REDACTED

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

TABLE OF CONTENTS

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

---

[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.

Continued on next page

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

[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.

---

[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

---

[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.

---

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

[11] Exh. NEER-1-8.

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

Continued on next page

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

---

[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."

Continued on next page

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.

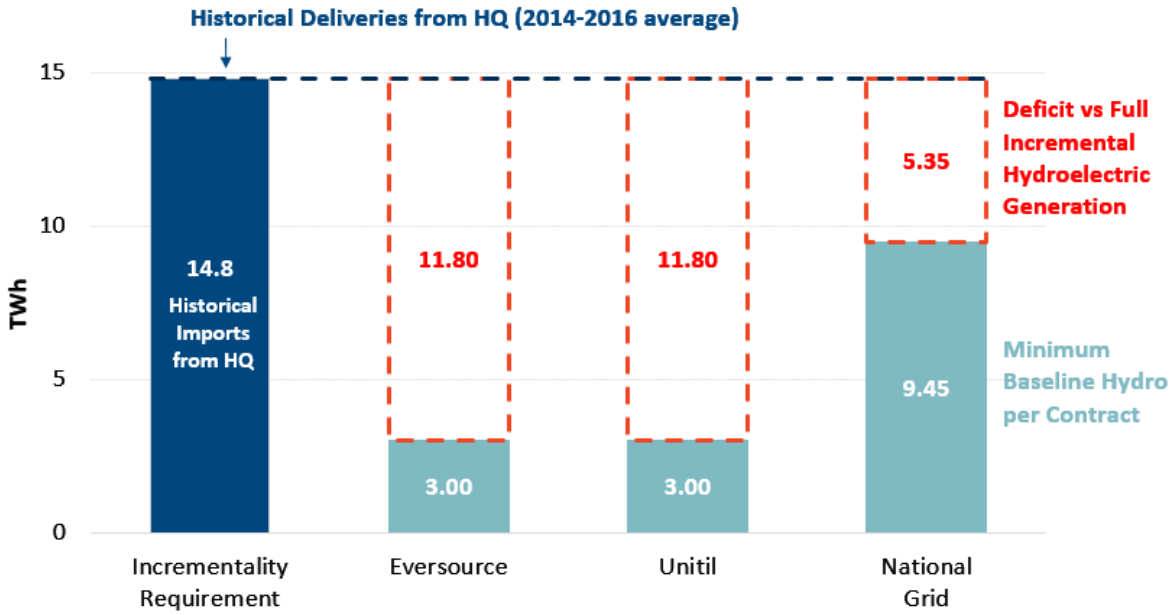
The incrementality requirements of the Eversource and Unitil contracts are even less stringent They are based on a Minimum Baseline quantity of 3.0 TWh,[17] so that the total clean energy deliveries into New England, including deliveries under the new contract, can be below historical average deliveries. 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 below 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).

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?

