COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of Proposed Long Term Contracts for Clean Energy Projects Pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12	)	D.P.U. 18-64
Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of Proposed Long-Term Contracts for Clean Energy Projects Pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12	)	D.P.U. 18-65
Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of Proposed Long-Term Contracts for Clean Energy Projects pursuant to Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188, § 12	)	D.P.U. 18-66

JOINT REPLY BRIEF
ON BEHALF OF MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY d/b/a NATIONAL GRID, NSTAR ELECTRIC COMPANY d/b/a EVERSOURCE ENERGY, AND FITCHBURG GAS AND ELECTRIC LIGHT COMPANY d/b/a UNITIL

Dated: April 3, 2019

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I. INTRODUCTION

A. Overview

On March 22, 2019, Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid (together, "National Grid"), NSTAR Electric Company d/b/a Eversource Energy ("Eversource") and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil") (collectively, the "Distribution Companies" or "EDCs," and singularly, "Distribution Company") submitted a Joint Initial Brief in the above-referenced proceeding, in accordance with the procedural schedule set by the Department of Public Utilities (the "Department"). The Joint Initial Brief pertained to the petitions submitted by the Distribution Companies for the Department's review and approval of a 20-year contract with H.Q. Energy Services (U.S.) Inc. ("HQUS"), an affiliate of Hydro Quebec ("HQ") (the "PPA"). The PPA provides for the purchase of an aggregate of 9,554,940 MWh annually of Qualified Clean Energy and associated Environmental Attributes from hydroelectric generation (the "PPA") to be delivered into New England over the NECEC Transmission Line, in accordance with a Transmission Service Agreement (the "TSA") executed by and between each of the Distribution Companies and Central Maine Power Company ("CMP").[1]

This Joint Reply Brief is submitted by the Distribution Companies to respond to the claims and recommendations put forth in initial briefs submitted on March 22, 2019, by the Massachusetts Office of the Attorney General ("Attorney General" or "AGO"); the Massachusetts Department of Energy Resources ("DOER"); Conservation Law Foundation ("CLF"); Central Maine Power Company ("CMP"); Hydro Quebec (US) ("HQUS"); New England Power Generators Association

[1] Each Distribution Company filed a separate petition for approval of its respective PPA and TSA, pursuant to the requirements of Section 83D of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188 §12 and 220 C.M.R. § 23.00. The Department docketed Eversource's petition as D.P.U. 18-64; National Grid's petition as D.P.U. 18-65; and, Unitil's petition as D.P.U. 18-66.

("NEPGA"); NextEra Energy Resources ("NEER" or "NextEra"); RENEW Northeast Inc. ("RENEW"); and Sierra Club.

II. THE PPA TERMS REGARDING INCREMENTAL HYDROELECTRIC GENERATION COMPLY WITH SECTION 83D AND PROVIDE ADDITIONAL PROTECTIONS FOR CUSTOMERS.

Several parties have argued in their initial briefs that the PPAs before the Department fail to comply with Section 83D and the RFP as issued because the PPAs do not require HQUS to deliver a sufficient quantity of baseline hydroelectric generation over and above the 9.55 TWh of Clean Energy Generation purchased by the Distribution Companies under the terms of the PPA. Specifically, the AGO argues that the NECEC Hydro bid offered contract energy that would be incremental as defined by the RFP, but that the proposed PPAs do not incorporate the requirement that the contract energy be incremental to historical average deliveries (AGO In. Br. at 17). The AGO asks the Department to require the Distribution Companies to renegotiate the PPAs with HQUS to subject HQUS to penalties if it fails to deliver a Minimum Baseline Hydro value of 14.8 TWh per year, *in addition to* the 9.55 TWh that the Distribution Companies are purchasing (id. at 26).[2]

NextEra similarly argues that the Distribution Companies have failed to justify the provisions of the PPA, claiming that the changes to the PPA related to the delivery of incremental hydroelectric generation render the evaluation of the NECEC proposal invalid (NextEra In. Br. at 11-12). NEPGA, RENEW, and the Sierra Club also claim that the PPA terms do not comply with the RFP's definition of Incremental Hydroelectric Generation, and therefore, the evaluation results are in question (NEPGA In. Br. at 7-9; RENEW In. Br. at 5; Sierra Club In. Br. at 7-11). In

[2] The specific recommendation of the AGO, including other proposed adjustments to the penalty calculation, are addressed in detail below.

addition, NextEra argues that the PPAs do not satisfy the definition of Clean Energy Generation under Section 83D, claiming that non-hydro energy will flow over the NECEC line (NextEra In. Br. at 3-4).

The Department should reject each of the above arguments regarding Incremental Hydroelectric Generation and approve the PPAs as submitted. As detailed below, Section 83D allows for the solicitation of firm-service hydroelectric power, without any requirements as to incremental deliveries above historic volumes (Exh. EDC-RB-1, at 16; Green Communities Act, Section 83B). The RFP went beyond the explicit language of Section 83D to require bids with Firm Service Hydroelectric Generation to provide "Incremental Hydroelectric Generation," representing a net increase in MWh per year as compared to the three-year historical average (Exh. EDC-RB-1, at 17). The NECEC Hydro bid complied with this requirement of the RFP.

During contract negotiations, the Distribution Companies, of their own accord without any statutory or regulatory requirement to do so, negotiated additional terms to incentivize HQUS to maintain additional deliveries of hydroelectric generation into New England over and above the purchases being made by the Distribution Companies. These provisions, contained in Exhibit H of each Distribution Company's PPA, provide additional protections to customers not previously contemplated by Section 83D, the Department's regulations, the RFP or the model PPA distributed at the time the RFP was issued. The terms are the result of reasonable negotiations between the Distribution Companies and HQUS and should be approved without modification.

A. The PPAs Comply With The Statutory Definition Of Clean Energy Generation.

Intervenors themselves state that "there is no statutory requirement that the hydroelectric energy be incremental" in Section 83D of the Green Communities Act. (NextEra In. Br. at 9; see also Exh. EDC-RB-1, at 16). Section 83D requires the Distribution Companies to solicit proposals of Clean Energy Generation and enter into cost-effective long-term contracts for an annual amount of electricity equal to approximately 9,450,000 MWh. Clean Energy Generation is defined by the Green Communities Act as "either: (i) firm service hydroelectric generation from hydroelectric generation alone; (ii) new Class I RPS eligible resources that are firmed up with firm service hydroelectric generation; or (iii) new Class I renewable portfolio standard eligible resources." Green Communities Act, Section 83B. Additionally, the Green Communities Act defines Firm Service Hydroelectric Generation as "hydroelectric generation provided without interruption for 1 or more discrete periods designated in a long-term contract, including but not limited to multiple hydroelectric run-of-the-river generation units managed in a portfolio that creates firm service through the diversity of multiple units." Id. The Department's regulations adopt the same definitions. 220 C.M.R. § 24.02.

NextEra, relying on a flawed and intentionally selective reading of the PPAs, argues that "HQUS' energy is neither from hydroelectric energy alone nor is the energy firm" (NextEra In. Br. at 3). NextEra rests on the definition of "Hydro-Quebec Power Resources" to argue that Hydro-Quebec's energy consists "predominantly" of hydroelectric energy, which allows for various sources of generation and imports to flow over NECEC line (NextEra In. Br. at 3-4). This argument ignores several key provisions of the PPAs that ensure the Distribution Companies are purchasing qualifying Clean Energy Generation and associated Environmental Attributes.

First, NextEra inaccurately describes the definition of "Hydro-Quebec Power Resources" under the PPAs. The full definition is as follows:

> "Hydro-Quebec Power Resources" shall mean, collectively, those existing hydroelectric generating station, located in the Province of Quebec and owned and operated as a system by Hydro-Quebec or its subsidiaries from time to time, that produce electric energy, which consists predominately of low-carbon and renewable hydroelectric energy during the Services Term, **which are further described in Exhibit A**.

(Exhs. JU-3-A at 13; JU-3-B at 14; JU-3-C at 13) (emphasis added). Exhibit A, in turn, identifies each of the 62 hydroelectric facilities that make up the Hydro-Quebec Power Resources (Exhs. JU-3-A at 70-71; JU-3-B at 78-79; JU-3-C at 70-71).

HQUS is required to physically supply Qualified Clean Energy to the Delivery Point at Larrabee Road and transfer that energy into the respective Distribution Company's ISO-NE account as settled at the Delivery Point (id. at 10 (defining "Deliver" or "Delivery")). Qualified Clean Energy is defined as follows:

> "Qualified Clean Energy" shall mean **energy produced by a hydroelectric generating resource**. For the avoidance of doubt, Qualified Clean Energy from the Hydro-Quebec Power Resources and delivered over the New Transmission Facilities during the Services Term. This energy must be tracked in the GIS to ensure a unit-specific accounting of the Delivery of Qualified Clean Energy to enable the Massachusetts Department of Environmental Protection to accurately account for such Qualified Clean Energy in the state greenhouse gas emission inventory, created under chapter 298 of the Acts of 2008.

(Exhs. JU-3-A, at 16-17; JU-3-B, at 18; JU-3-C, at 16-17).

Lastly, Section 4.1 of the PPAs provides that "[a]ll Deliveries of Energy and associated Environmental Attributes must be produced by the Hydro-Quebec Power Resources that are specified in Exhibit A…" (Exh. JU-3-A at 29; JU-3-B, at 31; JU-3-C, at 29). Section 4.1 also provides that the Distribution Companies are only obligated to pay for the lesser of the total Metered Output generated by the Hydro-Quebec Power Resources in any hour, and the amount of Qualified Clean Energy Delivered to the Delivery Point for the corresponding hour (Exh. JU-3-A at 28-29; JU-3-B, at 31; JU-3-C, at 28-29). Therefore, the Distribution Companies are not required to pay for generation that is not physically delivered at the Delivery Point and are not required to pay for energy delivered in excess of that generated by the specified Hydro-Quebec Power Resources (i.e. system energy that did not come from the specified hydroelectric generation facilities).

Reading these provisions together, as required to fairly interpret the PPAs, it is clear that the Distribution Companies are purchasing only energy and associated Environmental Attributes actually generated by one of Hydro-Quebec's specified 62 hydroelectric generation facilities, and physically delivered to the ISO-NE PTF at Larrabee Road. The energy must also be tracked in the NEPOOL GIS system to ensure unit-specific accounting of the Delivery of Qualified Clean Energy to accurately reflect such Qualified Clean Energy in the Massachusetts greenhouse gas emission inventory. In short, NextEra's interpretation of the word "predominately" in the definition of Hydro-Quebec Power Resources is completely lacking any nexus to the PPA and should be disregarded by the Department.

NextEra's arguments also suffer from a flawed legal analysis. NextEra argues that over five percent of Hydro Quebec's system mix is wind, biomass, biogas, waste and solar, with some nuclear and fossil fuel generation (NextEra In. Br. at 3, n. 5). In fact, NextEra's own exhibits demonstrate that Hydro-Quebec's sources of energy supply are composed of over 98 percent renewable sources (Exhs. EDC-NEER-1-2-3 Att.; EDC-RB-1, at 15; HQUS In. Br. at 9). Thus, NextEra's complaint seems to be that the Distribution Companies will inadvertently import wind energy over the NECEC line in addition to hydroelectric energy (NextEra In. Br. at 3, n. 5, stating that "Hydro-Quebec purchases all the output from 39 wind farms (3,508 MW)," and that "Attachment 1 to EDC-NEER 1-2 at 1, reflects purchases of wind energy at 11.2 TWhs and biomass at 1.8 TWhs."). The problem with NextEra's argument, aside from ignoring the multiple contractual provisions and the GIS accounting discussed above, is that the statutory definition of Clean Energy Generation includes new Class I RPS eligible resources that are firmed up with firm service hydroelectric generation. Thus, even if NextEra were correct that the energy flowing over the NECEC line may include a small percentage of energy from wind or other renewable energy sources, those circumstances would not run afoul of the definition of Clean Energy Generation, nor would it be a detriment toward meeting the Commonwealth's GWSA goals.

B. The NECEC Bid Complied With The Requirements Of The RFP.

Although Section 83D does not require firm hydroelectric energy generation to be incremental to historic deliveries, the RFP required bids with Firm Service Hydroelectric Generation to provide "Incremental Hydroelectric Generation," which is defined 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" (Exh. JU-2, at 5).

The Department accepted this definition when it approved the RFP. Fitchburg Gas and Electric Light Company d/b/a Unitil et al., D.P.U. 17-32, at 33 (2017). It is correct that the Department declined to accept HQUS's recommendation to amend the definition so that Incremental Hydroelectric Generation means "Firm Service Hydroelectric Generation that is capable of providing a net increase in MWh per year…" as opposed to generation that "represents a net increase in MWh per year…" Id. at 32-33. However, the Department also rejected a recommendation from Pattern Development to strike the "and/or otherwise expected" clause from the definition. Id. at 31, 33. The Department accepted the definition as proposed by the Distribution Companies and DOER, finding that the Distribution Companies "appropriately applied discretion when determining that hydroelectric generation should be incremental." Id. at 33. Thus, from the beginning, the Department recognized that the baseline energy deliveries compared to which NECEC Hydro's energy must be "incremental" might be different from actual deliveries made in one or more previous years.

The NECEC Hydro proposal complied with the requirement under the RFP to offer Incremental Hydroelectric Generation (Exh. EDC-RB-1, at 18). HQUS's affiliate, Hydro Renewable Energy, Inc. ("HRE"), confirmed that deliveries over the NECEC line will represent Incremental Hydroelectric Generation that could not otherwise have been delivered as Clean Energy Generation to New England, because the line will greatly increase the transfer capability between Québec and New England by adding a new 1200 MW interconnection (id. at 18-19; Exhs. EDC-RB-4 at 18-19; DPU-3-6). HRE also indicated that additional stations, including the Romaine 3 station completed in 2017 and the Romaine 4 station currently under construction, will supplement the HQ hydropower resources in the future, increasing the annual production capability of Hydro Quebec's system (Exh. EDC-RB-1, at 19, 20; Tr. 1, at 28), supporting the notion that the energy flowing over the NECEC line will be in addition to energy generated by Hydro Quebec in the past. In addition, HQUS subsequently indicated that it has spilled large quantities of water that could have been used to generate additional energy upward of 10.4 TWh had there been additional transmission export capability available (Exh. EDC-RB-1, at 20). This also indicates that energy deliveries over the NECEC line will be incremental to what would have been delivered in the absence of the line.

In fact, the Attorney General's witnesses concede that Hydro-Quebec can provide Incremental Hydroelectric Generation, as offered under its bid (Exh. AG-DM-Rebuttal-1, at 16-17). Despite criticizing the Distribution Companies and HQUS for allegedly being "vague" and "failing to offer clarity about what level of incremental hydro they are referring to, or what actual amounts of energy could be produced and delivered," (Exh. AG-DM-Rebuttal-1, at 14) the Attorney General's witness makes the following statement:

> This information on what HQ has been able to generate and deliver to New England in the past, and the increases in generating capacity it will have going forward,

> taken together with its reassuring (if imprecise) statements about its ability to deliver incremental power to New England if transmission capability is added, suggest that it should be able to achieve a Minimum Baseline Requirement of 14.8 TWh. (Through time averaging or some other mechanism would likely be advisable to accommodate variable hydrological conditions.) HQ's deliveries to New England have been at or above 14.8 TWh for the last several years, it has been spilling water, and the Romaine 3 and 4 additions will increase its capabilities further, so recent years are likely a better reflection of future capabilities. Hydro-Quebec has implied, at least, that it can provide incremental hydro to New England. So there is no evidence to suggest that HQ would be unable to provide fully Incremental Hydro.

(Exh. AG-DM-Rebuttal-1, at 16-17).

On this point, at least, the Attorney General's witness is exactly right. All evidence in the record indicates that HQUS has satisfied the requirement in the RFP to provide Firm Service Hydroelectric Generation that represents a net increase in MWh per year of hydroelectric generation compared to the 3-year historical average and/or otherwise expected delivery of hydroelectric generation within or into the New England Control Area. Moreover, Hydro Quebec is making a significant investment and long-term commitments to be able to deliver this incremental generation into New England (Tr. 1, at 41). Assuming future market conditions remain similar to average historical conditions, the reasonable expectation is that Hydro Quebec will continue delivering an average of 14.8 TWh into New England in addition to the firm commitment to deliver 9.55 TWh annually to the Distribution Companies under these PPAs (Exh. EDC-RB-1, at 27; Tr. 1, at 36-37, 50).[3]

[3] By the same token, if future market conditions diverge from what they have been in recent years, it is likely that the amount of energy delivered to New England would be "otherwise expected" to diverge as well, for exactly the reasons the Attorney General's witness adduces.

C. The Baseline Hydro Provisions In Exhibit H Of Each PPA Provides Greater Protections To Customers Than Initially Included In The RFP.

