certified Record, Briefs, Initial, AGO Initial Brief (hereafter "AGO Initial Brief").

[5] Each Company's market share in Massachusetts determines its proportionate share of the statutorily mandated 9.55 TWh/year.

energy (ranging between 3.0 and 9.45 TWh/year). RAVII/470 n.15, 528. Under the PPAs, HQUS must provide Unitil and Eversource with 3.0 TWh/year of energy plus each Company's proportionate share of the 9.55 TWh increase. In contrast, HQUS must provide National Grid with 9.45 TWh/year of energy plus National Grid's own proportionate share of the 9.55 TWh increase. These artificial "baselines" have been set without reference to the undisputed three-year historic average for the sale of electricity by HQUS into New England, and avoid the "net increase" requirement such that the power actually purchased pursuant to the PPAs is simply not incremental.

Additionally, the PPAs fail to guarantee that the incremental electric energy purchased by the Companies would be delivered by HQUS on a "firm" basis during critical winter months, and instead contain extremely broad "cure" provisions that permit the delivery of that energy in the *subsequent* calendar year (*i.e.*, after the extreme winter weather has already occurred and after the "guaranteed" energy was needed most), without penalty. Thus, the PPAs excuse HQUS' underperformance one winter by permitting over-performance in the next winter. This is not the "guarantee" that the Legislature contemplated and which Section 83D requires.

V. BACKGROUND

The Department's Order implicates grave social and environmental concerns. To understand these concerns, it is helpful to first understand the confluence of social and economic issues that helped lead to the passage of Section 83D.

A. The Polar Vortex

The "polar vortex," which besieged New England from January to March, 2014, provides the real-life backdrop for why Section 83D was enacted and how it intended to protect residents in a practical, common-sense way. "The first three months of 2014 were marked by historically cold weather, record high natural gas and electric demand, and record high natural gas prices, which translated into abnormally high electricity prices

… [and] tested the performance of natural gas and electricity systems … which at times came under extreme stress."[6]

In Massachusetts, the polar vortex negatively impacted the delivery of electricity to residents and businesses alike. ISO-NE reported that electricity demand in New England reached a near historic peak. The increased demand for electricity caused an increased demand for natural gas and fuel oil for heating purposes, and ultimately resulted in forced electric generation outages due to the extreme difficulties associated with electric generation plants obtaining the additional supplies of natural gas that were needed to continue operations.[7] As natural gas prices increased, gas-fired generation plants were displaced by lower cost, but higher emitting, fuel-oil generation plants. At that time, New England generally paid the highest electricity rates of any region in the country because of spiking regional

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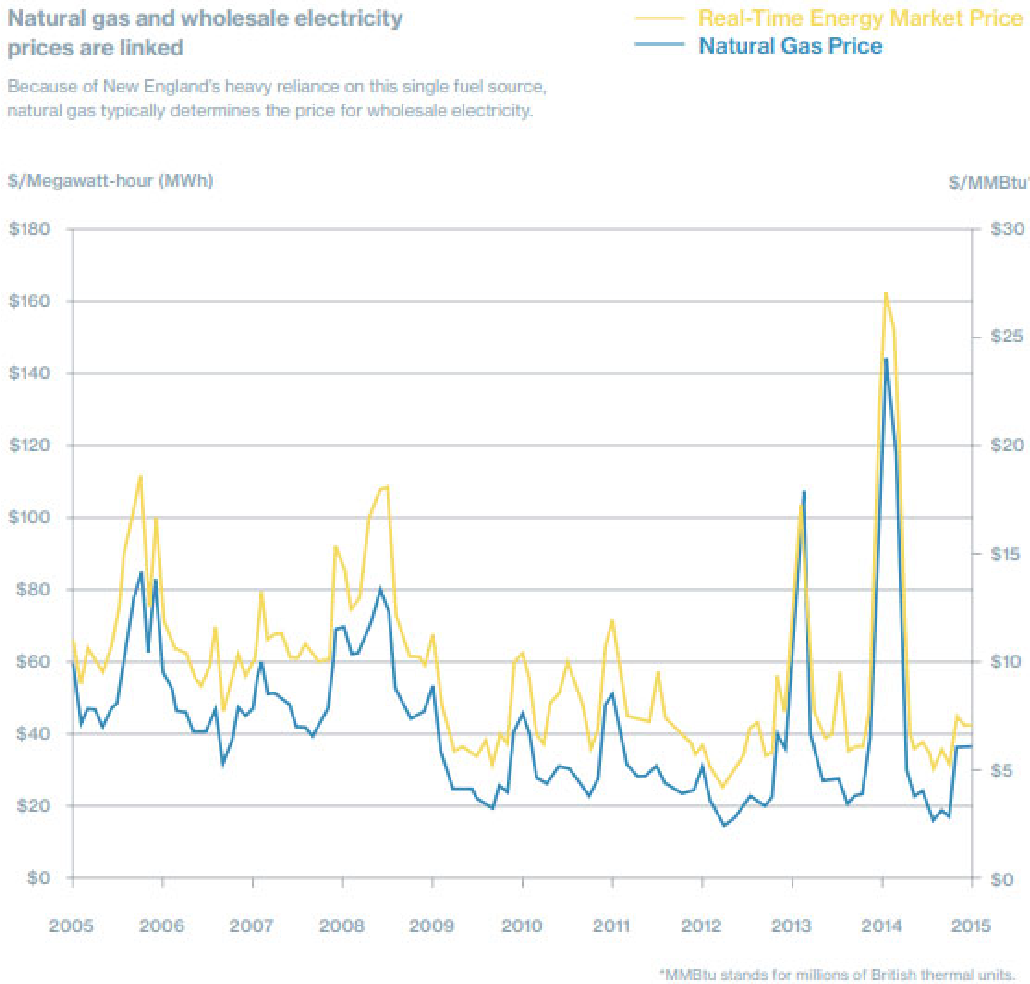
[6] Federal Energy Regulatory Comm'n, Winter 2013-2014 Operations and Market Performance in RTOs and ISOs, at 2 (Apr. 1, 2014), available at https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf ("FERC Presentation").

[7] FERC Presentation at 7-8.

natural gas prices.[8] The 2014 polar vortex significantly compounded that problem and caused dramatic price spikes for electric consumers throughout the region:

[8] Katharine Q. Seelye, Even Before Long Winter Begins, Energy Bills Send Shivers in New England, New York Times (Dec. 13, 2014), available at https://www.nytimes.com/2014/12/14/us/even-before-long-winter-begins-energy-bills-send-shivers-in-new-england.html.

Figure A. [9]



The increases in price per megawatt-hour during the polar vortex were pronounced and created a troubling economic impact to residents and businesses in the Commonwealth. Further, because of the decreased delivery of electric energy from natural gas-fired generation plants, ISO-NE was required

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[9] ISO New England, 2015 Regional Electricity Outlook, at 17, available at https://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf ("Electricity Outlook").

to dispatch higher-emitting oil- and coal-fired generation plants, leading to increases in regional air emissions.[10]

B. The Green Communities Act and Section 83D

Against this dire backdrop, in 2016 the Massachusetts Legislature enacted Section 83D. Section 83D is an extension of the Green Communities Act,[11] and explicitly sought to address the issues caused by the polar vortex. Section 83D and regulations implemented thereunder (220 Code Mass. Regs. 24.05(1)) state that the PPAs must:

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[10] Electricity Outlook, at 17.

[11] That Act "expressly states that its purpose is to provide forthwith for renewable and alternative energy and energy efficiency in the Commonwealth." Alliance to Protect Nantucket Sound, Inc. v. Department of Public Utils., 461 Mass. 166, 189 (2011) (alteration and internal quotations omitted). Aside from seeking to create *more* renewable energy, the statute also sought environmental and cost goals. As then House Speaker Salvatore DiMasi stated, "[s]hortly I will file the Green Communities Act of 2007, to create energy efficient communities … to reduce pollution, increase conservation, create additional sources of renewable energy, and provide support for families struggling with skyrocketing energy costs." 2007 Journal of the House of Representatives, vol. I, Jan. 3, 2007, p. 9. Those purposes are reinforced and apply equally to Section 83D, as demonstrated in 220 Code Mass. Regs. 24.05(1).

> 1. *Provide enhanced electricity reliability* within Massachusetts;
> 2. *Contribute to reducing winter electricity price spikes;*
> 3. Be cost effective to Massachusetts electric ratepayers over the term of the contract, taking into consideration potential economic and environmental benefits to the ratepayers;
> 4. Avoid line loss and mitigate transmission costs to the extent possible and ensure that transmission cost overruns, if any, are not borne by ratepayers;
> …
> 6. *Guarantee energy delivery in winter months***;**
> … and
> 8. Create and foster employment and economic development in Massachusetts, where feasible.

220 Code Mass. Regs. 24.05 (1)(a) (emphasis added).

Section 83D also reinforced the Commonwealth's commitment to reduce greenhouse gas emissions. Because the ISO-NE wholesale market does not place a value on environmental considerations *per se* (such as the emissions associated with a specific type of fuel), a legislator who supported the bill noted that the implementation of the Act would also "help Massachusetts meet its goals for reducing greenhouse gas emissions by promoting the expansion of clean and renewable energy resources, including hydropower and off-shore wind energy."[12]

Distilled to its essence, Section 83D effectively creates a narrow "exception" to the competitive wholesale electric market by permitting the Companies to purchase electric energy directly from a specific type of generation source (hydropower), as opposed to purchasing the needed supply through the ISO-NE competitive wholesale market.

C. The Competitive Wholesale Market

The competitive wholesale electric market as it exists today was created, in part, by the Electric Restructuring Act. The aptly named Restructuring Act restructured the electric utility industry in Massachusetts and helped establish a framework for a competitive wholesale market for electric generation, while

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[12] Mass.gov, Governor Baker Signs Comprehensive Energy Diversity Legislation, Statement of House Minority Leader Bradley H. Jones, Jr. (Aug. 8, 2016), available at https://www.mass.gov/news/governor-baker-signs-comprehensive-energy-diversity-legislation.

maintaining electric companies as exclusive service providers for distribution and transmission. See St. 1997, c. 164, § 1(f); see also Franklin W. Olin Coll. Of Eng'g v. Department of Telecomms. & Energy, 439 Mass. 857, 858 (2003).

A critical goal of the Restructuring Act was to reduce electric rates and enhance reliability by increasing competition in the industry. See St. 1997, c. 164, §§ 1(c), (f) (g), (k), and (w). It ended the State-regulated monopolistic system. Shea v. Boston Edison Co., 431 Mass. 251, 254 (2000).

> The primary component of the Act replaced the existing regulated monopolistic system with an open and competitive retail market … intended to result in long-term rate reductions for customers; [and] to encourage innovation, efficiency, and improved service from all market participants…

Id. (internal quotations omitted). The Legislature concluded that "ratepayers and the commonwealth will be best served … [and] it is in the public interest of the commonwealth to promote the prosperity and general welfare of its citizens … to foster competition and promote reduced electricity rates." St. 1997, c. 164, § 1.

D. The PPAs

On July 23, 2018, the three Companies filed petitions with the Department seeking approval for 20-year PPAs with HQUS for electricity that would be delivered over a newly proposed New England Clean Energy Connect ("NECEC") high-voltage direct current transmission line. The total energy contracted for in the three PPAs is 9,554,950 MWh per year. The PPAs are contracts that contemplate both energy generation and transmission (to the Larrabee Substation in Lewiston, Maine).

1. Power Delivery Amounts In The PPAs

The RFPs provided that the PPAs would ensure the delivery of "Incremental Hydroelectric Generation," or "a *net increase* in MWh per year of hydroelectric generation … as compared to the 3 year historical average and/or otherwise expected delivery of hydroelectric generation … into the New England Control Area." Addendum at 90 (emphasis supplied).

In the proceeding below, the witness for the Attorney General argued that:

> ...to be considered 'incremental,' the RFP requires the bidder to provide energy in addition to the bidder's 3-year historical average of deliveries into New England (or more than the bidder would have otherwise delivered). The 2014-2016, 3-year imports from HQ into New England is 14.8 TWh. Thus, for the 9.55 TWh of Qualified Clean Energy from the contracts to be fully incremental energy delivery, total deliveries would need to be 24.35 TWh annually.

Testimony of Dean M. Murphy, December 21, 2018, at 6:11-16.[13]

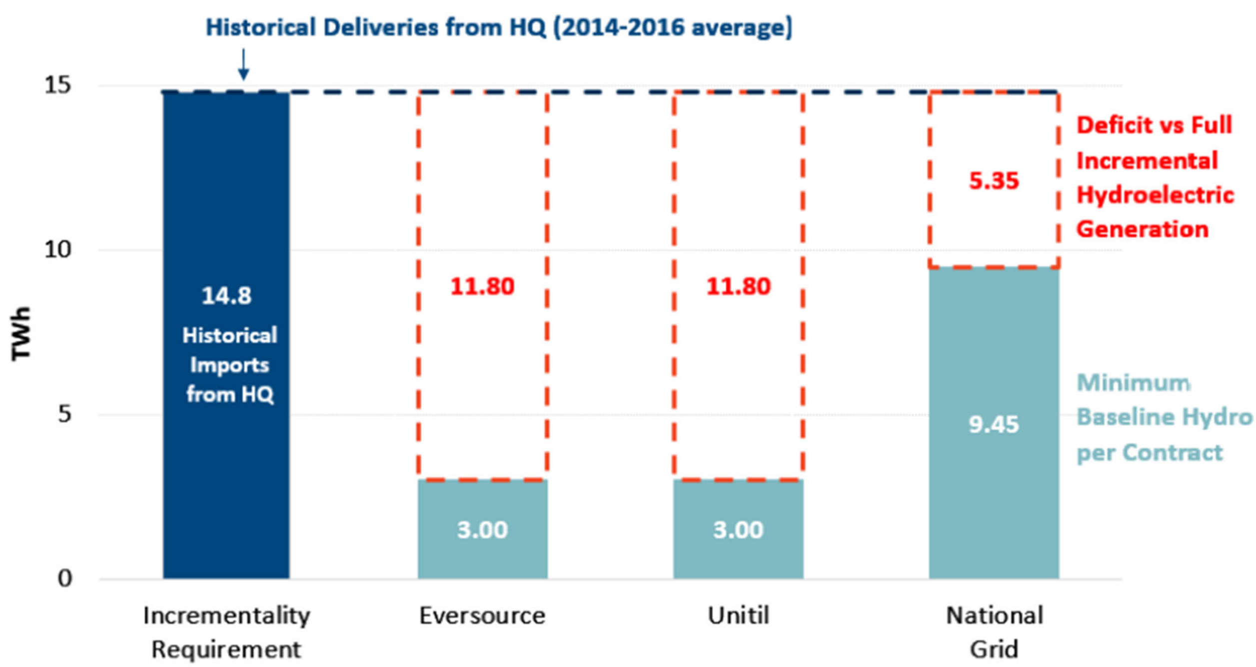
Notwithstanding that argument, the Order claims that the PPAs proceeded under the second prong of this standard. RAVII /697-98. However, no PPA sets forth the "amount" that the Companies "otherwise expect" HQUS to deliver, and none of the PPAs contains a definition of "Incremental Hydroelectric Generation."

Rather, the PPAs each provide for a differing minimum guaranteed "baseline" level of energy to be provided by HQUS

[13] *Available at* Certified Record, Intervenor Testimony, Attorney General, Redacted Testimony of Dean Murphy.

in each year (listed in Exhibit H to the respective PPAs), without reference to the undisputed three-year historical average of 14.8 TWh/year. For Unitil and Eversource, the expected baseline is 3.00 TWh/year, and for National Grid, the expected baseline is 9.45 TWh/year. A simple diagram produced by the Attorney General best illustrates this concern:

Figure B[14]



[14] Testimony of Dean M. Murphy, December 21, 2018, at 9 Figure 1 *available at* Certified Record on Appeal, Intervenor Testimony, Attorney General, Redacted Testimony of Dean Murphy.

No explanation is provided as to how, let alone why, the Companies selected these widely divergent baseline amounts (or why the baseline amounts are not the three-year historic average for the sale of electricity by HQUS into New England). Moreover, the Unitil and Eversource PPAs permit HQUS to decrease its overall exports of electricity into New England relative to the three-year historical average while receiving full payment under the PPAs (the Section 83D required amount of 9.55 TWh/year plus the 3.00 TWh/year "baseline" yields only 12.55 TWh/year). For the National Grid PPA, the expected baseline in addition to the amount purchased in the PPA (9.45 TWh/year plus the Section 83D required amount of 9.55 TWh/year) yields 19.00 TWh/year, or a "net increase" of only 4.2 TWh/year from the three-year average as opposed to the net increase of 9.55 TWh/year that Section 83D contemplates.

As an initial matter, there is nothing in the PPAs prohibiting HQUS from reducing its historic sales of electricity into New England and then rerouting the same amount of "historic" energy in satisfaction of the PPAs, thereby reducing any reliability benefits required by Section 83D. Further, diverting existing energy deliveries could substantially reduce the environmental benefits of the PPAs because the diversion from existing exports will not result in lower greenhouse gas emissions in New England. There can be no reliability or environmental benefits unless the energy delivered by HQUS under the PPAs is truly incremental relative to its average historic sales into the ISO-NE market.

Worse yet, the Order does not explain or justify the difference between these divergent "baselines" selected by Eversource and Unitil (on the one hand), and National Grid (on the other). RAVII/527. Rather, the Department simply admonishes the Companies to not take this unexplained and divergent approach in the future: "As the priorities of the Companies are not identical, the resulting terms in each Exhibit H are not identical. While these differences may have a legitimate basis, . . . [i]n future joint statewide long-term contract solicitations, the Department strongly encourages the

Companies to minimize differences among them regarding material PPA terms." RAVII/64 (internal citations omitted).

2. The Companies' Argument On Power Delivery Amounts In The PPAs Before The Department In The Proceedings Below

In the proceedings below, the Companies premised their "otherwise expect[ed]" amount on a number of issues and assumptions, none of which relates to, or is incorporated in, the PPAs. First, the Companies stated, "Assuming future market conditions remain similar to average historical conditions, the reasonable expectation is that [HQUS] will continue delivering an average of 14.8 TWh …." Companies' Joint Reply, at 9.[15] "By the same token, if future market conditions diverge … it is likely that the amount of energy delivered to New England would be 'otherwise expected' to diverge as well…." *Id.* at 9 n.3. Further, in decrying the arguments raised by the Attorney General as "rooted in a completely flawed conceptual basis," the Companies claimed that one must consider the "value [of]

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[15] *Available at* Certified Record, Briefs, Reply, EDCs, Reply Brief (Final).

expected market conditions … or HQUS's ongoing market incentives to continue delivering … consistent with its historical practices …" in evaluating the otherwise expected amount. *Id.* at 11-12.

The Companies explained their removal of the definition of "Incremental Hydroelectric Generation" by stating that the concept was addressed in Exhibit H to the PPA. *Id.* at 10. Specifically, "Exhibit H was intended to implement this definition with greater specificity and stronger enforcement provisions." *Id.* The Companies argued that Exhibit H "is not reflective of the level of expected deliveries," *id.* at 12, but also that Exhibit H "protects customers by requiring HQUS to maintain its non-contract deliveries … over the term of the PPA at levels reasonably 'otherwise expected'…." *Id.* at 15-16. The Order does not address this contradiction.

3. <u>Transmission Provisions In The PPAs</u>

Although the PPAs contemplate that the energy procured would be delivered into the ISO-NE control area at the Larrabee Road substation in Lewiston, Maine, the transmission of that hydroelectric power would occur in two separate stages: first, HQUS would be responsible for transmission from Quebec to the United States border, and thereafter "HQUS will transfer energy to the Companies through internal bilateral transactions executed through [ISO-NE] and settled" in Lewiston, Maine – the "delivery point." RAVII/470, 468 n.12, 469 n.14. In effect, the TSA between Central Maine Power and the Companies is the mechanism by which HQUS is able to meet its delivery obligations under the PPAs.

The PPAs contemplate that shortfalls in energy delivery might occur under certain circumstances, and provide for excuses from performance or opportunities to cure in the event those shortages arise due to transmission issues. As noted in the Order, the "PPAs provide that HQUS may deliver qualified shortfall energy in the event of a curable delivery shortfall." RAVII/541. Further, "[i]n the PPAs, 'curable delivery shortfall' is a defined term describing delivery shortfalls caused by … (1) a non-excused outage of NECEC … and/or (2) an outage or reduction in the availability of the Quebec Line due to a physical condition that affects the transfer capability of the Quebec line." *Id.* Under this formulation, all shortages due to transmission are either excused or curable. The only non-curable shortfall is the extreme scenario in which HQUS simply refuses to deliver hydroelectric power in its possession.

VI. ARGUMENT[16]

A. The PPAs Do Not Provide "More" Energy As Required By The Statute And By The Department's Order (17-32) Authorizing The RFPs.

Although the word "incremental" does not appear in Section 83D, in authorizing the RFPs the Department concluded that Sections 83B and 83D make clear that the purpose of the long-term contracts authorized under the statute is to acquire more energy than is otherwise available to the market in the Commonwealth, and to guarantee delivery of that energy during winter months. This makes sense because one of the goals of Section 83D is to guarantee the delivery of additional energy to

[16] The Court's standard of review under G.L. c. 25, § 5, and in cases involving statutory interpretation is well settled, and is set forth comprehensively in the principal brief of the Appellant, NextEra Energy Resources, LLC, at 15. NEPGA incorporates that standard by reference.

avoid winter price spikes, which consumers can neither afford financially nor for safety reasons face during the brutal winter months that the Commonwealth often endures.

