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D.P.U. 18-64/18-65/18-66
Exh. AG-DM
December 21, 2018
Hearing Officer: Alan Topalian

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of a long-term contract for procurement of Clean Energy Generation, 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, each d/b/a National Grid for approval by the Department of Public Utilities of a long-term contract for procurement of Clean Energy Generation, 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 by the Department of Public Utilities of a long-term contract for the procurement of Clean Energy Generation, 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**

TESTIMONY
OF
DEAN M. MURPHY

Dated: December 21, 2018

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Dean M. Murphy. I am a Principal with The Brattle Group in the Boston office, located at One Beacon Street, Boston, Massachusetts 02108.

Q. Please describe your professional experience and educational background.

A. I have over twenty-five years of experience in economic consulting, with the majority of my work focusing on the electricity sector. My work has encompassed topics such as resource and investment planning (including power and fuel price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, competitive industry structure and market behavior, and market rules and mechanics. I have experience examining these and other electric-sector matters from the perspectives of investor-owned and public electric utilities, independent producers and investors, industry groups, consumers, regulators, and system operators. I hold a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in Engineering-Economic Systems, both from Stanford University, and a B.E.S. in Materials Science and Engineering from the Johns Hopkins University.

Q. Have you previously testified before any regulatory body?

A. Yes. I have testified before the New Hampshire Public Utilities Commissions, the Connecticut Department of Public Utility Control, the New Jersey Department of Public Utilities, and the Public Utilities Board of Manitoba, and have presented to advisory committees to the Pennsylvania Department of Environmental Protection. I have testified before committees of the state legislatures in New Jersey, New York, and Pennsylvania. I have also testified before the United States Court of Federal Claims, the U.S. Bankruptcy Court (both New Jersey and Southern District of New York), and the United States District Court (Vermont). I have submitted written testimony on behalf of the Massachusetts Attorney General's Office addressing the procurement of offshore wind in the Section 83C proceedings. My CV is attached as Attachment 1.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Massachusetts Attorney General's Office.

Q. What is the purpose of your testimony?

A. Pursuant to Section 83D of the Green Communities Act, ("Act," or "Section 83D"), Eversource, National Grid, and Unitil (collectively, the "Distribution Companies" or "EDCs") jointly sponsored a competitive solicitation for Clean Energy Generation for an annual amount of electricity equal to approximately 9,450,000 MWh (9.45 TWh), to be procured by the Distribution Companies entering into cost-effective long-term contracts by 2022.[1] In accordance with Section 83D, the Distribution Companies issued a Request for Proposals ("RFP") for Long-Term Contracts for Clean Energy Projects. Thereafter, the Evaluation Team received and evaluated the proposals.[2]

The New England Clean Energy Connect Hydro bid ("NECEC Hydro") was ultimately selected for contract negotiations, following the siting denial of the Northern Pass Transmission Hydro bid ("NPT Hydro"), which had initially been selected. The NECEC Hydro bid consists of energy supplied by Hydro Renewable Energy, Inc. ("HRE") and a new HVDC transmission line constructed by Central Maine Power ("CMP") that interconnects Québec with the New England power grid in Maine.[3] The contract

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[1] Section 83D of Chapter 169 of the Acts of 2008 (the "Green Communities Act"), as amended by chapter 188 of the Acts of 2016, *An Act to Promote Energy Diversity* (the "Energy Diversity Act").

[2] The Evaluation Team was comprised of the Distribution Companies and the Department of Energy Resources ("DOER").

[3] HRE is a wholly-owned indirect unit of Hydro-Québec.

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negotiations resulted in power purchase agreements ("PPAs") for energy and Environmental Attributes ("EAs") between the EDCs and H.Q. Energy Services (U.S.) Inc. ("HQ"), and Transmission Service Agreements ("TSAs") between the EDCs and CMP. The PPAs specify the obligation of HQ to supply Qualified Clean Energy and Environmental Attributes from Hydro-Québec Power Resources ("HQPR").[4]

The purpose of my testimony is to discuss the reasonableness of the Section 83D solicitation process and the resulting PPAs and TSAs.

Q. What are the major findings from your analyses?

A. The proposed contracts, as written, do not ensure that the Qualified Clean Energy acquired via the contracts will comprise fully incremental energy deliveries into New England, as the RFP specified. The RFP required that the Qualified Clean Energy under the contract should be incremental to (*i.e.*, in addition to) the hydroelectric energy that HQ has delivered to New England historically, or that would otherwise be expected to be delivered. The proposed contracts implement much weaker requirements for incrementality and would allow most (and potentially all) of the contract energy delivered to substitute for historical deliveries. This aspect of the contracts must be corrected in order to conform with the RFP requirements, and the overall purpose of the Act. This could be done by modifying the requirements of the proposed contracts, assuming HQ is able and willing to provide fully incremental Qualified Clean Energy into New England. If HQ is unable or unwilling to provide fully incremental Qualified Clean Energy, other sources of clean energy could supplement or substitute to satisfy this requirement. For example, the HQ deliveries of hydroelectric energy could be supplemented with some renewable energy that does meet the RFP's incrementality

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[4] The PPAs define HQPR as "those existing hydroelectric generating stations, located in the Province of Québec and owned and operated as a system by Hydro-Québec or its subsidiaries from time to time, that produce electric energy, which consists predominantly of low-carbon and renewable hydro-electric energy services during the Services Term." Exh. JU-3-B, at 14.

requirement, or the HQ energy could be replaced in its entirety with energy from other renewable bids (which might have different transmission requirements). There were several alternative bids comprised of new renewable generation (and transmission) that would provide fully incremental clean energy, and some of these alternative bids scored well in the evaluation.

In addition, I have concerns about the selection process. Neither of the two top-scoring bids, [redacted], nor a potential portfolio comprised of just those two bids, were carried forward from the second stage of the evaluation into the third and final stage.[5] These alternatives that were dropped from consideration may have performed better than the NECEC Hydro project that was selected. This selection issue may be related to the previous question of whether the proposed contracts provide fully incremental clean energy, because the [redacted] projects would have fully satisfied the incrementality requirements of the RFP.

I am also concerned about the inclusion of bidders' affiliates in the Evaluation Team. This is generally considered inappropriate because it can bias the evaluation and selection process. Such concerns arose in multiple instances in the 83D evaluation process and were noted by the Independent Evaluator.[6]

My final concerns regard the potential for the scaling approach used in bid scoring to inadvertently and improperly affect the bid scores and ranking, and the metric used to calculate the Global Warming Solutions Act ("GWSA") benefits. Although these appear to be less important issues in this solicitation than the concerns noted above, they should be addressed in any future solicitations.

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5 Revised Independent Evaluator Final 83D Report Confidential, at 68, 70 (August 7, 2018). These two high-scoring bids were included as components of portfolios that scored relatively poorly in the evaluation; the lower scores for these portfolios may have been due to the inclusion of still other, lower-scoring bids in those portfolios.

6 *See, e.g., id.*, at 27-28, 32, 36, 48-49.

III. REVIEW OF KEY DOCUMENTS IN THE PROCEEDING

Q. What documents have you reviewed in this proceeding?

A. I have reviewed the RFP, the Independent Evaluator's report submitted by Peregrine Energy Group, responses to Information Requests, and the direct Joint Testimony and accompanying exhibits submitted by the Distribution Companies, including the Tabors Caramanis Rudkevich ("TCR") evaluation report, the bid selection letters, the scoring protocols, the qualitative scoring, portions of the bids, and the proposed contracts.

IV. THE PROPOSED CONTRACTS DO NOT PROVIDE INCREMENTAL HYDROELECTRIC GENERATION AS CONTEMPLATED BY THE RFP

Q. What is your concern regarding whether these proposed contracts will provide incremental hydroelectric generation?

A. The proposed contracts do not require that HQ provide incremental hydroelectric generation as specified in the RFP. The stated goal of the Act is to "facilitate the financing of clean energy generation resources."[7] That is, the legislature intended to bring additional clean energy into the Commonwealth. This goal is reflected in the RFP, the stated intent of which, in the context of a hydroelectric bid, was to acquire "Incremental Hydroelectric Generation"[8] that would be incremental to historical hydroelectric energy deliveries into New England.[9] My understanding of the purpose of this RFP requirement is to ensure that the hydroelectric or renewable energy resources procured under the long-term contracts would not substitute for historical clean energy deliveries, but rather would provide a long-term net increase in the amount of clean energy delivered into New England. As written, the proposed contracts include much

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[7] Section 83D(a).

[8] Exh. JU-2, at 18.

[9] Bids for renewable resources were required to be provided from new generation, which would necessarily be incremental to historical energy. Hydro suppliers were permitted to offer "Incremental Hydroelectric Generation" from existing resources but were required to show that the generation would be incremental.

weaker requirements. Although each EDC's contract has its own incrementality provisions, even the most stringent contract requires that less than half of the newly contracted clean energy provided be incremental to historical average generation.

Q. What did the RFP require in terms of incrementality?

A. The RFP defines incremental hydroelectric generation:

> "Incremental Hydroelectric Generation" means 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.[10]

That is, to be considered "incremental," the RFP requires the bidder to provide energy in addition to the bidder's 3-year historical average of deliveries into New England (or more than the bidder would have otherwise delivered). The 2014-2016, 3-year imports from HQ into New England is 14.8 TWh.[11] Thus, for the 9.55 TWh of Qualified Clean Energy from the contracts to be fully incremental energy delivery, total deliveries would need to be 24.35 TWh annually.

Q. Do the proposed contracts adopt the RFP definition of incrementality?

A. Although the preamble that appears in each of the proposed contracts asserts "WHEREAS, the output of the Hydro-Québec Power Resources, delivered through the New Transmission Facilities (as defined herein), shall constitute incremental hydroelectric generation during the Services Term,"[12] the contracts themselves do not define the term "incremental hydroelectric generation." Rather than repeating or referring to the definition in the RFP, or implementing equivalent requirements, each of the proposed contracts establishes considerably less stringent requirements.

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[10] Exh. JU-2, at 5.

[11] Exh. NEER-1-8.

[12] *See, e.g.*, Exh. JU-3-A, at 7.

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The contracts require two types of energy to be delivered: 1) "Guaranteed Qualified Clean Energy," which is the contracted total of 9.55 TWh across the three contracts, to be delivered through the NECEC,[13] and 2) "Baseline Hydroelectric Generation Imports" ("Baseline Hydro"), which consists of all other power deliveries from Hydro-Québec to New England.[14] Exhibit H to the proposed contracts establishes Minimum Required Baseline Hydroelectric Generation Imports ("Minimum Baseline") quantities.[15] Conceptually, to provide incremental generation, the Minimum Baseline should equal historical energy deliveries. But the values established for the Minimum Baseline quantities are substantially below the historical average, and so the contracts do not actually require the clean energy deliveries to be incremental.

The three EDCs' proposed contracts establish different requirements for the Minimum Baseline quantity. The National Grid contract establishes a Minimum Baseline of 9.45 TWh, which is substantially below the 14.8 TWh of historical deliveries.[16] This implies that HQ must deliver a total of 19.0 TWh annually to New England (9.45 TWh of Minimum Baseline plus 9.55 TWh from the contract). Even though the contracts

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[13] Exhibit B to the proposed contracts provides the Schedule of Guaranteed Qualified Clean Energy for each hour. For Eversource, this number is 579.335 MWh/hour (Exh. JU-3-A, at 72); for National Grid it is 498.348 MWh/hour (Exh. JU-3-B, at 80); and for Unitil it is 12.317 MWh/hour (Exh. JU-3-C, at 72). Summing across EDCs and multiplying by 8,760 hours/year yields total Guaranteed Qualified Clean Energy of 9.548 TWh/year.

[14] See, *e.g.*, Exh. JU-3-A, at 86. The Baseline Hydro amount refers to all other deliveries to New England, not the amounts that are specific to each EDC or their contracts.

[15] Exh. JU-3-B, at 92. While the Eversource and Unitil contracts do not use the phrase "Minimum Required Baseline Hydroelectric Generation Imports," the contracts do require a minimum level of "Baseline Hydroelectric Generation," against which damages are measured. Exh. JU-3-A, at 86.

[16] According to National Grid's response to Exhibit NEER-1-8, due to "the difficulties of predicting what differences from HQ's 3-year historical average annual delivery of approximately 14.8 TWh from HQ to New England from 2014-2016 could reasonably be expected over the twenty years following the targeted commercial operation date for this project, it is reasonable and acceptable to move forward with the contract based on HQ's agreement to the 9.45 TWh Minimum Required Baseline Hydroelectric Generation Imports."

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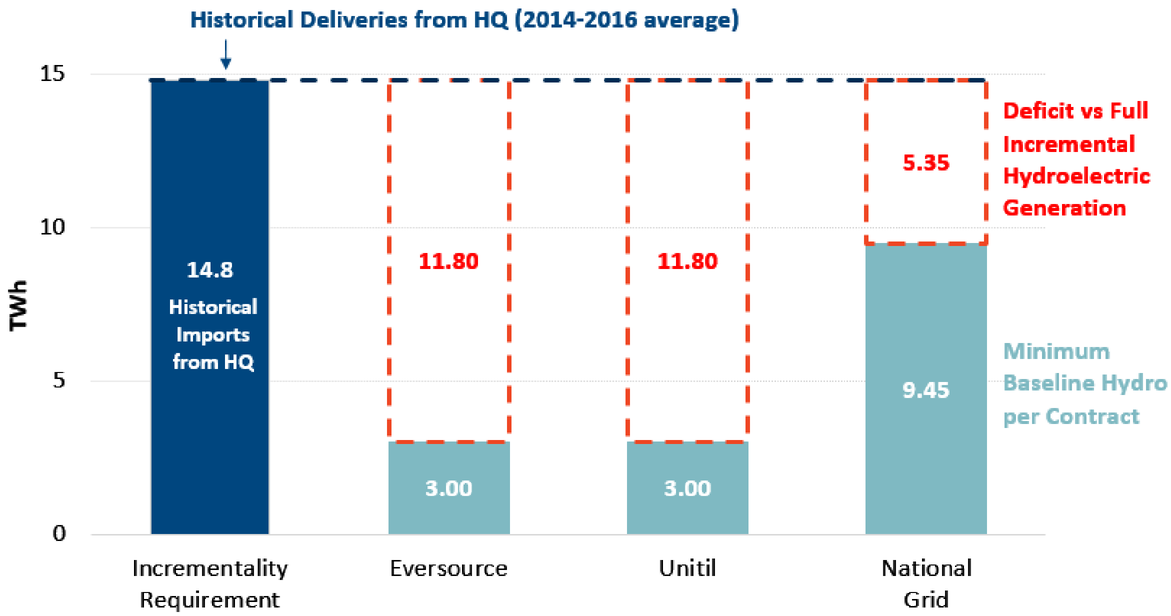
nominally represent incremental hydro of 9.55 TWh annually, HQ will be required to deliver to New England only 4.2 TWh more than it has delivered historically. In other words, less than half the contract energy is required to be incremental; for the remainder, HQ can simply substitute contract energy at the contract price for energy that it has historically sold into New England. In fact, the Minimum Baseline for National Grid may be reduced further (though not increased) by several potential adjustments.

