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September 9, 2016

Ms. Luly Massaro, Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: The Narragansett Electric Co. d/b/a National Grid - Docket 4627

Dear Ms. Massaro:

Enclosed please find an original and nine (9) copies of the following:

1. The Response of NextEra Energy Resources, LLC to the Lieutenant Governor's First Set of Data Requests.

Please note that an electronic copy of this document has been sent to the service list.

Thank you for your attention to this matter.

Sincerely,

Joseph A. Keough, Jr.

JAK/kf
Enclosure
cc: Docket 4627 Service List *(via electronic mail)*

State of Rhode Island
Public Utilities Commission
Docket 4627
Response of NextEra Energy Resources to
The Lieutenant Governor's
First Set of Data Requests

NEER-McKEE-1-1

Request:

Please provide an unredacted copy of the following document filed in the Massachusetts D.P.U. Docket number 16-05:

A. The direct testimony of Joseph P. Kalt and A. Joseph Cavicchi on behalf of NextEra Energy Resources LLC ("NextEra").

Response:

Please see MA DPU 16-05 Exhibit NEER-JPK-AJC-1(HSCI).

Prepared by or under the supervision of: Joseph P. Kalt and A. Joseph Cavicchi

REDACTED

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition for Approval of Gas Infrastructure Contracts with Algonquin Gas Transmission Co. for the Access Northeast Project	)	D.P.U. 16-05

DIRECT TESTIMONY OF

Joseph P. Kalt

and

A. Joseph Cavicchi

ON BEHALF OF

NextEra Energy Resources, LLC

June 20, 2016

I. Introduction and Summary of Conclusions

A. Qualifications

Q: **Prof. Kalt, please state your full name and business address.**

A: My name is Joseph P. Kalt. My business address is 4280 N. Campbell Avenue #200, Tucson, Arizona 85718.

Q: **And, Mr. Cavicchi, please state your full name and business address.**

A: My name is A. Joseph Cavicchi. My business address is 200 State Street, Boston, MA 02109.

Q: **Prof. Kalt, who are your employers and what are your professional positions?**

A: I am the Ford Foundation Professor (Emeritus) of International Political Economy at the John F. Kennedy School of Government, Harvard University. The Kennedy School of Government is Harvard's graduate school for public policy and public administration. I also work as a senior economist with Compass Lexecon, and submit this testimony in that capacity. Compass Lexecon is an FTI Consulting company with offices in Boston, MA; Washington, DC; Los Angeles, CA; Chicago, IL; Oakland, CA; Tucson, AZ, Europe, and Latin America.

Q: **Mr. Cavicchi, by whom are you employed and in what position?**

A: I am also employed by Compass Lexecon as an Executive Vice President.

Q: **Please briefly describe the services provided by Compass Lexecon.**

A: Compass Lexecon is an economics and financial consulting firm that provides corporations, law firms, and governments with analysis of complex economic and financial issues for use in legal and regulatory proceedings, and in strategic decision-making. Compass Lexecon is actively involved in a wide variety of matters that can arise in the areas of economics and finance. Our practice areas include energy and environmental economics, antitrust, industry regulation, securities, damages, intellectual property, as well as business consulting and public policy analysis.

Q: **Prof. Kalt, please describe your educational background and professional experience.**

A: I hold B.A., M.A., and Ph.D. degrees in economics and I am a specialist in the economics of competition, antitrust, and regulation. Throughout my professional career I have conducted research, published, taught, and testified extensively on the economics of market structure, contracting, regulation, pricing, and strategic performance.

At Harvard, I served as an Instructor, Assistant Professor, and Associate Professor in the Department of Economics over 1978-1986. I joined the faculty of the Kennedy School of Government at Harvard as a Professor with tenure in 1986. In the Department of Economics, I had primary responsibility for teaching the graduate and undergraduate courses in the economics of regulation and antitrust. At the Kennedy School, my teaching responsibilities have included the economics of regulation and antitrust; economics for public policy; natural resource and environmental policy; and economic development on American Indian reservations. At the Kennedy School, I have also served as Chair of the Economics and Quantitative Methods Program, Faculty Chair and Academic Dean for Research, Chair of Teaching Programs, Chair of Ph.D. Programs, and the faculty chair of the Harvard University Native American Program.

During 2005-2009, I served as a visiting professor at the University of Arizona's Eller College of Management. Since 2008, I have been a visiting professor at the University of Arizona's Rogers College of Law, and from 2009-2012, I served as visiting professor at the University of Arizona's School of Government and Public Policy. My teaching at the University of Arizona has included the economics of regulation and antitrust, as well as economic development policy.

I have worked as an economist with Compass Lexecon and its predecessors since the late 1980s. In the course of both my consulting and academic experience, I have extensively studied the economics of industrial organization, antitrust analysis, public goods, regulation and industrial oversight, and the principles of sound public policy. In addition to my university teaching, I have taught such matters to federal administrative law judges; elected and appointed federal, state and local officials; working journalists; and other mid-career audiences. The energy industries, including electric power, have been a primary focus of my professional work since the mid-1970s.

Over my career, I have frequently provided expert economic testimony on the regulation of the electric power and natural gas sectors and many other issues before state courts, public utility commissions, federal courts and regulatory agencies, and international tribunals, as well as before the United States Congress. My *curriculum vitae* is attached hereto as Appendix A and shows my prior testimony as an expert and my publications.

Q: **Mr. Cavicchi, please describe your educational background and professional experience.**

A: I hold Masters degrees in Technology and Policy, as well as Environmental Engineering, from the Massachusetts Institute of Technology and Tufts University, respectively. Prior to joining Compass Lexecon, I was a staff mechanical engineer and a project manager at the Massachusetts Institute of Technology, overseeing the development, permitting, engineering, construction, and start-up of a $40 million, 20 megawatt gas turbine-based cogeneration facility on the Cambridge campus. In addition, I was responsible for the implementation of various energy consumption monitoring programs, and optimization of the operation of a centrally distributed electricity, steam, and chilled water production facility.

I joined one of Compass Lexecon's predecessor companies in 1997. Throughout my tenure with the firm, I have provided economic analysis and expert testimony in various state and federal regulatory proceedings related to electricity markets. In particular, I work with clients on a variety of state regulatory and Federal Energy Regulatory Commission proceedings, and often file testimony and affidavits supported by economic analyses. Throughout my career I have been directly involved with corporations, private and public institutions, and state and federal regulatory authorities in connection with the economics of the electricity industry. For the past 19 years I have been working almost exclusively on the regulatory economics of the electricity industry, and, in particular, performing economic analyses of wholesale electricity markets.

I have testified on several occasions regarding wholesale electricity market competitiveness and design issues at the Federal Energy Regulatory Commission. In addition, I have previously testified on power supply procurement plans in Pennsylvania and Ohio. I have also testified on qualifying facility pricing policy and wholesale market design policy in the state of California. Finally, I have written articles on electricity industry structure and issues associated with procuring wholesale electricity supplies for delivery to retail customers.

Additional detail regarding my credentials and experience can be found in my *curriculum vitae*, which is attached as Appendix B to this testimony.

Q: **On whose behalf are you testifying in this matter?**

A: We are submitting this testimony at the request of NextEra Energy Resources, LLC ("NEER").

Q: **Please describe the purpose of your testimony?**

A: We have been asked to review the request put forth by Massachusetts Electric Company ("Mass Electric") and Nantucket Electric Company ("Nantucket Electric") each d/b/a National Grid ("Petitioner" or "National Grid") to the Commonwealth of Massachusetts, Department of Public Utilities ("Department" or "DPU") for approval of 20-year natural gas and storage transportation contracts between National Grid's affiliated electric distribution companies, Mass Electric and Nantucket Electric, and Algonquin Gas Transmission LLC ("AGT").[1] These Access Northeast Project ("ANE") contracts would

[1] Commonwealth of Massachusetts, Department of Public Utilities, Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval of Gas Infrastructure Contracts with Algonquin Gas Transmission Company for the Access Northeast Project, D.P.U. 16-05, January 15, 2016 at 2 ("Petition").

provide AGT the financial commitment it allegedly otherwise is lacking to build AGT's proposed ANE project.

ANE is a proposed joint venture natural gas pipeline project owned by unregulated affiliates of National Grid and Eversource, and by Spectra, the parent of Algonquin. Under the proposal, the joint venture pipeline has negotiated contracts (the "ANE contracts") under which the regulated New England utilities (in Massachusetts, National Grid's EDC's Mass Electric and Nantucket Electric, and Eversource's comparable regulated companies) will pay the joint venture (competitive affiliates of National Grid and Eversource plus Spectra) a fixed price of at least $526 million per year over 20-years. The fixed price could be increased in the event of construction cost overruns, subject to a cap.

We have been asked to address the economic and public policy implications associated with National Grid's proposed ANE contracts which would require retail electricity ratepayers in Massachusetts and the other New England states to bear the costs associated with the development of ANE. ANE is designed to expand pipeline capacity for delivering natural gas into New England for use during the coldest days of winter.[2] Section II presents the results of our analysis of the economic costs and benefits of National Grid's proposal.

We have also been asked to review the analysis put forth by National Grid's expert, Black & Veatch Management Consulting LLC ("Black & Veatch"), which

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[2] Exhibit NG-TJB/JEA at 16-17; Response to Information Request NEER-1-27; Response to Information Request NEER-1-32.

purports to show that National Grid's proposal to recover via a passthrough tariff the costs of the ANE contracts from electricity ratepayers[3] for the development and operation of ANE generates benefits for those ratepayers in excess of costs of the proposal. Section III below presents our assessment of National Grid's expert's claims and analyses.

B. Summary of Conclusions

Q: **Please summarize your key conclusions.**

A: First, looking at the proposed ANE contracts under the social cost-benefit test from the perspective of the economy as a whole, the proposed ANE contracts would result in a costly waste of resources—the cost to build the pipeline exceeds any reduction in the cost to generate electric energy that might reasonably be expected. Contrary to National Grid's claims, this indicates the reason that commercial developers have not proposed to build the pipeline at their own expense is not the result of a market failure.[4] Rather, the wastefulness of the pipeline tells us it is not needed; it does not add sufficient economic value to justify its very high cost.

Second, looking at the proposal from the perspective of New England electricity ratepayers only, consistent with the ratepayer impact standard adopted by the DPU for this proceeding,[5] the proposed ANE contracts would result in increasing certain ratepayer

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[3] *See, e.g.,* Exhibit NG-AEL-1. In this proceeding, National Grid is seeking approval of its proposed Long-Term Gas Transportation and Storage Contracts Tariff designed to ensure ratepayers bear the actual costs associated with transportation, storage and administration of the joint venture.

[4] Exhibit NG-MCC-1 at 20 and 22.

[5] The analysis requested by the DPU is focused only on the effects of the proposal on EDC customers. ("…, an EDC must demonstrate that the proposed contract . . . results in net benefits for the Massachusetts EDCs' customers at a reasonable cost,….") The Commonwealth of Massachusetts,

costs whose value is significantly greater than the value of the highly uncertain benefits of the proposal. Even assuming for the sake of argument that National Grid's unrealistic analysis has some level of validity, the contracts would require ratepayers to pay on a present value basis somewhere from several hundred million to several billion dollars more in a gas pipeline surcharge on their electric bills than they would experience in the form of a reduction to electric energy charges attributable to the ANE project..

Third, National Grid's assertion that the ANE contracts would benefit consumers is predicated on basic economic errors such as projections of natural gas prices that are unreasonably high. National Grid fails to account properly for at least two existing alternatives to gas pipeline expansion: New England's existing capacities to import liquefied natural gas ("LNG") and to generate electric energy using fuel-oil. Also, in discounting the benefits and costs associated with the ANE contracts to their present value, National Grid failed to take into account the wide disparity in the level of certainty for those benefits and costs. This error has a significant effect on the cost-benefit analysis given that the ratepayers' obligation to pay for the contracts would be virtually a certainty under the very favorable regulatory terms that National Grid has proposed, but the extent of any benefits over 20-years is in this case exceptionally speculative given the unreasonable fossil fuel pricing underlying National Grid's analysis, the projected increase in the development of renewable energy resources, the fact that National Grid

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Department of Public Utilities, ORDER DETERMINING DEPARTMENT AUTHORITY UNDER G.L. C. 164, § 94A, D.P.U. 15-37, October 2, 2015, hereinafter ("D.P.U. 15-37") at 43. Under D.P.U. 15-37 the ratepayer impact cost-benefit analysis set forth by the Department differs from standard economic cost-benefit analysis and the application of the standard requires consideration of discount rates pertinent to the specific case at hand.

has no electric generators under contract to take the capacity, and the projected decline in overall demand for electricity, among other factors.

Fourth, National Grid cannot justify the ANE contracts as a "solution" to a "problem" of retail price "volatility." National Grid does not even examine the impact on volatility of retail prices paid by ratepayers. Ratepayers typically pay monthly bills whose energy costs are based on fixed-price one-year term contracts procured semi-annually, not day-to-day and hourly wholesale gas and electricity market prices. As a result, retail prices are, and will remain, quite stable irrespective of whether there is hourly or daily fluctuation in the wholesale market (which National Grid improperly treats as relevant for evaluation of its proposal).

Finally, National Grid has not justified the pipeline as necessary for electric system reliability; that is, to "keep the lights on." Virtually any new generating plant integrated into the transmission system, or pipeline, in theory adds to system "reliability," so the real question is whether the pipeline is needed or is wasteful, not whether it would "help." National Grid provides no study or analysis to show such a need. Indeed, the New England grid operator, ISO-NE, which unlike National Grid has responsibility for system reliability, has acknowledged that concerns about winter gas constraints may be addressed by some combination of LNG, dual fuel operation or other upgrades,[6] and has not recommended a massive pipeline expansion such as ANE.

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[6] See, for example, 2016 Regional Outlook, ISO-NE at 3-4; and Challenges Facing the New England Power System, Gas-Electric Interdependency: The Realities of Keeping the Lights On, Gordon van Welie, March 26, 2015, National Press Club, Washington at 23.

Q: **What is the basis for your key finding that the costs of the ANE proposal outweigh the benefits?**

A: National Grid does not actually present a cost-benefit analysis of the ANE contracts. Specifically, Black & Veatch's "cost-benefit" analysis fails to employ the cost-benefit framework routinely and properly employed by professional economists when assessing the impacts of projects on the public interest. Indeed, Black & Veatch's cost-benefit calculations do not account for all of the costs and benefits which the proposal would impose on the public. The analysis, for example, ignores the costly distortions that National Grid's proposal would impose on the federally-regulated wholesale natural gas and power markets in New England. And it further ignores the adverse effect on ratepayers that would arise in the form of elevated prices in ISO-NE's *capacity* market if power producers lost *energy* market revenue they need to justify keeping plants operating as a result of the proposal's suppression of electric *energy* prices.[7]

The measurement of projected costs and benefits depends, of course, on such matters as: projected wholesale gas and electricity prices, including projected winter price spikes in New England; the costs of the project; its impact on price spikes; and the applicable discount rates employed to put values to a common present value basis. Simply correcting Black & Veatch's analysis to account for availability of fuel oil and LNG for electric generators in New England by employing the marketplace's own forecasts of wholesale gas prices and price spikes, National Grid's own figures as to ANE's costs, and risk-appropriate discount rates, demonstrates that National Grid's

[7] National Grid offers no reason for this exclusion.

proposal would saddle ratepayers with costs (in Net Present Value ("NPV")) that far exceed any benefits they might expect to realize.

These results are summarized in Tables 1A and 1B. Table 1A focuses on ratepayer impacts, i.e., focuses solely on the purported benefits to ratepayers of having the ANE project depress and distort prices in the region's federally-regulated wholesale power markets. As indicated, we find that, *at most and only under the extreme assumption that the depression of wholesale power prices gets passed through 100% to retail electric ratepayers*, the project might be able to generate benefits for ratepayers at a NPV of $3.24 billion ($3.471 billion less $229 million). On the cost side, however, National Grid's proposed ANE contracts are designed to pass all the costs of the ANE project onto retail electric ratepayers, which translates into payments of $5.9-[REDACTED] billion (in present value terms and including cost overrun allowance). These payments do not include the costs to ratepayers of the 2.75% financial incentive that National Grid requests that ratepayers fund,[8] and, which, if granted, would require National Grid's ratepayers to pay more for the proposal than Eversource's ratepayers. We have previously reported on our study of Eversource's proposal, finding that it does not produce positive net-benefits for ratepayers. National Grid's ANE proposal is even more of a loser for ratepayers than Eversource's.

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8 Exhibit NG-MCC-1 at 21.

Table 1A
Costs and Benefits of National Grid's proposal to New England Electricity Buyers
(2016 Present Value; $Millions)

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$3,471		
Electric Capacity		-$229	[REDACTED]
Pipeline Cost		-$5,892	[REDACTED]
Total Present Value	$3,471	-$6,121	[REDACTED]
Total Net Present Value		**-$2,650**	[REDACTED]

In claiming that benefits to retail ratepayers under its proposal would outweigh the costs those ratepayers would have to bear – National Grid simply assumes complete pass through of artificially depressed power prices, ignores New England's existing electric generation resource fuel diversity (i.e., ability to operate using LNG and fuel oil), and assumes that more new gas pipeline capacity and LNG storage is what New England needs. However, as ISO-NE recognizes, existing generation resource fuel diversity has proven that it can ensure electric system reliability during New England's coldest winter weather spells on a more cost-effective basis than National Grid's proposal.[9] Thus,

[9] "Our analyses and experience to date indicate that gas-fired generators will tend to select the most economic option available to them: installing 'dual-fuel' capability, which allows them to switch from

approving the ANE contracts that would require National Grid's (and most of New England's) ratepayers to put almost [REDACTED] billion dollars down on a speculative venture that only promises it could pay $3.24 billion in benefits is a bad deal for National Grid's retail ratepayers.

Table 1B shows the results of a standard social cost-benefit analysis, which concerns the overall public interest. Applying the standard economics of public cost-benefit analysis and, thereby, accounting for all costs and benefits of National Grid's proposal, reveals that the proposal's costs do not come close to being offset by any benefits it might create.[10] That is, the proposal fails the standard cost-benefit test for assessing whether a project is in the public interest. As indicated in Table 1B, we find that the present value of the costs of the proposal to the public outweigh the present value of the benefits to the public by $.6-[REDACTED] billion (with the higher figure again including the significant project cost overrun allowance).[11] Reasonable sensitivity tests

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gas to oil when the gas pipelines become constrained" Statement of Gordon van Welie, ISO-NE 2016 Regional Economic Outlook at 3. ("ISO-NE 2016 Outlook").

[10] In the context of electricity, standard cost-benefit analysis refers to an analysis that recognizes the quite low elasticity of demand for reliable electric power and compares the reduced electric production costs (i.e., the social benefits of the project) that result from increased consumption of lower priced natural gas against the associated costs that would be incurred to build and operate the ANE project. Under FERC's natural gas pipeline regulatory framework gas shippers (local distribution companies, gas-fired generators, marketers, large industrial customers etc.) and pipeline developers almost exclusively privately negotiate rates for pipeline additions and expansions as these facilities are needed based on market conditions. National Grid's proposal presumes that there should be market demand for new pipeline/storage infrastructure, and in its absence retail electric ratepayers should step into the shoes of those entities that are unwilling to bring forth additional new pipeline capacity. See, e.g., Exhibit NG-MCC-1 at 16-18.

[11] The results in Table 1B are also based on the marketplace's own forecasts of wholesale gas prices and price spikes, commercially available and widely used models of electricity price formation, National Grid's joint-venture partner's own figures as to ANE's costs, and risk-appropriate discount rates.

of these results leave the basic conclusion intact. The proposal is directly contrary to the public's overriding interest in avoiding projects that promise to cost the public more than they benefit the public.

Table 1B
Overall Costs and Benefits of National Grid's proposal to the Overall Economy
(2016 Present Value; $Millions)

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$2,825		
Electric Capacity		-$258	[REDACTED]
Pipeline Cost		-$3,146	[REDACTED]
Total Present Value	$2,825	-$3,404	[REDACTED]
Total Net Present Value		**-$578**	[REDACTED]

Q: **How is it possible that National Grid's expert's claim of [REDACTED] billion dollars of annualized benefits each year do not outweigh the current estimated annual cost of $526 million?**

A: National Grid's expert's cost-benefit calculations are flawed and misleading. Black & Veatch does not employ standard cost-benefit analysis. Instead, its findings are based upon an incomplete accounting of costs and benefits. In particular, Black & Veatch's cost-benefit analysis ignores costly wholesale market distortions that would result from the ANE project. In fact, Black & Veatch's modeling of the effects of ANE on New

England wholesale gas and electric power prices artificially constrains the marketplace from otherwise responding to tight natural gas supply conditions. The natural gas marketplace, however, is already signaling that there is a portfolio of fuel supply resources available to serve the region's diverse mixture of electric generation resources. This portfolio of resources can be expected to continue to attenuate future winter natural gas prices while providing security of electric power service to the region. Black & Veatch ignores direct evidence from the marketplace and contends that the ANE project is the answer for New England.

Q: **What do you mean when you say that Black & Veatch ignores direct evidence from the marketplace?**

A: By ignoring actual marketplace forecasts, Black & Veatch's modeling fails to capture, for example, the ability of LNG and fuel oil supplies to effectively supplant the need for additional pipeline gas on the coldest days of the year. The results are extreme price spikes that continually increase over time in Black & Veatch's New England gas price forecast. In stark contrast, pricing data from the gas futures market signals no expectation of winter price spikes anywhere close to the magnitude projected by Black & Veatch. Moreover, the price spikes in the Black & Veatch framework persist in spite of the fact that Black & Veatch assumes the addition of an equivalent quantity of generic pipeline capacity approximately equal to that of the ANE project by 2022 (i.e., 0.5 bcf/day of capacity in addition to ANE), and an additional 1 bcf/day of capacity after 2022. This growth in pipeline capacity far outpaces projected growth in natural gas demand. As we report below in Section III, reasonable corrections to Black & Veatch's modeling and calculations, supported by marketplace evidence, finds that even Black & Veatch's attenuated cost-benefit analysis yields costs that exceed benefits.

Q: **In summary, do you believe that National Grid's proposal is in the public interest?**

A: No, we do not. For the reasons we discuss below, whether evaluated from the perspective of ratepayers alone as requested by the Commission, [12] or from the perspective of the overall public's interest in a healthy and efficient economy that does not waste resources by incurring costs that outweigh benefits, the ANE project and its associated contracts are a net negative. Given that the ANE contracts are a net negative, the contracts are not in the public interest and should be rejected. Further, the project proposes to have National Grid's ratepayers pay for a pipeline that distorts the performance of the region's wholesale power markets. Indeed, National Grid's proposal is properly characterized as a design to undermine the efficiency of ISO-NE wholesale power markets.[13]

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[12] We also understand that the Department requires that National Grid structure a gas contract proposal so that it will be consistent with federal regulatory policy and not be subject to federal preemption (D.P.U. 15-37 at 35-36).

[13] Indeed, National Grid's proposal is directly at odds with the Department's commitment under its electric industry restructuring order to apply "rules and regulations [ ] in a fair and consistent manner to all participants in the [generation] market to enable them to compete based on their efficiency and productivity." See Investigation by the Department of Public Utilities on its own motion into electric industry restructuring, D.P.U. 95-30, August 16, 1995, at 20.

II. Cost-Benefit Analysis of National Grid's Proposal

A. National Grid's Proposal

Q: Could you more specifically describe National Grid's proposal in this proceeding?

A: National Grid requests the Department's approval of two 20-year firm natural gas transportation contracts for transportation and storage services on the ANE project. According to Eversource, the ANE contracts are for that "portion of Access Northeast that will serve electric generation in New England."[14] Under these proposed 20-year contracts as applied in Massachusetts, retail electric ratepayers of National Grid's EDCs, Mass Electric and Nantucket Electric, would be obligated to pay a very large portion (based on EDC peak electric demands) of the ANE project costs under proposed Long-Term Gas Transportation and Storage Contract ("LGTSC") tariffs. As described by National Grid, the LGTSC tariffs provide a mechanism to recover the actual costs for the provision of interstate pipeline transportation and gas storage services to subsidize a subset of gas-fired electric generation facilities in the ISO-NE region.[15]

In addition, National Grid proposes an associated FERC-regulated Electric Reliability Services ("ERS") tariff that would make available to electric generators those pipeline services that would be effectively held for power generators on a day-to-day basis (i.e., pipeline transportation and storage capacity will be held on behalf of electric

[14] D.P.U-15-181 Exhibit EVER-KRP-3 at 36.

[15] In particular, National Grid states that the project is designed to provide delivery-point flexibility to serve generators in four separate sub-regions of the ISO-NE market, referred to as Power Plant Aggregation Areas ("PPAAs"), which include Connecticut, Southeastern Massachusetts and Rhode Island, Central and Eastern Massachusetts, and Northern New England. See Petition at 3.

generators and then released if, and when, these electric generators seek to utilize the capacity to deliver gas to their generating units). While National Grid asserts that the revenue from natural gas pipeline capacity release will benefit its EDCs affiliates' customers by offsetting pipeline capacity contract costs, it provides no reasonable basis for finding that there may be financial benefits from such "capacity release" to ratepayers in association with its proposal.[16]

Finally, as noted and unlike Eversource, National Grid proposes an annual "incentive" equal to 2.75% of annual fixed contract payments under the Proposed Agreements.[17] This would require National Grid's ratepayers to pay more than Eversource's ratepayers for the proposed contracts.

Q: **According to National Grid, what benefits would retail ratepayers realize as offsets to their paying for the costs of the ANE project?**

A: National Grid asserts that the delivery via ANE of additional natural gas supplies into New England would cause natural gas prices to be lower in New England on certain cold winter days than they otherwise would be, and that this will lower the fuel costs of gas-fired electricity generation in the region during affected winter days.[18] According to National Grid and its expert, these lower gas costs would result in the suppression of electric power prices in New England's federally-regulated wholesale electricity markets,

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[16] Response to Information Request AG-1-47.

[17] Exhibit NG-MCC-1 at 21.

[18] National Grid asserts that the ANE Project is a purported solution to "the excessive winter electricity prices caused by inadequate pipeline capacity." Exhibit NG-MCC-1 at 17.

and lower wholesale power prices would be expected to translate into lower retail electricity costs for New England retail ratepayers. Lower electricity costs would offset the costs those ratepayers would have to bear in the form of mandated payments to cover National Grid's payments to the ANE joint venture.[19] In other words, National Grid asserts that wholesale electric energy market prices will decline with the ANE project and compensate retail ratepayers for their having to pay the LGTSC tariffs.

Q: **What costs would retail electricity ratepayers incur under the LGTSC tariffs?**

A: National Grid reports that the prospective EDC customers for the ANE project have negotiated, or are expected to negotiate, a total levelized payment of $526 million for the 20-year term of the contracts, although, as noted, this figure could well increase in the event of a construction cost overrun.[20] This payment by EDCs would be recovered from those EDCs' electric customers throughout New England via LGTSC tariffs. At the moment, at least the required annual $526 million in payments upon complete phase-in of the project would be collected from ratepayers. National Grid avers, however, that it

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[19] See, generally, Exhibit NG-JNC-3.

[20] See Exhibit NG-TJB/JEA-2 at 54-56 and Exhibit NG-TJB/JEA-3 at 53-55. We understand that Eversource asserts that long-term (15-20-year) agreements for the full capacity of the ANE project are necessary for the project to move forward. (See, for example, responses to Information Requests for the D.P.U-15-181 proceeding: NEER-2-26, NEER-2-27, NEER-2-44, NEER-3-20, 4-17, and DPU-1-3.) Note that if the full capacity of the ANE project is not subscribed, the EDCs will need to determine whether or not they will be able to go forward with the ANE contracts. However, there are numerous examples of pipeline certification proceedings at FERC in which pipelines have moved forward with considerably less than full subscription and based upon agreements that are often less than 20 years. See, for example, *Texas Gas Transmission, LLC*, 154 FERC ¶ 61,235 (2016) at P. 8 (74% of rated capacity sold under 15- and 20-year contracts) and *Gulf Crossing Pipeline Company* LLC, 123 FERC ¶ 61,100 (2008) at P. 14 (58% of rated capacity sold under 5- to 10-year contracts).

cannot yet tell the full costs of the project,[21] and that the ultimate amounts to be collected from the EDCs may differ from the current "bill" of $526 million. Its ultimate value will depend on what actual costs turn out to be, subject to a cap which allows for up to a [REDACTED] cost overrun relative to currently projected costs.[22] Adding [REDACTED] to $526 million puts ratepayers "on the hook" for [REDACTED] million per year.

Q: **Does the viability of National Grid's proposal depend upon approvals by other New England states?**

A: Yes. National Grid's witnesses Mr. Brennan and Mr. Allocca state that the ANE Project requires approval in New England states other than Massachusetts.[23] Thus, National Grid acknowledges that multiple New England states' public utility commissions will have to approve its proposal to have ratepayers underwrite ANE via LGTSC-type tariffs before National Grid will move forward with the project.

Q: **What would National Grid's proposal represent in terms of additional pipeline and storage facilities if the ANE project is approved?**

A: The ANE project is a proposal to construct an expansion of Algonquin's interstate pipeline running from the New York and New Jersey area to major markets in Connecticut, Rhode Island, and Massachusetts. As described by National Grid, the ANE project is designed to provide electric generators with: "(1) 500,000 MMBtu/day of

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[21] Response to Information Request AG-1-23.

[22] Exhibit NG-TJB/JEA-2 at 50 and 54.

[23] Exhibit NG-TJB/JEA-1 at 41.

access to the gas supplies in the Marcellus Shale region in Northeastern Pennsylvania through Algonquin's existing direct connections to the Millennium Pipeline at Ramapo, NY; the interconnection with Tennessee at Mahwah, NJ; and the interconnection with Iroquois at Brookfield, CT; and (2) 400,000 MMBtu/day of access to a proposed market-area domestic LNG storage facility. The new LNG storage facility in Acushnet, MA will provide storage withdrawal capacity for 400,000 MMBtu/day, liquefaction capability up to 54,000 MMBtu/day, and 6,400,000 MMBtu of LNG storage capacity. Together, the transportation and storage facilities will provide a total of 900,000 MMBtu/day of firm, incremental, integrated transportation and LNG deliverability to multiple generators."[24]

Q: **What is the objective of National Grid's ANE project?**

A: National Grid seeks to increase natural gas pipeline transportation and storage capacity to New England by almost 1 BCF/day. This increase would essentially immediately follow the completion of Algonquin's Algonquin Incremental Market ("AIM") Project, and Tennessee Gas Pipeline's Connecticut Expansion and Atlantic Bridge projects. Given gas pipeline transportation capacity to the region is reported as approximately 4.5 BCF/day following completion of the AIM, Connecticut Expansion and Atlantic Bridge Projects,[25] National Grid's ANE project would represent an increase in natural gas

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[24] See Exhibit NG-TJB/JEA-1 at 17. Eversource acknowledges that the project provides only indirect access to the Marcellus Shale region. D.P.U.-15-181 Exhibit EVER-JGD-1 at 19-20.

[25] See Callan, William, ISO New England, Winter 2014/15 Review, Electric/Gas Operations Committee (EGOC) Teleconference, June 29, 2015 ("ISO-NE Winter 2014/15 Review"), at 15, accessed May 20, 2016 at: http://www.iso-ne.com/static-assets/documents/2015/06/winter_2014_15_review.pdf which reports the ability to deliver approximately 4.1 BCF/day of pipeline natural gas into New England. Adding the expansion projects yields 4.5 BCF/day.

pipeline supplied gas of 20%. This increase in gas supply (via increased transportation and storage capacity) is targeted by National Grid for use by a subset of gas-fired generation plants which are geographically located such that this additional gas transportation infrastructure can increase gas supply available for delivery to the plants.[26]

Q: **Does National Grid's proposal provide retail electric services consistent with those typically provided by EDCs?**

A: No. Traditionally and typically, EDCs make investments on behalf of retail ratepayers. National Grid's proposal is unlike a traditional utility investment that provides direct benefits to customers in terms of reliability or more cost-effective service. National Grid's proposal is unique and unconventional. National Grid's expert, Dr. Michael Vilbert of the Brattle Group, acknowledges that National Grid's approach is "unique" and that the proposal "appears to be the only example anywhere in the U.S. of 'wire-only' EDCs (operating in restructured jurisdictions with organized electricity markets) procuring natural gas transportation infrastructure to serve electricity generators."[27] Under National Grid's proposal, ratepayer's payments under the LGTSCs will not result in traditional used and useful utility capital project (or equivalent thereof) that has tangible day-one benefits, such as a power purchase agreement, which have tangible day-one benefits. Indeed, National Grid is not a vertically integrated utility and has no ability to require any gas-fired generator to use the ANE project facilities for the benefit of its

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[26] Exhibit NG-TJB/JEA-1 at 30. National Grid also acknowledges that it "has no communications with generators about the potential interest in the purchase of the release capacity." Response to Information Request NEER-2-29.

[27] Exhibit NG-MJV-1 at 6.

customers. Under National Grid's proposal, ratepayers would be required to purchase a highly uncertain and very expensive option in the ISO-NE futures market at a virtually certain price.

Q: **What are the economic implications of that for assessing the costs and benefits of the proposal?**

A: The proposal imposes starkly asymmetric risks on retail electricity ratepayers. On the cost side, these ratepayers would bear the certainty of a LGTSC payment totaling more than a half a billion dollars per year. When it comes to benefits, however, customers will not receive any direct benefits associated with National Grid's service obligations as an EDC. Customers will instead bear the costs of National Grid's proposal based on the bet that wholesale energy market price suppression will provide indirect benefits large enough to offset the costs. Retail electricity ratepayers would, therefore, be in the position of accepting an unhedged and highly risky (see further below) prospect that wholesale power prices may turn out to be less than they otherwise would have been on a limited number of cold winter days and that such wholesale power price reductions will be passed through to their retail rates. As we explain further below, under the NPV of ratepayer impact, this unique asymmetry directly affects the discount rates appropriate to the proper calculation of costs and benefits.

Economically, National Grid is essentially seeking to interject new retail electricity ratepayer-funded gas pipeline infrastructure in New England with the hope of intentionally subsidizing gas-fired generators and distorting wholesale electric power market prices. Retail ratepayers would pay the equivalent of a mortgage payment of on the order of more than one half a billion dollars per year in exchange for a pipeline that even the expert for National Grid's joint venture partner represents as having materially positive value during only quite short periods of time.[28] Let us examine whether the costs of such a proposal outweigh the benefit.