The RFPs, as interpreted by the Department and consistent with the statute's purpose of purchasing the delivery of more energy, concluded that "incrementality" for purposes of determining "Incremental Hydroelectric Generation" is achieved by a comparison against one of two points of reference: (i) the "3 year historical average, and/or" (ii) "otherwise expected delivery of hydroelectric generation."

The Department approved the PPAs under the "otherwise expected" measurement, even though there is voluminous historic data for HQUS' historical average of hydroelectric generation into the New England Control Area. Common sense suggests that the purpose of the "otherwise expected" clause was to address instances where historical data (which is the most reliable measure) was not available. While conveniently ignoring the more valid and practical historical-average method, the Department's rubber-stamping of the Companies' approach of using the "otherwise expected" method effectively reads out altogether the definition of "Incremental Hydroelectric Generation" and any requirement that the power purchased in the PPAs be a "net increase," which the RFPs required and which is entirely consistent with the intent and purpose of Section 83D. The resulting defects from this approach, as discussed below, confirm that the Department's Order was without substantial evidence and was arbitrary and capricious.

First, the PPAs contradict the Department's own conclusion about the statutory purpose of Sections 83B and 83D by not accounting for, or otherwise incorporating, the concept of "Incremental Hydroelectric Generation." The PPAs removed the definition of "Incremental Hydroelectric Generation," and thus the PPAs on their face do not address the issue of incrementality. Joint Reply, at 10. The Department in its Order, and the Companies in their Joint Reply, reinforce this conclusion. Both make clear that the only guarantee of hydroelectric generation other than the 9.55 TWh/year purchased in the PPAs is tied to *neither* (a) HQUS' three-year average sales of 14.8 TWh/year, nor

(b) the range between 9.45 TWh and 18TWh annually of what they "otherwise expect," but rather is simply a "baseline" below which penalties are imposed for failing to deliver that quantity of energy. RAVII/525; Joint Reply, at 10-12. Although "Exhibit H was intended to implement this definition [of Incremental Hydroelectric Generation] with greater specificity and stronger enforcement provisions," it "is not reflective of the level of expected deliveries" and "does not establish the expected delivery … of hydroelectric generation during the contract term." Joint Reply at 11-12; RAVII/526.

The Department effectively eliminated the intended requirement of "Incremental Hydroelectric Generation" from the PPAs, creating the illogical outcome where the Companies can claim to "otherwise expect" 14.8 TWh per year from HQUS ("[a]ssuming future market conditions remain similar to average historical conditions" or valuing "expected market conditions in New England or HQUS' ongoing market incentives") (Joint Reply at 9, 11) or "between 9.45 TWh and 18 TWh annually" (“under currently effective conditions”) (RAVII/516), *without incorporating any such requirement into the PPAs.*

Second, to the extent Exhibit H to the PPAs is considered to be a representation of what the Companies “otherwise expect” HQUS to deliver (contrary to the Companies’ argument below and the Department’s Order), the Department’s approval of the Unitil and Eversource PPAs, which contain “otherwise expected” delivery from HQUS of 3.00 TWh annually - more than a 70% reduction from National Grid’s “otherwise expected” delivery in its PPA of 9.45 TWh annually[17] - without explanation or justification, is *per se* arbitrary and capricious.

The requirement for incremental hydroelectric generation is incorporated into the PPAs by separating the energy received from HQUS into two tiers: (i) the 9.55 TWh purchased pursuant to Section 83D; and (ii) the baseline hydroelectric energy, which

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[17] Assuming *arguendo* that the Department’s approval of the National Grid PPA’s “baseline” of 9.45 TWh/year is not arbitrary and capricious because it falls at the “low end” of the “otherwise expected” range of delivery from HQUS, it is without question that the Unitil and Eversource PPAs’ “baseline” of 3.00 TWh/year has no rational basis.

was based on the "incrementality" components above – the three-year historical average and/or otherwise expected delivery. The baseline hydroelectric energy set the reference point above which the energy purchased in the PPAs would be considered incremental, and therefore count toward the contracted amount in the PPAs.

The Order fails to address, let alone reconcile, the fact that the Companies "anticipate HQUS's deliveries apart from the PPAs to continue in the range of between 9.45 TWh and 18.00 TWh annually," on the one hand, and the fact that two of three PPAs, those with Eversource and Unitil, only require "a fixed amount of 3.00 TWh of baseline hydroelectric generation…." *Compare* RAVII/525 n.48 *with* RAVII/525. The Order provides no sufficient rationale and effectively requires this Court to speculate as to why it is appropriate or permissible for National Grid to "otherwise expect" that HQUS would deliver 9.45 TWh annually, and why Eversource and Unitil may "otherwise expect" that HQUS would only deliver 3.00 TWh. If Unitil and Eversource's interpretation is permitted, every TWh over 3.00 is considered incremental to what was otherwise expected, and therefore counts toward the contracted amount in the PPAs, whereas for National Grid, every TWh over 9.45 is considered incremental to what was otherwise expected. Such a result is simply illogical and allows the Companies to sidestep the requirements for incrementality as contemplated under Section 83D.

The Order does not address this dramatic difference between the "baselines" to the Eversource, Unitil, and National Grid PPAs, which are admittedly "material terms." The Order instead *surmises* that "the priorities of the Companies are not identical, [therefore] the resulting terms in each Exhibit H are not identical." RAVII/526. This assumption aside, the Order concedes that the differences in material terms *may be illegitimate*: "[w]hile these differences *may* have a legitimate basis, differences in the terms of Exhibit H could result in one company receiving more favorable treatment than others …." RAVII/526-27 (emphasis added). The Order concludes its discussion with a request, or "strong[] encourage[ment]," that the Companies "minimize differences among them regarding *material PPA terms*." RAVII/527 (emphasis added).

On its face, it is arbitrary and capricious for the Department to suggest (let alone declare) that it would "otherwise expect" HQUS to deliver both 3.00 TWh *and* 9.45 TWh of energy *in the same year*. But that is exactly what the Department did in its Order, and is why – regardless of the Department's explanation – the Order must be overturned.

Third, the Department's tortured efforts to approve PPAs that render the "Incremental Hydroelectric Generation" requirement from the RFPs meaningless make clear that the purpose of using the phrase "otherwise expected delivery of hydroelectric generation" was to address the anomalous situation where there was no such data for the bidder. The Companies' argument concerning Incremental Hydroelectric Generation, and the Department's adoption of it, renders the three-year historical average virtually meaningless.[18] The term

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[18] As implemented by the Companies in the PPAs, the "otherwise expected" language is so nebulous that it takes into

"Incremental Hydroelectric Generation" was defined to require a "net increase" in energy on an annual basis. The Attorney General, NEPGA, and the Sierra Club all argued to the Department that the three-year historical average delivery from HQUS of 14.8 TWh should be the appropriate baseline to ensure incrementality. By reading out the incrementality requirement from the RFPs and the 17-32 Order, the Department endorsed PPAs that do not provide any guaranteed "net increase" in power delivery to Massachusetts.

Ultimately, the impact of the PPAs on the total energy made available to and delivered into the New England region is stark and troubling.[19] Of the 9.55 TWh of energy identified in the

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account "expected market conditions" in the future and "ongoing market incentives to continue delivering" non-contracted-for power, such that those conditions can change what is "otherwise expect[ed]" in the future: "if future market conditions diverge from what they have been … it is likely that the amount of energy delivered to New England would be 'otherwise expected' to diverge as well." Joint Reply at 9 n.3.

[19] While NEPGA also has concerns about the negative impact of the Department's Order approving the PPAs on the competitive wholesale market, NEPGA understands that those concerns go beyond the scope of issues on which the SJC solicited amicus briefs.

PPAs for procurement under Section 83D, the PPAs require zero percent (for Eversource and Unitil) to at most 44 percent (for National Grid) to be incremental over the average for the amount HQUS provided over the last three years.[20]

B. The PPAs And The Department's Order Approving Them Do Not "Guarantee Energy Delivery In Winter Months" As Required By Section 83D.

In addition to requiring a reduction to winter electricity price spikes, to further protect the public Section 83D(d) requires guaranteed energy delivery in winter months. Addendum at 133; *see* RAVII/538 (quoting Section 83D(d)(5)(vi)) ("clean energy generating resources must 'guarantee energy delivery in winter months'").[21] Despite the requirement for guaranteed

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[20] Assuming *arguendo* that the National Grid PPA's "baseline" of 9.45 TWh/year is the reference point for determining incrementality, the PPAs for Eversource and Unitil still fail. In providing a "baseline" of 3.00 TWh/year, those PPAs only provide less than 33% of incremental energy.

[21] Given the legislative and factual history described above, the need for a "winter delivery guarantee" and "winter electricity price containment" featured prominently in the RFP approved by the Department, as well as the Department's review and, ultimately, improper approval of the PPAs. *See* Addendum at 140.

winter delivery, the cure provisions in the PPAs are so broad that such guarantee effectively is negated. In sum, non-excused energy delivery is subject to cure by delivery in the next year, where under a typical power purchase agreement in the marketplace non-excused energy delivery would constitute an event of default for which liquidated damages would be due and/or that would give rise to a right of termination. The Order must be reversed because it fails to provide for hydroelectric generation without interruption in violation of Section 83B and fails to guarantee energy delivery in winter months in violation of Section 83D.

Pursuant to their unambiguous terms, the PPAs only require hydroelectric energy to be delivered to Massachusetts (via the Larrabee Station in Lewiston, Maine) every other year for the next twenty years. Therefore, the plain language of the PPAs permits HQUS to deliver hydroelectric energy during the winter months every other year for the next twenty years while receiving the full value of the contract and without paying any penalty. This is irreconcilable with the plain language of Section 83D and is therefore based on an error of law.

The Department acknowledges that under the PPAs:

> HQUS may deliver qualified shortfall energy in the event of a curable delivery shortfall. In the PPAs, 'curable delivery shortfall' is a defined term describing delivery shortfalls caused by the following circumstances: (1) a non-excused outage of NECEC under the TSA; and/or (2) an outage or reduction in the availability of the Québec Line due to a physical condition that affects the transfer capability of the Québec Line.

RAVII/541 (internal citations omitted). Thus, energy shortfalls due to issues in the transmission for which HQUS is responsible may be excused, or they may be curable. Excused outages include force majeure, scheduled maintenance, outages in the transmission line, or regulatory decisions affecting operability. RAVII/541 n.52. However, all other transmission-related issues – which under an industry-standard power purchase agreement *would not be excused* and would instead give rise to an event of default – are nevertheless curable. As such, even though the Companies require that the electric energy purchased under the

PPAs be delivered to them at Lewiston, Maine, and (through the purchase price in the PPAs) are paying for the construction of the Central Maine Power transmission line that will deliver the energy from the United States border to that location, all outages on that transmission line are effectively excused and are subject to cure.

In this regard, the cure is to deliver the shortfall (otherwise known as "Qualified Shortfall Energy" under the PPAs): (i) during the same-season peak period in the current contract year, or (ii) in the same season for *the immediately succeeding contract year*. RAVII/542. Thus, if energy were needed in January 2030 and a transmission-related issue arose at that time causing a "shortfall," that "shortfall" could be remedied the following year (January 2031) without any penalty whatsoever. In other words, if another polar vortex were to hit New England in the winter of 2030, and the Companies and Commonwealth were counting on the delivery of energy under the PPAs to keep the lights on and homes warm in Massachusetts, HQUS nevertheless would have the right – without any penalty – to deliver that expected energy in the following year in the event that the transmission line which Massachusetts ratepayers had paid for was inoperable *for any reason*. In light of this result, any attempt by the Department or the Companies to claim that the PPAs ensure that energy is delivered on a firm basis during each critical winter month when it may be needed simply defies logic. Transmission outages happen. They particularly happen in winter months with extreme weather. However, when such events occur, it is common for the entity responsible with supplying electricity to replace the supply impacted by a transmission outage instantaneously, or at least in some limited period of time during that same season. If not, that entity typically is subject to liquidated damages, other severe financial penalties, or even cancelation of the contract.

Section 83D authorizes "long-term contracts" (each PPA covers a 20-year period) that "guarantee energy delivery in winter months." Section 83D's plain language does not allow for delivery in only "half of the winter months" or merely in "some winter months," but rather requires a guarantee that "firm" energy be delivered "in winter months." See Section 83B and Seciton 83D; see also Commonwealth v. Johnson, 482 Mass. 830, 835 (2019) (alterations and internal quotations omitted) ("We do not read into a statute a provision which the Legislature did not see fit to put there."); Engie Gas & LNG LLC v. Department of Pub. Utils. 475 Mass. 191, 197 (2016) (noting that the Court will reject the Department's interpretation of unambiguous statutory language if it contravenes the Legislature's intent). This result is entirely consistent with the plain language of Section 83B, which defines "firm service hydroelectric generation" as "generation provided *without interruption* for one or more discrete periods designated in a long-term contract" (emphasis supplied). There is no reasonable interpretation of the statute, or reasonable understanding of the word "firm," in which a provider is excused from performance today as long as it provides replacement power in the winter season of the following year. The Department's allowance for delivery of energy in a subsequent winter season not only violates the plain language of Section 83D, but is illogical and defies common sense.

The Department attempts to explain away the impermissibly broad cure provisions by claiming that the "transmission line outages leading to the curable delivery shortfall are not related to any voluntary actions or otherwise in the control of HQUS." RAVII/541. But these attempts are inconsistent with the RFPs, which, in conformance with Section 83D, requires *delivery* of energy to the ISO-NE control area. *See* RAVII/470 (internal quotations omitted) ("HQUS will transfer energy to the Companies through internal bilateral transactions executed through [ISO-NE] and settled at the southern terminus of NECEC in Lewiston, Maine (delivery point)").

Creating a distinction between HQUS and Central Maine Power in this scenario is artificial; the PPAs and the prices paid to HQUS thereunder are for HQUS' *delivery* of power to Lewiston, Maine (irrespective of how that power is delivered). The Order's strained explanation is contradicted by the requirement under the RFPs and the PPAs that the electricity purchased from HQUS be delivered into the ISO-NE control area. Put simply, the NECEC must be constructed to ensure that delivery by HQUS under the PPA occurs. The Order does not explain how the delivery of power (which is what *HQUS ultimately is responsible for and what Massachusetts electric consumers are paying for under the PPA*) is something that is outside the control of HQUS.

Further, creating an artificial distinction between HQUS and Central Maine Power as it relates to the delivery of power in Lewiston, Maine, as a basis to implement overbroad cure provisions, effectively reads the deliverability guarantee requirement in Section 83D out of existence. The Order's statement that "[g]iven the nature of electricity transmission, delivery shortfalls will occasionally happen" demonstrates a misunderstanding of the firm delivery required by Section 83D. *See* RAVII/542.

VII. <u>CONCLUSION</u>

For the foregoing reasons, the Department' erred as a matter of law in approving the PPAs and its Order approving the PPAs was arbitrary and capricious, and therefore the Department's Order should be vacated.

Respectfully submitted,

New England Power Generators
Association, Inc.

By their attorneys,

/s/ Mark C. Kalpin

Mark C. Kalpin (BBO #635836)
Brett D. Carroll (BBO #640569)
Christopher M. Iaquinto (BBO #685718)
HOLLAND & KNIGHT LLP
10 St. James Avenue
Boston, MA 02116
(617) 523-2700

March 19, 2020
Boston, Massachusetts

COMMONWEALTH OF MASSACHUSETTS

SUPREME JUDICIAL COURT

No. SJC-12886

NEXTERA ENERGY RESOURCES, LLC,
Plaintiff-Appellant,

v.

DEPARTMENT OF PUBLIC UTILITIES,
Third-Party Defendant-Appellee.

APPEAL OF AN ORDER OF THE DEPARTMENT OF PUBLIC UTILITIES
PURSUANT TO G.L. C. 25, § 5

ADDENDUM TO THE BRIEF OF NEW ENGLAND POWER GENERATORS ASSOCIATION, INC., AMICUS CURIAE

IN SUPPORT OF PETITIONER-APPELLANT NEXTERA ENERGY RESOURCES, LLC AND REVERSAL

Mark C. Kalpin (BBO #635836)
Brett D. Carroll (BBO #640569)
Christopher M. Iaquinto (BBO #685718)
HOLLAND & KNIGHT LLP
10 St. James Avenue
Boston, MA 02116
Tel: 617-523-2700
mark.kalpin@hklaw.com
brett.carroll@hklaw.com
christopher.iaquinto@hklaw.com

TABLE OF CONTENTS TO THE ADDENDUM

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 17-32 March 27, 2017

Joint Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, and NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy, for approval of a proposed timetable and method for the solicitation and execution of long-term contracts for renewable energy, pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12.

APPEARANCES: William D. Hewitt, Esq.
Roach Hewitt Ruprecht Sanchez & Bischoff, PC
66 Pearl Street
Portland, Maine 04101
FOR: FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
Petitioner

Laura Bickel
Senior Counsel
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
-and-
John K. Habib, Esq.
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
FOR: MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY
Petitioners

Danielle Winter, Esq.
Jessica Buno Ralston, Esq.
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110

FOR: NSTAR ELECTRIC COMPANY

-and-

WESTERN MASSACHUSETTS ELECTRIC COMPANY

Petitioners

I. INTRODUCTION AND PROCEDURAL HISTORY

On February 2, 2017, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid"), and NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource Energy") (together, "electric distribution companies" or "Petitioners") jointly filed a request with the Department of Public Utilities ("Department") pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169 ("Section 83D"),[1] for approval of a proposed timetable and method for the solicitation and execution of long-term contracts for renewable energy through a request for proposals ("RFP") process. The Department docketed this matter as D.P.U. 17-32.

On February 2, 2017, the Commonwealth of Massachusetts Department of Energy Resources ("DOER") submitted a letter in support of the Petitioners' proposed RFP. On February 6, 2017, the Department requested comments on the petition from interested persons. D.P.U. 17-32, Notice of Filing and Request for Comments (February 6, 2017). On February 10, 2017, pursuant to Section 83D, Peregrine Energy Group, Inc. ("Peregrine"), in its role as Independent Evaluator ("IE"), submitted an Independent Evaluator Report ("IE Report"). On February 21, 2017, the following entities submitted initial comments: Associated Industries of Massachusetts ("AIM"); the Attorney General of

[1] Section 83D was added to the Green Communities Act by An Act to Promote Energy Diversity, St. 2016, c. 188, § 12.

the Commonwealth ("Attorney General"); Bay State Wind LLC ("Bay State Wind"); Brookfield Renewable Partners ("Brookfield Renewable"); Central Maine Power Company ("CMP"); Citizens Energy Corporation ("CEC"); the Conservation Law Foundation ("CLF"); Emera, Inc. ("Emera"); the Environmental League of Massachusetts ("ELM"); Eversource Energy Transmission Ventures; Inc. ("EETV"); FirstLight Power Resources ("FLPR"); GridAmerica Holdings, Inc. ("GridAmerica"); H.Q. Energy Services (U.S.) ("HQUS"); Longroad Energy Holdings ("Longroad"); the Low-income Weatherization and Fuel Assistance Program Network (the "Network"); Nalcor Energy ("Nalcor"); the Northeast Clean Energy Council ("NECEC"); New Brunswick Power Corporation ("NB Power"); NextEra Energy Resources, LLC ("NEER") and New Hampshire Transmission, LLC ("NHT"); Pattern Development ("Pattern"); RENEW Northeast, Inc. ("RENEW");TDI New England ("TDI-NE"); and Senator Vinny deMacedo, Representative Thomas J. Calter, and Representative Matthew J. Muratore (collectively, the "Legislators"). On February 28, 2017, the following entities submitted reply comments: the Attorney General; CMP; DOER; Emera; FLPR, GridAmerica; HQUS; the Metropolitan Area Planning Council ("MAPC"); New England Energy Connection, LLC ("NEEC"); the Petitioners; and RENEW. On March 1, 2017, the Petitioners submitted a supplemental filing in which they proposed revisions to Sections 2.2.1.3 and 2.2.2.7 of the RFP in response to stakeholder comments ("Supplemental Filing").[2]

[2] Specifically, the Supplemental Filing includes: (1) a clarification the criteria for bids that contain hydroelectric generation resources and Class I RPS eligible resources; and

On March 1, 2017, DOER submitted sur-reply comments in support of the revisions the Petitioners proposed in the Supplemental Filing. On March 6, 2017, Emera submitted sur-reply comments also in support of the revisions proposed in the Supplemental Filing. On March 10, 2017, the Petitioners submitted a second supplemental filing in which they proposed additional language for Section 2.2.1.4 of the RFP to address instances of negative pricing that may occur, and explaining how the Petitioners will address the potential for negative locational marginal price ("LMP") in a Section 83D solicitation ("Second Supplemental Filing"). The Petitioners responded to 20 information requests.[3]

Pursuant to Section 83D, the electric distribution companies are required to jointly and competitively solicit proposals for Clean Energy Generation[4] not later than April 1, 2017; and, provided that reasonable proposals have been received, shall enter into cost-effective long-term contracts for Clean Energy Generation for an annual amount of electricity equal to approximately 9,450,000 megawatt-hours ("MWh") by December 31, 2022. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. In developing the provisions of long-term

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(2) a clarification of the requirements for guaranteeing energy deliver in winter months.

3 The Department, on its own motion, enters into the evidentiary record the Petitioners' February 2, 2017 filing, the Petitioners' March 1, 2017 Supplemental Filing, the Petitioners March 10, 2017 Second Supplemental Filing, the IE Report, and responses to information requests DPU 1-1 through DPU 1-20. 220 C.M.R. § 1.10(3).