The incrementality requirements of the Eversource and Unitil contracts are even less stringent They are based on a Minimum Baseline quantity of 3.0 TWh,[17] so that the total clean energy deliveries into New England, including deliveries under the new contract, can be below historical average deliveries. Thus, HQ could satisfy its long-term contract obligations by delivering only 12.55 TWh annually (9.55 contract + 3.0 Baseline), which would be 15% less clean energy than it has delivered historically. The difference could then, for example, be sold into the market to another buyer offering a higher price, which might include a premium for the fact that the hydro energy is clean.

Figure 1 below illustrates the contract quantity requirements, contrasting what would be required for full incrementality as described in the RFP, shown by the first column, with what is required by each of the proposed contracts. The figure shows that the Eversource and Unitil contracts require HQ to deliver just 3.0 TWh of Baseline Hydro to New England, 80% (11.80 TWh) below the historical average. The National Grid contract requires somewhat greater Baseline deliveries of 9.45 TWh, but still 36% (5.35 TWh) below the historical average. The Deficit indicated relative to each contract is the amount by which total hydro deliveries to New England (Qualified Clean Energy plus Baseline Hydro) can fall short of full incrementality without penalty.

[17] According to Exhibit NEER-1-9, Eversource and Unitil found that the requirement to deliver incremental generation was met in the bid response, and the 3 TWh Minimum Baseline that was negotiated would not make “the administration of such a provision problematic.”

Figure 1: Baseline Hydro Deliveries into New England Required by Proposed Contracts



Sources and Notes: Minimum Baseline Hydro per Contract is from contracts (Exhs. JU-3-A, JU-3-B, JU-3-C).

Q. Do the Minimum Baseline hydro generation levels established in the proposed contracts provide a reasonable assurance to Massachusetts ratepayers that the total clean energy delivered to the Commonwealth will increase if the proposed contracts are enacted?

A. No. As discussed above, the contract provisions do not ensure that energy deliveries under the contracts will be fully incremental relative to historical imports from HQ. In the case of Eversource and Unitil, total clean energy deliveries could fall <u>below</u> historical levels without penalty. Furthermore, the stated goal of the Act is to "facilitate the financing of clean energy generation" through "cost-effective long-term contracts."[18] If the proposed long-term contracts allow HQ to provide less clean energy to New England than it has historically, then it is not apparent that the contracts would be financing clean energy generation. It is also not clear that the contracts would be cost-effective, as ratepayers could be paying for energy and EAs as if they would be incremental to

[18] Section 83D(a).

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historical deliveries, but the deliveries would not necessarily be fully incremental because the contracts do not require it.

Q. How do the contracts enforce the Minimum Baseline requirements that they do include?

A. The Minimum Baseline requirements are enforced by a damages calculation that penalizes any Shortfall, the amount by which Baseline Hydro is below the Minimum Baseline. The damages, which would be applied to the energy payment to HQ, are calculated as a share of the TSA payments proportional to the Shortfall. For National Grid, the damages share is the Shortfall divided by the Minimum Baseline (9.45 TWh); whereas for Eversource and Unitil, the damages share is the Shortfall divided by the Minimum Baseline (3.0 TWh) plus the contract energy, totaling 12.55 TWh. In both cases, the damage amount is the relevant share multiplied by the annual TSA payments, with some time averaging and rolling average adjustments. Several factors may reduce the damages amount and/or reduce the Minimum Baseline deliveries that are required to avoid damages.[19]

Figure 2 below illustrates the contract incentives facing HQ to provide incremental energy, showing how the aggregate contract payments for energy and EAs change as the level of Baseline Hydro delivered changes. If HQ delivers fully incremental Baseline Hydro (equal to the historical average of 14.8 TWh), there are no damages and no

[19] Damages are only calculated if the Shortfall is positive (*i.e.*, HQPR delivers less than the Minimum Baseline). The Eversource and Unitil contracts provide a reduction in the Minimum Baseline subject to a *Force Majeure* provision, and a provision related to negative pricing in New England. Exhs. JU-3-A, at 86-87; JU-3-C, at 84-85. The National Grid contract provides for several factors that can reduce (but not increase) the Minimum Baseline, including on-peak prices relative to a floor, total transfer capabilities for deliveries into New England, total net electricity exports from Hydro-Québec, and changes in Hydro-Québec's firm transmission rights. The National Grid damages for Shortfall are also scaled down by 20% after each five years of the contract, starting at 100% of the Shortfall share times the TSA payment in the first 5 years, and falling to 40% in the last 5 years. Exh. JU-3-B, at 94.

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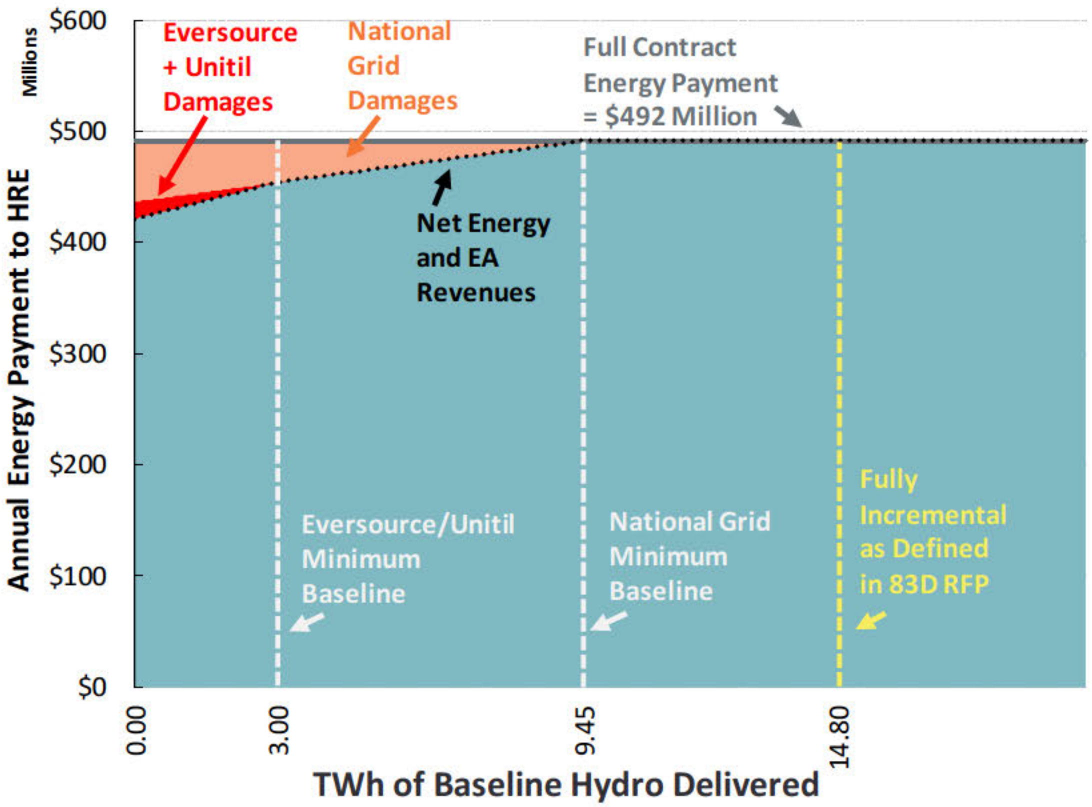
reduction to the net revenues earned under any of the EDCs' contracts. Damages are incurred when Baseline Hydro deliveries drop below the Minimum Baseline of the National Grid contract, 36% below the level that would be fully incremental. As Baseline Hydro falls below this level, net energy and EA revenues from National Grid are reduced according to the Shortfall relative to the National Grid Minimum Baseline, at a rate of \$5.80/MWh of Shortfall. Below the 3.0 TWh Minimum Baseline of the Eversource and Unitil contracts, which is 80% below full incrementality, Eversource and Unitil damages begin to be incurred as well; total damages across all three contracts in this range are \$10.98/MWh of Shortfall. Even at zero Baseline Hydro, total energy and EA payments across the three contracts are reduced by only 14.3%. These measures do not account for any of the other adjustments noted above, which could reduce (but not increase) the damage amounts.

Figure 2: EDC Energy Payment vs. Baseline Hydro Generation



Source and Notes: Contracted energy prices, contracted clean energy delivery, and contract details in relation to Baseline Hydro are from Exhibits JU-3-A, JU-3-B, JU-3-C. Transmission unit price and contract capacity are from Exhibits JU-

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4-A, JU-4-B, JU-5-C. For the purposes of this chart, it is assumed that all contracted clean energy (Guaranteed Qualified Clean Energy) is delivered. The chart reflects prices from contract year 1 (Nominal 2017 $).

Q. Do the damage mechanisms in the contracts give HQ sufficient incentive to provide fully incremental hydro deliveries?

A. No, the damage mechanisms do not give HQ the proper incentives to provide fully incremental deliveries of clean energy. There is no disincentive for HQ to under-provide Baseline Hydro until it falls well below the historical average, and even then, the disincentives for further Shortfall are modest.

Q. Has this potential for Massachusetts ratepayers to receive the same total clean energy generation but pay for it at an above market rate been raised previously?

A. Yes. The Department of Public Utilities ("Department") explicitly acknowledged this risk in response to HQ's comments,[20] in which HQ proposed amending the incrementality requirements in the RFP by changing the definition of incremental hydro generation to require only the capability to deliver incremental power, rather than the actual delivery of incremental power:

> The Department agrees that there would be a risk to ratepayers if an electric distribution company entered into a contract with a bidder based on the

[20] HQ proposed that Incremental Hydroelectric Generation be defined as: "Firm Service Hydroelectric Generation that is capable of providing a net increase in MWh per year of hydroelectric generation from the bidder and/or affiliate as compared to the 3 year historical average delivery of hydroelectric generation from the bidder and/or affiliate within or into the New England Control Area." *Fitchburg Gas and Electric Light Company d/b/a Unitil, Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, and NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy*, D.P.U. 17-32, Comments of H.Q. Energy Services (U.S.) Inc., at 8 (February 21, 2017). This proposed definition is aligned with HRE's response to how it provides incrementality in its bid for this solicitation: "[redacted]." *Section 83D Request for Proposal Application Form,* NECEC RFP Response (HRE) Confidential, Section 4.2, at 20 (emphasis added).

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> bidder's capability to provide a net increase in MWh/year of hydroelectric generation. If the bidder subsequently failed to provide a net increase in generation, ratepayers would have paid for a service (*i.e.*, Incremental Hydroelectric Generation) that the bidder did not deliver.[21]

In its 2016 background document on regulations to limit greenhouse gases ("GHG"), including the Clean Energy Standard ("CES"), the Massachusetts Department of Environmental Protection ("DEP") explicitly expressed a concern that "resource shuffling" of Canadian hydro (*i.e.*, the contractual or transactional reassignment of clean energy without increasing the total amount of clean energy overall) could result in the CES delivering no additional clean energy to the Commonwealth:

> Excluding existing resources from the CES would not be sufficient to prevent resource shuffling with respect to transmission of electricity from Canada. Currently, electricity imported from Canada is an important source of clean electricity for Massachusetts, but the ability to import additional electricity from Canada is limited by the amount of transmission capacity. Resource shuffling could occur if new hydroelectric generation resources were to displace existing hydroelectric resources as the source of the electricity traveling through existing transmission lines. In this case, CES compliance could occur without any change in the amount of clean energy available for use in Massachusetts.[22]

Although the DEP's comments were focused on the role of transmission, the issue of incrementality is not limited to transmission. Adding new transmission without requiring that deliveries be incremental would fail to address the issue, as illustrated in this proceeding and the development of the RFP.

[21] D.P.U. 17-32, at 33 (2017).

[22] Massachusetts Department of Environmental Protection, *Background Document on Proposed New and Amended Regulations*, at 30 (December 16, 2016).

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Q. Does the fact that the contracts add significant transmission capacity to enable greater deliveries to New England alleviate the concern about whether the contract energy would be incremental?

A. Energy deliveries from Québec are often constrained by the limits of the transmission interface between Québec and New England.[23] Thus transmission must be expanded to enable the delivery of incremental clean energy into New England. However, merely adding transmission does not ensure that clean energy deliveries will be incremental relative to historical deliveries, unless the contracts explicitly require this. As the proposed contracts are written, that will not necessarily be the case; clean energy deliveries could be far less than fully incremental and still satisfy the requirements of the proposed contracts.

V. ADDITIONALITY AND OFFSETTING GREENHOUSE GAS EMISSIONS

Q. Must the contracts require full incrementality for the 83D clean energy to create the desired offset to greenhouse gas emissions?

A. Even if the proposed contracts required energy deliveries to be fully incremental, this would not necessarily guarantee that GHG emissions would decrease by an amount corresponding to the Qualified Clean Energy of the contract. Incrementality is defined in the RFP only with respect to deliveries <u>into New England</u>, while GHG emissions must be measured at a <u>global</u> level.[24] It would be possible, at least in principle, to satisfy the requirements of full incrementality (*i.e.*, the Qualified Clean Energy is incremental to the full historical average deliveries into New England), and still not offset a corresponding amount of global GHG emissions. This could happen through resource shuffling—reassignment of a fixed amount of clean energy so as to increase the clean energy

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[23] *Section 83D Request for Proposal Application Form*, NECEC RFP Response (HRE) Confidential, Section 4.2, at 20.

[24] Exh. JU-2, at 5-6.

delivered to a particular destination without increasing the total amount of clean energy overall.