B. The Basic Economics of Social Cost-Benefit Analysis

Q: **Please describe the economic framework you have employed in assessing the costs and benefits to the public of the proposal?**

A: We have applied the economic framework used to conduct a standard social cost-benefit analysis. This framework recognizes that the public has an abiding interest in the development of projects that have benefits to the public which exceed their costs. Projects which are designed (as in the case at hand) to deliver certain goods and services to the public use up resources – labor, materials, energy, etc. – that the economy otherwise would deploy to produce other valuable goods and services the public wants. The latter are what a project *costs* the economy. A project serves the public's interest in a healthy economy if the benefits it generates for the public exceed its costs to the public, i.e., if the public gets more value than it gives up. Conversely, if a project's costs exceed its benefits, it is a waste of the economy's resources, shrinking the size of the economic "pie" that the public depends on for its well-being.

Q: **Why do you employ a social cost-benefit analysis in this case?**

[28] See Response to Information Request D.P.U.-15-181 AG-6-20. See also, for example, ICF International, New England Natural Gas Supply and Demand: Post-Winter Review, prepared for GDF Suez Gas North America, 29 May 2014 at 3, 11, and 13.

A: For at least two key reasons. First, National Grid argues that its proposal is needed because affected market participants have not been willing to undertake the risk and cost of the ANE project.[29] Specifically, National Grid asserts what economics terms a "market failure": i.e., the pipeline is needed by the public, but market forces and the market design of, particularly, ISO-NE's wholesale power markets prevent market participants from undertaking the project without compelling ratepayers to effectively underwrite and pay for it. A social cost-benefit test addresses this claim by assessing whether the project is "needed" in the sense that the benefits to the public outweigh the costs of the project to the public. We find that they do not.

Second, the foregoing basic economics of social cost-benefit analysis undergird sound public policy – i.e., policy that serves the public interest. In Massachusetts, this finds recognition in the Department's policy requiring that analyses assessing whether a gas contract proposal submitted by EDC is in the public interest "should be based on a quantitative analysis of the benefits and costs associated with the contracted resource(s) to the maximum extent practicable."[30] We undertake such an analysis here.

National Grid's proposal would clearly be quite costly to the public, most obviously by employing billions of dollars of the economy's resources to build and operate new pipeline and storage facilities. Under National Grid's proposal, the cost-

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[29] See Exhibit NG-MCC-1 at 19-20.

[30] D.P.U. 15-37 at 46. National Grid's expert, Black & Veatch, only examines alleged annualized nominal wholesale electric energy market price suppression benefits relative to the expense of the project, apparently under the assumption that D.P.U. 15-37 limits the cost-benefit analysis to only these two metrics. We consider Black & Veatch's truncated cost-benefit approach, as well as the standard economic social welfare cost-benefit analysis which we believe is consistent with D.P.U. 15-37.

benefit question is whether the benefits of such additional natural gas electricity production are worth the costs. To address this question, we first employ the standard economic framework of public cost-benefit analysis and report the results in this section of our testimony. In Section III below, we examine National Grid's proposal through the lens of National Grid's expert's partial, truncated cost-benefit examination of ratepayer impacts alone.

In this case, our application of standard cost-benefit economics has entailed the use of the same commercially available software modeling tools as employed by National Grid's expert and wholesale power and gas market data to estimate the benefits associated with National Grid's proposal's impact on wholesale power markets. We then rely on data National Grid and Eversource (National Grid's joint-venture partner) have provided in association with their proposals to calculate a reasonable measure of the proposal's projected costs.[31] Following standard practice so as to permit comparison of costs and benefits that extend over the time horizon of at least 20 years, benefits and costs are then expressed in terms of net present value. Our NPVs are calculated by discounting the future streams of benefits and the streams of costs to account for the time value of money and the applicable risks. This calculation, then, permits us to answer the question of whether the total benefits of the proposal to ratepayers exceed or fall short of the total costs to ratepayers.

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[31] Response to Information Request AG-1-23. See Exhibit NG-TJB/JEA-2 at 54-56 and Exhibit NG-TJB/JEA-3 at 53-55. Also see D.P.U.-15-181 Response to Information Request DPU-EVER-3-20

Q: **How does your analysis align with Federal Energy Regulatory Commission ("FERC" or the "Commission") policy relating to natural gas pipeline development and certification?**

A: Our analysis seeks to fully evaluate the costs and benefits of National Grid's proposal. This is consistent with the economics of federal policy regarding natural gas pipeline certification. That policy seeks to promote the public's interest in a productive and efficient economy by certificating pipelines (and storage) when it can be demonstrated that benefits to the public exceed the costs. FERC policy notes that an "effective certificate policy should further the goals and objectives of the Commission's natural gas regulatory policies. In particular, it should be designed to foster competitive markets, protect customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas. It should also provide appropriate incentives for the optimal level of construction and efficient customer choices."[32]

In practice, this policy is commonly implemented by the FERC by its certification of projects when investors are willing to risk their own capital based on the demand they have brought forth for a project.[33] This practice recognizes that well-functioning private markets readily perform requisite cost-benefit analyses – as when a pipeline project is rejected in the marketplace because would-be developers cannot secure

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[32] See Federal Energy Regulatory Commission, Statement of Policy, Certification of New Interstate Natural Gas Pipeline Facilities, Docket No. PL99-3-000, September 15, 1999, 88 FERC ¶ 61,227, at 13.

[33] See, for example, *Gulf Crossing Pipeline Company* LLC, 123 FERC ¶ 61,100 (2008) at P. 105 and *Ruby Pipeline, L.L.C.*, 131 FERC ¶ 61,007 (2010) at P. 23 discussing FERC's open season policy and the fact that pipeline developers may bear cost recovery risk depending upon the up-front capacity contracting of a proposed project.

enough demand from electric power producers, local gas distribution companies, industrial gas buyers, and the like to induce investors to risk development costs *because* the project cannot be shown to generate enough value in the marketplace for those who would otherwise use the project's goods and services.

This circumstance of private investors not being willing to commit their own capital in the marketplace because they do not anticipate being able to garner enough demand from willing buyers to justify the costs of a project appears to apply here. While this indicates that the marketplace of investors and customers see the ANE project as uneconomic (i.e., as having costs which exceed benefits), National Grid proposes to undertake the ANE project anyway by having New England retail electric ratepayers subsidize a subset of New England's gas-fired electric generators. In effect, National Grid proposes to have the New England state regulatory authorities, including the Department, use their powers to create demand for the ANE project where the record shows little demand exists.

Absent demand from *actual* natural gas producers and consumers (such as electric power producers) for increased gas pipeline transportation services, the FERC's focus on the public's interest in efficient projects leads us to undertake a complete economic cost-benefit analysis of National Grid's proposal. In so doing, we ensure that our economic analysis properly captures the costs and benefits which directly impact New England while also identifying effects outside of the New England region through changes in power imports and exports.

C. Modeling the Impact of National Grid's Proposal

Q: **How have you estimated the impacts of National Grid's proposal on the power markets?**

A: As we have stated, if National Grid's proposal is to generate public benefits it would have to do so by causing a reduction in electricity prices in New England at least certain times of the year by reducing the region's wholesale gas-fired power generators' costs of producing electricity. To capture these economics, we model New England's gas and power markets so as to project the impacts of National Grid's proposal on the region's gas and electricity (both energy and capacity) operations and, ultimately, prices. In doing so, we, as does National Grid, use ABB's "Promod" electricity system dispatch modeling software and GPCM® Natural Gas Market Forecasting Systems™ gas market modeling software. We employ these two modeling tools to estimate the change in wholesale energy and capacity market prices with and without the implementation of National Grid's proposal. GPCM® allows us to account for possible constraints on New England's gas transportation and storage system by ensuring that projected power generator and all other consumer natural gas demand are met within system constraints. Promod simulates the dispatch of the New England electric generation fleet, assuming that there can be instances when some gas-fired generators might be unable to obtain pipeline delivered natural gas resulting in the reliance on a fuel supply portfolio that includes LNG and fuel oil. Notably, as explained further below, instances where the gas transportation system operates under such constraints and prices of gas are thereby elevated are as recognized by the expert for National Grid's joint venture partner limited to approximately 30 days per year, an estimate consistent with that offered by ISO-NE.[34]

Q: **How do you measure the impacts of National Grid's proposal on the electricity markets?**

A: Given data inputs on overall system load (demand) and the location, mix (by fuel), fuel input costs, and size of New England's (and surrounding regions') power generation fleet, our modeling proceeds by deriving a set of projected energy prices for a future without the ANE project. We then use our modeling to change the assumption of "no ANE," allowing the project to come on line according to National Grid's proposal and affect regional natural gas prices (primarily showing up as lower peak gas prices during times of the year that experience extremely cold weather). Such lower gas prices, in turn, are modeled (with equilibration via iteration) as affecting New England energy and capacity prices.

1. Wholesale Energy Market Analysis

Q: **What input assumptions have you used in your power market modeling analysis?**

A: First, for natural gas and fuel oil prices, we have relied on actual futures market prices reported at the end of March 2016 as a near-term representation of expected fuel market prices in New England. Thus, we key our base case to the actual marketplace's current

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[34] See ICF International, New England Natural Gas Supply and Demand: Post-Winter Review, prepared for GDF Suez Gas North America, 29 May 2014 at 3, 11, and 13 and Megawatt Daily, ISO-NE still aching for new pipelines: van Welie, January 27, 2016 at 3, McGraw Hill Financial.

expectations of future fuel prices (as reported on the Intercontinental Exchange).[35] Recognizing the inherent uncertainty in fuel prices over long-term time horizons, we also evaluate fuel market price sensitivities that account for future uncertainty.

Next, we have adopted electric generation retirement and addition assumptions for New England which are based upon ISO-NE's 2015 CELT report, including the most recent announced additions and retirements.[36] We have also relied on ISO-NE's 2015 CELT report for future electricity market peak demands and energy forecasts.[37] In addition, we assume that the Environmental Protection Agency's Clean Power Plan is implemented and that New England state's renewable portfolio standards will be satisfied by increased additions of solar and wind resources. Finally, we assume aggregate, near-term retail consumer natural gas demand growth that is consistent with that reported by Massachusetts' local distribution companies, as well as longer-term annualized growth rates that are consistent with various other regional studies estimating future retail consumer gas demand in Massachusetts and New England.

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[35] Reported natural gas futures prices and delivery location basis swaps are used in the modeling for the time period through which they are available. For New England we use basis swaps only through 2019 to ensure that any possible expectation of the ANE project coming into service would not be inadvertently captured in the analysis. Prices in later years use standard analysis to inflate prices based on the U.S. Energy Information Administration's long-term annual growth rate for Energy Commodities and Services.

[36] See, generally, 2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission, ISO-NE System Planning, May 1, 2015, available at: http://www.iso-ne.com/system-planning/system-plans-studies/celt.

[37] Id. We note that we have not captured ISO-NE's most recent 2016 CELT report which now indicates negative demand growth over the next ten years as energy efficiency and renewable resource additions continue to offset any potential load growth.

Q: **How do your wholesale electric energy market modeling input assumptions compare to those used for the Black & Veatch Report?**

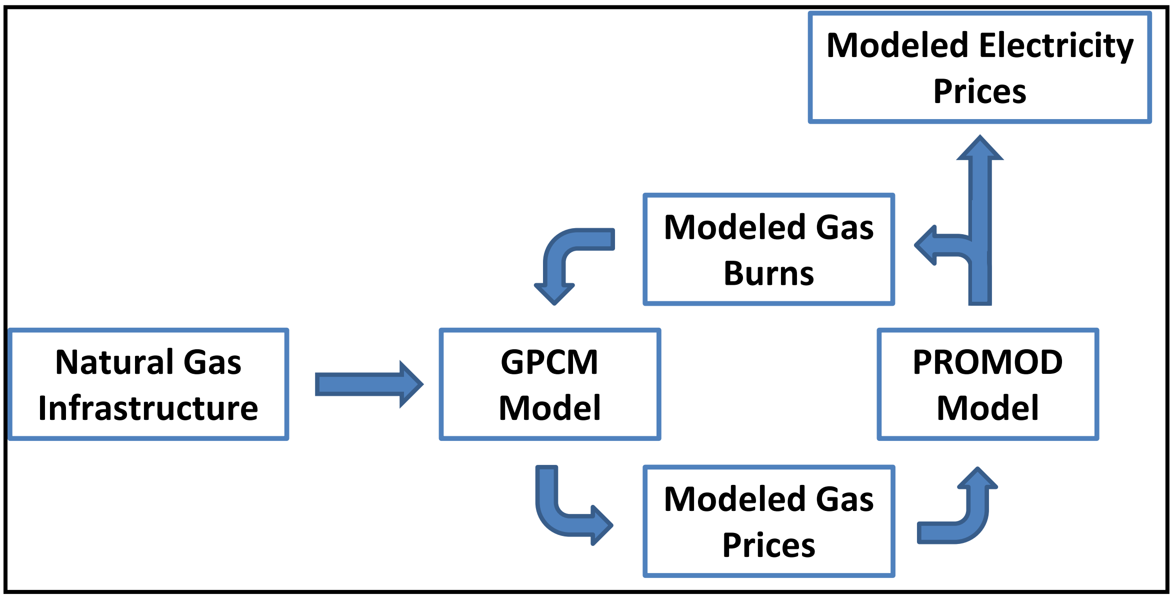
A: The majority of our energy market modeling input assumptions mirror those used in the development of the Black & Veatch Report. The main difference between our modeling and that used by Black & Veatch is that we adopt different input fossil fuel prices (e.g., using actual futures market prices for gas in our Futures Market Forecasts Case) and do not artificially constrain LNG imports.

2. Wholesale Energy Market Modeling: The Futures Market Forecasts Base Case and Sensitivities

Q: **How did you conduct your "Futures Market Forecasts" base case?**

A: We began our Futures Market Forecasts base case analysis by running Promod and GPCM® iteratively to capture accurately the interaction between electric energy and natural gas markets and ensure that natural gas pipeline system constraints are observed. Figure 1 provides a graphical depiction of the iterative modeling process. The Promod model uses GPCM® natural gas market hub prices as inputs and dispatches the U.S. eastern interconnect electric generation system creating for each natural gas-fired electric generation unit's projected natural gas consumption by month. Projected monthly generating unit natural gas consumption is then used in the GPCM® analysis to generate revised natural gas market hub prices. These revised natural gas prices are then used in a subsequent Promod analysis which generates a new set of monthly natural gas consumption by electric generating unit. This iterative process continues until the natural gas market hub prices generated by GPCM® are aligned with the electric generation unit natural gas consumption by month projected by Promod. That is, the GPCM® natural gas market hub prices used in the Promod modeling are based on Promod's projected electric generation unit natural gas consumption by month.

Figure 1
Modeling of Natural Gas and Power Markets



We conduct this iterative process assuming that electric generating units can access LNG and fuel oil resources. Thus, through this iterative process we observe which natural gas-fired power plants that are not dispatched during the winter peak demand period (modeled as the month of January) and subsequently prevent those plants from accessing natural gas when modeling our Futures Market Forecasts base case.[38] Once we have carefully established pipeline gas availability for natural gas generating resources

[38] The analysis identifies approximately 7,000 MW of generating capacity that does not consume natural gas during the peak winter demand month.

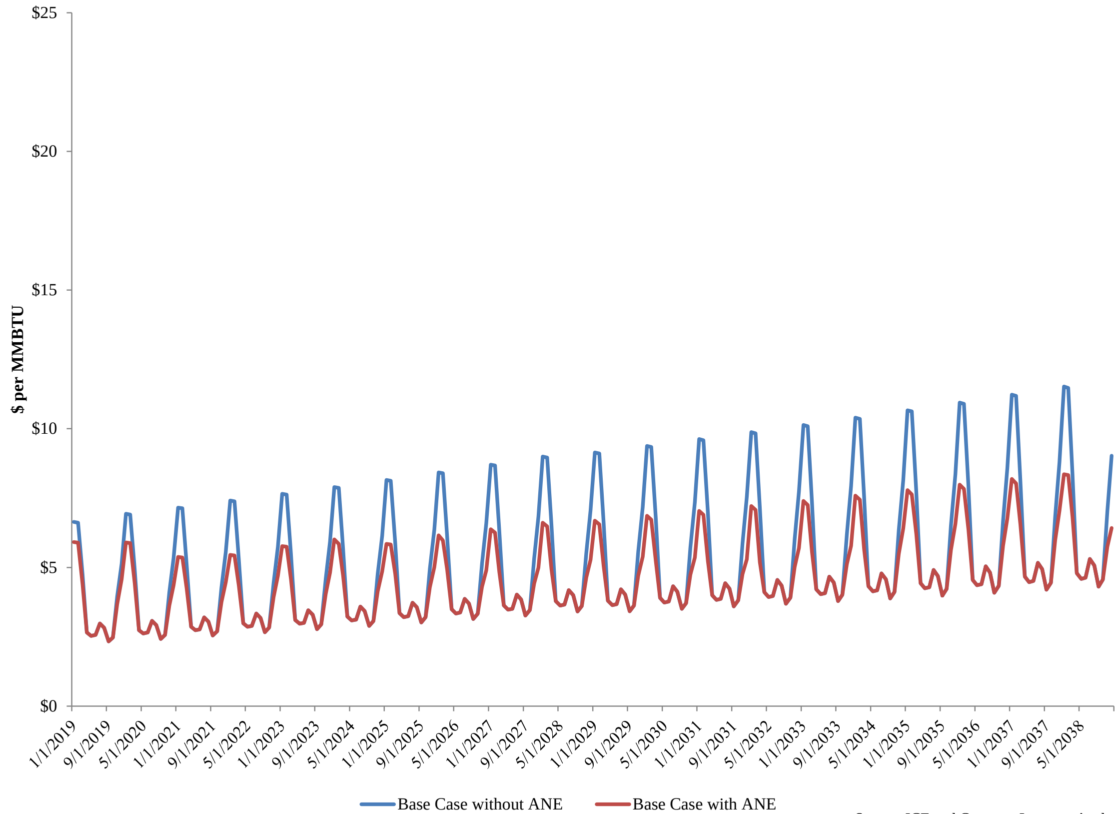
during the winter peak period we can then analyze our Futures Market Forecasts base case using reported natural gas and oil futures market prices.

Q: **How did you estimate the impact of National Grid's proposal on the natural gas market?**

A: We estimated the reduction in delivered natural gas prices resulting from the implementation of the ANE project based upon the findings of our iterative analysis described above. We observe in the results of our iterative analysis that the only notable impact of adding ANE occurs during the winter months of December–March, with the most noticeable effect in the winter peak demand months of January and February. Thus, in the Futures Market Forecasts base case, we assume that the projected impact of National Grid's proposal on wholesale winter natural gas monthly price levels will be similar to those peak winter monthly percentage price reductions that we observe in our iterative modeling analysis.[39] Figure 2 presents the resulting monthly natural gas prices used in our Futures Market Forecasts base case analysis.

[39] When modeling reduced deliver natural gas prices to New England we limit the reduction in prices to the reported futures prices at TETCO-M3 plus $0.10/MMBTU. This is necessary to acknowledge the fact that the price of gas at the primary source for National Grid's proposal cannot be higher than the price of gas delivered downstream to New England.

Figure 2
Futures Market Forecast (Base) Case:
New England Natural Gas Prices with and without ANE



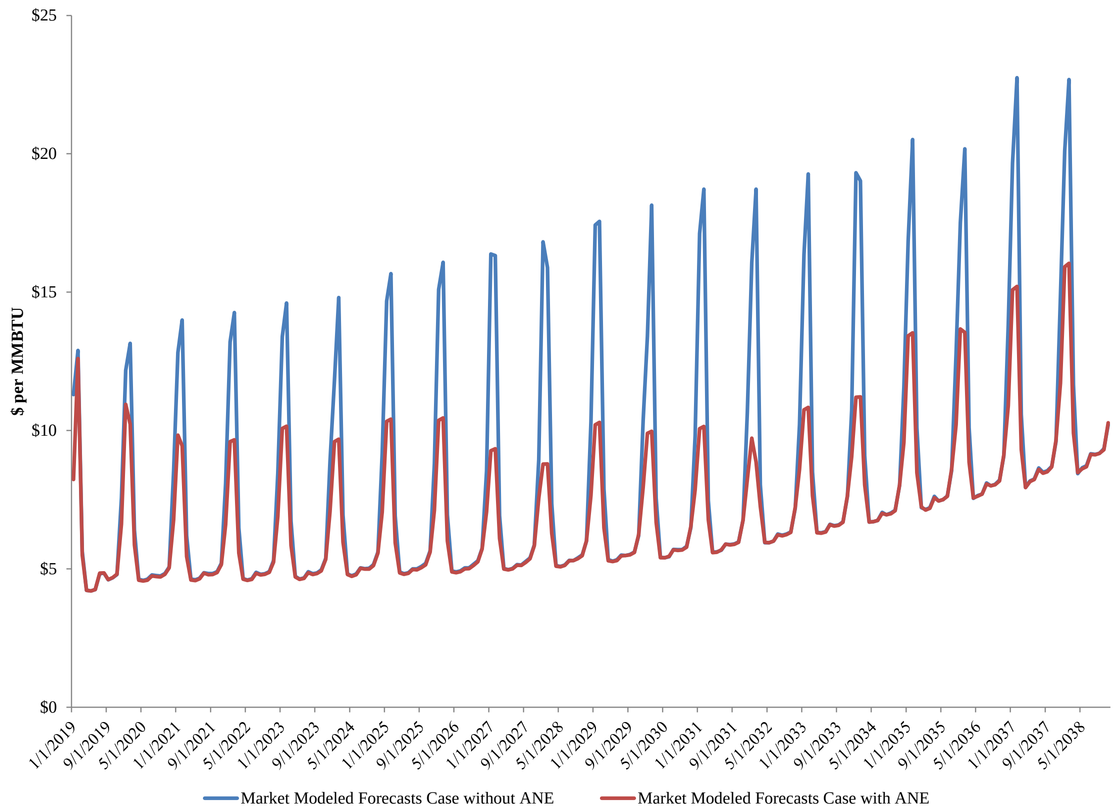
Note: Prices at Algonquin City-Gate.

Source: ICE and Compass Lexecon Analysis

Q: **Please describe your sensitivity analysis of gas prices.**

A: In addition to our ISO-NE Futures Market Forecasts base case, we have also considered a key sensitivity analysis in which we use GPCM® (as opposed to futures market) projections of delivered natural gas prices with and without the ANE project as inputs to the Promod model. In this sensitivity analysis, we directly employ the results of our iterative process assuming that electric generating units can access LNG and fuel oil resources. The result is a Modeled Market Forecast Case. Figure 3 presents the projected delivered natural gas prices used in this sensitivity analysis with and without the assumed addition of the ANE project. As Figure 3 shows, these "modeled" natural gas prices are notably higher than the reported futures market natural gas prices and accordingly represent a high gas price sensitivity analysis.

Figure 3
Model Market Forecasts Case:
New England Natural Gas Prices with and without ANE



Note: Prices at Algonquin City-Gate. Source: ICE and Compass Lexecon Analysis

We assessed the reasonableness of our reliance on this scenario as representative of the possibility of higher benefits attributable to the ANE project by examining natural gas market data. Specifically, to assess the possibility that gas prices in coming years may turn out higher than the futures market currently anticipates, we looked at the volatility of monthly average of daily Algonquin City Gate prices relative to gas supply basin prices. The price differential between Algonquin City Gate prices and supply basin prices captures the historical time pattern of the occasional, seasonal spikes in realized gas prices due to weather and constraints in the gas transportation system, only some of which might be relieved by ANE.

To capture these factors in our analysis, we add the observed one standard deviation in the monthly gas price differential – which is larger in the winter months and smaller in the summer months – to the futures prices. This reflects the possibility that the monthly average gas prices in the future may turn out higher than the market currently expects. The resulting gas prices are similar to the results we obtain from the iterative procedure described above, providing further support for the reasonableness of this procedure (i.e., the iterative gas price determination using GPCM®) as a "high" case estimate of benefits.

3. Impacts on ISO-NE's Capacity Market

Q: **Has National Grid provided any analysis of the financial impact of its proposed ANE project on future ISO-NE Forward Capacity Market prices?**

A: No. National Grid's filing focuses exclusively on presenting an analysis of the introduction of new gas pipeline and storage capacity on wholesale electric energy prices.

Q: **Would National Grid's proposal be expected to have an impact on ISO-NE Forward Capacity Market prices?**

A: Yes. ISO-NE's wholesale electric energy markets and capacity markets are inextricably linked. Wholesale electric energy market prices provide earnings (margins) for electric power suppliers that invest in and own generation resource capacity. However, FERC puts caps on ISO-NE electric energy prices. This can lead to problems of insufficient margin to warrant building and/or maintaining generation capacity. In response, FERC and the ISOs under its jurisdiction rely on centralized capacity markets to ensure that sufficient generation capacity will be available to meet peak energy demand. Centralized capacity markets provide the additional revenues necessary for generation resource owners to maintain and invest in generation capacity.

Q: **Why is it important to recognize the linkage of electric energy and capacity markets?**

A: The fact that supplier energy market margins are held down by FERC wholesale energy market price caps at those time when demand pushes up against total system supply (including operating reserves) is referred to as the well-known "missing money" problem. The "missing money" problem is described as a situation in which, because of energy market price caps, energy revenues alone are insufficient to induce the capacity investments needed to prevent shortage situations. As explained in a frequently cited paper by economist John Chandley, "capacity-based mechanisms" seek "to address the missing money problem by providing payments to reward demand-side resources and pay generators the money they would otherwise receive if wholesale market prices for energy and operating reserves properly reflected the value during shortages – that is, the full value when the system is short on operating reserves."[40] Thus, if generation resource energy market revenues (and margins) are reduced, all else equal, the reduction needs to

[40] Chandley, John, "PJM's Reliability Pricing Mechanism: (Why It's Needed and How It Works)," March 2008, at 3.

be recovered through higher capacity market revenues to ensure ongoing generation reliability.

Q: **How does the ISO-NE Forward Capacity Market capture the impact of reduced energy market margins?**

A: The ISO-NE Forward Capacity Market captures energy market margins by calculating and imputing an energy and ancillary services markets offset ("E&AS Offset") in association with the estimation of new and existing generation capacity market resource offer prices. When making these estimates ISO-NE relies on detailed cost data it compiles on different types of generation capacity resources. It uses this cost data and E&AS Offset values to estimate capacity resource market offer prices. With respect to the estimation of new generation capacity resource offers, ISO-NE undertakes an extensive evaluation of the costs associated with developing new capacity resources in New England. With respect to existing capacity resources, ISO-NE extensively evaluates those generation capacity resources that are expected to rely significantly on capacity market revenues to maintain operations. When making these calculations, ISO-NE carefully incorporates an estimate of the E&AS Offset. Applied to the case before us, to the extent that the ANE project would lower natural gas and, hence, electric energy prices in New England, the project would also lower ISO-NE's E&AS Offset and raise the Net-Cost of New Entry ("Net-CONE").

Q: **Please explain.**

A: The latter effect has two components. First, when estimating the cost associated with the development and construction of new generation capacity, ISO-NE calculates the Net-

CONE. Net-CONE is used by ISO-NE to establish the demand curve pricing schedule used in its capacity market auctions and represents the range of capacity market prices that can result in ISO-NE's capacity auctions.[41] Net-CONE is estimated triennially and was last calculated on behalf of ISO-NE in early 2014.[42] The calculation of the E&AS Offset occurs as part of the Net-CONE analysis and is an important input to the study.

For example, the ISO-NE Net-CONE Study reports that the E&AS Offset for the 2018 Forward Capacity Market was equal to $3.33/kW-Month, or about 25% of the total estimated CONE of $14.04/kW-Month. Because the ISO-NE capacity market demand curve pricing schedule is based upon Net-CONE, a reduction in the E&AS Offset (which would result under National Grid's proposal) will result in an increase in Net-CONE. Moreover, the ISO-NE Net-CONE Study shows that monthly E&AS Offset margins during winter months are a significant source of earnings for generation resource owners.[43] A reduction in winter E&AS Offset margins induced by the ANE project would raise Net-CONE and would be in an ISO-NE demand curve pricing schedule that is higher than it would be otherwise. Such an increase in Net-CONE would push capacity market prices upward relative to where they otherwise would settle.[44]

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[41] Section III.13.2.2., ISO New England Inc. Transmission, Markets, and Services Tariff, available at: http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

[42] See Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, Federal Energy Regulatory Commission Docket No. ER14-1639-000, April 1, 2014, (hereinafter "ISO-NE Net-CONE Study").

[43] ISO-NE Net-CONE Study at Figure 5.

[44] ISO-NE recognizes that generating unit capacity market offers will adjust upward in response to energy market price reductions associated with out of market subsidies. See Response to Information Request D.P.U.-15-181 NEER-3-45 and Attachment D.P.U.-15-181 NEER-3-45(b) at 31.

Second, when ISO-NE calculates its estimate of an acceptable offer-price floor for what it expects to be its less frequently operated generation capacity resources, but likely still needed, it also incorporates an estimate of the E&AS Offset. ISO-NE reports in its most recent calculation of this offer floor price that it is based on the net going forward costs of a fossil steam generation capacity resource (e.g., an oil-fired steam electric generation unit).[45] The net going forward costs are equal to the generating unit variable cost (fuel and operations and maintenance) plus avoidable capital expenditures and overhead, less revenue from energy and ancillary services markets (i.e., the E&AS Offset). Thus, as is the case with the Net-CONE, an ANE-induced decrease in the E&AS Offset would result in an increase in the floor offer price, which, all else equal, would push capacity market prices upward. This would be felt as a cost by wholesale electricity market buyers.

Q: **Have you calculated the impact of National Grid's proposal on ISO-NE capacity market prices?**

A: Yes. Based on our modeling of price effects in wholesale electric energy markets, we estimate that National Grid's proposal would be expected to push up capacity prices in the Forward Capacity Market by $1.40-$2.70/kW-Yr over the term of the proposal.

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[45] See, ISO New England, Increasing the Dynamic De-list Bid Threshold, Robert Laurita, Manager, Market Monitoring, NEPOOL Markets Committee, March 10, 2015, available at: http://www.iso-ne.com/committees/markets/markets-committee/?eventId=125207.

D. Calculation of Energy and Capacity Market Benefits and Costs

Q: What economic principles have guided your cost-benefit calculations?

A: In order to assess the impact of National Grid's proposal on the economy (i.e., the public interest), our analysis captures *all* of the costs and benefits associated with National Grid's proposal that would be borne by the public. Thus, we do not restrict our analysis (as National Grid does) to examining only uncertain wholesale electricity market buyer benefits arising from supposed wholesale electricity market energy price reductions.[46]

From the perspective of the overall economy, any benefits of the ANE project would have to arise because the project would reduce wholesale prices of natural gas in New England and, thereby, reduce the costs of producing electricity in the region. It is a benefit to the public if the electricity that New England uses can be produced at a lower cost. Because the demand for electricity is highly inelastic (i.e., changes in power prices in the ranges at issue do not materially affect overall system load),[47] benefits of the proposed project would then take the form of reduced electricity *production costs* – i.e., producing a given amount of electricity, but using lower cost resources (natural gas delivered to New England power plants) to produce that electricity. A proper cost-benefit test then compares the present value of such production cost savings to the present value

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[46] National Grid refers to its measure of benefits as "benefits to electric consumer" (see, e.g., Exhibit NG-JNC-3 at 8). In fact, Black & Veatch measures *wholesale market buyer* cost savings and provides no demonstration as to the extent to which such savings are passed through to electricity consumers.

[47] In the modeling discussed below, both we and Black & Veatch treat the aggregate demand for electricity (system load) as exogenously given.

of the costs incurred by the public to achieve those benefits – i.e., the cost of the ANE project.

These basic economics of a social cost-benefit analysis are widely recognized, and are embodied in, for example, ISO-NE's criteria for assessing the desirability of transmission projects in the federally-regulated wholesale power markets. Referring to "Transmission Upgrades" (and the ANE project can be characterized as an "upgrade" in the system by which New England power plants acquire natural gas), ISO-NE notes:

"Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade."[48]

On the cost side, note that the analog in this case to the present value of the "carrying cost of the identified transmission upgrade" is the present value of the proposed cost of the project proposed by National Grid and its ongoing estimated annual operational costs.[49] Our Futures Market Forecasts base case cost-benefit analysis accordingly considers the present value of such "carrying costs." As discussed above, however, National Grid's proposal allows for a substantial increase in LGTSC tariffs

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[48] ISO New England Inc. Transmission, Markets, and Services Tariff, Sect ii, Attachment N at II.B

[49] See D.P.U.-15-181 Response to Information Request DPU-EVER-3-20 and attachment DPU-EVER-3-20.

[REDACTED] beyond the cost estimate provided by Grid. Accordingly, we also consider the impact of such higher costs of the project in our cost-benefit analyses.

1. Public Benefits

Q: **How have you measured the benefits of National Grid's proposal?**

A: As described above, National Grid's proposal would be expected to lower the costs of meeting New England's electricity system load (demand) to the extent additional gas supplies made available to gas-fired power generators put downward pressure on gas prices and hence generator's costs of producing power. Lower costs of gas-fired generation would be expected to result in reduced electric energy prices – as our modeling finds. On the other hand, as we have seen, electric energy production cost savings induced by the ANE project would be expected to raise the cost of capacity resources in ISO-NE's Forward Capacity Market. In determining the magnitude of overall production cost savings, we calculate both sources of production cost effects on a yearly basis over the 20-year term of National Grid's proposal.[50] We then discount these annual production cost savings and capacity market cost increases to their 2016 present values.

Q: **How do you determine the discount rate to use in your analysis of wholesale energy and capacity market benefits?**

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[50] Our standard societal cost-benefit analysis appropriately nets out transfers of economic rents and surplus between producers and consumers or between ratepayers and the EDCs, resulting in zero net social benefit or cost from these transfers.

A: Following standard practice, we select our discount rate based on the risks associated with energy and capacity-related cash flows. Because hoped-for public benefits[51] under National Grid's proposal depend upon future prices in wholesale electric energy markets, market participant beneficiaries are similar to, for example, a merchant generation facility whose operations, and, hence, cash flows, are exposed to wholesale power market price fluctuations. Accordingly, market participants are exposed to wholesale power market fluctuations and when it comes to valuation of hoped-for benefits under National Grid's proposal, we select a discount rate based on the risk that wholesale power market merchant generators face. Our base case discounts benefits at 8% per annum, based on ISO-NE's most recent analysis of merchant generator wholesale market risk.[52] Due to the fact that a generator's ability to recover the costs of this capacity is highly uncertain in the current ISO-NE market design, a discount rate that includes an appropriate risk premium is appropriate. The resulting values are shown for our Futures Market Forecasts base case and our Modeled Market Forecast sensitivity case in Table 2. (The base case in the top panel of Table 2 repeats Table 1B, discussed above in our summary of conclusions.) The present value today of the estimated public benefits of National Grid's proposal in our base case totals \$2.57 billion (See top panel of Table 2; \$2.825 billion minus \$258 million). Public benefits are similar – at \$2.52 billion – in our Modeled

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[51] The hoped-for benefits take the form of reduced prices in wholesale electricity markets resulting from reduced electric generator production costs. The incidence of any such price reductions would be split among retail and wholesale electric market buyers, depending on whether wholesale market price changes would be fully, or only partially, passed through to retail rates.