4 Clean Energy Generation means either: (1) firm service hydroelectric generation from hydroelectric generation alone; (2) new Class I RPS eligible resources that are firmed up with firm service hydroelectric generation; or (3) new Class I renewable portfolio standard eligible resources.

contracts, the electric distribution companies shall consider long-term contracts for renewable energy certificates ("RECs"), for energy, or for a combination of both RECs and energy, if applicable. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. The electric distribution companies, in coordination with DOER, shall consult with the Attorney General regarding the choice of solicitation methods. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. The electric distribution companies and DOER shall jointly propose a timetable and method for the solicitation and execution of long-term contracts. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. The timetable and method for the solicitation and execution of such contracts are subject to review and approval by the Department. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq.

An electric distribution company may decline to pursue proposals having terms and conditions that would require the contract obligation to place an unreasonable burden on the company's balance sheet. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. All proposed long-term contracts are subject to the review and approval of the Department prior to becoming effective, and as part of its review and approval process for any proposed long-term contracts, the Department must take into consideration recommendations from the Attorney General, which must be submitted to the Department within 45 days following the filing of contracts with the Department. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. Section 83D provides that the Department shall consider both the potential costs and benefits of such contracts and shall approve a contract only upon a finding that it is a cost-effective mechanism for procuring low-cost clean energy on a long-term basis taking into account the factors outlined in this section. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq.

If DOER, in consultation with the electric distribution companies and the IE,[5] determines that reasonable proposals were not received pursuant to a solicitation, DOER may terminate the solicitation, and may require additional solicitations to fulfill the requirements of Section 83D. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. If an electric distribution company deems all proposals to be unreasonable, it shall submit a filing to the Department within 20 days of the date of its decision, including documentation to support its decision. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. Within four months of the date of an electric distribution company's filing, the Department must approve or reject that company's decision and may order the electric distribution company to reconsider any proposal. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. If the electric distribution companies are unable to agree on a winning bid following a solicitation, the matter shall be submitted to the DOER which shall, in consultation with the IE, issue a final, binding determination of the winning bid, provided that the executed contract is subject to review by the Department. St. 2016, c. 188, § 12; 220 C.M.R. § 24.00 et seq. In this Order, we assess whether the timetable and method of solicitation and execution of long-term contracts

5 Section 83D requires that DOER and the Attorney General jointly select, and DOER contract with, an IE to submit a report to the Department analyzing the timetable and method for solicitation and the solicitation process implemented by the electric distribution companies and the DOER, including recommendations, if any, for improving the process. See Section III, below, for further discussion of the IE's role in this solicitation.

in the electric distribution companies' RFP comply with Section 83D and 220 C.M.R. § 24.00 et seq.

II. SUMMARY OF THE PETITION

A. Introduction

The Petitioners jointly developed and seek approval of a proposed timetable and method for the solicitation and execution of the long-term contracts for Clean Energy Generation in accordance with Section 83D (Petitioners Cover Letter at 1). The Petitioners state that they developed the RFP in conjunction with DOER, and that they consulted with the Attorney General during the RFP's development (Petitioners Cover Letter at 2). For purposes of meeting the requirements of Section 83D, "Clean Energy Generation" means either: (1) firm service hydroelectric generation from hydroelectric generation alone; (2) new Class I Renewable Portfolio Standard ("RPS") eligible resources that are firmed up with firm service hydroelectric generation; or (3) new Class I RPS eligible resources (Petitioners Cover Letter at 1-2, citing Section 83B of An Act Relative to Green Communities, St. 2008, c. 169 ("Section 83B")).[6] The RFP states that its fundamental purpose is to satisfy the policy directives encompassed within Section 83D and to assist the Commonwealth with meeting its

[6] Pursuant to Section 83B, "new Class I renewable portfolio standard eligible resources" means Class I renewable energy generating sources, as defined in Section 11F of Chapter 25A of the General Laws, that have not commenced commercial operation prior to the date of execution of a long-term contract or that represent the net increase from incremental new generating capacity at an existing facility after the date of execution of a long-term contract.

Global Warming Solution Act ("GWSA") goals (RFP § 1.1).[7] The RFP states that Section 83D requires that the electric distribution companies, in coordination with DOER: (1) solicit proposals from developers of Clean Energy Generation projects in a fair and non-discriminatory fashion; and (2) enter into cost-effective long-term contracts for Clean Energy Generation (Petitioners Cover Letter at 2). The Petitioners state that the standards and criteria set forth in this RFP are designed so that the proposals selected for contract negotiations will satisfy Section 83D by facilitating financing, and providing a cost-effective source of long-term Clean Energy Generation to the Commonwealth (Petitioners Cover Letter at 2).

The RFP solicits four categories of bids: (1) Clean Energy Generation from Incremental Hydroelectric Generation via long-term contract; (2) Clean Energy Generation from new Class I RPS eligible resources via long-term contract; (3) Clean Energy Generation and Class I environmental attributes/renewable energy certificates ("RECs") via long-term contract from a combination of incremental hydropower generation and new Class I RPS eligible resources; and (4) Clean Energy Generation from incremental hydropower generation and/or new Class I RPS eligible resources with Class I environmental attributes and/or RECs via long-term contract with a transmission project under a Federal Energy Regulatory Commission ("FERC") tariff (RFP § 2.2.1.3).

[7] The RFP states that the GWSA requires the Commonwealth to establish goals and meet targets for the reduction of greenhouse gas emissions by 2020, 2030, 2040, and 2050 (RFP § 1.2). The goals established by the Commonwealth specifically require a reduction of 25 percent below 1990 levels by 2020 and a reduction of 80 percent below 1990 levels by 2050 (RFP § 1.2).

The Petitioners state that the RFP is the first solicitation set forth in Section 83D for Clean Energy Generation (Petitioners Cover Letter at 2). Through this solicitation, and possible additional solicitations, the Petitioners state that they are obligated to enter into cost-effective long-term contracts, provided such contracts do not place an unreasonable burden on an electric distribution company's balance sheet, that, in the aggregate, total approximately 9,450,000 MWh per year (Petitioners Cover Letter at 2). The Petitioners state that the precise amount of Clean Energy Generation for which the electric distribution companies would execute contracts through this solicitation will depend upon the bids submitted and ensuing contract negotiations (Petitioners Cover Letter at 2).

B. Bid Evaluation Process

Under the RFP, the evaluation of bids will occur in three distinct stages: (1) review of bids; (2) quantitative and qualitative evaluation of bids and ranking of bids; and (3) final evaluation (RFP § 2.1). During any stage of the bid evaluation process, the Evaluation Team reserves the right to disqualify and eliminate from further consideration any proposal that it reasonably believes does not meet the RFP's eligibility requirements (RFP § 2.1).[8] During any stage of the procurement process, if the Evaluation Team determines that a proposal is deficient and missing applicable information needed to continue the evaluation process, the Evaluation Team will notify the respective bidder and permit the bidder a reasonable

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8 The Evaluation Team consists of the electric distribution companies and DOER (Petitioners Cover Letter at 2). The Evaluation Team will engage an Evaluation Team Consultant to assist the Evaluation Team with the technical methodologies and findings for eligible proposals (RFP at Definitions B).

opportunity to cure the deficiency and/ or supply the missing information (RFP § 2.1). Following the bid evaluation process, the electric distribution companies and DOER will consider the evaluation results and project rankings to determine projects for selection (RFP § 1.4). The electric distribution companies will be responsible for negotiation and execution of any final contracts, and DOER will have the opportunity to monitor contract negotiations between the electric distribution companies and selected bidders (RFP § 1.4).

1. Stage One

During Stage One, the Evaluation Team will review proposals to ensure that they satisfy certain eligibility, threshold, and other minimum requirements (RFP § 2.2.1). To be eligible to participate in the solicitation, a bidder must own Clean Energy Generation or the development rights to Clean Energy Generation and a bid must fall within one of the four eligible bid categories (RFP § 2.2.1).[9] Additionally, the RFP contains eligibility requirements regarding: (1) the allowable forms of pricing;[10] (2) bidder disclosure of affiliations and affiliate relationships; (3) a contract between 15 and 20 years; minimum generating capability of a generating unit of 20 megawatts;[11] (4) capacity requirements;

9 The RFP states that projects selected and under contract, or in the contract negotiation and regulatory approval stage under either of the two RFPs solicited pursuant Section 83A of An Act Relative to Green Communities, St. 2008, c. 169, are ineligible for this current RFP, except for projects seeking to add capacity to existing projects (RFP § 2.2.1.2).

10 This includes the Second Supplemental filing which contains a provision for a negative LMP (RFP § 2.2.1.4 (f)).

11 A bidder may bid the entire production or any portion of the production of energy and/or RECs from its eligible facility (RFP § 2.2.1.7).

interconnection and delivery requirements; proposal completeness; and (5) bid fees (RFP § 2.2.1).

The Evaluation Team will evaluate bids that meet the eligibility requirements to determine whether they comply with threshold requirements, which, according to the Petitioners, are intended to screen out proposed projects that: (1) are insufficiently mature from a project development perspective; (2) lack technical viability; (3) impose unacceptable financial accounting consequences for the electric distribution companies; (4) do not satisfy the minimum requirements set forth in Section 83D; (5) are not in compliance with RFP requirements pertaining to credit support; or (6) fail to satisfy minimum standards for bidder experience and ability to finance the proposed project (RFP § 2.2.2).[12]

2. Stage Two

In Stage Two, the Evaluation Team scores and ranks bids that meet the requirements of Stage One evaluation based on the results of quantitative and qualitative analyses (RFP § 2.3). The Evaluation Team will score proposals on a 100 point scale, with 75 points possible for quantitative factors and 25 points possible for qualitative factors (RFP § 2.3).

The Stage Two quantitative analysis process takes place in multiple steps. The first step consists of a screening process during which the Evaluation Team directly compares bids to determine whether bids are economically competitive when compared to other bids

[12] Of the approximate total 9,450,000 MWh of cost-effective clean energy contracts being sought in this RFP, the electric distribution companies encourage proposals that are able to commit to begin deliveries prior to the end of 2020 to maximize the Commonwealth's ability to meet its GWSA goals (RFP § 1.2.5).

(RFP § 2.3.1). The Evaluation Team will remove from further consideration bids that are, in the consensus of the Evaluation Team, not economically competitive based upon an objective benchmark (RFP § 2.3.1). The Evaluation Team will consider bids that it deems to be economically competitive based on their direct and indirect economic and environmental costs and benefits (RFP § 2.3.1). The Evaluation Team will conduct the review based on a combination of a bid's direct contract price and cost and benefits, and other costs and benefits to retail customers, where applicable, including, but not limited to: (1) impacts on electricity markets; (2) contribution to reducing winter electricity spikes; and (3) other winter or summer peak electricity market benefits (RFP § 2.3.1).

Direct contract price costs and benefits include, but are not limited to: (1) an evaluation of Clean Energy Generation on a mark-to-market comparison of the price of any eligible Clean Energy Generation under a contract to projected market prices at the delivery point with and without the project in-service; (2) an evaluation of new RPS Class I eligible resources on a mark-to-market comparison of the price of any eligible Clean Energy Generation under a contract to projected market prices at the delivery point with and without the project in-service; and (3) for proposals including transmission costs, the cost of the transmission, including associated interconnection and upgrade costs, and expected benefits, if any, of revenue from sales of excess transmission capacity (RFP § 2.3.1.2). Following its evaluation of the indirect economic benefits and direct contract benefits, the Evaluation Team will rank bids on the benefit-to-cost ratios of projects (RFP § 2.3.1.3).

Additional economic and environmental costs and benefits that the Evaluation Team may take into consideration include, but are not limited to: (1) impacts of changes on LMP customers in the Commonwealth pay and/or impact on production costs; (2) the environmental attributes of generation from Incremental Hydroelectric Generation and new Class I RPS eligible resources which the Evaluation Team may assess using an economic proxy value for their contribution to GWSA requirements; (3) additional impacts, if any, from the proposal on the Commonwealth's GHG emission rates and overall ability to meet GWSA requirements; (4) the economic impacts associated with resource firmness; and (5) indirect impacts, if any, for retail customers on the capacity or ancillary services market prices with the proposed project in service (RFP § 2.3.1.1).

The qualitative evaluation will consist of factors Section 83D requires as well as factors the Evaluation Team considers, including: (1) overall project viability; (2) operational viability; (3) extent to which the project can support the GWSA requirement by delivering Clean Energy Generation and/or RECs or environmental attributes on or before January 1, 2020; (4) siting and permitting considerations, including site control status and governmental permitting status; (5) reliability benefits; (6) benefits, cost, and contract risk; (7) environmental impacts from siting; and (8) economic benefits to the Commonwealth (RFP § 2.3.2).

3. Stage Three

In Stage Three, the Evaluation Team will consider remaining proposals based on Stage Two evaluation criteria and, at its discretion, the following factors: (1) the portfolio effect;[13] (2) risks associated with project viability of the proposals; (3) risks to customers associated with projects proposing to recover transmission costs through transmission rates not fully captured in the Stage Two evaluation; (4) benefits to customers not fully captured in the Stage Two evaluation; and (5) other considerations, as appropriate, to ensure selection of proposals providing the greatest impact and value consistent with the objectives of Section 83D (RFP § 2.4). The Petitioners state that the Stage Three evaluation will provide greater assurance that the proposed RFP will lead to successful results by using the Stage Two evaluation results as a guide to the Evaluation Team, while providing for the Evaluation Team to apply a reasonable degree of considered judgment based on the criteria in the RFP (RFP § 2.4). The Petitioners state that the objective of Stage Three is to select the proposal(s) that provide the greatest impact and value consistent with the stated objectives and requirements of Section 83D, as set forth in the RFP (RFP § 2.4). The Petitioners state that the Evaluation Team will prioritize viable projects that provide low-cost Clean Energy Generation with limited risk (RFP § 2.4).

C. Proposed Timetable

Table 1 below sets forth the proposed timetable for the bidding process (RFP § 3.1).

13 The Petitioners state that the portfolio effect is: (1) the overall impact of various portfolios of proposals on the Commonwealth's policy goals, as directed by DOER, including GWSA goals; and (2) the overall cost effectiveness of various portfolios of proposals (RFP § 2.4).

Table 1: Proposed Solicitation Timetable

Event	Anticipated Date[14]	Elapsed Time
Issue RFP	March 31, 2017	Day 0
Bidders Conference	April 14, 2017	Day 14
Submit Notice of Intent to Bid	April 21, 2017	Day 21
Deadline for Submission of Questions	April 21, 2017	Day 21
Due Date for Proposal Submissions	July 27, 2017	Day 120
Selection of Projects for Negotiation	January 25, 2017	Day 300
Negotiate and Execute Contracts	March 27, 2018	Day 360
Submit Contracts for Department Approval	April 25, 2018	Day 390

Once the Department approves the method and timetable for solicitation and execution of the long-term contracts, the Petitioners will promptly issue the RFP to a wide range of potentially interested parties (Petitioners Cover Letter at 5). The Petitioners state that, pursuant to Section 83D, they have consulted with: (1) DOER and the Attorney General regarding the choice of contracting methods and solicitation methods; and (2) DOER regarding the proposed timetable (Petitioners Cover Letter at 5). The Petitioners further state that the February 3, 2017 filing submitted to the Department represents an agreed upon timetable and method for the solicitation and execution of long-term contracts for renewable energy (Petitioners Cover Letter at 5).

14 Anticipated Date refers to the anticipated number of days from the date of issuance of the RFP.

III. INDEPENDENT EVALUATOR REPORT

A. Introduction

Section 83D requires that DOER and the Attorney General jointly select, and DOER contract with, an IE to submit: (1) a report to the Department analyzing the timetable and method for solicitation and the solicitation process implemented by the electric distribution companies and DOER, including recommendations, if any, for improving the process;[15] and (2) a report to the Department summarizing and analyzing the solicitation and bid selection process, and providing an independent assessment of whether all bids were evaluated in a fair and non-discriminatory manner to be submitted when the Department opens an investigation to review a proposed contract. Section 83D(f). Pursuant to Section 83D, DOER and the Attorney General selected Peregrine to serve as the IE with respect to this solicitation (IE Report at 1).[16]

The IE Report states that the structure of the solicitation, consistent with 83D, provides for bids from a variety of resources and products (IE Report at 2). Examples of the eligible resources, and potential decisions the Evaluation Team will consider are: (1) firm power from existing hydroelectric resources competing with unit-contingent intermittent power from new wind and solar RPS Class I generating facilities; and (2) generation-only

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15 Consistent with this provision, Peregrine submitted the IE Report on February 10, 2017.

16 The Petitioners state that Peregrine will also serve as IE during a solicitation for offshore wind generation under Section 83C of the Act that the electric distribution companies will conduct later this year (IE Report at 1).

bids under power purchase agreements ("PPA") competing with PPAs packaged with proposed new transmission projects (IE Report at 2). According to Peregrine, comparing these disparate types of proposals presents a challenge to the Evaluation Team (IE Report at 2). The IE concludes that, for the most part, the RFP satisfies Section 83D's standards for an open, fair, and transparent solicitation that is not unduly influenced by affiliates (IE Report at 2). However, the IE Report concludes that certain modifications to these standards could strengthen the RFP (IE Report at 2).

B. IE Conclusions and Recommendations

Peregrine concludes that, in some instances, the RFP applies stricter requirements to Class I RPS eligible resources than Section 83D, ISO New England ("ISO-NE") rules, the characteristics of these generating resources, and industry practices require (IE Report at 26). The IE contends that the RFP includes these stricter requirements for certain resources in order to maintain comparability with firm hydropower resources (IE Report at 26). In contrast, the IE contends that the RFP allows more lenient treatment of transmission proposals than warranted by these same authorities, particularly with respect to abandoned plant cost recovery (IE Report at 26). Accordingly, the IE recommends that the Department adopt the following four recommendations to increase the RFP's compliance with Section 83D's "fairness" requirements:

1. RPS Class I resources should not be required to incorporate in their bids the cost of network upgrades that go beyond those required to satisfy ISO-NE Capacity Capability Interconnection Standard;[17]

2. The Evaluation Team should be allowed to modify the requirement that bidders must provide studies based on the current serial ISO-NE interconnection study system to recognize the evolving status of a proposal by ISO-NE to convert to a cluster study system, which the New England Power Pool ("NEPOOL") Participants Committee approved on February 3, 2017;

3. If the Evaluation Team subsequently determines that renewable portfolio standard ("RPS") Class I RECs/environmental attributes will be valued in a way that is comparable to the valuation of the hydroelectric generation environmental attributes, the RFP and form PPA provisions allowing the electric distribution companies to not pay for RECs if there is an RPS change in law (such as elimination of the RPS law) should be eliminated because there are no similar provisions applicable to hydroelectric generation environmental attributes; and

4. Any transmission bidder will be required to limit the recovery of abandoned plant cost at the FERC, if it seeks such recovery, to costs incurred after the issuance of the RFP; recovery of development costs incurred before such time would not be allowed; losing bidders will not be able to recover abandoned plant costs; a winning transmission bidder will not have any right to recover abandoned plant costs from electric distribution companies until execution of contract(s) for its proposed project and receipt of required regulatory approvals, subject to any other negotiated limitations (IE Report at 27).

In addition to its four primary recommendations, the IE offers two suggestions that it contends could increase the transparency of the solicitation process (IE Report at 26). First, the IE states that it is willing to perform an independent oversight function with respect to monitoring of contract negotiations, which the IE contends would be most useful if a counterparty is an affiliate of one of the electric distribution companies (IE Report at 26).

[17] The Capacity Capability Interconnection Standard requires network upgrades to assure deliverability within the capacity zone in which the project is located, and is required in order for the project to qualify to provide capacity in the ISO-NE capacity market (IE Report at 14).

The IE states that the RFP provides that DOER has the right to perform that function, and that, while DOER oversight should be adequate, the IE's participation would provide a stronger degree of oversight, and would be consistent with prevailing industry practice (IE Report at 27). Lastly, the IE maintains that while the use of joint Subject Matter Experts ("SMEs") as proposed in the Standards of Conduct is acceptable, it would be preferable to eliminate the use of joint SMEs (IE Report at 27). The IE contends that the proposed joint use of SMEs by both the Selection Team and Evaluation Team increases the risk of transfer of confidential information between teams and may undermine the appearance of fairness and impartiality (IE Report at 27). The Department addresses each of the IE's recommendations in greater detail.in Section V, below.

IV. INITIAL MATTERS

A. Scope of the Department's Review

The scope of this proceeding is statutorily limited to a review of the timetable and method for soliciting long-term contracts for Clean Energy Generation. Section 83D(b)[18]. In RFP review proceedings such as this, we wish to avoid predetermining or limiting the consideration of proposed contracts or evaluation models. Long-Term Contracts for Renewable Energy, D.P.U. 15-84, at 22 (2015); Fitchburg Gas and Electric Light Company et al., D.P.U. 09-77, at 22 (2009), citing Long-Term Contracts for Renewable Energy,

18 The Department notes that any substantive issues related to the general criteria for long-term contracts and Clean Energy Generation sources are contained within Section 83D(d) and may be the subject of the Department's consideration of a proposed long-term contract filed pursuant to Section 83D. See 220 C.M.R. § 24.05.