For instance, with the new NECEC transmission link, if HQ increased deliveries into New England by the contracts' 9.55 TWh relative to historical New England deliveries, this would achieve full incrementality as defined in the RFP. But if HQ accomplished this by reducing its exports to other neighboring regions rather than by increasing clean energy generation overall, then global GHG emissions would not necessarily be reduced. Diverting clean energy from other regions to New England would enable a reduction in fossil generation and emissions within New England, but the reduced deliveries to other regions may need to be replaced by additional fossil generation in those regions. This would effectively substitute fossil generation in other regions for fossil generation in New England, shifting emissions from one region to another, without causing a material decrease (the actual impact would depend on the relative emissions intensities of each region).[25]

Q. What would be required to ensure a reduction in GHG emissions?

A. For the 83D contracts, or any project, to reliably reduce GHG emissions, they would need to provide clean energy that is "additional." Additionality is a commonly-used concept in the climate change discussions; it refers to emissions reductions that occur <u>because of</u> a proposed action, reductions that would not have occurred otherwise under "business as usual." Importantly, it must involve overall global emissions reductions, not reductions in one region or sector that might be offset by a corresponding increase that is triggered elsewhere, or reductions that would have occurred regardless of the proposed action. For example, a PPA that supports the development of a new wind farm will generally be additional. The new wind farm produces clean energy that would not otherwise be

[25] This shifting of emissions from one region to another through resource shuffling is analogous to "leakage," defined 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." G.L. c. 21N, § 1.

produced, displacing fossil energy and reducing emissions, so the clean energy and the emissions reductions are additional to what would have occurred without the PPA. Clean energy, however, is not always additional in this sense. If an existing wind farm with an expiring PPA signed a renewed PPA with a different buyer, the renewed PPA does not result in additional clean energy. The existing wind farm would have continued to produce clean energy even without the renewed PPA; the output may have been sold to a different buyer or in the spot market. The renewed PPA does not increase the total clean energy produced and consumed or reduce emissions; it just reallocates clean energy that would be produced in any case. It can sometimes be challenging to define and determine additionality in practice, primarily because doing so can require a very precise specification of the alternative "business as usual" circumstance—*i.e.*, additional to what? But for the purposes of the 83D procurement, the important point is that a global perspective is necessary. The RFP requirement that the contract energy be incremental <u>to New England</u> (even if the proposed contracts required full incrementality) does not ensure that it would be additional or necessarily result in corresponding GHG reductions.

Q. Do the proposed contracts require the energy to be additional in this sense of offsetting GHGs globally?

A. No, not necessarily. HQ has committed to using <u>existing</u> HQPR facilities to supply the contracted energy.[26] If these facilities were spilling significant amounts of water due to transmission constraints that would be relieved by the NECEC transmission, or if Hydro-Québec undertook investments to expand its system—to increase output from existing facilities or add new generation or storage capability—then a portion of the generation may be considered additional. But the contracts do not require this, nor has HQ indicated that it is the case.

[26] *See, e.g.*, Exhibit JU-3-A, at 70-71 for a list of existing facilities that will be used to provide the contracted energy.

VI. POTENTIAL CHANGES TO THE PROPOSED CONTRACTS TO ENSURE INCREMENTALITY

Q. How could the proposed contracts be modified to ensure the energy provided is fully incremental relative to historical deliveries?

A. Increasing the Minimum Required Baseline Hydroelectric Generation Imports quantity in Exhibit H to the proposed contracts will increase the amount of energy that is required to be incremental. Unfortunately, it may not be as simple as increasing this value to equal the 14.8 TWh historical average of deliveries into New England (and removing the provisions that can reduce the Minimum Baseline). This simplistic approach could create difficulties because the amount of hydroelectric energy that HQPR is able to produce can vary from year to year based largely on hydrologic conditions. Dry years will have less total energy available, and it may not be possible to export the historical average amount; similarly, the appropriate Baseline Hydro amount could exceed the historical average in years with above-average energy. Some further adjustment mechanisms may be necessary; these might include indexing the Minimum Baseline to water conditions or to total exports from Hydro-Québec, and/or making the Minimum Baseline a multi-year or rolling requirement (the National Grid contract contains some such adjustments). A desirable principle for defining the Baseline Hydro energy (as well as the 83D contract energy) is that it should take priority over HQ exports to other regions to ensure that the contract energy is incremental to what would have been delivered to New England absent the contracts. But the existing low minimum thresholds for Baseline Hydro delivery in the proposed contracts, and the modest incentives to meet even those minimum thresholds, are insufficient to ensure that Massachusetts ratepayers will receive the fully incremental clean energy that was solicited in the RFP.

Q. Would HQ be able to provide fully incremental energy to meet such a contract requirement with its existing system?

A. In Section 4.2 of its bid materials, HRE [redacted]

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[redacted]

Q. If HQ is unable or unwilling to provide hydro production that is fully incremental, are there other options that could improve the performance of the contracts on this dimension?

A. If HQ is unable or unwilling to provide fully incremental hydro, as that might be reasonably defined, then another option could be to include other energy sources that can provide incremental energy. For example, if some new renewable energy was used to supplement the HQ hydro supply, the demands on HQPR's existing hydro system could be reduced while maintaining the total amount of incremental energy provided to New England under the contract. An alternative bid included both wind and hydro generation with the NECEC transmission, the "NECEC Wind/Hydro" bid [redacted]. In this bid, SBx (a joint venture of Gaz Metro and Boralex) would develop the wind generation as a complement to the existing hydro power. [redacted]

[27] *Section 83D Request for Proposal Application Form,* NECEC RFP Response (HRE) Confidential, Section 4.2, at 20.

[28] [redacted].

[29] [redacted] he difference between [redacted] and the [redacted] provided in the wind portion of the bid, leaves [redacted] TWh of the contract to be fulfilled by hydro generation.

Continued on next page

REDACTED

Q. Would this amount of supplemental wind energy enable HQPR's existing hydro system to provide the balance of the energy requirements for fully incremental energy?

A. It may, though it is possible that even with the [redacted], HQ might not be able or willing to provide the lower [redacted] of hydro required for incremental generation. In that case, it may be necessary to turn to other suppliers for the required amount of incremental energy. [redacted].[30] If the NECEC Hydro bid cannot provide fully incremental energy, these other bids would be unable to do so. Fortunately, there were other bids that could supply the desired fully incremental clean energy requirements. In fact, because many of these other bids were based on new renewable generation, they would be additional, and thus would ensure that the clean energy delivered to New England would offset GHG emissions, which even fully incremental energy from existing hydro resources might not necessarily do, as discussed above. The Evaluation Team created and evaluated several portfolios of renewable energy projects in Stage 3 that could be candidates if the NECEC Hydro bid [redacted] could not provide incremental clean energy. In addition, the two highest-scoring bids in the Stage 2 evaluation were [redacted] bids; although they were not evaluated on a standalone basis in Stage 3, they could be potential candidates.

VII. PROJECT SELECTION

Q. What is your concern regarding project selection?

A. There appear to be some issues regarding which projects and portfolios were selected to carry forward into Stage 3 of the evaluation. Specifically, the two highest-scoring projects in Stage 2, [redacted], were not carried forward into the

30 [redacted]

Stage 3 evaluation individually. This may have been because each bid offers less clean energy than the 9.45 TWh desired in the solicitation, though that would not necessarily disqualify these projects as standalone bids, since there was no requirement that the full amount be acquired in a single solicitation, and multiple solicitations were contemplated. Further, a portfolio consisting of just these two projects would have provided about [redacted] of the energy targeted by the procurement and may have performed very well. These two projects were included as components in several larger portfolios, though these larger portfolios included other, lower-scoring bids that may have diluted their value.

Q. Do your concerns regarding project selection relate to the question of whether the NECEC Hydro bid offers fully incremental clean energy?

A. Yes. The [redacted] bids both [redacted], and so there is no concern about whether they would offer incremental energy to New England. In fact, they would be additional as well, in the sense discussed above, and are not subject to concerns over resource shuffling, so they would offer confidence regarding global GHG reductions.

Q. Please briefly describe the evaluation of bids and bid selection process.

A. The bids were evaluated in three stages, which was followed by bid selection. In Stage 1, bids were evaluated against the RFP threshold requirements. Bids that met the threshold requirements were carried to Stage 2, where they were evaluated on both quantitative and qualitative dimensions. The Evaluation Team then selected several large proposals from Stage 2, plus several portfolios made up of multiple projects, for further evaluation in Stage 3, and ultimately project selection.

Q. Were all the bids that were evaluated in Stage 2 also evaluated in Stage 3?

A. No. As stated in the RFP, it was not expected that all bids from Stage 2 would be evaluated in Stage 3. The RFP provides three metrics for including bids in Stage 3: 1) the rank order of the proposals at the end of the Stage 2 evaluation; 2) the cost effectiveness of the proposals based on the Stage 2 quantitative evaluation; and 3) the total annual generation of the proposals relative to the procurement target.[31]

Q. Were the proposals with the highest rank order and highest cost-effectiveness from Stage 2 brought forward into Stage 3?

A. As standalone projects, no. [redacted] were the two most highly ranked large proposals in Stage 2. They received the highest Net Total Benefit scores and highest Net Direct Benefits scores.[32] Both the [redacted], and thus would provide energy to New England that would be both incremental to New England and additional globally. [redacted] was the top ranked bid in Stage 2, receiving a total score of 85.94; [redacted] was the second highest ranked bid in Stage 2, with a total score of 80.24. The NECEC Hydro bid was ranked third with a score of 79.95, more than 5 points below the top-ranked [redacted] Each of these portfolios included between [redacted] other smaller projects that had lower net direct benefits and higher costs,[33] which may have depressed the portfolio scores. The Evaluation Team did not evaluate [redacted] bids individually or in a portfolio composed solely of these two projects.

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31 Exh. JU-2, at 41.

32 [redacted]

33 As previously discussed, the [redacted] is an exception. *See supra* note 32.

Continued on next page

REDACTED

Q. Is it likely that the [redacted] bids would have scored well in Stage 3, either individually or combined in a portfolio consisting of just these two bids?

A. Yes. [redacted] bids were ranked first and second in the Stage 2 evaluation. The Stage 3 scoring used the same quantitative and qualitative evaluation approaches as Stage 2, so these bids would have ranked first and second in Stage 3 as well, above the NECEC Hydro bid.[34] I believe that these two bids should have been considered on a standalone basis, so that an explicit tradeoff could be made [redacted] and their better performance.

Further, a portfolio consisting of just these two bids would likely have scored quite well, and would have provided most of the energy targeted in the procurement. The Stage 3 portfolios that included [redacted] along with other projects likely scored lower due to the inclusion of these other lower-scoring projects, and so do not offer good guidance regarding the value of a portfolio consisting solely of these two bids. To calculate the total benefits of this new portfolio would require a full evaluation, including a new simulation with TCR's Enelytix model, as requested in Information Request AG 3-2.[35] I believe that a portfolio consisting of just the [redacted] projects would have been attractive and might have been preferred to the NECEC Hydro bid, and thus should have been evaluated. Further, these bids, either individually or in a portfolio, would provide greater confidence regarding the delivery of fully incremental clean energy to New England, and GHG emissions offsets.

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[34] The scaling of quantitative scores was performed independently in Stage 3, so the scoring would differ slightly from the Stage 2 scoring (*see* Section IX on the impact of scaling). The Stage 3 scaling slightly increases the advantage of the [redacted] bids over the NECEC Hydro bid.

[35] While the direct benefit portion of the total quantitative benefits should be additive and thus not require another simulation, and the qualitative benefits are not affected by inclusion in a portfolio, the indirect benefits may not be additive and would require a separate simulation to evaluate.

Continued on next page

Q. In combination, would the [redacted] bids satisfy the full clean energy procurement requirement under section 83D?

A. [redacted] the Act allows the EDCs to carry out multiple procurements to acquire the full 9.45 TWh of desired clean energy.[36] Had the EDCs selected a bid or a portfolio that did not satisfy the full 9.45 TWh goal, a second procurement could have been held to acquire the remaining clean energy. In fact, several other portfolios evaluated in Stage 3 offered less than the 9.45 TWh desired, though none fell short by as much as [redacted]

VIII. EVALUATION TEAM COMPOSITION

Q. In your opinion, is it appropriate that the utilities participated in bid evaluation, given that their affiliates had submitted bids in this solicitation?

A. In general, I do not find it appropriate that the Evaluation Team included the utilities whose affiliates had submitted bids. This apparent conflict of interest raises serious concerns, for several reasons.

Q. Is this just a perceived conflict of interest, or are there reasons that this could influence the outcome of the procurement process?

A. The perception of a possible conflict of interest is rooted in real reasons for concern. One concern is the possibility of information sharing that could offer the affiliate a bidding advantage. This is particularly relevant in this procurement, where bidders were not generally aware of the precise scoring mechanism that would be used to evaluate bids. The risk that bid evaluators might share information with some bidders and not others is increased if members of the bid Evaluation Team are affiliated with some bidders.

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[36] Section 83D(b).

Q. Does walling off the Evaluation Team from direct or indirect communications with the bidding team alleviate the concerns regarding bidder affiliates on the Evaluation Team?

A. An ethical wall can be established between members of the Evaluation Team and the bidding teams, with the intent of minimizing the possibility of inappropriate information sharing. I understand that Standards of Conduct were established to create such ethical walls in this instance, though I cannot attest to their efficacy.

But in addition to concerns about inappropriate information sharing, incentive problems can arise. If the EDC stands to benefit if its affiliate prevails in the procurement process, then the EDC members on the Evaluation Team may—consciously or subconsciously—be influenced by those incentives, and favor bids from the affiliate. An apparent bias in evaluation toward an EDC affiliate's bid, either intentional or unintentional, occurred at several points in this 83D solicitation, and was explicitly identified and documented by the Independent Evaluator:

> Based on our observations, Eversource favored, or had the appearance of favoring, NPT in various stages of the evaluation and selection process, especially toward the end. This included the deliberations with respect to the interest rate assumption in the quantitative evaluation and the qualitative evaluation with respect to several criteria, [redacted]. This was also the case with respect to the Stage 3 and bid selection process, where Eversource focused on aspects of the evaluation, evaluation metrics and assumptions that supported selection of Northern Pass. It was perhaps even more apparent when Eversource sought to keep NPT in play for contract negotiations even after the required New Hampshire siting approval was denied, with a remote possibility for a prompt reversal in order for Northern Pass to be able to build the project anywhere near the timeframe proposed.[37]

The issue of favoritism toward an affiliate's bid is clearly problematic both in theory, and in practice in this solicitation. Here, if it had not been for the removal of the NPT Hydro bid from consideration due to the siting denial, there might have been good reason to contest the final winner on these grounds.