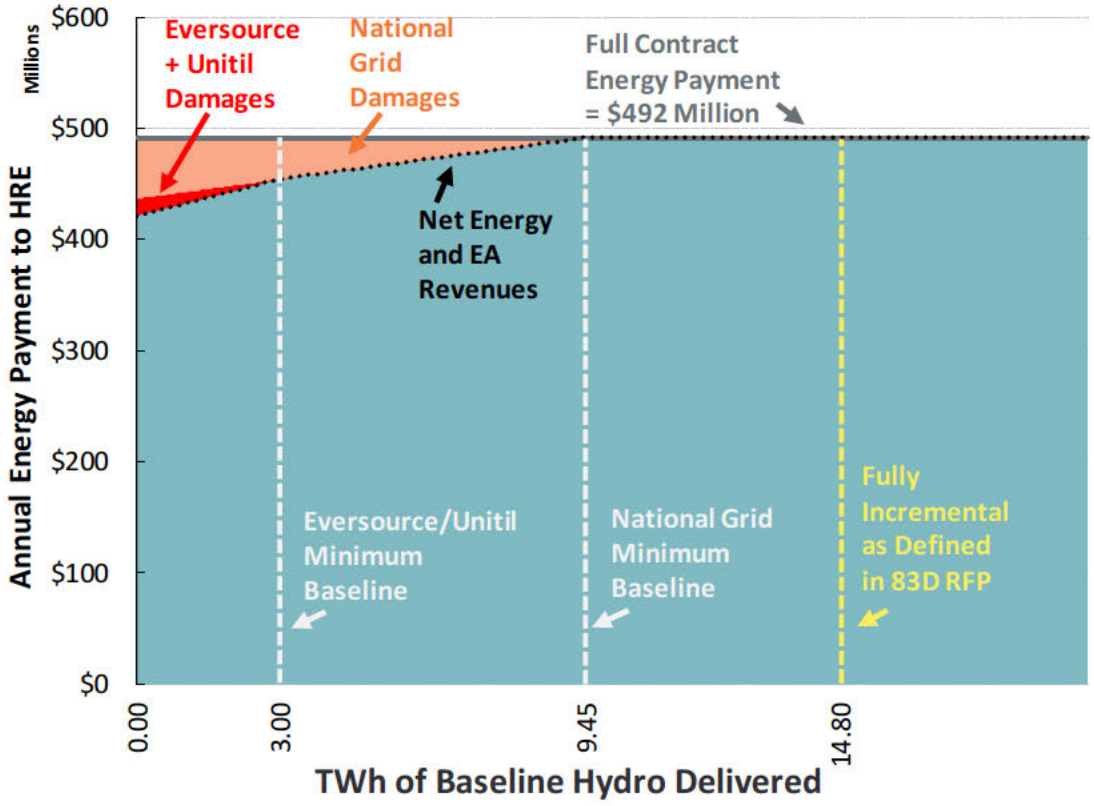
A. The Minimum Baseline requirements are enforced by a damages calculation that penalizes any Shortfall, the amount by which Baseline Hydro is below the Minimum Baseline. The damages, which would be applied to the energy payment to HQ, are calculated as a share of the TSA payments proportional to the 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.

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-

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).

Continued on next page

> 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).

Continued on next page

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 into New England, while GHG emissions must be measured at a global 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

---

[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 to New England (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 existing 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]

[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

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]

[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.

---

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

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.

---

[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.

---

[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]

---

[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.

---

[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.

DEAN M. MURPHY

Principal

Boston, MA +1.617.864.7900 Dean.Murphy@brattle.com

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.

Efficiency and Nuclear Energy: Complements, not Competitors, for a Low-Carbon Future., by Dean M. Murphy and Mark P, Berkman, August 2017, To be submitted to The Electricity Journal in response to

Amory Lovins, " Do Coal and Nuclear Generation Deserve Above-Market Prices?," The Electric Journal July 2017, Vol. 30, Issues 6, Pages 23-30

Berkman, Mark P., Dean M. Murphy "Ohio Nuclear Power Plants' Contribution to the State Economy," Prepared for Nuclear Matters, August 25, 2017. This report finds that Ohio's nuclear energy plants will contribute approximately $510 million to the state gross domestic product (GDP) over the next ten years (2018-2027), in addition to other economic and societal benefits.

"Hurry or Wait? Pacing the Roll-Out of Renewables in the face of Climate Change," Presented at Boston University's Institute for Sustainable Energy's Spring 2017 Seminar Series, by Jürgen Weiss and Dean M. Murphy, April 13, 2017

Murphy, Dean M. and Mark P. Berkman. "Perserving Upstate Nuclear Saves New York Consumers Billions, Compared With Additional Renewables Beyond CES Goals," December 8, 2016

Berman, Mark P. and Dean M. Murphy. " Pennsylvania Nuclear Power Plants' Contribution to the State Economy," December 2016. Prepared for Pennsylvania Building and Construction Trades Council, The Pennsylvania Chamber of Business and Industry, Allegheny Conference on Community Development, and Greater Philadelphia Chamber of Commerce

Celebi, Metin, Marc Chupka, Frank C. Graves, Dean M. Murphy and Ioanna Karkatsouli. " Nuclear Retirement Effects on CO_2 Emissions: Preserving a Critical Clean Resource," Published by The Brattle Group, December 2016

Murphy, Dean M. and Mark P. Berkman. Comment on "Green Overload" - an Issue Brief by the Empire Center, October 18, 2016

Berkman, Mark P. and Dean M. Murphy. "Electricity Cost and Environmental Effects of Retiring the Quad Cities and Clinton Nuclear Plants," Prepared for the Chicagoland Chamber of Commerce, the Illinois Hispanic Chamber of Commerce, and the Illinois Retail Merchants Association, October 2016. The report estimates the effects that two Illinois nuclear plants, the Quad Cities and Clinton plants, have on electricity costs to Illinois consumers, and on emissions of CO_2 and other pollutants.