D.P.U. 08-88-A at 10 (2009). We have found that to do so could constrain the flexibility of buyers and sellers in contract negotiations to seek the best sharing of risks and benefits under the contracts. D.P.U. 15-84, at 21; D.P.U. 09-77, at 21, citing D.P.U. 08-88-A at 10. Further, the Department has found that parties have the opportunity to raise all relevant substantive issues with respect to the evaluation of proposed projects, to all phases of contract development and negotiation, and to the specific terms and conditions contained in the resulting PPA(s) in the context of the adjudication before the Department of individual long-term contracts for renewable energy. See D.P.U. 15-84, at 21; D.P.U. 09-77, at 22; D.P.U. 08-88-A at 10.

We have found that the appropriate time to address these substantive issues is when each electric distribution company submits a proposed contract for Department approval. See D.P.U. 15-84, at 21; D.P.U. 09-77, at 22; D.P.U. 08-88-A at 10-11. Determinations regarding whether the specific contents of the contracts that result from this solicitation are consistent with the public interest and result in just and reasonable rates must be made in the context of individual adjudications, where the Department will weigh evidence and arguments in order to make fact-based decisions on a case-by-case basis. D.P.U. 15-84, at 21; D.P.U. 08-88-A at 10-11.

B. Participation of Other States in the Solicitation

4. Introduction

Section 83D provides, in part, that: "a solicitation may be coordinated and issued jointly with other New England states or entities designated by those states." Section

83D(b). Section 83D is otherwise silent with regard to the participation of other states in any subsequent phase of the contracting process. See Section 83D. Section 1.1 of the RFP states the following:

> The Commonwealth of Massachusetts will consider the participation of other states as a means to achieve the Commonwealth's clean energy goals if such participation has positive or neutral impact on Massachusetts ratepayers. If the Commonwealth[19] determines that such participation provides a reasonable means to achieve its clean energy goals cost effectively through multi-state coordination and contract execution, a portion of selected projects may be allocated to one or more electric distribution companies in such state, subject to applicable legal requirements in the Commonwealth and the respective state (RFP § 1.1, n.8).

CMP is the only party to comment on the potential participation of other states in this solicitation. CMP states that it supports the participation of other states in the RFP process because doing so could enhance economies of scale, product offering diversity, and risk sharing, but recommends that the RFP more clearly define how the Petitioners will facilitate any such participation (CMP Comments at 4). CMP specifically seeks greater clarity regarding: (1) whether other states will issue separate solicitations with separate evaluation criteria; (2) whether the Petitioners will share the bids received in this solicitation with representatives from other states; and (3) what measures the Petitioners will take to protect bid confidentiality (CMP Comments at 4).

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19 The Petitioners state that, in the context of the participation of other states in this solicitation and/or procurement process, "the Commonwealth" consists of the electric distribution companies and DOER (Exh. DPU 1-3).

5. Analysis and Findings

The Petitioners represent that they will not issue the RFP jointly with other states (Exh. DPU 1-1). They also represent that the Commonwealth has not yet made any determination regarding the future participation of other states (Exh. DPU 1-2). Specifically, the Petitioners state:

> Section 83D contemplates coordination with other New England states as a part of this solicitation process. The Commonwealth has not yet made any determination regarding the participation of other states, but Section 1.1, n.8 leaves open the option for such participation. A future determination regarding participation of other states will be based upon whether such multi-state participation provides a neutral or beneficial impact, for Massachusetts ratepayers, on the cost-effectiveness of proposals received in response to the RFP. Such determination would be made during the evaluation process, utilizing the methodology and criteria enumerated in the Stage Two Quantitative and Qualitative Analysis and Stage Three Portfolio Analysis, as applicable, to determine the impact of multi-state participation on the cost-effectiveness of proposals for Massachusetts ratepayers of allocating a portion of selected projects to one or more electric distribution companies in the New England states (Exh. DPU 1-2).

Based on the above representations, other states will not participate in the solicitation process, but may begin their participation during the bid evaluation process (Exh. DPU 1-2). We note that this arrangement may be inconsistent with Section 83D(b)'s provision that any other states should begin their participation during the solicitation of bids. Thus, if the Petitioners allow other states to participate during the evaluation process, the Petitioners must demonstrate that any resulting contracts comply fully with Section 83D and the Department's regulations. Furthermore, consistent with the Petitioners' representations, we will also expect the Petitioners to show that the involvement of other states resulted in a neutral or beneficial impact, specifically for Massachusetts ratepayers.

We decline to direct the Petitioners to remove the possibility of multi-state participation in the evaluation process from the RFP. It is our expectation that any method an electric distribution company uses to solicit and enter into long-term contracts with developers of Clean Energy Generation will be developed and implemented in a manner that is consistent with the intent and language of Section 83D, and we will consider this compliance at the time we review any executed contracts proposed to the Department for approval. See D.P.U. 15-84, at 23; D.P.U. 09-77, at 24. The Department emphasizes that we, and not the electric distribution companies, are the final arbiters of whether such proposals are reasonable and whether the resulting long-term contracts achieve the objectives of Section 83D. See D.P.U. 15-84, at 23.

C. Negative Locational Marginal Price

4. Introduction

On March 10, 2017, the Petitioners submitted the Second Supplemental Filing in which they propose to include a new Section 2.2.1.4.i.(f) of the RFP to address instances of negative LMPs that may occur in a PPA resulting from this Section 83D solicitation. [20] Specifically the Petitioners added language that states under the terms of the PPA, in the event that LMP for Clean Energy at the delivery point is negative, the buyer will purchase the delivered energy at the contract rate (RFP § 2.2.1.4 (f)). Further, the seller, in its

[20] The Petitioners state they have consulted with DOER and the Attorney General regarding this additional revision to the RFP, and are authorized to represent that both DOER and the Attorney General support its inclusion in the final version of the RFP (Second Supplemental Filing at 2).

monthly invoice, is required to credit the buyer an amount equal to the product of the Clean Energy delivered and the absolute value of the hourly LMP at the delivery point (RFP § 2.2.1.4 (f)). The Petitioners submitted the Second Supplemental Filing after the close of comments. None of the commenters requested leave to respond to the Second Supplemental Filing.

5. Analysis and Findings

Section 2.2.1.4.i.a. of the RFP provides that a proposal to sell Clean Energy Generation and associated environmental attributes from Firm Service Hydroelectric Generation pursuant to a contract must propose a price either: (1) on a $/MWh basis; or (2) indexed at or below the ISO-NE Day Ahead or Real-Time LMP (RFP § 2.2.1.4 (a)). The Petitioners assert that the proposed addition of Section 2.2.1.4.i.f. is necessary to address instances of negative LMPs that may occur in a PPA resulting from this Section 83D solicitation. Although the Petitioners submitted the Second Supplemental Filing following the close of this proceeding's comment period, we find that potential instances of negative LMPs do not implicate matters related to the timetable and method for solicitation and execution of contracts that may result from the RFP. We find that it is beyond the scope of this proceeding, and may be more appropriately addressed in the context of a long-term contract review proceeding. Accordingly, we accept the Second Supplemental Filing and the inclusion of proposed Section 2.2.1.4.i.f. in the final version of the RFP.

V. ISSUES RAISED BY COMMENTERS

A. Timing of Solicitation

1. Introduction

The proposed RFP provides the selection of projects for negotiation will occur 300 days from RFP issuance, or January 25, 2018, assuming that the RFP issues on April 1, 2017 (RFP § 3.1). Two commenters propose modifications to the timing of the solicitation (see Emera Comments at 6-7; TDI-NE Comments at 2-3).

2. Summary of Comments

Emera argues that, in order to avoid increased carrying costs and project risk associated with requiring proposals to be valid for 240 days from the date of submission, the timeframe for selection of winning bidders should be shortened from 300 days to 200 days (Emera Comments at 6). TDI-NE agrees with Emera that the timeline should be shortened and recommends decreasing the RFP timeline by 90 days (TDI-NE Comments at 2). TDI-NE argues that this revised timeline is reasonable because: (1) it will help bidders reach the electric distribution companies' goal of beginning deliveries prior to the end of 2020 to maximize the Commonwealth's ability to meet its GWSA goals; (2) the draft RFP clearly lays out the evaluation criteria so the Evaluation Team should have ample guidance and time to efficiently review the bids within 90 days; and (3) potential bidders have been aware since August 2016 that the bid would be released on April 1, 2017, and have had ample time to start to prepare their bids (TDI-NE Comments at 3).

3. Analysis and Findings

The Department notes that DOER supports the proposed timetable for solicitation of Clean Energy Generation as provided in the RFP (see DOER Comments). Because Section 83D affords DOER a consultative role in the process, we have found it appropriate to give considerable weight to DOER's judgment in matters pertaining to the development of the timetable and method for solicitation and execution of long-term contracts, including DOER's consideration of carrying costs and project developer risks. See D.P.U. 15-84, at 24; D.P.U. 09-77, at 21-22. The Department finds that the RFP's proposed timetable provides sufficient time to solicit competitive bids and is reasonable.[21] Furthermore, consistent with Section 83D, the electric distribution companies developed the timetable for soliciting and executing long-term contracts for renewable energy with DOER in consultation with the Attorney General. Therefore, we approve the proposed timetable for solicitation of Clean Energy Generation as provided in the RFP.

B. Bidder Eligibility

1. Introduction

The RFP defines an "eligible bidder" as "the owner of Clean Energy Generation" or as an entity "in possession of the development rights to Clean Energy Generation" (RFP

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[21] Section 83D requires that the electric distribution companies conduct one or more competitive solicitations through a staggered procurement schedule that the electric distribution companies and DOER develop and that the schedule must ensure that the electric distribution companies enter into cost-effective long-term contracts for Clean Energy Generation equal to approximately 9,450,000 megawatt-hours by December 31, 2022.

§ 2.2.1.1). The RFP also allows for the following four categories of bids: (1) Clean Energy Generation from Incremental Hydroelectric Generation via long-term contract; (2) Clean Energy Generation from new Class I RPS eligible resources via long-term contract; (3) Clean Energy Generation and Class I environmental attributes/RECs via long-term contract from a combination of incremental hydropower generation and new Class I RPS eligible resources; and (4) Clean Energy Generation from incremental hydropower generation and/or new Class I RPS eligible resources with Class I environmental attributes and/or RECs via long-term contract with a transmission project under a FERC tariff (RFP § 2.2.1.3). Certain commenters argue that the definition of "eligible bidder" and categories of eligible bids should be broadened to allow for transmission-only bids (see, e.g., CMP Comments at 5-6; EETV Comments at 2; GridAmerica Comments, Attachment A at 11; HQUS Comments at 3-4).

2. Summary of Comments

CMP, EETV, GridAmerica, and HQUS maintain that the RFP's definition of "eligible bidder" should be broadened to include transmission owners and/or entities in possession of the development rights to transmission facilities, in addition to energy generation owners (CMP Comments at 5-6; EETV Comments at 2; GridAmerica Comments, Att. A at 11; HQUS Comments at 3-4). Brookfield Renewable and Emera suggest that the RFP's definition of "eligible bidder" be amended to include bidders that have contractual rights to deliver Clean Energy Generation (Brookfield Renewable Comments at 4; Emera Comments at 21-22).

Similarly, commenters argue that the RFP should be amended to include independent transmission projects as an additional eligible bidding category (CEC Comments at 1-2; GridAmerica Comments at 2-5; GridAmerica Reply Comments at 5-6; NEEC Reply Comments at 4). CEC and GridAmerica assert that allowing transmission-only projects to participate in the RFP will ensure that the Petitioners select the most cost-effective transmission projects (CEC Comments at 1-2; GridAmerica Comments at 4; GridAmerica Reply Comments at 5-6). CEC maintains that including transmission-only projects in the solicitation would result in a more efficient process by mitigating the risk of litigating transmission-only options during the contract review process (CEC Comments at 3). GridAmerica argues that the Department has declined to limit the bid categories in prior RFP review proceedings, and that including transmission-only bids would result in the most cost-effective and executable means of delivering the best generation bids and pairing those projects to arrive at the optimal delivered procurement solution for customers (GridAmerica Comments at 4, citing D.P.U. 15-84, at 21-25). GridAmerica argues that the RFP should allow for transmission-only bids because the Evaluation Team will then have the opportunity to identify the most cost-effective and executable means of delivering the best generation bids and to pair those projects to arrive at the optimal delivered procurement solution for customers (GridAmerica Comments at 4).

TDI-NE requests clarification of the RFP with regard to the preferred bidding and contractual arrangement between energy suppliers, transmission developers, and electric distribution companies (TDI-NE Comments at 1). TDI-NE states that it appears that the

RFP's preferred arrangement is an energy producer-only contract, but that the RFP also implies that transmission developers could have a contractual arrangement directly with the electric distribution companies for the transmission lines (TDI-NE Comments at 1).

In response to these comments, the Petitioners argue that the definition of "eligible bidder" appropriately requires that bids be tied to specific Clean Energy Generation projects, consistent with Section 83D (Petitioners Reply Comments at 3). The electric distribution companies assert that the Department should reject arguments for adding transmission-only bids, because doing so would not further the purpose of Section 83D, specifically the obligation to enter into cost-effective contracts for Clean Energy Generation (Petitioners Reply Comments at 2-3). The Petitioners reject the arguments that the requirements in the RFP to include associated transmission costs in bids and to authorize the recovery of transmission costs through federal transmission rates imply that transmission-only bids should be permitted (Petitioners Reply Comments at 2-3).

The Petitioners argue that it is clear that the RFP permits packaged bids with generation and transmission components, including bids submitted jointly by an owner of Clean Energy Generation development rights to Clean Energy Generation and a transmission developer that does not own such rights (Petitioners Reply Comments at 3, citing RFP § 2.2.1.3(iv)). Accordingly, the Petitioners maintain that the RFP is sufficiently clear that packaged bids for Clean Energy Generation and transmission are eligible.

3. Analysis and Findings

Regarding requests for a clarification of the eligibility of packaged bids for energy and transmission, we find the RFP is clear. RFP § 2.2.1.3(iv) allows for a "proposal to develop a transmission project as part of a packaged bid with the Incremental Clean Energy Generation resources." Regarding the alleged preference in the RFP for energy-only projects to packaged bids for energy and transmission, we find no support in the RFP for such an assertion (see TDI-NE Comments at 1). Having found that the RFP's provisions are clear with regard to the eligibility of packaged bids for energy and transmission, we decline to direct the Petitioners to clarify the definition of "eligible bidder" in this RFP.

Furthermore, we decline to direct the Petitioners to revise the RFP to expand the definitions of "eligible bidders" and categories of eligible bids. GridAmerica's argument regarding Department precedent on RFP eligible bid categories misapplies that precedent (see GridAmerica Comments at 4). In D.P.U. 15-84, the Department was addressing comments that recommended the elimination from the RFP of specific products that the electric distribution companies had included as eligible bid categories in the RFP.[22] D.P.U. 15-84, at 23. Here, the opposite holds, as certain commenters propose the inclusion in the RFP of an additional category of eligible projects the Petitioners have not proposed in the RFP (see CEC Comments at 1-2; GridAmerica Comments at 2-5). In the instant case, the Petitioners have properly applied the requirements of Section 83D in developing the RFP's four eligible

22 Specifically, the various commenters recommended removal of bids for hydroelectric power and bids using a delivery commitment model. D.P.U. 15-84, at 23.

bid categories.[23] Section 83D includes no requirement that the electric distribution companies include a transmission-only bid category. See Section 83D. Because the electric distribution companies developed the RFP's four eligible bid categories consistent with the requirements of Section 83D, the Department declines to require the electric distribution companies to incorporate transmission-only projects as an eligible category in this RFP.

C. Proposed Bid Requirement Revisions

1. Introduction

With regard to suggested bid requirement revisions, various commenters addressed the following topics: (1) product definition; (2) site control; (3) forms of security; (4) experience and expertise; (5) RFP requirement inconsistencies; (6) form PPA; (7) commercial availability; (8) liquidated damages; (9) abandonment costs; and (10) change in RPS provision. Each topic is discussed in further detail below.

2. Product Definition - Incremental Hydroelectric Generation

a. Introduction

The RFP defines "Incremental Hydroelectric Generation" as:

> "Firm Service Hydroelectric Generation that represents a net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the 3 year historical average and/or otherwise expected delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England Control Area" (RFP § Definitions).

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23 Section 83D requires that, in developing long-term contracts for Clean Energy Generation, the electric distribution companies consider long-term contracts for renewable energy certificates for energy and for a combination of both renewable energy certificates and energy, if applicable. Section 83D(c).

Certain commenters argue that the electric distribution companies should clarify or broaden the definition of "incremental" as it pertains to "Incremental Hydroelectric Generation" (Brookfield Renewable Comments at 3-4; HQUS Comments at 7-8; Pattern Comments at 2).

b. Summary of Comments

Regarding the definition of "Incremental Hydroelectric Generation," Pattern contends that the inclusion of "and/or otherwise expected delivery of hydroelectric generation from the bidder" introduces the potential for gaming and subjectivity, and that a sensible verifiable standard is the three-year historical average (Pattern Comments at 2). Pattern maintains that the three-year historical average should be used in this definition and requests that the electric distribution companies clarify that this means the annual quantities of hydroelectric generation from the years ending in 2014 through 2016 (Pattern Comments at 2). Furthermore, Pattern argues that the three-year historical average should be verifiable by government data such as the National Energy Board electricity export reports or should be tracked against the Canadian electricity export authorization numbers (Pattern Comments at 2).

HQUS argues that the current definition could be interpreted to require a bidder to agree to a continuous expected delivery commitment for the 2014-2016 average quantities in addition to the RFP bid quantities (HQUS Comments at 7). However, HQUS also indicates that the language in Appendix B of the RFP limits the bid requirement to committing the capability of the generation resource under the bid proposal at the time the bid is submitted, rather than requiring a proposal for a delivery commitment for the historical deliveries

(HQUS Comments at 7-8). HQUS therefore recommends that the definition of "Incremental Hydroelectric Generation" should be amended as follows:

> Incremental Hydroelectric Generation means Firm Service Hydroelectric generation that is capable of providing net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the 3 year historical average delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England Control Area (HQUS Comments at 8).

Emera and RENEW object to HQUS' proposal, arguing that the proposed amendment would result in a situation where the RFP requires only that the bidder indicate a hypothetical ability to provide a net increase to its current hydroelectric generation delivery volumes, not a commitment to increase such delivery (Emera Reply Comments at 5; RENEW Reply Comments at 2-3).

Brookfield Renewable recommends broadening the definition of "Incremental Hydroelectric Generation" to enable eligibility of all firm service hydroelectric generation not already accounted for in Massachusetts' most recent greenhouse gas emissions inventory, regardless of whether it is located within or outside of the New England control area (Brookfield Renewable Comments at 3-4). Brookfield Renewable argues that broadening the definition in this manner would provide demonstrable incremental carbon benefits to Massachusetts and allow increased competition, which should therefore reduce overall RFP costs to the Commonwealth (Brookfield Renewable Comments at 4). Emera counters that Brookfield Renewable's proposed change would allow resources that are already delivering to the New England control area to be eligible under this RFP rather than introduce new Clean Energy Generation to the market through the RFP (Emera Reply Comments at 6-7).

c. Analysis and Findings

Regarding the definition of "Incremental Hydroelectric Generation" the Department agrees with Emera and RENEW's argument concerning HQUS' proposed amendments (see Emera Reply Comments at 5; RENEW Reply Comments at 2-3; HQUS Comments at 7). The Department agrees that there would be a risk to ratepayers if an electric distribution company entered into a contract with a bidder based on the bidder's capability to provide a net increase in MWh/year of hydroelectric generation. If the bidder subsequently failed to provide a net increase in generation, ratepayers would have paid for a service (i.e., Incremental Hydroelectric Generation) that the bidder did not deliver. In addition, Section 83B's definition of "New Class I renewable portfolio standard eligible resources" states that there must be a "net increase from incremental new generating capacity." Because Section 83D was designed to "facilitate the financing of Clean Energy Generation resources," the Department finds that the electric distribution companies appropriately applied discretion when determining that hydroelectric generation should be incremental. Therefore, the Department rejects the Brookfield Renewable, HQUS, and Pattern recommendations that the electric distribution companies change the RFP's definition of "Incremental Hydroelectric Generation".

3. Site Control

a. Introduction

With respect to site control requirements, the RFP requires that the bidder:

> "demonstrate that it has control or an irrevocable option [...] to acquire control over the site for its proposed generation project, including any rights necessary

> to access the project site. If a bid includes associated transmission […], the bidder must specifically describe the portions of the transmission route for which the bidder has control and must demonstrate, with specificity, a reasonable and achievable plan to acquire control over the remainder of the transmission route and access to that route" (RFP § 2.2.2.1).

The RFP also details the documentation that the bidder must provide to demonstrate that it has control or rights to acquire control of a site (RFP § 2.2.2.1). Several commenters recommend amendments to the site control requirements of the RFP (see Emera Reply Comments at 10; RENEW Comments at 5; TDI-NE Comments at 2).

b. Summary of Comments

TDI-NE recommends that the site control requirements for transmission lines be the same as those applicable for generation sites (TDI-NE Comments at 2). Emera and NEEC disagree with TDI-NE's recommendation (Emera Reply Comments at 9-10; NEEC Reply Comments at 5). Emera argues that TDI-NE does not provide a reason for requesting the change and therefore infers that the request would serve to benefit TDI-NE's transmission proposal at the expense of other proposals (Emera Reply Comments at 9-10). NEEC maintains that the Section 2.2.2.1 of the RFP appropriately provides that transmission providers must show that a "bidder must specifically describe the portions of the transmission route for which the bidder has control and must demonstrate, with specificity, a reasonable and achievable plan to acquire control over the transmission route and access to that route" (NEEC Reply Comments at 5).