[37] Revised Independent Evaluator Final 83D Report Confidential, at 48–49 (August 7, 2018).

Q. Did having affiliates on the Evaluation Team cause a problematic outcome?

A. The possibility that affiliate favoritism may have influenced the evaluation and selection process in some subtle way cannot be ruled out, even after NPT Hydro was removed from consideration. Project selection was ultimately made by the DOER, as the EDCs did not agree on the selection. Eversource and Unitil favored NPT Hydro, a bid affiliated with Eversource. National Grid favored NECEC Hydro. After the DOER selected NPT Hydro, this bid was removed from consideration and the non-affiliated NECEC Hydro bid was selected. But this does not eliminate all concern, because the DOER only discussed the NPT Hydro and NECEC Hydro bids in its selection letter.[38] It did not, for example, consider the high-scoring [redacted] discussed above for potential final selection. In the end, I do not have enough evidence to either exclude the possibility that affiliate favoritism may have affected bid scoring or selection, nor to conclude that the outcome was tainted by having affiliates on the Evaluation Team. Nonetheless, I would not recommend this for any future solicitations.

IX. SCALING OF QUANTITATIVE NET BENEFIT

Q. Please summarize your analysis and findings regarding the scaling of quantitative net benefit in Stage 2 and Stage 3.

A. The quantitative net benefit calculated for the proposals in the evaluation process is scaled onto a 75 point scale, with qualitative scoring accounting for up to another 25 points.[39] The scaling approach implies that the dollar value of each point depends on the particular values of the Net Total Benefit of the proposals, and the dollar value of a point affects the relative importance of quantitative vs. qualitative dimensions. The value of Net Total Benefit depends in turn on other analytic assumptions used in the evaluation. Thus using this scaling approach means that the choice of analytic assumptions could alter the relative importance of the qualitative vs. quantitative dimensions in the

[38] Exh. JU-10, at 1.

[39] Revised Independent Evaluator Final 83D Report, at 11 (August 7, 2018).

evaluation, potentially influencing the ranking of proposals in ways the Evaluation Team may not intend or even understand.

In this solicitation, quantitative and qualitative scores are negatively related among several of the higher-scoring proposals, with bids that scored high on quantitative measures scoring low qualitatively, and vice versa. For example, [redacted] had a Stage 3 quantitative score of 65.69 and a qualitative score of 19.13. Conversely, the NECEC Hydro bid had a higher Stage 3 quantitative score of 75, and a lower qualitative score of 15.63.[40] These are conditions under which the scaling approach, with its potential to influence the relative weighting of quantitative and qualitative factors, could influence the ranking of portfolios, and potentially the outcome of the solicitation. While the weighting would have had to change significantly in this case to influence the ranking of these two bids, this potential impact illustrates why this scaling approach should be reconsidered for future energy solicitations.

X. EVALUATION OF GWSA BENEFITS

Q. Please describe the metric used to evaluate the GWSA impact of the proposals.

A. The GWSA metric is designed to measure "the value of the Proposal's contribution toward meeting the Global Warming Solutions Act (GWSA) over and above compliance with the RPS and CES."[41] It was calculated in the 83D bid evaluations as the dollar value of the difference between the emissions decrease (relative to the Base Case) and the amount of RECs or CECs created by the project and used for compliance with the RPS or CES. According to the Evaluation Team (excluding National Grid), the RECs and CECs are subtracted off in an attempt to avoid double-counting the REC and CEC value of the projects.[42]

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[40] Exh. JU-6, at 25.

[41] *Id.*, at 31.

[42] Revised Independent Evaluator Final 83D Report Confidential, at 17–18 (August 7, 2018).

Q. Does the GWSA metric accurately reflect a proposal's contribution toward meeting GWSA requirements?

No. The GWSA requires an economy-wide reduction in GHG emissions. The appropriate metric regarding GWSA benefits involves the GHG reduction attributable to the project relative to the Base Case, without deducting the REC/CEC quantity.[43] This is the same position that National Grid has expressed.[44] Ultimately, the GWSA calculation error did not impact the ranking of NECEC Hydro as the highest ranked bid.[45]

Q. Does this conclude your current testimony?

A. Yes.

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[43] D.P.U. 18-76/18-76/18-78, Exh. AG-DM-1, at 17 (November 5, 2018).

[44] Revised Independent Evaluator Final 83D Report Confidential, at 18; D.P.U. 18-77, Exh. NG-TJB-1, at 6 (November 30, 2018).

[45] Exh. AG-2-2-C, Attachment.

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Dr. Dean Murphy is an economist with a background in engineering. He has expertise in energy economics, competitive and regulatory economics and finance, as well as quantitative modeling and risk analysis. His work centers on the electric industry, encompassing issues such as resource and investment planning (including power and fuel price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, competitive industry structure and market behavior, and market rules and mechanics. He has addressed these issues in the context of business planning and strategy, regulatory hearings and compliance filings, litigation and arbitration. Dr. Murphy has examined these matters from the perspectives of investor-owned and public electric utilities, independent producers and investors, industry groups, regulators, system operators, and consumers.

Dr. Murphy holds a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in Engineering-Economic Systems, both from Stanford University, and a B.E.S. in Materials Science and Engineering from the Johns Hopkins University. Prior to joining The Brattle Group in 1995, Dr. Murphy worked as an associate with Applied Decision Analysis, Inc.

AREAS OF EXPERTISE

- Resource Planning, Investment, and Forecasting
- Valuation for Energy Contract Disputes and Energy Asset Transactions
- Climate Policy Analysis
- Market Structure and Competitiveness
- Electricity Markets: Energy, Capacity, and Ancillary Services
- Procurement and Restructuring

EXPERIENCE

Resource Planning, Investment, and Forecasting

- For Manitoba Hydro, which is evaluating large investments in hydroelectric capacity and transmission expansion that would facilitate significant off-system sales, Dr. Murphy testified in a public hearing regarding the potential evolution of long-term power prices in the export market. He also developed a set of future scenarios based on the possible future evolution of several key market drivers, and forecast long-term market prices of power for each scenario. The scenario drivers included fuel prices, climate policy, coal plant retirements, renewable energy portfolio standards, and load levels, which are affected by price feedback and active demand management programs. This assignment has been repeated in subsequent years to understand how changing market drivers have influenced the potential range future of power prices.

- Dr. Murphy assisted the investor-owned utilities and regulators in Connecticut in complying with a legislative mandate to develop annual resource and procurement plans for the state, over several annual cycles. He focused particularly on the development of a set of scenarios against which alternative resource plans were evaluated, in order to illuminate the risks that might be associated with such plans. Key issues were potential federal climate legislation, natural gas prices, electricity demand, and demand side management strategies, and the complex interplay between these factors. He also evaluated energy security issues, including interactions between natural gas availability and electric reliability, as well as the potential role of nuclear power and emerging technologies, and their impacts on energy security.
- For a consortium in the initial stages of developing a major long-distance offshore DC transmission link designed to integrate multiple thousands of megawatts of new wind generation into several electric markets, Dr. Murphy performed a preliminary evaluation of the potential energy and capacity value of the project, and the approximate customer cost impact. These analyses were designed to assist in securing FERC approval for incentive rate treatment and abandoned cost recovery.
- For a merchant electric generator contemplating renewing or replacing an expiring output contract for a gas-fired generator, Dr. Murphy used a power market simulation model to forecast potential long-term power price trends under several scenarios involving fuel costs, generator retirements and renewable additions. Using the forecasts of potential long-term trends, he simulated the plant's short-term operations and its resulting financial performance. A key factor that had a significant effect on the plant's value in this analysis was characterizing the short-term volatility of power prices and the plant's ability to respond to capture short periods of attractive prices.
- Dr. Murphy developed a long-term forecast of Renewable Energy Credit (REC) prices across multiple states and interconnected electricity markets for a renewable generation developer. He considered state-level Renewable Portfolio Standard (RPS) requirements over time, as well as potential federal renewable requirements, looking at the cost and geographic availability of several potential renewable resource types and incorporating the effect of in-state requirements and alternative compliance payments.
- Dr. Murphy worked with a manufacturer of an energy storage technology to estimate its value on several dimensions across a range of potential applications. He used simulated charge-discharge cycles with historical prices in several markets to demonstrate not only the technology's energy and capacity value, but also its potential ancillary service and reliability benefits.
- For the Tennessee Valley Authority (TVA), Dr. Murphy assisted in the development of TVA's long-range Strategic Plan to deal with the development of competitive markets and a changing regulatory environment. He organized and performed numerous operational and financial analyses to understand TVA's performance under a wide variety of scenarios, and

integrated the results into a strategic framework, considering numerous potential outside influences (e.g., fuel price scenarios) and TVA responses (e.g., product unbundling or changes to TVA's pricing structure).

- For a utility client interested in building a merchant transmission line, Dr. Murphy evaluated the benefits of the line, designed and implemented an auction for the rights to use the line once constructed, and evaluated the bids received in the auction.
- For an entrepreneurial client investigating the opportunities for an electric storage technology in the deregulated electric market, Dr. Murphy developed a model that optimizes facility operations with respect to a set of forecasted electric commodity price profiles. The model was used to evaluate the technology's potential profitability on several different electricity systems. Commodity price profiles for each system were projected by integrating historical real-time system marginal cost data with the projected cost of additional capacity.

Valuation for Energy Contract Disputes and Energy Asset Transactions

- In a bankruptcy hearing, Dr. Murphy testified regarding the fair market value of the post-petition energy services (electricity, chilled and hot water) provided under contract by a creditor, in order to determine the debtor's responsibility for these costs.
- Dr. Murphy assisted the Staff of the New Hampshire Public Utility Commission in understanding the customer cost savings associated with a proposed utility divestiture of generating assets, as assessed by the utility. Key issues were whether the utility's analysis had correctly represented the operational benefits of the assets to customers in reducing their energy costs, and whether the capacity value of the assets had been accurately captured.
- Dr. Murphy assisted an Asian energy company in deepening their understanding of U.S. electricity and natural gas markets, as part of their plan to acquire assets in the region. Brattle helped to characterize market rules, including recent and proposed changes, in several regional ISOs, and how these rules may affect the financial opportunities of generators located in these ISOs.
- In a major arbitration dispute, Dr. Murphy assisted a merchant generating company in determining the value lost when the government agency with whom it had contracted to develop a gas-fired power plant decided to terminate the contract before the plant was completed. A key contributor to the value lost was the potential riskiness of the contract revenues. The contract's unusual structure insulated the merchant generating company from many of the risks normally associated with electricity markets, transferring these risks to the government agency over the contract's twenty-year term. This transfer of risk had a major effect on the value of the contract and thus on the magnitude of the arbitration claim.
- Dr. Murphy calculated the damages that resulted from several partial derates of a nuclear plant. The plant's owner had a unit-contingent output contract with a regional utility, and during the derate events, the plant delivered less power than it would have if it had operated normally. The utility had to replace the missing power (or equivalently, in some hours lost

the opportunity to resell the power) at higher market prices, and also lost some of the capacity value of the plant in the regional capacity market.

- For an investor exploring the acquisition of several gas-fired generators in markets without retail deregulation, Dr. Murphy helped to analyze the potential profitability of the assets under a range of assumptions about future natural gas and CO_2 allowance prices. Building on simulation results developed by another consultant, Dr. Murphy and the Brattle team were able to investigate several factors specific to the individual assets in question but not captured by a broad market simulation model.
- Dr. Murphy advised a committee of bondholders of a foreign subsidiary of a U.S. merchant power company that was undergoing restructuring. He advised regarding the value of several power contracts and assets in which the subsidiary had an interest, including a potential damage claim for a terminated long-term contract.
- In a dispute related to a terminated long-term power contract for an electric generating facility, the original contract contained clauses that may be triggered in the event of a default, based on the value of available replacement opportunities. For a group of bondholders of the facility, Dr. Murphy prepared an affidavit regarding the market value of the available replacement opportunities, and how they related to the facility's debt and operating costs.
- For an independent power producer, Dr. Murphy supported expert testimony to value damages due to termination of a long-term electric generator tolling contract, requiring power market forecasting and finance valuation techniques. Key to this case was the increase in risk caused by the loss of the contract, in an environment (following the collapse of the power sector in 2001) in which it was not possible to obtain a long-term replacement contract.
- For a bondholder of a power marketing company, Dr. Murphy evaluated the likely outcome of an arbitration hearing regarding damages due as a result of the termination of a long-term generation contract.
- For an independent power producer forced into bankruptcy by the rejection of a long-term power contract by its counterparty, Dr. Murphy assessed the economic damages due to the loss of the contract.
- In the context of a dispute over damages in a terminated gas supply contract, Dr. Murphy analyzed and provided written testimony regarding the potential to resell contracted natural gas that could not be utilized by the purchaser.
- For a utility client attempting to acquire a partially completed generating station to be held as a utility affiliate, Dr. Murphy analyzed the acquisition and affiliate transaction to determine whether there would be any violation of market power regulations.

Climate Policy Analysis

- With a Brattle co-author, Dr. Murphy evaluated the contributions of nuclear plants to the U.S. economy, as well as their environmental effects in reducing carbon and other emissions. This study used a power sector simulation model in combination with a dynamic input-output model of the U.S. economy, and found that the primary economic effect was that nuclear plants hold down power prices, reducing what all consumers pay for electricity. This savings, because it is significant and widespread, gives a substantial boost to the economy overall.
- Similar to the study described above, Dr. Murphy and his co-author have performed more detailed evaluations at the level of several individual states where nuclear is an important generation source. They have examined specific nuclear plants that are facing financial challenges to determine how these plants affect electricity prices, economic activity, and emissions of CO_2 and other pollutants within their state.
- Dr. Murphy helped the senior executives of a major coal producer to assess the long-term implications of U.S. climate policy on the electricity generating infrastructure. He characterized the effects of different potential policy structures and stringency on CO_2 prices, the economics of existing and future electric generating technologies, and likely generation expansion and retirement decisions over several decades, in order to forecast power sector costs and CO_2 emissions under these policy approaches. The project also involved estimating the long-term effects on CO_2 emissions in the transportation and other sectors.
- In seeking regulatory approval for a generation expansion plan, an investor-owned utility engaged Dr. Murphy to help understand the interrelationship between potential climate policy, the cost of natural gas, and the cost of generation technologies. He helped the client to incorporate these interacting factors into the client's existing planning models.
- Dr. Murphy assisted the executives of a major U.S. electric company in developing a proposed policy structure to mitigate greenhouse gas emissions (carbon dioxide) that would be economically efficient, effective, and manageable for industries and the economy. The research evaluated the impact on the electric industry, addressing overall, regional, and company-level effects of alternative policies and stringency of legislation. It also addressed the effects on consumers and other industries.