Preliminary Comment on New York Department of Public Service "Staff's Responsive Proposal for Preserving Zero-Emissions Attributes" by Dean M. Murphy and Mark P. Berkman, July 12, 2016. Prepared for the New York State IBEW Utility Labor Council, Rochester Building & Construction Trades Council, and Central and Northern New York Building & Construction Trades Council

Berkman, Mark P. and Dean M. Murphy. Comments on the New York DPS "Clean Energy Standard White Paper – Cost Study," April 21, 2016, Prepared for the New York State IBEW Utility Labor Council, Rochester Building & Construction Trades Council, and Central and Northern New York Building & Construction Trades Council

Berkman, Mark P. and Dean M. Murphy. "New York's Upstate Nuclear Power Plants' Contribution to the State Economy," December 2015, Prepared for the New York State IBEW Utility Labor Council, Rochester Building and Construction Trades Council, and the Central and Northern New York Building and Construction Trades Council

Berkman, Mark, Dean Murphy. "The Nuclear Industry's Contribution to the U.S. Economy," Nuclear Matters, July 2015. In addition to this national report, similar state-level reports were produced for New York, Pennsylvania, Maryland, Michigan and Ohio.

Celebi, Metin, Kathleen Spees, J. Michael Hagerty, Samuel A. Newell, Dean Murphy, Marc Chupka, Jürgen Weiss, Judy Chang, and Ira Shavel. "EPA's Proposed Clean Power Plan: Implications for States and the Electricity Industry," Policy Brief. June 2014.

Electricity Market Overview for Manitoba Hydro's Export Market in MISO, with Onur Aydin and Kent Diep, The Brattle Group, July 2013.

Plugging In - Can the grid handle the coming electric vehicle load?, by Dean M. Murphy, Marc Chupka, Onur Aydin, and Judy Change, Public Utilities Fortnightly, June 2010.

"Connecticut 2010 IRP Overview," presentation before the Energy and Technology Committee of the Connecticut General Assembly regarding the Connecticut 2010 Integrated Resource Plan, January 8, 2010.

"Integrated Resource Plan for Connecticut," with Sam Newell, Marc Chupka, Judy Chang, and Mariko Geronimo, The Brattle Group, January 2010.

"Promoting Use of Plug-In Electric Vehicles Through Utility Industry Acquisition and Leasing of Batteries, Chapter 13 of 'Plug-In Electric Vehicles: What Role for Washington?'," with Peter Fox-Penner and Mariko Geronimo, *The Brookings Institution*, 2009.

"When Sparks Fly: Economic Issues in Complex Energy Contract Litigation," Energy 2009 No. 1, The Brattle Group.

"Connecticut 2009 IRP Overview," presentation before the Energy and Technology Committee of the Connecticut General Assembly regarding the Connecticut 2009 Integrated Resource Plan, February 5, 2009.

"Integrated Resource Plan for Connecticut," with Onur Aydin, Judy Chang, Marc Chupka, Mariko Geronimo, Samuel Newell, and Joseph Wharton, The Brattle Group, January 2009.

"Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches," Energy 2008 No. 1, The Brattle Group.

"Integrated Resource Plan for Connecticut," with Marc Chupka, Ahmad Faruqui, Samuel Newell, and Joseph Wharton, The Brattle Group, January 2008.

"U.S. Climate Policy: Effects on Business and the Environment," presentation before The Conference Board, September 26-28, 2007.

"On Setting Near-Term Climate Policy While the Dust Begins to Settle: The Legacy of the Stern Review," with Gary Yohe and Richard S.J. Tol, *Energy and Environment*, Vol. 18, No. 5, 2007.

"Guest Commentary – U.S. Should Price Carbon, Directly," *Carbon Market North America*, Point Carbon, June 6, 2007.

"The Economics of U.S. Climate Policy: Impact on the Electricity," Technical Paper, The Brattle Group with FPL Group, March 2007.