Emera suggests striking a provision in Section 2.2.2.1 of the RFP subjecting generator leads in transmission generation combined projects to the same site control requirements required of standalone projects (Emera Reply Comments at 10). Emera argues that it is likely to be impractical to document current site control for most generators given the nature of the approvals required and the fact that generators generally obtain such control later in the project development process (Emera Reply Comments at 10). RENEW contends that more flexibility should be provided to meet site control requirements (RENEW Comments at 5). RENEW argues that a bidder should be able to demonstrate site control by =letters of intent, which previous Massachusetts long-term contract RFPs allowed, rather than via site leases (RENEW Comments at 5).

c. Analysis and Findings

In its review of the method of solicitation described in the RFP, the Department seeks to balance the goals of promoting project viability while ensuring the RFP is competitive and does not inappropriately disadvantage any project. See D.P.U. 08-88, at 10; D.P.U. 09-77, at 20; D.P.U. 15-84, at 48. Previous long-term contract solicitations under Sections 83 and 83A resulted in approval of long-term contracts for projects whose developments failed, and the Department consequently encouraged the electric distribution companies to collaborate with DOER and the Attorney General to develop additional evaluation criteria, including site control requirements, to assess project viability as part of the subsequent Section 83A solicitation. See D.P.U. 13-146 through D.P.U. 13-149, at 84.

In D.P.U. 15-84, we found that it was appropriate to require generation projects to demonstrate a "substantial level of site control" at the time of bid submission and a "credible plan for acquiring remaining property interests" to participate in the solicitation.

D.P.U. 15-84, at 48. Here, we find that the RFP's more stringent site control requirements both for transmission and generation projects are reasonable and not unduly restrictive given Section 83D's intent for the electric distribution companies to enter into cost-effective contracts for the firm delivery of Clean Energy Generation by December 31, 2022 (see RFP § 2.2.2.1). We expect the Petitioners to apply the site control provisions of the RFP reasonably during the bid evaluation process. Moreover, in any future filings that result from this solicitation, we expect the electric distribution companies to provide full documentation demonstrating that the Evaluation Team fairly and consistently applied these bid evaluation criteria across all bids. See D.P.U. 15-84, at 48-49. Accordingly, the Department will not require any revisions to the site control requirements in the RFP.

4. Form of Security

a. Introduction

The RFP requires bidders to post security in the form of cash or a letter of credit from a bank that meets certain minimum standards (RFP § 2.2.2.11). Certain commenters request that the electric distribution companies amend the security requirements to allow a parent company guarantee (Bay State Wind Comments at 7; GridAmerica Comments at 4) and another commenter proposes that bidders submit a letter of credit with their bids (TDI-NE Comments at 1).

b. Summary of Comments

Bay State Wind and GridAmerica maintain that, in lieu of cash or a letter of credit, a bidder should be able under appropriate circumstances to employ the use of a parent company guarantee, which these commenters argue has the potential to reduce financing costs significantly and would encourage greater participation in the solicitation (Bay State Wind Comments at 7; GridAmerica Comments at 4). Bay State Wind contends that the savings from use of a parent company guarantee would then be passed on to consumers in the form of a lower electricity price (Bay State Wind Comments at 7). Bay State Wind argues that the use of a parent company guarantee should be allowed only when the parent company: (1) reports assets on its most recent balance sheet of at least $10 billion; and (2) has an investment grade credit rating (Bay State Wind Comments at 7). CMP requests that the Department clarify Section 2.2.2.11 of the RFP regarding the duration of time the electric distribution companies would hold all security posted for transmission projects and the circumstances, if any, when such security would be returned to the transmission developer (CMP Comments at 13).

TDI-NE recommends that in addition to the non-refundable bid fees, bids should be accompanied by a letter of credit (TDI-NE Comments at 1). TDI-NE maintains that the Petitioners would return the letter of credit to bidders who do not execute long-term contracts or would credit it to bidders who execute contracts per the security requirements outlined in Section 2.2.11 of the RFP (TDI-NE Comments at 1).

c. Analysis and Findings

We find that matters pertaining to forms of security exceed the statutory authority granted to the Department by Section 83D to review and approve the timetable and method for solicitation of long-term contracts. See Section 83D. Forms of security represent subject matter that more appropriately fall within the purview of a contract review proceeding. Accordingly, we decline to direct the Petitioners to revise this aspect of the RFP.

5. Experience and Expertise

a. Introduction

The RFP requires bidders to demonstrate that they have sufficient relevant experience and expertise to successfully develop, finance, construct, operate, and maintain the project in a cost-effective manner (RFP § 2.2.2.3). One commenter maintains that the experience and expertise requirements set forth in the RFP should be more stringent (Bay State Wind Comments at 11).

b. Summary of Comments

Bay State Wind maintains that it appreciates the standards set forth in Section 2.2.2.3 of the RFP regarding a bidder's requisite level of experience and expertise in project development and financing. However, Bay State Wind argues that the current language of the RFP allows a bidder that has never actually developed or financed a project of similar size, technology, or complexity to demonstrate that it has sufficient relevant experience and expertise to successfully develop and finance its proposed project (Bay State Wind Comments at 11). Bay State Wind recommends that the RFP require bidders to demonstrate their experience and expertise requirement by satisfying the following standards: (1) successful development and construction of one or more projects of similar type, size, and complexity; and (2) successful financing of power generation or transmission projects or demonstrating the ability to finance the project (Bay State Wind Comments at 12).

In response to Bay State Wind's concerns, NEEC argues that FERC Order No. 1000 sets forth technical and financial qualification standards that address the potential for bid submission by unqualified or inexperienced transmission (NEEC Reply Comments at 5-6). NEEC maintains that it would not object if the Department relies on the existing ISO-NE qualified transmission developer qualification process as evidence for meeting the requirements of Section 2.2.2.3 of the RFP (NEEC Reply Comments at 5-6).

c. Analysis and Findings

We find that matters pertaining to bidder experience and expertise exceed the statutory authority granted to the Department by Section 83D to review and approve the timetable and method for solicitation of long-term contracts. See Section 83D. Bidder experience and expertise represent subject matters that more appropriately fall within the purview of a contract review proceeding. Accordingly, we decline to direct the Petitioners to revise this aspect of the RFP.

6. RFP Requirement Inconsistencies

a. Introduction

Two commenters maintain that there is an inconsistency in the RFP between Section 1.7.2 and other portions of the RFP (CMP Comments at 5; EETV Comments at 2).

b. Summary of Comments

CMP and EETV assert that certain sections in the RFP may warrant review by the electric distribution companies. CMP and EETV contend that Section 1.7.2 (Proposal Validity) establishes a 240-day validity period but that other portions of the RFP require a longer period (CMP Comments at 5; EETV Comments at 2). CMP and EETV also maintain that items from Section 3.4 of the RFP (Organization of the Proposal), such as item 3 (transmission pricing information), are not included in Appendix B, although Section 3.4 of the RFP states that Section 3.4 and Appendix B contain consistent instructions (Proposal Submission Instructions) (CMP Comments at 16; EETV Comments at 2, citing RFP § 3.4). In response to CMP's and EETV's comments, the electric distribution companies indicate that they will correct the RFP prior to its issuance to state that the validity period for proposals should be 270 days and that the language of the RFP will be consistent between Section 3.4 and Appendix B (Petitioners Reply Comments at 11).

c. Analysis and Findings

CMP and EETV raise issues regarding an inconsistency between the 240 day validity period and other portions of the RFP that require a longer period. In response, the electric distribution companies concede that a correction to the RFP prior to issuance is warranted to state that the validity period for proposals should be 270 days, and that doing so will maintain consistency with other sections of the RFP, specifically Section 3.4 and Appendix B. The Department finds it appropriate for the Petitioners to make these changes, and directs the Petitioners to do so prior to issuance of the RFP.

7. Form Power Purchase Agreement

a. Introduction

As part of a responsive bid, bidders must provide any exceptions to the form PPA (RFP, Appendix B). The RFP itself does not include a form PPA. One commenter, Bay

State Wind, requests that the electric distribution companies release a form PPA for public comment as soon as possible (Bay State Wind Comments at 3-5).

b. Summary of Comments

Bay State Wind represents that the RFP does not provide substantive detail on certain issues of importance to developers of large-scale projects, particularly force majeure issues and applicability of liquidated damages (Bay State Wind Comments at 3-4). Bay State Wind argues that the lack of detail in the RFP is primarily attributable to the absence of a form PPA in the RFP (Bay State Wind Comments at 4). Bay State Wind requests that the electric distribution companies release the form PPA for public comment as soon as possible (Bay State Wind Comments at 5). Lastly, Bay State Wind argues that, if bidders are not able to provide comments ahead of time, bidders should not be penalized in the evaluation process for proposing reasonable revisions to the form PPA that are intended to address project specific concerns, and which could result in a lower delivered cost of electricity to consumers (Bay State Wind Comments at 5). The Petitioners state that form PPA remained under development when the RFP was submitted for approval, and was therefore unavailable for inclusion, and that a review of form PPAs is not required during Department RFP review proceedings (Exh. DPU 1-9).

c. Analysis and Findings

The Department is required to approve the timetable and method for the solicitation and execution of long-term renewable contracts for Clean Energy Generation as set forth in the RFP. Section 83D. While public review of form PPAs prior to bid submission would allow stakeholders an opportunity to comment on the form PPAs, the Department has not required the opportunity for such public review in previous solicitations. See D.P.U. 15-84, at 53, citing Long-Term Contracts for Renewable Energy, D.P.U. 13-57. We note that although bidders are discouraged from proposing material changes to the form PPAs, they are not prohibited from proposing any changes, material or otherwise, to the form PPAs should they determine that such changes are appropriate (RFP § 2.2.1.10). Because bidders have an opportunity to propose revisions to the form PPAs when they make their bids, we decline to accept Bay State Wind's proposal that the Department require the Petitioners to provide the form PPAs for public review prior to the issuance of the RFP. However, we encourage the Petitioners in future solicitations to make the form PPAs and other required bidder forms available for public review prior to issuance of an RFP, as appropriate.

8. Commercial Availability

The RFP requires that a bidder demonstrate that the technology it proposes to use is technically viable (RFP § 2.2.2.2). Bidders may demonstrate technical viability by showing that the technology is commercially available and has been used successfully (RFP § 2.2.2.2). One commenter argues that bidders should be able to propose "next generation" technology instead of commercially available technology (Bay State Wind Comments at 5-6).

a. Summary of Comments

Bay State Wind argues that the RFP requires that bidders demonstrate that the proposed technology is ready and deployable at the time of the bid, for transfer to the design and construction phases (Bay State Wind Comments at 5, citing RFP § 2.2.2.2). Bay State Wind argues that many of the power generation technologies that are currently "commercially available" continue to be significantly refined and upgraded, and that the use of "next generation" equipment should not be discouraged (Bay State Wind Comments at 5). Furthermore, Bay State Wind argues that the long lead-time for generation resources such as wind may cause a gap of several years between the award of a PPA and the procurement of the specific wind turbine generators (Bay State Wind Comments at 6). Bay State Wind therefore requests that the electric distribution companies clarify that the term "commercially available" does not preclude bidders from having the flexibility to propose the use of "next generation" or "upgraded" technologies as appropriate (Bay State Wind Comments at 6).

b. Analysis and Findings

Bays State Wind asserts that bidders should be able to propose "next generation" technology instead of commercially available technology as part of the bid process. In our review of Section 2.2.2.2 of the RFP, we find that it appropriately balances the goals of promoting project viability while ensuring the RFP is competitive, and does not inappropriately disadvantage any project because the term "commercially available" does not restrict any type of technology. See D.P.U. 08-88, at 10; D.P.U. 09-77, at 20; D.P.U. 15-84, at 48. As such, it is incumbent on the prospective bidders to address their technology preferences in their specific responsive bids. Accordingly, we decline to direct the Petitioners to change the RFP's definition of "commercially available".

9. Liquidated Damages

a. Introduction

The proposed RFP requires the seller to be responsible for liquidated damages associated with its failure to meet delivery obligations (RFP §§ 2.2.1.3, 2.2.2.7). Several commenters raise concerns regarding the lack of information on how the electric distribution companies propose to calculate and assess liquidated damages (see CLF Comments at 5; Longroad Comments at 4-5; Pattern Comments at 3). These commenters suggest that the final RFP should specify the terms of liquidated damages (see CLF Comments at 5; Longroad Comments at 4-5; Pattern Comments at 3).

b. Summary of Comments

CLF suggests that the final RFP should define an industry standard liquidated damages provision that specifies the amount and terms of liquidated damages (CLF Comments at 5). Pattern is also concerned that the proposed RFP does not disclose the terms of liquidated damages (Pattern Comments at 3).

Longroad argues that the proposed RFP contains little information on how the Evaluation Team would calculate and assess liquidated damages, therefore making it extremely difficult to understand the extent of the risk of missing the required delivery commitment (Longroad Comments at 4-5). Longroad recommends that the RFP set liquidated damages at a fixed $/MWh price, or market-based with a floor and ceiling capped at the actual damages of the buyer (Longroad Comments at 5). Brookfield Renewable recommends that the RFP include reasonable mitigation options to the firmness requirements, such as a cap on liquidated damages (Brookfield Renewable Comments at 3).

c. Analysis and Findings

The Department has held in previous RFP review proceedings that consideration of the need for and form of a liquidated damages provision is a matter best addressed by the electric distribution companies in the course of contract negotiations. D.P.U. 15-84, at 54. We find that the same reasoning applies here. Section 83D is silent with regard to the imposition of liquidated damages. See Section 83D. Accordingly, we decline to accept commenters' recommendations that we direct the Petitioners to modify the RFP to address liquidated damages and we expect parties to address the particulars of any liquidated damages provisions during the course of contract negotiations.

10. Abandonment Costs[24]

a. Introduction

Section 2.2.2.6.2 of the RFP provides that, if a bidder cancels or abandons a transmission project under the RFP, the bidder will be allowed to propose to recover its abandonment costs from the electric distribution companies, consistent with FERC rules and policies, unless the abandonment was caused directly or indirectly by an act or failure to act of the bidder (RFP § 2.2.2.6.2). The RFP states that the evaluation process will favor proposals that do not seek to recover abandonment costs from ratepayers or that include limits on abandonment costs (RFP § 2.2.2.6.2). The IE and the Attorney General contend that the RFP should contain more stringent

[24] The RFP defines abandonment costs as prudently-incurred project-related costs (RFP § 2.2.2.6.2).

restrictions for recovering abandoned costs, while the Petitioners maintain that the RFP's provision is appropriate (see Attorney General Comments at 7-8; IE Report at 25; Petitioners Reply Comments at 5-6).

b. Summary of Comments

The Attorney General agrees with the IE recommendation that the RFP should minimize ratepayer exposure to abandonment cost risk (Attorney General Comments at 7-8, citing IE Report at 25). The Attorney General recommends that the RFP limit recovery of abandonment costs to costs incurred incur after the passage of Section 83D, while the IE recommends limiting abandoned cost recovery to those costs incurred after issuance of the RFP (Attorney General Comments at 7-8; IE Report at 24-25). Both contend that developers who incurred costs either prior to the passage of Section 83D or prior to the issuance of the RFP should bear the risks of those costs (Attorney General Comments at 7-8; IE Report at 24-25). The electric distribution companies maintain that the RFP encourages bidders to place a limit on abandonment costs favoring such proposals, and argue that this provision will result in more competitive proposals (Petitioners Reply Comments at 5-6).

c. Analysis and Findings

The electric distribution companies have a public service obligation to provide reliable service at the lowest cost to customers. Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 6-7 (1986) (citations omitted); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986); Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57 (2009). This public service obligation also requires a distribution company "to represent the best interests of its ratepayers." Western Massachusetts Electric Company, D.T.E. 04-40/D.T.E. 04-109/D.T.E. 05-10, at 5-6 (2006); D.T.E./D.P.U. 06-107-B at 57. In that regard, while remaining mindful of the Department's mission and charge to ensure that utility consumers are provided with the most reliable service at the lowest possible cost, we note that the RFP's stated favoring of proposals that limit abandoned costs will help to limit ratepayer exposure to abandoned costs by encouraging bidders to minimize the amount of abandoned costs included in their bids (see RFP § 2.2.2.6.2). However, we further note that this is not a matter that implicates this RFP's timetable and method for solicitation, and that it would be more appropriately addressed during a long-term contract review proceeding. Accordingly, we decline to direct the Petitioners to accept commenters' recommendations.

11. Change in RPS Provision

a. Introduction

Section 2.2.1.4.d of the RFP provides that, for proposals including Clean Energy Generation from new Class I RPS eligible resources and RECs, or a portion thereof, if an electric distribution company agrees to purchase both Clean Energy Generation and RECs under a long-term contract and the RECs cease to conform to the RPS Class I eligibility criteria, the electric distribution company may only pay for electric energy under that long-term contract. Certain commenters and the IE are critical of the change in law provision regarding the purchase of RECs (see Emera Comments at 20; NEER and NHT Comments at 7-8; RENEW Comments at 3; IE Report at 22). The Petitioners argue that the

Department has previously allowed change in RPS law provisions in RFPs, and that it should remain in the RFP (Petitioners Reply Comments at 6).

b. Summary of Comments

The IE recommends that RPS change in law provision be deleted from the RFP (IE Report at 22). The IE maintains that this arrangement could unfairly advantage firm service hydroelectric generation, which includes associated environmental attributes and is priced on a $/MWh basis, and is therefore not subject to the change in law provision (IE Report at 22). Commenters support the IE's recommendation to eliminate the change in RPS law provision (Emera Comments at 20; NEER and NHT Comments at 7-8; RENEW Comments at 3). Emera agrees with the IE that the change in law provision creates a competitive disadvantage for Class I RPS eligible resources because there is no comparable change in law risk imposed on firm service hydroelectric generation (Emera Comments at 19-20). NEER and NHT and RENEW argue that keeping the provision will result in a higher cost to ratepayers because it will increase developers' risk and require them to demand a higher rate of return, costs which ratepayers will bear (NEER and NHT Comments at 7-8; RENEW Comments at 3). HQUS argues that the Petitioners should not remove the change in RPS law provision from the RPS, arguing that doing so would give preferential treatment to Class I RPS resources (HQUS Reply Comments at 9-10).

The Petitioners contend that they included the change in RPS provision clause to ensure that ratepayers would pay for RECs that lose their value due to a change in RPS Class I eligibility criteria during a 15-20 year contract (Petitioners Reply Comments at 6). The

Petitioners maintain the provision gives bidders more control over this risk because it allows them to structure their prices for Clean Energy Generation and RECs to adjust for the risk of the RECs losing Class I eligibility (Petitioners Reply Comments at 6). Further, the Petitioners argue that this provision is consistent with prior long-term contract RFPs (Petitioners Reply Comments at 6, citing D.P.U. 15-84; D.P.U. 13-57, at 24).

The Petitioners acknowledge that proposals for firm hydroelectric service do not carry a change in law risk, but argue that these types of variations are inherent in the qualities of the resources (Petitioners Reply Comments at 6-7, citing IE Report at 18). The Petitioners contend that there are other inherent trade-offs between hydroelectric generation and Class I RPS eligible resources, such as an obligation to deliver firm power versus unit contingent power, and that pushing supplier regulatory risk onto ratepayers is not an appropriate solution to such trade-offs (Petitioners Reply Comments at 6-7).

c. Analysis and Findings

The Petitioners correctly note that the change in law provisions contained in the RFP were also included in previously approved long-term contracts for renewable energy executed pursuant to the solicitation approved by the Department. See, e.g., D.P.U. 11-05/D.P.U. 11-06/D.P.U. 11-07, Exhs. NSTAR-JGD-2 (rev.) § 4.1(b); D.P.U. 13-57, at 24. Changes in RPS requirements are outside of the control of the Petitioners as well as project developers. D.P.U. 13-57, at 24. Bidders are best situated to evaluate the risk of loss from subsequent changes in RPS requirements. D.P.U. 13-57, at 24. Although such risk could, in theory, increase contract costs, the Department finds that the change in law provision in

Section 2.2.1.4.d of the RFP appropriately protects the electric distribution companies' customers from paying for non-conforming RECs. See D.P.U. 13-57, at 24. Accordingly, we decline to direct the electric distribution companies to change the RFP with respect to the change in RPS provision.

D. Transparency

1. Introduction

Several commenters suggest amendments and additional procedures to ensure the overall transparency of the solicitation process, including the need to address concerns related to entities affiliated with the Petitioners participating in the process (see Attorney General Comments at 5-6; CLF Comments at 4; Emera Comments at 7-8; GridAmerica Reply Comments at 2-3; NEER and NHT Comments at 3-5). Commenters address the following transparency-related topics: (1) role of the IE; (2) role of SMEs; (3) annual remuneration eligibility; and (4) Evaluation and Selection Team composition.

2. Role of the IE

a. Introduction

Section 83D, requires that the IE submit a report analyzing the timetable and method for solicitation and the solicitation process with respect to the proposed RFP. The Department received comments regarding the scope of the IE's role during the contract negotiation phase (see Attorney General Comments at 5; CLF Comments at 4; Emera Comments at 7; GridAmerica Reply Comments at 2-3; Petitioners Reply Comments at 4).

b. Summary of Comments

Certain commenters agree with the IE's assertion that the process would be stronger if the IE monitored contract negotiations, and therefore recommend that the Department require the Petitioners to amend the RFP accordingly (Attorney General Comments at 5; CLF Comments at 4; Emera Comments at 7; GridAmerica Reply Comments at 2-3). Emera suggests that the Department require the Petitioners to document and, potentially, disclose discussions between the IE and the Evaluation Team to enhance transparency (Emera Comments at 7).