Market Structure and Competitiveness

- Dr. Murphy leads the Brattle team as the Independent Auction Monitor for the Southern Companies' Energy Auction, which has been in operation since April 2009. The auction is governed by FERC tariff, which is designed to mitigate potential market power. The tariff requires Southern to administer auctions for standard day-ahead and hour-ahead energy products for delivery "Into SoCo," and to offer its available capacity at a cost-based rate into these auctions. The Brattle team has developed data structures, monitoring protocols and automated tools to track Southern Companies' load forecasting, purchases and sales, outage declarations, and unit capabilities and costs. On this basis, Brattle monitors Southern's offers into each auction to ensure in compliance with the FERC cost-based tariff. Brattle also ensures that the auction functions and clears properly, and monitors the behavior of third party participants in the Auction. Monitoring is done on a daily basis, with reports annually on auction performance and tariff compliance to the FERC.

- Dr. Murphy participated in a market power analysis in the context of a major electric utility merger, focusing on the analysis of how transmission availability and constraints affect the potential for the exercise of market power. He coordinated the collection and interpretation of transmission data from numerous utilities. To correct for the inherent data weaknesses, he designed and oversaw a separate, integrated transmission modeling effort to determine the ability of the grid to support short-term power transactions.
- Dr. Murphy evaluated the potential anti-competitive effects of a merger between a major regional natural gas company and an electric utility in a region where electric generation is highly dependent on natural gas as a fuel. He examined the potential for the merged company to exercise vertical market power by manipulating the price of natural gas to influence the competitive price of electricity, and what effect that would have on the competitiveness of the electric market.
- In several other cases, Dr. Murphy analyzed whether proposed energy company mergers or acquisitions would create the potential for the exercise of horizontal and/or vertical market power, developing mitigation strategies where appropriate.
- In a proposed merger involving an East Coast electric utility, Dr. Murphy assisted senior management in evaluating the effects of retail access on the financial health of both the client company and the potential merger partner, taking into account projected operating costs, the timing of open access, market prices for power, customer loss, and stranded cost recovery.

Electricity Markets: Energy, Capacity, and Ancillary Services

- For a competitive energy supplier and generation owner, Dr. Murphy analyzed the role of demand-side resources, such as interruptible load, in an ISO-sponsored capacity market. He examined the extent to which demand-side resources could supply capacity needs, and the risk that frequent utilization of such resources might dissuade their participation in the market.
- Dr. Murphy assisted a U.S. electric ISO with understanding the implications of expanding ISO membership on the ancillary service requirements of both existing and proposed new ISO members.
- For a major hydroelectric generator, Dr. Murphy assessed the planning and decision system used to determine when and how to allocate energy (e.g., in spot or forward markets). Both value and risk implications are important, and both are affected by large uncertainties and correlations in forward and spot prices, weather, energy (water) availability, and non-electric restrictions, among other factors. Dr. Murphy developed a number of recommendations for improving the accuracy of the utility's forecasts and models, thus improving the decisions based on them.

- Dr. Murphy assisted a major Northwest hydroelectric generator in understanding the role of electric ancillary services, including voltage control and reserve generating capacity, in a restructured electric market. Issues included the interaction between the energy market and the ancillary services market, and the implications of embedded cost pricing as compared to competitive market-based pricing of ancillary services. This engagement involved coordinating work across the generation and transmission groups within the client organization to determine appropriate tariff rates for these ancillary services.
- In a series of projects for the Electric Power Research Institute (EPRI), Dr. Murphy examined the potential for hydroelectric generators to provide reserve generating capacity in a restructured electricity market. Dr. Murphy developed an economic framework for understanding how the markets for electric energy and reserve capacity interact, and whether hydro's technical advantages in providing reserve capacity are likely to make reserves a natural niche market for hydro. Dr. Murphy also evaluated the probable effect of industry restructuring on the value of hydroelectric power assets, taking account of their technical capabilities to store and release energy according to market conditions, and provide ancillary services.
- For a utility client, Dr. Murphy evaluated the effects of pricing structure on demand for electricity, load shape, and revenues. Changes in pricing structure can stimulate electric demand, increasing revenue without increasing the per unit electricity price. This may be a useful mechanism for mitigating a utility's stranded costs as the industry is restructured.

Procurement and Restructuring

- Dr. Murphy assisted the Staff of the New Hampshire Public Utility Commission in an analysis of customer savings that would result from the divestiture of a New Hampshire utility's remaining generation assets. Concerns and disagreements about an earlier analysis had led to disputes over whether to move ahead with the divestiture, including a split within the PUC Staff. Dr. Murphy's analysis and his testimony before the NHPUC helped to unite the parties in support of moving ahead with the divestiture.
- Dr. Murphy assisted an electric utility client with regulatory strategy regarding a state proposal to allow utilities to earn a "premium" on long-term power purchases, in order to account for the risks involved in committing to purchased power contracts.
- Dr. Murphy assisted a California utility in hearings before the California Public Utilities Commission regarding the establishment of a process for the California utilities to resume power procurement in the wake of the western power crisis of 2000-2001.
- In several engagements, Dr. Murphy assisted utility clients facing potential customer loss through municipalization. As part of these analyses, he determined the stranded costs (unrecovered investment) that municipalization would involve.
- Dr. Murphy assisted an electric utility client in planning for industry restructuring by characterizing alternative paths that restructuring could take, and developing potential strategies that respond to a competitive market and regulatory changes. He developed a

detailed spreadsheet-based system and financial model to evaluate the effects of various strategies and scenarios on the magnitude of stranded costs and the client's financial performance. This modeling effort required analysis and forecasting of the changes in the structure of the market for electricity, as well as probable regulatory changes and their implications. The model served as the basis for several follow-up studies addressing more specific decisions and issues, performed by the client and by The Brattle Group.

Other Engagements

- In eight different litigation cases involving 14 nuclear reactors at 11 plants, Dr. Murphy has evaluated the Department of Energy's (DOE) failure to honor its commitment to remove spent nuclear fuel from U.S. nuclear plants. He led the analytical effort in all of these cases, and provided expert witness testimony in one of them, to characterize how the government should and would have carried out its contractual obligation. Dr. Murphy simulated a nationwide market for the exchange of spent fuel removal rights, as was enabled by the contract, which made it possible to determine the timing of spent fuel removal from each individual plant in the non-breach world. The results of these analyses were used to support the damage claims of the client nuclear owners for ongoing spent fuel storage costs that would have been unnecessary if the DOE had performed its contract obligations.
- Dr. Murphy assisted in a review of the auction of an ownership share in a nuclear generating plant, in order to determine whether the sale was performed using commercially reasonable means to ensure mitigation of the regulated seller's stranded costs.

PUBLICATIONS AND PRESENTATIONS

Murphy, Dean M, Mark P. Berkman. Comment on Acadian Consulting Group's " Report on Nuclear Portion of Senate Bill 877" Prepared for PSEG and Exelon, February 12, 2018

Berkman, Mark P., Dean M. Murphy. "Salem and Hope Creek Nuclear Power Plants' Contribution to the New Jersey Economy," Prepared for PSEG and Exelon Generation, November 2017. This report finds that the Salem and Hope Creek nuclear power plants make substantial contributions to the environment, reducing CO_2 emissions by 14 million tons annually. They also keep New Jersey power prices lower by $400 million per year, which boosts New Jersey's GDP by $800 million.

The Future of the U.S. Coal Generation Fleet., by Metin Celebi, Marc Chupka, Dean M. Murphy, Samuel A. Newell and Ira H. Shavel, Excerpt from the Fall 2017 newsletter for the ABA Antitrust Section, Transportation and Energy Industries Committee, November 30, 2017. The article analyzes the decline in coal-generated electricity in North America and discusses the implication of a recently proposed U.S. Department of Energy (DOE) rule that could shield certain coal and nuclear plants from competitive market forces.

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REDACTED

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of a long-term contract for procurement of Clean Energy Generation, 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, each d/b/a National Grid for approval by the Department of Public Utilities of a long-term contract for procurement of Clean Energy Generation, 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 by the Department of Public Utilities of a long-term contract for the procurement of Clean Energy Generation, 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**

REBUTTAL TESTIMONY
OF
DEAN M. MURPHY

Dated: **February 15, 2019**

REDACTED

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Dean M. Murphy. I am a Principal with The Brattle Group in the Boston office, located at One Beacon Street, Boston, Massachusetts 02108.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes. I submitted direct testimony in this proceeding on December 21, 2018, on behalf of the Massachusetts Attorney General's Office. In that testimony, I addressed (a) that the proposed Power Purchase Agreements ("PPAs") with H.Q. Energy Services (U.S.) Inc. ("HQ") do not provide incremental hydroelectric generation as defined in the RFP and (b) the concepts of additionality and offsetting greenhouse gas emissions. I provided recommendations on (c) potential changes to the proposed PPAs to ensure incrementality, (d) project selection, (e) evaluation team composition, (f) scaling of the quantitative net benefit and (g) the evaluation of the GWSA benefits.

Q. Please clarify how you will be referring to the various parties throughout your testimony.

A. The Massachusetts utilities, Eversource, Unitil, and National Grid, are counterparties to proposed PPAs with HQ, and proposed Transmission Service Agreements ("TSAs") with Central Maine Power Company ("CMP"). I collectively refer to the PPAs and the TSAs as "the Contracts."

Due to the number of organizations involved in this proceeding, I will use the following taxonomy with regard to Hydro-Québec. For all matters directly related to the bid, I will refer to Hydro Renewable Energy ("HRE"), a wholly owned subsidiary of Hydro-Québec which was the bidding party. For matters directly related to the PPAs, I will refer to H.Q. Energy Services (U.S.) Inc. ("HQ"), which is the Hydro-Québec counterparty to those

PPAs. When referring to documentation from Hydro-Québec and not from its subsidiaries (*e.g.*, HRE or HQ), I will refer to it directly as Hydro-Québec.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to several issues raised in the rebuttal testimony offered by Jeffery S. Waltman (Eversource), Nicolas H. Baldenko (Eversource), Timothy Brennan (National Grid), and Robert S. Furino (Unitil), collectively the "EDCs." I specifically respond to the their points on 1) the requirements of the proposed PPAs to provide hydro generation that is incremental, 2) the evaluation of MCPC 3 and GSPL II in Stage 3, and 3) the potential for future high value clean energy projects in future solicitations.

III. THE PPAS DO NOT ENSURE INCREMENTAL HYDRO GENERATION AS REQUESTED IN THE RFP AND OFFERED IN THE NECEC HYDRO BID

Q. Please summarize your response to the EDCs' rebuttal testimony regarding the PPAs' requirements for Incremental Hydroelectric Generation.

A. In my direct testimony, I showed that the proposed PPAs with HQ do not require the power delivered under the PPAs to be fully incremental to historical energy deliveries, as requested in the RFP.[1] The New England Clean Energy Connect ("NECEC") Hydro bid offered to provide 9.55 TWh of energy ("Contract Energy") that is incremental to historical deliveries, and the bid was evaluated and ultimately selected on this basis. The PPAs operationalize this incrementality requirement in Exhibit H first by defining "Baseline Hydroelectric Generation Imports," deliveries from HQ to New England that are outside the 83D PPA ("Baseline Hydro"). Exhibit H then establishes the "Minimum

[1] Exh. AG-DM, at 5-14.

Required Baseline Hydroelectric Generation Imports," ("Minimum Baseline") the required level of Baseline Hydro below which contract payments are penalized for under-delivery, to ensure that the Contract Energy will actually be incremental.[2] However, the Minimum Baseline values specified in Exhibit H to the PPAs fall far short of the historical average deliveries solicited in the RFP. In their rebuttal testimony, the EDCs have improperly re-interpreted the incrementality solicited the RFP, claiming that a very large share of historical imports are not appropriate for inclusion as Baseline Hydro. In effect, they imply that the appropriate Minimum Baseline might be near zero, pointing out that the PPAs offer stronger protections than this. The PPAs, particularly this Minimum Baseline requirement, should be amended to reflect historical average deliveries as solicited in the RFP, offered in the bid, and evaluated and selected.

Q. How does the RFP define Incremental Hydroelectric Generation?

A. The RFP states:

> "Incremental Hydroelectric Generation" means 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.[3]

The form PPA that accompanied the RFP adds specificity, identifying 2014-2016 as the 3 year historical period for the average.[4] Incremental Hydroelectric Generation or "Incremental Hydro" is apparently defined in this way to use historical average hydro deliveries as a proxy for what future energy deliveries from HQ would be in the absence of these PPAs. Thus, the incrementality requirement ensures that the Contract Energy

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[2] The three PPAs use slightly different terms to refer to this Baseline concept, and they set the Minimum Baseline energy at different levels, as discussed below. Eversource and Unitil PPAs do not use the term "Minimum Required Baseline Hydroelectric Generation Imports." Instead the PPAs require a minimum level of "Baseline Hydroelectric Generation," against which damages are measured. *See*, *e.g.*, Exh. JU-3-A, at 86.

[3] Exh. JU-2, at 5.

[4] Draft Power Purchase Agreement, at 7 (May 12, 2017).

will be additional hydro energy, relative to HQ deliveries to New England without the Contracts.