1. Exhibit H Introduces An Enforcement Mechanism Not Included In The RFP Or Model PPA.

After the NECEC Hydro proposal was selected for contract negotiation, the Distribution Companies each negotiated additional provisions of the PPA subjecting HQUS to penalties if it fails to maintain a minimum level of Baseline Hydroelectric Generation delivered into New England in addition to the Clean Energy Generation purchased under the PPA (Exh. EDC-RB-1, at 20-21; Tr. 1, at 28, 44-45). The additional requirement established by each Distribution Company is stated in Exhibit H to the respective PPAs (id. at 21). The terms of Exhibit H are intended to protect customers against the risk of paying for a net increase in hydroelectric generation not delivered by HQUS by requiring HQUS to reimburse National Grid and its customers for Transmission Service Payments incurred under the TSA in years where HQUS's non-PPA deliveries fall below the applicable Minimum Required Baseline Hydroelectric Generation Imports[4] (id. at 22).

Exhibit H was not included in the model PPA appended to the RFP (Exh. EDC-RB-1, at 21). The model PPA included a definition of Incremental Hydroelectric Generation similar to the definition included in the RFP (id.; Exh. WP Support Tab G at 19). That definition was removed from the RFP when Exhibit H was negotiated because Exhibit H was intended to implement this definition with greater specificity and stronger enforcement provisions. Importantly, the model RFP did not include any provisions for tracking HQUS's baseline deliveries into New England, nor did it include any concept of imposing penalties should HQUS fail to maintain deliveries representing a net increase in MWh/year than deliveries that might otherwise have been expected

[4] Eversource and Unitil use the term "Baseline Hydroelectric Generation" in their Exhibit H.

without the PPA (Exh. EDC-RB-1, at 22). Accordingly, the Baseline Hydroelectric Generation provisions in Exhibit H negotiated by each Distribution Company provide greater protections than the terms included in the form PPA for firm hydroelectric power (Exh. EDC-RB-1, at 21).

2. The Minimum Required Baseline Hydroelectric Generation Import Levels Established To Measure Damages Are the Result of Reasonable, Good-Faith Negotiations.

The Attorney General argues that the PPAs undermine the intent and purpose of the Section 83D solicitation because the PPAs do not include the requirement that contract energy be incremental to historic deliveries (AGO In. Br. at 17-18). The Attorney General takes the position that the PPAs must be amended to require a Minimum Baseline Hydro value of 14.8 TWh (id. at 26). The Attorney General criticizes the Distribution Companies for negotiating the Minimum Required Baseline Hydroelectric Generation Import value in Exhibit H, and incorrectly argues that the Distribution Companies excluded non-firm deliveries when determining the minimum baseline value (id. at 21, 25). NextEra argues Section 4.3(c) and 9.2(f) provide HQUS with flexibility resulting in non-firm hydroelectric service (NEER In. Br. at 22-23). RENEW, NEPGA and Sierra Club offer similar arguments that the "lowered" minimum baseline unfairly disadvantaged other bidders and the energy contracted for is not incremental (NEPGA In. Br. at 8-9; RENEW In. Br. at 7-8; Sierra Club In. Br. at 5)

The arguments raised by the Attorney General and other intervenors are rooted in a completely flawed conceptual basis. The Attorney General suggests that the PPAs will obtain no incremental deliveries in the case of Eversource and Unitil, and at most 44 percent incremental deliveries for National Grid (AGO In. Br. at 20). However, this position considers Exhibit H in isolation and attributes no value to expected market conditions in New England or HQUS's ongoing market incentives to continue delivering over the Phase II line consistent with its historical practices (which market incentives are the whole reason HQUS has been making these deliveries historically). As the Distribution Companies have repeatedly explained, the baseline values in each Exhibit H represent a known and measurable level at which penalties would be assessed and provides a measurement of potential penalties (Exh. EDC-RB-1, at 22; Tr. 1, at 25). It is not reflective of the level of expected deliveries and it "is not a cap on what those deliveries will be otherwise" (Tr. 1, at 25). Rather, in assessing HQUS's incentives for continued deliveries, one must add the PPA's contractual penalties *on top of* its ordinarily existing market incentives (i.e., the fact that HQUS does not get paid for energy it does not deliver either under the PPA or as part of its baseline sales). It would make little sense from HQUS's point of view to spend large amounts of time and energy to bid for and negotiate the PPA, only to offset profits from sales over NECEC by reducing profits from its baseline sales. It would make even less sense for HQUS to spend significant amounts of its own money building the Canada portion of the transmission line if it merely intended to offset its profits in this way.

As confirmed by HRE in its bid, and acknowledged by the Attorney General's witness, the purchase of 9.55 TWh/year of firm hydroelectric generation represents an entirely new quantity of energy that could not be delivered today without the NECEC project in service (Exhs. AG-DM-Rebuttal-1, at 16-17; EDC-RB-1, at 18-19). No party has provided any evidence to suggest that HQUS will decrease its other imports to New England as a result of entering into these PPAs. Rather, HQUS should be expected to respond to market conditions when scheduling deliveries over the Phase II line in the same or similar manner that it has done historically. The penalties introduced under Exhibit H provide additional incentives for HQUS to continue delivering into New England, even if market conditions become less favorable over the 20-year term of the PPA.

However, when determining the appropriate Minimum Required Baseline Hydroelectric Generation Imports quantity at which to begin subjecting HQUS to penalties, the parties agreed that it would be unreasonable to lock HQUS into its 3-year historic average of 14.8 TWh for 20 years into the future without taking into consideration what level of deliveries might otherwise be expected if market conditions change (Exh. EDC-RB-1, at 23). It is difficult to predict what differences from the 2014 to 2016 historical average could reasonably be expected for a period beginning several years later and continuing over the 20 years of the PPA, especially considering that the majority of Hydro Quebec's historical deliveries into ISO-NE are made on a non-firm and/or short-term basis (id. at 24). These deliveries could change quickly and significantly in future years if conditions change from those experienced historically (id.). For example, the Distribution Companies explained that the large amounts of offshore wind-generated energy that will be supplied to New England in future years could reduce the demand for the non-firm and short term HQUS resources (id.). Other factors could also influence expected deliveries, including changes in market conditions or energy policies in HQ's neighboring control areas (id.).

To be clear, the Distribution Companies did not exclude non-firm deliveries from the baseline value, as the AGO incorrectly suggests (AGO In. Br. at 21). In fact, the Distribution Companies' witnesses repeatedly corrected the AGO on this point:

> Q. So here you contend that non-firm and spot deliveries may not be appropriate for inclusion in the baseline to which future deliveries are compared. Can you please explain why non-firm and spot deliveries should be excluded?
>
> A. [Brennan] I guess I wouldn't say – and they weren't – at least in National Grid's they weren't entirely excluded, because any of these – any of these minimum required amounts that we had are primarily based on you know, the short-term trades.

(Tr. 1, at 39).

Q. If the intent of the RFP and form PPA was to exclude non-firm deliveries, why didn't the RFP and form PPA define incremental hydroelectric generation as being incremental to just ongoing long-term firm transactions, rather than incremental to total historical deliveries?

A. [Brennan] The intent was not to exclude those from the requirement. Again, here's the three-year – you know, we want to make sure that, you know – we decided to use the most recent three-year average and say, you know, to the bidders, "You're expected for this contract not simply to utilize" – if that was the most they could do, we wouldn't want them simply saying, "We're going to take that excess we have and just shift it to the contracted amount" and then the other stuff disappears. That's not what we wanted to happen.

We wanted to say, "You must prove as a starting point and commit in your bid that you are capable of delivering more than that starting point." And that's what they committed in their bids to start with.

And then the question is, you know, what checks and balances – or checks and penalties, incentives, might you have to make sure that once they've proven their capability, you know, they're still kept to that minimum amount.

(Tr. 1, at 46-47).

To arrive at the appropriate level of penalties and incentives, the parties negotiated acceptable levels of Minimum Required Baseline Hydroelectric Generation Imports that account for the kinds of future uncertainties discussed above while still providing HQUS a strong incentive to import hydroelectric generation into New England *in addition to* the contracted quantities of 9.55 TWh, and to protect Massachusetts customers against the risk of paying for the NECEC line without receiving a net increase in annual MWhs of clean hydroelectric energy. Again, this is an additional level of customer protection that was not included in the RFP or the model PPA. In fact, for this reason, as the IE has explained, neither the IE nor DOER believed that the Distribution Companies should impose upon HQUS a PPA obligation to deliver a specific level of baseline imports; in fact, the IE and DOER raised a concern that imposing such obligations on HQUS "raised a fairness question" (Exh. IE Evaluation Report at 51). The IE advised that it was acceptable to negotiate a contractual commitment from HQUS for additional baseline deliveries, "but cautioned that it be pursued in a manner that would not cause a collapse of the negotiations" (id. at 52). Thus, during negotiations, the Distribution Companies were being encouraged not to push too hard on the incrementality issue.

The Distribution Companies acted in the best interest of customers when negotiating these provisions. The Distribution Companies should not be criticized for negotiating these terms, and HQUS should not be penalized now just because it assented to the inclusion of potential penalties during negotiations. If anything, this demonstrates HQUS's strong intent to continue providing additional hydroelectric energy into New England for the foreseeable future.

D. The Attorney General's Recommended Changes To Exhibit H Are Unnecessary And Would Likely Increase The Cost Of The PPA.

The Attorney General asks the Department to direct the Distribution Companies to revise Exhibit H of each PPA to increase the Minimum Required Baseline Hydroelectric Generation Imports to 14.8 TWh such that the total required deliveries under the contracts would be 24.35 TWh/year (AGO In. Br. at 20, 26). The AGO suggests using National Grid's Exhibit H as a framework, but to make two other material changes: (1) striking adjustment factor "A," which reduces the baseline when on-peak prices are below a threshold amount; and (2) increasing the penalty calculation (AGO In. Br. at 27-29). In short, the AGO seeks to require HQUS to maintain baseline deliveries at its average 2014-2016 historic levels over the 20-year term of the PPA, no matter how the economic conditions may change, and to penalize HQUS by greater amounts if it reacts to conditions in a way that it would have been "otherwise expected" to do.

The AGO's recommended "solution" is unreasonable and would likely jeopardize important economic and environmental benefits provided by the PPAs. Exhibit H protects customers by requiring HQUS to maintain its non-contract deliveries into New England over the term of the PPA at levels reasonably "otherwise expected," as provided in the RFP and approved by the Department. Changing a material and hard-fought provision of the PPA as the Attorney General advocates would inevitably reopen negotiations over other provisions as well – with consequences not necessarily beneficial to customers.

Under Section 18 of the PPAs, the PPAs may only be amended by written agreement by the parties (Exhs. JU-3-A at 62; JU-3-B at 70; JU-3-C at 62). Therefore, HQUS would not be obligated to accept the amendments proposed by the Attorney General, even if the Department were to order such revisions. The bids received in response to the RFP were valid for 270 days from the submission date, or April 27, 2018, and are no longer valid. Accordingly, if the Department directed the Distribution Companies to amend Exhibit H, and HQUS refused to accept any amendments at it's the current price, the Distribution Companies would be required to reissue the Section 83D RFP and start this entire process from scratch.

As detailed above, the terms of Exhibit H are the result of reasonable, good faith negotiations and provide additional protections for customers that were not contemplated in the RFP or model PPA. The Department should reject the Attorney General's request to materially modify the terms of the agreement.

III. THE PPAs INCLUDE ADEQUATE PROTECTIONS AGAINST NON-DELIVERIES.

NextEra argues that the contracts will not satisfy the statutory criteria to reduce winter price spikes and guarantee winter deliveries because the cover damages provisions in the PPAs are insufficient (NextEra In. Br. at 19). NextEra suggests that because "HQUS is a marketing entity that operates to arbitrage markets to maximize profits," it will seek every opportunity avoid its firm obligations under the PPAs and instead just pay damages (id.). Additionally, relying on data that was discredited at the evidentiary hearings, NextEra argues that HQUS has historically chosen not to deliver into ISO-NE in the winter (id.) Finally, NextEra falsely claims that the PPAs' cover damages will only recoup 10% of the price increases to Massachusetts customers (id. at 19-20). NEPGA similarly argues that the PPAs will not guarantee energy delivery in winter months (NEPGA In. Br. at 9). Relying on statements from NextEra's witnesses, NEPGA argues that HQUS may choose not to deliver in the winter and just pay damages instead (id. at 9-10).

The Department should reject these arguments because they are not supported by a reasonable interpretation of the PPAs, because the PPAs provide strong incentives for HQUS to perform as promised, and because NextEra has not offered any evidence to substantiate its allegations about HQUS's likelihood to pursue arbitrage strategies instead of delivering firm energy as required under the contracts.

A. The PPAs Secure Firm Hydroelectric Generation Resources On Behalf Of Customers.

It is a well-known principal of contract interpretation that contracts should be given the intent of the contracting parties at the time the contract was entered. De Freitas v. Cote, 342 Mass. 474, 476-477 (1961) (citing McQuade v. Springfield Safe Deposit & Trust Co., 333 Mass. 229, 233 (1955); Malaguti v. Rosen, 262 Mass. 555, 560 (1928)). The circumstances surrounding the making of the agreement must be examined to determine the objective intent of the parties. Louis Stoico, Inc. v. Colonial Development Corp., 369 Mass. 898, 902, 343 N.E.2d 872 (1976).

The RFP defines the circumstances surrounding the making of these agreements. The PPAs are the result of a solicitation for Clean Energy Generation, including hydroelectric generation provided on a firm basis (Exh. JU-2 at 12). Bidders were informed that the fundamental purpose of the RFP is to satisfy the policy directives encompassed within Section 83D and to assist the Commonwealth with meeting its GWSA goals (id. at 8). Bidders were specifically put on the notice that they "must demonstrate that the proposed project will contribute to a reduction in winter electricity price spikes" by "guaranteeing delivering during the peak winter months as well as delivering when an event is called by ISO-NE" (id. at 30, 33).

The PPAs are consistent with this intent. HQUS is required to provide energy and Environmental Attributes on a firm basis, consistent with the Delivery Schedule set forth in Exhibit B (Exh. JU-3-A at 28-29, 72). HQUS's obligation to deliver energy in accordance with the Delivery Schedule "are firm and not subject to interruption except to the extent caused by Force Majeure, excused under Section 4.2(a) or cured in accordance with Section 4.3(c)" (Exhs. JU-3-A at 29; JU-3-B at 31; JU-3-C at 29). Section 4.2(a) excuses deliveries during negative LMP periods, and Section 4.3(c) relates only to circumstances where HQUS cannot deliver because of a non-excused outage of the NECEC transmission line or an outage or reduction in the availability of the Quebec Line (id. at 23-25).

For avoidance of doubt, Section 4.1(c) of the PPA provides that:

> Except in the case of any default by Buyer, Seller shall not sell, divert, grant transfer or assign the Products or any right, claim, certificate or other attribute associated with such Products to any Person other than Buyer during the Term. Seller shall not claim or enter into any agreement or arrangement under which such Products can be claimed by any Person other than Buyer. Buyer shall have the exclusive right to resell or convey such Products in its sole discretion.

(Exhs. JU-3-A at 23; JU-3-B at 31; JU-3-C at 29). HQUS acknowledged the applicability of this provision to its firm obligations under the PPA, including its obligations to guarantee delivery in winter months (HQUS In. Br. at 11).

As another example, in the event of an Uncured Delivery Shortfall, HQUS is obligated to pay damages equal to the net of the price that would have been paid under Section 5.1 of the PPA and: (1) the Replacement Price of energy applicable to the Uncured Delivery Shortfall; (2) any additional transmission costs and charges incurred to transmit Replacement Energy to the Delivery Point; (3) any other costs reasonably incurred to purchase Replacement Energy and/or

Replacement Environmental Attributes; (4) any applicable ISO-NE penalties or costs; (5) any other costs or losses reasonably incurred by the Distribution Companies; and (6) any costs or charges incurred by the Distribution Companies under the TSA for the quantity of energy not delivered (Exhs. EDC-RB-1, at 31; JU-3-A at 3).

Despite these clear terms, NextEra incredulously argues that the cover damages provision "transforms the entire PPA from a guaranteed sale … to a put option in favor of HQUS (Exh. NEER-RSW-1 at 16). In NextEra's view, HQUS entered into these PPAs for firm qualified clean energy from hydroelectric generation with the intent of seeking every opportunity "[a]t any time" to "divert those sales to a more profitable market" (id.). NextEra's position assumes that HQUS is willing to ignore its contractual obligations under the PPAs, risk significant damages and/or termination, and disrupt its relationship with major customers in order to pursue marginal arbitrage positions.[5] NextEra's allegations do not represent a feasible or valid foundation for its recommendation that the Department reject that PPAs. Its interpretation of the PPAs is completely counter to the clear intent of the contracting parties, as embodied in the contract terms, and must be rejected.