In response to these comments, the electric distribution companies argue that the IE is statutorily limited to participating only in the solicitation process and bid evaluation/selection process (Petitioners Reply Comments at 4). The electric distribution companies also note that DOER will be monitoring the contract negotiations (Petitioners Reply Comments at 4). Finally, the electric distribution companies argue that any differences in contract terms between affiliated and non-affiliated entities will be within the Department's purview to investigate during its review of any contracts executed as a result of this solicitation (Petitioners Reply Comments at 4).

c. Analysis and Findings

The Department acknowledges that the RFP may result in the submission of bids from the electric distribution companies' affiliates or may include projects in which the electric distribution companies or their affiliates have a financial interest. Therefore, the solicitation process must include appropriate safeguards to ensure that no potential bidder receives preferential treatment, and that the RFP does not result in any actual or apparent conflict of interest.

Several commenters recommend that the Department require the Petitioners to amend the RFP to provide for the IE to monitor contract negotiations (see Attorney General Comments at 5; CLF Comments at 4; Emera Comments at 7; GridAmerica Reply Comments at 2-3). The electric distribution companies argue that the IE's role is limited by statute to the solicitation process and bid evaluation/selection process, and maintain that DOER will be monitoring the contract negotiations (Petitioners Reply Comments at 4).

Section 83D requires an IE for the express purpose of ensuring an open, fair, and transparent solicitation and bid selection process that is not unduly influenced by an affiliated company. Section 83D(f). In addition to the IE Report, the IE will file a report with the Department summarizing and analyzing the solicitation and the bid selection process, and providing its independent assessment of whether all bids were evaluated in a fair and nondiscriminatory manner upon the Department opening an investigation to review a proposed long-term contract resulting from this solicitation. Section 83D(f). The Department acknowledges the IE's recommendation that it monitors contract negotiations in order to strengthen oversight, and the Department agrees that it may strengthen the overall process (see IE Report at 27). However, we decline to require that the electric distribution companies retain the IE to monitor contract negotiations both because Section 83D does not require it and because DOER's role in monitoring contract negotiations provides adequate oversight of the process. See Section 83D(f). This determination in no way changes the

Department's standard of review for long-term contracts that the electric distribution companies submit to the Department for review pursuant to Section 83D. At the time of that review, the electric distribution companies will bear the burden of demonstrating that the solicitation process was fair, transparent, and competitive. See D.P.U. 15-84, at 22; D.P.U. 09-77, at 22-23; NSTAR Electric Company, D.P.U. 11-05; 11-06; 11-07, at 42, citing New England Gas Company, D.P.U. 10-114, at 221 (2011); NSTAR Electric Company, D.P.U. 07-64-A at 60-61 n.21 (2008); Boston Gas Company, Colonial Gas Company, and Essex Gas Company, D.T.E. 04-9, at 10 (2004).

3. Role of Subject Matter Experts

a. Introduction

SMEs are individuals who may provide guidance, advice, information, or support to the Bid Team and/or the Evaluation Team in the normal course of their responsibilities (RFP, Appendix G). The IE expresses concern that the use of joint SMEs (i.e., SMEs providing guidance to both the Bid Team and the Evaluation Team) increases the risk of transfer of confidential information between teams and may undermine the appearance of fairness and impartiality (see IE Report at 10). Two commenters agree with the IE that it would be preferable to eliminate the use of joint SMEs (see CLF Comments at 4; Emera Comments at 7).

b. Summary of Comments

Emera and CLF support the IE's recommendation that it would be preferable to eliminate the use of joint SMEs in order to improve the transparency of the process and minimize concerns regarding potential affiliate conflicts of interest (CLF Comments at 4; Emera Comments at 7). The electric distribution companies state that the joint SMEs necessarily will be constrained by the limited number of personnel with expertise in a specialized role within each Company's organization where no duplicate exists (Exhs. DPU 1-15, DPU 1-16). The electric distribution companies argue that their agreement to limit the number of SMEs to the extent practicable and to publicly disclose the names of the SMEs is an appropriate compromise regarding the use of SMEs and, therefore, the Department should not require changes to the RFP (Petitioners Reply Comments at 4-5).

c. Analysis and Findings

In response to the IE's concerns regarding the use of joint SMEs, the electric distribution companies have agreed to limit the number of SMEs to the extent practicable, to train and certify each SME consistent with the Standards of Conduct, and to publicly disclose the names of the SMEs (see Petitioners Reply Comments at 4-5; Exh. DPU 1-16). The IE finds that the electric distribution companies' approach to be acceptable (IE Report at 10). The Department agrees that eliminating the use of joint SMEs would be preferable to limit the risk of transfer of confidential information between teams; however, we also recognize that the required expertise and cost of retaining an SME limits the number of SMEs an electric distribution company is financially able to include in its rate structure. Therefore, we find the electric distribution companies' approach to limit the number of joint SMEs, to train and certify each SME consistent with the Standards of Conduct, and to publicly disclose the names of the SMEs is appropriate and decline to require the elimination of the use of joint SMEs.

4. Annual Remuneration

a. Introduction

For accepting the financial obligation of the long-term contract, an electric distribution company may receive an annual remuneration up to 2.75 percent of the annual payments under a long-term contract. Section 83D(d); 220 C.M.R. § 24.07. Two commenters argue that any long-term contract between an electric distribution company and any affiliated company should not be eligible for annual remuneration (CLF Comments at 4; Emera Comments at 7-8).

b. Summary of Comments

Emera asserts that it is important that the Department clarify in advance of the solicitation that the electric distribution companies are not eligible to seek annual remuneration for any contracts with affiliated companies (Emera Comments at 7). Emera argues that allowing affiliated companies to bid prices where it is assumed that the affiliated electric distribution company will also receive remuneration will allow the affiliated company to price that remuneration into its bid, providing an unfair competitive advantage (Emera Comments at 8). The electric distribution companies argue that the issue of annual remuneration is beyond the scope of this proceeding and therefore the Department should reject any recommendations related to annual remuneration (Petitioners Reply Comments at 5).

c. Analysis and Findings

Section 83D expressly provides an annual remuneration up to 2.75 percent of the annual payments under a contract to compensate an electric distribution company for accepting the financial obligation of the long-term contract for renewable energy. See also 220 C.M.R. § 24.07. Section 83D also requires the Department to act upon this provision at the time of contract approval. See also 220 C.M.R. § 24.07. Because Section 83D states that an electric distribution company may collect "up to 2.75 percent" of the annual contractual payments, the Department will make a determination of the actual amount that electric distribution companies will collect during contract review proceedings. At the time of the contract review proceedings, the Department will consider the implications of potential affiliate contracting in determining the appropriate level of any remuneration. Accordingly, the Department declines to direct the electric distribution companies to change the RFP's requirements regarding annual remuneration.

5. Evaluation and Selection Team Composition

a. Introduction

One commenter makes arguments regarding the composition of the Bid Team, Evaluation Team, and Selection Team to support a fair and transparent solicitation process (see NEER and NHT Comments at 3-5).

b. Summary of Comments

NEER and NHT request that the Department require the electric distribution companies to post the names and titles of Evaluation Team members to ensure that bidders are able to comply with the prohibition on bidders contacting the Evaluation Team (NEER and NHT Comments at 3-4). NEER and NHT maintain that the definitions of the Evaluation Team and Selection Team are overly broad and appear to be inconsistent with the proposed Utility Standard of Conduct, and therefore further request that the Department direct the electric distribution companies to clarify the definitions of the Evaluation and Selection Teams (NEER and NHT Comments at 3). Finally, NEER and NHT request that the Department require the electric distribution companies to provide a statement that no employee or contractor on the Three State RFP[25] Evaluation and Selection Team has participated or is now participating on one of the current RFP Bid Teams to ensure that no Bid Team has an unfair advantage over another (NEER and NHT Comments at 5). In response, the electric distribution companies argue that the recommendation to eliminate any overlap of members on the Bid Teams for the Three State RFP and the current RFP is beyond the scope of this RFP (Petitioners Reply Comments at 3, n.3).

c. Analysis and Findings

The Department declines to require any revisions to the composition of the Evaluation Team or Selection Team. The Department finds that there are adequate safeguards in place to ensure that the evaluation and selection processes will proceed in a fair, transparent, and competitive manner. First, the Petitioners seek to address any concerns about self-dealing by

25 The Three State RFP was a multi-state clean energy procurement coordinated by entities representing Massachusetts, Connecticut and Rhode Island. D.P.U. 15-84, at 3-4. The Department reviewed and approved the Three State RFP's timetable and method for soliciting long-term contracts in D,P.U. 15-84. See D.P.U. 15-84, at 56-58.

signing a Standard of Conduct as described in the RFP (RFP at App. G). Second, in addition to the Standard of Conduct included in the RFP, the electric distribution companies' personnel remain bound by the obligations found in the Department regulations at 220 C.M.R. § 12.00 et seq., which provide standards of conduct for distribution companies and their affiliates. Third, DOER and the Attorney General have participated in developing the RFP, as required by Section 83D (see Petitioners Filing Letter at 2). In addition, DOER will serve as an advisory participant to the Selection Team, which is responsible for bid selection, contract negotiations, and contract execution (RFP § 1.3). The Petitioners and DOER have also engaged the IE to ensure an open, fair, and transparent solicitation process that is not unduly influenced by an affiliated company (see Petitioners Filing Letter at 3). Finally, should a party find evidence or become aware of any violations of the Standard of Conduct and/or 220 C.M.R. § 12.00 et seq., that party may file a complaint with the Department, which the Department will investigate as appropriate. During its review of the contracts arising from the RFP, the Department will examine the selection process to ensure that it is objective and free from self-dealing and provides for adequate transparency. Should the Department find that the selection process did not meet these criteria, we will weigh this failure carefully in our consideration of the final contracts that the electric distribution companies submit for approval, consistent with Section 83D.

E. Evaluation Criteria

1. Introduction

Commenters raise issues concerning the criteria the electric distribution companies will employ to evaluate bids. Comments related to the evaluation criteria fall into three categories: (1) valuation of environmental attributes and RECs; (2) weighting; and (3) criteria inclusions/exclusions.

2. Valuation of Environmental Attributes and RECs

a. Introduction

The RFP states that the environmental attributes of generation from proposed resources will be evaluated using an economic proxy for their contributions to GWSA requirements (RFP § 2.3.1.1(ii)). Commenters raised concerns with regard to the methods the Evaluation Team will use in its consideration of environmental attributes and RECs (see, e.g., Brookfield Renewable Comments at 2; CLF Comments at 7; Emera Reply Comments at 10-11; HQUS Comments at 5; RENEW Comments at 12; RENEW Reply Comments at 4-5).

b. Summary of Comments

Many commenters recommend that the RFP provide more clarity on how the Evaluation Team will value environmental attributes for purposes of GWSA compliance relative to the RECs associated with a project in order to avoid double-counting of environmental benefits (see Brookfield Renewable Comments at 2; CLF Comments at 7; Emera Reply Comments at 10-11; HQUS Comments at 5; RENEW Comments at 12; RENEW Reply Comments at 4-5). HQUS maintains that no additional value should be ascribed to RECs beyond the value of the environmental attributes for GWSA compliance, and that doing so would double-count the environmental benefits of RPS Class I eligible resources and discriminate against bids by non-Class I resources (HQUS Comments at 5; HQUS Reply Comments at 2). Brookfield Renewable recommends that the value of RECs should be net of the economic proxy value for contributions to GWSA to avoid double-counting of environmental benefits (Brookfield Renewable Comments at 2). RENEW and Emera argue that the value of RECs and environmental attributes for compliance with GWSA are separate and distinct, and therefore the REC value should be assessed as incremental to GWSA compliance value (Emera Reply Comments at 10-11; RENEW Comments at 12; RENEW Reply Comments at 4-5). CLF argues that the Evaluation Team should carefully assess GWSA compliance as a creditable environmental attribute (CLF Comments at 2). CLF recommends that the Evaluation Team should consider lifetime emissions when assessing the environmental attributes of bids (CLF Comments at 3).

The electric distribution companies disagree with HQUS' concern that the valuation of RECs will unfairly benefit Class I RPS eligible resources (Petitioners Reply Comments at 10). The electric distribution companies note that, as stated in Section 2.3.1.1(ii) of the RFP, "new RPS Class I eligible resources will be evaluated using a mark-to-market comparison of the price of any RPS Class I eligible RECs under a contract to their projected market price" (Petitioners Reply Comments at 10, citing RFP § 2.3.1.1(ii). The Petitioners maintain that the mark-to-market comparison may result in a positive or negative value, depending on the bidder's price (Petitioners Reply Comments at 10). The electric distribution companies assert that the Evaluation Team does not intend to double-count the environmental attributes of RECs, nor do the criteria regarding REC valuation result in such a double-counting and therefore do not recommend any changes to the RFP (Petitioners Reply Comments at 10).

CMP recommends that the Department require the Petitioners to amend the RFP to clarify how the Evaluation Team will consider pending Massachusetts Department of Environmental Protection implementation rules related to the GWSA and whether bidders will have the opportunity to modify their proposals based on these rules (CMP Comments at 4-5).

Several commenters suggest that the RFP specify the economic proxy price for environmental attributes and future REC price assumptions that the Evaluation Team will use during its review process (Brookfield Renewable Comments at 2; CLF Comments at 5; CMP Comments at 18; EETV Comments at 1; Emera Comments at 19).

c. Analysis and Findings

With respect to the valuation of environmental attributes and RECs, commenters argue that the environmental attributes for purposes of GWSA compliance and the RECs associated with a project should not be double-counted, and that the final RFP should specify the price assumptions that the Evaluation Team will use during the evaluation process (Brookfield Renewable Comments at 2; CLF Comments at 7; Emera Reply Comments at 10-11; HQUS Comments at 5; RENEW Comments at 12; RENEW Reply Comments at 4-5). The Petitioners assert that they do not intend to double-count environmental attributes of RECs, and argue that providing additional details regarding how the Evaluation Team intends to apply the evaluation criteria, including disclosing REC forecasts, would not be appropriate given the nature of this competitive solicitation process (Petitioners Reply Comments at 1, 9-10). Consistent with the Petitioners' representations, we expect that the Petitioners will not double-count environmental attributes of generation resources during bid evaluation. Further, in any future filings that result from this solicitation, the Department expects the electric distribution companies to provide full documentation demonstrating that the Evaluation Team fairly and consistently applied this bid evaluation criteria across all bids. With this understanding, the Department will not require any revisions to the evaluation criteria related to the valuation of RECs or environmental attributes of generation for contribution to GWSA requirements.

3. Weighting

a. Introduction

The Department received comments regarding the methodologies the Petitioners will use when weighting evaluation criteria during a quantitative evaluation (see, e.g., CMP Comments at 13-14; EETV Comments at 1; HQUS Comments at 1; Pattern Comments at 3; RENEW Comments at 11).

b. Summary of Comments

Several commenters recommend that the Department require the Petitioners to amend the RFP to set forth a numerical weighting of the evaluation criteria so that bidders can better understand the relative importance of the criteria when formulating bids (CMP Comments at 13-14; EETV Comments at 1; HQUS Comments at 1; Pattern Comments at 3; RENEW Comments at 11).

HQUS argues that when conducting the quantitative evaluation, the Evaluation Team should not disqualify any project based solely on direct contract costs and benefits and without consideration of other costs and benefits to retail customers since a substantial amount of the net project value is in the cost reduction of wholesale energy, which the Evaluation Team calculates in other costs and benefits to retail customers (HQUS Comments at 6; HQUS Reply Comments at 2). The electric distribution companies maintain that the RFP is clear that during the quantitative evaluation the Evaluation Team will consider both direct contract costs and benefits and other costs and benefits (Petitioners Reply Comments at 10).

The Legislators recommend that the Department require that the Evaluation Team review all proposals with respect to qualitative criteria, and prioritize projects with direct economic benefits for Massachusetts (Legislators Comments at 1). Similarly, Emera recommends that the Department require the Petitioners to amend the RFP to require a more robust application of the qualitative criteria to ensure that the Evaluation Team fairly consider the Commonwealth's interest in selecting projects that contain a range of direct benefits to the Commonwealth (Emera Comments at 23). The Attorney General agrees that the Evaluation Team's discretion to eliminate a proposal with a poor quantitative score may be reasonable, but suggests that the Department require the Petitioners to amend the RFP to eliminate any confusion (Attorney General Comments at 9).

CMP recommends that the Department direct the Evaluation Team to establish and publish the evaluation framework with the final RFP or at least no later than 60 days in advance of the due date for submission of proposals to promote transparency (CMP Reply Comments at 3-4).

RENEW suggests that the RFP should list the value the Evaluation Team will use for the weighted average value of the electric distribution companies' cost of capital (RENEW Comments at 13).

The electric distribution companies argue that providing additional details regarding how the Evaluation Team intends to apply the evaluation criteria, including disclosing REC forecasts, would not be appropriate given the nature of this competitive solicitation process (Petitioners Reply Comments at 1, 9-10).

c. Analysis and Findings

In reviewing the proposed timing and method of solicitation and execution of contracts pursuant to Section 83D, including the method of evaluation, the Department seeks to balance goals of ensuring nondiscriminatory treatment of all potential eligible resource options with providing the electric distribution companies discretion to implement a flexible bid evaluation methodology to accommodate a broad range of bids to be solicited pursuant to this RFP. D.P.U. 15-84, at 33; Long-Term Contracts for Renewable Energy, D.P.U. 08-88, at 10; D.P.U. 09-77, at 20. Several commenters recommend that the Department require the Petitioners to amend the RFP to set forth a numerical weighting of the evaluation criteria (CMP Comments at 13-14; EETV Comments at 1; HQUS Comments at 1; Pattern Comments at 3; RENEW Comments at 11). Other commenters request that the Department require the Petitioners to amend the RFP to require a more robust application of the qualitative criteria to ensure that projects with direct economic benefits for Massachusetts are prioritized (Emera Comments at 23; Legislators Comments at 1). The Petitioners maintain that providing additional details regarding how the Evaluation Team intends to apply the evaluation criteria would not be appropriate given the nature of this competitive solicitation process (Petitioners Reply Comments at 1, 9-10).

After consideration of the comments on this issue, the Department declines to require revisions to the RFP bid evaluation criteria. At the time of our review of executed contracts resulting from this procurement, the electric distribution companies bear the burden of demonstrating that the solicitation method used was developed and implemented in a manner consistent with the intent of Section 83D, and that the solicitation process was fair, transparent, competitive, and non-discriminatory pursuant to Section 83D. See D.P.U. 15-84, at 32; D.P.U. 09-77, at 22-23; D.P.U. 11-05; 11-06; 11-07, at 42, citing New England Gas Company, D.P.U. 10-114, at 221 (2011); NSTAR Electric Company, D.P.U. 07-64-A at 60-61 n.21 (2008); Boston Gas Company, Colonial Gas Company, and Essex Gas Company, D.T.E. 04-9, at 10 (2004). At that time any party to a proceeding will have the opportunity to raise relevant substantive issues with respect to the evaluation of proposed projects in the context of an adjudication before the Department. D.P.U. 15-84, at 34; D.P.U. 09-77, at 23-24.

4. Inclusions/Exclusions

a. Introduction

Several commenters recommend that certain criteria should be included in or excluded from the quantitative evaluation criteria (see, e.g., HQUS Comments at 6; TDI-NE Comments at 2; RENEW Comments at 12; Legislators Comments at 2; Attorney General Comments at 10; GridAmerica Reply Comments at 4; Network Comments at 2).

b. Summary of Comments

Two commenters recommend that the Department require the Petitioners to amend the quantitative evaluation criteria to include consumer benefits from lower natural gas prices that would result from the injection of new clean energy into the New England power system (HQUS Comments at 6; TDI-NE Comments at 2).

HQUS suggests that the qualitative evaluation of the operational flexibility resulting from a proposed project take into account both the costs associated with projects that reduce operating flexibility in addition to the benefits associated with projects that increase operating flexibility (HQUS Comments at 7).

RENEW suggests that the Evaluation Team explicitly recognize the hedge value of fixed-price bids in the quantitative evaluation metrics (RENEW Comments at 12).

The Legislators suggest that the evaluation criteria include benefits that directly support communities that have been or will be affected by the closure of generating plants or by actions resulting from policy efforts to ensure the energy market transitions to generation with lower greenhouse gas emissions (Legislators Comments at 2). The Legislators also suggest that the qualitative evaluation consider benefits from proposals that use or repurpose existing energy infrastructure (Legislators Comments at 2).

The Attorney General suggests removing the final additional evaluation factor in the Stage Three process, arguing that it is overly broad and likely covered by other factors (Attorney General Comments at 10). The electric distribution companies argue that the Department should reject the Attorney General's recommendation noting that the 2013 Section 83A RFP included similar language (Petitioners Reply Comments at 10).

CLF recommends that the RFP should give weight to bids that meet the following transmission criteria: co-location with existing lines; burial of lines; on-ramp capability for multiple resources; and transmission lines with multi-value functions (CLF Comments at 2-3). CLF also recommends that the RFP reflect a preferential hierarchy of qualifying hydropower resources, from lowest generating emissions potential to highest (CLF Comments at 3). MAPC recommends including a qualitative evaluation criterion that assesses the lifecycle emissions as well as land use change impacts of any proposed generation resource (MAPC Reply comments at 2). HQUS maintains that it is inappropriate to rank Clean Energy Generation in the manner suggested by CLF, arguing that it is inconsistent with the internationally accepted method of assessing greenhouse gas emissions on a net lifecycle basis rather than on an instantaneous basis (HQUS Reply Comments at 3-4).