Q. What is the Minimum Baseline requirement in the proposed PPAs, and how does this relate to historical deliveries?

A. As I outlined in my direct testimony, Exhibit H of each of the PPAs establishes an annual Minimum Baseline that must be delivered to New England in addition to the Contract Energy. The Minimum Baseline quantity differs across the PPAs. The National Grid PPA sets it at 9.45 TWh, allowing several adjustments that can reduce (but not increase) this amount.[5] The Eversource and Unitil PPAs set the Minimum Baseline at 3.0 TWh, with adjustments only for Force Majeure events.[6] Both of these Minimum Baseline requirements are far below the level of historical deliveries into New England, which averaged 14.8 TWh in 2014 through 2016.[7]

Q. Do the EDCs acknowledge that the Appendix H requirements of the PPAs are less stringent than the definition of Incremental Hydroelectric Generation in the RFP?

A. No. The EDCs claim that the PPAs contain "an appropriate threshold for the delivery of additional quantities of hydroelectric power"[8] despite the obvious discrepancy between the 14.8 TWh historical average and the much lower Minimum Baseline values of the PPAs, either 3.0 or 9.45 TWh. In fact, the EDCs claim that the incrementality requirements of the proposed PPAs are actually <u>stronger</u> than those of the RFP:

> "In fact, the Baseline Hydroelectric Generation provisions in Exhibit H negotiated by each Distribution Company provide greater protections than the

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[5] Exh. JU-3-B, at 92-95.

[6] Exhs. JU-3-A, at 86-87; JU-3-C, at 84-86.

[7] Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE), Appendix B to the RFP (Confidential), Section 4.2, at 19; Exh. NEER-1-8.

[8] Exh. EDC-RB-1, at 21.

> terms included in the form PPA for firm hydroelectric power, which was issued as part of the RFP."[9]

Q. How do the EDCs explain the gap between the PPA requirements for Minimum Baseline and the 14.8 TWh of historical average generation?

A. The EDCs begin by identifying the difficulty with establishing the differences attributable to "otherwise expected delivery." In this context, to reconcile the Exhibit H requirements of the proposed PPAs with the language of the RFP and bid, the EDCs appear to put great weight on the "and/or otherwise expected" qualifying phrase in the definition of Incremental Hydroelectric Generation ("as compared to the 3 year historical average <u>and/or otherwise expected</u> delivery of hydroelectric generation" [emphasis added]).[10] They give this qualifier more weight than the primary descriptor, the "3 year historical average." In doing this, they redefine the concept of incrementality, by explicitly excluding most of the historical energy deliveries from HQ into New England:

> …current deliveries may be non-firm and result from spot market trading decisions or may be under existing contracts that may not be renewed or extended. Thus, there are current deliveries that may not be appropriate for inclusion in the 'baseline' to which future deliveries are compared.[11]

[redacted] By redefining the Minimum Baseline requirement to exclude non-firm historical deliveries, the EDCs effectively claim that the clean energy deliveries under the PPA should be allowed to <u>substitute</u> for [redacted] historical deliveries, rather than being incremental to <u>total</u> historical deliveries. This appears to explain how the EDCs arrived at the low Minimum Baseline requirements in the PPAs, and their claim that these requirements are more stringent than the RFP. But the definition of Incremental Hydroelectric Generation established in the

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[9] Exh. EDC-RB-1, at 21.

[10] Exh. JU-2, at 5.

[11] Exh. EDC-RB-1, at 17.

[12] Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE), Appendix B to the RFP (Confidential), Section 4.2, at 19.

RFP made no mention of excluding non-firm, spot, or any other types of transactions when determining the historical average deliveries that would set the baseline. [redacted].[13] The EDCs' revised interpretation of Incremental Hydro effectively says that the Contract Energy must be incremental to historical deliveries, though ignoring the vast majority of historical deliveries. This interpretation holds HQ to nothing beyond its existing contractual obligations to other parties, and makes the concept of Incremental Hydro essentially meaningless.

Q. If the EDCs' interpretation of the "and/or otherwise expected" phrase in the RFP language is not correct, how should it be interpreted?

A. The RFP does not specify how this phrase should be interpreted, but the plain language suggests that this 3-year historical average is at least a good starting point for what would be reasonably expected to occur absent the Contracts. Including the "and/or otherwise expected" phrase acknowledges that in at least some circumstances, the 3-year average might <u>not</u> be the expected amount. This can be understood as allowing for the fact that HQ may not be able to achieve that historical average in each and every year, due primarily to normal variability in hydrologic conditions. In a dry year where Hydro-Québec is unable to generate as much hydroelectric power, the reasonable expectation for HQ's deliveries into New England, absent the Contracts, might be less than 14.8 TWh. A high-water year might lead to a higher expectation. Over the three historical years used in the average, 2014-2016, HQ's deliveries to New England ranged from [redacted]

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[13] [redacted]

[redacted];[14] they were 17.9 TWh in 2017.[15] But on average over time, HQ should be able to match the 14.8 TWh historical deliveries. The addition of the NECEC transmission project will facilitate an increase in the amount of power that can be delivered to New England, enabling 9.55 TWh of Contract Energy in addition to the (average) 14.8 TWh of Baseline Hydro. There would have been no point in the RFP specifying the use of historical average deliveries in defining Incremental Hydro, particularly specifying which 3 years to use for the average, if this amount was not intended to guide expectations. The EDCs' interpretation that the vast majority of historical deliveries should be excluded from the Minimum Baseline, strips all meaning from the requirement that existing hydro bids should provide incremental deliveries.

Q. Have the EDCs provided any evidence that future deliveries of electricity from HQ to New England, absent the Contracts, would be expected to be lower than the three-year historical average?

A. To my knowledge, the EDCs have not expressed any particular view of how the "otherwise expected" deliveries might differ from the historical average. Their rebuttal testimony, in describing the rationale for the 9.45 TWh Minimum Baseline value used in the National Grid PPA, did claim that it would be difficult to determine the "otherwise expected" deliveries, and named some factors that might affect future deliveries, including the addition of offshore wind in Massachusetts (which might reduce demand for non-firm and short-term HQ resources), or significant changes in market conditions and/or energy policies in HQ's neighboring control areas (which could work in either direction).[16] Ultimately, "National Grid determined that it was reasonable to move forward

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14 [redacted]

15 Hydro-Québec's 2017 annual report states that exports to New England were 52% of the 34.4 TWh of exports. Hydro-Québec Annual Report 2017, at 11.

16 Exh. EDC-RB-1, at 23-25.

based on HQUS's agreement to the 9.45 TWh Minimum Required Baseline Hydroelectric Generation Imports."[17] It is not surprising that HQ would agree to this value, of course, and even less surprising that it would agree to the 3.0 TWh Eversource and Unitil value. However, from the perspective of Massachusetts ratepayers, HQ's willingness to agree to these values would not seem to be a good justification for dramatically relaxing, and potentially eliminating, the requirement that contract deliveries be incremental to historical deliveries.

Q. What explanation did the EDCs provide for the Eversource and Unitil Minimum Baseline values being lower than National Grid's?

A. The EDCs appear to provide multiple interpretations. According to the IE's report, National Grid was interested in negotiating a minimum baseline clause while neither Unitil nor Eversource thought it was necessary.[18] The IE also indicated that the Unitil and Eversource provisions were negotiated to be [redacted][19] Eversource and Unitil state that the cover damages were priorities over other issues, including incrementality.[20] Later, they asserted that the addition of Appendix H and the requirement for a baseline of 3.0 TWh was negotiated as a further requirement for delivery without making the administration of such a provision "problematic".[21]

Q. In the quantitative evaluation of the NECEC Hydro project, did the Evaluation Team model imports from Québec at the Minimum Baseline levels specified in the proposed PPAs?

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[17] Exh. EDC-RB-1, at 25.

[18] Independent Evaluator Final 83D Report Redacted, at 51 (July 24, 2018).

[19] [redacted] Revised Independent Evaluator Final 83D Report Confidential, at 53 (August 7, 2018).

[20] Exh. DPU 1-23.

[21] Exh. NEER-1-9, at 1.

A. No. The quantitative evaluation of the NECEC Hydro project is consistent with fully Incremental Hydro. In its modeling, TCR assumed that the interchanges with Québec would reflect 2012 levels, noting that 2012 was reflective of 2014-2016, the years specified in the form PPA for incrementality.[22] There are two other paths through which Hydro-Québec can deliver electricity into the New England ISO – through New Brunswick and through New York. TCR modeled import levels from New Brunswick to New England at 2016 levels and deliveries from New York to Massachusetts were dispatched on an hourly economic basis in the analysis.[23]

Q. Would the benefits attributable to the NECEC Hydro project in the evaluation be affected if the project had been evaluated using the Minimum Baseline deliveries reflected in the PPAs, rather than assuming it would be fully incremental as it was actually evaluated?

A. No, almost certainly not. The quantitative indirect benefits associated with GHG abatement were assessed by comparing a model run including the NECEC Hydro project with a "Base Case" run without the NECEC Hydro project.[24] If the power flows from Québec into New England were reduced in the analysis to mirror the Minimum Baseline requirements of the proposed PPAs, alternative generation would be needed to serve Massachusetts, altering the project's GHG effects and the impact on the Massachusetts GHG inventory. The extent of the changes would depend on the resource mix that replaced the reduction in HQ deliveries. Accurately quantifying the impact to the benefits would require a new Enelytix run performed by TCR; to my knowledge, such a sensitivity case has not been analyzed.

Q. Can you estimate the potential GHG impact of lower deliveries from HQ?

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22 Exh. JU-6, at 142.

23 *Id*.

24 The base case was common across all projects evaluated.

A. I can at least establish some reference points for the potential GHG impact. The Global Warming Solutions Act ("GWSA") compliance benefits reflect the GHG reductions attributable to the project, and are likely to decrease with lower overall deliveries from Québec.[25] The low Minimum Baseline values in the PPAs reflect considerably less clean energy from HQ than the fully incremental deliveries evaluated; 11.8 TWh less with the Eversource and Unitil Minimum Baseline, or 5.35 TWh less with the National Grid value.[26] Lower deliveries would need to be made up with alternative generation, at least some of which would almost certainly be fossil, leading to greater overall Massachusetts GHG emissions.

In Figure 1, I provide an indicative estimate of the impact using three alternative assumptions about the generation that might replace the historical HQ generation not required by the proposed PPAs. I consider replacements consisting of zero-emission energy, energy equivalent to average Massachusetts imports, or a natural gas combined cycle unit. I estimate the amount of energy replaced at the National Grid Minimum Baseline (rows [2] – [4]), and again at the Eversource/Unitil Minimum Baseline (rows [5] – [7]). Of course, rows [2] and [5] show that replacement by zero-emissions generation substitutes one clean energy source for another, with no emissions impact.[27] If the lower HQ deliveries are replaced by increasing imports to Massachusetts from regions other than Québec, the replacement generation would have relatively low emissions reflecting the generation sources in those regions. At the higher National Grid

[25] The GWSA metric as employed in this solicitation also includes a component related to the number of RECs or CECs used for CES compliance, and I do not agree that this component should be included in the GWSA metric, as discussed in my direct testimony. Exh. AG-DM, at 27. For the purposes of this discussion, I have assumed that there is no adjustment to the number of CECs provided by the NECEC Hydro project for CES compliance.

[26] As discussed previously, this 5.35 TWh is lower bound on the decrease in clean energy deliveries that would be assured. National Grid's 9.45 TWh Minimum Baseline may be further reduced by several factors.

[27] The emissions factor used for Québec in the inventory model used by TCR is approximately [redacted] MMT CO_2e/MWh. For the purposes of illustration, I have assumed that a hypothetical Zero-Emitting generator would have this same *de minimis* emissions rate.

Minimum Baseline, the 2 million tons per year CO_2e abatement of a fully incremental NECEC Hydro project would drop to 0.8 million tons per year, just 41% of its former value. The Eversource/Unitil Minimum Baseline is so low that it would allow HQ to actually decrease clean energy deliveries relative to the historical average, wiping out the project's GHG offsets entirely.

Figure 1: Indicative Changes in GHGs Attributable to Massachusetts

[redacted]

Sources and Notes: Baseline Hydro imports into New England from Exhs. JU-3-A through C. Massachusetts average imports emissions rate is calculated as the weighted average emission rate for modeled imports excluding those from Québec (based on Att. B2 - NECEC Hydro Stage 3.xlsx, HSCI). Average emissions rate for a gas combined cycle is taken from *Environment Baseline, Volume 1: Greenhouse Gas Emissions from the U.S. Power Sector* (US Department of Energy, June 2016). Reductions in flows are assumed to occur on the direct interfaces between Hydro-Québec and New England, with flows through other regions being unaffected.

If instead of relatively low-emitting imports, the lower HQ deliveries were replaced by an efficient natural gas combined cycle plant (probably a better estimate of the actual marginal replacement in the region), all of the GHG emissions reductions of a fully incremental project could be cancelled out under either the National Grid or the Eversource/Unitil Minimum Baseline values. This is not to say that the project would necessarily cause an increase in emissions, since deliveries from HQ are unlikely to actually be <u>lower</u> with the NECEC Hydro project than without (though replacement with all gas could cause emissions to rise even if HQ deliveries increase overall. But this does illustrate the fact that if the PPA Minimum Baseline values do not <u>require</u> HQ's contract deliveries to be fully incremental, the GHG benefit attributed to the project and anticipated by ratepayers can be put in serious jeopardy.

Q. At what point during the solicitation process did the discrepancy arise between the RFP's definition of Incremental Hydroelectric Generation and the proposed PPAs?

A. It apparently arose at the last stage of the process, in the drafting of the PPAs. The definition of Incremental Hydroelectric Generation was stated in the body of the RFP, and again in the form PPA issued with the RFP, where it was given greater specificity by identifying 2014 to 2016 as the specific historical years to be used.[28] In its bid, HRE proposed to meet this definition, reflected particularly in the fact that [redacted].[29] The Evaluation Team evaluated the proposal assuming that the energy provided would be fully incremental; they ultimately selected the NECEC Hydro project as the winning bid on this basis. Up through this point, there was no apparent dispute or question about what the RFP had requested or what the NECEC Hydro bid had offered, and thus full incrementality with respect to historical generation was an integral component of the bid, similar to the bid price. In fact, if the bid had proposed to provide only the weaker version of incrementality now reflected in the proposed PPAs, the Evaluation Team should have considered disqualifying it altogether for failing to offer Incremental Hydro.