[52] ISO-NE Net-CONE Study at Table 15.

Market Forecasts sensitivity case. How do such hoped-for benefits stack up against the costs of the project? Let us turn to this question now.

Table 2
Economic Costs and Benefits of National Grid's ANE Proposal[1]
2016 Present Values; $Millions

CASE: Futures Market Forecasts

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$2,825		
Electric Capacity		-$258	[REDACTED]
Pipeline Cost		-$3,146	[REDACTED]
Total Present Value	$2,825	-$3,404	[REDACTED]
Total Net Present Value		**-$578**	[REDACTED]

CASE: Modeled Market Forecasts

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$2,863		
Electric Capacity		-$343	[REDACTED]
Pipeline Cost		-$3,146	[REDACTED]
Total Present Value	$2,863	-$3,489	[REDACTED]
Total Net Present Value		**-$625**	[REDACTED]

Note:
1) Energy market benefits, construction costs, operational costs, and capacity market costs discounted at 8% weighted average cost of capital approved by ISO-NE for Net Cost of New Entry analysis. See Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, Federal Energy Regulatory Commission Docket No. ER14-1639-000, April 1, 2014

Source: National Grid and Compass Lexecon Analysis

2. Costs of National Grid's Proposal to the Public

Q: **What are the costs to the public of National Grid's proposal?**

A: To determine the full cost to the economy of the ANE Project, we have proceeded by using what record evidence is available on up front capital costs, as well as operations and maintenance costs, and calculated the present value (as of 2016) of the resource cost of the ANE project. In arriving at this value, we have employed a discount rate of 8%, reflecting what the marketplace commonly charges as a cost of capital and the value that ISO-NE has recently found to be applicable to incremental capacity additions on projects subject to wholesale power market risks.[53] Due to the fact that a generator's ability to recover the costs of this capacity is highly uncertain in the current ISO-NE market design, a discount rate that includes an appropriate risk premium is appropriate. As shown in Table 2, we calculate the present value of the total cost to the economy of the ANE project under National Grid's proposal to be approximately $3.15-[REDACTED] billion (including at the upper end of the range National Grid's allowance for cost overruns).

3. Costs to the Public of Distortions to Capacity Markets

Q: **You noted above that to the extent that the public might realize a gross benefit from lower prices for electric energy, such an impact would be offset to some extent by increases in prices in ISO-NE's forward markets for electric generating capacity. Have you calculated the present value of the cost to the economy of that offset?**

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[53] ISO-NE Net-CONE Study at Table 15.

A: Yes, we have. The results are shown in Table 2. In our Futures Market Forecasts base case, the proposed ANE project would be expected to cost the public approximately $258 million in present value (top panel of Table 2). Larger price reductions in our Modeled Market Forecasts sensitivity case correspond to larger price increases in forward capacity market cost, causing the cost to the economy from such increases to rise to $343 million (bottom panel of Table 2).

E. National Grid's Proposal Fails the Standard Economic Cost-Benefit Test

Q: **When you compare all of the public costs and benefits of the ANE project as it is set out in National Grid's proposal, does it pass the social cost-benefit test for being in the public interest?**

A: No, it does not. As shown in Table 2, in our Futures Market Forecasts base case, the project would produce public benefits of approximately $2.57 billion, but getting these benefits would cost anywhere from $3.15 to [REDACTED] billion (accounting for likely cost overruns). Costs exceed benefits by $.6-[REDACTED] billion. This means that, on a net present value basis, the project would be a waste. As such, it would be contrary to the public's interest in an efficient and healthy national economy. In colloquial terms, National Grid's proposal, therefore, would cost far more – at least $.6 billion more – than the benefits it could hope to generate.

The same basic conclusion applies under our high natural gas prices, Modeled Market Forecasts sensitivity analysis. As shown in the bottom panel of Table 2, the present value of the costs to the public of National Grid's proposal would exceed the present value of hoped-for public benefits by $0.6-[REDACTED] billion.

We have considered the implications of other sensitivities, as well. We have also tested the sensitivity of our results to the use of higher discount rates. Specifically, we have applied a discount rate equal to the value used by Eversource's expert ICF when conducting prior analysis on the ANE project. In this instance, when ICF was asked by the New Hampshire Public Utility Commission to provide the carrying cost rate used to calculate the $400 million in levelized annual cost associated with ICF's analysis of the ANE project, ICF utilized a weighted average cost of capital of 11.5% as the discount rate for deriving its annualized cost.[54] Using ICF's discount rate of 11.5% results in costs to the public that exceed hoped for public benefits by greater amounts than shown in Table 2. In our Futures Market Forecasts case, the present value of National Grid's proposal is negative $.8-[REDACTED] billion. In the Modeled Market Forecasts case, the corresponding figures are negative $0.9-[REDACTED] billion.

Finally, we have considered the possibility that fuel oil prices could rise in the future. We considered for our futures market modeled case the possibility that oil prices would rise to the higher levels observed in the market place prior to the oil price decline in late 2014.[55] We find that the impact would not fundamentally change our findings. Higher oil prices would be expected to result in higher cost savings when ANE is assumed to be in service when gas would be otherwise unavailable. This effect is capped

[54] Spectra Energy Partners' Responses to July 15, 2015 Initial Staff Questions to Spectra Energy in Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices, 31 July 2015 at 4. Note it is unclear why the projected annualized cost was so much lower than the now proposed $526 million per year less than a year ago. See also Response to D.P.U 15-181 Information Request NEER-5-11.

[55] In our high oil analysis we assume that fuel oil futures prices are 100% higher than the values reported at the end of March, 2016.

by the availability of LNG whose price is based upon U.S. domestic natural gas prices and available at prices lower than oil. We calculated that high oil prices could increase benefits approximately $500 million ($2016 present value) over the proposed ANE contracts' term, but this would not alter our findings that the cost to ratepayers exceed their benefits.

In short, the ANE contracts that National Grid proposes fail the standard economic test of yielding benefits that exceed costs. Instead, just the opposite would occur under National Grid's proposal. By having retail ratepayers bear costs associated with an option unrelated to the distribution and transmission service National Grid provides as an EDC in exchange for highly uncertain benefits to gas generators, the project's developers would recover the costs on a wasteful project. This would be contrary to the public interest in a healthy economy, and is the antithesis of sound regulatory policy.

Q: **How do your results compare to those reported by National Grid's expert, Black & Veatch?**

A: Black & Veatch has provided no results to which ours can be compared. In fact, Black & Veatch did not report a standard economic cost-benefit analysis that included all costs and benefits to the maximum extent practicable as requested in the DPU's order in DPU 15-137. In particular, it did not address the question of the public interest and whether National Grid's proposal would generate electricity production cost savings that outweigh the cost of the ANE project.

III. Assessment of National Grid's Economic Claims

A. Summary of National Grid's claims

Q: **Please describe the cost-benefit analysis provided by National Grid.**

A: Black & Veatch has sponsored a report that presents various estimates of hoped-for electric energy cost reduction benefits as a consequence of National Grid's ANE proposal. These projected benefits would purportedly flow from the ANE project as a result of its suppression of prices in the federally-regulated wholesale electricity markets.[56]

The core of National Grid's purported net benefit analysis is a limited examination of the asserted forecasted impact of the implementation of the proposed joint venture natural gas pipeline and storage project on New England wholesale electric energy market prices. Black & Veatch's analysis is represented as exhibiting a reasonable forecast of future expected natural gas prices and wholesale electricity market prices in New England with and without the joint venture pipeline. These forecasts are then used as a basis to measure the estimated benefits of the ANE project, which are defined as the annual change in wholesale electricity prices multiplied by the associated annual projected electric energy consumption. Black & Veatch adds to these purported benefits the alleged gains to ratepayers arising from an asserted reduction in the volatility of retail electricity consumer rates as a result of a reduction in the volatility of daily

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[56] See Exhibit NG-JNC-3.

wholesale electric energy prices supposedly attributable to the ANE project. The benefits are then discounted.

From the price-suppression benefits it calculates, Black & Veatch deducts the *assumed* annual costs of the joint venture pipeline that National Grid's proposal would require retail electricity ratepayers pay for the actual costs of the ANE contracts (assuming all utilities identified as participants by National Grid also negotiate equivalent ANE contracts). The assumed and effectively certain costs are discounted at the same rate as the highly uncertain and risky hoped-for-benefits. The consequence is that Black & Veatch then asserts that its measures of annual ratepayer benefits exceed the cost ratepayers would have to pay for the ANE project by on the order of $10.2 billion.[57]

Q: **Please summarize your findings as to National Grid's purported cost-benefit analysis**

A: As addressed more fully below, we find the results of National Grid's analyses and its asserted conclusions unreliable for the following reasons:

Inconsistency with Current and Future Natural Gas Markets: Black & Veatch and National Grid ignore the recent responses of New England wholesale markets to natural gas price volatility during Winter 2013/2014. Increased deliveries of LNG and reliance on fuel-oil electric generation demonstrate that these fuel sources can, and will, substitute for pipeline delivered natural gas. Moreover, increased natural gas pipeline delivery capacity coming on-line in 2016 and 2017 provide incremental system capacity

[57] See Exhibit NG-JNC-3 at 24.

that can be expected to reduce the likelihood of unexpectedly high natural gas prices and volatility over the next few years.

Reliability: Neither Black & Veatch nor National Grid demonstrates that absent the development of the ANE pipeline that the reliability of the regional electricity grid is at risk. While National Grid repeatedly implies that the proposal will contribute to reliability, it has presented no analysis that demonstrates that, but for the development of the ANE project, electricity consumers will suffer costly load shedding measures. In fact, as discussed in more detail below, the evidence indicates that insinuations of "lights going out" scenarios are unfounded; New England and ISO-NE have repeatedly demonstrated the ability to adjust to changing energy markets and satisfy reliability requirements. No basis is provided for the proposition that it is in the public interest to have retail ratepayers incur the cost of subsidizing a subset of New England gas-fired electric generators with no reasonable guarantee of future benefits large enough to cover the costs.

Retail Price Volatility: Black & Veatch's supposed wholesale market volatility analysis does not support the assertion that electric consumer *retail* rates would be lower or less volatile due to the alleged reduction in volatility in spot market *wholesale* electricity prices. In fact, as we discuss further below, the evidence indicates that large price spikes in wholesale electricity markets are repeatedly smoothed out by seller hedging of prices and the like. The result is that such spikes are virtually non-existent in retail prices.

Benefits and Costs Measurement: Finally, Black & Veatch's cost-benefit analysis is incomplete – leaving the proffered calculations unreliable. First, Black &

Veatch inaccurately calculates annualized benefits. Second, even within its own framework, it omits significant costs that would be borne by ratepayers by excluding the distortionary, price-raising impacts of the ANE proposal on capacity markets. Third, Black & Veatch's discount rates are at odds with the unique economic structure of National Grid's proposal and, thus, inapplicable to its determination of purported annualized net benefits. Fourth, Black & Veatch creates a strawman "but for" setting in which, notwithstanding very high payoffs from doing so, alternatives to the ANE project are not undertaken in the marketplace. Finally, as we explain below, National Grid and Black & Veatch have grossly understated the cost ratepayers would bear if forced to shoulder the cost, with virtual certainty, of $526-[REDACTED] million per year in LGTSC tariffs proposed by National Grid.

B. National Grid's proposal and New England's Current Wholesale Gas and Power Markets

Q: **How have recent events in the natural gas market in New England colored National Grid's proposed ANE project?**

A: National Grid's proposal comes on the heels of the 2013-2014, so-called "Polar Vortex" winter which presented a small number of particularly cold days and natural gas price volatility throughout the Mid-Western, Mid-Atlantic and Northeastern United States. As shown through Heating Degree Days ("HDDs") data,[58] the coldest days of the 2013-14 winter occurred over a period of 4-5 days and represented a notable cold weather period

[58] HDDs measure the difference between the average daily dry-bulb temperature and 65 degrees. For example, if the average daily dry-bulb temperature is 0 degrees, then there are 65 HDDs for that particular day.

for New England. Resulting high spikes in wholesale prices for natural gas in the New England region drew attention to the fact that New England electric generation facilities generally obtain natural gas supply day-to-day when making supply offers into wholesale electricity markets.[59]

Q: **How did New England prepare for and respond to the very cold weather days in 2013-2014?**

A: Prior to the 2013-2014, ISO-NE had observed that electric generation unit availability had declined and pinpointed design short-comings in the wholesale markets that failed to create appropriate incentives for electric generators to be available when operations were in greatest demand. To guard against potential operational failures, ISO-NE subsequently implemented what it called a "winter reliability program" in order to ensure that its fleet of electric generation facilities—many of which are fueled by both oil and gas, or just oil—would have sufficient oil supply available to operate in the event of extreme winter demand. ISO-NE's winter reliability program thus helped alleviate certain market design problems and, further, ensured ISO-NE could respond to cold weather spells.[60]

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[59] The extent to which the cold weather affected a large geographic region is highlighted by the fact that on one of the notably coldest days during Winter 2014 (January 28th 2014, HDD=47.75, 11th coldest day of the season), the natural gas price west of New England where the ANE project will source its natural gas (Tetco M3 zone located along the New Jersey/Pennsylvania border) was $81.3/MMBTU. The contemporaneously reported Algonquin City Gates price was $73/MMBTU.

[60] See, for example, Letter from Gordon van Welie, President and CEO to Commission Judith Gordon, 6 July 2015, at 3, noting that the winter reliability programs "have proven to be a cost-effective short-term solution to help keep the lights on in New England during the winter." ("van Welie letter of 6 July 2015 to DOER")

When first implementing its winter reliability program, ISO-NE focused on ensuring that generation plants which could operate on fuel oil had such supply available for operations. Initially, ISO-NE did not allow suppliers using LNG to participate in its winter reliability program as the ISO was concerned that providing incentives to gas suppliers or generators to ensure incremental gas supply would affect wholesale electricity prices by inadvertently distorting the gas costs that make up the bulk of a gas-fired generator's energy offer.[61] Beginning with the winter of 2014-2015, ISO-NE revised its winter reliability program to allow increased deliveries of LNG supply to qualify under its program.

Q: **What happened during the winter of 2014-2015?**

A: The winter of 2014-2015 was notably much colder in New England than the "Polar Vortex" winter of 2013-2014, with an extended cold spell in the month of February. In fact, total heating degree days ("HDDs") exceed 3,300 in the winter of 2014-2015 (measured for the months December–February). This was well above average for the last decade and greater than the 3,162 HDDs observed over the same period in the winter of 2013-2014. Nevertheless, wholesale natural gas and electricity prices were noticeably lower in the winter of 2014-2015.

[61] See, *ISO New England Inc.*, 144 FERC 61,204 at P. 45 (2013). In particular, FERC noted ISO-NE was concerned that compensating natural gas resources for incremental natural gas could reduce opportunity costs, and thus wholesale electric prices, at times of high natural gas demand, thereby sending the wrong signal during times of natural gas scarcity.

Q: **Why were wholesale electricity prices lower in the face of a much colder winter season?**

A: ISO-NE's allowing of LNG supply to participate in its winter reliability program contributed to a marked increase in LNG deliveries and a decline in New England natural gas prices relative to 2013-2014. This result occurred in spite of the 2014-2015 winter season being at near record low temperatures.[62] Figure 4 shows the monthly average of daily delivered natural gas prices to New England over the past five years and reveals the notable reduction in gas prices in 2014-2015 relative to 2013-2014. In sum, higher than average wholesale natural gas prices in New England in the winter of 2013-2014 and ISO-NE reforms brought forth additional sources of fuel supply (including LNG). This softened demand for pipeline natural gas and served to relieve pressure on the region's wholesale natural gas prices.

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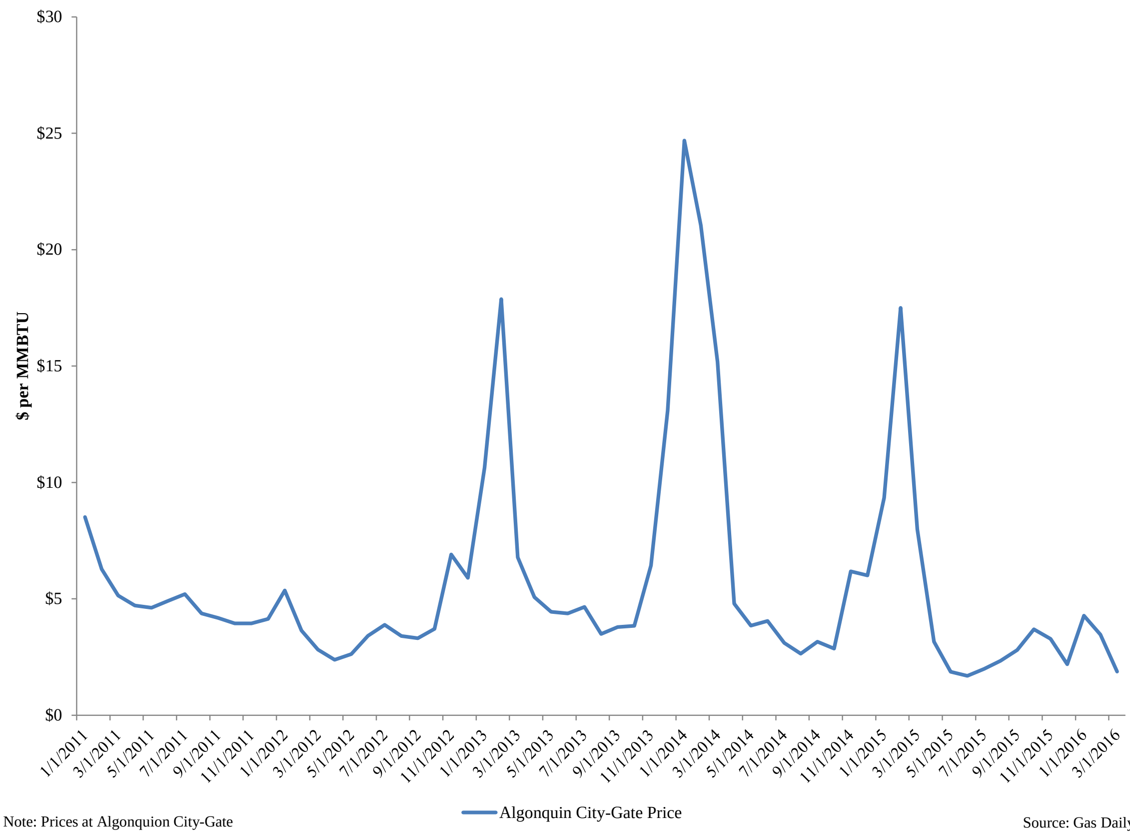
62 ISO-NE Internal Market Monitor, First Quarter 2015, Quarterly Market Report, 9 June 2015 at 7.

Figure 4
Historic New England Natural Gas Prices (January 2011-March 2016)



Note: Prices at Algonquion City-Gate

Source: Gas Daily

Q: **How have natural gas prices evolved in New England since the winter of 2013-2014?**

A: As shown in Figure 4, New England's wholesale natural gas prices during peak winter demand have declined significantly from the 2013-2014 winter season through to the present. The most recent winter of 2015-2016 was notably milder than the previous two winters and wholesale natural gas prices were concomitantly much lower than in previous years. Such prices stand in stark contrast to Black & Veatch's prediction of high and ever increasing wholesale natural gas prices for New England.

Q: **But haven't these recent periods of elevated prices created concern that New England's reliance on natural gas-fired generation resources portends ever increasing winter electricity prices?**

A: National Grid seeks to argue that ever increasing winter electricity prices are what New Englanders can expect, thereby insinuating the need for the ANE project to suppress electricity prices on the coldest days of the year in New England.[63] However, the market's and ISO-NE's responses to date—including increased LNG and fuel oil supplies—have shown that any immediate concerns of continued high natural gas prices are unfounded. Moreover, the AIM project and other ongoing pipeline system expansion projects (which, combined, will serve to increase natural gas supply to New England by roughly 0.41 BCF/day) are expected to begin operations in the fall of 2016.[64] Not surprisingly, investors and other marketplace participants do not foresee the sharply higher prices for wholesale natural gas in the New England region that Black & Veatch's analysis is predicated upon. This is evident in Figure 5, which compares actual market participants' forecasts of New England gas prices as embodied in actual futures prices to Black & Veatch's forecasted futures prices. The latter are grossly inconsistent with actual marketplace forecasts found in futures prices for the winter periods.

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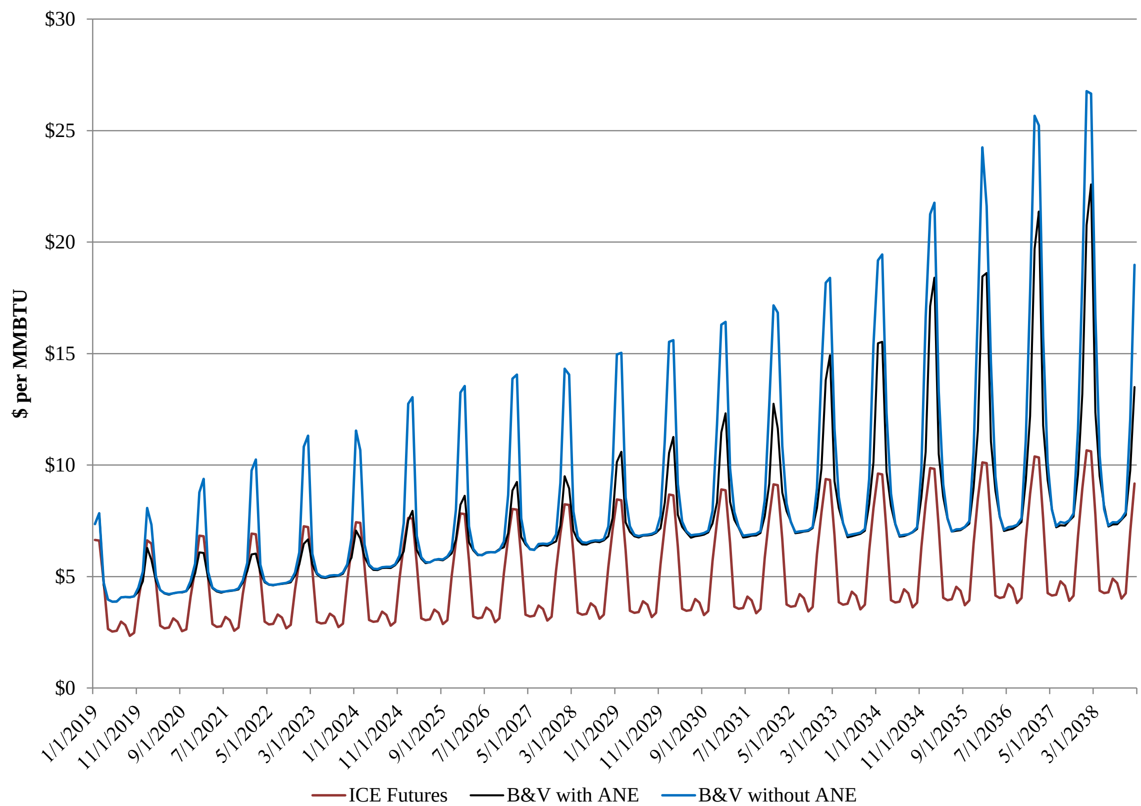
[63] See Exhibit NG-JNC-3 at Figure 10.

[64] See http://www.kindermorgan.com/business/gas_pipelines/east/connecticut/ and http://www.spectraenergy.com /Operations/US-Natural-Gas-Operations/New-Projects-US/Algonquin-Incremental-Market-AIM-Project/. Note that Spectra' Atlantic Bridge Project is expected to be completed in November 2017 adding an additional .13 BCF/day of pipeline capacity to New England.

Figure 5
New England Natural Gas Prices: Black & Veatch Forecasts (with and without ANE) v. Forecasts Based on Futures Market
January 2019-December 2038



Note: Futures estimated employing EIA Long-Term Outlook Energy inflator. Prices at Algonquin City-Gate.

Source: Black and Veatch, ICE, and EIA

Q: **What might explain such a stark inconsistency between marketplace expectations and Black & Veatch's analysis?**

A: Several factors are at work here. Black & Veatch's New England gas market price forecasting model relies on [REDACTED] to forecast future gas market prices.[65] As

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[65] See GPCM ® modeling documentation.

noted, at the time when extremely colder weather descended on New England in the winter of 2013-2014, ISO-NE's winter reliability program had not yet focused on incentives to ensure the availability of LNG. As a result, there was little LNG fuel supply readily available to help alleviate tight supply conditions at periods of peak weather-driven demand. This limited the marketplace's ability to respond to tightness in overall fuel supply. The results were sharply elevated gas prices for a number of days. As discussed above, the winter of 2014-2015 was different. Aided by ISO-NE's winter reliability program, the marketplace responded with additional fuel supplies and gas prices remained substantially below the peaks seen in the previous year (see Figure 4).

By relying on historical market pricing data to project future market pricing, Black & Veatch's gas price forecasting picks up a series of prices spikes, but fails to pick up the reality that past price spikes induce market and policy responses that dampen future price spikes. As seen in Figure 5, the resulting *marketplace* forecasts make it clear that Black & Veatch's forecasted winter gas prices in New England are far higher than can be supported by those who participate in futures market transactions.

Q: **But isn't it the case that forecasted increases in natural gas demand in the region will result in higher and higher gas prices?**

A: Not necessarily. In particular, there are several factors – as shown by Black & Veatch's own modeling – that collectively indicate that future natural gas supply/demand conditions are not expected to result in ever-tighter winter supply and demand conditions. First, natural gas pipeline capacity is being steadily expanded. This is occurring *without* the retail ratepayer funded ANE proposal.

Such expansion serves to alleviate potential constraints in the pipeline network serving he marketplace, including electric generators. As Eversource noted in its application to the Department for approval of firm transportation contracts with Algonquin (Spectra) for the AIM project, "design day shortfalls are eliminated through [2024]", while limiting design winter shortfalls to no more than "modest".[66] Similarly, National Grid notes that the addition of AIM pipeline capacity to its portfolio will provide its fuel supply portfolio with additional flexibility. National Grid indicates that this flexibility will result in a recurring ability to re-sell unneeded pipeline capacity to benefit retail gas ratepayers and will allow for ongoing optimization of its fuel supply portfolio.[67]

Turning to the demand side, Black & Veatch's model builds in rising demand, with it, upward pressure on prices. While there is inevitably uncertainty regarding the growth of natural gas demand, the U.S. Energy Information Administration ("EIA") projects *declining* retail natural gas demand in New England over the next decade.[68] However, even zero growth in retail demand has significant implications for the ANE project as it both lowers the absolute level of future prices and the subsequent reduction in those prices with the introduction of the ANE capacity. Specifically, zero growth in

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[66] NSTAR Gas Company Request for Approval of Firm Transportation Contract with Algonquin Gas Transmission, LLC, Massachusetts Department of Public Utilities Docket 13-159, Prefiled Testimony of Max A. Gowen, Exhibit NSTAR-MAG-1 at 20, September 25, 2013.

[67] Company Request for Approval of Firm Transportation Contract with Algonquin Gas Transmission, LLC, Massachusetts Department of Public Utilities Docket 13-157, Direct Testimony of Elizabeth Arangio and John Allocca at 28, and also Direct Testimony of Theodore Poe, Jr. at 11-15, September 16, 2013. See also, Response to Information Request AG-1-2, DPU 13-157, November 20, 2013.

[68] See Direct Testimony of Michael Zenker on Behalf of Nextera Energy Resources LCC, June 20, 2016 ("Zenker Testimony").

retail natural gas demand causes projected winter-months' wholesale gas prices to be, on average, 32% lower.[69] Similarly, the projected reduction in winter-months' wholesale gas prices due to the addition of the ANE project declines, on average, from 23% to 11%. The ANE project's impact is further reduced under this scenario by the fact that the absolute value of projected winter-month gas prices prior to the assumed addition of the ANE capacity are lower. In sum, lower retail natural gas demand growth would clearly reduce the benefits of the ANE project.[70]

ISO-NE, meanwhile, projects no growth in electricity demand for the indefinite future.[71] As far as the power sector's demand for natural gas is concerned, the penetration of renewable resources and passive demand response in New England is expected to continue to expand, dampening natural gas demand for electric generation as it does.[72] At the very least, actual natural gas futures prices tell us that the marketplace does not foresee rising demand as supporting Black & Veatch's forecasts of very high prices.

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[69] Using the GPCM ® model; winter months defined as December through February; holding retail demand constant as of 2017.

[70] This scenario is consistent with Black & Veatch's efforts for the New England States Committee on Electricity, which considered a "Low Demand Scenario" defined as "flat or declining gas use across all sectors." Black & Veatch concluded that in such a scenario "infrastructure solutions are not needed or justified" and that "no long-term infrastructure solutions should be implemented." See, Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England, Black & Veatch, Prepared for the New England States Committee on Electricity, 16 August 2013 at 8-9, 13 and 17. ("Black & Veatch NESCOE Infrastructure Study")

[71] See, generally, 2016-2025 Forecast Report of Capacity, Energy, Loads, and Transmission, ISO-NE System Planning, May 1, 2016, available at: http://www.iso-ne.com/system-planning/system-plans-studies/celt.

[72] This is exactly what is happening in California as renewable resource penetration continues. See, for example, Megawatt Daily, Solar pushes California net load, prices lower, May 3, 2016, McGraw Hill Financial.

This is not surprising. Market forces operate to dampen upward pressure on prices as higher prices call forth more supply and relieve upward price pressures. Thus, growth in gas demand tends to bring forth more supply of natural gas delivery capacity such that New England's electric generation sector has found little sustained difficulty obtaining pipeline natural gas. For example, the Lake Road Generating Company ("Lake Road"), located downstream of Algonquin's west-to- east flow constraint, reported that after several years of operation that the "supply of natural gas and natural gas pipeline capacity has expanded significantly in the intervening years" such that "the likelihood of natural gas curtailment that would necessitate operation on fuel oil is remote."[73] Lake Road's actions underscore the reality that New England electric generators have been able to rely almost exclusively on pipeline natural gas, so much so that in some instances secondary fuel oil supply diversity options were disabled.[74] These factors are reinforced by ISO-NE's continuing efforts to ensure reliability. Going forward there is no reason to believe that the foregoing patterns and forces will not continue.

C. Reliability Will Not Be Compromised Without ANE

Q: **Please describe the market design changes ISO-NE has implemented over recent years.**

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[73] State of Connecticut, Connecticut Siting Council, Docket No. 189, Motion to Reopen Docket No. 189, Lake Road Generating Company, L.P., October 24, 2011 at 2. Ironically, this Lake Road filing was sought and received permission to disable dual fuel firing capability already available at its power generation station.

[74] Testimony of Peter Brandien on Behalf of ISO New England, Federal Energy Regulatory Commission Docket No. ER-24-2407 et al, July 11, 2014 at 12.

A: Since 2013, ISO-NE has implemented numerous improvements to its wholesale power market design and operating practices. It has done so in order to ensure reliable performance of its fleet of generation resources. Of these market design changes, the most visible and widely acknowledged has been the upcoming applicability of the "Pay for Performance" ("PFP") economic framework for ensuring that generation resources taking on ISO-NE Forward Capacity Market ("Forward Capacity Market") obligations will perform reliably.[75] In addition to PFP, ISO-NE has modified its FERC tariff to: a) redefine shortage events in the Forward Capacity Market;[76] b) improve generation resource audits;[77] c) enhance forward market reserve incentives and increase the amount of reserves purchased in the forward reserve market;[78] d) introduce shorter timelines in its day-ahead energy market;[79] e) enhance resource market offer flexibility;[80] and, f) improve information sharing with interstate natural gas pipelines.[81] As recently noted by ISO-NE, it has "[m]ost significantly, strengthened the financial incentives for power resources to perform as required. These incentives drive will drive generators to invest in

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[75] See, generally, *ISO New England Inc.* Docket Nos. ER14-2419, EL 14-52; 30-Day Compliance Filing to Revise Tariff section III.13.7 ("PFP Tariff Filing").

[76] See *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (2013).

[77] See *ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 (2013).

[78] See Letter Orders, Docket No. ER13-1733-000 (issued August 15, 2013) and Docket No. ER 13-465-000 (issued February 8, 2013).

[79] See *ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (2013).

[80] See *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,073 (2014).

[81] See Letter Order, Docket No. ER14-970-000, 146 FERC ¶ 61,159 (2014).

maintenance and capital improvements and, importantly, to assure that they have fuel to operate when needed."[82]

Q: **What was the impetus for ISO-NE's wholesale market design changes?**

A: Prior to making the noted reforms, ISO-NE observed that the electricity system presented operational challenges on some winter days during periods of extended cold-weather periods or winter storms.[83] ISO-NE identified that such operational challenges arose when natural gas-fired electric generation resources that can obtain fuel only from natural gas pipelines had not secured fuel supply ahead of being called upon to operate. In addition, some oil fired generators did not maintain fuel oil storage that would allow continued operations during a stretch of cold outdoor air temperatures. At the time, ISO-NE identified a number of market design improvements that could be implemented to ensure that generation resources would operate reliably.

Q: **What was the focus of ISO-NE's market design improvements?**

A: ISO-NE introduced market design changes to ensure the reliability of the region's generation and transmission system by ensuring that the region's generation resource fleet could expect to receive appropriate compensation whenever called upon to operate. These changes provide appropriate financial incentives for generation resources to make

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[82] 2016 Regional Energy Outlook, ISO-NE, at 3.