B. NextEra Has Not Provided Any Evidence That HQUS Will Intentionally Fail To Meet Its Guaranteed Delivery Obligations.

Despite claiming that HQUS may divert its firm sales under the PPAs to more profitable markets at any time, NextEra has not provided any evidence to support its contentions. When asked in discovery to "provide any information and analysis, up to and including historical pricing information for the last 5 years on any and all markets that Hydro-Quebec could arbitrage in

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[5] NextEra also fails to explain why HQUS should pull energy from the Distribution Companies – losing the PPA sale price of the energy as well as paying the contractual penalties – to pursue arbitrage opportunities when it manifestly generates enough energy from its hydroelectric facilities to do both. Much of NextEra's argumentation relies on a false premise: that the only downside for HQUS in failing to perform under the PPAs is the penalties prescribed therein, ignoring the lost sales of the energy itself as well as the other issues discussed in the text.

(including NYISO, Ontario and Quebec)" NextEra simply responded: "There are no documents responsive to this request" (Exh. EDC-NEER-1-34; Tr. 2, at 314-315). In fact, Mr. Russo testified that "[i]t is not our job, nor is it within our capabilities, to understand exactly how the large physical and financial portfolio of Hydro-Quebec has developed and their power traders may be managed" (Tr. 2, at 316). Even though Mr. Russo was informed by the hearing officer in Maine Public Utilities Commission Docket 2017-00232 (the "Maine Proceeding") on January 11, 2019 that "from the commissions perspective … it would be important to understand how likely it might be for Hydro-Quebec to [arbitrage]," he made no attempt to quantify how likely it may be or how often HQUS could chose to sell or not to sell under the PPA in his February 15, 2019 surrebuttal testimony in this proceeding (Tr. 2 at 317-319; Exh. EDC-Hearing-3, at 47).

Unlike Mr. Russo, the Distribution Companies *have* analyzed the likelihood of such arbitrage conditions occurring. The Distribution Companies have explained that a price change that might reasonably lead to a potential arbitrage opportunity would be if the price in NYISO and/or Quebec became *more than $50 per MWh higher than the price in Maine* (Exh. EDC-RB-1, at 35). This $50 per MWh spread is based on a calculation of the Cover Damages payment HQUS would need to make to the Distribution Companies using the TCR Base Case cost of replacement energy in 2025, the CES compliance cost, and the loss of PPA revenue for HQUS (id. at 35, n. 18). Based on analysis of prices from 2014 through 2018, the Distribution Companies concluded that NYISO prices exceeded Maine prices by $50 per MWh in 0.2 percent of hours over that period (id. at 35). Therefore, the Distribution Companies concluded that historical prices do not indicate virtually no opportunity for HQUS to profit by diverting energy from NECEC into NYISO and/or Quebec (id.). Ontario has a power market that relies heavily on contracted power, and therefore does not present a lucrative arbitrage opportunity for HQUS (id. at 35-36).

Tellingly, NextEra's witnesses admitted that they "haven't done any analysis to refute this" (Tr. 2, at 332-333). As the Department is aware, it must base its findings on substantial evidence in the record, which is evidence that a reasonable mind might accept as adequate to support a conclusion. G.L. c. 30A §§ 1(6), 14(7); Sinclair v. Director of the Div. of Employment Security, 331 Mass. 101, 102 (1954); Norwood Ice Co. v. Milk Control Comm., 338 Mass. 435, 441 (1959); Singer Sewing Mach. Co. v. Assessors of Boston, 341 Mass. 513, 517 (1960); McCarthy v. Contributory Retirement Appeal Bd., 342 Mass. 45, 47 (1961). Therefore, the Department cannot reasonably rely on NextEra's pure conjecture and speculation that HQUS will intentionally fail to fulfill its obligations under the PPAs.

NextEra also argued that "HQUS has historically chosen not to deliver into ISO-NE in the winter, when ISO-NE needs the HQUS energy the most" (NextEra In. Br. at 19). With this claim, NextEra appears to be relying on the figures it prepared and provided as Figure RSW-1 in surrebuttal testimony, which NextEra claims show "direct correlations between price spikes at the ISO-NE Internal Hub and HQUS's exports over the existing Phase II and Highgate interties during the winter months" (Exh. NEER-RSW-S-1, at 17, 19-21).

However, this data was discredited at hearings. First, as Mr. Brennan explained, it is not even clear how the data was prepared because it does not indicate whether the charts are reporting hourly averages, peak averages, on-peak averages or daily averages (Tr. 1, at 237). NextEra's witnesses were not even able to confirm whether the data represents averages or some other figure (Tr. 2, at 322). From this record, the data could represent a snapshot of the lowest imports on any given day compared to the highest price, which may or may not occur to the same time. There is no way to know; indeed, NextEra's own witnesses neither knew nor supported their methodology.

Moreover, it was demonstrated that the data *does not show* that HQUS "chose" not to deliver when prices spike. NextEra agreed that the data for December 2013 to January 2014 reflects the 2013-2014 polar vortex, which "was a unique event in recent memory" (Tr. 2, at 323-324). During that time, prices increased in mid-December with only a minor reduction in imports over the Phase II line (id. at 324; Exh. NEER-RSW-S-1, at 19). The data does not reflect a direct correlation between price spikes and HQUS backing off imports. Additionally, NextEra's witnesses acknowledged that the December 2014 reduction in imports was due to an event of sabotage causing HQ to lose two 745-kV lines feeding Montreal and requiring an emergency ramp-down of imports over Phase II and Highgate to zero (Tr. 2, at 327-328). Additionally, in the winter of 2017 to 2018 the Phase II line was reduced due to the loss of a pole on the line (id. at 328). Thus, the largest instances of reduced imports into New England are easily explained by events unrelated to HQUS's economic choices to deliver to markets other than New England. Again, NextEra's contentions are not supported by credible evidence.

C. The PPAs Include Significant Protections For Justified Circumstances When HQUS May Not Be Able To Deliver In Winter Months.

The PPAs contain significant provisions to protect Massachusetts customers in the event of non-deliveries, including during winter months. The Cover Damages provision is one such protection (Exh. EDC-RB-1, at 31). In the event of an Uncured Delivery Shortfall, HQUS is obligated to pay damages equal to the net of the price that would have been paid under Section 5.1 of the PPA and: (1) the Replacement Price of energy applicable to the Uncured Delivery Shortfall; (2) any additional transmission costs and charges incurred to transmit Replacement Energy to the Delivery Point; (3) any other costs reasonably incurred to purchase Replacement Energy and/or Replacement Environmental Attributes; (4) any applicable ISO-NE penalties or costs; (5) any other costs or losses reasonably incurred by the Distribution Companies; and (6) any costs or charges incurred by the Distribution Companies under the TSA for the quantity of energy not delivered (Exhs. EDC-RB-1, at 31; JU-3-A at 3). The Cover Damages ensures that customers will not pay more than they would have under the contract if HQUS fails to deliver at any time, including during winter peak periods.

Additionally, the ability to cure delivery shortfalls due to circumstances where HQUS cannot deliver because of a non-excused outage of the NECEC transmission line or an outage or reduction in the availability of the Quebec Line pursuant to Section 4.3(c) f the PPAs provides an important enhancement in the contract firmness for the benefit of customers (Exh. EDC-RB-1, at 34). Per the terms of the PPAs, in the event of a Curable Delivery Shortfall, the Shortfall Cure Amount of Qualified Shortfall Energy may only be delivered during the corresponding period of the Shortfall Cure Period during the off-peak/on-peak (id.). Therefore, if the shortfall occurs in the Winter Period as defined in the PPAs, then the delivery of the shortfall cure energy must take place in the corresponding Winter Period of the Shortfall Cure Period (Exhs. EDC-RB-1, at 34; JU-3-A, JU-3-B and JU-3-C, § 4.3(c)(vii)). Section 4.3(c) allows for HQUS to cure shortfalls due to transmission outages with physical energy flows instead of paying a penalty under the PPAs, which provides benefits to Massachusetts customers by supporting firm energy deliveries, including in winter months (Exh. EDC-RB-1, at 34-35).

NextEra, in an attempt to demonstrate that the PPAs do not contribute to reducing winter electricity price spikes and to guarantee energy delivery in winter months, alleges that the Cover Damages provisions of the PPAs will not make Massachusetts customers whole in the event that HQUS fails to deliver energy under the PPAs (NextEra In. Br. at 19-20). NextEra claims that Massachusetts customers will only recoup approximately 10 percent of the price impact in the event of a failure to deliver under the PPAs (id. at 20). NextEra's novel interpretation of the PPAs' terms is commercially infeasible and, if adopted, would likely lead to increased costs that are ultimately borne by customers.[6,7]

In essence, NextEra, through the improper introduction of extra-record evidence in the form of Attachment A to its initial brief,[8] seeks to interpret Section 83D as requiring the PPAs to contain provisions that would require HQUS, in the event that it was unable to deliver energy under the contract, to absolutely eliminate the fiscal impact of that non-delivery. As an initial matter, the Department should squarely reject NextEra's self-serving attempt to interpret Section 83D(d)(ii) in this manner. The Massachusetts Supreme Judicial Court (the "Court") has consistently held that "statutory language should be given effect consistent with its plain meaning and in light of the aim of the Legislature unless to do so would achieve an illogical result." Welch v. Sudbury Youth Soccer Ass'n, 453 Mass. 352, 354-355 (2009) (quoting Sullivan v. Town of Brookline, 435 Mass. 353, 360 (2001)); see also Bay State Gas Co., D.P.U. 14-134, at 7 (Apr. 30, 2015). ("[A] basic tenet of statutory construction is to give the words their plain meaning in light of the aim of the Legislature."). The Court has further stated that "[n]one of the words of a statute is to be regarded as superfluous, but each is to be given its ordinary meaning without overemphasizing its effect upon the other terms appearing in the statute, so that the enactment considered as a whole shall constitute a consistent and harmonious statutory provision capable of effectuating the presumed intention of the Legislature." Bolster v. Commissioner of Corps. &

6 Again, NextEra argues as if the contractual penalty is the only downside to HQUS if it fails to deliver. In point of fact, this penalty must be added on top of the fact that HQUS will not be paid for any energy it does not deliver.

7 In the event of an Uncured Delivery Shortfall, the Distribution Companies reserve the right to seek to recover any costs, including "any other costs and losses reasonably incurred by Buyer as a result of that Uncured Delivery Shortfall" consistent with the Cover Damages provision of their respective PPAs.

8 The Distribution Companies have addressed NextEra's Attachment A in greater detail earlier in this reply brief.

Taxation, 319 Mass. 81, 84-85 (1946); see also International Org. of Masters v. Woods Hole, Martha's Vineyard & Nantucket S.S. Auth., 392 Mass. 811, 813 (1984).

Within the statutory scheme promoting the development of renewable generation resources, the plain words of Section 83D(d)(5)(ii) demonstrate the General Court's intent to require long-term contracts under Section 83D to "[c]ontribute to reducing winter electricity price spikes." There is no reasonable interpretation of Section 83D(d)(5)(ii) that could be read as requiring a single long-term contract to *eliminate* winter electricity price spikes entirely, yet this is exactly what NextEra is seeking to do when it asks the Department to set aside well-established statutory precedent. The Department should refuse to contemplate NextEra's requested interpretation in this instance.

Furthermore, even if such an interpretation of Section 83D(d)(5)(ii) were somehow consistent with the plain meaning of the statute, which it is not, NextEra is asking the Department to support the use of a commercially unreasonable contract provision that would likely result in either contract termination or, at the very least, a substantial increase in costs to Massachusetts customers. Essentially, NextEra is arguing that, under the PPAs' Cover Damages provisions, HQUS should be responsible for making Massachusetts customers whole for any and all price impacts that may flow from HQUS's failure to deliver energy under the PPA (NextEra In. Br. at 19-20). NextEra has provided no evidence that such a clause is a commercially achievable in a reasonably-priced PPA. Certainly, none of the other long-term contracts entered into pursuant to the Green Communities Act, including the PPAs entered into under Section 83C, have included comparable provisions.

Additionally, were the Department to accept NextEra's patently flawed argument, which it should not, the RFP did not include a requirement that bidders factor a complete assumption of risk to eliminate winter electricity price spikes into their bid price. As such, none of the bidders under the RFP, including HQUS, were on notice that such an assumption of risk would be required. Even assuming the bidders were willing to take on such an assumption of risk, it is a given that each bidder would want to analyze their potential exposure and incorporate the costs of that exposure into their submitted bid. Given that none of the bidders were given this opportunity, it is fair to conclude that the filed bids, including the winning bid, did not price this risk. It is also fair to conclude that this understatement of cost is significant given the magnitude of the risk that NextEra is arguing the winning bidder should assume.

NextEra has failed to support its flawed contentions and interpretation of the requirements under Section 83D(d)(5)(ii), nor has it provided the Department with the slightest reason to throw out established precedent and instead subscribe to NextEra's self-serving statutory interpretation. Accordingly, the Department should disregard NextEra's argument and tacit recommendation in its entirety.

IV. THE NECEC PROJECT WILL PROVIDE A SIGNIFICANT GHG REDUCTION BENEFIT TO MASSACHUSETTS.

A. TCR's Quantitative Analysis Is The Best Evidence Of Expected GHG Reductions And GWSA Benefits.

TCR modeled a projected greenhouse gas ("GHG") emission reduction of 36.61 MMTCO2e for the years 2019 through 2040 as a result of the NECEC project being in service, relative to the 83D Base Case (Exhs. JU-1, at 44; JU-7, at 2). The project is also expected to result in significant direct economic benefits from the use of Environmental Attributes towards CES compliance (see, e.g., Exh. NEER-1-1-B-14 Att. (Confidential)).

The Attorney General, NextEra and the Sierra Club argue that the GHG and GWSA results modeled by TCR are not reliable because TCR's base case assumed that Hydro Quebec's other imports into New England would continue at 2012 load profile levels (AGO In. BR. at 24; NextEra In. Br. at 12; Sierra Club In. Br. at 10-11). Those parties argue that TCR should have re-run its analysis assuming non-contract deliveries from Hydro Quebec would be limited to the Minimum Required Baseline Hydroelectric Generation Imports set forth in each Exhibit H (id.). This argument is unreasonable because the Minimum Required Baseline Hydroelectric Generation Imports quantities do not reflect the average level of expected deliveries over the 20-year term of the PPAs.

TCR's model used historical schedules of energy from Hydro-Quebec over the period of 2012 and assumed the same hourly schedule would persist into the future (Tr. 1, at 48-49). The same quantities of deliveries were used in every case that was evaluated (id.). TCR did not also model deliveries equal to the Minimum Required Baseline Hydroelectric Generation Imports because that is not what the Evaluation Team expected and decided was a reasonable evaluation (id. at 50).

As discussed at length above, the baseline values in each Exhibit H represents a known and measurable level at which penalties would be assessed and provides a measurement of potential penalties (Exh. EDC-RB-1, at 22; Tr. 1, at 25). It is not reflective of the level of expected deliveries and it "is not a cap on what those deliveries will be otherwise" (Tr. 1, at 25, 50-51). Therefore, it is reasonable for TCR's base case to assume that Hydro Quebec's deliveries will continue at 2012 load profiles. TCR's base case assumptions are also reasonable considering that there is general agreement that HQUS is capable of providing 9.55 TWh/year under the PPA on a fully incremental basis (Exh. AG-DM-Rebuttal-1, at 16-17).

B. The Intervenors' Resource-Shuffling Arguments Are Unsupported By Evidence And Inconsistent With The GWSA.

The Sierra Club argues that "[t]here is no environmental benefit to shifting the greenhouse gas emissions of existing generation from one jurisdiction's greenhouse gas balance sheet to another" (Sierra Club In. Br. at 12). NEPGA also repeats the arguments from NextEra regarding "resource shuffling" to suggest that the PPAs will not deliver environmental benefits (NEPGA In. Br. at 11). On this point, NEPGA repeats NextEra's incorrect claim that HQUS "is required only to deliver system power, and not electricity from specified renewable facilities, to satisfy its obligations" (id., citing Exh. NEER-RSW-1, at 10). NextEra also argues in its brief that the use of the NEPOOL GIS tracking system is "thwarted by the location of the Appalaches AC-DC converter station of the Quebec Line, which allows the system generation mix of Hydro Quebec to flow over NECEC to the Larrabee Road delivery Point" (NextEra In. Br. at 8).

These arguments suffer from several fatal flaws. First, the PPAs require unit-specific accounting of all energy and Environmental Product sales sufficient to demonstrate that the Distribution Companies are purchasing only qualified Clean Energy Generation from the specified Hydro-Quebec Power Resources in Exhibit A of the PPA. Second, the GWSA only seeks to regulate Massachusetts' statewide GHG emissions including emissions from the generation of electricity delivered to and consumed in the Commonwealth, not emissions in other states associated with energy not delivered to Massachusetts. Additionally, NextEra has not considered applicable GHG policies in other states and regions.