It was only in the final stage of the process, in drafting the PPAs, that the Incremental requirement was loosened. This late change, after bid selection, to lower the Minimum Baseline requirement fundamentally alters the terms of the agreement in a way that unfairly disadvantages the EDCs and their customers, who would pay for the fully incremental deliveries solicited but might receive substantially less. It might also be unfair to competing bidders, who structured their bids on the reasonable presumption that any competing hydro bids would be required to provide fully incremental generation.

[28] Exh. JU-2, at 5; Draft Power Purchase Agreement at 7 (May 12, 2017).

[29] [redacted]

Q. Is HQ able to provide energy that is fully incremental with respect to historical average deliveries?

A. The EDCs, in their rebuttal testimony, go to some length to argue that HQ is able to provide incremental generation to New England, and that the Contracts will provide it.[30] They refer to several statements in the HRE's bid that indicate that power flows from HQ into New England are currently limited by the transfer capability of the direct interties between the control areas.[31] By relieving this limitation, the new NECEC transmission link will enable the delivery of "a vast amount of clean energy generation capacity" into New England as Incremental Hydroelectric Generation.[32] The EDCs also cite a brief two-page letter from Hydro-Québec that was supplied in the Maine Public Utility Commission ("MPUC") Docket No. 2017-00232.[33] This letter claims that existing transmission limitations caused Hydro-Québec to spill water equivalent to 4.5 TWh in 2017, and 10.4 TWh in 2018 (through December 14), implying that the 2018 level of spillage could persist in the future. The letter also cites an independent meteorological study that indicates that in the 2050 horizon, average water flows in northern Québec are expected to increase on the order of 12%, which could lead to additional spilling (though 2050 is outside the PPA term).[34] The implication is that if additional transmission capability was available, this spilled water could instead be used to generate and export power to New England. The EDCs also note that Hydro-Québec recently added a new generation project in 2017 and will add another in 2020,[35] further increasing the amount of energy that can be generated, if there is the transmission capability to export it.

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[30] EDC-RB-1, at 15-16, 18-20.

[31] EDC-RB-1, at 18-20 and Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE) Confidential, at 3, 19-20.

[32] EDC-RB-1, at 18-19, referring to HRE bid excerpts, Exhs. EDC-RB-3 and EDC-RB-4.

[33] EDC-RB-5.

[34] EDC-RB-5.

[35] EDC-RB-1, at 20.

Q. Does this mean that HQ would be able to provide fully Incremental Hydro as solicited by the RFP?

A. The statements by HQ and the EDCs do not make this entirely clear. Both the EDCs and the bidders have been vague, 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. They offer apparent reassurance that HQ would be able to provide sufficient generation to New England, without being specific about what that means. While stating that added transmission capability will increase the amount of power that is deliverable to New England, they offer no analysis or even an unambiguous statement regarding whether the total amount of energy delivered would or could equal the full 9.55 TWh of the Contract Energy, in addition to the 14.8 TWh of the relevant historical average. So ultimately, it is not entirely clear whether the EDCs and/or the bidders are claiming that HQ will be able to deliver fully incremental hydro, as solicited and as offered. In this respect, it would be helpful if HQ would make a clear statement about how much energy it can provide. Clearly, though, the proposed PPAs do not <u>require</u> HQ to deliver fully Incremental Hydro, with respect to historical average deliveries.

Q. Do HQ's actual historical exports to New England offer any insight?

A. HRE disclosed in its bid its historical deliveries to New England for years 2014-2016, averaging 14.8 TWh per year;[36] and the Hydro-Québec 2017 Annual Report cites 17.9 TWh of deliveries into New England in that year.[37] I do not have the details of Hydro-Québec's calculations, but the New England ISO publishes information on historical

[36] Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE) Confidential, Section 4.2, at 19; Exh. NEER-1-8. HRE reported its total deliveries from Québec to New England through the Phase II, Highgate and Derby interties or by wheeling through the New Brunswick and NYISO control areas in 2014, 2015, and 2016.

[37] Hydro-Québec 2017 Annual Report, at 11 (calculated as New England's 52% share of 34.4 TWh total sales outside Québec). The EDCs stated in rebuttal testimony that 2017 deliveries were 18.2 TWh, though the exhibit they cite references Hydro-Québec's export <u>capabilities</u>, not actual exports. Exh. EDC-RB-1, at 20, *citing* Exh. EDC-RB-5.

flows across the direct interface between Hydro-Québec and New England (the Phase II and Highgate interties), which provides additional perspective. Figure 2 below shows the ISO-NE data on flows on the direct interface (blue line) for the past 10 years, and overlays the available information from Hydro-Québec (bars). Comparing these data sources for the 4 years where they overlap, the average annual flow across the direct interface (ISO-NE data) in these years was about 13.26 TWh, which is about 2.29 TWh below the average 15.55 TWh of reported sales into New England. This difference is not surprising; HRE notes that Hydro-Québec sales into New England include power flows [redacted].[38]

Figure 2: Historical Deliveries from Québec into New England

[redacted]

Sources and Notes: Imports shown in the blue line are the sum of imports over the Highgate and Phase II interties, as reported by ISO-NE in Net Energy and Peak Load datasets. Derby intertie is not included in imports reported by ISO-NE.

The red horizontal line represents the three year average imports for 2014-2016 as reported by HRE in Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE) Confidential, Section 4.2, at 19; and Exh. NEER-1-8. The light blue bars represent HQ delivery of energy into New England as reported by HRE in their bid and in rebuttal testimony (Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE) Confidential,

[38] Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE) Confidential, Section 4.2, at 19.

Section 4.2, at 19 and Exh. EDC-RB-1, at 20) for 2014-2016. The 2017 deliveries are reported in Hydro Québec's 2017 Annual Report. The gray dashed lines are the Minimum Baseline values from the proposed PPAs.

Q. Is there other information that is relevant to the question of whether HQ would be able to provide fully incremental generation?

A. Yes. Hydro-Québec has been adding significant amounts of generation during this timeframe. After the 2014-2016 historical period that should determine the Minimum Baseline, and before the anticipated 2023 start of delivery on the PPA, HQ is adding two more generating stations as part of its Romaine complex. The 395 MW Romaine 3 station came online in 2017, and the 245 MW Romaine 4 station is anticipated in 2021.[39] These two units account for 41% of total Romaine capacity; if they provide a similar share of its 8 TWh energy, it will give HQ an additional 3.3 TWh of annual energy, on top of what it has been spilling, with which to provide Contract Energy that is fully incremental to the historical deliveries of 2014-2016.

Q. What do you conclude about whether HQ would be able to provide fully incremental generation, defined by the historical average?

A. 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. (Though time averaging or some other mechanism would likely be advisable to accommodate variable hydrologic 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-Québec has implied, at least, that it can provide incremental

[39] *See* https://www.hydroquebec.com/projects/romaine.html.

hydro to New England. So there is no evidence to suggest that HQ would be unable to provide fully Incremental Hydro.

Q. If HQ were to confirm unambiguously that it will be able to provide fully incremental hydro as solicited by the RFP, would that resolve your concerns in this regard?

A. No, not by itself. Whether HQ is <u>able</u> to deliver incremental energy is important, of course, but is not the only relevant question. Equally important is whether the proposed PPAs <u>require</u> HQ to deliver fully incremental energy. Although the EDCs claim that HQ has made a commitment to deliver incremental energy,[40] the proposed PPAs as currently written do not require incrementality.

Q. What would be the impact if the PPAs do not require HQ to deliver the full historical average energy as Baseline Hydro?

A. If the PPAs do not <u>require</u> HQ to deliver the full historical average as Baseline Hydro, then it becomes HQ's option whether to provide the product that was solicited in the RFP and offered in the bid. HQ could, at its discretion, <u>substitute</u> Contract Energy for historical energy deliveries to New England, rather than providing Contract Energy that is incremental on top of the historical average. That is, it could shuffle existing resources from historical Baseline Hydro deliveries to the new contract sales into New England. Because it would not be required to sell the <u>full</u> historical average generation into New England as Baseline Hydro, it would then be able to sell a portion of this energy into other markets, perhaps earning a clean-energy premium on that alternative sale. Under the current PPAs, HQ would nonetheless be paid the full PPA price on the entire 9.55 TWh of Contract Energy.

[40] *See*, *e.g.*, Exh. EDC-RB-1, at 25-26 describing HQ's "commitments under Section 4.2 of its bid to deliver incremental hydroelectric generation." Section 4.2 states that HRE <u>could</u> provide incremental energy.

Q. Would the need for the NECEC transmission project be affected if HQ does not provide fully incremental energy?

A. The NECEC transmission link might not be necessary to deliver the amount of power required by the PPAs, since they do not require fully incremental hydro deliveries. The Eversource and Unitil PPAs require total deliveries to New England of only 12.55 TWh (9.55 TWh of Contract Energy, plus 3.0 TWh Minimum Baseline). The National Grid PPA requires total deliveries of 19.0 TWh (9.55 plus 9.45). Even the higher 19.0 TWh requirement of the National Grid PPA could be delivered by the existing transmission system with little or no expansion. Hydro-Québec has stated that its 2017 export capability to New England was 18.2 TWh,[41] and it actually delivered 17.9 TWh in 2017.[42]

This calls into question why Massachusetts customers should pay for the NECEC transmission project if it is not actually needed for the deliveries that are required under the proposed PPAs. This conundrum cannot be what was intended by the RFP, or by HRE in its bid. Further, Section 83D specifically states that its goal is to facilitate the financing of clean energy generation resources.[43] The bid itself and bidder statements since make clear the need for additional transmission, which would need to be financed (HRE confirmed that financing is necessary only for the transmission component of the bid), to deliver the Contract Energy.[44] But if the NECEC transmission is in fact not necessary because of the PPAs' weak requirements, there might be nothing to finance, undermining the 83D goal. The only logical interpretation is that the Contract Energy

41 Exh. EDC-RB-5.

42 Hydro-Québec's 2017 annual report states that exports to New England were 52% of the 34.4 TWh of exports in 2017. Hydro-Québec Annual Report 2017, at 11.

43 Section 83D(a) states that, "In order to facilitate the financing of clean energy generation resources…every distribution company shall jointly and competitively solicit proposals for clean energy generation and, provided that reasonable proposals have been received, shall enter into cost-effective long-term contracts for clean energy generation…"

44 Section 83D Request for Proposal Application Form, NECEC RFP Response (HRE), Appendix B to the RFP (Confidential), Section 1, at 2-3, Section 4.2, at 19-20 and Section 5.1.1, at 26; Exh. EDC-RB-5.

should be incremental to full historical deliveries, and the PPAs should require 14.8 TWh of Baseline Hydro.

Q. Under the proposed PPAs, would Massachusetts ratepayers pay for the NECEC transmission line if the energy delivered is not incremental?

A. The Minimum Baseline damages calculation of the proposed PPAs would impose no penalty until HQ's Baseline Hydro deliveries fall below 9.45 TWh, which is 5.35 TWh below the 14.8 TWh 2014-2016 historical average deliveries. That is, ratepayers would pay for the full NECEC transmission project, even if only 44% of the Contract Energy is incremental hydro.[45] Below 9.45 TWh, damages are paid on the National Grid PPA; Eversource/Unitil damages are not incurred until Baseline Hydro falls below 3.0 TWh. In fact, if HQ provided zero Baseline Hydro, delivering far less total energy than the historical average (even including the Contract Energy), Massachusetts ratepayers would still pay 41% of the total TSA payments.[46]

Q. How would you remedy this flaw in the PPAs?

A. In principle, this is relatively straightforward, as I outlined in my direct testimony.[47] For a hydro bid, maintaining Baseline Hydro deliveries at the level of historical imports, as a proxy for imports that would have occurred absent the PPA, is a key component of this procurement. The terms of the PPAs should be adjusted to provide what the RFP solicited, what the NECEC Hydro bid offered, and the way the bid was evaluated and selected. They should require the delivery of fully incremental clean hydro generation

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[45] At the National Grid Minimum Baseline of 9.45 TWh, total deliveries are 19.0 TWh, only 4.2 TWh above the historical average. This is 44% of the 9.55 TWh Contract Energy.

[46] Ratepayers would actually continue to pay for the NECEC via full TSA payments regardless of the Baseline Hydro delivered. Damage payments in the context of Exhibit H Minimum Baseline shortfalls reduce the payments to HQ under the PPA, even though they are expressed as a share of the TSA payment; I refer to them here in the same way.

[47] Exh. AG-DM, at 17-19.

— *i.e.*, require 9.55 TWh of Contract Energy, in addition to 14.8 TWh of Minimum Baseline Hydroelectric Generation.

As I had noted in my direct testimony, it may be necessary to allow some adjustments to the Minimum Baseline calculation, for instance to allow for year-to-year variability in hydro conditions.[48] It might be possible to index to hydrologic conditions or total exports from Hydro-Québec, or use multi-year or rolling average requirements to smooth year-to-year variations in available energy. Five-year averaging for the Minimum Baseline requirement is already a component of the proposed National Grid PPA,[49] and time-averaging is commonly used to accommodate performance variability in PPAs, so this should not present a significant challenge.

Q. How could the proposed PPAs be modified to avoid the situation wherein ratepayers pay for unnecessary transmission capacity?