[83] See, for example, ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

those cost-effective capital investments that allow the resources to operate reliably during periods when system peak demands occur. In particular, ISO-NE widely reported its implementation of major enhancements to the wholesale markets indicating "[e]nhancements improve market incentives, help address grid reliability risks stemming from natural gas pipeline constraints."[84]

Q: **Why would generation resources face the risk of being undercompensated when being called upon to operate?**

A: ISO-NE's now outdated market rules did not provide generation resources the flexibility to reflect actual fuel costs in their market offers and required that financially binding offers be established ahead of when actual fuel costs would be known. For example, a gas-fired generation resource would be expected to submit supply offers more than 24 hours prior to when its supply may be needed in the marketplace. Because a gas-fired resource would be at risk of not recovering its operational costs when making offers ahead of when actual gas supply would be purchased, a resource owner could not provide the operational flexibility that ISO-NE requires. Moreover, resources that could switch between oil and gas were precluded from maximizing profits as ISO-NE sought to impose upon resources fuel selection criteria that impeded resource flexibility. The elimination of these supply offer flexibility impediments, along with a number of

[84] ISO New England Implements Major Enhancements to Wholesale Energy Market, ISO New England Press Release, December 18, 2014, available at: http://www.iso-ne.com/static-assets/documents/2014/12/ emof_final_12182014.pdf.

additional enhancements to allow better coordination of gas procurement and wholesale market offers (see above), have substantially improved ISO-NE's market design.[85]

Q: **How does ISO-NE's PFP serve to ensure reliable resource operations?**

A: As recognized by the expert of National Grid's joint venture partner, ICF, the PFP market design imposes what ICF appropriately terms "severe" financial penalties in the event a capacity resource does not perform during a Capacity Scarcity Condition.[86] For example, capacity performance penalties beginning in 2018 are set at $2,000/MWh, rising to $3,500/MWh in June 2021, and to $5,455/MWh in June 2024.[87] The practical implication of ISO-NE's PFP penalty structure is that generation resources can no longer assume that there is little or no cost associated with being unavailable during Capacity Scarcity Conditions.

Q: **How have new generation capacity resources responded to ISO-NE's PFP?**

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[85] ISO New England's Internal Market Monitor ("IMM") reported on June 9, 2015: "The ISO implemented Energy Market Offer Flexibility ("EMOF") changes on December 3, 2014. EMOF allows market participants to vary energy market offers by hour and to change offers in real time during the Operating Day. The IMM has reviewed aspects of EMOF and found that generators are utilizing the flexibility afforded by the rule changes. Generators are now using price more frequently, and changing price across hours, to signal changes to underlying variable production and opportunity costs," ISO New England's Internal Market Monitor First Quester 2015, Quarterly Markets Report, ISO New England Inc., Internal Market Monitor, June 9, 2015 at 2.

[86] See PFP Tariff Filing at Section III.13.7.2.5 Capacity Performance Payment Rate. Note that a Capacity Scarcity Condition is a defined term in ISO-NE's Market Rule 1. See also D.P.U-15-181 Exhibit EVER-KRP-3 at 35 where ICF notes that ISO-NE, in its capacity as the federally-regulated wholesale electricity market organizer for New England, has "developed a market enhancement that is intended to improve generation availability."

[87] PFP Tariff Filing at Section III.13.7.2.5

A: New generation resources have responded by including as part of their generation plant design the ability to generate electricity using fuel oil in the event that natural gas is not available, or when fuel oil operation is less expensive than operation on natural gas. As shown in Table 3, all but one of the new generation resources that are being developed in New England, and which have cleared in ISO-NE's recent Forward Capacity Market auctions, are capable of dual-fuel operation. These generation resources have determined that the least-cost response for meeting ISO-NE's PFP requirements is to provide the capability to burn fuel oil in the event that natural gas is unavailable or excessively expensive.

Table 3
ISO-NE Dual-Fuel and Gas-Only Generation Capacity
Current and Expansions to 2019

	Dual-Fuel Capacity (MW)	Gas-Only Capacity (MW)
Existing Capacity	7,877	8,907
2016 Additions	0	0
2017 Additions	0	688
2018 Additions	1,494	34
2019 Additions	817	70
Total	**10,188**	**9,698**

Source: 2016-2025 Forecast Report of Capacity, Energy, Loads, and Transmission, ISO-NE System Planning, May 1, 2016 and ISO-NE Forward Capacity Auction Obligations, June 2016 through May 2020.

Note: Data excludes generation units that are dual fuel capable but have not yet commissioned or re-commissioned fuel oil burning capability. Includes generator uprating in addition to new plants.

Q: **Is the reliance of generating resources on dual-fuel capability surprising?**

A: No. In fact, the response of generation capacity resources has been expected. Various studies and analyses developed in association with improving resource performance incentives for electric capacity markets and gas-electric system coordination have demonstrated that dual-fuel burning capability is the most cost effective approach to fulfill performance obligations. For example, ISO-NE sponsored a study examining the likely impact of its PFP/Forward Capacity Market financial incentives which found that the addition of fuel-oil firing capability by gas-fired generating units was the most economic response to the enhanced market design.[88] Similarly, the Eastern Interconnection Planning Collaborative clearly demonstrated the long-term annualized cost of making an otherwise gas-fired only plant dual-fuel capable in New England is less than $15/kW-Year while the cost of firm gas pipeline transportation to Massachusetts is approximately $100/kW-year.[89] As noted by ISO-NE, "[its] analysis and experience to date indicate that gas-fired generators will tend to select the most economic option available to them; installing 'dual-fuel' capability, which allows them to switch from gas to oil when gas pipelines are constrained."[90]

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[88] See, Todd Schatzki and Paul Hibbard, *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives,* September 2013 at 4 and Appendix C. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/a3b_analysis_group_fcm_pi_impact_assessment_report_09_2013.pdf.

[89] Eastern Interconnection Planning Collaborative, Gas-Electric System Interface Study, Target 4 Report, Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives, DOE Award Project, DE-OE0000343, CEII Redacted, December 1, 2014, Levitan and Associates, Inc. at 86-87. Note cost is expressed on a levelized annualized basis. Available at: http://www.eipconline.com/gas-electric-documents.html.

[90] 2016 Regional Outlook, ISO-NE at 3.

This evidence is consistent with what we have seen in the PJM wholesale market. In association with the adoption of new capacity performance requirements, PJM's independent market monitor reported that firm pipeline transportation costs are greater than the estimated cost of reliance on dual fuel generation capabilities.[91] The evidence shows that it is economically attractive for power generators in New England to be capable of firing fuel oil and gas as opposed to committing significant financial resources to the purchase of long-term firm gas pipeline transportation that would only provide value for a limited number of days each year.

Q: **Why is it then suggested that natural gas pipeline constraints create grid reliability concerns?**

A: Unfortunately, there is not a clear answer as National Grid simply asserts that increased pipeline gas means electric generators will be more reliable. National Grid has cited several statements made by ISO-NE that National Grid uses to insinuate that periods of relatively high utilization of the existing natural gas pipeline infrastructure, namely in the winter months or what ISO-NE refers to as high demand periods, "creates grid reliability concerns."[92] Notwithstanding the fact that National Grid's insinuations have not been formally addressed in any of the studies or statements cited, they stand contradicted by ISO-NE's own actions and statements. As recognized by the President and CEO of ISO-

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[91] Monitoring Analytics, Capacity Performance Product Assumptions, September 15, 2014, available at: http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_ELC_Capacity_Performance_Product_Assumptions_20140915.pdf.

[92] ISO-NE State of the Grid: ISO on Background, 26 January 2016 at 9 ("State of the Grid").

NE, Mr. Gordon van Welie, ISO-NE has undertaken those actions that serve to "help improve fuel security and protect power system reliability."[93]

Q: **What does ISO-NE identify as its approach for maintaining electric system reliability during periods of colder weather?**

A: ISO-NE identifies investment in fuel resource diversity as the means by which ISO-NE will continue to maintain electric system reliability. For example, ISO-NE has stated that "additional investments in fuel infrastructure (including gas pipelines, LNG, and oil storage)" maintain power system reliability."[94] As we explain, recent experience in New England shows that reliance on existing resource fuel diversity maintains reliability. Going forward the market expects that fuel resource diversity will continue to play an important role in New England as a mixture of gas pipeline capacity additions, LNG and fuel oil resources allow electric generators to comply with ISO-NE's operational requirements.

Q: **Please explain the impact of ISO-NE's acknowledgement that reliance on fuel resource diversity demonstrates that National Grid's proposal is not necessary to maintain electric system reliability.**

A: In addition to the PFP described above, ISO-NE has articulated how its Winter Reliability Program has demonstrated that fuel supply diversity in New England ensures electric system reliability. For example, with respect to the Winter Reliability Program:

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[93] Comments on State of the Grid at 7-8.

[94] Challenges Facing the New England Power System, Gas-Electric Interdependency: The Realities of Keeping the Lights On, Gordon van Welie, March 26, 2015, National Press Club, Washington DC at 23.

- ISO-NE first initiated the Winter Reliability Program to "ensure that there [would be] enough fuel to keep the lights on" by "ensur[ing] that generators have the fuel they need to run during those extended cold periods when natural gas pipelines are constrained."[95]
- "The programs succeeded in providing a hedge for system operators when pipelines were constrained and gas-fired generators had limited access to pipeline gas. In those instances, operators could rely on oil-fired generation."[96]

ISO-NE appears to recognize that reliance on its electric generation fleet's fuel diversity can, as should be expected, ensure system reliability. Moreover, recognizing that the Winter Reliability Program was a stop-gap measure, ISO-NE made the many changes discussed above including PFP, with respect to which ISO-NE has publicly noted:

- With the PFP program "*resource owners are expected to make investments that will ensure their resources will perform as expected during periods of stress*. For many of these owners, the most cost-effective investment is to convert to dual fuel capability [for periods] when they can't get natural gas or the price is too high."[97]
- The PFP "will create strong incentives for gas-fired generators to firm up their fuel supply", while simultaneously acknowledging that "installing dual capability is the most cost-effective option for a typical gas generator" – even

[95] Comments on State of the Grid at 7-8

[96] van Welie letter of 6 July 2015 to DOER at 3

[97] Remarks of Gordon van Welie, Chairman, ISO-NE State of the Grid, 26 January 2016 at 7-8 (emphasis added).

> relative to "long-term contracts needed to fund additional gas infrastructure."[98]

Simply put, National Grid can only offer insinuations of system reliability problems absent the ANE project. ISO-NE has actually – and appropriately -- undertaken those actions that serve to ensure system reliability, as acknowledged by ISO-NE, *in a manner less burdensome and economically risky to rate payers*.

Q: **Why should we expect that ISO-NE would continue to take those actions necessary to ensure system reliability?**

A: Such actions are consistent with ISO-NE's objective "in its capacity as an RTO [Regional Transmission Organization]…to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation."[99] As ISO-NE indicates in its recent 2016 CELT Report, there is no plausible concern that ISO-NE will be unable to meet projected electric demand for the indefinite future.[100]

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98 van Welie letter of 6 July 2015 to DOER at 2.

99 Letter to Honorable Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 11 July 2014, from ISO-NE and New England Power Pool Participants Committee.

100 ISO-NE 2016 CELT Report Section 4.2 of tabs 1.1 Summer Peak and a.2 Winter Peak where installed reserve margins are significantly in excess of projected peak demands, especially during winter peak periods.

D. National Grid's Volatility Analysis Is Inapplicable to the Matter at Hand

Q: **What are National Grid's claims regarding the impact of the proposal on retail consumer rate volatility?**

A: National Grid asserts that the ANE project will lower retail electric consumer rate variability by reducing wholesale power market prices that can occur in New England during cold weather.[101] In addition, Black & Veatch claims that the implementation of the ANE project will result in a reduction of natural gas wholesale market price volatility, and that such a reduction will translate into significant additional benefits for retail electricity consumers. Neither National Grid nor Black & Veatch, however, offers a cogent analysis to support these claimed benefits.[102]

Q: **Why doesn't the proposed ANE project produce the additional "volatility dampening" alleged by National Grid?**

A: The vast majority of retail electricity customers do not purchase their electric power from ISO-NE's wholesale electricity spot markets. In fact, retail electricity rates are based on power purchases made on behalf of consumers in *forward* markets, not spot markets. This means that retail electricity rates do not vary with daily (or hourly) changes in natural gas and wholesale electric energy markets as those spot wholesale prices vary with very short-term changes in weather and electric system resource variations. Thus, neither a short-term cold snap nor a colder than average winter has a direct effect on the

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[101] See, e.g., Exhibit NG-JNC-3 at 22-24 and Exhibit NG-TJB/JEA-1 at 11-14 and 17.

[102] [REDACTED] See Response to Information Request NEER-1-13.

level or volatility of retail electric consumer rates. Alleged claims of National Grid of supposed increases in wholesale natural gas and electricity prices being directly incurred by consumers during, for example, the Polar Vortex – and by extension in the future such events – are baseless. ICF has not, in fact, analyzed retail price volatility. Indeed, retail power prices are set in advance of power delivery and their variation is not measured using historical wholesale spot natural gas and wholesale electricity prices.

Q: **Why don't daily wholesale gas and electricity prices directly influence retail electricity rates?**

A: Retail electricity consumer rates are set based on forward wholesale power market purchases and do not have a direct relationship to day-to-day wholesale electricity spot market prices. Thus, nearly all retail electricity customers are effectively "hedged" against volatile wholesale market prices, either through their purchase of default service power supply from their utility (in this case National Grid's or its affiliated electric distribution companies) or by purchasing power supply from a retail power supplier. National Grid procures power supply for a large majority of its Default Service customers (i.e., those that do not shop) via a laddered auction where 50% of expected default service load is purchased under a 12-month term contract twice per year—fall and spring.[103] National Grid's price to non-shopping customers is either fixed or variable rate per kWh

[103] http://www.mass.gov/eea/docs/dpu/orders/dpu-15-40-basic-service-noi.pdf [accessed June 16, 2016].

(opted into by residential customers) set twice per year based on the pricing obtained through the solicitation of electricity suppliers.[104]

Shopping customers—those who do not elect National Grid's default service—may select fixed rates for periods as long as 36 months. In this regard the Commonwealth's electricity consumers have ready access to competitive retail electricity suppliers who make it their business to attract customers with price and service packages that customers want. Thus, consumer demand for rate stability is being served by the marketplace. In fact, competitive retail suppliers make elimination of retail rate volatility a central selling point. This includes, for example, explicit marketing that prominently offers consumers the ability to "[l]ock in a competitive fixed electricity rate for the life of your plan and gain protection against possible price spikes"[105] with up to 36 months of fixed rates. In contrast to National Grid's suggestions, the Commonwealth's electricity customers are hedged against the volatility of day-to-day wholesale market prices.[106]

These facts are well-known. As noted by ISO-NE, "[c]onsumers won't see high or low wholesale prices reflected in their retail bills right away. While wholesale electricity prices change every five minutes, retail rates in customers' bills usually change only every six months or a year."[107]

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[104] http://www9.nationalgridus.com/masselectric/non_html/summary_of_rates_MA.pdf [accessed June 7, 2016].

[105] Direct Energy, https://www.directenergy.com/ma/electricity-plans [accessed April 23, 2016].

[106] There can, of course, be large, sophisticated consumers of electricity that chose to obtain power supply priced on shorter terms and even at spot market prices. However, these customers actively chose not to be hedged.

[107] http://www.iso-ne.com/static-assets/documents/2016/01/20160126_remarks_2016stateofthegrid.pdf.

Q: **Why do forward market electricity products protect retail customers against unexpected market volatility?**

A: Because longer-term forward market power prices do not exhibit the level of volatility that we observe in wholesale gas and electricity spot-markets. Table 4 compares the volatility of power prices at ISO-NE's Mass Hub for power product durations ranging from one day to one year. While price volatility is relatively high for daily products, for longer term products the volatility of prices is much, much lower. The annualized volatility of daily on-peak prices at ISO-NE's Mass Hub is 343%, while the annualized volatility of one-year duration on-peak prices is only 22%. This implies that the volatility of one-year duration prices is only approximately 6.4% that of daily duration prices.

Table 4
New England Volatility of Energy Prices by Product Duration
October 2010 – February 2016

	Product Duration			
Type	Year	Half-Year	Quarter	Day
On-Peak	22%	51%	78%	343%
Off-Peak	23%	58%	85%	364%

Note:

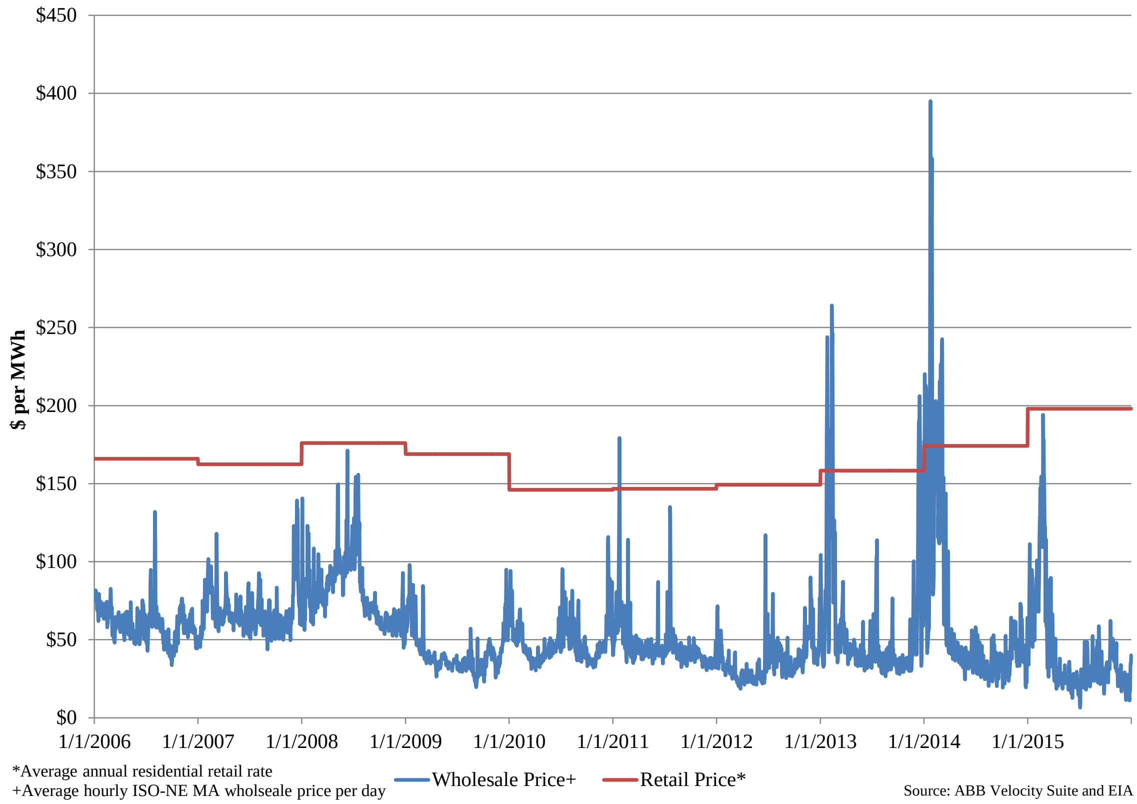
1) Mass Hub prices reported by Platts are used for the forward curve prices. Historical day ahead prices reported by Platts for Mass Hub are used from October 2010 through October 2014. Historical day ahead prices reported by Platts for ISO-NE's Internal Hub are used from November 2014 through February 2016.

Source: Platts and Compass Lexecon analysis.

Q: **Is there evidence that retail customers are effectively insulated against unexpected wholesale market volatility and unusual weather events?**

A: Yes. Figure 6 compares Massachusetts's annual retail residential customer revenue rates against daily wholesale electricity prices for the time period 2006-2015. As Figure 6 makes clear the volatility of daily wholesale power prices is not transmitted through to default service retail rates. Even notable events such as the spike in wholesale prices during the Polar Vortex of January 2014 do not show up as spikes in retail rates. Overall, in fact, default service retail rates have not even been positively correlated with daily wholesale power prices in recent time periods. In this case, National Grid is counting as a purported benefit to ratepayers a benefit *ratepayers already receive* – smoothed retail electricity prices. These benefits are being realized without incurring the billions of dollars in costs that National Grid proposes to pass through to ratepayers.

Figure 6
Massachusetts Daily Wholesale Electricity Prices
v. Average Annual Retail Electricity Prices, 2006-2015



Q: **How does your analysis presented in Figure 6 affect the validity of ICF's assertion that National Grid's proposal provides additional "volatility reduction" benefits to retail ratepayers beyond its power price suppression effects?**

A: It confirms that Black & Veatch's claimed benefits of up to $549 million per year associated with alleged volatility reductions are false. Massachusetts' retail consumer power product prices are based on forward market energy purchases whose volatility is more than 15 times lower than wholesale energy spot-market price volatility. Moreover, even Black & Veatch's New England wholesale gas price projections for the setting in which the ANE project is in operation continue to show expected natural gas price spikes in January. This means that Black & Veatch's own modeling implies that wholesale price volatility will continue with or without the ANE project.[108] Black & Veatch's supposed "volatility" benefits are without analytical foundation and are not properly included in any evaluation the purported benefits of the ANE project.

E. Black & Veatch's Net Benefits Analysis

Q: **Please summarize your general findings as to the results of Black & Veatch's purported cost-benefit analysis.**

A: Black & Veatch's analysis does not and cannot reliably demonstrate whether the ANE project has net positive benefits for ratepayers who would accept the shifting of billions of dollars in financial and economic costs from the joint venture's owners.

As to benefits, Black & Veatch's analysis is premised on its implicit assumption that power producers, consumers, and regulators responsible for overseeing the functioning of the region's wholesale energy markets will not or cannot take efficient actions that pass cost-benefit tests so as to optimally adapt to supply and demand conditions expected to prevail in gas and electricity markets. That is, Black & Veatch implicitly assumes, *contrary to evidence relied upon by Black & Veatch, National Grid, and Eversource*, that National Grid's proposal to subsidize a subset of gas-fired generators is effectively the only mechanism by which benefits claimed by Black & Veatch may be realized. In making such an assumption, however, the study does not and

[108] See Exhibit NG-JNC-3 Figure 10.

cannot demonstrate that National Grid's proposal is necessary to capture the benefits asserted by Black & Veatch and National Grid.

As to costs, Black & Veatch's analysis grossly understates the cost that would be borne by ratepayers by employing a discount rate that, even within the non-standard framework employed by Black & Veatch, is at odds with National Grid's proposal. Proper accounting for the fact that, if National Grid's proposal were imposed on them, retail electricity ratepayers would face the virtual certainty of having to pay an annual total of $526 million (plus [REDACTED] more) to National Grid for a term of 20 years means that the proposal would impose costs on ratepayers with a present value today of almost $5.9 billion.

As we discuss below, when we correct key errors of analysis in Black & Veatch's ratepayers' cost-benefit analysis, we find that National Grid's proposal promises to harm, rather than benefit, ratepayers. In present value terms, ratepayers would realize a net loss on the order $2.7-[REDACTED] billion if National Grid's proposal were implemented.

1. Measurement of Benefits

Q: **Please describe how Black & Veatch calculates purported benefits to ratepayers and attributable to National Grid's proposal?**

A: Benefits to ratepayers in the Black & Veatch framework arise through a multi-step chain of claimed economic causation: The chain begins with increased deliveries of natural gas to New England via the ANE project putting downward pressure on the region's natural gas prices during cold spells with high natural gas demand. This, in turn, is modeled as having a depressing effect on wholesale electric energy prices in the federally-regulated

ISO-NE power markets. The price suppression in wholesale electric energy markets calculated by Black & Veatch is shown by the difference between the "B&V without ANE" (blue) line and the "B&V with ANE" (black) line shown in Figure 5 (discussed above). Finally, depressed wholesale prices get translated into retail ratepayer price reductions under the implicit assumption that all wholesale price changes are passed through in their entirety to retail rates. Benefits in total nominal dollars are then calculated by Black & Veatch to be the retail electric energy price change it attributes to ANE, multiplied by the amount of electric energy consumed by ratepayers.

Q: **Doesn't Black & Veatch also assign "benefit" to National Grid's proposal based on claimed dampening of volatility in retail ratepayer's rates during "high stress" cold winter periods?**

Yes. As discussed above, Black & Veatch incorrectly implies that wholesale electricity price volatility is passed directly through as volatility in retail rates. Moreover, by employing historical average weather conditions, Black & Veatch's modeling, as well as ours, by definition includes periods of "high stress/high wholesale prices" and periods of "low stress/low wholesale prices." In terms of the calculations of ratepayer impacts, this means that both Black & Veatch's and our own calculations are overstatements for some years in the future and understatements for other years. Thus, Black & Veatch's claim of additional benefits during "high stress" years represents a double counting and should be disregarded.

Q: **National Grid asserts that with respect to one of the marketplace responses that you mention – generators' entering into contracts for firm gas supplies – that generators in the past have not entered into such arrangements.[109] Does that create a justification for retail ratepayers to bear the cost of the ANE project?**

[109] See Exhibit NG-TJB/JEA-1 at 32.

A: No, it does not. First, as we have seen, the focus on one possible response overlooks the fact that multiple other responses in the portfolio of marketplace options may be more efficient and appear without the need to also have generators enter into firm gas supply contracts. Indeed, as we have seen, the very cold winter weather of 2014-2015 was met with a portfolio of price-dampening responses. But even if markets were failing to bring forth otherwise efficient responses in the form of, for example, firm gas supply arrangements by generators, sound policy that serves the public interest would not take the form of using EDC ratepayer funds to distort and depress prices in the federally-regulated wholesale electricity markets, as National Grid's proposal would do. Instead, if the design of wholesale markets impedes or blocks otherwise efficient responses by, for example, giving generators insufficient incentive to ensure they have gas supplies during cold winter periods, sound policy looks to ISOs and federal policy to remove such distortions in wholesale markets. Of course, this is precisely the nature of ISO-NE's responses and improvements to wholesale market design in the face of, for example, the Polar Vortex (see discussion above).

Q: **National Grid asserts, however, that the ANE project will assist ISO-NE in meeting its reliability system mandate.**

A: We recognize that National Grid and its expert Black & Veatch have asserted that the ANE proposal will serve to assist ISO-NE meet its reliability system mandate.[110] However, ISO-NE has, in implementing its PFP regime, signaled it is a responsible party

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[110] See, for example, Exhibit NG-TJB/JEA-1 at 29, 32, and 34; Responses to Information Requests NEER-1-27 and 1-32; Exhibit NG-JNC-3 at 25.

by compelling performance via penalties. Such responsible actions are consistent with and are to be reasonably expected from the principles of public policy which underlie federal regulation of wholesale energy markets, including New England wholesale electricity and natural gas markets. Black & Veatch, however, fails to recognize that what Eversource's expert ICF properly represents as severe PFP penalties knocks the base out from under National Grid's claim that electric ratepayers must be saddled with the costs and risks of National Grid's proposed ANE contracts because electric generators will not sign up for firm pipeline capacity. *The severity of the PFP penalties is designed to induce generators to take the steps necessary to ensure reliable power service*. In rationally avoiding the PFP penalties, generators will, as recognized by ISO-NE, be incented to select the least costly option for avoiding PFP penalties.[111]

We know this from the recent experience in, for example, the ISO-NE and PJM operating regions where the evidence demonstrably shows power generators undertaking those actions to ensure performance. These include but are not limited to the activation of existing dual-fuel capabilities, the inclusion of dual-fuel capabilities in new generating facilities (see Table 3 above), and the contracting of firm capacity for the supply of natural gas – all of which have economic benefits of the form alleged by National Grid. In fact, we see that electric generation resources will contract for firm natural gas transportation supply when it is economically attractive. For example, a recent PennEast gas pipeline expansion included execution of precedent agreements by Talen Energy Marketing, LLC (5 years) and PSEG Power LLC (15 years), each of which own and

[111] ISO-NE 2016 Outlook at 3.

operate gas-fired generation resources in the Mid-Atlantic Region of the U.S.[112] In sum, the severe PFP penalties recognized by ICF represent a less costly, less distortive, and less onerous for ratepayers substitute for National Grid's proposal.

Q: **Is the foregoing the only such example of contradictions and unsupportable assumptions in Black & Veatch's modeling?**

A: No. Black & Veatch's study includes additional contradictions, all of which serve to undermine the integrity of the report's purported findings. Consider, for example, Black & Veatch's assumptions regarding regional natural gas demand growth and its implications for the natural gas pipeline capacity that will be available to serve New England's gas-fired electric generation.

Figure 7 compares (1) the non-ANE related gas pipeline capacity additions in Black & Veatch's modeling analysis to (2) its forecasted growth in New England natural gas demand. As shown by the figure, Black & Veatch's projected non-ANE related expansions to New England's natural gas pipeline system (or what Black & Veatch refers to as "generic pipeline capacity additions") significantly outpace its projected regional natural gas demand growth.[113] The difference between the two indicates excess pipeline

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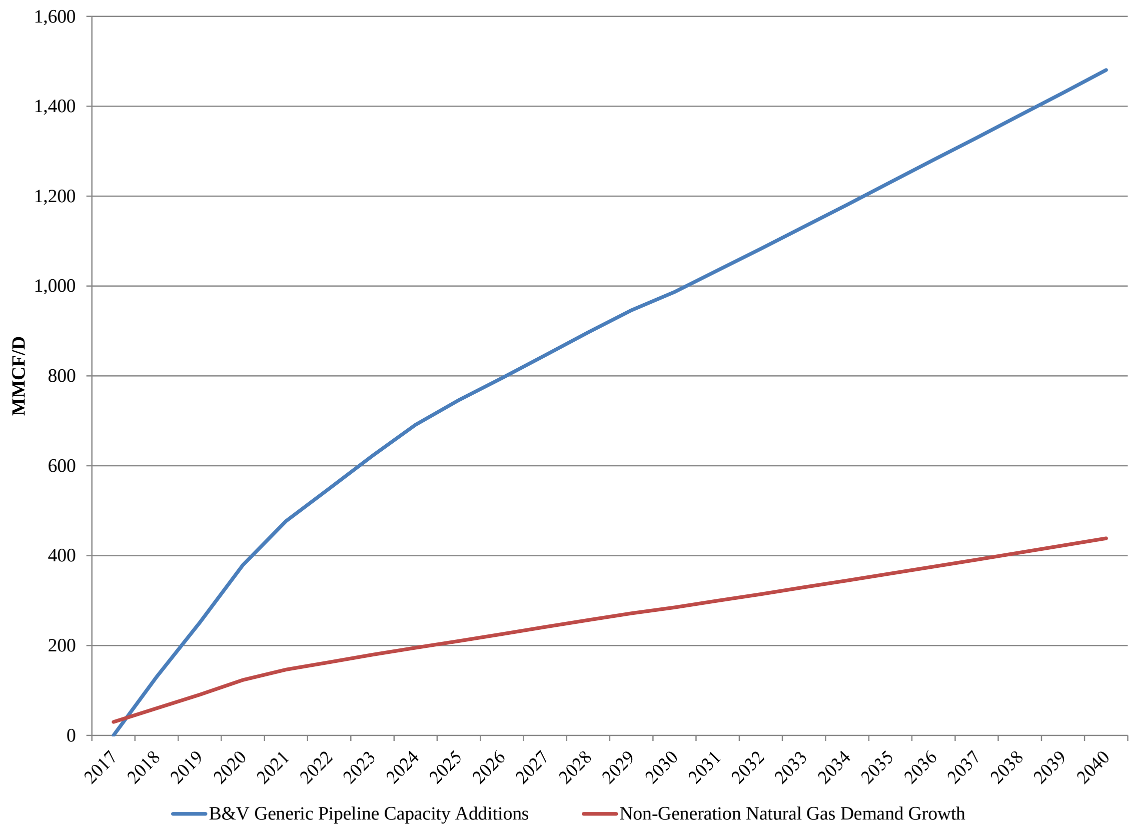
[112] See Application of PennEast Pipeline Company, LLC for Certificates of Public Convenience and Necessity and Related Authorizations under CP15-558, FERC Dokcet No. CP15-558-000, 09/25/2015 at 10. Like ISO-NE, PJM also recently established capacity performance penalties that are intended to ensure generator performance. Note also that we find no evidence that Talen and PSEG have long-term power sale agreements associated with these long-term pipeline transportation agreements.

[113] Black & Veatch forecasts regional firm gas design-day demand to increase at a compound annual growth rate of 1.15%. It further assumes that, for any given year, LDC design-day firm gas load equals [REDACTED] its projected average annual load over the analysis period. Incremental generic pipeline capacity additions are assumed to be placed into service prior to each winter season. Responses to Information Requests AG-2-9, NEER-1-10, and NEER-1-14.

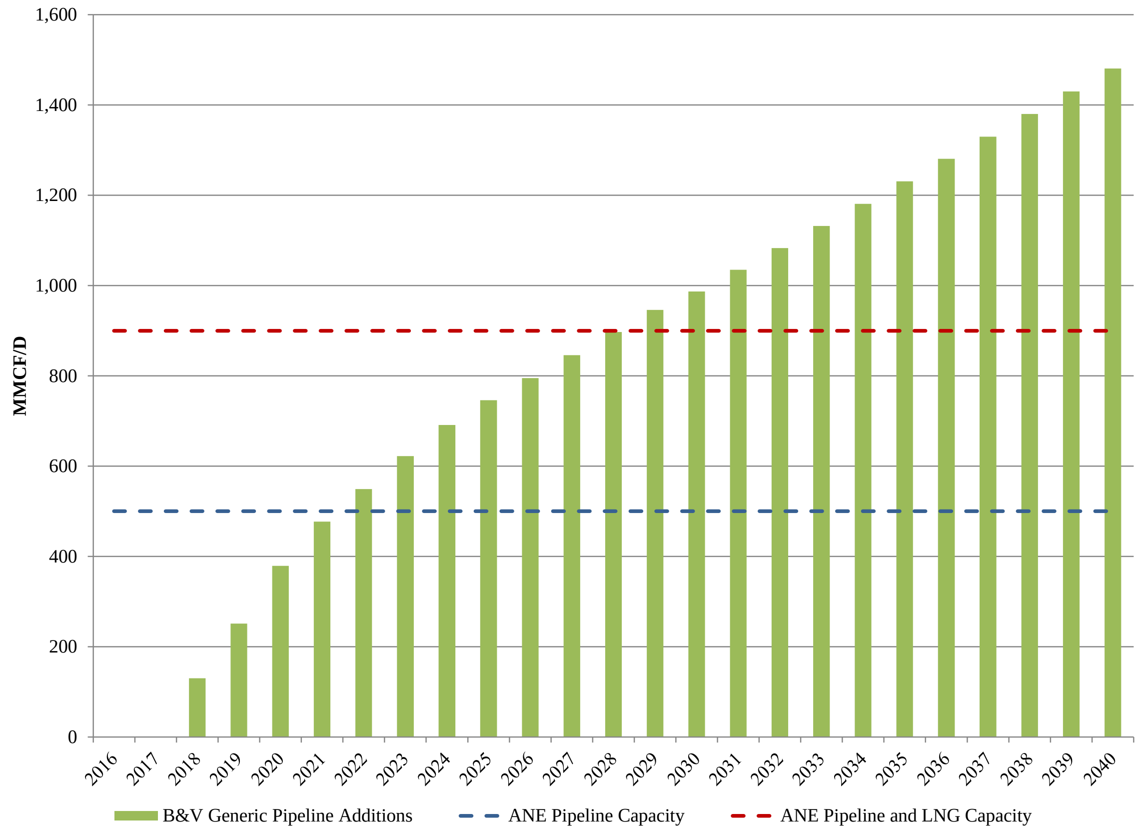
capacity that would reasonably be expected to be available to serve the region's natural-gas fired electric generation. In fact, within Black & Veatch's model, generic capacity expansions exceed the pipeline capacity associated with the ANE project (500,000 MMcf/d) by 2022, and exceed the total capacity of the ANE Project (900,000 MMcf/d) by 2029. (See Figure 8)

Figure 7
Black & Veatch's Modeled Increases in Generic Pipeline Capacity
v. Black & Veatch's Forecast of New England Natural Gas Demand Growth
2017- 2040



Note: Figure 7 excludes the addition of the ANE project.