1. The PPAs Require Sufficient Unit-Specific GIS Accounting of Hydroelectric Energy and Environmental Attributes.

As noted in Section I above, the energy delivered by HQUS must be tracked in the GIS to ensure a unit-specific accounting of the Delivery of Qualified Clean Energy to enable the

Massachusetts Department of Environmental Protection to accurately account for such Qualified Clean Energy in the state greenhouse gas emission inventory, created under chapter 298 of the Acts of 2008 (Exh. JU-3-A, at 16-17). The energy must be tracked in the NEPOOL GIS, and HQUS is solely responsible to demonstrate that the Hydro Quebec Power Resources from which its is delivering energy and Environmental Attributes are sourced from Qualified Clean Energy Generation Units (Exhs. EDC-RB-1, at 13; NEER-3-1). The Distribution Companies are not obligated to accept or pay for any Environmental Attributes that do not constitute an Environmental Attribute associated with the specified MWh of generation from Qualified Clean Energy Generation Units (Exhs. EDC-RB-1, at 13-14; JU-3-A, JU-3-B and JU-3-C, § 4.1(b)). The Massachusetts Department of Environmental Protection ("MADEP") confirmed that this unit-specific accounting arrangement will be sufficient for purposes of complying with the CES (Exhs. EDC-RB-1, at 14; EDC-RB-2; NEER-1-13 Att, at 3-4).

For those reasons, NextEra and NEPGA are wrong to suggest that the Distribution Companies are only purchasing system power from HQUS. They are also wrong to conflate the unit-specific accounting arrangements under the PPA to situations in which Hydro-Quebec has wheeled hydroelectric energy through New York's transmission system to ISO-NE (NextEra In. Br. at 9). Mr. Brennan explained that the GIS accounts for wheeled energy through NYISO as system sales from New York rather than treating it as hydroelectric generation (Tr. 1, at 42). But unlike general sales of energy wheeled through New York, the Distribution Companies are purchasing the exclusive right and title to the Environmental Attributes associated with HQUS's sales under the PPAs (Exhs. JU-3-A at 29; JU-3-B at 31; JU-3-C at 29). HQUS is required to transfer the Environmental Attributes associated with all Qualified Clean Energy or Qualified Shortfall Energy purchased by the Distribution Companies by means of an irrevocable Forward

Certificate Transfer (as defined in the GIS Operating Rules) within 15 days after the end of the calendar month in which such Qualified Clean Energy or Qualified Shortfall Energy was generated (id. at 30). Payment is only due after the Forward Certificates are actually deposited into the Distribution Company's GIS account (id.). Accordingly, the arrangement under the PPAs is much different than the general system sales approach involved with wheeled power through the NYISO. NextEra again ignores the plain wording of the PPA in making its flawed argument.

2. The GWSA Regulates Massachusetts GHG Emissions.

Without providing any supporting evidence or considering applicable GHG policies in other states and regions, NextEra suggests that "resource shuffling" could result in increased emissions in other regions if HQUS meets its obligations under the PPA by diverting clean energy from other regions (Exhs. NEER-RSW-1, at 20-21; EDC-NEER-1-10). This argument fails to consider that under the GWSA, Massachusetts is making its own valuable contribution to broader carbon reductions by increasing its own demand for clean, low-carbon energy, but that Massachusetts cannot be expected to – and the GWSA does not attempt to – singlehandedly solve the whole nation's carbon problems.[9] If other regions like New York or Ontario do in fact decrease their consumption of hydroelectric energy from Hydro-Quebec resources as a result of these PPAs, those regions will need to find other clean energy resources to help meet their GHG emissions policies (see Exh. EDC-RB-1, at 11 (identifying the applicable policies in New York and Ontario)).

The Court has acknowledged the Massachusetts-specific framework of the GWSA. In Kain v. Department of Environmental Protection, the Court rejected the argument that regulations passed under the GWSA need not achieve GHG reductions specific to the Commonwealth, but

[9] The GWSA defines "Statewide greenhouse gas emissions" as "the total annual emissions of greenhouse gases in the Commonwealth" including "all emissions of greenhouse gases from the generation of electricity delivered to and consumed in the Commonwealth" even if that electricity is produced elsewhere. G.L. c. 21N, § 1; New England Power Generators Association, Inc. v. Dep't of Env'tl Protection, 480 Mass. 398, 401 (2018).

may be regional in nature. 474 Mass. 278, at 298 n. 25 (2016). The Court found that, not only is this argument inconsistent with the statute's central purpose of reducing emissions in the Commonwealth, but it also presumes that MADEP has the authority to promulgate regulations that have force outside the Commonwealth; yet nothing in the language of the statute or of G.L. c. 21A purports to do so. Id.

The Court has also specifically addressed claims regarding "leakage" of emissions in addressing a challenge to the MADEP's GHG cap regulations promulgated under 310 C.M.R. § 7.74 pursuant to the GWSA. New England Power Generators Association, Inc. v. Dep't of Env'tl Protection, 480 Mass. 398 (2018). In that case, the plaintiffs argued that the GHG cap regulations were arbitrary and capricious because the regulations may cause modest emissions leakage, which is defined in G.L. c. 21N, § 1 as "the offset of a reduction in emissions of greenhouse gases within the Commonwealth by an increase in emissions of greenhouse gases outside of the Commonwealth." Id. at 408. The Court rejected this argument, first noting that the cap regulations must be read in concert with the CES, which was intended to work together with the cap regulations to maximize the reduction in GHG emissions. Id. at 409. The Court went on to explain that:

> [E]ven if the Cap Regulation does result in an increase in electricity imports, the agencies project that an increasing percentage of those imports will be derived from zero-emission sources, in part due to the CES Regulation's mandate that the Commonwealth consume greater percentages of clean energy each year. Finally, far from causing increased greenhouse gas emissions from out-of-State generators, according to the agencies, the two regulations together will send a market signal that Massachusetts' neighbors should invest in clean energy development in order to satisfy the Commonwealth's increasing demand for renewable energy.

Id. at 409-410.

The PPAs are an important step towards meeting the CES regulations and GWSA goals. By procuring firm deliveries and exclusive rights and title to the Environmental Attributes associated with 9.55 TWh/year of clean hydroelectric energy from HQUS for the next 20 years, the PPAs are providing significant cost-effective clean energy sources and Massachusetts GHG inventory reductions. In our regional energy market, where other states have and continue to pass similarly aggressive GHG reduction policies, there is significant competition to secure cost-effective low or zero carbon energy sources. Securing these particular hydroelectric resources for the benefit of Massachusetts is particularly valuable as there are finite sources of large-scale hydroelectric generation in the region. As noted by the MADEP and acknowledged by the Court, this procurement, which will be used for CES compliance, will only increase competition to build new renewable energy resources to meet the growing demand in Massachusetts and the region.

V. THE NECEC PROJECT WILL ENHANCE RELIABILITY IN MASSACHUSETTS.

The Distribution Companies detailed in their initial brief how the NECEC Project will enhance reliability in Massachusetts (EDC In. Br. at 22-24). In short, the Distribution Companies explained that NECEC: (1) agreed to commit any qualifying capacity into ISO-NE exclusively; (2) agreed to comply with the RFP requirement to interconnect at the strict Capacity Capability Interconnection Standard ("CCIS"); (3) will perform significant upgrades to the existing Bulk Electric System in New England to allow for more reliable operation of the grid; and (4) will provide additional firm hydroelectric deliveries into the ISO-NE Pool Transmission Facility, increasing fuel security and diversity (Exhs. EDC-RB-1, at 37-38; EDC-RB-4, at 43; EDC-RB-1, at 47; JU-1, at 40; Tr. 2, at 263, 266). Additionally, the Distribution Companies demonstrated that TCR's dispatch model and related analysis confirmed that the NECEC project will deliver benefits into New England (Tr. 2, at 264, 268-270). TCR's analysis, using very conservative assumptions, modeled all known ISO-NE system constraints and definitively showed reduced LMPs in Massachusetts with NECEC operating (Exh. EDC-RB-1, at 37-38, 42-45; Tr. 2, at 264, 268-270).

In its initial brief, NextEra continues to argue that the project will not enhance reliability in Massachusetts or mitigate transmission costs because transmission interfaces below Suroweic-South at the Maine-New Hampshire and North-South interface will constrain flows from NECEC at peak periods unless ISO-NE requires additional significant system upgrades at additional costs to Massachusetts customers (NextEra In. Br. at 13-18). NextEra's arguments lack any credibility because NextEra failed to provide any modeling of alleged congestion with the NECEC project in service, despite having prepared *multiple* models in the Maine Proceeding and despite being asked for those models in discovery. NextEra's claims are also inconsistent with its own affiliate bid in the Section 83D RFP, and in relation to future upgrades, are purely speculative and cannot be relied upon by the Department.

A. NextEra's Arguments Are Not Credible.

1. <u>NextEra Withheld Responsive Documents From the Record.</u>

In asserting its claims in this proceeding, NextEra attempts to rely on "evidence showing there is historical and forecasted congestion on these interfaces," which it says are "from ISO-NE and the former COO of ISO-NE, which are and have been charged with the reliability of the ISO-NE region" (NextEra In. Br. at 15-16). Here, NextEra is referring to the testimony of its witness, Mr. Stephen Whitley, who relied upon a presentation from ISO-NE regarding the Forward Capacity Auction 14 capacity zone development preview and a summary of installed capacity requirements proposed by ISO-NE (<u>Exh</u>. EDC-NEER-1-27; Tr. 2, at 335-336). The ISO-NE materials relied upon by NextEra do not take into consideration the system upgrades that will be completed by CMP in connection with the NECEC line, nor do they model the effect of the

NECEC project (Exhs. RSW-6; EDC-NEER-1-13 Att. 1).[10] Neither Mr. Whitley nor anyone else on behalf of NextEra offered any independent modeling of constraints at the Maine-New Hampshire or North-South interfaces impacting the NECEC line in this proceeding (Exh. EDC-NEER-1-27; Tr. At 336-337). In fact, NextEra denied the existence of any independent modeling when asked in discovery for models showing constraints at the Maine-New Hampshire or North-South interfaces, models showing contingencies or failure modalities with respect to the NECEC project, and models regarding effects on energy market LMPs as a result of the PPAs (Exhs. EDC-NEER-1-27; EDC-NEER-1-31; EDC-NEER-1-35).

Yet under cross-examination, Mr. Whitley acknowledged that he and several NextEra employees had prepared *multiple* models in the Maine Proceeding that would have been responsive to the Distribution Companies information requests (Tr. 2, at 337-344). First, NextEra and Mr. Whitley prepared and relied upon a production cost model and load flow model to assess reliability issues with NECEC in the Maine Proceeding (Exh. EDC-Hearing-1, at 8; Tr. 2, at 337-338). In fact, NextEra submitted multiple iterations of that model to address criticisms of the model raised by CMP (Tr. 2, at 339). NextEra did not provide any of those iterations of the model in this proceeding, despite a specific request to do so by the Distribution Companies during discovery (id.).

The production cost models and load flow models that NextEra prepared in Maine used a modeling software called GridView to conduct an hourly simulation model of economical

[10] NextEra relied on Exhibit RSW-6 for the statement that "[s]ufficient potential MW exists in the system impact study process for the Maine zone to become export-constrained" and Attachment 1 to EDC-NEER-1-13 to state that ISO-NE does not currently have a plan to increase the Maine-New Hampshire interface capacity to a significantly higher value (Exh. EDC-NEER-1-27). However, whether or not a zone is characterized as export-constrained changes annually based on the capacity market, not due to issues identified through the planning construct or system operations (Exh. EDC-RB-1, at 40). Moreover, NECEC will be performing all of the upgrades to the existing PTF identified by ISO-NE for the western cluster in the 2016/2017 Maine Resource Integration Study (id. at 41).

dispatches, run as a base case without NECEC and again injecting NECEC energy at the planned delivery point (Exh. EDC-Hearing-2, at 138; Tr. 2 at 340-341). Thus, the modeling performed by NextEra in the Maine Proceeding but withheld from this record is the same type of modeling that TCR performed (Tr. 2, at 341-342). This modeling could have also been used to produce projected energy market LMPs as a result of injecting the NECEC energy at the planned delivery point (Tr. 2, at 343-344). Therefore, the models would have been responsive to Information Request EDC-NEER-1-35, but the information was improperly withheld by NextEra from that response as well (Exh. EDC-NEER-1-35; Tr. 2, at 343-344).

In addition, Mr. Whitley admitted that NextEra prepared an N-1 study in the Maine Proceeding (Tr. 2, at 339). NextEra did not provide the N-1 study in this proceeding, even though it would have been responsive to Information Request EDC-NEER-1-31 (id. at 339-340). Notably, all of these models were run before NextEra provided its testimony in this proceeding (id. at 340).

Accordingly, the record demonstrates that NextEra denied the existence of and withheld multiple studies that it conducted and relied upon in the Maine Proceeding to address issues about the reliability of the NECEC project. Given these facts, the only reasonable conclusion the Department can draw is that the models NextEra prepared and revised multiple times to respond to criticisms raised by CMP, do not actually support NextEra's position in this case.[11] The Department must reach this conclusion when balancing the weight of the evidence because the quantitative analysis performed by TCR, produced on the record, and provided to NextEra's witnesses, did not result in significant congestion on the Maine-New Hampshire or North-South interfaces (Exhs. EDC-RB-1, at 41-43; JU-6, at 11-12, 95 (HSCI); JU-8 (HSCI); WP Support Tab

[11] In fact, the Maine Public Utilities Commission, after reviewing NextEra's modeling, found that NextEra's assertions about the potential impacts of the NECEC line 5-10 years in the future were not persuasive. Central Maine Power Company Request for Approval of CPCN, Docket No. 2017-00232 Examiners' Report at 54 (March 29, 2019).

E (HSCI); NEER-1-1 Attachments; NEER-1-2). Furthermore, placing any reliance or credence on NextEra statements, testimony, or briefing relying on or relating to such modeling would in effect reward NextEra for its improper and mendacious false discovery responses, creating perverse incentives for future litigants before the Department to pursue similar improper conduct.

2. NextEra's Allegations Are Contradicted By Its Own Bid.

NextEra submitted multiple proposals in response to the Section 83D RFP in partnership with CMP for the Maine Clean Power Connection ("MCPC") proposal (Exhs. EDC-RB-1, at 43; EDC-Hearing-4). The MCPC bids proposed to deliver new wind generation in Maine over a new transmission line that would have also connected at the Larrabee Road substation, with the same level of system upgrades to the Suroweic-South interface as NECEC (Exhs. EDC-RB-1, at 43-44; EDC-Hearing-4; EDC-NEER-1-20; EDC-NEER-1-21; EDC-NEER-1-22; EDC-NEER-1-23; EDC-NEER-1-24). NextEra submitted multiple bids for the MCPC project, one of which in total included 1,100 megawatts of renewable resources in western Maine (Exh. EDC-Hearing-4; Tr. 2, at 379).

In NextEra's MCPC proposal, which would have injected energy at the same delivery point (and with roughly the same upgrades to the Suroweic-South interface as the NECEC proposal), NextEra stated that: "[t]his transmission project is tailored for each NextEra bid option to alleviate **any** transmission constraints from the area, **allowing the full generating capacity of the NextEra bidding affiliates to reach the PTF and benefit the Commonwealth of Massachusetts** by alleviating transmission constraints typical of moving energy out of Maine" (Exh. EDC-Hearing-4 at 15; Tr. 2, at 350-352) (emphasis added). Clearly, NextEra sees no ethical issue testifying to one thing when advocating in favor of its proposals, but then saying the complete opposite through its paid consultants when fighting to oppose a competitor's project.

NextEra's position in the Maine Proceeding also belies its claimed concerns about congestion. In the Maine Proceeding, NextEra stated that it had no objection to the concept of the NECEC project (Tr. 2, at 27). Instead, NextEra "recommended that any approval of CMP's project be conditioned on CMP being required to construct approximately 80 to 40 miles of 345-kV HVAC transmission line in Maine" by locating a DC to AC converter substation approximately midway between the Maine-Canadian border and the Larrabee Road substation, within a few miles of a 150 MW solar facility being developed by NextEra (Exh. EDC-Hearing-1, at 18; Tr. 2, at 295-296, 377). The purpose of that recommendation was to integrate renewable wind and solar resources in Maine into the transmission system (Tr. 2, at 298-303). The ultimate intent would be to deliver those resources into the rest of New England (Tr. 2, at 290-291).

Again, NextEra's statements in other documents and other proceedings do not square with their contentions in this case. NextEra invested significant time and money in the Maine Proceeding to advocate for an alternative transmission line design that would allow for the integration of *more* energy to the delivery point at Larrabee Road because it wants to connect its renewable generation facilities to the ISO-NE PTF. It would be illogical for NextEra to do so if it truly thought that energy would still be constrained and trapped in Maine due to the Maine-New Hampshire and North-South interfaces.