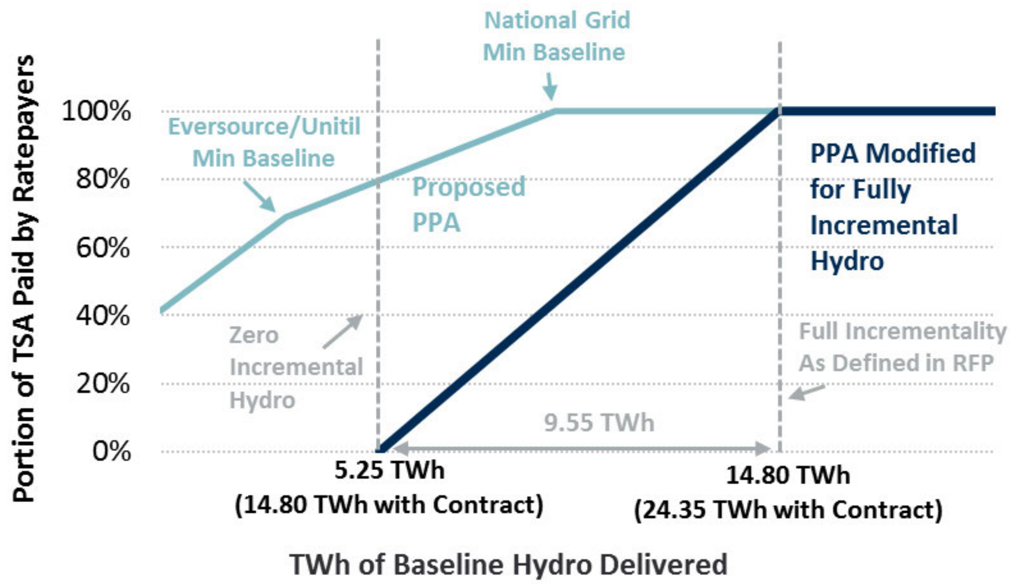
A. One reasonable approach would be to calibrate the damages calculations in Exhibit H to reflect the amount of transmission needed to deliver Incremental Hydro, as illustrated in Figure 3. Under this construct, the Minimum Baseline would be set to full incrementality, 14.8 TWh per year. Damages would be zero if HQ delivered fully Incremental Hydro — 14.8 TWh of Baseline Hydro in addition to 9.55 TWh of Contract Energy, totaling 24.35 TWh. At 5.25 TWh of Baseline Hydro, total energy delivered (including Contract Energy) would be 14.8 TWh, meaning that contract energy would just be substituting for historical average energy, and none of the energy delivered would be incremental. This 14.8 TWh could easily be accommodated with existing transmission facilities; this much and more has been delivered in recent years. Thus damages would equal 100% of the TSA payment, and ratepayers would not be required to pay for the unused NECEC transmission capacity. In essence, damages would reflect

[48] Exh. AG-DM, at 17.

[49] Exh. JU-3-B, at 92-95.

the cost of transmission capacity constructed but not needed, due to a shortfall below the Minimum Baseline.

Figure 3: Exhibit H Damages Calculation
Proposed PPAs vs PPAs Modified for Fully Incremental Hydro



Sources and Notes: Minimum Baseline values and Proposed PPA damages from Exhibits JU-3-A through C, Exhibit H. PPA Damages with Fully Incremental Hydro is equal to the TSA payment multiplied by the shortfall in Baseline Hydro, divided by the Contract Energy amount, where the shortfall in Baseline Hydro is 14.8 TWh minus Baseline Hydro delivered, and Contract Energy is 9.55 TWh.

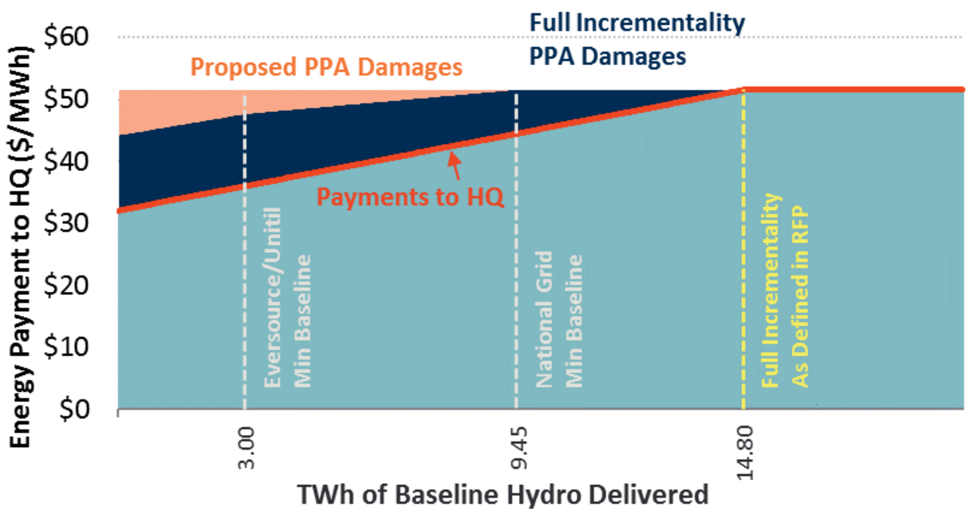
Q. Under the approach discussed above, should additional damages be assessed beyond the full TSA amount if HQ Baseline Hydro deliveries fall below 5.25 TWh?

A. Most likely, yes. The damages calculation should incentivize HQ to provide more Baseline Hydro at every level up to full incrementality of 14.8 TWh. Whether the damages function should continue at the same rate below 5.25 TWh of Baseline Hydro, or at a different rate, may warrant further consideration.

Q. If the Minimum Baseline amount was increased to 14.8 TWh, and if adjustments to that were limited, would this threaten financial harm to HQ?

A. Of course, relaxing the requirements of any contract can make it more lucrative, as the low Minimum Baseline values in the proposed PPAs are likely to do. So, relative to the current proposed PPAs, establishing the Minimum Baseline at 14.8 TWh might make the PPAs somewhat less lucrative for HQ. This could occur to the extent the lax incrementality requirements give HQ opportunities to redirect energy from New England to other markets if it is more profitable to do so. But the contract payments are intended to compensate the Seller for not just the Contract Energy, but also for the fact that this energy is incremental to the full historical Baseline Hydro. This was clear in the RFP and in HRE's bid. The contract revenue will help to offset the financial impact on HQ, if any, of strengthening incrementality requirements to reflect historical average deliveries. Figure 4 below shows how the suggested Exhibit H adjustments above would affect HQ's overall PPA revenues, as a function of its Baseline Hydro deliveries (assuming full delivery of Contract Energy). The orange area at the top left represents the damages for under-delivery of Baseline Hydro as the PPAs are currently drafted. The dark blue area represents the damages for under-delivery if the PPA was revised to require full incrementality, calibrating the amount of damages to the share of the NECEC transmission capability needed to deliver the Baseline Hydro. That is, with 14.8 TWh of Baseline Hydro, which is fully incremental, there is no penalty. At 5.25 TWh, total deliveries including Contract Energy would equal historical deliveries; Contract Energy is just substituting for historical deliveries. Since all the energy could be delivered over the existing transmission system, the penalty would be equivalent to the entire TSA payment.

Figure 4: Impact of Baseline Hydro Shortfall on PPA Payments to HQ
Proposed PPAs vs PPAs Modified for Fully Incremental Hydro



Sources and Notes: Minimum Baseline numbers and Proposed PPA damages from Exhibits JU-3-A through C, Exhibit H. The full energy price for HQ is the year one PPA price from Exhibits JU-3-A through C, Exhibit D. PPA Damages with Fully Incremental Hydro are equal to the TSA payment multiplied by a shortfall in Baseline Hydro divided by the Contract Energy amount, where this shortfall is 14.8 TWh minus Baseline Hydro delivered, and the Contract Energy is 9.55 TWh. Figure assumes penalty continues at the same rate below 5.25 TWh of Baseline Hydro.

Q. Did the Independent Evaluator ("IE") raise questions of fairness with regard to requiring full incrementality?

A. Yes. The IE stated the opinion that "The form PPA did not contain any specific provision requiring…any amount of energy other than that being committed to under the proposed contract."[50] This could be argued, given that the form PPA explicitly defined Incremental Hydro as the 2014-2016 average deliveries, though it did also qualify this with "and/or otherwise expected deliveries."[51] The IE appears to be taking the same position as the EDCs in their rebuttal testimony, relying more on the qualifying "otherwise expected" phrase than the primary description of how Incremental Hydro should be interpreted. But

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50 Independent Evaluator Final 83D Report Redacted, at 51 (July 24, 2018).

51 Draft Power Purchase Agreement, at 7 (May 12, 2017).

in any case, the IE claimed that requiring fully incremental Baseline Hydro would have been a major liability and "raised a fairness question."[52] This fairness question is different from the one I pose above; it focuses on fairness to HQ rather than on fairness to the ratepayers ultimately responsible for the cost of the Contracts, and perhaps to other bidders. The IE did, however, recognize that the issue of providing full incrementality had been raised previously, and concluded that it would be "acceptable" to negotiate a contractual commitment for incrementality.[53]

Q. Would other potential adjustments be necessary to the Minimum Baseline value, for instance like those included in the proposed National Grid PPA?

A. Some adjustments would be warranted, particularly time averaging like the mechanism already included in the National Grid PPA, or some alternate mechanism to accommodate variability in hydrologic conditions. Some further adjustment may be necessary for longer-term shortfall in total exports, as is also included in the current National Grid PPA. On the other hand, a downward adjustment of the Minimum Baseline for low power prices, which is also currently included in the National Grid PPA, may not be necessary, since the Baseline was determined under a range of conditions that also included low prices.

Importantly, potential adjustments to the Minimum Baseline requirement should be bi-directional, to accommodate adjustments that may make the appropriate Minimum Baseline either higher or lower than the historical average, as conditions warrant. For instance, for wet years that have above average total Hydro-Québec generation (or periods of consecutive wet years, if averaging across time), the Minimum Baseline should likely be set above the historical average. Adjustments to the Minimum Baseline should protect the EDCs and their customers as well as HQ.

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52 Independent Evaluator Final 83D Report Redacted, at 51 (July 24, 2018).

53 *Id*., at 52.

IV. HIGHEST SCORING STAGE 2 BIDS SHOULD HAVE BEEN EVALUATED AS STANDALONE PORTFOLIO

Q. Please summarize your response to the EDCs' rebuttal testimony regarding the evaluation of the [redacted] and [redacted] bids.

A. In my direct testimony, I observed that the two highest scoring "large" projects from Stage 2 were not carried into Stage 3 as a standalone portfolio (*i.e.*, without other projects) and that such a standalone portfolio would satisfy about [redacted] of the energy targeted by the procurement.[54] In their rebuttal testimony, the EDCs asserted that a standalone portfolio of the two top bids would not fulfill the energy target for the procurement as required by the Stage 3 Evaluation Protocol, and that a future solicitation would be unlikely to procure a high-value project to fill the difference between such a portfolio and the procurement target.[55]

Q. Does the Stage 3 Protocol include a threshold requirement for the size of portfolios?

A. No. While the protocol describes the "overall goal" of the solicitation to contract for 9.45 TWh of energy, there is no stated threshold for portfolio size, and there is no requirement that all of the Contract Energy under 83D must be procured in this solicitation (as opposed to subsequent 83D solicitations). With respect to portfolio composition, the protocol states:

> The Evaluation Team will develop various combinations of top-ranked project proposals for evaluation as portfolios to determine their portfolio effect with respect to:
>
> a) The overall impact of various portfolios of proposals on the Commonwealth's policy goals, including GWSA goals as directed by DOER
>
> b) The overall cost effectiveness of various portfolios of proposals, including those portfolios that the Evaluation Consultant identifies as optimized in the Evaluation model

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54 Exh. AG-DM, at 19-20.

55 Exh. EDC-RB-1, at 68-69.

Nowhere in this statement does the protocol provide a minimum portfolio size for evaluation in Stage 3. Furthermore, in the section of the protocol that outlines the selection process, the Evaluation Team outlines six factors for consideration. None of these factors explicitly includes a minimum annual generation quantity.

Q. Did the Evaluation Team analyze any portfolios in Stage 3 that had annual generation of less than 9.45 TWh?

A. Yes. Of the 12 portfolios that the Evaluation Team selected for analysis in Stage 3, [redacted] would have supplied less than the 9.45 TWh target.[56] The smallest Stage 3 portfolio evaluated would have supplied [redacted] target. By comparison, a portfolio consisting solely of [redacted] and [redacted] would have supplied [redacted] of this target. The EDCs now appear to imply that there is a size threshold somewhere between [redacted] and [redacted], though the Stage 3 Protocol contains no such strict threshold. In any case, a strict size threshold is not necessary if it is possible to acquire additional generation in a subsequent solicitation as is the case here. Particularly since these two bids scored so well individually, and together would have satisfied [redacted] of the overall targeted energy, a portfolio consisting of just these two should have been considered and evaluated. The results of that evaluation could have informed the tradeoff between the better performance of this portfolio versus its somewhat smaller size and the potential need for a subsequent solicitation.

Q. Do you agree with the EDCs' assertion that future procurements are unlikely to produce high scoring proposals that could "fill-in" the difference between the 9.45 TWh 83D goal and the energy supplied by the [redacted] and [redacted] bids?

A. No. In attempting to dismiss the possibility that a future procurement might produce additional attractive projects, the EDCs state that "There is no evidence to suggest that

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[56] Revised Independent Evaluator Final 83D Report Confidential, at 70 (August 7, 2018).

an additional solicitation for the remaining 1.95 TWh would result in materially different result."[57] First, the absence of evidence is not evidence of absence. More importantly, it is unlikely that the potential renewable resources in and around New England have been exhausted by the proposals offered into this 83D solicitation. It is certainly possible, and perhaps likely, that future solicitations would attract additional high quality proposals. For example, the most recent 83C solicitation produced a winning bid whose direct price was within $6/MWh of the NECEC Hydro bid, and was below all but [redacted] of the "small" 83D proposals.[58] In addition, there were also 16 projects disqualified in this solicitation for not meeting interconnection/delivery or site eligibility requirements; several of these would have produced more than [redacted] GWh/year. These might continue development and meet requirements for a future solicitation.[59] There may also be additional potential projects that did not bid into this solicitation for any number of reasons. Indeed, TCR estimated that an additional [redacted] of renewable energy per year will need to be acquired between 2019 and 2040 to meet the existing Renewable Portfolio Standard ("RPS") targets of the New England states,[60] and this will increase further with the recent increase in the Massachusetts RPS requirement.[61] So it is unlikely that this one solicitation has revealed all of the attractive bids that might potentially be available in the region.

Q. Does this conclude your testimony?

A. Yes.

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[57] Exh. EDC-RB-1 at 69.

[58] The Vineyard Wind 800 MW GLL bid offered a direct price of $64.97/MWh while the NECEC Hydro Bid offered a direct price of $59.05/MWh. Independent Evaluator Final 83C Report Redacted, at 56 (August 3, 2018), Independent Evaluator Final 83D Report Redacted, at 70 (July 24, 2018).

[59] Revised Independent Evaluator Final 83D Report Confidential, at 67 (August 7, 2018). One additional project was disqualified due to being an existing facility.

[60] [redacted] TWh refers to the RPS increase between the 2019 RPS requirement ([redacted] TWh) and the 2040 RPS requirement ([redacted] TWh).

[61] *An Act to Advance Clean Energy*, Bill H.4857 Section 12 at lines 59-63. (July 30, 2018).