Two commenters recommend that the Department require the Petitioners to amend the RFP to specify how the Evaluation Team will determine the extent to which proposals demonstrate a benefit to low-income ratepayers (GridAmerica Reply Comments at 4;

Network Comments at 2). MAPC recommends that the RFP not restrict the definition of low-income to those ratepayers using the low-income discount, and instead suggests using the Environmental Justice criteria to structure how bids receive preference (MAPC Reply Comments at 2-3).[26]

c. Analysis and Findings

Several commenters propose additions to the evaluation criteria, including; (1) consumer benefits from lower natural gas prices that would result from the injection of new clean energy into the New England power system; (2) costs associated with projects that reduce operating flexibility; (3) the hedge value of fixed-price bids; (4) benefits that directly support communities that have been or will be affected by the closure of generating plants; (5) benefits from proposals that use or repurpose existing energy infrastructure; and (6) lifecycle emissions as well as land use change impacts of any proposed generation resource (see HQUS Comments at 6-7; Legislators Comments at 2; MAPC Reply comments at 2; RENEW Comments at 12; TDI-NE Comments at 2). One commenter recommends that the RFP give weight to bids that meet certain transmission criteria, and that the RFP reflect a preferential hierarchy of qualifying hydropower resources (CLF Comments at 2-3). Finally, two commenters recommend that the Department require the Petitioners to amend the RFP to

[26] In Massachusetts, a community is recognized as an Environmental Justice community if any of the following is true: (1) block group whose annual median household income is equal to or less than 65 percent of the statewide median ($62,072 in 2010); (2) or 25 percent or more of the residents identifying as minority; or (3) 25 percent or more of households having no one over the age of 14 who speaks English only or very well (Limited English Proficiency). Commonwealth's Executive Office of Energy and Environmental Affairs 2017 Environmental Justice Policy.

specify how the Evaluation Team will determine the extent to which proposals demonstrate a benefit to low-income ratepayers (see GridAmerica Reply Comments at 4; Network Comments at 2). After consideration of the comments relating to recommended inclusions/exclusions to the evaluation criteria, the Department declines to require revisions to the RFP bid evaluation criteria or process. The RFP is the product of coordinated process during which stakeholders were provided the opportunity to provide input on a number of key areas, including evaluation criteria (see Petitioners Cover Letter at 2, n.4). We find that such revisions to the evaluation criteria are beyond the scope of this proceeding, and represent subject matter that will be more appropriately considered in the context of a contract review proceeding resulting from this solicitation.

F. Interconnection and Delivery Requirements

1. Introduction

Several commenters oppose certain interconnection and delivery requirements in the proposed RFP. The commenters either suggest striking out requirements related to New Class I RPS Eligible Resources, or request the Petitioners to change requirements to make it more practical for New Class I RPS Eligible Resources to comply with them.

2. Firm Service Requirements

a. Introduction

In order to achieve firm service, the Petitioners require that proposals include a commitment to interconnect to the ISO-NE Pool Transmission Facilities at the Capacity Capability Interconnection Standard as defined by ISO-NE (RFP § 2.2.1.3). The Petitioners also require proposals to provide an annual schedule of Clean Energy Generation specified for each hour in the proposed delivery profile (RFP § 2.2.1.3.i). In addition, there are a few specific requirements for winter delivery guarantee in the original proposed RFP (RFP § 2.2.2.7).

b. Summary of Comments

ELM and NB Power are concerned that the proposed RFP will greatly disadvantage New Class I RPS Eligible Resources such as solar and wind, and that the RFP directly conflicts with Section 83D which states that there should be a preference for proposals that combine New Class I RPS Eligible Resources and firm hydroelectric generation (ELM Comments at 2, and NB Power Comments at 6). CLF shares the IE's concern that the Petitioners' interpretation of Section 83D's general statutory language regarding reliability and winter delivery far exceeds requirements placed on wind generators by the ISO-NE (CLF Comments at 6, citing IE Report at 16).

Nalcor and NB Power comment that the proposed "firm service" delivery requirements have gone far beyond what is intended by Section 83D (Nalcor Comments at 4, NB Power Comments at 6). Nalcor also notes that these prescriptive requirements will remove the flexibility the bidders need to design innovative and competitive proposals. In addition, Nalcor asserts that these requirements are more related to capacity commitment than to energy delivery, and thus inappropriately extend the requirements to matters already addressed in the ISO-NE capacity market (Nalcor Comments at 5-6).

Emera claims that the annual load profile commitments and winter delivery commitments will unduly favor large-scale hydroelectric projects (Emera Comments at 5). Emera further argues that these requirements also carry significant risks for ratepayers because they are likely to increase the costs and bid prices for all projects that have to build in risk premium for potential liquidated damages (Emera Comments at 13). Nalcor, NB Power, NECEC, and CMP express similar opinions (Nalcor Comments at 4, NB Power Comments at 5, NECEC Comments at 2 and 3-4, and CMP Reply Comments at 2).

RENEW contends that Section 2.2.2.7 of the RFP states that hydroelectric generation resources must submit a delivery profile with no winter peak period hour less than 60 percent of their highest annual single hourly delivery claimed in their annual delivery profile (RENEW Comments at 7). RENEW maintains that Sections 2.2.1.3(i), (iii), and (iv) of the RFP make that the requirement for all hours, and therefore seeks clarification that the requirement applies only to the winter period (RENEW Comments at 7). RENEW also contends that the Winter Peak Period delivery requirement for proposals that combine New Class I RPS Eligible Resources and firm hydroelectric generation is more stringent than the requirement for proposals with New Class I RPS Eligible Resources only (RENEW Comments at 7-8).

The Attorney General agrees with several commenters that the proposed RFP's firm service requirements should properly recognize differences between (or "among") generation resources (Attorney General Reply Comments at 3-5). Furthermore, the Attorney General supports the IE's recommendation to strike the RFP requirement that bid proposals include all network upgrade costs required to ensure full dispatch of the proposed generation unit (citation). The Attorney General argues that ensuring full dispatch beyond the point of interconnection is a significant cost driver that may result in a less competitive and potentially unfair procurement (Attorney General Comments at 6). MAPC maintains that the proposed requirements in the RFP will result in an undue burden on New Class I RPS Eligible Resources, and suggests adopting the IE's recommendation (MAPC Reply Comments at 2). Regarding full dispatch, RENEW states that the ISO-NE's interconnection standards, either "energy only" or "energy and capacity", do not provide interconnection customers with information on the level of curtailment that might occur; nor do they evaluate the economic consequences of curtailment for new interconnecting generators (RENEW Comments at 8).

The Petitioners argue that the proposed firm service requirements, including interconnection, full dispatch and network upgrades costs, are necessary to satisfy Section 83D's requirements that that purchased clean energy will contribute to reducing winter electricity price spikes and benefit Massachusetts ratepayers and that bidders include all associated transmission costs in a proposal (Petitioners Reply Comments at 7). HQUS expresses a similar opinion (HQUS Reply Comments at 6-8).

The Petitioners also disagree with the IE's recommendation to revise the proposed requirement that all studies must use the current ISO-NE's interconnection process that includes a serial study system, to include an option for bidders to use a proposed cluster study system (Petitioners Reply Comments at 7-8). The Petitioners contend that given the deadline of issuing the RFP by April 1, 2017 and pending federal approval of the proposed cluster study system, it is appropriate for the RFP to require compliance with the current ISO-NE rules, while allowing bidders the flexibility to submit cluster studies as a supplement to serial studies (Petitioners Reply Comments at 7-8).

c. Analysis and Findings

Section 83D includes new requirements that are in addition to the requirement of providing enhanced electricity reliability in previous clean energy solicitations. Specifically, Clean Energy Generation that is procured should: (1) contribute to reducing winter electricity price spikes; and (2) guarantee energy delivery in winter months. Section 83D(d). At the same time, Section 83D requires giving preference to proposals that combine new Class I RPS Eligible Resources and firm hydroelectric generation. Section 83D(d). We find that the statute seeks to strike a balance between procuring reliable clean energy and encouraging the participation of new Class I RPS Eligible Resources. Therefore, the Department agrees with the Petitioners that the RFP should include reasonable firm service requirements necessary to ensure that the clean energy procurement contracts meet the statutory requirement of Section 83D. Likewise, we agree with the commenters that the initially proposed RFP appears to set an inappropriately high standard for proposals that combine new Class I RPS Eligible Resources with firm hydroelectric generation ("combined proposals"). This higher standard for combined proposals is likely to result in the solicitation falling short of the statutory requirement that allows DOER to give preference to combined proposals.

In response, the Petitioners acknowledge that they should revise the original language in Sections 2.2.1.3 (iii) and 2.2.2.7 of the RFP to clarify how the combined proposals will be responsible for the delivery requirements (Petitioners Reply Comments at 8-9; Exhs. DPU 1-17; DPU 1-18). The Petitioners have updated these two sections of the RFP in the Supplemental Filing, as described below (Petitioners Supplemental Filing Cover Letter at 1-3).

3. Hourly Delivery Requirement

a. Introduction

The original proposed RFP requires that proposals provide an annual schedule of Clean Energy Generation specified for each hour in the proposed delivery profile. If the sellers fail to fulfill the hourly delivery commitment, they will be responsible for the payment of liquidated damages for the energy not delivered, and for the associated environmental attributes not provided (RFP § 2.2.1.3.i).

b. Summary of Comments

Certain commenters argue that the year-ahead hourly delivery requirement inherently discriminates against New Class I RPS Eligible Resources paired with firm hydroelectric generation, pointing out that since intermittent resources cannot predict their hourly delivery accurately, the hydroelectric generation paired with intermittent resources as a firming resource cannot accurately predict its output. Therefore, the higher risk premium associated with output uncertainty will make these combined proposals less competitive than hydroelectric generation-only proposals (ELM Comments at 2, Emera Comments at 11-12, NB Power Comments at 7, and NECEC Comments at 2-3).

Emera and NB Power argue that the annual hourly delivery requirement is not found in and violates the intent of Section 83D that the solicitation process be flexible enough to allow for a variety of contracts for diverse resources (Emera Comments at 9-10; NB Power Comments at 7). Emera maintains that the hourly delivery requirement will significantly reduce the number of competitive proposals (Emera Comments at 12). Emera further notes that this requirement, while potentially driving up bid prices, may not necessarily bring benefits to ratepayers during periods of peak demand, because the proposed RFP requires energy to be available according to the year-ahead schedule, which may or may not be when energy is most needed (Emera Comments at 14). Nalco and NECEC express a similar opinion (Nalcor Comments at 5; NECEC Comments at 4).

The Petitioners argue that requiring an hourly profile is typical for firm service, and that bidders should be responsible for risk mitigation in their proposals (Petitioners Reply Comments at X). The Petitioners clarify that New Class I RPS Eligible Resources will not be subject to liquidated damages in the same way as firm hydroelectric generation, because their contracts with the Petitioners will define their responsibility for liquidated damages (Petitioners Reply Comments at X). The Petitioners therefore conclude that they do need to clarify the hourly delivery requirement related to New Class I RPS Eligible Resources that are combined with firm hydroelectric generation (Petitioners Reply Comments at 8).[27]

[27] The electric distribution companies addressed this issue in the Supplemental Filing.

c. Analysis and Findings

Section 2.2.1.3(iii) of the RFP as originally proposed required combined proposals to meet the hourly delivery requirement in its entirety. Section 2.2.1.3(iii) of the RFP as updated in the Supplemental Filing only subjects the firm hydroelectric generation portion of a combined proposal to the hourly delivery requirement, including paying for liquidated damages in case of failure to deliver. The updated Section 2.2.1.3(iii) requires the contracts with Petitioners to separately define the delivery requirement and delivery failure penalty for the portion of New Class I RPS Eligible Resources in combined proposals. The Department finds that these revisions appropriately take into account the inherent difficulty for New Class I RPS Eligible Resources to commit to hourly delivery schedules, and at the same time hold the firm hydroelectric generation portion of combined proposals accountable for reliable clean energy delivery. Therefore, the Department accepts these revisions to Section 2.2.1.3 (iii) of the RFP and directs the Companies to incorporate these revisions in the RFP.

4. Winter Peak Delivery Requirements

a. Introduction

The original proposed RFP requires that combined proposals as well as firm hydroelectric generation only proposals should submit a delivery profile with no Winter Peak Period hour less than 60 percent of their highest annual single hourly delivery. In addition, the Petitioners require that New Class I RPS Eligible Resources proposals should guarantee that 70 percent of energy in their delivery profile of the Winter Peak Period is delivered over the course of every Winter Peak Period (RFP § 2.2.2.7).

b. Summary of Comments

Certain commenters argue that the proposed requirement that no Winter Peak Period hour can be less than 60 percent of the highest annual single hourly delivery that the bidder specifies in the proposal's annual delivery profile will result in fewer bid commitments and that the winter peak delivery requirement will discourage bids with a mixed portfolio and drive up bid prices (see ELM Comments at 3, Emera Comments at 13, Longroad Comments at 4, Nalco Comments at 5, and NECEC Comments at 3).

Longroad and NB Power contend that the Winter Peak Period delivery requirement is not found in Section 83D and this requirement is stretching beyond what Section 83D mandates for winter delivery (Longroad Comments at 3; NB Power Comments at 8). Furthermore, multiple commenters support the IE's statement that the common industry practice is to apply a 70 percent of the highest annual single hourly delivery guarantee with a much longer measurement period than what is proposed in the RFP (Longroad Comments at 3-4; NB Power Comments at 9; RENEW Comments at 6; and Pattern Comments at 2-3). CLF and RENEW agree with the IE's recommendation that the RFP should not set the winter period guarantee at a level at which the seller will be penalized for normal variation in production due to weather that it cannot control (CLF Comments at 7; RENEW Comments at 6). CLF also argues that the winter delivery requirement advantages hydroelectric generation-only bids over blended bids (CLF Comments at 7).

NEER and NHT suggest that the RFP should base the winter delivery requirement on a three -year rolling average of actual deliveries relative to the delivery profile during the

Winter Peak Period, starting with the first full Winter Peak Period post commercial operations (NEER and NHT Comments at 10). NEER and NHT also state that the 60 percent hourly delivery requirement seems low for firm hydroelectric generation and for New Class I RPS Eligible Resources combined with firm hydroelectric generation, while on the other hand, New Class I RPS Eligible Resources must guarantee 70 percent of Winter Peak Period delivery (NEER and NHT Comments at 10). NEER and NHT suggest changing both of these requirements to 65 percent to ensure equity for the different types of bids (NEER and NHT Comments at 3).

CLF is concerned that the requirement laid out in Section 2.2.2.5 of the RFP (Contribution to Reducing Winter Electricity Price Spikes) appears impossible to meet for a bid involving only New Class I RPS Eligible Resources (CLF Comments at 6). CLF suggests this section should outline an alternate standard that intermittent resources could satisfy (CLF Comments at 6). Nalcor notes that the proposed RFP is asking potential suppliers of clean energy to supply what is, in effect, a capacity product (Nalcor Comments at 5). According to Nalcor, this may result in ratepayers paying twice for the same capacity product, as bidders would need to factor in the risk premium related to this requirement, and also do the same when participating in the capacity markets (Nalcor Comments at 5).

Longroad suggests that the winter delivery requirement should exclude RECs, because the timing of the delivery of RECs or other environmental attributes has no relevance to the objective of energy delivery (Longroad Comments at 5). Longroad suggests some specific changes regarding the Winter Peak Period delivery requirement in the proposed RFP[28] (Longroad Comments at 5).

The Petitioners contend that they are obligated to adopt reasonable standards to address the winter supply reliability and price spike mitigation requirements of Section 83D, and in their judgment, the proposed winter peak delivery requirements in the RFP meet this obligation (Petitioners Reply Comments at 9). In addition, the Petitioners acknowledge that they do need to clarify the winter peak delivery requirements related to New Class I RPS Eligible Resources combined with firm hydroelectric generation (Petitioners Reply Comments at 9) [29]

c. Analysis and Findings

Section 2.2.2.7 of the RFP, as originally proposed, required combined proposals as well as firm hydroelectric generation-only proposals to submit a delivery profile with no Winter Peak Period hour less than 60 percent of their highest annual single hourly delivery. Section 2.2.2.7 of the RFP as updated in the Supplemental Filing removes this requirement for combined proposals.

28 Longroad's proposed changes are as follows: (1) reduce the 70 percent threshold to 50 percent; (2) make the guarantee applicable to all winter hours (both peak and non-peak); (3) increase the measurement period to three winter periods on a rolling basis; (4) set liquidated damages at a fixed $/MWh, or market-based with a floor and ceiling, capped at the actual damages of the buyer; and (5) exclude RECs, other environmental attributes, and associated transmission infrastructure support costs (if applicable) from the guarantee and liquidated damages.

29 The electric distribution companies addressed this issue in the Supplemental Filing.

In addition, the updated Section 2.2.2.7 includes a new paragraph describing the winter delivery requirements for combined proposals that provides that: (1) only the firm hydroelectric generation portion must meet the 60 percent hourly delivery requirement; and (2) the New Class I RPS Eligible Resources portion must submit a delivery profile for the Winter Peak Period based on the project's modeled site data and must guarantee that the bidder delivers at least 70 percent of this profile over the course of every Winter Peak Period. In addition, the updated Section 2.2.2.7 requires that the combined proposal bidder deliver the combined delivery profile from New Class I RPS Eligible Resources and firm hydroelectric generation in all hours during the Winter Peak Period.

Because a winter energy delivery guarantee and winter electricity price containment are requirements of Section 83D, the Department agrees that the RFP should include specific winter delivery provisions to address the statutory requirements. In the updated Section 2.2.2.7, the Petitioners have narrowed the 60 percent hourly delivery requirement to the firm hydroelectric generation portion of combined proposals. Also in the updated Section 2.2.2.7, for the New Class I RPS Eligible Resources portion, the Petitioners have placed emphasis on the Winter Peak Period, during which bidders need to guarantee at least 70 percent of the delivery profile they submit. After carefully considering the comments on this matter, the Department finds that the Petitioners have applied reasonable judgment in crafting revised firm delivery requirements that achieve an appropriate balance between ensuring Winter Peak Period delivery and accounting for the intermittency of New Class I RPS Eligible Resources. Therefore, the Department accepts these revisions to Section 2.2.2.7 of the RFP as proposed in the Supplemental Filing, and directs the Petitioners to incorporate these revisions in the RFP.

5. Capacity Capability Interconnection Standard

a. Introduction

The proposed RFP require that proposals must include a commitment to interconnect to the ISO-NE Pool Transmission Facilities at the Capacity Capability Interconnection Standard as defined by ISO-NE (RFP § 2.2.1.3).

b. Summary of Comments

CLF and Longroad share the IE's concern that the use of the Capacity Capability Interconnection Standard disadvantages qualifying projects in Maine (CLF Comments at 5; Longroad Comments at 2). CLF argues that Section 83D does not authorize the Petitioners to procure capacity in addition to RECs and/or energy and the ISO-NE does not require all new interconnections to pass the Capacity Capability Interconnection Standard (CLF Comments at 6), Therefore, CLF maintains that there is no justification for the RFP to require the use of this standard for resources that would otherwise qualify for the RFP (CLF Comments at 6). CLF also argues that since the Petitioners are not procuring capacity under the RFP, the capacity requirement in Section 2.2.1.8 of the RFP will be unduly prejudicial to wind resources, particularly when paired with the interconnection standards (CLF Comments at 6).

NEER and NHT argue that imposing the Capacity Capability Interconnection Standard is not consistent with the fact that the proposed RFP is not procuring capacity (NEER and

NHT Comments at 5). NEER and NHT suggest allowing the use of an Elective Transmission Upgrade ("ETU") for a generator to interconnect into an ISO-NE pricing node as provided in the Three State RFP (NEER and NHT Comments at 5).

RENEW contends that while the "energy only" interconnection standard is feasible for bidders to obtain, obtaining the "energy and capacity" interconnection standard may take longer than the time the RFP solicitation process allows, because there is a significant backlog in the ISO-NE's interconnection queue (RENEW Comments at 9-10). In addition, RENEW maintains that even the overlapping impact test the ISO-NE performs for "energy and capacity" service may not provide the information required to identify network overloads and upgrade needs (RENEW Comments at 8). As a result, RENEW suggests that the interconnection standard in the RFP should be replaced with the requirement that proposals make commercially reasonable efforts to be a capacity resource (RENEW Comments at 9-10). NEER and NHT support RENEW's suggestion (NEER and NHT Comments at 2, n.2).

The Petitioners argue that the interconnection requirements, including the requirement to use the Capacity Capability Interconnection Standard, are necessary to satisfy the requirement of 83D that all associated transmission costs are included in a proposal (Petitioners Reply Comments at 7, citing Section 83D(d)(4)). The Petitioners maintain that the requirements are also necessary to ensure that Clean Energy Generation purchased under long-term contracts actually will benefit Massachusetts customers and contribute to reducing winter electricity price spikes in Massachusetts. (Petitioners Reply Comments at 7, citing Section 83D(d)(5)(ii)). The Petitioners argue that the interconnection requirements set out in the RFP are intended to avoid purchasing Clean Energy Generation that is locked in remote areas with poor interconnections, which would not benefit Massachusetts customers (Petitioners Reply Comments at 7).

c. Analysis and Findings

We agree with the Petitioners that the Capacity Capability Interconnection Standard should remain in the RFP unchanged. The Petitioners' determination to include the Capacity Capability Interconnection Standard, is necessary both to include transmission costs in bids and to increase project viability (see Petitioners Reply Comments at 7, citing Section 83D(d)(4); 83D(d)(5)(ii)).