Figure 8
Black & Veatch:
Increases in Generic Pipeline Capacity v. ANE Capacity Expansion
2017- 2040



Q: **Are there other such examples of contradictions and unsupportable assumptions?**

A: Yes. Black & Veatch's treatment of LNG, a source of fuel supply for the region's wholesale electricity markets offers another. The gas model that we and Black & Veatch employ solves for zonal-level natural gas deliverability or supply capability, including LNG import levels. For the purposes of the analysis put forth by Black & Veatch in this proceeding, Black & Veatch has – in contradiction of its own analysis, as well as testimony sponsored by ICF, and without any coherent foundation for doing so—

constrained regional LNG import levels at a level determined outside its own model and that is significantly less than region's actual LNG sendout capacity.

Black & Veatch states that "[its] analysis *assumed* an average annual send out at the [Distrigas gas LNG terminal] to be approximately 150 MMcf/d with peak winter send out of approximately 250 MMcf/d, similar to the observed volumes during the 2014-2015 winter season."[114] The peak send out volumes represent less than 35% of the facility's sustainable daily sendout capacity (715 MMcf/d) and 25% of its maximum daily sendout capacity (1,000 MMcf/d).[115]

Black & Veatch makes this assumption despite recognizing that such volumes are well below the terminal's maximum daily vaporization quantity,[116] and in contrast to its findings of significant net benefits to New England from the importing of additional LNG cargoes. Specifically, the Black & Veatch NESCOE Infrastructure Study found that "LNG imports can be implemented each year with spot cargoes or over a three year period, as seen in supply agreements at terminals in the region."[117] Such findings are consistent with those of Eversource's ICF expert, Mr. Petak, project manager for a 2014 study undertaken on behalf GDF Suez (aka Distrigas) which "*concluded that the Everett*

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[114] See Exhibit NG-JNC-3 at 13 (emphasis added).

[115] D.P.U.-15-181 Response to Information Request AG-1-4(a) and Overview of LNG in New England, September 22, 2010, GDF Suez.

[116] Response to Information Request NEER-1-11.

[117] Black & Veatch NESCOE Infrastructure Study at 49.

terminal could provide additional gas on days during the winter when the market is most constrained."[118]

Black & Veatch similarly asserts that supplies received at the Canaport facility (St. John, Canada) are expected to decline relative to historical norms and that it "*does not expect* significant LNG import volumes at Canaport, Neptune, or Northeast Gateway."[119] In so doing, Black & Veatch limits the imports of LNG via the Distrigas (Everett, MA) facility to be no more than approximately 250-300 MMcf/d during peak winter periods.[120] In sum, Black & Veatch's approach here only serves to restrict its model's ability to solve for LNG import levels by removing approximately 1.4 Bcf/d of potential natural gas from the regional marketplace. (See Figure 9.) It thereby undermines the results of the study undertaken on behalf of National Grid.

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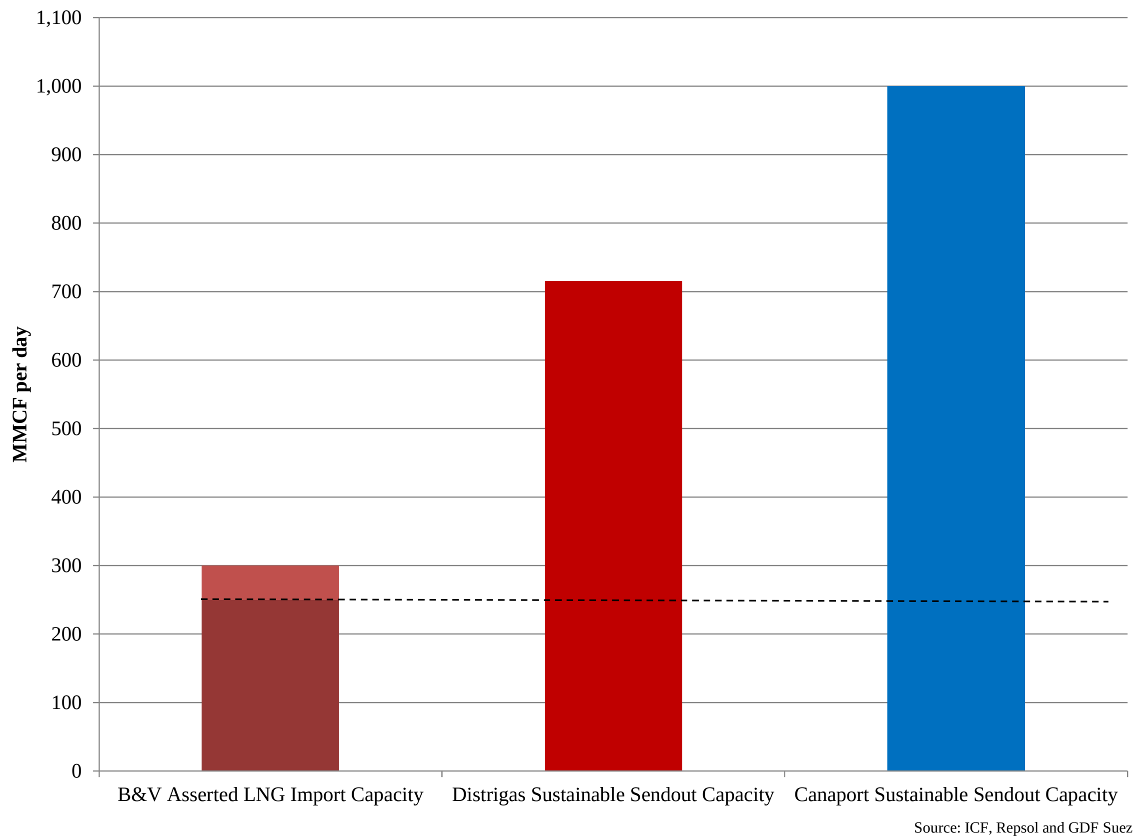
[118] Response to D.P.U-15-181 Information Request NEER-3-29. ICF rejects its own finding, however, on nothing more than the assertion that the study "did not address the reasons why the facility *has not been* more fully utilized." (Emphasis in original.) Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs, prepared for the ISO-NE Planning Advisory Committee by ICF International, LLC, June 21, 2012 at page 9.

[119] See Exhibit NG-JNC-3 at 13 (emphasis added)..

[120] See Exhibit NG-JNC-3 at 13; Attachment Response to Information Request NEER-1-11(a); and Black & Veatch NESCOE Infrastructure Study at 46.

Figure 9
Black & Veatch's Asserted Daily LNG Sendout Capacity v. Actual Daily Sendout Capacity



Q: **How does the imposition of an artificially determined constraint reflect a contradiction in National Grid's position in this proceeding?**

A: The contradiction contained within Black & Veatch's analysis is demonstrated through both evidence from the marketplace, and the testimony by Eversource's expert, Mr. James Stephens.[121] Figure 10 shows the actual historical send out from the Distrigas

[121] D.P.U.-15-181 Exhibit EVER-JMS-1 at 40-42.

facility, highlighting the years which Black & Veatch appears to claim supports its basis for limiting this source of supply to the New England region. As evidenced by the exhibit, Distrigas has in the very recent past provided over 2.2 times the volumes to the region than the years identified by Black & Veatch's arbitrary limit.[122] Moreover, during the winter of 2015-2016 (December through February), Distrigas daily sendout reached 240 MMCD/d, an increase of 24% over the prior winter and a 79% increase relative to the "Polar Vortex" winter (despite much colder temperatures).[123] In addition, ISO-NE reported that during winter 2015, LNG sendout nearly reached or exceeded 1 BCF/day on five days.[124] The data show that LNG can and, in fact, has served to increase the supply of natural gas, and thereby better ensure that regional power generators have the fuel needed to meet their operational obligations to the region's wholesale energy markets.

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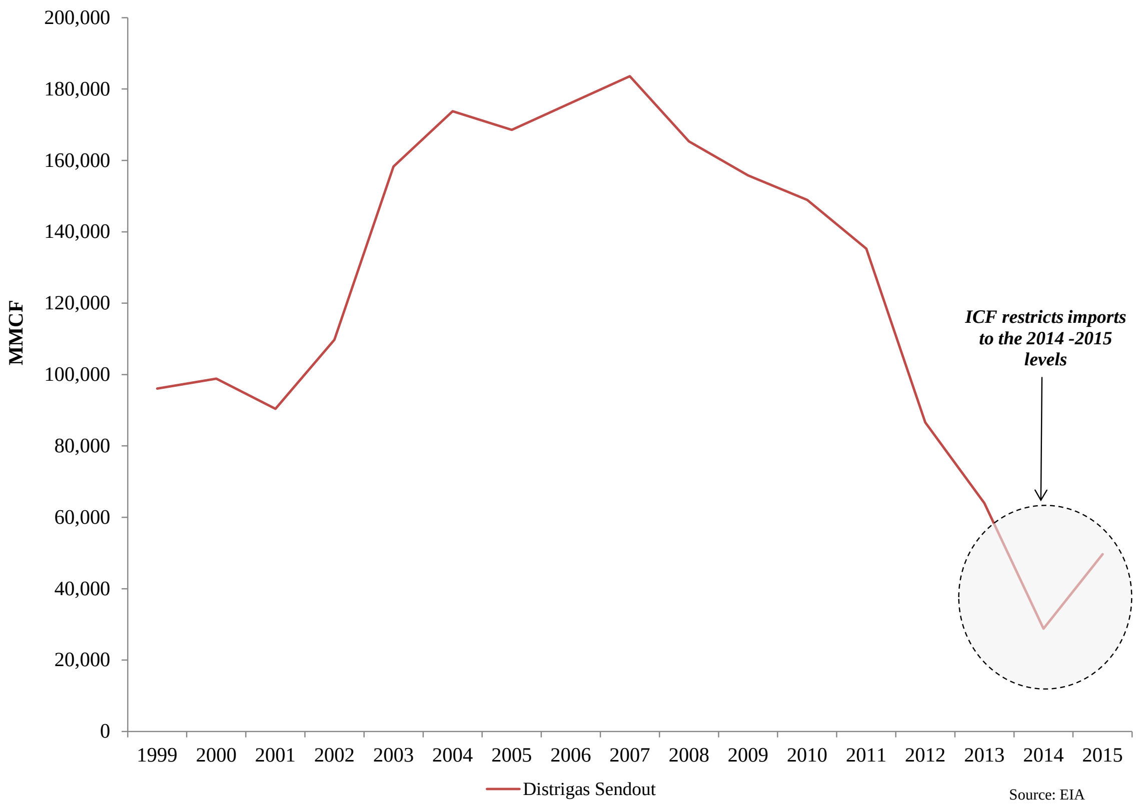
[122] D.P.U.-15-181Response to Information Request CLF-2-1(a).

[123] D.P.U.-15-181 Response to Information Request CLF-2-1(a). Note also in the months of January and February 2016 Distrigas sendout was an average 340 MMCF/day and 295 MMCF/day, respectively.

[124] ISO-NE Winter 2014/15 Review at 15.

Figure 10
Distrigas LNG Sendout Volumes
1999-2015



The contradiction in National Grid's position that ratepayers should absorb the billions of dollars required for the construction of the ANE proposal is made plain by the testimony of Eversource's expert James Stephens that acknowledges the ability of marketplace participants, including power generators, to contract for LNG (under varying terms and conditions as most appropriate to the buyer) when such an alternative represents a cost-effective option to the regional wholesale energy markets. Mr. Stephens found that "[a]lthough the New England market experienced an increase in LNG cargoes during the most recent winter that increase was partially attributable to *a reduction in global oil prices* and *expectations of high New England natural gas prices* resulting from infrastructure constraints."[125]

Eversource's expert's findings are affirmed by ISO-NE's Market Monitor's analysis of the 2013/2014 and 2014/2015 winters. As concluded by the Market Monitor: "Despite the general consistency in weather conditions [between the two winters], natural gas prices were substantially lower [in the winter of 2014/2015] even under colder weather conditions. For example, the average Algonquin gas price was roughly $7/MMBtu lower in February 2015 than in January 2014, although February 2015 was colder. This was attributable to several factors:

- "High gas production in the Marcellus region;
- *More LNG was delivered to New England this winter because of high natural gas prices in the prior winter*;
- *Oil prices fell substantially since mid-2014, which limited the increase in natural gas prices during periods of gas pipeline constraints*."[126]

Put plain, the evidence demonstrates that, as recognized by Black & Veatch, LNG, as well as other factors such as prices for alternative fuels, can effectively provide the same economic benefits as the proposed ANE contracts.

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[125] D.P.U.-15-181 Exhibit EVER-JMS-1 at 43 (emphasis added). See also Response to Information Request AG-8-2.

[126] 2014 Assessment of the ISO New England Electricity Markets, Potomac Economics as prepared by David B. Patton, Pallas LeeVanSchaick, and Jie Chen; External Market Monitor for ISO-NE, June 2015 at 36. (Emphasis added.)

Q: **National Grid asserts that the proposed ANE project would insulate its LNG facility from the volatility of world LNG prices.[127] Please respond.**

A: National Grid's assertion is without foundation. Price volatility captures how quickly or widely prices can change. Those changes are driven by changes in the underlying supply and demand for the commodity in question. Changes in underlying supply and demand conditions impact domestic, as well as foreign, supplied natural gas.

As it applies to LNG, Eversource's expert Mr. Stephens recognizes these economics in testifying to the reduction in the current and near-term expected price for LNG as a consequence of the significant reduction in global oil prices. Specifically, Mr. Stephen's data show near term expected prices for LNG having collapsed from approximately \$15 to \$20 per MMBtu to approximately \$10 per MMBtu.[128]

Mr. Stephen's analysis shows that for the period over which the data is displayed (March 2017) prices for LNG are expected to remain in the range of \$10 per MMBtu. These expected prices are consistent with the analysis put forth by Intervenor Repsol's witness Mr. Vincent Morrissette. He presents a worldwide LNG price forecast, including an analysis of the supply and demand factors underlying future expected LNG prices, from the present through 2025.[129] The LNG price forecast shows the price for LNG in

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[127] See Exhibit NG-TBJ/JEA-1 at 34.

[128] D.P.U.-15-181 Exhibit EVER-JMS-1, Figure 16: LNG Market Signals (January 2009 – March 2017) at 43.

[129] Testimony of Vincent C. Morrissette on Behalf Of Repsol Energy North America Corporation, D.P.U. 16-05, June 17, 2016 at Figure 5.

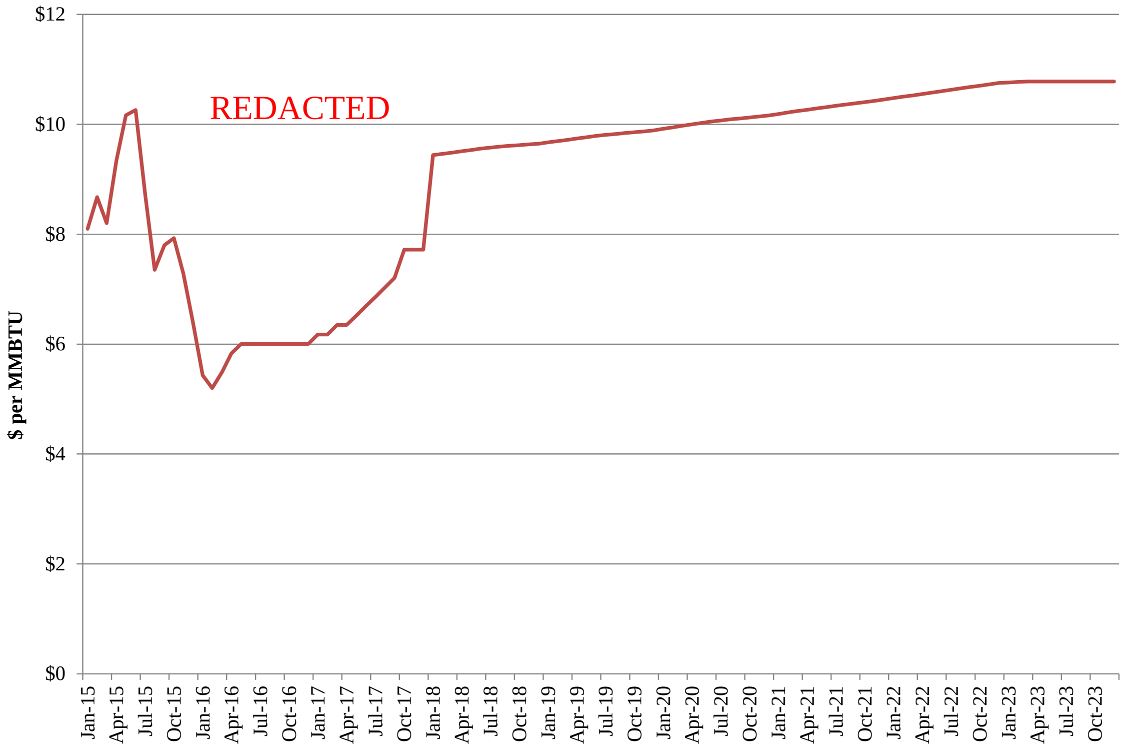
the Atlantic Basin rising from less than $5/MMBtu in 2016 (i.e., representative of Mr. Stephen's "collapse" in oil prices) to approximately $11/MMBtu as of 2025.

Those prices are comparable to the prices for LNG as predicted by Black Veatch's and [REDACTED].[130] Figure 11 employs that methodology, using the marketplace's expectation of the price of Brent crude oil, in showing the expected prices for LNG. The results are consistent with the testimony offered by Mr. Morissette and price expectations for LNG as recently put forth by the World Bank.[131]

[130] Black & Veatch asserts that "[t]he delivered cost of additional LNG cargoes is expected to be strongly tied to oil-indexed global LNG prices…[t]he future of oil indexation of global LNG prices may weaken, thus having the effect of reducing global LNG prices for spot cargoes into New England." Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England, Prepared for the New England States Committee on Electricity, 26 August 2013 at 46; and DPU-15-181 Response to Request for Information NEER-1-11.

[131] Commodity Markets Outlook, World Bank Group, January 2016.

Figure 11
Forecasted Prices for LNG Based on Black & Veatch's Pricing Methodology[1]

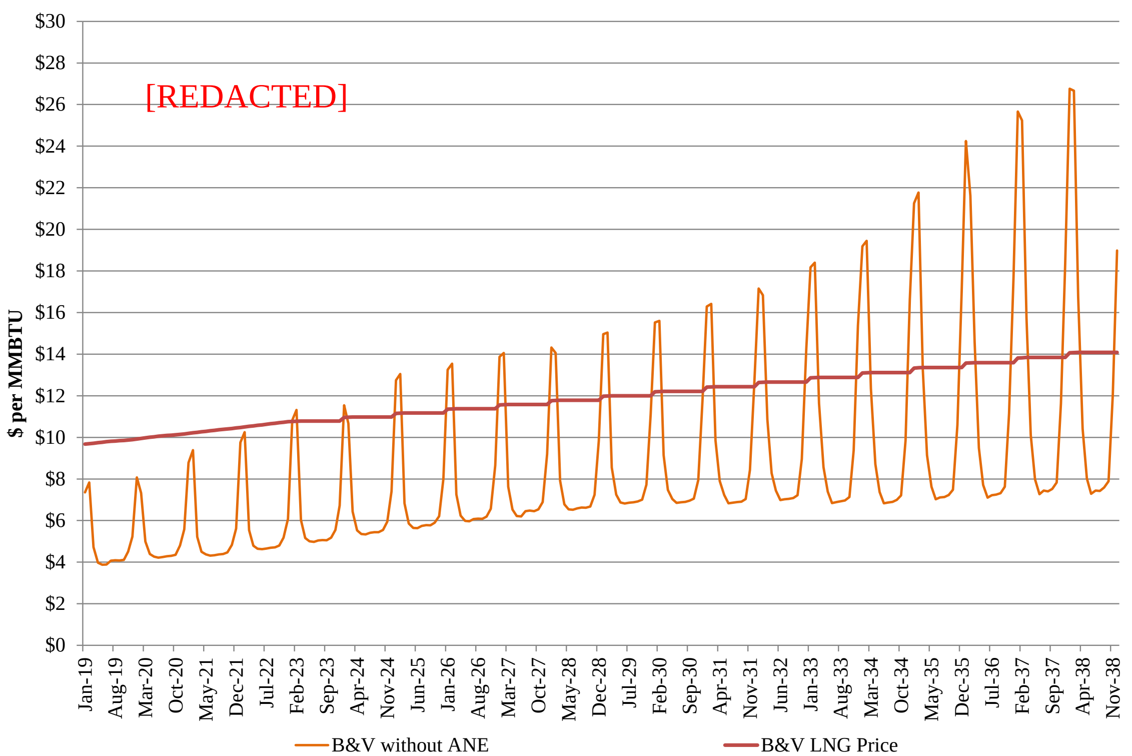


[REDACTED] Source:ICF, EIA, and [REDACTED]

Q: **How do these prices compare to Black & Veatch's predicted regional prices for wholesale natural gas?**

A: Figure 12 compares Black & Veatch's forecasted wholesale price of natural gas in the New England region (without the proposed ANE project) to a forecasted price for LNG determined through the use of Black & Veatch's LNG pricing methodology. As shown by the exhibit, during periods of peak demand the price of LNG as predicted by Black & Veatch *is significantly less than Black & Veatch' forecasted wholesale natural gas prices*. In sum, the evidence demonstrates that prices for LNG are expected to remain relatively low – and far below Black & Veatch's predicted price for wholesale gas in New England for the foreseeable future.

Figure 12
Black & Veatch's Forecasted Prices for LNG
v. Black & Veatch's Forecasted Wholesale Natural Gas Prices for New England[1]



[REDACTED] Source:ICF, EIA, and [REDACTED]

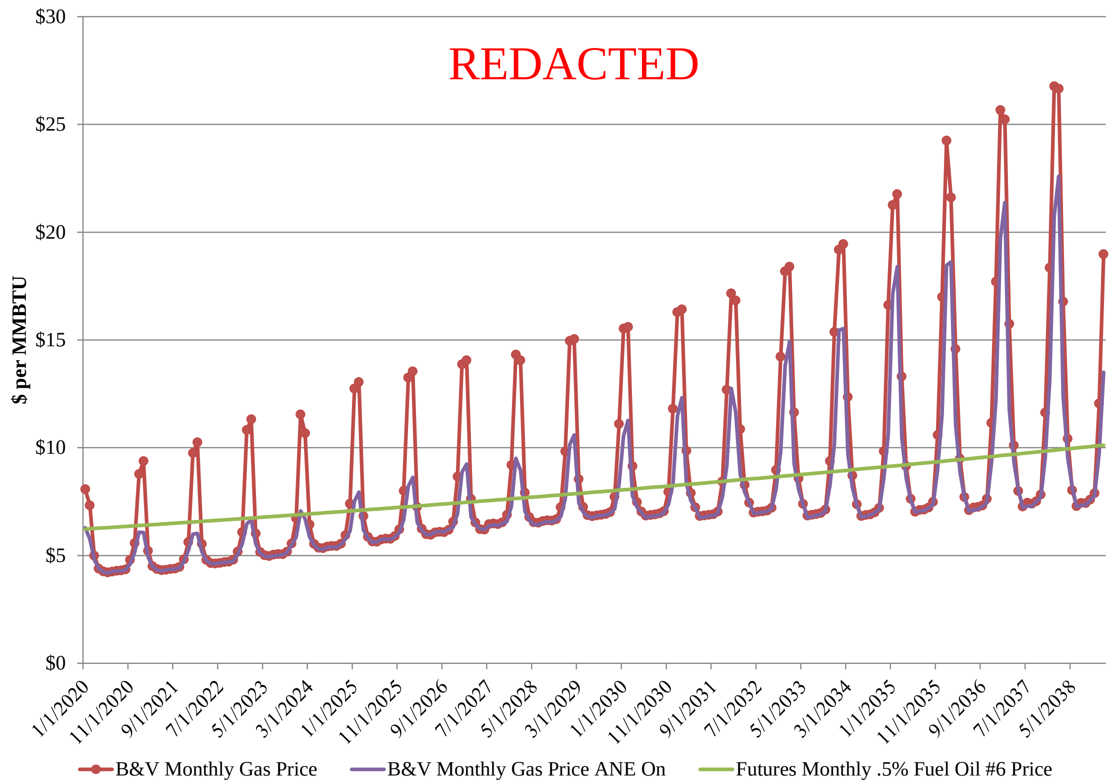
Accepting for the sake of argument that Black & Veatch's forecasted wholesale natural prices for the New England region represent the expectations of the marketplace, the magnitude of the differences in the price of LNG and wholesale regional gas prices would serve to induce wholesale consumers, including power generators, to contract for

LNG. Such contracting provides the same economic benefits without ratepayers bearing almost $5.9 billion in costs.

Q: **Does National Grid's modeling produce a result similar to LNG with respect to the reliance on fuel oil as an alternative source of fuel supply for New England?**

A: Yes. Black & Veatch relies on a projection of fuel oil prices that is not supported by recent prices realized in New England. Figure 13 graphically depicts the residual fuel oil prices reported by Black & Veatch as part of its modeling inputs against futures market pricing as of March 2016 and Algonquin natural gas prices produced by Black Veatch's gas market modeling. As Figure 13 shows, Black & Veatch's model's fuel oil prices are [REDACTED] than those being reported in the futures markets. Moreover, fuel oil prices have declined considerably over the past several months and residual fuel oil resources can be expected to be able to compete against natural gas-fired resources based on Black Veatch's gas price forecast, especially during winter months. Instead, [REDACTED] that residual fuel oil plants would not be expected to supplant generating units otherwise burning natural gas and would not reduce demand for natural gas.

Figure 13
Black & Veatch's Forecasted Prices for Residual Fuel Oil
v. Black & Veatch's Forecasted Wholesale Natural Gas Prices for New England



Source: B&V and CME

Such a prediction is contrary to recent experience, which shows that New England's generators will operate on residual fuel when it is economic to do so.[132]

Q: **How does this inconsistency impact Black & Veatch's modeling?**

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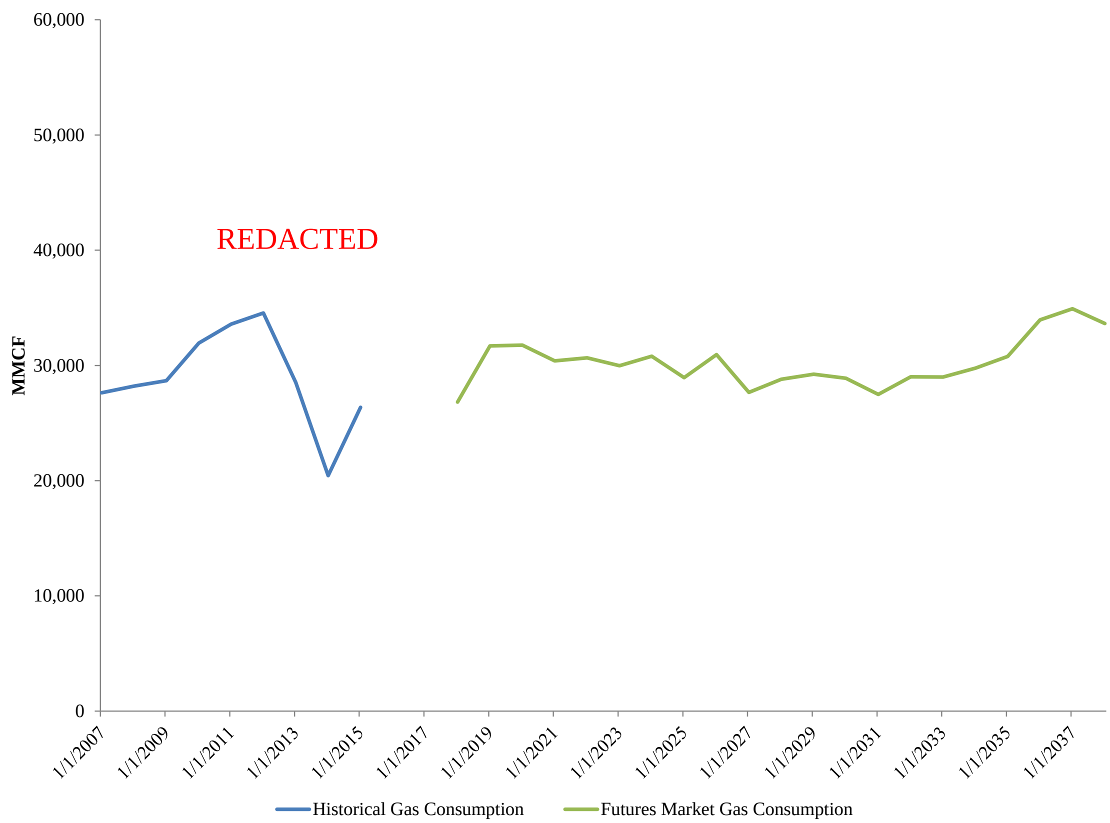
[132] 2014 Assessment of the ISO New England Electricity Markets, Potomac Economics as prepared by David B. Patton, Pallas LeeVanSchaick, and Jie Chen; External Market Monitor for ISO-NE, June 2015 at 36.

A: Figure 14 compares for each month of January Black & Veatch's forecast of the (pre-ANE) quantity of gas consumed by New England generators to the quantity of gas historically consumed by the region for the purposes of electricity generation and such quantities as forecasted based on futures prices for natural gas. As shown by the figure, Black & Veatch's model shows, relative to historical natural gas consumption, an [REDACTED] in the average quantity of gas being burned by the region's generators. That is, Black & Veatch's analysis starts from base case in which it projects an [REDACTED] in the demand for natural gas.

Figure 14
Power Demand Natural Gas Consumption:
Black & Veatch Forecast v. Historical and Compass Lexecon Forecast
Month of January, 2007 - 2038



Q: **Is there any other aspect of Black & Veatch's modeling results that is contrary to reasonable expectations of electricity prices?**

A: Yes. A key driver of the benefits reported by Black & Veatch is notably high electricity prices during winter months. When these prices are reduced upon the addition of ANE's capacity, the modeling yields very large price reductions. Fed through Black & Veatch's modeling, the consequence is correspondingly very large, albeit implausible, modeled benefits for ratepayers.[133] The starting point of very high "without ANE" winter electricity prices, however, is inconsistent with the volume of natural gas consumed in New England according to Black & Veatch's modeling results. That is, if there is so much gas available to fuel New England power plants during the winter months, we would expect lower electricity prices.

The source of Black & Veatch's relatively high electricity prices is explained by the electric generating units that appear to be "setting" the ISO-NE power prices in Black & Veatch's modeling. For example, if we take Black & Veatch's core winter months (January/February) electricity prices and calculate the implied efficiency (measured by "heat rate" in the power industry, MMBTU of fuel consumed per MWh of energy produced) we find that Black & Veatch's modeling results show heat rates, on average during winter months, of nearly [REDACTED] (See Figure 15). However, as Figure 15 shows, this heat rate is [REDACTED] than that actually observed over the last several years and [REDACTED] than that projected in our Futures Market Modeled case.

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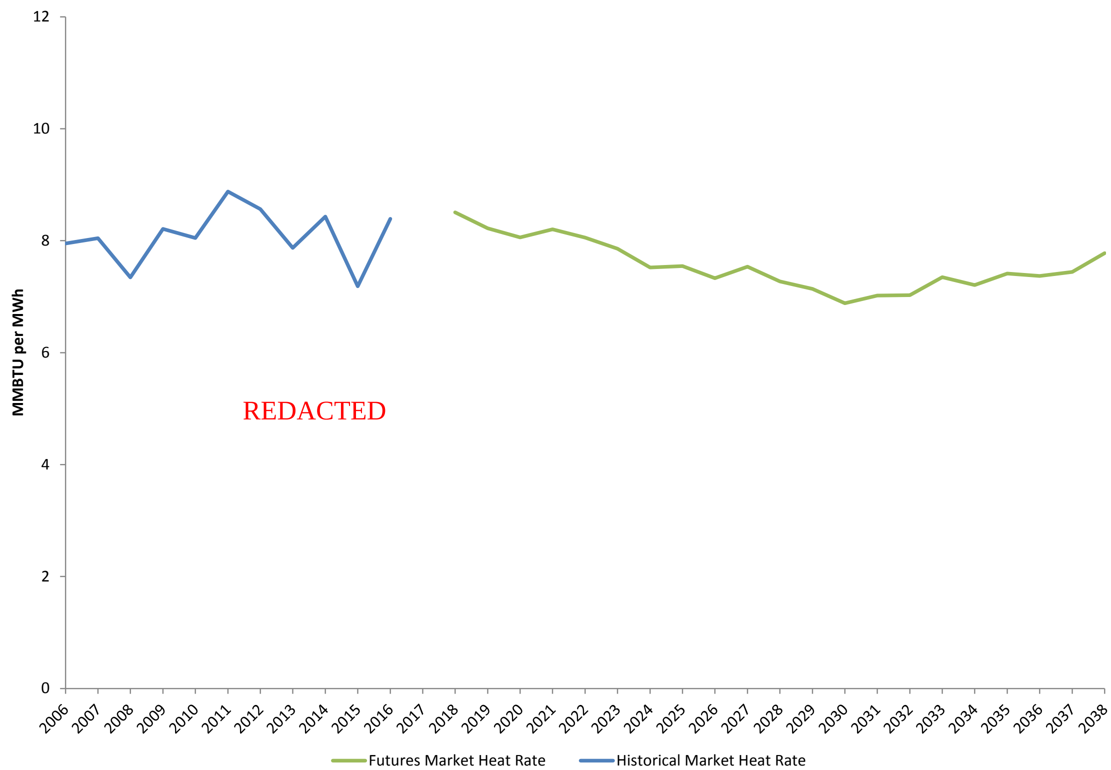
[133] For example, excluding alleged volatility benefits, and comparing Black & Veatch's reported nominal benefits through 2035 against ICF's reported benefits reveals that Black & Veatch's reported benefits are $4.7 billion (undiscounted) greater than ICF's. Given that Black & Veatch's forecast natural gas prices are notably lower than ICF's (compare D.P.U. 15-181 Exhibit EVER-KRP-3 at page 27 against Figure 5), Black & Veatch's benefits appear to be much greater than one would logically expect.