B. NextEra's Arguments Regarding Future Transmission Upgrades Are Purely Speculative.

NextEra argues that to address congestion at the Maine-New Hampshire and North-South interfaces, ISO-NE will require upgrades costing between \$5 to \$10 billion, approximately half of which will be paid by Massachusetts customers (NextEra In. Br. at 16). As noted above, NextEra plucks these claims out of thin air, without offering any forecasts, models or studies of expected conditions with the NECEC project in service. In contrast, TRC's studies, using a detailed representation of the transmission topology and all major ISO-NE interfaces and frequency bidding constraints using historical data from 2012 through June 23, 2017, shows that the Maine-New Hampshire and North-South interfaces were not limiting for the delivery of energy from NECEC between Maine and the rest of New England (Exh. EDC-RB-1, at 42-44).

In addition, it is important to note that Maine is not currently designated as an export-constrained zone (Exh. EDC-RB-1, at 46). It is being considered by ISO-NE as a potentially export-constrained in the 2023-2024 capacity commitment period (id.). A potentially export-constrained zone will not necessarily result in a binding constraint in the forward capacity market (id.). More importantly, adding capacity to a potentially export-constrained zone can and will contribute to the resource adequacy of New England (id.). NextEra fails to consider the possibility that old, inefficient, expensive and unreliable fossil-fuel units that currently have capacity supply obligations in Maine may retire in the coming years due to market effects, which will in turn alleviate potential energy constraints from Maine to the rest of New England, while also benefiting the environment (id.). The TCR analysis supports this position.

The Distribution Companies analyzed the potential for future upgrades due to the NECEC line by reviewing multiple transmission planning studies provided by NECEC and discussing long-term impacts the transmission system with ISO-NE (Exhs. EDC-RB-1, at 48; NEER-2-2; NEER-1-50). Even if ISO-NE determines in the future that additional upgrades may be required, NextEra is wrong to suggest that Massachusetts customers will be responsible for those costs.

Under the CCIS, "[t]he study resource will be responsible for such recorded overloads within the Load Zone to which it is electrically interconnected and such recorded overloads within a neighboring Load Zone…" and "[t]he study resource will be responsible for addressing impacts…where the addition of the study resource results in a transfer above the interface transfer capability of the modeled intrazone stability or voltage limited interface" (Exh. EDC-RB-1, at 44-45; ISO-NE Planning Procedure 10 ("PP-10"), at 21). In order to interconnect at CCIS as required under the TSA, NECEC will be required to resolve any system impacts in the Maine load zone and neighboring load zones, specifically New Hampshire (Exh. EDC-RB-1, at 45). NECEC is solely responsible for the costs associated with resolving these system impacts (id.). Thus, NextEra's contention that the impacts of NECEC's interconnection elsewhere in the transmission system will not be addressed is baseless.

NextEra relies exclusively on the general statements of Mr. Whitley, which are unsupported by any specific analysis of the NECEC project. However, the Department cannot reasonably rely on these speculative statements to impute unknown and unstudied future costs to the NECEC project.

VI. THE ATTORNEY GENERAL'S RECOMMENDED CHANGES TO THE EVALUATION PROCESS SHOULD BE DENIED.

A. The Attorney General's Recommendations Are Premature.

The Attorney General recommends that the Department require certain changes to the evaluation process "in future procurements," including (1) establishing clear rules for prioritizing high-ranking Stage 2 projects in Stage 3 portfolio development; (2) direct the EDCs to remedy the scaling approach used in bid scoring; (3) require the GWSA metric be revised to directly reflect changes in GHG emissions;[12] (4) separate bidding team members from evaluation team members;

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[12] It is important to note that the AGO admits that the scaling approach and GWSA benefit calculations did not impact the project rankings or the selection of the NECEC project in this case (Exh. AG-DM at 26-27). Should the Department decide to address these issues notwithstanding the lack of impact on the evaluation at issue, Eversource and National Grid have addressed the merits of the Attorney General's contentions in separate letters filed contemporaneously with this joint reply brief.

and (5) require the EDCs to disclose estimated remuneration costs to customers (AGO In. Br. at 30, 31).[13]

Section 83D requires the Distribution Companies to solicit, and provided that reasonable proposals have been received, enter into cost-effective long-term contracts for clean energy generation for an annual amount of electricity equal to approximately 9,450,000 megawatts-hours. Section 83D(a). If the Department approves the PPAs before it in this case, the Distribution Companies will have fully satisfied their obligations under Section 83D. At this time, the Legislature has not introduced any directives for the Distribution Companies to solicit additional long-term contracts for Clean Energy Generation. Without any enabling legislation describing the nature of a future solicitation, or any guidance to the Department, Distribution Companies and DOER, it would be premature to require changes in a yet undefined evaluation.

B. The Evaluation Team Appropriately Considered Top-Ranked Projects From Stage 2 In The Stage 3 Portfolio Analysis.

The Attorney General argues that the highest-ranking projects in Stage 2 should be prioritized in the Stage 3 portfolio analysis, and recommends that future solicitations either not include a size threshold for portfolio selection, or set a threshold in advance of the evaluation process (AGO In. Br. at 31, 33). As addressed above, it is inappropriate to accept the Attorney General's recommendations about size thresholds for portfolio development in the absence of any legislative directives concerning the quantity of energy to be procured in a future solicitation, whether the solicitation should be conducted in staggered procurements, or other relevant

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13 The AGO's suggestion that the Distribution Companies did not provide the estimated cost of remuneration on the public record in this case is wrong. The Distribution Companies provided the annual remuneration value for these contracts in Exhibit DPU-2-16-1 Att.). To the extent the AGO asks the Department to preemptively rule on the confidentiality of information in a future petition without a motion or relevant facts before it, the AGO's request is improper and should be denied.

guidelines. In addition, the Attorney General's argument that the Evaluation Team did not prioritize the two top-ranking projects from Stage 2 in its portfolio analysis is incorrect.

The Evaluation Team included the top-ranking Stage 2 projects in three different portfolios (see Exhs. JU-7 (HSCI); EDC-RB-1, at 69; AG-3-2). Those projects accounted for over 80 percent of the annual energy of each portfolio (id.). The quantitative modeling of these three Stage 3 portfolios demonstrated that the indirect benefits would be reduced significantly versus the Stage 2 results after the projects were combined into a portfolio. For example, one of the portfolios containing those two projects saw indirect benefits reduced by approximately two-thirds when compared against the indirect benefits of the two top-ranked projects separately in Stage 2 (Exh. JU-6, at 19-25 (HSCI)). This negative impact on indirect benefits when combining smaller projects was consistently observed during the evaluation. As indicated in Appendix 1 and Appendix 2 of Exhibit JU-6, small proposals and portfolios containing small proposals generally scored lower than the selected portfolios as costs increased with decreasing marginal increases in indirect benefits (Exhs. AG-3-2; JU-6, at 19-25).

The Evaluation Team did not consider a portfolio consisting only of the two top-ranking projects from Stage 2 because a portfolio of only those projects would have equaled only 7.5 TWh, which is 1.95 TWh short of the Section 83D directive to procure Clean Energy Generation of approximately 9.45 TWh annually (Exhs. AG-3-2; EDC-RB-1, at 68-69). As DOER's witnesses confirmed, the Evaluation Team was confident that it received enough competitive bids to be able to build portfolios up to the 9.45 TWh (Tr. 3, at 470-471).

C. The Attorney General's Recommendation Regarding The Evaluation Team And Bid Team Personnel Is Contrary To Section 83D and Inconsistent With Current Practice.

In her initial brief, the AGO posits that having entities on both the Bid Team and Evaluation Team that are also bidders in the solicitation, either directly or through affiliates, creates an inherent conflict of interest and potentially introduces intentional or unintentional bias into the evaluation process (AGO In. Br. at 37). The AGO relies on the Independent Evaluator ("IE") report ("IE Evaluation Report"),[14] filed consistent with Section 83D, to support this assertion (id. at 37-38). The AGO recommends that, while Section 83D precludes the full separation of bidders from the Evaluation Team, the Department should restructure the process to address the perceived conflict when the Distribution Companies are members of both the Evaluation Team and the Bid Team (id.). The AGO also recommends that, in future solicitations, the IE should be granted the ability to monitor contract negotiations with full access to bidder communications and draft contracts (id. at 38-39). The AGO correctly notes that the IE was not granted access to draft contracts and bidder communications due to the Distribution Companies' objections (id. at 39).

The Department should find that the Distribution Companies have taken ample steps to protect against the potential for undue affiliate influence or related conflicts of interest.[15] The Attorney General's decision to selectively quote from the IE Evaluation Report in support of her recommendations is telling. Despite determining that during the course of the evaluation, Eversource favored or "[h]ad the appearance of favoring" the bid submitted by its affiliate, the IE concluded that, due in part to its oversight, that the Stage 2 and Stage 3 evaluations were fairly

[14] The IE submitted its initial IE Evaluation Report on July 24, 2018, followed by a revised report on August 7, 2018.

[15] Unitil did not have an affiliate that submitted a bid in response to the Section 83D RFP.

conducted and not unduly preferential toward any bid nor unjustly discriminatory toward any bid (IE Evaluation Report at 48-49).

Section 83D states that, if the IE concludes that a solicitation and bid selection was not fair and objective and that the process was substantially prejudiced as a result, the Department shall reject the contract. Section 83D(f). The IE saw nothing in the solicitation and evaluation process that led it to make such a conclusion. Furthermore, the Attorney General, in her September 6, 2018 report submitted in accordance with Section 83D(e), made no mention of any concerns she may have had regarding any potential conflicts of interest raised in the IE Evaluation Report. Lastly, the AGO's witness, Mr. Murphy, did not and could not conclude that the outcome of the solicitation was somehow negatively affected by the composition of the Evaluation and the Bid Teams (Exh. AG-DM at 25).

Since the development and use of their comprehensive standards of conduct ("SOC") during the Section 83D solicitation and evaluation,[16] both Eversource and National Grid have further refined their respective SOCs, including incorporating input from the IE. The most significant enhancement under the revised SOCs was the elimination of the use of SMEs under the SOCs. The Attorney General was included on the various communications regarding the revisions to the SOCs as part of its role in developing the second RFP under Section 83C of An Act Relative to Green Communities, St. 2008, c. 169, as amended by St. 2016, c. 188 §13. The finalized SOCs were included with the initial filing of the second Section 83C RFP, which was filed on March 27, 2019 and docketed as D.P.U. 19-45. The Department should find that the Distribution Companies have continued to proactively refine the SOCs to ensure that these standards maintain a strict

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[16] The Department reviewed and accepted the Standards of Conduct, including the use, training and certification of the National Grid and Eversource subject matter experts ("SMEs") in D.P.U. 17-32, at 54-55.

standard that ensure there is no real or perceived affiliate influence in the solicitation and evaluation of bids.

Additionally, the Department should disregard the AGO's recommendation that the IE be given full access to draft contracts and bidder communications during the contracting process. As an initial matter, the IE's oversight is limited by the provisions of Section 83D. Specifically, in order to ensure an open, fair and transparent solicitation and bid selection process that is not unduly influenced by an affiliated company, the IE is required to monitor and report on the solicitation and bid selection process and provide its independent assessment of whether all bids were evaluated in a fair manner. Section 83D(f). Section 83D(f) requires that the IE have access to all information and data related to the competitive solicitation and bid selection.

Consistent with the requirements under Section 83D(f), the IE was given complete access to all materials necessary to oversee and report on the bid solicitation and evaluation. However, Section 83D does not authorize or require IE oversight of the Distribution Companies contracting process with the winning bid counterparties. Section 83D does not require, nor does it authorize IE oversight of an arms-length negotiation between sophisticated business entities. The AGO is seeking, impermissibly, to expand the IE's duties under Section 83D(f). The Department should disregard the AGO's recommended course of action.

While the Distribution Companies agreed to allow the IE to monitor contract negotiations at the DOER's request, certain precautionary steps were taken to ensure that draft contracts and communications between the bidders and the Distribution Companies were maintained as confidential, both during the negotiating process and the subsequent Department proceeding. This was necessary to avoid a chilling effect on the negotiations. Consistent with this, the IE was allowed to review all contract drafts via WebEx but was not allowed to retain them and was invited to monitor negotiations, which were conducted via conference calls, as well as internal Distribution Companies' conference calls (IE Evaluation Report at 33, nt. 64, and 40). This enabled the IE to monitor the contract negotiations without compromising the confidentiality of the process. While the Distribution Companies' review requirements were certainly reasonable and legitimate, they absolutely were not required under Section 83D. Accordingly, the Department should reject the AGO's attempt to expand the IE's powers under Section 83D.

VII. RESPONSE REGARDING REMUNERATION

A. Overview

The plain terms of Section 83D state that the Department "shall promulgate regulations" and that "the regulations shall:"

> (3) provide for an annual remuneration for the contracting distribution company up to 2.75 percent of the annual payments under the contract to compensate the company for accepting the financial obligation of the long-term contract, such provision to be acted upon by the department of public utilities at the time of contract approval.

Thus, the statute mandates that the Department set remuneration and also further specifies that the remuneration is compensation for "accepting" the financial obligation of the long-term contract pending before the Department for approval. The statute does not specify the analytical framework to be applied by the Department in determining the effect of an EDC's agreement to "accept" the financial obligation, nor does the statute set any limits, requirements or prescriptions as to how the Department should conduct its inquiry.[17]

In particular, the statute does not stipulate or even suggest that the EDCs must demonstrate that they are taking on either project risk or cost-recovery risk in order to qualify for remuneration. To the contrary, the statute is explicit in delineating that the EDCs will obtain cost recovery and

[17] A comprehensive discussion of the legal parameters of the Department's consideration of the statutory language is set forth in the Initial Brief of the Distribution Companies, at Section V.C.1.

how that cost recovery will occur, while at the same time separately directing the Department to set remuneration "up to 2.75 percent of annual contract payments." As a result, the plain language of the statute conveys the Legislature's clear recognition of the important role that EDCs are carrying out in relation to the fulfillment of the Commonwealth's clean energy goals. Without the EDCs' willingness to serve in this role, long-term contracts for renewable energy would not likely be executed and the Commonwealth's plan for a clean energy future would be frustrated because the EDCs are uniquely situated to take on the role of contract counterparty on long-term agreements requiring the payment of approximately $15 billion over a 20-year period, given their strong financial profiles. Without the EDCs in this role, it would be impossible for Massachusetts consumers to obtain the benefit of **cost-effective** renewable generation resources because project developers cannot build without financing; cannot obtain financing without credit-worthy contract partners; and cannot attract reasonable-cost financing without the strong balance sheets, equity investors and credit quality maintained by the EDCs.

The record shows that the contract quantities secured prior to the commencement of the Section 83C and Section 83D contracts are relatively small and have not yet attracted the attention of investors or credit-rating agencies (Exhs. JU-1, at 46-47; Att. AG-1-4-1; Att. DPU 2-16-1; Tr. 1, at 79-80, 82, 84, 94). The record further shows that the contracts under review in this case will increase the financial obligations of the EDCs by multiples – and that the clear objective is to layer several more contracts on top of the ones that are the subject of this docket (id.).[18] Thus, the cumulative impact of contracts approved by the Department, including the Section 83C and

[18] See, e.g., Exh. JU-1, at 47 (stating, "the Distribution Companies estimate that their collective financial commitment over the length of the contracts entered into pursuant to the Green Communities Act exceeds $22 billion."); Exh. EDC-RBH-GET-1, at 70. St. 2018, c. 227 § 21 (directing DOER to investigate the necessity, benefits and costs of an additional procurement for 1,600 MWs of offshore wind).

Section 83D contracts, is substantial, unparalleled across the U.S. for electric distribution companies and untested in terms of impact on the equity and credit rating processes.

The framework encompassed within Massachusetts law to achieve the procurement of significant quantities of renewable energy **depends squarely upon the continued participation** of the EDCs. However, continued participation depends on the EDCs ability to retain the financial flexibility to bear the financial obligation of the contracts, even with a stable cost-recovery mechanism. Maintaining this financial flexibility is important for customers because there is a very real and immediate impact on customers where changes in the cost of borrowing or issuing equity occur, increasing the cost of capital paid by customers through customer rates.

The financial wherewithal of the EDCs will be harmed where equity analysts, investors or credit-rating entities perceive uncertainty, risk or the loss of financial flexibility due to the decision to enter into and manage large-scale financial obligations -- even where cost recovery is established by statute (Exh. EDC-RBH-GET-1, at 41, 43). By definition, the harm that has the potential to arise for an EDC in accepting the financial obligations of the contracts is diminished or degraded equity and credit quality. If it occurs, the harm is extraordinarily expensive for utility customers (Exh. EDC-RBH-GET-1, at 45, 73). If it occurs, the harm is very difficult to remediate and the possibility of restoring the status quo will take time and require special regulatory treatment that undoubtedly would come at great cost to customers. Investigation by the Department of Public Utilities, on its Own Motion, into the Effect of the Reduction in Federal Income Tax Rates on the Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15-F (Feb. 15, 2019) (recognizing that a credit downgrade could ultimately harm ratepayers); Berkshire Gas Company, D.T.E. 03-89, at 31 (2004) ("[a] weaker financial condition may result in a higher cost of capital required to fulfill the Company's financial obligations.").