In RFP review proceedings, the Department seeks to balance the goals of promoting project viability while ensuring that the RFP is competitive and does not inappropriately disadvantage any project. See D.P.U. 08-88, at 10; D.P.U. 09-77, at 20; 15-84, at 50. Project viability is an important element of the RFP bid evaluation process. D.P.U. 15-84, at 50. Because projects that can meet the Capacity Capability Interconnection Standard have a higher likelihood of viability, we accept this as a reasonable requirement for bid inclusion.

The Petitioners did not address the comments related to the following issues: (1) applying a longer delivery period to the 70 percent Winter Peak Period delivery requirement for New Class I RPS Eligible Resources; (2) excluding RECs from the winter delivery requirements; 3) potential double counting of capacity risk premiums for ratepayers in Section 2.2.2.5 of the proposed RFP; and (4) excluding the capacity requirement in Section 2.2.1.8 of the proposed RFP based on assertions that it is prejudicial to wind resources and irrelevant to an RFP that does not procure capacity. In the context of the review of this proceeding, the Department declines to opine on the Petitioners' judgment in designing the RFP provisions with regard to the above issues the commenters raised. However, when the Petitioners file the selected bids with the Department, the Department expects the Petitioners to provide detailed information to demonstrate that they considered and have sufficiently addressed the above issues.

G. Other Issues

1. Introduction

Commenters make recommendations for clarifications and refinements to the RFP, on various other topics, including, but not limited to: (1) forms of pricing; (2) capacity requirements; (3) energy storage; (4) environmental attributes tracking system; (5) pricing disclosure; (6) contract termination and regulatory considerations; (7) commercially reasonable timeframe; (8) information requirements; and (9) NEER and NHT clarification requests.

2. Forms of Pricing

a. Summary of Comments

Emera recommends that the Department require the Petitioners to revise Sections 2.2.1.4.i.a and 2.2.1.4.i.b of the RFP to eliminate proposals for long-term contracts indexed at or below the day-ahead or real-time LMP (Emera Comments at 22). Emera argues that this LMP indexed pricing approach is at odds with the notion of a long-term contract and is inconsistent with the statute (Emera Comments at 22). Pattern notes that it is unusual to allow an indexed pricing mechanism in an RFP for long-term contracts (Pattern Comments at 2). Pattern maintains that should the RFP offer this pricing mechanism, it should clarify what pricing forecast the Evaluation Team will use to compare market-based proposals with fixed or escalating bids (Pattern Comments at 2). Bay State Wind argues that in order to achieve the goals of transparency, cost-containment and offering the lowest price electricity to consumers, bidders should first present each bid price without any reduction for the production tax credit or the investment tax credit (Bay State Wind Comments at 8). Bay State Wind contends that each bid should then clearly identify and explain the amount of reduction attributable to any assumed credit or incentive (Bay State Wind Comments at 8). NECR recommends that the Department require the Petitioners to modify the RFP to require bidders to make cost containment proposals legally binding (NECR Reply Comments at 6).

b. Analysis and Findings

As described in Section IV.A, above, the scope of our review in this proceeding is to review the timetable and method for solicitation and execution of contracts that may result from the RFP. We have determined that these comments regarding forms of pricing exceed the scope of this proceeding, and represent subject matter that the Department may consider in the context of a contract review proceeding resulting from this solicitation. Accordingly, we decline to direct the electric distribution companies to make any revisions to the RFP with regard to forms of pricing.

3. Capacity Requirements

a. Summary of Comments

HQUS recommends that the Department require the Petitioners to amend Section 2.2.1.8 of the RFP: (1) to clarify the specific capacity qualification commitments the Evaluation Team will require for a bid to demonstrate that the generation units in a proposal meet the Forward Capacity Auction qualification requirements in the ISO-NE Tariff, and (2) to provide guidance as to what demonstration is sufficient to show that a bidder will remedy any issues identified in the overlapping impact analysis with respect to the requirement to satisfy the Capacity Capability Interconnection Standard (HQUS Comments at 4). NEER and NHT request that the Department require the Petitioners to amend Section 2.2.1.8 of the RFP to clarify that bidders of generation resources paired with energy storage may include a forward capacity auction qualification amount that takes into consideration the increase in capacity value resulting from the pairing of the resource with energy storage (NEER and NHT Comments at 9).

CLF asserts that the electric distribution companies are not procuring capacity under this RFP and should therefore remove Section 2.2.1.8 (CLF Comments at 6). CLF argues that including this requirement would be "unduly prejudicial to wind resources" and may be discriminatory to certain otherwise qualified bidders (CLF Comments at 6).

b. Analysis and Findings

After consideration of these comments, we find that Section 83D does not require the Department to address the specific recommendations regarding capacity requirements and therefore are beyond the scope of this proceeding (see Section 83D; HQUS Comments at 4; NEER and NHT Comments at 9). These issues may be appropriately addressed in a contract review proceeding. Accordingly, we decline to direct the Petitioners to accept these recommendations.

4. Energy Storage

a. Summary of Comments

NEER and NHT recommend that the Department require the Petitioners to amend Section 2.2.1.2 of the RFP to clarify the requirement for generators to pair with energy storage to require that the bid must co-locate the storage system with the Clean Energy Generation resource and commit to only store energy produced by that resource (NEER and NHT Comments at 7). FLPR argues that NEER and NHT's proposed amendment of the definition of energy storage would be inappropriate and would defy the statutory intent of Section 83D (FLPR Reply Comments at 2). CMP recommends that the RFP clarify whether hydroelectric generation facilities with storage capabilities qualify as electric storage systems (CMP Comments at 3).

b. Analysis and Findings

As described in Section IV.A, above, parties to any adjudication of individual long-term contracts for renewable energy that an electric distribution company submits to the Department for approval pursuant to Section 83(e) will have the opportunity to raise relevant concerns including the evaluation of proposed projects, all phases of contract development and negotiation, and the specific terms and conditions contained in the resulting PPA(s). See

D.P.U. 15-84, at 21; D.P.U. 09-77, at 22; D.P.U. 08-88-A at 10. Accordingly, we find that matters pertaining to energy storage not statutorily required by Section 83D and may be considered as part of a Department contract review proceeding.

5. Environmental Attributes Tracking System

a. Summary of Comments

Several commenters recommend that the Department require the Petitioners to clarify Section 2.2.2.10 of the RFP to specify that an appropriate tracking system for GWSA goals must be compatible with NEPOOL GIS (CLF Comments at 7; CMP Comments at 13; HQUS Reply Comments at 4). CMP notes that there is currently no procedure for accounting for hydroelectric environmental attributes and recommends that the RFP specify what bidders must provide to demonstrate compliance with this requirement (CMP Comments at 13).

RENEW argues a tracking system alone is insufficient to ensure that imports are providing incremental clean energy (RENEW Comments at 10). RENEW argues that the RFP should require that imports from control areas outside of the Regional Greenhouse Gas Initiative make public detailed historical data since the GWSA reduction became law and future data on the environmental characteristics of power flows into and out of its host control area (RENEW Comments at 10; RENEW Reply Comments at 3). RENEW further recommends that imports should not consist of energy a bidder previously supplied to the host control area or another control area if supplying it to New England will cause the other control area to replace a portion or all of the transferred supply with carbon-emitting generation (RENEW Comments at 10-11; RENEW Reply Comments at 3). RENEW argues that this higher standard for imports is necessary to ensure that a bidder is not meeting the winter delivery requirement in the RFP with imports of carbon-emitting generation that it wheeled from other control areas, whether directly or used to fill reservoirs under its energy trading program (RENEW Comments at 11). HQUS argues that the restriction proposed by RENEW should be rejected since suppliers cannot dictate how states in other control areas choose to meet their environmental objectives (HQUS Reply Comments at 5).

b. Analysis and Findings

We find that the above recommendations regarding environmental tracking systems implicate neither the timetable nor the method of solicitation for long-term contracts for Clean Energy Generation resources under this RFP. This represents subject matter that the Department may more appropriately be addressed during a contract review proceeding. Accordingly, we decline to accept these recommendations.

6. Pricing Disclosure

a. Summary of Comments

The Attorney General and GridAmerica recommend that the Department require the Petitioners to revise Section 1.7.4 of the RFP to require the public disclosure of contract pricing upon the Department's approval of a contract to balance the need for transparency and concerns regarding sensitive competitive pricing information (Attorney General Comments at 6; GridAmerica Reply Comments at 3).

b. Analysis and Findings

. A determination of whether it is appropriate to require the Petitioners to publicly disclose pricing terms upon the Department's approval of a long-term contract for renewable energy may be a matter for consideration during a contract review proceeding. Accordingly, the Department declines to direct the Petitioners to revise the RFP as the Attorney General and GridAmerica recommend.

7. Contract Termination and Regulatory Considerations

a. Summary of Comments

CLF recommends that the Department require the Petitioners to amend Section 2.6.1 of the RFP to remove the provision that allows an electric distribution company to terminate a contract if the Department's approval contains unsatisfactory terms or conditions, including the denial of annual remuneration (CLF Comments at 8). CLF argues that such a clause is unauthorized under Section 83D (CLF Comments at 8). NEER and NHT recommend that the Department require the Petitioners to amend Section 1.2 of the RFP to eliminate the unilateral right of a single electric distribution company to deem all proposals unreasonable (NEER and NHT Comments at 10). Bay State Wind recommends that the final RFP and any resultant PPAs should provide an appropriate amount of flexibility for each bidder to clearly state its assumptions regarding the regulatory approval process, and should not penalize a developer if it fails to meet agreed upon deadlines due to regulatory delay or inaction (Bay State Wind Comments at 10-11).

b. Analysis and Findings

The Department agrees that Section 83D does not authorize unilateral contract termination by an electric distribution company if the Department's approval contains unsatisfactory terms or conditions, including the denial of annual remuneration. However, we decline to direct the Petitioners to remove it from the RFP because it is not within the scope of the Department's review of timetable and method for solicitation of long-term contracts in these proceedings. We note that in Section 83D requires the Department to act upon the annual remuneration matter at the time of contract approval. As we explain in Section V.D.4., Section 83D states that an electric distribution company may collect "up to 2.75 percent" of the annual contractual payments, and the Department will make a determination of the actual amount that electric distribution companies will collect during contract review proceedings. At the time of the contract review proceedings, the Department will take into consideration all relevant factors in reaching a determination of the appropriate level of any remuneration.

Furthermore, the Department finds that Section 83D provides for an individual electric distribution company to submit an application with the Department supporting its decision to decline all proposals and we thus decline to adopt NEER and NHT's recommendation to strike this provision from the RFP. Finally, we find Bay State Wind's recommendation that the final RFP and any resultant PPAs provide flexibility for each bidder to clearly state its assumptions regarding the regulatory approval process, and not penalize a developer if it fails to meet deadlines due to regulatory delay or inaction to be beyond the Department's scope in this proceeding.

8. Commercially Reasonable Timeframe

a. Summary of Comments

Pattern recommends that the Department require the Petitioners to amend Section 2.2.2.8 of the RFP's requirement for a bidder to demonstrate project viability within a commercially reasonable timeline to reflect a timeline of not later than December 31, 2022, to be in accordance with Section 83D (Pattern Comments at 3).

b. Analysis and Findings

Section 83D requires that the electric distribution companies enter into cost-effective long-term contracts for clean energy generation equal to approximately 9,450,000 MWh by December 31, 2022. Section 83D is not specific with regard to additional project development milestones. Accordingly, we find that the 2.2.2.8 is consistent with Section 83D and we decline to accept Pattern's recommendation.

9. Information Requirements

a. Summary of Comments

EETV contends that the RFP should explicitly require the same information requirements for project components located within and outside of ISO-NE (EETV Comments at 1-2). EETV argues that without such complete information, the Evaluation Team would be handicapped in assessing the viability and maturity of projects with infrastructure outside of New England (EETV Comments at 2).

b. Analysis and Findings

We find that the particulars of information requirements for generation projects and transmission improvements within the ISO-NE control area and in other control areas are beyond the scope of this proceeding's review of the RFP's timetable and method for solicitation of long-term contracts. Accordingly, we decline to accept this recommendation.

10. NEER and NHT Clarification Requests

a. Introduction

NEER and NHT submitted the following requests for clarification of various aspects of the RFP, below.

b. Summary of Comments

NEER and NHT recommend that Section 2.2.1.5 of the RFP limit the requirement for a bidder to list all affiliated entities or joint ventures doing business in the energy sector to those currently transacting or planning to transact business in the ISO-NE energy sector as part of the RFP process (NEER and NHT Comments at 6). NEER and NHT request that the RFP clarify the definition of "event" in the context of the requirement for a project to contribute to a reduction in winter electricity price spikes (NEER and NHT Comments at 6-7). NEER and NHT recommend that the Department require the Petitioners to add new language to Section 2.2.1.8 of the RFP to clarify that the bidder will retain any ancillary service revenues received from ISO-NE (NEER and NHT Comments at 8).

c. Analysis and Findings.

As described in Section IV.A, above, the scope of our review in this proceeding is to review the timetable and method for solicitation and execution of contracts that may result from the RFP. After consideration of each of the above comments and requests for clarification, we have determined that each is beyond the scope of this proceeding, and represents subject matter that the Department may consider in the context of a contract review proceeding resulting from this solicitation. Accordingly, we decline to direct the electric distribution companies to make any revisions to the RFP with regard to these issues.

VI. CONCLUSION

After review, and consistent with the Department's scope as identified herein, the Department finds that the timetable and method for the solicitation and execution of long-term contracts for renewable energy contained in the RFP is consistent with the requirements of Section 83D and 220 C.M.R. § 24.00 et seq. The Petitioners propose to solicit proposals for Clean Energy Generation, and provided that reasonable proposals have been received, to enter into cost-effective long-term contracts with a term of between 15 and 20 years for an annual amount of electricity equal to approximately 9,450,000 MWh by December 31, 2022, consistent with Section 83D and 220 C.M.R. § 24.04(5) (RFP §§ 1.1, 2.2.1.6). The Department finds that, in developing the provisions of long-term contracts, the electric distribution companies appropriately considered long-term contracts for RECs for energy or for a combination of RECs and energy as required by Section 83D and 220 C.M.R. § 24.04(1). The Department also finds that the RFP defines eligible products as (1) Clean Energy Generation from Incremental Hydroelectric Generation via long-term contract; (2) Clean Energy Generation from new Class I renewable portfolio standard ("RPS") eligible resources via long-term contract; (3) Clean Energy Generation and Class I environmental attributes/renewable energy certificates ("RECs") via long-term contract from a combination of incremental hydropower generation and new Class I RPS eligible resources; and (4) Clean Energy Generation from incremental hydropower generation and/or new Class I RPS eligible resources with Class I environmental attributes and/or RECs via long-term contract with a transmission project under a FERC tariff (RFP § 2.2.1.3).

Consistent with Section 83D and 220 C.M.R. § 24.06, DOER and the Attorney General jointly selected, and DOER contracted with, an IE to monitor and report on the solicitation (RFP § 1.5). Section 83D and 220 C.M.R. § 24.05(1) require the Department to determine that a renewable energy generating source: (1) provides enhanced electricity reliability within the Commonwealth; (2) contributes to reducing winter electricity price spikes; (3) will be cost-effective to Massachusetts ratepayers over the term of the contract taking into consideration potential economic and environmental benefits to the ratepayers; (4) avoids line loss and mitigates transmission costs to the extent possible and ensures that transmission cost overruns, if any, are not borne by ratepayers; (5) allows long-term contracts for Clean Energy Generation resources to be paired with energy storage systems; (6) guarantees energy delivery in winter months; (7) adequately demonstrates project viability in a commercially reasonable timeframe; and (8) creates and fosters employment and economic development in Massachusetts, where feasible. These criteria are included in the first and second bid evaluation stages described in the RFP (RFP §§ 2.2, 2.3). Section 83D and 220 C.M.R. § 24.05(5) require that proposals for long-term contracts include associated transmission costs and that, if transmission costs are included in a bid and, if the Department finds that recovery to be in the public interest, the Department may authorize or require the contracting parties to seek recovery of such transmission costs of the project through federal transmission rates, consistent with FERC policies and tariffs. The electric distribution companies have included this provision in the RFP's allowable forms of pricing (RFP § 2.2.1.4). Finally, consistent with Section 83A and 220 C.M.R. § 24.05(4), the RFP provides that the electric distribution companies will allocate the products purchased under the contracts on a pro-rata basis based on total energy demand (RFP § 2.5).

With the modifications addressed in Section V.C.6.b, above, in the Supplemental Filing, and in the Second Supplemental Filing, the Department finds that the proposed timetable and method for solicitation and execution of long-term contracts for renewable energy included in the RFP are consistent with the requirements of Section 83D and 220 C.M.R. § 24.00 et seq. Accordingly, with the inclusion of all of the modifications authorized in this Order, the Department approves the Petitioners' proposed timetable and method for solicitation and execution of long-term contracts for renewable energy.

VII. ORDER

Accordingly, after due notice, opportunity for comment, and consideration, it is

ORDERED: That the petition of Fitchburg Gas and Electric Light Company, Massachusetts Electric Company and Nantucket Electric Company, and NSTAR Electric Company and Western Massachusetts Electric Company, for approval of a proposed timetable and method for solicitation and execution of long-term contracts for renewable energy is APPROVED, subject to the directives contained herein; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company, Massachusetts Electric Company and Nantucket Electric Company, and NSTAR Electric Company and Western Massachusetts Electric Company, shall comply with all other directives contained in this Order.

By Order of the Department,

/s/
Angela M. O'Connor, Chairman

/s/
Jolette A. Westbrook, Commissioner

/s/
Robert E. Hayden, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

CERTIFICATE OF COMPLIANCE

I, Mark C. Kalpin, hereby certify that the forgoing brief complies with the rules of court, including, but not limited to:

Mass. R. App. P. 16(a)(13) (addendum);

Mass. R. App. P. 16(e) (references to the record);

Mass. R. App. P. 17 (briefs of amicus curiae);

Mass. R. App. P. 18 (appendix to the briefs);

Mass. R. App. P. 20 (form and length of briefs, appendices, and other documents); and

Mass. R. App. P. 21 (redaction).

I further certify, pursuant to Mass. R. App. P. 16(k) and Mass. R. App. P. 17(c)(9), that the forgoing brief complies with the length limitation in Mass. R. App. P. 20 because it is printed in a proportional spaced font, Book Antiqua, at size 14 point, and contains 7,305 words in Microsoft Word 2016.

/s/ Mark C. Kalpin

Mark C. Kalpin

CERTIFICATE OF SERVICE

I, Mark C. Kalpin, on behalf of New England Power Generators Association, Inc., hereby certify that on March 19, 2020, I caused copies of the foregoing to be served upon the attorney of record for each party accepting EFile MA, and also served the individuals identified below by email, all of whom assented to electronic service:

David Bogan, Esq.
LOCKE LORD LLP
111 Huntington Ave.
Boston, MA 02199

Laura Christine Bickel, Esq.
NATIONAL GRID LEGAL DEPARTMENT
40 Sylvan Road
Waltham, MA 02451

Donald E. Frechette, Esq.
LOCKE LORD LLP
20 Church Street, 20th Floor
Hartford, CT 06103

Patrick Hugh Taylor, Esq.
UNITIL SERVICE CORP.
6 Liberty Lane West
Hampton, NH 03842

Matthew Murphy, Esq.
LOCKE LORD LLP
2800 Financial Plaza
Providence, RI 02903

Andrew O. Kaplan, Esq.
PIERCE ATWOOD LLP
100 Summer Street
Boston, MA 02110

Shane P. Early, Esq.
DEPARTMENT OF PUBLIC UTILITIES
One South Station, 5th Floor
Boston, MA 02110

Jed M. Nosal, Esq.
Jesse S. Reyes, Esq.
BROWN RUDNICK LLP
One Financial Center
Boston, MA 02111

Adam Ramos, Esq.
Gerald J. Petros, Esq.
HINKLEY, ALLEN & SNYDER
100 Westminster Street, Suite 1500
Providence, RI 02903

Joshua Dunlap, Esq.
Jared S. des Rosiers, Esq., *pro hac vice*
PIERCE ATWOOD LLP
Merrill's Wharf
254 Commercial Street
Portland, ME 04101

Kerri Mahoney, Esq.
Danielle C. Winter, Esq.
Matthew Campbell, Esq.
KEEGAN WERLIN LLP
99 High Street, Suite 2900
Boston, MA 02110

Elizabeth Mahoney, A.A.G.
OFFICE OF THE ATTORNEY GENERAL
One Ashburton Place
Boston, MA 02108

John K. Habib, Esq.
Matthew Stern, Esq.
Ashley Wagner, Esq.
KEEGAN WERLIN LLP
99 High Street, Suite 2900
Boston, MA 02110

Robert Hoaglund, Esq.
DEPARTMENT OF ENERGY RESOURCES
100 Cambridge Street, Suite 1020
Boston, MA 02114

Amy Boyd, Esq.
ACADIA CENTER
31 Milk Street, Suite 501
Boston, MA 02109

Caitlin Sumner Peale Sloan, Esq.
CONSERVATION LAW FOUNDATION
62 Summer Street
Boston, MA 02110

Charles Harak, Esq.
NATIONAL CONSUMER LAW CENTER
7 Winthrop Square
Boston, MA 02110

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, MA 01930

/s/ Mark C. Kalpin
Mark C. Kalpin
(BBO #635836)
HOLLAND & KNIGHT LLP
10 St. James Avenue
Boston, MA 02116
(617) 523-2700