Figure 15
Average January/February Heat Rate:
Black & Veatch Forecast v. Historical and Compass Lexecon Forecast
January 2007 to December 2038



Note: Because Black & Veatch only provided monthly results,
analysis assume that gas is the marginal fuel for each hour of both months.

Q: **What is the impact of Black & Veatch's model's implied winter heat rates?**

A: The reduction in electricity price attributed to the addition of the ANE project is amplified resulting in greater modeled benefits. For example, assume that the addition of ANE results in a monthly gas price reduction of $5/MMBTU (e.g., $15/MMBTU - $10/MMBTU). If we next assume a modeled heat rate of 10 MMBTU/MWH, this translates to an electricity price reduction of $50/MWh ($15/MMBTU - $10/MMBTU multiplied by 10 MMBTU/MWh). However, if the modeled heat rate is 8 MMBTU/MWh, the reduction is $40/MWh. The higher heat rate results in a projected

REDACTED

electricity price reduction that is 25% greater. This heat rate increase results in increased benefits, which are especially amplified in later years when Black & Veatch's forecasted natural gas prices are at their highest levels.

Q: **Are there yet further Black & Veatch's results that call into question the reliability of the analysis?**

A: Yes. Black & Veatch's analysis shows a substantial amount of benefits occurring in non-winter months. Over the 20-year time period modeled, $1.1 billion (undiscounted, nominal) benefits are shown as occurring in non-winter months. This result is out of step with the observation that materially positive gas price basis differentials between Algonquin and New Jersey are winter phenomena. They generally have not occurred, and are not reasonably expected to occur, during non-winter months. In addition, both our modeling and Eversource's expert ICF's modeling results (see above at Figure 2 and D.P.U. 15-181 Exhibit EVER-KRP-3 at Figure 12), do not reveal any expected impact from ANE during non-winter months. Black & Veatch's findings of non-summer months' "benefits" are illogical artifacts of what appears to be faulty modeling.

2. The Net Present Value of Ratepayer Impacts

Q: **Why are you presenting an NPV analysis of ratepayer impacts?**

A: In the Department's October 2, 2015 order, it set forth a standard of review where an EDC gas capacity contract proposal must be shown to be consistent with the public interest and that: "…, an EDC must demonstrate that the proposed contract . . . results in net benefits for the Massachusetts EDCs' customers at a reasonable cost,…."[134] Adopting the Department's standard of review, we also analyze the ANE contracts from the ratepayer perspective only, comparing what the ratepayers will be committed to pay (the $526 million or greater fixed annual levelized payment) against potential benefits from the suppression of wholesale electric prices which, without accepting as true or accurate, we assume for purposes of our analysis will be passed through in lower retail rates.

Q: **How has Black & Veatch interpreted the application of the Department's standard of review?**

A: Black & Veatch estimates the supposed nominal, annual wholesale power market price reductions that would result from the construction of the ANE project, and assumes these estimated price reductions would be passed through to retail ratepayers. Black & Veatch discounts the annual benefits and costs "using a discount rate equal to National Grid's current nominal weighted cost of capital of 7.06%."[135].

Q: **Do you agree with Black & Veatch's approach?**

A: No. Black & Veatch's use of National Grid's current nominal weighted average cost of capital is inapplicable given, as explained further below, the economic attributes of the ANE Project, which do not mirror a typical EDC utility investment.

Q: **What analytical framework do you use to evaluate the NPV of ratepayer impacts?**

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[134] D.P.U. 15-37 at 43.

[135] See Exhibit NG-JNC-3 at 24, footnote 6.

A: To begin, we recognize that the National Grid's proposal is unique and is not structured as a typical utility investment in that it does not provide direct and reasonably quantifiable benefits to ratepayers. It therefore requires an analytical approach that addresses the unusually speculative nature of the benefits in this case as compared with the effectively certain costs to ratepayers.

We perform the NPV analysis we understand that the Department suggests it will apply as part of its ratepayer impact cost-benefit analysis standard of review under D.P.U. 15-37. In doing so, we apply a framework that evaluates the costs, benefits, and risk components of the National Grid proposal from the ratepayer perspective, and not a utility business cost-benefit case or cost-effectiveness perspective. Unlike a standard social cost-benefit analysis, a ratepayer NPV analysis excludes the costs, benefits, and risks accruing to or borne by the ANE project owners and to wholesale electric generators, and treats pure transfers of revenues from producers to consumers as benefits. Importantly, in our analysis we calculate the present value dollar amounts of the estimated benefits and costs to account appropriately for the uncertainty associated with the two different payment streams affecting EDC customers.

Q: **Does the structure of the National Grid proposal impact the NPV calculation of ratepayer impacts?**

A: Yes. National Grid proposes that in exchange for the EDCs' contractual payment of at least $526 million per year (up to [REDACTED] million per year including the cost overrun allowance), the ANE joint venture will provide specified quantities of gas transportation and related services, but not the gas commodity itself, to gas-fired generators under the ERS. National Grid proposes to pass through to its retail ratepayers the fixed contractual payment obligation of at least $526 million per year (or the increased amount if there is cost overrun). To effectuate the recovery of the ANE contract payments, National Grid proposes the implementation of a non-bypassable retail tariff.[136] The tariff provides for the recovery of that portion of the ANE contracts' costs that is allocated to National Grid's Massachusetts retail ratepayers. The tariff would be adjusted periodically to reflect a reduction for any revenues that the regulated utilities actually receive for resale of the gas transportation capacity, but, although it has made some estimates of potential resale revenue, National Grid commits to no reduction in the tariff rate based on that revenue, and National Grid assumes no financial risk that any level of capacity resale will be achieved. Both the uniquely proposed benefits and the pure pass through of costs under the proposed tariff impact the calculation of present value dollars for the ratepayer impacts, and, specifically the discount rates for the benefits and the costs.

Q: **How do you analyze the alleged benefits of National Grid proposal from a NPV ratepayer perspective?**

A: First, we, like National Grid expert Dr. Vilbert,[137] recognize that National Grid's proposal is unlike a utility investment that is intended to provide customers direct benefits associated with a utility's provision of service to its customers (e.g., construction of distribution and transmission facilities or entering into long-term PPAs). Under National

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[136] Petition of Massachusetts Electric Company and Nantucket Electric Company, Each D/B/A National Grid for Approval of Gas Infrastructure Contracts with Algonquin Gas Transmission Company for the Access Northeast Project at 2-3..

[137] See Exhibit NG-MJV-1 at 6.

Grid's proposal ratepayer benefits arise as a result of hoped-for wholesale electricity market price suppression. National Grid's proposal cannot ensure the use of the gas transportation capacity that will be added by the ANE project is used because none of the gas-fired generation targeted by the ANE proposal is owned or controlled by National Grid.[138] Instead, any benefits are completely dependent on how generators beyond National Grid's control respond to projected and uncertain market forces, such as the demand for natural gas, the price of natural gas, fuel oil and LNG, the demand for electricity, and the increasing amount of electric generation (e.g., renewable resources) that do not use gas. Thus, National Grid is requesting approval of a massive 20-year bet that it can, without any current commitments, induce the ISO-NE gas-fired generating fleet to use the proposed ANE project facilities—rather than consider other options such as relying on existing and future fuel diversity—by subsidizing these electric generators with the hopes of lowering New England power prices, all else equal.[139]

Moreover, National Grid's unique proposal is based on market modeling analyses results that are significantly out of step with current market data and state policy development. As explained above, National Grid's projected benefits are based on market analyses that ignore New England's existing generation resource fuel diversity

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[138] National Grid's EDCs do not own or control gas-fired generating units in Massachusetts (See 2016 CELT Report at Section 2.1).

[139] National Grid assumes that its subsidization proposal is consistent with Department and federal policy and will not interfere with the operation of federally regulated wholesale electricity markets. However, a recent Supreme Court decision affirming the FERC's authority over the regulation of wholesale electricity markets identifies the importance of considering the interaction of state and federal regulatory policy on wholesale power markets (see, generally, *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288 (2016)).

and its ability to reduce demand for natural gas. In addition, a coalition of New England states is nearing completion of an evaluation of several major clean energy procurement options that are expected to result in the addition of as much as 1,000 MW of renewable resources to the region's resource mixture by 2020, reducing the demand for natural gas.[140] Also, a recent Supreme Judicial Court decision requires that Massachusetts implement declining annual emission caps for sources and categories of sources of greenhouse gas emissions in the Commonwealth, which can also be expected to reduce demand for natural gas, all else equal.[141] Further, National Grid did not provide any planning studies that show a need for the ANE contracts or that there is an electric system reliability risk without them. National Grid's proposal fails to account for these important factors which further makes the supposed benefits less certain and more speculative.

Q: **How do you account for the non-traditional structure of National Grid's proposal when evaluating the NPV of the ANE project from the perspective of ratepayers?**

A: The structure of the National Grid proposal creates a unique separation between the benefits and the costs of the proposal to ratepayers. Unlike a traditional utility investment in capital or a contract for services, such as purchased power, that would directly benefit customers, National Grid's customers will not directly benefit from the ANE contracts. Because the purported benefits depend on the actions of unaffiliated generators operating in ISO-NE's wholesale power markets and over which neither

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[140] See: https://cleanenergyrfp.com/bids/

[141] *Kain v. Dep't of Envtl. Protection*, 474 Mass. 278, 300 (2016).

National Grid nor the Commonwealth exercises decision-making control or oversight, they are highly uncertain and must be accounted for properly when calculating a NPV. The costs, on the other hand, are directly subject to State ratemaking authority, and once in place represent a nearly certain, fixed and on-going cost to ratepayers over time. [142] The costs remain whether the pipeline is ever used and regardless of the magnitude of the inherently uncertain benefits, if any, resulting from the project.

Q: **What is your basis for using different discount rates for the costs and benefits?**

A: The uncertainties and risks, associated with the purported benefits and the certain fixed costs facing customers, are very different. It is a foundational result of modern finance that valuing the components (various costs and benefits) of a project by rates reflecting the risks associated with those components will equal the value of the project as a whole determined by discounting the project by the discount rate for the project as a whole.[143] So by accurately reflecting the risks of the costs and benefits, respectively, a more accurate valuation of the project can be determined.

Q: **How do you determine the discount rate appropriate to measuring the present value of ratepayer benefits?**

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[142] National Grid expert Dr. Vilbert notes "…it is imperative that the Department provide the most rigorous assurance of full cost recovery for the duration of the Proposed Agreement, so that a zero or near-zero risk-factor is appropriate." See Exhibit NG-MJV-1 at 28.

[143] The net present value of a group of assets is equal to the sum of the net present value of each individual asset. See Richard Brealey, Stewart Myers, and Franklin Allen, *Principles of Corporate Finance 10th ed.*, McGraw-Hill Irwin, 2011 at 104. The discount rate used for the net present value for each component of a project must reflect the relevant risk associated with that component of the project, including claims against that project or asset. See, for example, David Wessels, Marc Goedhart, and Tim Koller, *Valuation 5th ed.*, John Wiley & Sons, Inc., 2010 at 101, Appendix C and Appendix D.

A: The fact and magnitude, if any, of hoped-for ratepayer benefits from suppression of wholesale electricity prices in New England depend upon the evolution over a 20-year horizon of such matters as natural gas and oil prices, electricity demand in New England and beyond, and the technologies of the various means of generating electricity. As a result, National Grid's proposal subjects hoped-for ratepayer benefits to risks that are driven by factors similar to those that a merchant generation facility would face, although the degree of uncertainty, depending on limited, extreme winter-time events is greater than those facing a merchant generator overall. Accordingly, we conservatively select a discount rate associated with the risk that wholesale power market merchant generators face based on ISO-NE's most recent analysis of merchant generator wholesale market risk (see discussion above).

In the standard public cost-benefit analysis conducted above (as summarized in Table 2), we employed a discount rate of 8% per annum to reflect the fact that the proposed project's public benefits would turn on economic factors and risks of the type that affect the performance of investments in the merchant generation sector. Unlike merchant generators and their costs of capital, however, ratepayers do not benefit from a reduction in taxes associated with the deductions for interest on corporate debt that reduce the cost of capital for generators. Adjusting for this difference in tax treatment between merchant generators and ratepayers yields an applicable discount rate for determining the present value of hoped-for ratepayer benefits of approximately 9%. We use this value in our calculations.[144]

Q: **How do you evaluate the costs borne by ratepayers under National Grid's proposal?**

A: As discussed above, National Grid/Black & Veatch state that the cost of the ANE contracts to ratepayers will be no more than [REDACTED] billion, resulting in no more than [REDACTED] million in annualized payments. Integral to Black & Veatch's "annualized" net benefits of $1.1 billion from the ANE proposal is the $526-[REDACTED] million in annual fixed payments to be paid for the ANE contracts over the 20-year horizon modelled by Black & Veatch.[145]

Black & Veatch's method of "annualizing" the costs of the proposal effectively converts those costs to a stream of payments to be made by retail ratepayers, regardless of that fact that electric ratepayers do not receive a utility-related benefit from the project as they would otherwise when National Grid invests in transmission and distribution assets regulated by public utility commissions. In effect, National Grid's proposal would put retail electric ratepayers in the position of incurring a mortgage payment of $526-[REDACTED] million per year for no less than 20-years without sufficient evidence that ratepayers are receiving a corresponding benefit that outweighs this cost.

Thus, the essentially fixed costs from the proposed ANE contracts are simply passed through in the proposed tariff. Determining the present value of this obligation

---

[144] The basic result that costs to ratepayers outweigh benefits continues to hold when we employ discount rates for benefits of 8% or ICF's 11.5%.

[145] See Exhibit NG-JNC-3 at Table 3.

requires a discount rate that reflects the likelihood or prospect that the required annual payment could be avoided. As a one-time regulatory approval of a long-term contract, the straightforward pass through of costs for a contract unrelated to the EDC's service to customers is significantly different than the risks associated with a typical utility capital project investment or capital project equivalent in the form of a contract (e.g., PPA).

Q: **How do you determine the discount rate appropriate for measuring the present value of ratepayer payments under National Grid's proposal?**

A: Any discount rate can be decomposed into two components: a pure time value of money component and a risk component. The pure time value of money is measured by the risk-free rate of interest. Today, that is approximately 2% looking over a 20-year period. Now, consider the risk component. What is uncertain or risky about whether ratepayers would have to pay at least the $526 million per year that National Grid requests under the ANE contracts? Certainly, the risk is not related to National Grid's management of an investment used to serve customers, because National Grid cannot use the capacity facilitated by the contracts – by statute, it is prohibited from owning generation facilities.[146] In fact, the very reason that National Grid says the LGTSC tariff is needed is because National Grid says the investors need certainty of payment in order to be induced to make the investment in the ANE project.[147] In other words, *it is elimination of risk by having retail customers paying for the project that is the essence of the proposal before*

[146] See Massachusetts G.L. c. 164 § 1A.

[147] See Exhibit NG-MJV-1at 2.

the DPU. Thus, the only identifiable uncertainty is that maybe someday the regulators will relieve ratepayers from having to pay the full $526+ million per year.

We, thus, employ a discount rate of 3.75% consistent with high-grade corporate bond debt yield, and a level greater than that for a "riskless" treasury bond of similar term. Employing a discount rate of 3.75%, we find that the relatively certain stream of annual payments of $526-[REDACTED] million that National Grid's proposal would collect from ratepayers results in total payments by retail ratepayers that have a present value today of approximately $5.9-[REDACTED] billion.

Q: **Is the reasoning you employ consistent with the testimony put forth by National Grid?**

A: Yes. National Grid's expert Dr. Vilbert emphasizes that under the proposed Agreements the EDCs' obligations to make 20-years of fixed payments under the terms of the contracts is similar in nature to the requirement to make payments on debt. We agree with Dr. Vilbert that the proposed Agreements impose an obligation "similar in nature to the requirement to make a payment on debt."[148] The obligations that are being requested implicitly impose a payment obligation similar to debt, and the cost of that obligation

---

[148] See Exhibit NG-MJV at 28. Dr. Vilbert argues that investors and rating agencies will view these obligations, either implicitly or through an imputation process, like debt. Dr. Vilbert states that National Grid is not asking for additional financial remuneration for the purported additional risk, but instead that the "most rigorous possible assurance of full cost recovery for the duration of the Proposed Agreements" be provided. To the extent that the payment obligation imposed on the utility's customers through the regulatory and legislative structure is equally as secure, then the customers' obligation to the EDC and the EDC's obligation to the pipeline project's owners will fully offset and there is no change in the financial costs of the EDC. Dr. Vilbert argues that if the customers' obligations to the EDC are less secure than the EDC's obligation to the pipeline owners, then the EDC's financial risk will have been increased by this project, and the costs of obtaining funds from investors will have been increased. See Exhibit NG-MJV at 28.

ought to be recognized as similar to debt. Dr. Vilbert's arguments are equally true for the EDC's customers who are being asked to make fixed payments over the life of the Proposed Agreements in an amount equal to the payment obligations of the EDCs under the contracts. Indeed, the proposal, and the import of Dr. Vilbert's testimony, holds that the ratepayers should be required with as much certainty as possible to make the fixed payments over the requested 20-year period regardless of whatever benefits actually accrue from the proposal to ratepayers. It is therefore appropriate to value the obligations of the ratepayers like debt - as recognized by National Grid. Thus, we calculate the value of this debt obligation reflecting the certainty that the debt will be repaid.

Q: **What happens when you correct for the unsupportable assumptions and modeling errors in Black & Veatch's framework for assessing ratepayer impacts?**

A: Black & Veatch's assertion of positive net impacts on New England's ratepayers is reversed. This is seen in Table 5. Here, we have employed our Futures Market Forecast base case modeling and our Modeled Market Forecasts sensitivity case modeling (described above) to calculate ratepayer impacts. Retail ratepayers would, of course, realize lower electric energy prices *if wholesale price suppression that would be created under National Grid's proposal is passed through to retail rates.* Again, however, suppression of wholesale electric energy rates causes higher prices in ISO-NE's wholesale electric capacity market – to the detriment of retail ratepayers to the extent such higher prices are passed through to retail rates. As indicated in Table 5, we find the present value of the negative effect on ratepayers arising from price elevation in ISO-NE's capacity markets to be on the order of $229 million. In order to arrive at the net impact on ratepayers, the impact on the ISO-NE's capacity markets plus costs associated with the LGTSC tariffs must be weighed against any retail electricity price suppression benefits ratepayers might hope to realize. As shown by Table 5, the costs to electric ratepayers exceed the benefits by no less than $640 million in net present values.

Table 5
Wholesale Electricity Buyer Impacts of National Grid's Black & Veatch proposal[1]
2016 Present Value; $ millions

CASE: Futures Market Forecasts

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$3,471		
Electric Capacity		-$229	[REDACTED]
Pipeline Cost		-$5,892	[REDACTED]
Total Present Value	$3,471	-$6,121	[REDACTED]
Total Net Present Value		**-$2,650**	[REDACTED]

CASE: Modeled Market Forecasts

	Benefits	Estimated Costs	[REDACTED]
Change in Electricity Production Costs			
Electric Energy	$5,557		
Electric Capacity		-$305	[REDACTED]
Pipeline Cost		-$5,892	[REDACTED]
Total Present Value	$5,557	-$6,196	[REDACTED]
Total Net Present Value		**-$640**	[REDACTED]

Note:
1) Energy market benefits and capacity market costs discounted at 9% unlevered cost of capital approved by ISO-NE for Net Cost of New Entry analysis. See Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, Federal Energy Regulatory Commission Docket No. ER14-1639-000, April 1, 2014. Pipeline costs discounted at 3.75%, based on high grade bond yields.
2) The estimated costs do not include the costs to ratepayers of the 2.75% financial incentive that ratepayers would provide to National Grid as described in Exhibit NG-MCC-1.

Source: National Grid and Compass Lexecon Analysis

In no case in Table 5 do retail ratepayers realize net positive benefits from National Grid's proposal. This conclusion ultimately arises because forcing ratepayers to bear the costs of subsidizing gas-fired electric generators by having to pay $526-[REDACTED] million per year swamps any benefits they might reasonably realize from the distortion and depression of wholesale electric energy prices. In the base case, the net present value to ratepayers of National Grid's proposal is hugely negative – negative $2.7-[REDACTED] billion. (The base case in the top panel of Table 2 repeats Table 1B, discussed above in our summary of conclusions). If the project encounters cost overruns, we can expect the result to be at the more negative range of the NPV.[149]

The negative effects on ratepayers of National Grid's proposal also hold at the much higher natural gas prices projected in our Modeled Market Forecasts sensitivity case. As shown in the bottom panel of Table 5, this analysis finds that National Grid's proposal results in a NPV for ratepayers of -$0.64 to [REDACTED] billion. Thus, whether assessed using the unconventional cost-benefit framework employed by National Grid (as corrected in Table 5), or using the standard economic cost-benefit analysis (as in Table 2), the ANE project does not provide positive benefits to Massachusetts' retail electricity ratepayers.

Q: **Does this conclude your direct testimony?**

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[149] It is critical to take into account the potential for cost overruns. When building a recent New Jersey/New York pipeline expansion Spectra's actual incurred costs were 48% higher than originally estimated rising from $789 million to $1.167 billion (Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC, *Abbreviated Application for a Certificate of Public Convenience and Necessity Volume I*, December 2010, Docket No. CP11-56-000, also see Texas Eastern Transmission, LP and Algonquin Gas Transmission, LLC, *Final Statement of Costs*, May 2014, Docket No. CP11-56-000).

REDACTED

A: Yes.

NEER-McKEE-1-2

Request:

At the same time that NextEra is opposing the Access Northeast project in the Massachusetts docket [D.P.U. 16-05], NextEra is also in a joint venture with Spectra Energy and Duke Energy to design, construct and operate a 515-mile interstate natural gas pipeline to provide transportation services for power generation needs in Florida (Sabal Trail Transmission). In fact, NextEra subsidiary Florida Power and Light will purchase fuel transportation capacity from the pipeline when it enters service in 2017. Please explain why that pipeline is in the interest of Florida electricity ratepayers while the Access Northeast project is not in the interest of Rhode Island electricity ratepayers.

Response:

NEER does not regard comparisons of Florida Public Service Commission determinations or Florida state energy policies as relevant to the subject proceeding. Notwithstanding the lack of relevance, NEER responds as follows:

In contrast to this case where National Grid does not own or operate natural gas generators that would be using gas capacity on the Access Northeast project and the pipeline is therefore not used and useful to National Grid, Florida Power & Light Company ("FPL") proposed entering into definitive agreements with two pipeline projects specifically and solely for the purpose of providing incremental natural gas transportation capacity to serve natural gas fired generators that FPL owns and operates. The Florida Public Service Commission determined that the FPL pipeline proposal was in the interest of customers because: (1) FPL's decision to enter into long-term natural gas transportation contracts with Sabal Trail was based on a fair and open RFP process; (2) the pipeline is projected to save up to $450 million over the term of the contracts when compared to the next most cost-effective proposal; (3) the prudence of the actual transportation costs will be examined in annual proceedings; and (4) FPL is eligible to seek recovery of costs associated with the firm natural gas transportation.

Prepared by or under the supervision of: Brian J. Tobin

NEER-McKEE-1-3

Request:

The purpose of the Access Northeast project is to lower wholesale prices in New England. From the generator point of view, this means they will command a lower price for their product. Please explain how this factors into the decision-making process (if at all) for a generator who is evaluating whether or not to obtain capacity from the Access Northeast project.

Response:

NEER provided testimony in the Massachusetts DPU case explaining that NEER's Bellingham plant does not plan to purchase capacity on the Access Northeast project for the following reasons: First, Bellingham would not want to commit to any gas transportation capacity because, even following ISO-NE and FERC changes to help improve coordination between the gas and electric markets, Bellingham would have to do so before knowing whether the plant would actually run. If Bellingham were to purchase gas capacity that is ultimately not needed, it would take a loss. This is especially the case given that the rules of the program proposed by National Grid would prohibit generator purchasers from reselling the capacity to anyone else. Second, given the enormous gas capacity that would be available if the Access Northeast project were completed, without scarcity of capacity there would be little reason to pay to reserve it.

Prepared by or under the supervision of: Brian J. Tobin

NEER-McKEE-1-4

Request:

ISO New England's Pay-for-Performance ("PFP") program has been designed to motivate gas-fired electric generators to firm up their winter fuel supply in order to ensure that they are available when needed, including during winter peak periods.

A. In your view, are the PFP penalties severe enough to drive the generators to take actions needed to ensure they are available in the winter peak period?
B. What does the evidence show concerning the steps that natural gas fired generators are taking to firm up their fuel supply in the winter?
C. Under what circumstances will electric generators contract for firm natural gas transportation supply?

Response:

A. Each generator owner will have their own company-specific risk tolerances they will review against their plants unique situations to determine what actions are necessary to ensure they are available in the winter peak period and to manage PFP penalties. NEER's Bellingham plant is duel fuel and we believe we are prepared to operate the plant successfully once the PFP program begins without purchasing capacity on the Access Northeast project.
B. NEER does not have information on what other generators are doing in regard to fuel supplies in the winter.
C. Each power plant that utilizes natural gas will have unique facts and circumstances to be analyzed in determining the potential need for natural gas transportation supply.

Prepared by or under the supervision of: Michelle Gardner

NEER-McKEE-1-5

Request:

What levels of pipeline capacity release and LNG storage would you likely contract for from the Access Northeast project for your gas-fired electric generation in New England?

Response:

Please refer to NEER's response to NEER-McKee 1-3. NEER has no plans to contract with the Access Northeast project for our gas-fired electric generation in New England.

Prepared by or under the supervision of: Brian J. Tobin

NEER-McKEE-1-6

Request:

Is there any risk that the gas price suppression coupled with likely subsidization of a subset of gas-fired generators will result in further retirements of non-gas-fired generation in New England? How much additional non-gas-fired generation would be at risk to be retired? Assuming that these units would be replaced by additional new gas-fired generation, how much additional demand for natural gas in New England would they represent?

Response:

As explained in NextEra Energy Resources, LLC's Complaint and Request for Fast Track Processing to the Federal Energy Regulatory Commission (attached), the proposal to use EDC ratepayer funds to build the Access Northeast Project is simply a cost shift, requiring generators, in effect, to pay for the pipeline expansion through revenues lost as a result of lower clearing prices in the ISO-NE market. Essentially, money diverted from generators through lower clearing prices will reimburse the EDCs and the retail ratepayers, at least in part, for their cost outlay for the uneconomic pipeline expansion, and fund any additional ratepayer savings that the EDCs expect will result from the price suppression. This cost shift may have unintended reliability and market consequences, such as forcing the early retirement of generation and making investment in new generation less likely. The quantification of how much non-gas-fired generation is likely to retire and of additional natural gas demand in New England depends on the timing of the Access Northeast Project, what gas prices are at that time, and other inputs that are not known at this time.

Prepared by or under the supervision of: Brian J. Tobin

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June 24, 2016

VIA ELECTRONIC FILING

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

RE: **NextEra Energy Resources, LLC and PSEG Companies v. ISO New England Inc.: EL16-__-000**

Dear Ms. Bose:

Enclosed please find the Complaint of NextEra Energy Resources, LLC and the PSEG Companies for electronic filing at the Federal Energy Regulatory Commission in a new docket. The following documents comprise this filing:

- Complaint of NextEra Energy Resources, LLC and the PSEG Companies;
- Appendix A: Examples of Potential Market Solutions for ISO-NE Consideration;
- Certificate of Service;
- Form of Notice; and
- Exhibits A-I.

Please do not hesitate to contact me with any questions regarding this submission.

Sincerely,

*/s/ Noel Symons*_____

Noel Symons

Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NextEra Energy Resources, LLC,	)	
PSEG Companies,	)	**Docket No. EL16-___ -000**
v.	)	
ISO New England Inc.	)	

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COMPLAINT AND REQUEST FOR FAST TRACK PROCESSING

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June 24, 2016

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NextEra Energy Resources, LLC,	)	
PSEG Companies,	)	**Docket No. EL16-___ -000**
v.	)	
ISO New England Inc.	)	

COMPLAINT AND REQUEST FOR FAST TRACK PROCESSING

State regulators in Massachusetts, New Hampshire, Connecticut and Rhode Island are on the verge of implementing a scheme expressly intended to artificially suppress prices in wholesale energy markets in New England. The Massachusetts Department of Public Utilities ("MDPU") and the New Hampshire Public Utilities Commission ("NHPUC") have before them for review contracts filed by their Electric Distribution Companies ("EDCs") to buy substantial quantities of Algonquin Gas Transmission, LLC ("Algonquin") capacity that the EDCs cannot use. These purchases would result in an expansion of a pipeline, dubbed the Access Northeast Project. Having no use for the pipeline capacity, the EDCs would release the capacity at below market rates—first to gas-fired generators, if the Federal Energy Regulatory Commission ("FERC" or the "Commission") supports this preference in a separate proceeding,[1] and then whatever is left will be released to the marketplace. This transportation subsidy would artificially flood ISO-New England ("ISO-NE") markets with gas, thereby unreasonably suppressing gas prices and wholesale power prices.[2]

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[1] *See Algonquin Gas Transmission, LLC*, Docket No. RP16-618-000, "Bidding Requirements Waiver for State-Regulated Electric Reliability Programs" (Feb. 19, 2016) (filing to exempt certain customers from capacity release bidding requirements).

[2] Two other states appear to be set to follow suit. As discussed further below, the Connecticut Department of Energy and Environmental Protection issued a final notice of request for proposals for natural gas capacity procurement on June 2, 2016, with EDCs acting as contracting parties. The Rhode

The EDCs propose to do this even though they themselves have no use for natural gas or pipeline capacity—it is purely a scheme to suppress wholesale prices, as all concerned freely admit.[3] Indeed, the MDPU has said it would not approve such a plan unless there is a "net benefit" to consumers, such as "lower overall winter electric prices."[4] And both EDCs seeking MDPU and NHPUC approval of retail cost recovery for pipeline capacity purchases have submitted testimony claiming that there will indeed be a significant price-suppressive effect.[5]

As the Commission knows, the "benefits" of the lower prices that state regulators seek are illusory when they are not consistent with market fundamentals. Subsidization "can harm competition," thereby "producing unjust and unreasonable wholesale rates by artificially depressing … prices."[6] While the Commission has taken the view that some level of price

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Island Public Utilities Commission is also expected to review contracts as soon as they are filed by the EDC in that state, which National Grid has indicated will occur in June 2016. The NHPUC is evaluating briefs filed in Phase 1 of its proceeding on Eversource Energy's Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC, Docket No. DE 16-241.

3 *See, e.g.*, Order Determining Department Authority Under G.L.C. 164, § 94A, Mass. D.P.U. 15-37, at 27 (Oct. 2, 2015) (appeal pending) ("*MDPU Order*") ("[W]holesale generators will have the opportunity to take advantage of this pipeline capacity. This opportunity would afford generators additional supply options in the marketplace, with the intended result of lower energy prices.").

4 *MDPU Order* at 43.

5 *See* Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, for Approval of Firm Gas Transportation and Storage Agreements with Algonquin Gas Transmission Company, LLC, pursuant to G.L. c. 164, § 94A, MDPU Docket 15-181, Exhibit No. EVER-KRP-1, "Prepared Direct Testimony of Kevin R. Petak" ("Eversource MDPU Petition") (Dec. 18, 2015) (attached as Exhibit D); Petition of Massachusetts Electric Co. and Nantucket Electric Co., each d/b/a as National Grid, for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project, MDPU Docket No. 16-05 ("National Grid ANE Petition") (Jan. 15, 2016) (attached as Exhibit F).

6 *Consolidated Edison Co. of N.Y.*, 150 F.E.R.C. ¶ 61,139 at P 2 (2015) (citing *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157 at PP 90-91 (2009)). *See also Indep. Power Producers of N.Y., Inc. v. N.Y. Indep. Sys.Operator, Inc.*, 150 FERC ¶ 61,214 at P 69 (2015) (noting that subsidized generation "might deter new entry or displace less-costly existing [generation]").

suppression may be acceptable if it is a well-examined and carefully mitigated side-effect of some more important public policy goal,[7] there is no such goal here.

The evidence submitted by the EDCs in the state proceedings is almost exclusively directed at demonstrating that the purchase by the EDCs of a product they will not use, pipeline capacity, will push down prices in the market for another product, wholesale electricity. To be sure, the EDCs do also invoke "reliability" benefits, but they have made no substantive demonstration that the proposed pipeline expansion is necessary for ISO-NE to reliably operate the grid. They also have failed to explain why their conclusory judgment as to grid reliability, and the judgment of their state commissions, ought to supersede that of this Commission, which has painstakingly addressed measures to preserve reliability in ISO-NE in a manner consistent with market fundamentals in numerous orders over many years. It is clear that what the EDCs and the states really seem to be saying is that price suppression will lower costs attributable to pipeline constraints.[8]

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[7] *See ISO New England Inc.*, 155 FERC ¶ 61,023 at P 35 (2016), *reh'g pending* (accepting renewables exception to ISO-NE minimum offer price rule even though it may cause "some price impact" because the price impact would "not be significant when paired with a downward sloping demand curve" and because the exemption accommodated "public policy objectives" on renewables) ("*ISO-NE Renewable Exemption Order*"). While NextEra and PSEG oppose the conclusion reached in that case, and have sought rehearing, NextEra, PSEG and the Commission are in full agreement that state action to suppress prices for the sake of price suppression can never be lawful.

[8] For example, Eversource Energy, the parent of two of the Massachusetts EDCs, mentioned price "mitigation" but not reliability in explaining the Access Northeast Project to investors in its 2015 10-K:

> *New England Natural Gas Pipeline Capacity*: In 2014, the six New England states began to explore ways to address and mitigate winter natural gas price volatility and the associated impact on electric power supply costs attributable to winter pipeline capacity constraints. Five states are currently pursuing natural gas capacity expansion efforts….

Eversource Energy 10-K for the Fiscal Year ended December 31, 2015, available at https://www.sec.gov/Archives/edgar/data/13372/000007274116000063/f2015form10k.htm.