Consequently, the Department's foremost goal in this proceeding must be **the avoidance of harm**. We are at the beginning of a long road. The simple fact is that it is not yet clear whether and for what reason equity investors and credit-rating entities may perceive a quantum of uncertainty, risk or loss of financial flexibility as a result of the Commonwealth's renewable energy procurement plan, or precisely what circumstances or accumulation of circumstances may trigger such a reaction. Moreover, if and when such a point is reached, it will be too late for modest measures like a remuneration adjustment to correct the harm. Not only would there be a negative impact in terms of the cost of future clean energy procurements, but also in terms of the cost of debt and equity used to finance assets across the EDC operations providing customers with electric service. When such a point is reached, the "damage is done" (Tr. 1, at 88-89). At that point, the cost to the EDCs and their customers of reversing this harm and regaining the ability to obtain debt and equity at reasonable cost is likely to be high. This is particularly so given the very long duration of the contracts and the massive financial obligations embedded within those contracts.

To that end, there is no evidence in the record suggesting a basis for changing the level of remuneration allowed by Massachusetts law and allowed in past solicitations. Remuneration is a statutory creation, explicitly incorporated into the regulatory compact as a method of demonstrating a *quid pro quo* for the agreement to accept long-term financial obligations for the benefit of Massachusetts customers and to advance the energy and environmental objectives of the Commonwealth. The Distribution Companies have deep, long-standing experience with the equity and credit-rating processes and, for them, the threat of a destabilized regulatory environment, and the consequential adverse impact for customers, is very real (Tr. 1, at 88-89).

For the Distribution Companies, the solitary tool that exists to offer a level of protection in maintaining the financial flexibility necessary to continue in the contracting role is the payment of remuneration at 2.75 percent as provided for in legislation since 2012, with the enactment of Section 83A. A change in the remuneration regime that has proved successful thus far in retaining EDC financial flexibility in the context of the considerable RFP commitments established by Massachusetts law would create uncertainty and risk, with the attendant potential of a degradation of equity and/or credit quality. No intervenor in this case has established a basis for the Department to reduce the remuneration rate in place since 2012 or that has provided the Department with any assurance that a change in the remuneration rate will be overlooked or accepted without detrimental impact by equity investors, equity analysts and/or credit-rating agencies.

To the contrary, the substantial weight of the record evidence demonstrates that: (1) the impact of the "financial obligation" undertaken to further the Commonwealth's long-term contracting objectives will ultimately be determined through the equity and credit-rating processes; (2) equity and credit-rating processes are not conducted by the Department, but rather are conducted by independent investors, equity analysts and rating agencies that evaluate balance-sheet strength; (3) the evaluation of equity and credit quality is primarily a qualitative exercise aimed at assessing the stability and equilibrium of numerous integrated considerations; (4) the scale of commitment will be apparent in the EDCs' financial reporting and will surpass the magnitude of the EDCs' utility-related investment base and cash flows by many times; and (5) uncertainty and retrenchment in the regulatory environment will be a catalyst in signaling the loss of equilibrium. In this important context, the Distribution Companies have proven that the interests of customers are best served by maintaining remuneration at 2.75 percent, as contemplated by statute. Accordingly, the Department should exercise its discretion and authorize a remuneration rate of 2.75 percent in this case.

B. Response to the Attorney General

The Attorney General recommends that the Department reject the EDCs' request for annual remuneration of 2.75 percent because the EDCs have failed to provide quantitative support for their remuneration request (AGO In. Br. at 8). However, this statement misconstrues the fundamentally complex and largely qualitative process involved in evaluating the tangible and intangible impacts of substantial, long-term, renewable contract obligations on the Distribution Companies' equity and credit quality. In addition, the AGO's position ignores the overwhelming seriousness of the issue before the Department, jeopardizing the interest of customers. Therefore, for the reasons stated below, the Department should squarely reject the AGO's propositions in this case as baseless and mistaken.

1. The AGO's Witness Is Not Qualified to Advance the Argument Put Forth by the AGO.

In this proceeding, the Attorney General has sponsored the testimony of Vincent Musco, Managing Director at Bates White Economic Consulting on the issue of remuneration (Exh. AG-VM, at 1). Mr. Musco states that he is a financial economist (Exh. AG-VM-1, at 3). Through Mr. Musco, the AGO is alleging that a "quantitative" method for determining the "financial obligation" of the proposed PPAs exists in Standard & Poor's ("S&P") Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements (the "S&P Imputed Debt Method") and that application of that methodology confirms that the "risk factor" associated with the proposed contracts "would be something at or near zero" for the Distribution Companies, "suggesting an imputed debt amount of at or near zero" (Tr. 3, at 422; Exhs. AG-VM-1, at 24-25; AG-VM-Rebuttal-1, at 4-5) (AGO In. Br. at 10).

However, the record makes it abundantly clear that the AGO's witness lacks the expertise and experience to support his thesis that: (1) S&P will, in fact, apply the S&P Imputed Debt

Method in evaluating the financial obligation of the PPAs; (2) the S&P methodology can or should be used to quantify the impact of the PPA-related financial obligation accepted by the EDCs; and (3) that application of that methodology would or should result in zero or little risk for the Distribution Companies (AGO In. Br. at 8, 10-11). Therefore, the Department should flatly reject the thesis expounded by Mr. Musco, who repeatedly testified that he had no knowledge of how S&P might actually view the contracts, but was simply "putting the method in the record in S&P's own words" in order to "inform the record" and to "put something on the record that was not there, that no one would have read but for my testimony" (see, e.g., Tr. 3, at 412, 418, 419, 420).

More specifically, the record shows that Mr. Musco has no expertise applicable to the utility equity and credit-rating process, nor did he take any discernible steps to evaluate the considerations that factor into the determination of "financial obligations" for public utility companies, or the equity and credit-quality processes undertaken to assess the impact of those obligations on financial strength. For example, Mr. Musco was unable to demonstrate any personal knowledge of, or participation in, the utility credit-rating process or other consultation with S&P regarding its utility ratings process or impact of renewable-contract procurement on utility balance sheets (Tr. 3, at 408-409; Exh. EDC-AGO-1-2). Mr. Musco testified that he is not an expert in treasury and finance for regulated utilities and is also not a lawyer (Tr. 3, at 409). Nor is he an expert in financial accounting for public utility companies (Tr. 3, at 408-409). Therefore, Mr. Musco does not possess even a single credential or bit of experience that would qualify him to testify on the impact of the PPA financial obligations on the EDCs.

In particular, his work experience falls far short of qualifying him to opine on the impact of long-term financial obligations for public utilities and the utility equity and credit-rating processes. By his own testimony, his work experience lies in serving as the independent monitor or independent evaluator in procurements for renewable generation, RECs, energy and capacity, involving work to review, analyze and comment on the purchased power agreements that underlie those procurements, and performing work focusing on utility expenditures and requests for cost recovery, including purchased power costs (Tr. 3, at 424-426). None of this work qualifies him to testify on the manner in which S&P *will or will not apply* its imputed debt methodology or the equity and credit-rating processes for electric utilities, which is the reason that he repeatedly testifies that he is merely submitting the S&P Imputed Debt Method to the record to "inform" the record "in S&P's own words" (see, e.g., Tr. 3, at 412, 418, 419, 420). Nor does his work experience qualify him to opine on the strength of the Massachusetts cost-recovery framework as a matter of law, which is an opinion that is at the very core of his claims regarding the alleged "quantification" of financial obligations in Massachusetts, although he admits he is not a lawyer.

When asked to provide a list of "any direct experience with Standard & Poor and its utility evaluation or credit rating process," Mr. Musco testified that he "relied upon the S&P's methodology" (Exh. EDC-AGO-1-3). When asked to elaborate on how he "relied upon the S&P methodology," Mr. Musco testified that, "I relied upon the S&P methodology that I put forth in my testimony, using S&P's words that they have in their documentation" (Tr. 3, at 413, lns. 2-11). In other words, Mr. Musco's "direct experience" with S&P's credit-rating process is limited to his reading of a single, publicly available S&P bulletin, which falls far short of an informed presentation of S&P's methodology. Mr. Musco also testified he became aware of this methodology through his work as an independent observer on behalf of the Hawaii Public Utilities Commission where the S&P Imputed Debt Method was utilized for a wholly different purpose than he is suggesting should be undertaken in this case (Tr. 3, at 414, lns 13-16, 424-425, lns 22-5).

Here, the record is clear that Mr. Musco's so-called "direct experience" is "direct experience" with the use of the S&P Imputed Debt Method to devise "adders" to renewable contract bids as part of the contract selection process, and is *not in any way* "direct experience" with the S&P's method for establishing the credit rating of a public utility, or in assessing PPA financial obligations within that process. Mr. Musco testified that, in the context of the procurement processes in which he was involved, the S&P Imputed Debt Method was implicated where the utility was requesting that an "adder" be affixed to a third-party bid to represent properly the cost that the utility was *already incurring* as a result of S&P decisions to impute debt to the utility's balance sheet associated with third-party PPAs already entered into (Tr. 3, at 425-426). He testified further that, as the independent observer, "part of our role is to review and issue an official opinion on the draft request for proposal documents, RFP documents, power purchase agreements" and "we **were shown the evidence** that S&P had imputed debt. It's in their credit reports." (Tr. 3, at 425-426) (emphasis added). Thus, the independent observer is called upon to review proposals to affix an additional cost to third-party bids, not to perform the calculations of the financial obligation or to make a determination of debt imputation.

In fact, Mr. Musco's experience as Independent Observer in Hawaii has not provided him with experience in the process that S&P undertakes to assess credit quality, or how S&P determines when to deem PPAs to be debt obligations, or regarding the qualitative decisions that S&P has made regarding the strength of Hawaii's cost-recovery provisions and associated risks. Mr. Musco testified that, in Hawaii, he was not involved in S&P's decision to impute debt and that his understanding is that S&P has imputed debt in relation to PPAs "for decades" (Tr. 3, at 425-427). Mr. Musco also testified that, as the Independent Observer, his role is to "review and issue an official opinion on the draft request for proposal documents, RFP documents, power purchase agreements, and the documents that underpin the procurement itself." (Tr. 3, at 425). Thus, he had no role in making a determination as to whether the proposed contracts in Hawaii would be treated by S&P as imputed debt, and has gained no experience from that role that informs his role in this case.

Rather, Mr. Musco's experience arises solely in a case where financial harm has already occurred; where he was "shown" S&P's rating report discussing that financial harm; and where he is able to see discussion regarding the imputation of debt on certain pages affirming that S&P "had imputed debt (Tr. 3, at 426, lns. 16-17). Consequently, Mr. Musco's "experience" is in the role of a passive non-expert observing an existing ratings report in a situation lacking crucial characteristics of the facts in the instant proceeding, i.e., in a situation where financial harm has already happened and the S&P methodology has been used to support the inclusion of additional cost in the bid prices. This is a far cry from having experience using and applying the S&P methodology to quantify the financial obligation of long-term PPAs and TSAs entered into by the Distribution Companies, or more importantly, to determine the impact of those financial obligations on the Distribution Companies equity and credit quality. To the contrary, when asked about his *opinion* of whether there might be a negative credit-rating impact, Mr. Musco refused to offer such an opinion, conceding that it is "folly to try to say exactly what a rating agency is going to do" (Tr. 3, at 450, lns. 19-20).

Lastly, as discussed in greater detail below, the AGO's reliance on the "S&P methodology" as a way to "quantify" the impact of the financial obligations is ill-adapted to this proceeding, fundamentally misguided and potentially harmful to customer interests. Mr. Musco's sole source of "experience" on the S&P methodology is limited to a single set of circumstances confronted by Hawaii Electric. These circumstances are patently dissimilar from this case. Mr. Musco's "experience" and "expertise" also fall far short of enabling him to extrapolate from the Hawaii situation to opine on the way in which S&P may view the EDCs' financial obligations in Massachusetts, under Massachusetts law. Accordingly, there is no reasoned basis for the Department to rely on the testimony of this witness or to give credence to the conclusions and recommendations that he is asserting on behalf of the Attorney General's office.

2. There Is No Reliable Method for Quantifying the Impact of the EDCs' Acceptance of the Financial Obligation; Nor Is a Quantification Necessary.

The AGO argues that the EDCs have not met their burden on the issue of remuneration because the EDCs have not provided "quantitative support" for the remuneration request of 2.75 percent (AGO In. Br. at 8, 10-11). However, there is no existing or accepted method for quantifying the impact of the EDCs' acceptance of the financial obligation, and a quantitative approach is neither required nor appropriate under the circumstances.

In this proceeding, the Department should set remuneration at 2.75 percent in this case on the basis of record evidence demonstrating that: (1) the financial obligation created by the PPAs creates considerable business and financial uncertainties for the equity and credit profiles of the Distribution Companies and, therefore, creates uncertainties for both equity and debt investors; (2) the Distribution Companies' balance sheets enable the Project's cost-effective financing, thereby creating significant customer and public benefits, even after taking into account the 2.75 percent remuneration rate provided by Section 83D; and (3) there are no special circumstances suggesting the Department should depart from the 2.75 percent remuneration rate provided under the prior (and considerably smaller) Section 83A renewable contracts.

Moreover, there is no logical, practical or legal basis for the Department to limit its inquiry to a purported "quantitative method." In fact, such an approach would be unreasonably narrow; would fail to encompass or adequately account for record evidence showing the complexity of the equity and credit rating processes and the qualitative factors that serve as important underpinnings of those processes; and would be wholly inadequate for purposes of determining the issues of fact that must underlie the Department's ultimate decision. It is therefore appropriate for the Department to consider the qualitative factors presented by the EDCs in this case.

Although the point is entirely ignored by the AGO and its "expert" witness, the "quantitative methodology" offered by the Attorney General's witness is just one element within one component of a much larger credit rating methodology. As Mr. Musco conceded, there are two types of analysis that comprise the S&P Methodology – business risk and financial risk (Tr. 3, at 435, lns. 1-4). The Purchased Power Adjustment factor is just one element of the financial risk component comprising the overall S&P credit-rating methodology (Tr. 3, at 435, lns. 20-22). Further, as Mr. Musco further conceded, the financial risk component is given less weight in the credit-rating process than business risk (Tr. 3, at 438, lns. 9-12).

Thus, Mr. Musco attempts to persuade the Department the S&P Imputed Debt Method is the appropriate method of determining a utility company's financial obligation in Massachusetts, but he rests his opinion exclusively on one, narrow element (that may not even be applicable to the Massachusetts contracts) of a far more extensive credit rating methodology. Although Mr. Musco asks the Department to make a determination in this case on the basis of "S&P's own words," Mr. Musco has ignored a multitude of statements and discussion by S&P in its credit-rating methodology indicating how its overall credit-ratings process will work, including the fact that the elements or factors comprising the financial risk and business components do not have pre-determined weightings, but rather the "significance of specific factors varies from situation to situation" (Tr. 3, at 438, lns. 1-8; Exh. EDC-RBH-GET-7, at 3).

Accordingly, the Department should disregard the AGO's insistence that this case be decided solely on a "quantitative" basis and disregard the unduly narrow "imputed debt" construct offered by the AGO. In addition to the fact that this construct does not take equity investors or their analytical approaches into account, this construct will not be applied by the credit-rating agencies in isolation, apart from their overall credit-rating methodology.

3. <u>The Financial Obligations Imposed by the Contracts Ultimately Will Be Measured As Part of the Equity Investor and Credit-Rating Processes.</u>

On brief, the AGO claims that, under Section 83D, the purpose of remuneration is to "compensate the company for accepting the financial obligation of the long-term contract," and therefore, the Department must first determine "what, if any, financial obligations the EDCs accepted through the PPAs" (AGO In. Br. at 9). The AGO further claims that the EDCs have not met their burden on the issue of remuneration because: (1) the EDCs did not provide the Department with evidence detailing the costs each company will incur from accepting the financial obligation of the PPAs; (2) the EDCs have not provided "quantitative support" for the remuneration request of 2.75 percent; and (3) the EDCs have not "attempted to quantify the financial obligations they will incur or incurred from the Proposed PPAs" (AGO In. Br. at 9).

Notably, the AGO posits (in a footnote) that the language regarding a company's ability to decline to enter a contract due to the impact of a "proposal" on the company's balance sheet is a "separate clause," and that Section 83D(c) "stands alone with respect to the treatment of and considerations for remuneration," which seems to imply that the AGO does not view the impact of long-term financial obligations on the balance sheet to be part of the Department's inquiry on remuneration (AGO In. Br. at 9, fn. 9). This premise is completely flawed given the Attorney General's entire focus in this case.