"Transmission Management in the Deregulated Electric Industry: A Case Study on Reactive Power," with Frank Graves and Judy Chang, *The Electricity Journal*, October 2003.

"Price-Responsive Electric Demand: A National Priority," with Peter Fox-Penner, presented at the EPRI International Energy Pricing Conference, Washington, DC, July 26, 2000.

"Opportunities for Electricity Storage in Deregulating Markets," with Frank Graves and Thomas Jenkin, *The Electricity Journal*, October 1999.

"Competitive Markets for Reserve Services," presented at the 1999 National Hydropower Association Annual Conference, Washington, DC, March 1999.

"The FERC, Stranded Cost Recovery, and Municipalization," with Peter Fox-Penner, Gregory Basheda, Darrell Chodorow, Jason Hicks, Eric Hirst, James Mitchell, and Joseph Wharton. *Energy Law Journal*, Vol. 19 (1998): 351-386.

"Ancillary Services in the Restructured Electric Industry," presented at the EUC Conference on Reliability and Competition, Denver, CO, November 1998.

"Mechanisms for Evaluating the Role of Hydroelectric Generation in Ancillary Service Markets," (with others), for the Electric Power Research Institute, TR-111707, November 1998.

"The Future of Hydro Resources under Deregulation," presented at HydroVision '98, Reno, NV, July 1998.

"Electricity Price Volatility and Implications," presented at the Electric Power Research Institute Conference on Technology Directions, Business Opportunities and Success Strategies, San Francisco, CA, December 1997.

"Ancillary Service Benefits of Hydroelectric Power," presented at the 1997 National Hydropower Association Annual Conference, Washington, DC, March 1997.

"Utility Capital Budgeting Notebook," (with others), for the Electric Power Research Institute, TR-104369, Palo Alto, California, July 1994.

TESTIMONY

Oral testimony before the New Hampshire Public Utilities Commission regarding the divestiture of the generating assets of Public Service of New Hampshire (Eversource). At issue were the customer savings that would result from divestiture. February, 2016.

Oral testimony before the United States Bankruptcy Court, District of New Jersey, on behalf of Revel AC, Inc., Debtor (Case No: 14-22654-CMB) regarding the fair market value of energy services received from creditor ACR Energy Partners, December 4, 2014. Expert report October 22, 2014.

Before the Public Utilities Board of Manitoba, in the Needs For and Alternatives To Review (NFAT) of Manitoba Hydro's Preferred Development Plan: provided oral testimony regarding future energy prices and price drivers in Manitoba Hydro's U.S. export market in MISO, March 2014.

Deposition, Central Vermont Public Service Corporation and Green Mountain Power Corporation, Plaintiffs, vs. Entergy Nuclear Vermont Yankee, LLC, Defendant. Docket No. 2:12-cv-10-wks, United States District Court, Vermont, April 2013. Expert report February 14, 2013; revised June 5, 2013. Case settled before trial.

Oral testimony before the Connecticut Department of Public Utility Control, in support of several annual versions of the Integrated Resource Plan for Connecticut, Dean M. Murphy and Samuel A. Newell, September 2008, June 2009, June 2010

Oral testimony before the United States Court of Federal Claims, on behalf of Kansas Gas & Electric Company, et al., (Case No. 04-99C), regarding the removal of spent nuclear fuel, Dean M. Murphy, March 2010

Oral testimony before the United States Court of Federal Claims, on behalf of Wolf Creek Operating Company, (Case No. 04-99C), regarding the removal of spent nuclear fuel, March 2010. Expert report September 15, 2009.

Oral testimony before the Connecticut Department of Public Utility Control, in support of the "Integrated Resource Plan for Connecticut," for several subsequent versions of the Plan: June 3, 2010; June 30, 2009; September 22-25, 2008.

Affidavit to the Supreme Court of New York on behalf of Trilogy Portfolio Company LLC, Harbert Distressed Investment Master Fund LTD and Freedom Power Corporation (Index No. 601380/2005), regarding the economic value of the replacement options for a terminated power contract, April 2006. Case settled before trial.

Expert report before the United States Bankruptcy Court, Southern District of New York, on behalf of Contrarian Funds, LLC (Case No. 01-16034), regarding economic damages due to the termination of a natural gas supply contract, August 19, 2005. Case s