In short, the express intent of these programs is for the states to impermissibly substitute their judgment on proper wholesale market pricing and functioning for the Commission's.[9] This is not just a "who decides" jurisdictional issue. The states have no obligation, or incentive, to ensure that wholesale rates remain just and reasonable. They do not share this Commission's concern over the long-term health and efficiency of regional markets, as evidenced by their interest in a costly pipeline to address winter peak capacity needed for what the EDCs have admitted is at most about 30 days per year in lieu of more efficient utilization of dual-fueled generating capacity and the use of additional liquefied natural gas ("LNG").[10] The states do not have this Commission's experience with market issues, such as the importance of providing investors with price signals that are consistent with market fundamentals of supply and demand. Also, the evaluation by each state is narrow, focused on its own ratepayers, and to date the only analyses that have been submitted ostensibly showing ratepayer benefits have been conducted by EDCs. Regional evaluation by ISO-NE has shown that Pay for Performance incentives should lead to expanded dual fuel capability and LNG sourcing that can address winter peak issues more efficiently than pipeline expansion.[11] In fact, when the states sought to advance essentially the

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[9] *See Hughes v. Talen Energy Mktg.*, 136 S. Ct. 1288, 1298 (2016) (rejecting state proposal attempting to "interfere with FERC's authority by disregarding interstate wholesale rates that FERC ha[d] deemed just and reasonable," namely rates set by the PJM Interconnection, L.L.C. ("PJM") capacity market) ("*Hughes*").

[10] As will be litigated in State proceedings, the Eversource EDCs overstate the alleged "need" because the projection does not take into account the potential for additional LNG supplies using existing infrastructure or additional dual-fuel capacity.

[11] *See, e.g.*, Levitan & Associates, Inc. report to the Eastern Interconnection Planning Collaborative, "Gas-Electric System Interface Study Target 4 Report: Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives" at 89 (Dec. 1, 2014) (comparing the economics and reliability benefits of dual fuel capability versus firm pipeline transportation and finding that "with few exceptions, dual-fuel capability appears to be much less costly with respect to reducing the direct cost as a strategy to achieve fuel assurance") http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

same pipeline plan through an amendment to the ISO-NE Tariff, that effort failed. Rather than file a complaint with this Commission, the states and the EDCs have chosen a path that seeks to evade Commission jurisdiction and review.

This is discouraging, because stakeholders in New England have been engaged in discussions, slated to continue this summer, intended to provide wholesale market solutions for new entry by renewables and other zero emission resources. We have participated in such discussions and plan to continue to do so in good faith. But putting a finger on the scales by building uneconomic pipeline capacity could well undermine such efforts to achieve a balanced approach to a "next step" in the ISO-NE market evolution.

If allowed to proceed without mitigation, this scheme will render ISO-NE markets unjust, unreasonable, and unduly discriminatory and result in manipulation of the ISO-NE market. Prompt Commission action is required to protect markets by altering ISO-NE rules to neutralize the effect of the manipulative scheme and—equally importantly—to send a message that the scheme will not work, before state regulators permit their EDCs to lock in to 20-year contracts for uneconomic pipeline capacity. That is expected to occur by the end of the year, and could occur as early as October of this year.

Accordingly, pursuant to Section 206 of the Federal Power Act ("FPA"),[12] and Rule 206 of the Commission's Rules of Practice and Procedure,[13] complainants here—the "Indicated Generators"[14]—hereby request that the Commission expeditiously order ISO-NE to revise its

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12 16 U.S.C. § 824e (2012).

13 18 C.F.R. § 385.206 (2015).

14 The Indicated Generators each own generating facilities that participate in ISO-NE's energy and electric capacity markets, but do not run on natural gas or are not located on the subsidized pipeline, and so will be forced to compete on an unlevel playing field with gas-fired generation that receives subsidies. The Indicated Generators are NextEra Energy Resources, LLC ("NextEra") and the PSEG Companies ("PSEG").

Transmission, Markets and Services Tariff ("Tariff") to ensure that prices in its energy and electric capacity markets remain just and reasonable in light of the anticipated state actions described herein ("Complaint").

Specifically, we request that the Commission issue an order by August 23, 2016, and make a factual and legal finding that development of a prophylactic tariff fix is warranted to fully mitigate the price suppressive effect of the subsidized gas pipeline capacity, and direct ISO-NE to propose such a fix within 90 days. As discussed further below, we propose that this be followed by a technical conference, which will provide opportunities for transparency and additional stakeholder participation, and final Commission action on the ISO-NE mitigation fix on or before January 31, 2017. This timing is needed to allow time for the ISO-NE Tariff amendments requested here to be effective before ISO-NE's next capacity auction in February 2017.

I. Preliminary Statement

Early last year, in a move representative of what was also occurring in other New England states,[15] one Massachusetts agency went to another with a highly unusual proposal. The Massachusetts Department of Energy Resources ("DOER") wanted MDPU to consider whether MDPU had authority to allow EDCs to recover from retail ratepayers the costs of firm gas

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15 While all of the New England states other than Vermont have or are expected to have proceedings involving EDC procurement of gas pipeline capacity, for the sake of simplicity we focus here on one state, Massachusetts, given the expected decisional timeline, noting that the remedies we propose will be equally effective against all of the proposed manipulation attempts. Although the state of Maine opened a proceeding, it is not yet as clear whether the state intends to participate in the State Pipeline Scheme, and, as discussed below, Maine PUC staff recently recommended against supporting the State Pipeline Scheme. *See* Maine Public Utilities Commission, Examiners' Report, *Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A.M.R.S. § 1901*, Docket 2014-00071, at 1 (June 8, 2016) (concluding that Energy Cost Reduction Contract proposals "are not in the public interest [and] are not reasonably like[ly] to be cost-beneficial").

transportation. What made the request unusual was that the EDCs do not actually have any use for natural gas, much less gas transportation.

The DOER, of course, knew that the EDCs could not use the pipeline capacity it wanted them to purchase. That was part of the plan. The DOER wanted the EDCs to buy enough pipeline capacity to cause pipelines into New England to expand, thus increasing supply and lowering prices for natural gas, and thereby lowering wholesale power rates. The DOER also wanted the EDCs to ultimately release the pipeline capacity to others who they believed could in fact use the capacity: natural gas-fired generators, thereby directly subsidizing their delivered costs of gas, again with the goal of decreasing clearing prices in markets administered by ISO-NE and subject to the Commission's exclusive jurisdiction. This pipeline investment, therefore, would not be driven by reliability needs, or by legitimate economic needs based on market fundamentals. It was simply the roundabout means chosen to achieve wholesale price suppression.

The MDPU agreed that the DOER plan was within the MDPU's jurisdiction[16] and adopted a brand new legal standard to ensure that a purchase of pipeline capacity that was not economic in its own right would nonetheless provide a financial "benefit" to ratepayers on a net basis because of the price suppressive effect the purchase would have on electricity markets. The purpose of the EDCs' capacity purchase is to "simply put a resource into the market that

[16] Unlike FERC commissioners, neither the MDPU commissioners nor DOER commissioner should be considered independent. They are appointed by the Massachusetts Secretary of Energy and Environment with consent of the Governor, and can be removed without cause by the Secretary with consent of the Governor. *See* MASS. GEN. Laws Ch. 25, § 2 (2016) (appointment and removal of MDPU commissioners); MASS. GEN. Laws Ch. 21A, § 7 (appointment and removal of DOER commissioner). Given Governor Charlie Baker's express support for the pipeline projects (*see, e.g.*, https://www.bostonglobe.com/business/2015/04/23/energy/uOR8a4XhH9VM4N1a7YbBYN/story.html), and the removal without rights clause, the MDPU and DOER commissioners ought not be considered politically independent.

could operate to mitigate higher peak-period electric prices."[17] The MDPU determined that it could and would authorize the recovery of gas pipeline costs if purchase of the pipeline capacity had such "net benefits" to ratepayers. The "netting" to be performed would be a comparison of costs with so-called "benefits," i.e., whether expected wholesale price suppression would be substantial enough to outweigh the cost of making an otherwise pointless purchase of pipeline capacity.

Four Massachusetts companies, NSTAR Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource EDCs") and Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid plc ("National Grid EDCs"), promptly submitted applications to recover the costs of purchasing pipeline capacity they would never use. The EDCs submitted extensive testimony indicating their views that their purchases of unneeded pipeline capacity and subsequent release of such capacity would significantly lower wholesale power prices. This overt effort at price suppression by the Massachusetts EDCs, together with the lead-in encouragement and path-clearing from the two Massachusetts agencies, and the similar efforts in three other New England states described below, is at times referred to in this Complaint as the "State Pipeline Scheme."

The EDCs are seeking authorization for contracts to enable them to secure pipeline capacity and storage on the Access Northeast Project, which will be owned by affiliates of Algonquin (40%), the Eversource EDCs (40%) and the National Grid EDCs (20%). These pipeline capacity reservations by the Eversource EDCs and National Grid EDCs will make the Access Northeast Project viable, meaning that the pipeline capacity purchases will substantially benefit affiliates and the corporate parents of the EDCs. The Access Northeast Project will have

[17] *MDPU Order* at 26-27.

500,000 MMcf/d of pipeline capacity plus 400,000 MMcf/d of liquefied natural gas capacity, and proposes to commence operation in 2018.

State authorization will result in EDC retail ratepayers paying a fixed rate, for twenty years, for the Access Northeast Project pipeline capacity that the EDC ratepayers cannot use. A "Capacity Manager" appointed by the EDCs will then release the capacity into the secondary market, with a priority for gas generators, thus shrinking the market by omitting, for example, gas local distribution companies. There is no expectation that the Capacity Manager, as the releasing shipper, will maximize proceeds from the capacity release because, as represented in the state proceedings, the purpose of the State Pipeline Scheme is to suppress wholesale power prices during the winter months,[18] and because the priority for release to gas generators will artificially shrink demand for the released capacity.

There are many legitimate ways to lower prices to customers, such as by increasing efficiency, but this is not one of them. The Commission-approved ISO-NE Tariff has been constructed and fine-tuned with the goal of providing incentives for infrastructure expansion when such expansion is warranted consistent with market fundamentals. The most economic infrastructure expansion in New England right now is to add dual fuel capability and LNG access to gas-fired generators, as a winter peak alternative. ISO-NE's Pay for Performance initiative was intended to incentivize such low cost, efficient decisions in the marketplace, which would not artificially suppress prices. On the other hand, subsidized construction of a new pipeline, which is otherwise inefficient as a winter peak resource, would suppress prices. So that is the winter peak option the states prefer in lieu of the more efficient Commission-approved ISO-NE market design.

[18] Notably, the EDCs have asked the states to approve the pipeline capacity purchase prior to releasing the full details of the arrangement with the Capacity Manager.

The price suppression planned here will divert from generators revenues that the generators would have earned in an un-manipulated market. That money would go to retail ratepayers who would use the money to pay, on a pass-through basis, for the pipeline expansion project that is 60% owned (collectively) by affiliates of the EDCs that made the filings in Massachusetts and New Hampshire. This scheme does not result in greater economic efficiency for the system. It is simply a revenue shift at the expense of generators effectuated through price suppression. And while the Commission has indicated some willingness to allow limited price suppressive effects where such effects are mitigated by market rules and where such effects are incidental to a public policy goal such as renewable portfolio standards,[19] here the effect is not incidental or mitigated, it is intentional. Interference with price formation in the wholesale markets is not a valid public policy goal. Price suppression is the express intent, and it is intended to have a huge, unmitigated impact on wholesale power prices.

This case is virtually indistinguishable from the Minimum Offer Price Rule ("MOPR") cases.[20] Those cases involved state efforts to suppress wholesale prices by subsidizing the construction of new generation. In the MOPR cases, the owner of the new generation was sheltered from market risks through payment of a guaranteed cost of service rate funded by retail ratepayers, who were expected to recoup their investment through reduced wholesale power prices. The Commission, two federal district courts, two circuit courts of appeal, and the U.S. Supreme Court all said the states could not do that.[21] Rather than accepting these outcomes, the

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[19] *See supra* note 7.

[20] *See PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 (2011) (revising MOPR rule in PJM to eliminate exception for state-sponsored programs); *ISO New England*, 131 FERC ¶ 61,065 (2010) (adopting ISO-NE's "Alternative Price Rule", subject to paper hearing).

[21] *PPL EnergyPlus, LLC v. Hanna* , 977 F.Supp.2d 372, (D.N.J. 2013) (finding New Jersey's Long-Term Pilot Capacity Project to be preempted by the FPA), *aff'd, sub nom.*, *PPL EnergyPlus, LLC v.*

EDCs and the states have attempted the same scheme through a different infrastructure medium: subsidized pipeline expansion. The pipeline (part owned by affiliates of the EDCs) and the EDCs themselves are both guaranteed to recover their money for twenty years, just like the subsidized generators in the MOPR cases. And just like the MOPR cases, it is unsubsidized generators and the market as a whole that will be harmed if the price suppression scheme goes forward without mitigation.

This Complaint, therefore, is being submitted for the purpose of mitigating the price suppressive and market distorting effects of the State Pipeline Scheme. This scheme warrants mitigation because the EDCs have both "the incentive *and* ability to exercise [buyer side] market power."[22] Accordingly, the Commission should direct ISO-NE to amend its Tariff to neutralize the price suppressive effects of the State Pipeline Scheme. In other words, with the Tariff amendments, the market should be in more or less the same position it would have been in but for the manipulative scheme.

While it is not our burden to propose a just and reasonable replacement rate,[23] to speed the process of ISO-NE's development of a proposal, the Indicated Generators identify in Appendix A to this Complaint potential fixes to the ISO-NE electric energy and electric capacity markets. In our view, fixes could be designed for the energy market, the capacity market, and/or on a make-whole basis. The important thing is that the mix of fixes selected must return the market to its pre-manipulation status quo.

Solomon, 766 F.3d 241 (3rd Cir. 2014); *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. 2013), *aff'd*, 753 F. 3d 467 (4th Cir. 2014), *aff'd sub nom. Hughes*.

22 *N.Y. Pub. Serv. Comm'n, et al.*, 153 FERC ¶ 61,022 at P 36 (2015) (emphasis in original).

23 *See, e.g.*, *Md. Pub. Serv. Comm'n v. FERC*, 632 F.3d 1283 at n.1 (2011) (clarifying that in a complaint proceeding, "[i]t is the Commission's job—not the petitioner's—to find a just and reasonable rate").

The Commission should not delay issuing an order to evaluate and rule upon the merits of the potential fixes identified in the Appendix—timing is too important, as discussed below. Instead, we propose a two-part process. The first part—acting on this Complaint—should be limited to a factual and legal finding that development of a prophylactic tariff fix is warranted to fully mitigate the price suppressive effect of the State Pipeline Scheme, and direction to ISO-NE to propose such a fix (or a package of fixes) within 90 days. The second part would involve a technical conference on the resulting ISO-NE proposal and substantive action on the merits of the fix. Because of the tight timeline, and the likely difficulty of achieving a quick consensus view through a stakeholder process, the technical conference process we propose here appropriately balances the need for transparency and input with the need for expedition. A timeline of the proposed process is provided in Section III.B.2 below.

Expeditious Commission action on this Complaint is critical. The first state expected to take the next step and possibly lock in retail ratepayer commitment to provide subsidies, irreversibly, for twenty years, is Massachusetts, which is expected to act as early as October. Commission action in this case, before then, could send a powerful message that twenty years of subsidies will not be allowed to cause the intended price suppression.

Requiring ISO-NE to develop a Tariff mechanism to stop price suppression and market distortion could lead Massachusetts and other states to abandon their efforts, thus mooting the need to ever apply the new anti-manipulation mechanism and preserving orderly functioning of wholesale markets in the cleanest fashion possible. Put differently, a timely order could have a preemptive effect (in the non-constitutional sense) that could avoid the need for applying the mechanisms requested here, as well as possible court proceedings to invoke constitutional preemption, or Commission investigation of manipulative conduct by state agencies. Accordingly, we respectfully request Commission action by August 23, 2016.

II. Correspondence and Communications

Complainants request that all correspondence and communications regarding this filing be addressed to the following persons, who should be placed on the Commission's official service list in this proceeding:[24]

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Raymond V. DePillo
Senior Director – Market Development
PSEG Energy Resources & Trade LLC

[24] Complainants respectfully request waiver of Rule 203(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b) (2015), to the extent necessary to allow each of these individuals to be included on the official service list in this proceeding.

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III. Description of Complainants and Respondent

1. Complainants

NextEra is the competitive generating subsidiary of NextEra Energy, Inc. NextEra subsidiaries own and operate over 19,000 MW of generation in 25 states and Canada, including approximately 12,000 MW of wind resources and 1,600 MW of solar resources. In the ISO-NE region, NextEra's subsidiaries own several exempt wholesale generators that are engaged in the wholesale generation and sale of electric power, with net capacity totaling over 2,200 MW. These facilities are located in Massachusetts, New Hampshire and Maine.

The PSEG Companies are each wholly owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). The principal and executive offices of PSEG are located at 80 Park Plaza, Newark, New Jersey 07102. PSEG is a public utility holding company engaged in, among other things, the generation of electric energy, and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

PSEG Power is a wholesale energy supply company that integrates its generation asset operations with its wholesale energy, fuel supply, energy trading and marketing, and risk management functions through three principal subsidiaries: (i) PSEG Nuclear LLC ("PSEG Nuclear"), which owns and operates nuclear generating stations; (ii) PSEG Fossil LLC ("PSEG Fossil"), which develops, owns, and operates domestic fossil-fuel fired and other non-nuclear generating stations; and (iii) PSEG ER&T, which is described below.

PSEG Power CT, a direct subsidiary of PSEG Fossil, owns two plants located in Connecticut: (i) the Bridgeport Harbor Generating Station; and (ii) the New Haven Harbor

Generating Station (collectively the "PSEG Power CT Generation Assets") with a total capacity of nearly 1000 MWs. The PSEG Power CT Generation Assets are interconnected with the transmission system under the control of ISO-NE.

PSEG ER&T, an indirect subsidiary of PSEG, sells power and energy and certain ancillary services at market-based rates. PSEG ER&T markets the capacity and production of PSEG Nuclear's and PSEG Fossil's generating stations, manages the commodity price risks and market risks related to generation, and provides gas supply services. PSEG ER&T is engaged in extensive asset-based energy trading operations throughout the Northeast.

2. Respondent

ISO-NE is a private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE administers the New England energy and capacity markets and plans and operates the New England bulk-power system pursuant to the ISO-NE Tariff and the Transmission Operating Agreement with the New England Transmission Owners.

IV. Background

A. The Access Northeast Project

According to the most recent Eversource Energy ("Eversource") form 10-K submitted to the Securities and Exchange Commission:

> Access Northeast is a natural gas pipeline and storage project (the "Project") being developed jointly by Eversource, Spectra Energy Corp and National Grid. Access Northeast will enhance the Algonquin and Maritimes & Northeast pipeline systems using existing routes and will include two new LNG storage tanks and liquefaction and vaporization facilities in Acushnet, Massachusetts that will be connected to the Algonquin gas pipeline. The Project is expected to be capable of delivering approximately 900 million cubic feet of additional natural gas per day to New England on peak demand days. **Eversource and Spectra Energy Corp each own a 40 percent interest in the Project, with the remaining 20 percent interest owned by National Grid**. The total projected cost for both the pipeline and the LNG storage is expected to be approximately $3 billion with anticipated

> in-service dates commencing in November 2018. The Project is subject to FERC and other federal and state regulatory approvals. On November 17, 2015, the FERC accepted the Project's request to initiate the pre-filing review process. Upon completion of the pre-filing review, a certificate application will be filed with the FERC. In late 2015, the Project bid into the New England Natural Gas Pipeline Capacity RFP conducted by certain EDCs in Massachusetts and Rhode Island, including NSTAR Electric and WMECO in Massachusetts, and in December 2015 and January 2016, those Massachusetts EDCs filed with the DPU seeking approval of the contracts for pipeline and storage capacity with the Project. We expect the Rhode Island EDC to file its selected contracts with the Rhode Island regulatory agencies in the first half of 2016. In February 2016, PSNH filed for approval with the NHPUC, of its proposed contract for natural gas pipeline capacity and storage with the Project.[25]

B. The ISO-NE electric energy and capacity markets

ISO-NE operates a Day-Ahead Energy Market and Real-Time Energy Market. The Real-Time Energy Market establishes the locational marginal price ("LMP") that is paid or charged to Day-Ahead Energy Market participants when demand or generation deviates from their day-ahead commitments.

ISO-NE ensures long-term resource adequacy through the FCM. The FCM is intended to send appropriate price signals to incentivize new investment and to provide sufficient compensation to existing resources when (and where) they are needed. On an annual basis, ISO-NE procures electric capacity (i.e., generation, imports, and demand response resources) by holding a three-year advanced FCA. New capacity resources submit offers, reflecting the price at which they will enter the market. Existing electric capacity resources are in some respects price takers. By default, they do not submit offers; however, they may choose to submit one of

[25] Eversource 10-K for the Fiscal Year ended December 31, 2015, available at https://www.sec.gov/Archives/edgar/data/13372/000007274116000063/f2015form10k.htm (emphasis added).

several types of "de-list" bids. These de-list bids specify a price below which a supplier does not wish to provide capacity from an existing resource (whether temporarily or permanently).[26]

Suppliers of capacity that clear an FCA take on a Capacity Supply Obligation,[27] which requires them to offer into ISO-NE's Day-Ahead Energy Market during the Capacity Commitment Period and be available to operate during Shortage Events (or pay penalties). Capacity resources receive payments during every month of the Capacity Commitment Period for the Capacity Supply Obligation.[28] As part of ISO-NE's Pay for Performance-related market design changes, non-performance penalties are increased and capacity performance is paid through two settlements. A Base Payment is determined by the associated FCA clearing price, and a Capacity Performance Payment is determined by performance during reserve deficiencies. Most of the two-settlement market design changes will be phased in, beginning on June 1, 2018, at the start of the capacity commitment period associated with FCA 9.[29]

In its order approving the Pay for Performance design, the Commission concluded that "ISO-NE has persuasively demonstrated that revising its FCM market design to more closely link capacity revenues to real-time performance will address this concern by **providing better incentives for investment decisions appropriate for the New England region**."[30] Moreover, the adoption of the Pay for Performance market design was intended to drive *private* investment

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26 *See ISO New England, Inc.*, 155 FERC 61,029 at P 2 (2016).

27 All capitalized terms not otherwise defined in this complaint shall have the definitions assigned by the Tariff.

28 *See generally ISO New England, Inc.*, 147 FERC ¶ 61,172 at P 2 (2014), *reh'g denied*, 153 FERC ¶ 61,223 (2015), *review pending*, *New England Power Generators Ass'n v. FERC*, No. 16-1023 (D.C. Cir.).

29 *See id.* at P 44 and n.8.

30 *Id.* at P 36 (emphasis added).

to ensure reliability through resource adequacy,[31] unlike the State Pipeline Scheme, which is intended to fund pipeline construction with money diverted from generators to retail ratepayers.

C. The State Pipeline Scheme to suppress wholesale market prices

1. The New England states first attempted, and failed, to get the pipeline built through changes to the Commission-jurisdictional ISO-NE Tariff

It is widely understood that nearly all of the New England states have a high interest in the development of new gas pipeline capacity into New England.[32] Through NESCOE,[33] the New England states designed and brought a plan to New England Power Pool ("NEPOOL") stakeholders in 2014 to have the costs associated with a new pipeline paid for under a FERC-regulated ISO-NE Tariff.[34] Withdrawing that effort,[35] some of the New England states now seek to fund a significant pipeline expansion through their EDCs. But as described below, the EDCs

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31 *See* 153 FERC ¶ 61,223 at P 34.

32 *See, e.g.*, the New England States Committee on Electricity ("NESCOE") presentation at the New England Energy and Commerce Association, Inc. 14th Annual Power Markets Conference at slide 5 (Nov. 17, 2015) *available at* http://nescoe.com/wp-content/uploads/2015/11/NESCOE_NECA_17Nov2015.pdf (quoting the New England Governors April 2015 Energy Forum's discussion on new natural gas infrastructure: "With these infrastructure investments, our region can reduce energy costs").

33 NESCOE is a not-for-profit entity that "represents the collective perspective of the six New England Governors in regional electricity matters." *See* NESCO.COM, http://nescoe.com/.

34 This effort was abandoned in the face of lack of stakeholder support and serious legal doubts about Commission authority to pass pipeline costs through the ISO-NE Tariff. For discussion of the former, see Morningstar Commodities Research, "Eastern Gas Basis: Pipeline Pain or Gain? Takeaway capacity additions and their impact on basis prices" at 5-7 (Aug. 26, 2014), *available at* http://www.morningstarcommodity.com/Research/Morningstar_Eastern_Gas_Basis_Research.pdf (noting that NEPOOL had requested an extension to consider the NESCOE Incremental Gas for Electric Reliability ("IGER") initiative); For additional analysis of the IGER concept, see FERC Staff, Gas-Electric Coordination Quarterly Report to the Commission at Slide 4 (June 19, 2014), *available at* http://www.ferc.gov/legal/staff-reports/2014/06-19-14-gas-electric-cord-quarterly.pdf; Letter from Eric Johnson (Director, External Affairs, ISO-NE) to New England Conference of Public Utility Commissioners at 6-7 (May 30, 2014), available at http://www.iso-ne.com/committees/comm_wkgrps/othr/clg/mnthly_issu_memo/may_2014_necpuc_memo.pdf.

35 NESCOE's IGER plan was presented to NEPOOL, but NEPOOL, ISO-NE, and NESCOE were ultimately unable to come to a resolution. Rod Kuckro, E&E Publishing, LLC, "New England Effort to Expand Gas Pipelines, Transmission Hits a Snag" (Aug. 11, 2014), http://www.eenews.net/stories/1060004298.

will not bear financial responsibility for funding the pipeline project. Rather, the pipeline expansion will occur because retail ratepayers will pay the EDCs for the pipeline expansion. Those retail ratepayers in turn are intended to be, in effect, reimbursed (and more) by the money they save through price suppression in wholesale energy markets. So after failing in the bid to amend the Commission-jurisdictional ISO-NE Tariff to fund construction of a pipeline expansion, the State Pipeline Scheme seeks to leverage retail rate regulation to create wholesale price suppression and thereby effectively divert the money for the pipeline expansion from generators.

The Indicated Generators understand that the ISO-NE Chief Executive Officer and even some Commissioners have expressed that added pipeline capacity in New England would be beneficial. This Complaint is not aimed at stopping infrastructure investment—even where it may not be the most cost effective means of relieving a reliability constraint. Rather, the Indicated Generators believe that it is necessary for the Commission to thwart the EDCs plainly intended manipulation of the wholesale energy markets through the State Pipeline Scheme. The proposals we offer in Appendix A for changes to market rules all are examples of how suppressive **effects** of subsidized new pipeline capacity can be mitigated; they do not seek to prohibit the construction of the pipeline.

2. The MDPU adopted a new standard requiring a showing that "benefits" of wholesale price suppression would outweigh costs of unneeded new pipeline capacity

While all of the New England states other than Vermont have or are expected to soon have proceedings involving EDC procurement of gas pipeline capacity,[36] for the sake of

[36] *See, e.g.*, Eversource Energy, Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC, NHPUC Docket 16-241 (Feb. 18, 2016); in Rhode Island, Notice of Request for Proposals, Natural Gas Capacity, Liquified Natural Gas (LNG), and Natural Gas Storage Procurement, issued by The Narragansett Electric Company d/b/a National Grid (Oct. 23, 2015);

simplicity we focus here on one state, Massachusetts, noting that the proposed remedy will be equally effective against all of the proposed manipulation attempts. In fact, the proceedings in each of the New England states are focused on funding the same out-of-market plan: construction of the Access Northeast Project co-owned by affiliates of Algonquin, the Eversource EDCs and the National Grid EDCs.

On April 2, 2015, the DOER filed a petition with the MDPU requesting that the MDPU investigate how new natural gas capacity could be added to the New England energy market. DOER asked the MDPU to adopt a standard for authorizing EDCs to contract for new pipeline capacity and recover costs through electric distribution rates. The DOER asked the MDPU to consider whether the MDPU had the authority to approve such contracts absent new legislation, noting that it "would be a matter of first impression for the [MDPU]" [37]—unsurprisingly, no one had ever before thought to ask whether an EDC could acquire pipeline capacity it did not intend to use and pass the costs through to ratepayers.

Connecticut Department of Energy and Environmental Protection, Notice of Request for Proposals (RFP), Natural Gas Capacity, Liquefied Natural Gas (LNG), and Natural Gas Storage Procurement (June 2, 2016), *available at* http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/32723b39b1c8b69885257fc6006cf337/$FILE/DEEP_Final%20Gas%20RFP_6.2.16.pdf; Maine Public Utilities Commission, Docket No. 2014-00071, *Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A.M.R.S.A. Section 1901*, Notice of Investigation (Mar. 20, 2014). Although the state of Maine opened a proceeding, it is not yet as clear whether the state intends to participate in the State Pipeline Scheme.

[37] Dep't of Energy Resources, Request to Open an Investigation into New, Incremental Natural Gas Delivery Capacity for Thermal Load and Electric Generation, MDPU Docket 15-37 at 5 (Apr. 2, 2015) ("DOER Petition"). Specifically, DOER asked the MDPU to consider whether:

> (1) there is an innovative mechanism for electric distribution companies ("EDCs") or other suitable parties to secure new, incremental gas delivery capacity into the region to the benefit of electric ratepayers; (2) review for cost-recovery of EDC contracts for natural gas capacity by the Department under G.L. c. 164, §94A ("§94A") is appropriate; and, (3) the standard of review the Department would apply to contracts submitted for approval under that section should be different.

Id. at 1.

DOER described the impetus for its petition as the high costs of electricity in Massachusetts in the winter, caused, according to DOER, by constrained natural gas delivery capacity.[38] DOER said that potential investors in interstate pipelines lack an incentive to build new capacity when they do not have long-term contracts in place, and that wholesale generators "who sell into an unregulated power market are generally unwilling or unable . . . to secure firm gas capacity."[39] Therefore, DOER argued, an "innovative mechanism" was necessary to increase natural gas capacity available for electric generation during times of peak demand and that "the challenges for . . . ratepayer costs associated with electricity generation . . . may be alleviated, in part, with new, incremental gas delivery capacity in the region."[40]

The MDPU agreed with the DOER as to both the alleged problem (high prices in wholesale electricity markets) and the ostensible solution (suppressing wholesale market prices through a program of subsidized pipeline expansion and capacity release). On October 2, 2015, the MDPU issued an order finding that DOER provided "sufficient information to support [its] assessment of current New England **wholesale** market conditions" and concluded "that **increasing regional gas capacity will lead to lower wholesale gas and electricity prices**."[41] The MDPU determined that it did have authority under Massachusetts law to review and approve long-term contracts for natural gas capacity filed by EDCs that would never use the gas capacity themselves.[42]

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38 *See id.*at 1 ("There is a widespread belief among many industry stakeholders that the high cost of electricity in the winter market in Massachusetts has been cause by constrained natural gas delivery capacity.").

39 *Id.* at 3.

40 *Id.* at 2.

41 *MDPU Order* at 12 (emphasis added).

42 *MDPU Order* at 26.

Importantly, the MDPU also established a new standard of review that it would apply for gas capacity contracts filed by EDCs—a standard specifically aimed at identifying wholesale price suppressive effect. Under the modified standard, an EDC seeking approval for a gas capacity contract filed pursuant to Section 94A must demonstrate: (1) that the proposed contract results in net benefits for its Massachusetts customers at a reasonable cost, and (2) compares favorably to the range of alternative options reasonably available to the EDC at the time of acquisition of the resource or contract negotiation. The MDPU gave wholesale price suppression as an example of a benefit: "… benefits could include … lower overall winter electric prices."[43] And as shown in the next section, that is exactly the "benefit" the affected EDCs sought to prove when they made filings seeking approval of pipeline capacity purchases a few months later.

3. Eversource EDCs and National Grid EDCs have filed price suppression proposals with the MDPU

The Eversource EDCs and National Grid EDCs, which are affiliated with Access Northeast, have filed with the MDPU applications for approval of long-term transportation agreements for pipeline capacity they will not use. Similar actions have or will soon commence in other states, but the MDPU is expected to act first. We discuss the Eversource EDCs' and the National Grid EDCs' MDPU applications in turn.

On December 18, 2015, the Eversource EDCs filed a petition with the MDPU for approval of firm transportation and storage services contracts between the Eversource EDCs and Algonquin for the development of the Access Northeast Project.[44] The Eversource EDCs claim that their filing meets the requirements set out by MDPU.[45] The Eversource EDCs provide evidence and expert reports that they claim "demonstrate[] that [the project] would generate

43 *Id.* at n.6 (citing the DOER Petition at 5).

44 *See generally* Eversource MDPU Petition.

45 Eversource MDPU Petition at P 7-8.

significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England power generators, and subsequently, **wholesale energy prices in all New England states.**"[46] Specifically, the Eversource EDCs predicted wholesale power price reductions of up to $12/MWh, converting to wholesale power price reductions of up to $3.1 billion per year,[47] and annual price reduction, net of the cost of the pipeline expansion, of $0.9 to $1.3 billion.[48] Subsequently, NextEra and others filed opposing testimony presenting evidence demonstrating that, while price suppression would occur, it would not occur at levels sufficient to offset the substantial cost of pipeline expansion, such that there would be no net "benefit" to ratepayers. While NextEra disputed the amount of the price suppressive effect, NextEra agreed that price suppression would occur in wholesale power markets if the plan goes forward.[49]

The National Grid EDCs filed their petitions with the MDPU on January 15, 2016, for approval of two long-term transportation agreements with Algonquin and two long-term agreements with Tennessee Gas Pipeline, LLC ("Tennessee").[50] On April 20, 2016, Tennessee suspended work on the Northeast Energy Direct project,[51] and shortly thereafter the National

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[46] *Id.* P 21 (emphasis added).

[47] *See id.* at P 21 and Eversource MDPU Petition, Exhibit No. EVER-KRP-3, ICF Report at 36.

[48] Eversource MDPU Petition at P 21.

[49] The Eversource EDCs did not address the effect on capacity markets in their petition. In considering the net benefits in the MDPU proceeding, as discussed *infra*, the calculation of Net CONE would have to be increased to reflect the reduction of energy and ancillary services payments to suppliers, although it far from offsets the decrease in the ISO-NE energy markets (*e.g.*, NextEra estimates a capacity market increase to be as high as $258 million per year). *See* Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi on behalf of NextEra Energy Resources, LLC, D.P.U. Docket 15-181 at Table 1B (June 13, 2016).