In addition, the AGO's reading of the Section 83D statute is erroneous, as are its contentions regarding the "failure" of the EDCs to make the requisite showing to support remuneration equal to 2.75 percent. In that regard, there are several reasons that the AGO's arguments are flawed.

First, Section 83D provides for "an annual remuneration for the contracting distribution company up to 2.75 per cent of the annual payments under the contract **to compensate** the company **for accepting the financial obligation** of the long-term contract . . ." Section 83D(d)(3) (emphasis added). There is no question as to the financial obligations that will be accepted by the Distribution Companies in this proceeding. The clearest measure of the *financial obligation* that the EDCs will be *accepting* in this case is the approximately $15 billion in payments the EDCs are obligated to disburse under the terms of the PPAs and TSAs (Exhs. EDC-RBH-GET-1, at 14, 15; Exhs. Att. DPU-2-16-1; Att. DPU-1-1 (HSCI); JU-3-A through JU-3-C; JU-4-A through JU-4-C). Accordingly, under a plain reading of the statute, the EDCs have met the threshold statutory requirement to receive remuneration as compensation for accepting the financial obligation of the long-term contracts. In "S&P's own words," it is clear that "PPAs . . . add financial obligations that heighten financial risk" (Exh. EDC-AGO-1-8, Att. 2, at 6).

Second, the AGO's attempt to construe the statutory framework so as to cast customers, and not the Distribution Companies, as the bearer of the "financial obligations" generated by the PPAs, is flawed. The "financial obligations" that will arise as a result of the long-term contracts with HQ are the stream of payments *due to HQ under the PPA* (Exh. EDC-RBH-GET-1, at 9, 24). HQ has no recourse to customers for payment of the financial obligations encompassed in the PPAs (Exhs. EDC-RBH-GET-1, at 25; JU-3-A; JU-3-B; JU-3-C at § 5.2, §7.1(c) (providing that the Distribution Companies will be invoiced and that the PPA constitutes a legal, valid and binding obligation on the Distribution Company)). Further, contrary to the Attorney General's assertions, the fact that customers pay the cost of service does not confer ownership, or the obligations and risks of ownership on them, it is the Companies that must pay those obligations, regardless of revenue, cash flow, or access to financial liquidity (Exh. EDC-RBH-GET-1, at 24, lns. 9-12).

In that respect, it is clear that the Distribution Companies will pay the costs due under the contracts and then must turn to customers for reimbursement. Moreover, under the terms of the proposed PPAs, the Distribution Companies are committed to pay those costs, regardless of whether the cash flows generated by revenue collections from customers are adequate or aligned with those payments. The cash-flow requirements associated with the contract payments amount to approximately $15 billion, which is a very significant amount for all three Distribution Companies, and an amount far exceeding any other existing contractual commitment relating to utility operations (Exhs. EDC-RBH-GET-1, at 14, 46-47; Att. DPU 2-16-1). In quantifying the contract payments for the record, the EDCs have provided the Department with appropriate evidence detailing the costs each company will incur from accepting the financial obligation of the PPAs and have quantified the financial obligations they will incur from the proposed PPAs and TSAs, despite the AGO's claims to the contrary (AGO In. Br. at 9).

Third, the Attorney General's attempt to posit that the impact on a Distribution Company's balance sheet is not a valid inquiry in relation to a request for remuneration under Section 83D(d) is thoroughly misguided (AGO In. Br. at 9, fn. 9). This proposition is belied by the fact that the AGO's own witness rests his entire thesis on the applicability of S&P's Imputed Debt Method, which is just one component of S&P's overall credit-rating methodology (Exhs. AG-VM at 7-8; AG-R-VM at 2; Tr. 3, at 435). Moreover, Section 83D(d) provides for remuneration as "compensation" for "accepting" the financial obligation; thus, it is the *action* of accepting the financial obligation that warrants compensation not the incurrence of project risk or cost-recovery risk. By definition, this means that the crux of the Department's inquiry as the proper compensation has to focus on: (1) the value produced by the EDC *acceptance* of the contract counterparty role; and (2) the impact that *acceptance* of the contract counterparty role may have on the financial wherewithal of the Distribution Companies. To that end, the Distribution Companies have produced a detailed net-benefits analysis proving the value produced for customers by the EDC acceptance of the contract counterparty role (Exh. EDC-RBH-GET-1, at 48-66). This analysis was not refuted with substantive record evidence by the AGO or other intervenors.

The AGO implicitly endorses the relevance of the second element, i.e., the impact on the financial wherewithal of the Distribution Companies, in its mistaken claim that "the Proposed PPAs and TSAs will have little to no impact on the EDCs' financial wherewithal" (AGO In. Brief at 8 citing Exh. AG-VM-1, at 27). However, the nature and extent of the "financial obligation" and its impact on the Distribution Companies' financial wherewithal is not an inquiry that can be performed either by the Attorney General, the Distribution Companies or by the Department, but rather is a determination that will ultimately be determined through the overall equity and credit-quality reviews conducted by external parties, including S&P, Moody's and Fitch. In putting forth the "S&P methodology" as the basis for quantifying the remuneration rate in this case (at zero or near zero) on brief, it appears that the AGO fails to grasp that S&P would only ever apply that procedure in the course of its evaluation of credit quality for an electric utility.

In fact, the AGO's witness Mr. Musco testified numerous times at hearing that S&P and the other credit-rating agencies are "independent" entities that make their own determinations regarding the impact of the PPAs. For example, Mr. Musco testified that "and, *of course*, none of us can speak to exactly what the rating agencies are going to do" (Tr. 3, at 418, lns. 4-6) (emphasis added). Mr. Musco also testified that "no one can say what the rating agencies are going to do. It's folly to try to say exactly what a rating agency is going to do" (Tr. 3, at 418; 450).

On brief, the AGO argues that "the only claim put forth by the EDCs centers on a potential financial obligation that may arise because the Proposed PPAs may not be immediately recoverable from ratepayers" and that these circumstances "might have a negative impact on their short-term borrowing rates" (AGO In. Br. at 9). The AGO summarily dismisses these concerns on the basis that EDCs "have not suffered this fate with their current Section 83 and Section 83A long-term contracts" and the EDCs "have not attempted to quantify the amount of such costs under the Proposed PPAs and TSAs" (id. at 9-10). However, these arguments are specious because the record shows that: (1) the magnitude of cash flow associated with the current Section 83 and Section 83A long-term contracts is relatively small as compared to the cash flows associated with the Section 83D (and Section 83C) contracts (Exh. EDC-RBH-GET-1, at 10, 69, 70; Tr. 1, at 82, 84); (2) the actual contract payments and associated customer revenues will not be a reality for several years; therefore, there is no basis to study the cash flows now when circumstances could be entirely different at the time of contract commencement; and (3) the Department has set the remuneration rate of 2.75 percent in accordance with law in relation to the Section 83A contracts, mitigating potential harm.

The Distribution Companies raised the issue of cash flow because it is a major consideration in the overall equity and credit-rating processes and will undoubtedly be reviewed in view of the financial obligations imposed by the proposed PPAs, *when those PPAs become actionable* (Exh. EDC-RBH-GET-1, at 21; Tr. 1, at 109, 114). In fact, it is indisputable that cash flow is a major issue in the credit-rating process (see, e.g., Exh. EDC-AGO 1-8, Att. 3, at 46).

Therefore, the idea that the S&P Imputed Debt Method represents the totality of the analytical construct that S&P will apply to the evaluation of the financial obligations associated with the PPAs and TSAs is ludicrous.

For example, the Moody's Rating Methodology referenced by Mr. Musco as one of the three, exclusive methods he knows of to quantify the impact of the PPAs states that "PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios" (Exh. EDC-AGO 1-8, Att. 3, at 46). Mr. Musco acknowledged the importance of cash-flow metrics (Tr. 3, at 443). Mr. Musco also testified that the two credit-metric core ratios are EBITDA to debt and funds from operation to debt, both of which relate to cash flow (Tr. 3, at 443). Mr. Musco further acknowledged that S&P looks at "FFO to debt, funds from operations to debt" and how it impacts "the entity's ability to cover its debt" (Tr. 3 at 444).[19] Thus, the record is clear that credit exposure goes far beyond debt imputation, covering the entire ratings methodology, including the regulatory, liquidity, financing, and volatility considerations (Exh. EDC-RBH-GET-1, at 36).

Accordingly, in weighing the issues in this case, the Department should reject the AGO's arguments that no financial obligation is attaching because customers are "ultimately" paying for the contract costs, and conversely, should recognize that the acceptance of the significant, long-term fixed obligations associated with the proposed PPAs creates multiple business and financial challenges, each of which would be considered in the equity analysis and credit-ratings process. This is the fundamental reason that the legislation contains a provision to compensate the EDCs for accepting the long-term obligations associated with the PPA and TSAs. A degradation of equity or credit quality would diminish the financial strength of the EDC balance sheets; increase

[19] The record shows that Moody's assigns a 40 percent weight to measures of financial strength and liquidity (Exhs. DPU-2-11; EDC-AGO-1-8, Att. 3).

costs for utility operations (borne by utility customers); and impair the ability to rely on the EDCs as the counterparties for long-term renewable contracts. This would be an unacceptable result for customers and a defeat for the Commonwealth's renewable energy procurement program. Accordingly, the impact on equity and credit quality constitutes the crux of the matter in setting remuneration.

4. The S&P Method for Imputing Debt is Not a Method for Determining the Financial Obligation and Endangers the Interests of Customers.

On brief, the AGO makes the following claim in relation to S&P's imputed-debt methodology:

> Despite such a lavish request, the EDCs fail to provide evidence quantifying their financial obligations arising from the Proposed PPAs and TSAs via calculations of either historic or estimated impacts. Nor do the EDCs demonstrate that the collection of annual remuneration will result in just and reasonable rates.
>
> Instead, the EDCs argue that they cannot calculate these costs, even though credit rating agencies offer an established methodology for doing so. AGO witness Musco used such a methodology, the Standard and Poor's ("S&P") method, and found that the Proposed PPAs and TSAs will have little to no impact on the EDCs' financial wherewithal and/or access to capital. Thus, the EDCs' financial obligation under the Proposed PPAs and TSAs would be zero or close to zero

(AGO In. Br. at 8) (citations omitted).

There are many flaws and inaccuracies in these statements. There are also inconsistencies between the arguments that the AGO is making regarding the application of the "S&P methodology" in this case and the testimony of its witness, Mr. Musco.

The Department should recognize that the entire proposition put forth by the AGO on the issue of the "S&P methodology" has the potential to endanger the interests of customers. The adoption of imputation of debt as a proxy for the "financial obligation" imposed by the proposed

PPAs and TSAs (or any future PPAs and TSAs) would irreparably damage the credit ratings of the Distribution Companies; would create substantial cost impacts for utility customers in relation to utility operations; and, would require the Department to take action to impute hypothetical equity on which the Company would earn a return to counteract the damaging impacts of that imputed debt, as the Hawaii Public Utility Commission found necessary for Hawaii Electric.

The flaws, inaccuracies and inconsistencies in the AGO's claim regarding the application of the S&P methodology are as follows:

(a) There is no requirement or suggestion in Section 83D(d) for the EDCs "to quantify the costs of their financial obligations" in order to set remuneration.

The first sentence of the quote above from the AGO's initial brief states that the EDCs have failed "to provide evidence quantifying their financial obligations arising from the Proposed PPAs and TSAs via calculations of either historic or estimated impacts" (AGO In. Br. at 8). Nowhere in the statute is there language implying that remuneration would be set on the basis of the "cost" of the financial obligation. The AGO's underlying premise here is that the remuneration rate is intended to be a function of the cost-recovery risk associated with the financial obligation; however, there is no basis in law or fact for the proposition that the remuneration rate is linked to the presence of cost-recovery risk.

Section 83D provides for "an annual remuneration for the contracting distribution company up to 2.75 per cent of the annual payments under the contract **to compensate** the company for **accepting** the financial obligation of the long-term contract . . ." Section 83D(d) (emphasis added). In addition to providing for remuneration, Section 83D provides for recovery of the difference between the net costs of payments under the long-term contracts and the net proceeds from the sale of energy and RECs. Section 83D(i); see also 220 C.M.R. 24.06(2)(c) (providing that if a

Distribution Company sells the energy and RECs obtained through the long-term contracts it shall design a reconciliation process to recover all costs incurred under such contracts, subject to review and approval by the Department). The dual reference to cost recovery and remuneration is significant.

Under Massachusetts law, it is a fundamental principle of statutory construction that no part of a statute should be interpreted as superfluous and no statute should be construed in a way that produces absurd or unreasonable results. Providence & Worcester R.R. Co. v. Energy Facilities Siting Bd., 453 Mass. 135, 142-143, 145 (2009); see also Manning v. Boston Redevelopment Auth., 400 Mass. 444, 453 (1987) (holding that an enactment should not be construed in such a way as to make a nullity of pertinent provisions). The plain and unambiguous language of Section 83D shows that the General Court intended to provide compensation to the EDCs in return for the EDCs' acceptance of the financial obligation associated with the Section 83D PPAs and TSAs, and *in addition* intended to provide complete recovery of contract costs.

Although consistently ignored by the AGO, the statute provides that remuneration is "compensation" for "accepting" the financial obligation. By definition, this means that the crux of the Department's inquiry as the proper compensation has to focus on: (1) the value produced by the EDC *acceptance* of the contract counterparty role; and (2) the impact that *acceptance* of the contract counterparty role may have on the financial wherewithal of the Distribution Companies.

To that end, the Distribution Companies have produced a detailed net-benefit analysis proving the value produced for customers by the EDC acceptance of the contract counterparty role (see, e.g., Exh. EDC-RBH-GET-1, at 48-66). This analysis was not refuted by the AGO or other intervenors. The impact of acceptance on the financial wherewithal of the Distribution Companies will be assessed and ultimately determined by the independent equity and credit-rating entities.

The Department's exercise of discretion in setting remuneration is therefore an exercise in the *avoidance of harm* and the preservation of a regulatory construct that is characterized by success and equilibrium, and is working to the benefit of customers.

Further, there is no requirement that the EDCs demonstrate project risk or cost-recovery risk, and there is no requirement that the EDCs must "quantify the cost" of their financial obligations as some ephemeral concept apart from the contract payments. Accordingly, this statement by the AGO is flawed and inaccurate.

(b) There is no "calculation of either historic or estimated impact" that is relevant or valid.

The first sentence of the quote above from the AGO's initial brief states that the EDCs have failed to quantify "their financial obligations" using "calculations of either historic or estimated impacts." However, there are no "historic or estimated impacts" that would pertain to the Department's current exercise of authority on the remuneration rate in relation to the Section 83D (and Section 83C) contracts. The magnitude of the procurement program, and the current proposed contracts within that program, far outstrips any commitment made previously.

(c) The credit rating "agencies" do not offer "an established methodology" for calculating the "cost" of financial obligations under the PPAs.

The declaration that the credit-rating *agencies* have an *established methodology* for calculating the *cost of financial obligations* under the PPAs is wrong in multiple respects.

First, there is only one methodology that Mr. Musco puts forth as applicable in this case, among the separate, credit-rating methodologies established by S&P, Moody's and Fitch, which is the S&P methodology he puts forth to "inform" the record in "S&P's own words." (Tr. 4, at 420; Exh. AG-VM, at 6). Mr. Musco attempts to claim that Moody's methodology is similar to S&P's. However, this is not true. Moody's credit-rating methodology has an entirely different focus and indicates that the PPAs would be treated and evaluated as operating costs (Exhs. AG-VM at 28; EDC-AGO-1-8, Att. 3 (Moody's); Exhibit EDC-RBH-GET-1, at 39 - 40).

Second, the record shows that Mr. Musco is incorrect in claiming that the S&P methodology is the "most accepted method" (Exh. AG-VM, at 6). Nor is the S&P methodology an established methodology for calculating the "cost of financial obligations" associated with PPAs. When asked which other clients Mr. Musco had direct experience working with the S&P methodology, Mr. Musco cited only to two states Hawaii and Oregon, neither of which have used the methodology to establish the financial obligation imposed by the PPAs – and only one of which he has put forward as the basis for his testimony (Tr. 3, at 414-415).[20]

Third, the "S&P methodology" that the AGO purports to rely on is in fact not a calculation of the "cost of financial obligations," as the AGO claims. The "S&P methodology" referenced by the AGO is entitled: "Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements" (Exh. EDC-AGO-1-8, Att. 2). This methodology describes the "mechanics of debt imputation" and the circumstances under which S&P would find that a PPA has created a "fixed, **debt-like**, financial obligation" representing "substitutes for debt-financed capital investments in generation capacity" (id. at 2) (emphasis added). Once a debt obligation is found, the S&P imputed-debt methodology calculates an adjustment to the reported financial metrics to capture PPA capacity payments and multiplies those capacity payments by "risk factors" based on S&P's assessments regarding "the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs" (id. at 3). Accordingly, the S&P methodology is not an "established methodology" for calculating the "cost of financial obligations," as the AGO

[20] When asked for a record request showing that Oregon is using imputed debt as a cost adder in the procurement process, Mr. Musco stated "I'm not sure I'd agree that I said they're using this. It's an option that's available within the RFP that the utility can exercise" (Tr. 3 at 416, lns 13-15).

repeatedly alleges, but merely a small part of a larger analysis that also includes qualitative factors, judgment, and assessments of contextual factors.

Fourth, there is no basis for assuming that the credit-rating agencies will evaluate the impact of the financial obligations associated with the PPAs exclusively through a PPA-specific inquiry. Equity investors, equity analysts and the credit-rating agencies will evaluate the totality of the Company's financial obligations and will apply a broad range of qualitative judgments to the determination of financial wherewithal and balance-sheet strength.

Accordingly, the AGO's proposition that the credit-rating "agencies" offer "an established methodology" for calculating the "cost" of financial obligations specific to the PPAs is incorrect. The Attorney General is attempting to cherry pick sections of the "Standard & Poor's Methodology for Imputing Debt for U.S. Utilities' Power Purchase Agreements" that support their argument, while ignoring the remainder of the document (Exh. EDC-AGO-1-8, Att. 2). The alleged "methods" are not standalone computations endorsed by the rating agencies for the singular purpose and application suggested by the AGO, but rather are part of an overall, comprehensive credit-evaluation framework involving myriad qualitative and quantitative considerations. The impact of the EDC's financial obligations will be reviewed and ultimately determined through the overall equity and credit-rating processes conducted by independent third parties in accordance with their own approaches. This will encompass an assessment of both business and financial risk with regulatory environment as a significant element within that analysis.

(d) The "S&P methodology" is not an "established" method for determining that the financial obligation under the Proposed PPAs would be zero or close to zero.

On brief, the AGO argues that the only quantitative evidence in the record suggests that "because the financial obligations under the Proposed PPAs and TSAs rests with the ratepayers, and not with the EDCs, remuneration should be minimal, at best" (AGO In. Br. at 10). The AGO further argues that in determining the appropriate risk factor to assign to a PPA, S&P focuses on two factors: (1) is there a legislatively-created cost-recovery mechanism; and (2) does the EDC act as an intermediary between suppliers and customers rather than a generator (id. at 11). The AGO claims that because the EDCs have a statutory right to cost recovery and are barred from owning and operating generation, the S&P methodology "would likely apply a very low risk factor" (id. at 12). However, as with other claims asserted by the AGO, there is a wealth of inaccuracies, misrepresentations and inconsistencies in these statements.

For example, as discussed above, the AGO's witness, Mr. Musco testified numerous times that S&P and the other credit-rating agencies are independent entities that make their own determinations regarding the impact of the PPAs. For example, Mr. Musco testified that "none of us can speak exactly to what the ratings agencies are going to do" (Tr. 3, at 418). When asked, in his experience, whether any ratings agency will find a credit-negative impact arising from the contracts, Mr. Musco testified that "no one can say what the rating agencies are going to do. It's folly to try to say exactly what a rating agency is going to do" (Tr. 3, at 450).

Mr. Musco also further testified that "I would not expect them to arrive at a number anywhere but **at or near zero percent"** (Tr. 3, at 421). However, Mr. Musco was not able to convey that he has any basis for opining on the manner in which S&P would treat the Massachusetts PPAs beyond what he has read in S&P's imputed-debt methodology, nor does he have any particular insight into how S&P would evaluate the risk of cost recovery. Moreover, Mr. Musco could not provide any specific information regarding the debt-imputation methodology he was required to consider in Hawaii because that information is "confidential"—which is troublesome given how heavily Mr. Musco has relied on his experience in Hawaii as the basis for his claimed understanding of the S&P imputed-debt methodology in this case (Tr. 3, at 414-415, 426-427).

(e) The S&P method itself recognizes the importance of the regulatory environment.

The AGO claims that application of the S&P imputed-debt methodology indicates that the proposed PPAs would have little to no impact on the EDCs' financial wherewithal and/or access to capital (AGO In. Br. at 8). However, the S&P method itself recognizes "the regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment" (Exh. EDC-AGO-1-8, Att. 1, at 4). Therefore, it is clear the Department's decision regarding remuneration is of crucial importance. The financial stability and wherewithal of the Distribution Companies cannot be left up to *one element* of one component of one credit-rating agency's process supported by a witness who admits the rating agencies are independent and "no one can say what the regulatory agencies are going to do" (Tr. 3 at 450).

5. The Department Should Not Wait for Actual Harm to Occur

The Distribution Companies strongly disagree that the Department's decision on remuneration should rest on a showing of actual harm. Actual harm will cost customers dearly in relation to routine utility operations, and actual harm will likely terminate the Commonwealth's procurement program for renewable energy resources because the Distribution Companies will not be in a position to continue as the contract counter party.

For example, the AGO argues that, although it appears that S&P may have raised questions about the impact of potential Green Community Act contracts on NSTAR Electric prior to the passage of the GCA in 2008 and again prior to discussions with Cape Wind in 2012, the calls and concern from S&P appear to have ceased for now (AGO In. Br. at 14, fn. 16). The AGO further alleges that Section 83D was signed into law in August 2016; yet, the EDCs have "produced no evidence of negative reactions from the rating agencies" (AGO In. Br. at 13). This statement is alarming in the lack of awareness it demonstrates that a "negative reaction" by the ratings agencies would be bad for customers. Moreover, the statement evinces a lack of understanding that the ratings agencies are unlikely to act upon legislation where the terms of that legislation will be carried out in the future by the Department as it fulfills its statutory mandate.

a) Uncertainty in Remuneration Has Not Yet Occurred and There is No Downward Trend in the Remuneration Rate, Unless the DPU Creates One Here.

In this proceeding, there have been numerous references to a declining remuneration rate, along with the suggestion that the change in remuneration has not caused any concern or uncertainty from the perspective of the ratings agencies (AGO In. Br. at 8, 12-13). For example, the AGO argues that the EDCs "fared no worse in the financial community" when the remuneration rate dropped from 4 percent under Section 83 to 2.75 per cent under Section 83A (AGO In. Br. at 14-15). The AGO further argues that the EDCs have not shown that the "progression of remuneration" through the various "iterations" of the Green Communities Act solicitation requirements for renewable energy resources has "led to undue regulatory uncertainty" (id. at 13). However, these claims ignore how the statutory changes are actually viewed externally.

However, there has been only one change in the remuneration rate from four percent in Section 83 to 2.75 percent in the Section 83A, Section 83C and Section 83D procurements. Compare St. 2016, c. 188, § 12, Section 83C(d), Section 83D(d) and St. 2012, c. 209, § 36. Although, the General Court modified the language of "equal to 2.75 percent" used in Section 83A to "up to 2.75 percent" in Sections 83C and 83D, the numerical value set by the General Court stayed exactly the same. The alteration in language delegated authority to the Department to vary the remuneration rate from the designated level of 2.75 percent, and this case is the first time that the Department will be considering a change (and it will be doing so in the context of a vastly *growing magnitude* of commitments). Therefore, the regulatory environment surrounding the contract procurement framework in Massachusetts has remained much more stable than the AGO attempts to portray.

Conversely, the AGO and other parties argue that the EDCs have failed to provide any evidence, either in credit rating reports specific to the EDCs or in general credit rating agency documents, that shows that remuneration "is integral to a credit-supportive regulatory environment" (AGO In. Br. at 14). However, the conclusion regarding a "credit-supportive regulatory environment" rests heavily on the assessment that the Massachusetts regulatory environment has been stable and predictable, with the existing allowance for 2.75 percent remuneration embedded in that assessment. Although the AGO suggests that evidence is needed to find that "remuneration is integral," the S&P method, endorsed by the AGO's witness, states "the regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment" (Exh. EDC-AGO-1-8, Att. 1, at 4). Further, Moody's considers the regulatory environment "one of the most important credit considerations," and S&P identifies the regulatory environment, which informs both its business risk and financial risk scores, as "one of the most important factors in [its] credit analysis of regulated utilities" (Exhs. DPU 4-2; DPU 4-2-A; DPU 4-2-B). Therefore, the record evidence supports the fact that existing regulatory mechanisms factor into the "credit-supportive" rating given to Massachusetts utilities.

b) The EDCs Have Produced Substantial Evidence that Just and Reasonable Rates Will Result from the Payment of Remuneration.

On brief, the AGO contends that the EDCs have failed to provide the Department with evidence demonstrating that the proposed remuneration rate will result in just and reasonable rates.

However, this is not correct: the Attorney General's decision to simply ignore record evidence does not mean that the EDCs have failed to present that evidence.

The overarching purpose of the "Section 83" procurements is to facilitate the financing of renewable energy. See, St. 2008, c. 169, as amended by St. 2012, c. 209, §§ 35, 36 ("Section 83A"), and St. 2016, c. 188, §12 ("Section 83C") ("Section 83D"). The EDCs' credit quality enables the cost-effective financing of renewable power procurements, which, in turn, enables the public benefits that the GCA intends to achieve. In fact, Section 83D(a) explicitly recognizes the importance of the EDCs' balance-sheet strength in facilitating cost-effective financing. St. 2016, c. 188, § 12 (allowing EDCs to decline to contract in view of an "unreasonable burden" on the balance sheet). Therefore, a key consideration for the Department is whether the Section 83D contract costs (including remuneration) are more cost-effective when financed through long-term contracts with the EDCs as counterparties, than if the project were to be financed on a merchant basis (Exhs. EDC-RBH-GET-1, at 51, 48-66; DPU-2-11). This inquiry is embedded in Section 83D's "cost-effective" financing objective:

> The department of public utilities **shall consider the potential costs and benefits** of the proposed long-term contract and shall approve a proposed long-term contract if the department finds that the proposed contract is **a cost-effective mechanism for procuring reliable renewable energy** on a long-term basis**, taking into account the factors outlined in this section.**

St. 2016, c. 188, § 12, Section 83D(e).

Under a range of scenarios considering reductions in: (1) the cost of debt; (2) the cost of equity; (3) the equity ratio; and (4) the overall rate of return, the reduction in capital costs produced by financing the Project through long-term PPAs with the EDCs far outweighs the incremental cost associated with a 2.75 percent remuneration rate (Exh. EDC-RBH-GET-1, at 51). In fact, under Section 83D's "cost-effective financing" objective, the rate of remuneration could be as high as 21.81 percent and still produce net benefits for customers (id. at 51-52). The analytical premise underlying the net-benefit inquiry is that if the sum of total payments under the Section 83D PPAs and TSAs plus 2.75 percent remuneration is less than the cost of the Project under a "merchant" financing structure, the EDCs' balance sheets have created net customer benefits (id. at 52) in the billions of dollars.

The AGO argues that proponents of an incentive proposal, such as the proposal for remuneration under 83D, bear the burden of demonstrating that the proposal is consistent with the just and reasonable standard. D.P.U. 94-158, at 52 ("[a]ny incentive proposal would…be subject to the standard of review of [Section 94], which requires that rates be just and reasonable."). This includes demonstrating that the proposal is consistent with the Department's goal of providing a framework that ensures that the utilities it regulates provide safe, reliable, and *least-cost* service. However, this showing has been made in this case, in an identical fashion to the manner in which the AGO's witness testified was used in Hawaii.

In summary, the EDCs analyses demonstrate that the financing and customer benefits enabled by the EDCs' balance sheets warrant the 2.75 percent remuneration rate. The costs of the Section 83D PPAs and TSAs plus remuneration amply meet the "cost-effective" financing objective set forth under Section 83D. The EDCs' proposed 2.75 percent remuneration rate is analytically justified and in the public interest. Rates set by the Department to recover the approved remuneration rate will be just and reasonable given that the Department has evaluated the contracts in accordance with Section 83D criteria and the public-interest standard, and the EDCs have demonstrated that the remuneration is needed and has produced very substantial net benefits for customers. Accordingly, the Department should approve annual remuneration equal to 2.75 percent of the annual payments under each of the contracts submitted for approval in this case.

C. Response to Conservation Law Foundation

CLF argues the following: (1) that the record supports remuneration lower than 2.75 percent (CLF In. Br. at 9-12); and (2) that the Distribution Companies have not provided a justification for a remuneration award of 2.75 percent using the AGO's methodology (id. at 10);.

The Distribution Companies have provided substantial evidence on the record of this proceeding to support remuneration equal to 2.75 percent, as we have discussed in detail above. The suggestion that the record supports remuneration lower than 2.75 percent or that the EDCs are required to use the "AGO's methodology" is in error. There is no evidence on the record supporting a remuneration rate lower than 2.75 percent. The only witness in the proceeding testifying to a rate below 2.75 percent is the AGO's witness and, in its Initial and Reply Briefs, the Company has demonstrated the fallacies involved with the AGO's proposed application of the S&P methodology.

D. Response to Western Massachusetts Industrial Group

WMIG argues that the Distribution Companies have not provided the Department with sufficient information in the record to support the maximum percentage of remuneration in this case (WMIG In. Br. at 2).

Further, WMIG argues the Distribution Companies' regulatory support argument ignores the fact that Section 83D specifically requires the Department to affirmatively decide the percentage of remuneration and the Legislature reduced the remuneration percentage in earlier settings that did not negatively impact the financial situation or credit ratings of Massachusetts utilities (id. at 5). Lastly, WMIG claims the Distribution Companies' "fair return" on capital argument is flawed as well because they are not deploying capital since there is mandatory rate recovery from ratepayers who bear the financing (id. at 5-6). We have responded to these arguments in detail above.

As discussed above, there has been only one change in the remuneration rate from four percent in Section 83 to 2.75 percent in the Section 83A, Section 83C and Section 83D procurements. Compare St. 2016, c. 188, § 12, Section 83C(d), Section 83D(d) and St. 2012, c. 209, § 36. Although, the General Court modified the language of "equal to 2.75 percent" used in Section 83A to "up to 2.75 percent" in Sections 83C and 83D, the numerical value set by the General Court stayed exactly the same. The alteration in language delegated authority to the Department to vary the remuneration rate from the designated level of 2.75 percent and this case is the first time that the Department will be considering a change. Therefore, the regulatory environment surrounding the contract procurement framework in Massachusetts has remained much more stable than the WMIG attempts to portray.

E. The EDCs' Request for Remuneration Is Analytically Justified.

The General Court has delegated authority to the Department to set the remuneration rate at the time of contract approval. Inherent in that authority is the discretion to apply an appropriate analytical framework to the question of whether there is any reason to depart from the 2.75 percent remuneration provided under the prior Section 83A procurement. An analytical framework comprised of the following three qualitative and quantitative factors is the proper inquiry to inform the Department's determination:

I. Do the financial obligations that will be accepted by the EDCs in relation to the PPAs create risks and uncertainties for debt and equity investors?

II. Does the compensation level set by the remuneration rate produce net benefits for customers and further the objectives of the Commonwealth's clean energy policy consistent with the Department's public interest standard?

III. Are there any special circumstances that would weigh against the 2.75 percent remuneration rate specified in Section 83A?

As discussed in the foregoing sections, the substantial evidence presented in this case demonstrates that the EDCs' proposal for a remuneration rate equal to 2.75 percent is justified and warranted, as measured against these three applicable criteria.

VIII. CONCLUSION

This proceeding is of paramount importance given the magnitude, longevity and number of procurements called for in the Green Communities Act ("GCA") and the recent change in legislation that delegates authority to the Department to determine whether the specific facts and circumstances in the Section 83D proceeding warrant remuneration of 2.75 percent. As demonstrated herein, the Distribution Companies have shown through substantial evidence in the record that: (1) their execution of their respective long-term contracts satisfies the requirements of Section 83D of the GCA; (2) they have followed the provisions of the RFP as approved by the Department in D.P.U. 17-32; (3) the proposed PPAs compare favorably on price and non-price factors to the range of generation resources proposed in response to the RFP and are thus a cost-effective alternative for securing cost-effective renewable energy; and (4) a remuneration rate of 2.75 percent is warranted.

For the reasons discussed above, the Distribution Companies respectfully request the Department make the following findings:

(1) The PPAs fulfill the Section 83D requirements, are in the public interest and are approved;

(2) Remuneration equal to 2.75 percent is supported by the record evidence, warranted, and approved;

(3) The recovery of the PPA- and TSA-related expenses incurred by the Distribution Companies to solicit, evaluate and obtain regulatory approval through the fully reconciling, uniform charge to all distribution customers as proposed by each of the Distribution Companies, including 2.75 percent remuneration, is approved; and

(4) The proposed modifications to the LTRCA tariffs are approved.

Respectfully submitted,

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