[50] Petition of Massachusetts Electric Co. and Nantucket Electric Co., each d/b/a as National Grid, for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project, D.P.U. Docket No. 16-05 ("National Grid ANE Petition") (Jan. 15, 2016).

[51] On April 20, 2016, Kinder Morgan, Inc. and its subsidiary Tennessee Gas Pipeline Company, issued a press release stating that work and expenditures on the Northeast Energy Direct project had been suspended.

Grid EDCs submitted to the MDPU a motion to withdraw their petition for approval of the contracts with Tennessee,[52] which was granted on April 27, 2016. The National Grid EDCs, like the Eversource EDCs, provide expert testimony and reports in support of their claims that the Access Northeast Project contracts will lower wholesale prices. NextEra and others have intervened in and have filed notices of intent to sponsor witnesses in the National Grid EDCs' proceeding. NextEra also filed intervenor testimony in the Algonquin-related proceeding on June 20, 2016.

The MDPU is poised to act on the Access Northeast Project EDC contracts by the end of the year, and possibly as early as October.

4. Other New England states are considering similar price suppressive schemes

There are initiatives aimed at suppressing wholesale power prices through procurement of uneconomic gas pipeline capacity funded by retail ratepayers in every New England state other than Vermont.[53] The timelines for the initiatives vary, but the impetus for some of them can be traced to legislative action dating to 2013, and in some states hearings have been held or will be held by the end of 2016. The Commission action requested here, therefore, is timely. It is also necessary because the states have no qualms about touting price suppression as the goal of the initiatives. The Maine Public Utilities Commission's ("MPUC") "Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act" began with a reference to a regional analysis prepared by the Sussex Economic Advisors.[54] The

[52] Motion to Withdraw of National Grid, D.P.U. Docket No. 16-07 (Apr. 26, 2016).

[53] Although the state of Maine opened a proceeding, it is not yet as clear whether the state intends to participate in the State Pipeline Scheme.

[54] *Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A.M.R.S.A. Section 1901*, MPUC Docket No. 2014-00071, Notice of Investigation at 1 (Mar. 20, 2014) ("We will refer to the regional analysis provided by the Sussex Economic Advisors titled

"Benefits Estimation" in that regional analysis includes the benefit of a "Reduction in LMPs: The resulting estimated New England natural gas wholesale price reduction would likely result in lower LMPs in the ISO-NE power market, which would benefit electricity customers in the region, including customers in Maine."[55] In Rhode Island, the National Grid EDC operating in that state, Narragansett Electric Company, issued a request for proposals for natural gas capacity procurement under the 2014 Affordable Clean Energy Security Act in October 2015;[56] in Connecticut, the Department of Energy and Environmental Protection issued a final notice of request for proposals for natural gas capacity procurement on June 2, 2016. And in New Hampshire, briefs have been filed for Phase 1 of the proceeding addressing the NHPUC's jurisdiction over the proposal.

V. Complaint

A. ISO-NE should be required to amend its Tariff to neutralize the price suppressive effects of the State Pipeline Scheme to manipulate wholesale markets

The State Pipeline Scheme is, by design, intended to suppress wholesale prices.[57] It will do so by favoring costly gas pipeline construction to address winter peaks over more efficient means incentivized by the Commission-approved Pay for Performance program, such as addition

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'Review of Natural Gas Capacity Options' dated February 26, 2014 to assist in this analysis"). Hearings were held in late April and briefs were filed May 10, 2016, in the Maine proceeding.

55 Sussex Economic Advisors, Review of Natural Gas Capacity Options at 43 (Feb. 26, 2014) http://www.iso-ne.com/committees/comm_wkgrps/othr/egoc/mtrls/2014/mar62014/maine_puc_gas_study_022614.pdf.

56 Notice of Request for Proposals, Natural Gas Capacity, Liquified [*sic*] Natural Gas (LNG), and Natural Gas Storage Procurement, issued by The Narragansett Electric Company d/b/a National Grid (Oct. 23, 2015), *available at* https://www9.nationalgridus.com/energysupply/current/20151027/Final%20NARRAGANSETT%20RFP%20-%20Natural%20Gas%20for%20Electric%20Generation.pdf.

57 *MDPU Order* at 27 ("[W]holesale generators will have the opportunity to take advantage of this pipeline capacity. This opportunity would afford generators additional supply options in the marketplace, with the intended result of lower energy prices.").

of dual fuel capability to existing generators. Such inefficient and intentional price suppression is not in and of itself legitimate public policy and must be neutralized. The most effective and timely solution is for the Commission to issue an order requiring ISO-NE to amend its Tariff so that the manipulative intent of the scheme fails. And importantly, with quick action, the MDPU and other states will know how the Commission intends to deal with the State Pipeline Scheme before the states lock their ratepayers into 20-year contracts for uneconomic pipeline capacity.

1. The State Pipeline Scheme is intended to and will suppress wholesale rates under the ISO-NE Tariff, rendering those rates unjust, unreasonable, and unduly discriminatory

a. The MDPU and the EDCs admit that their goal is to suppress wholesale prices, and the EDCs have testified that price suppression will indeed occur

In response to its view that high wholesale power prices were causing high retail rates during winter months, DOER proposed an "innovative mechanism" for EDCs to lower rates by "secur[ing] new natural gas capacity into the region to benefit electric ratepayers."[58] The MDPU's judgment in turn was that "increasing regional gas capacity will lead to lower wholesale gas and electricity prices."[59] Accordingly, MDPU set up a new "net benefits" test designed to encourage that price-suppressive result. Under the test, an EDC that has no use for gas for its own consumption can nonetheless recover from retail ratepayers the costs of pipeline expansion if it can show that wholesale electric price suppression "benefits" to ratepayers will exceed costs of pipeline expansion.[60] The MDPU added that lower retail rates are a benefit, and that "[u]nder typical market conditions, lower retail electricity prices follow lower wholesale

58 *MDPU Order* at 1.

59 *Id.* at 12.

60 *Id.* at 43.

electricity prices."[61] In other words, the MDPU plainly signaled that wholesale price suppression would be a "benefit" that meets the test.

The Eversource EDCs and the National Grid EDCs promptly took advantage of the new test, and submitted contracts for 20-year recovery of the costs of unneeded pipeline capacity. The EDCs demonstrated that they understood the MDPU's price-suppressive intent, as they submitted testimony quantifying, and taking credit for, predicted price suppression. The Eversource EDCs stated that their contracts with the Access Northeast Project would "generate significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England power generators, and subsequently, **wholesale energy prices** in all New England states."[62] The National Grid EDCs stated that their contracts would provide net benefits through "improved electric reliability **and price relief**."[63] In their request for proposals for pipeline capacity contracts, the National Grid EDCs explained that "[t]he **primary objective** of this RFP is to identify cost-effective resources that would function to increase the reliability of electric service and reduce electric costs for the benefit of the EDCs' electric customers."[64]

If the MDPU accepts the EDC contracts, and this Commission does nothing to mitigate the impact, wholesale prices in New England will be artificially suppressed and private investors will have little confidence in the future of the New England markets. The Eversource EDCs estimate that approval of their contracts will result in up to a $12/MWh decrease in wholesale power prices.[65] The National Grid EDCs estimate that their contracts for transportation on the

[61] *Id.* at 43 n.24.

[62] Eversource MDPU Petition at P 21 (emphasis added).

[63] National Grid ANE Petition at P 74 (emphasis added).

[64] *Id.*, Exhibit NG-TJB/JEA-5 at 4 (emphasis added).

[65] Eversource MDPU Petition, Exhibit No. EVER-JGD-1 at 42:2-7 (citing ICF Report).

Access Northeast Project will result in up to a $10.85/MWh "average annual electric price reduction" over the next 20 years.[66]

We note that NextEra filed testimony at the MDPU arguing that the cost-benefit analysis conducted by the EDCs is flawed and, as a result, the price suppression will be less effective than predicted by the EDCs, in an effort to demonstrate that the long-term cost of subsidies is not worth the resulting market distortion. However, even with disagreement on the fundamental cost-benefit analysis, there is agreement that there will be price suppression in wholesale power markets and market distortion in electric capacity markets. For present purposes, we respectfully submit that the Commission should consider that there are a range of forecast outcomes, and all of them recognize the likelihood of material price suppression if the State Pipeline Scheme goes forward unchecked.[67]

The money at issue here is material. By way of comparison, the average real-time wholesale power Hub[68] price in 2014 was $63.32/MWh, a 13% increase from the 2013 Hub price.[69] The high 2014 Hub price can be attributed to the anomalous "Polar Vortex" events of 2014. For the fall of 2015, a generally less constrained year, the average Hub price was $31.53/MWh.[70] The reduction in wholesale power prices occurred even though the winter of

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[66] National Grid ANE Petition, Exhibit No. NG-JNC-3 at 21.

[67] As discussed below, while all parties agree that the EDCs' proposal will result in price suppression, parties including NextEra and the Massachusetts Office of Attorney General have presented evidence that the price suppression will not provide a net "benefit" to EDC customers because price suppression, while substantial, will not offset the even more substantial cost of the pipeline expansion.

[68] The "Hub" is a collection of ISO-NE nodes that are not typically congested. ISO-NE's market monitor uses this as a reference point for the ISO-NE market. *See* ISO-NE's Internal Market Monitor: 2014 Annual Markets Report at 12 (May 20, 2015), available at http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf ("2014 ISO-NE Market Report").

[69] 2014 ISO-NE Market Report at 12.

[70] *See* ISO-NE's Internal Market Monitor: Fall 2015 Quarterly Market Report at 10 (Jan. 29, 2016), available at http://www.iso-ne.com/static-assets/documents/2016/01/qmr_q4_2015_final.pdf.

2014-2015 was much colder than the winter of 2013-2014. Notably, the ISO-NE Internal Market Monitor attributed this decline to ISO-NE's 2014-2015 winter reliability program, in which ISO-NE allowed LNG supply to participate (in addition to fuel oil and demand response resources), and its participation resulted in a marked increase in LNG deliveries and a decline in New England natural gas prices relative to 2013-2014, in spite of near record low temperatures.[71] Whether considering a highly constrained year like 2014 or a more typical year like 2015, a $12 annual average difference is significant—19% and 38%, respectively.

b. Subsidized pipeline construction will render ISO-NE market clearing prices unjust, unreasonable, and unduly discriminatory, unless the price suppressive effect is neutralized

Under the unique circumstances here, subsidization of pipeline capacity will be harmful, unless mitigated, because: 1) it will bypass more efficient market-based solutions to artificially suppress ISO-NE wholesale market prices, for the sake of price suppression; 2) the price suppression is not justifiable as a carefully mitigated incidental side effect of a legitimate public policy objective; 3) the increased pipeline capacity is not needed for anything other than price suppression—it is simply intended to reshape outcomes in the wholesale market to the liking of the states and the EDCs; and 4) the subsidy is a long-term out of market solution that runs contrary to the Commission's policy preferences for market solutions and fuel-neutrality, and will unduly discriminate against suppliers who will be at a competitive disadvantage because they do not receive the subsidy.

[71] *See* ISO-NE Internal Market Monitor, First Quarter 2015, Quarterly Market Report at 7 (June 9, 2015), http://www.iso-ne.com/static-assets/documents/2015/06/q1_2015_qmr_for_publication_0609.pdf.

(1) Construction and release of subsidized pipeline capacity will suppress wholesale market clearing prices by artificially flooding the market with supply and by artificially decreasing transportation costs

Decreased gas commodity prices will have a major impact on the Real-Time and Day-Ahead energy markets. Construction of additional pipeline capacity on a subsidized basis will artificially flood the market with additional gas supply, thus suppressing markets by manipulating supply and demand mechanics. In response to discovery in Massachusetts, the Eversource EDCs candidly admitted that "**gas prices will be depressed and corresponding electric prices will follow, achieving one of the main goals of the program**."[72]

Further, subsidized capacity release will reduce the transportation costs of subsidized generators. Generally speaking, the largest component of a gas-fired generator's offer into ISO-NE energy markets is the price of delivered gas, typically purchased on an interruptible basis. Subsidized generators will be able to make lower offers into ISO-NE energy markets. Because "Algonquin serves approximately 57 percent of the natural gas-fired and dual-fuel generating capacity directly connected to an interstate pipeline in New England,"[73] the threat to ISO-NE markets is not merely theoretical. Even generators not on the Algonquin system will be affected by this dramatic increase in gas pipeline capacity. As discussed above, all agree that there will be a material price suppressive effect.

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[72] *See* MDPU Case No. 15-181, Response to Discovery Request NEER-3-5 (Apr. 27, 2016), available at http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fNEER35.pdf. *See also* Eversource MDPU Petition at P 13 ("[t]he **overriding objective** … is to enter into contracts that will lead to the development of gas transportation and/or storage capacity that will have the greatest potential to improve reliability and **reduce prices in the wholesale electric market**.") (emphases added).

[73] *See* Eversource MDPU Petition, Testimony of James M. Stephens, Exhibit EVER-JMS-1 at 6:8-10 and n.2 ("Stephens Testimony").

Capacity release prices also are likely to be artificially low because the "Capacity Manager" who runs the capacity release program is required to give priority in sales to gas-fired generators as opposed to, for example, gas local distribution companies.[74] This means both that supply of capacity available for release will be expanded artificially through the subsidy, while demand for the newly available supply will be constricted artificially through the generator priority.

(2) The State Pipeline Scheme is not a justifiable, mitigated side effect of any legitimate public policy goal

Where, as here, there is no legitimate policy goal that may outweigh incidental price suppression in the ISO-NE capacity market,[75] state action such as the State Pipeline Scheme must fail. The planned price suppression here does not strike "an appropriate balance of competing interests."[76] It is not incidental to a plan involving, for example, investment tax credits, production tax credits, or other measures intended to address environmental or other public policy goals. Instead, the scheme is intended to substitute the states' view of appropriate wholesale rates for the Commission's, and as explained below the resulting rate will be based upon inefficiencies inconsistent with Commission policy. Moreover, it does not include carefully designed safeguards intended to limit price suppression that is incidental to some other goal.[77] The sole true goal here is to suppress prices as much as possible, as made evident by,

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74 *See* Eversource MDPU Petition, Testimony of James G. Daly at 24:1-2 ("The proposed [Access Northeast] Contracts require Algonquin to propose a FERC tariff change to allow capacity-release allocations specific to gas-fired generation").

75 *ISO-NE Renewable Exemption Order* at P 32 (2016). As discussed above at note 7, NextEra is seeking rehearing on the outcome of this case, but fully agrees with the Commission that state action to suppress prices for the sake of price suppression can never be lawful.

76 *Id.* at P 36.

77 *Compare id.* at P 28 (Commission finding that it was "satisfied with the steps ISO-NE has taken to minimize any price suppression," namely through "implementation of a sloped demand curve" that would lessen the impact on price and by an annual cap on the renewables exemption).

among other things, the request from DOER, the MDPU response to that request, and the detailed analysis of price suppression "benefits" submitted by the EDCs, and parallel actions in other states.

States have a legitimate role in resource planning, but that role is tempered by federalism, and attempts to manipulate wholesale rates cannot be saved by couching them as something else. EDCs that are sanctioned to acquire a resource (pipeline capacity) they will not use with the intent of lowering wholesale prices for a different product are not engaged in resource planning, they are manipulating wholesale prices. In such circumstances, the Commission has differentiated between judging the propriety of state policy and acting to mitigate unreasonable market impacts of such a policy. The Commission has said it does not intend "to pass judgment on state and local policies and objectives with regard to the development of new … resources, or unreasonably interfere with those objectives," but that it is "forced to act, however, when subsidized entry supported by one state's or locality's policies has the effect of disrupting the competitive price signals that [the RTO market] is designed to produce, and that [the RTO] as a whole, including other states, rely on to attract sufficient capacity."[78]

The focus, thus, is on interference with markets. That analysis also considers whether the interference is the main objective of state action, or incidental to such action. As the U.S. Supreme Court recently made clear, when it comes to state actions that interfere with wholesale markets, intent matters, and state programs intended to impact or set wholesale rates fail.[79] "States, of course, may regulate within the domain Congress assigned to them even when their

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[78] *See PJM Interconnection, LLC*, 137 FERC ¶ 61,145 at P 3 (2011), *reh'g denied*, 138 FERC ¶ 61,194 (2012).

[79] *See Oneok, Inc. v. Learjet, Inc.*, 135 S. Ct. 1591, 1599 (2015) (whether the Natural Gas Act (NGA) preempts a particular state law turns on "the *target* at which the state law *aims*").

laws **incidentally affect** areas within FERC's domain**.**"[80] However, "States may not **seek to achieve ends**, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates…."[81]

What emerges from examination of these and other recent cases is a continuum, with clearly permissible state action at one end, and clearly impermissible state action at the other. For example, as Justice Ginsburg, writing for the majority in *Hughes*, was careful to point out, the opinion of the Court did "not address the permissibility of various other measures States might employ to encourage development of new or clean generation."[82] And in a thoughtful concurrence, Justice Sotomayor described the FPA as a "collaborative federalism statute[],"[83] such that "courts must be careful not to confuse the 'congressionally designed interplay between state and federal regulation,' [citation omitted] for impermissible tension that requires preemption under the Supremacy Clause."[84] But, fortunately, this is not a case where it is difficult to discern where the state action falls on the continuum: it is not justified by any "congressionally designed interplay between state and federal regulation," but rather is all the way at the "state action not permitted" end.

While in Massachusetts the EDCs sometimes couch their scheme as a means to support "reliability"[85] (they have not done so in New Hampshire or Maine), their claims are vague and unsupported. There is no reliability crisis in New England. Even during the "Polar Vortex" winter of 2013-2014 and the even notably colder winter of 2014-2015, ISO-NE did not shed any

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80 *Hughes* at 1298, citing *Oneok* (emphasis added).

81 *Id.* (emphasis added).

82 *Id.* at 1299.

83 *Id.* at 1300 (Sotomayor, J., concurring).

84 *Id.*

85 *See, e.g.*, National Grid ANE Petition at P 34; Eversource MDPU Petition at P 34.

firm load.[86] In fact, the evidence is that no new pipeline is needed to maintain electric system reliability.[87] Accordingly, the "talismanic invocation of reliability" is "inadequate" to justify a reasoned conclusion that the pipeline expansion has a basis other than price suppression.[88]

The lack of evidence supporting pipeline construction for reliability purposes is not surprising. Since 2013, ISO-NE has implemented numerous improvements to its wholesale power market design and operating practices for the purpose of ensuring reliable performance by generation resources. Of these market design changes, the most visible and widely acknowledged has been the Pay for Performance framework, which commences in the 2018-2019 Capacity Commitment Period. Pay for Performance "provid[es] better incentives for investment decisions appropriate for the New England region."[89] In addition to Pay for Performance, ISO-NE has modified its FERC tariff to: a) redefine shortage events in the Forward

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86 *See, e.g.*, Technical Conference on Winter 2013-2014 Operations and Market Performance in RTOs and ISOs, Docket No. AD14-8-000, Tr. at 23:5-10 (Apr. 1, 2014) (Alan Haymes, FERC Office of Enforcement explaining that significant generator forced outages "did not cause [ISO-NE or the other] RTOs to drop firm load" during the extreme cold weather events). Furthermore, Pay for Performance and other ISO-NE market design initiatives are intended to support reliability in the region. In short, the system is working, and new development will occur when it is needed and when it is economic.

87 *See, e.g.,* Attachment D to Comments of GDF SUEZ Gas NA LLC, MDPU Docket 15-37 (June 15, 2015), Energyzt Advisors, LLC, New England: Assessment of Energy Infrastructure, Need for New Pipelines and Economic Solutions to Winter Reliability at 6 (May 2015), *available at* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-37%2fGDF_SUEZ_GasNA_061515.pdf; Levitan & Associates, Inc. report to the Eastern Interconnection Planning Collaborative, "Gas-Electric System Interface Study Target 4 Report: Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives" at 89 (Dec. 1, 2014) (comparing the economics and reliability benefits of dual fuel capability versus firm pipeline transportation and finding that "with few exceptions, dual-fuel capability appears to be much less costly with respect to reducing the direct cost as a strategy to achieve fuel assurance") "), *available at* http://nebula.wsimg.com/ef3ad4a531dd905b97af83ad78fd8ba7?AccessKeyId=E28DFA42F06A3AC21303&disposition=0&alloworigin=1.

88 *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157 (Bay, dissenting, at p. 3) (2016)), *reh'g pending*.

89 *ISO New England, Inc.*, 144 FERC ¶ 61,204 at P 36 (2013), *reh'g denied*, 147 FERC ¶ 61,026 (2014), *aff'd sub nom. Transcanada Power Mktg. Ltd. v. FERC,* 811 F.3d 1 (D.C. Cir. 2015).

Capacity Market;[90] b) improve generation resource audits;[91] c) enhance forward market reserve incentives and increase the amount of reserves purchased in the forward reserve market;[92] d) introduce shorter timelines in its day-ahead energy market;[93] e) enhance resource market offer flexibility;[94] and, f) improve information sharing with interstate natural gas pipelines.[95] Moreover, the Algonquin Incremental Market Project and other ongoing pipeline system expansion projects (which, combined, will serve to increase natural gas supply to New England by roughly 0.5 BCF/day) are expected to begin operations in the fall of 2016.[96]

As this shows, the market is responding appropriately and efficiently to market signals. The Commission-approved ISO-NE Tariff has been continually refined, over many years, and after due consideration by the Commission and balancing of interests, including interests not addressed in the state analyses, such as long-term market health and appropriate investment incentives. Of course, the market rules also address reliability needs at length, and create a market that will send price signals for appropriate, unsubsidized infrastructure development that is consistent with market fundamentals of supply and demand. Achieving reliability goals in this fashion is important because it allows investors to make predictions and investments based upon

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90 *See ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (2013).

91 *See ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 (2013).

92 *See ISO New England Inc.*, Letter Order, Docket No. ER13-1733-000 (issued Aug. 15, 2013); *ISO New England Inc.*, Letter Order, Docket No. ER13-465-00 (issued Feb. 8, 2013).

93 *See ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (2013); *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Pub. Util.*, 151 FERC ¶ 61,049 (2015).

94 *See ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,073 (2014).

95 *See ISO New England Inc.*, Letter Order, Docket No. ER14-970-000, 146 FERC ¶ 61,159 (2014).

96 *See* "Algonquin Incremental Market (AIM) Project," http://www.spectraenergy.com/Operations/US-Natural-Gas-Operations/New-Projects-US/Algonquin-Incremental-Market-AIM-Project/ (listing a November 2016 completion date).

their views of market fundamentals, rather than trying to predict the changing political winds of state retail politics.

In any event, as discussed below, properly-tailored ISO-NE Tariff mechanisms in the energy and capacity markets would address and neutralize the price suppressive **effect** of the State Pipeline Scheme – it would not prohibit the EDCs and the states from still pursuing pipeline expansion for otherwise legitimate purposes. To the extent the firm transportation contracts before the MDPU and other states provide reliability benefits that have yet to be demonstrated, mitigation along the lines proposed in this Complaint would preserve those benefits if the states choose to pursue pipeline expansion in the absence of price suppression. But we are under no illusion that the real goal here is anything other than wholesale price suppression.

In sum, state action that affects wholesale rates is appropriate only when a set of carefully prescribed parameters are met, namely that the state action 1) has a legitimate public policy purpose other than setting a wholesale price,[97] 2) is not intended to affect Commission-administered markets or change Commission-jurisdictional wholesale rates,[98] 3) does not

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97 *See, e.g.*, *ISO-NE Renewable Exemption Order* at P 23; *N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,208 at P 30 (2015) (allowing a state to "seek an exemption from the Commission pursuant to section 206 of the FPA if it believes that the inclusion in the … Offer Floor of rebates and other benefits under a state program interferes with a legitimate state objective."), *reh'g pending*; *New England States Comm. on Elec.*, 142 FERC ¶ 61,108 at P 35 (2013) ("the Commission must balance two considerations. The first is its responsibility to promote economically efficient markets and efficient prices, and the second is its interest in accommodating the ability of states to pursue other legitimate state policy objectives.") ("*NESCOE*"), *reh'g denied*, 151 FERC ¶ 61,056 (2015); *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 143 (2011) ("the Commission acknowledges the rights of states to pursue legitimate policy interests").

98 *See, e.g.*, *Oneok* at 1599-1600; *Hughes* at 1299 (noting that "States interfere with FERC's authority by disregarding interstate wholesale rates FERC has deemed just and reasonable" and, at 1298, that the Court had previously "invalidated the States' attempts to second-guess the reasonableness of interstate wholesale rates."); *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090 at P 54 (2013) (approving tariff provisions designed to ensure that "subsidized entry supported at the state level does not have the effect of disrupting the competitive price signals that PJM's wholesale capacity market protocols are

encourage economically irrational behavior inconsistent with market fundamentals,[99] and 4) does not in fact have significant impacts on Commission-jurisdictional markets or rates, but instead only has impacts that are incidental to the public policy purpose, and that are mitigated.[100] The State Pipeline Scheme fails all of these tests.

(3) The State Pipeline Scheme is intended to reshape outcomes in wholesale markets to the liking of the states and the EDCs

The State Pipeline Scheme seeks to replace the ISO-NE market price signals deemed appropriate by the Commission by making pipeline expansion attractive to EDCs that do not need pipeline capacity and do not intend to use it. This is not the first time that a New England state has tried to suppress wholesale power prices. Like the current efforts, some prior attempts have required Commission action.[101] Although the EDCs have attempted to thinly wrap the

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designed to produce and on which PJM's market participants, region-wide, rely to attract sufficient capacity") (citing *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 89 (2011)), *reh'g denied*, 153 FERC ¶ 61,066 (2015).

[99] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator*, 153 FERC ¶ 61,229 at P 127 (2015) (allowing load-serving entities ("LSEs") to opt-out of the Midwest Independent System Operator's ("MISO") fixed resource adequacy plan by self-supplying capacity in accordance with state resource plans because MISO is characterized primarily by largely self-sufficient vertically integrated utilities and "LSEs do not have an incentive to exercise market power in the MISO region. Therefore, in this context in which the Commission determined that the possibility for market manipulation was unlikely, our acceptance of the fixed resource adequacy plan option is reasonable.").

[100] *See id.*; *see also ISO-NE Renewable Exemption Order* at P 32.

[101] For example, the Commission has previously extended the ISO-NE capacity market price floor to mitigate the effects of out of market ("OOM") entry. *See ISO New England Inc.*, 131 FERC ¶ 61,065 at P 97 (2010) ("the Commission finds it appropriate to extend the price floor as a transitional measure pending … revisions [to tariff provisions preventing OOM entry]."), *order on reh'g*, 132 FERC ¶ 61,122 (2010), *affirmed*, *New England Power Generators Ass'n v. FERC*, 757 F.3d 283 (D.C. Cir. 2014); *see also ISO New England Inc.*, 138 FERC ¶ 61,238 at P 27 (2012) (extending price floor to FCA 7). OOM revenues are

> any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner.

ISO-NE Tariff Appendix A, section III.A.21.2(b)(i).

Access Northeast Project in the cloth of "reliability," as discussed above, they provide no actual evidence of an ostensible reliability need beside high natural gas prices during the Polar Vortex in 2014, when there was no loss of load, nor even a reserve shortage event—meaning that even under their evidence this is about price, not reliability.

Looking forward, existing ISO-NE market mechanisms send appropriate signals to ensure investment in system reliability. Based on programs such as Pay for Performance, ISO-NE generators must make rational economic decisions about how to meet their capacity commitments. Historically, generators have chosen not to purchase firm transportation rights – it was not economic to do so. Rather, under current and expected market conditions, imported LNG and operation of dual-fuel generating units on oil provide alternatives to natural gas much more economically[102] than construction of a $3.2 billion new pipeline.[103] The implementation of Pay for Performance is sending price signals to most efficiently mitigate performance risk in winter months through addition of new dual fuel capability.[104] This efficient effect was

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[102] *ISO New England, Inc.* Docket No. ER14-1050-000, "Filings of Performance Incentives Market Rules Changes," Attachment I-1g, Affidavit of Todd Schatzki on behalf of the ISO and Impact Assessment by Analysis Group, Inc., Attachment B, FCM Pay for Performance Impact Assessment at 4-5 (Jan. 17, 2014) (noting that "dual fuel capability provides the most cost-effective option to mitigate [] risks" of non-performance) ("Pay for Performance Impact Assessment").

[103] For the cost estimate, *see* Eversource MDPU Petition, Exhibit EVER-KRP-3, "Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England Consumers" at 36. Inexplicably, in a petition before the NHPUC, the same Eversource witness provides a $2.4 billion cost estimate for the Access Northeast Project. *See* Eversource Energy, Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC, NHPUC Docket 16-241, Attachment EVER-KRP-2 at 33 (Feb. 18, 2016), *available at* http://www.puc.state.nh.us/Regulatory/Docketbk/2016/16-241/INITIAL%20FILING%20-%20PETITION/16-241_2016-02-18_PSNH_DBA_EVERSOURCE_ATT_DTESTIMONY_K_PETAK.PDF.

[104] In FCA 10 for the 2019-2020 Capacity Commitment Period, the auction led to the three new generation plants totaling 1,302 MW clearing, all with dual-fuel capacity: the 485 MW Burrillville Energy Center 3 Unit in Rhode Island, the 484 MW Bridgeport Harbor 6 Unit in Connecticut and the 333 MW Canal 3 Unit in Massachusetts. *See ISO-NE 10th FCA sees 'robust' competition*, POWERMARKETSTODAY, Feb. 12, 2016, http://www.powermarketstoday.com/public/ISONE-10th-FCA-sees-robust-competition.cfm.

predicted and welcomed by ISO-NE's witness Dr. Todd Schatzki, Vice President at Analysis Group Inc., in his affidavit submitted in support of ISO-NE's Pay for Performance proposal:

> [T]he analysis indicates that **[Pay for Performance] would induce actions aimed at mitigating performance risks associated with gas supply curtailments, particularly during the winter gas season**. The analysis finds that **increased dual fuel capability provides the most cost-effective option to mitigate these risks**. To the extent that other options (e.g., contracts with existing LNG resources, **new pipeline capacity dedicated for electricity generation**) become less costly to market participants than dual fuel upgrades, our analysis would understate investment in reliability solutions. Across the range of winter gas market conditions evaluated, up to 7,988 MW of additional dual fuel capability is developed…. [Pay for Performance] would also mitigate any further mothballing of dual-fuel capability that would likely occur absent market incentives, although the analysis does not quantify this risk to reliability (absent [Pay for Performance]).[105]

This focus on efficient expansion of dual fuel capability will preserve reliability in the most economic fashion possible, but it will not create the artificial wholesale price suppression desired by the state.

To be clear, pipeline expansion that is justified by market fundamentals is already occurring in New England. The Algonquin Incremental Market Project and other ongoing pipeline system expansion projects will begin commencing operations later this year. These projects will address reliability, like the increased use of dual fueled generators. The Indicated Generators do not oppose such expansion, where need is demonstrated by market demand and reflected by legitimate contracts. But the State Pipeline Scheme is not justifiable on such a basis.

The economics are plain. All of the experts in the MDPU proceeding agree that any potential need for new capacity is limited in time to a few peak days each year—with the

105 *Id.* (second emphasis added). This report was intended to provide ISO-NE stakeholders with information about potential impacts of ISO-NE's implementation of its Pay for Performance program, including "potential benefits (including reliability improvements), costs, impacts on consumer payments, and other changes relevant to policy goals." See id. at 3. In finding that dual fuel was most cost effective, the report considered firm transportation services from a new gas pipeline as an alternative means for securing winter fuel supplies. *See id*. at 19-20.

Massachusetts Attorney General's expert projecting a need of only nine days per year, [106] while even the Eversource EDCs' expert concludes that "New England is likely to need additional fuel supplies about 30 days per year."[107] This means that the proposed new pipeline capacity would go unused between 335 days and 356 days of the year—that is, 92% to 97% of the time. And the evidence indicates that this minimal use of the pipeline would tend to shave power prices and divert money from the generators to EDCs affiliates that own the pipelines, rather than contribute materially to reliability, as discussed above.

The peak shaving effect of constructing the pipeline is not efficient. The Eversource EDCs claim that the **net** "benefit" of the additional pipeline expansion resulting from the State Pipeline Scheme will be between $0.9 to $1.3 billion per year.[108] If that were a real benefit, consistent with market fundamentals, then the pipeline capacity would be built as a result of ordinary functioning of the market, as investors scrambled to capture that value.

The fact that additional pipeline capacity on the scale contemplated here is not being built shows that the so-called "benefit" is illusory. It is simply a cost shift, requiring generators, in effect, to pay for the pipeline expansion through revenues lost as a result of lower clearing prices. Essentially, money diverted from generators through lower clearing prices will reimburse the EDCs and the retail ratepayers, at least in part, for their cost outlay for the uneconomic pipeline expansion, and fund any additional ratepayer savings that the EDCs expect will result from the

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[106] The Analysis Group report for the Massachusetts Attorney General, which created a "stress system sensitivity" that assumes approximately 20 percent of existing oil-fired resources in New England do not have oil, limits the number of days of "problem" to nine (9) per year. Paul J. Hibbard and Craig P. Aubuchon, Analysis Group, "Power System Reliability in New England, Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas," at iii (Nov. 2015) http://www.mass.gov/ago/docs/energy-utilities/reros-study-final.pdf.

[107] ICF International, New England Natural Gas Supply and Demand: Post-Winter Review at 15 (May 29, 2014), *available at* http://nescoe.com/uploads/GDF-SUEZ_CommenstonIGER_30May2014.pdf ("New England experiences gas pipeline constraints about 30 days per year") ("May 29 ICF Report").

[108] Eversource MDPU Petition at P 21.

price suppression. That is the express math of the MDPU's so-called "net benefits" test – it produces a benefit to some, at substantial, unwarranted cost (in the form of lost energy market revenues) to others.

The cost shift is unreasonable. Units operated on other fuels, particularly nuclear, already have extensive costs associated with fueling. They should not be required to effectively fund, through their lost revenues, firm gas transportation that they cannot use. The cost shift may have unintended reliability and market consequences too, such as forcing the early retirement of generation and making investment in new generation less likely given knowledge that the states have the ability and intent to artificially suppress wholesale market prices.

By contrast, Commission policy on RTO construction of electric transmission to relieve congestion where there is a net benefit in the form of wholesale price reduction focuses on overall net benefits, without providing a built-in advantage to generation running on one kind of fuel or another.[109] In such cases, because fuel-neutral new **electric** transmission is being built, it optimizes the ability of generation with the most efficient cost structure to serve load according to market fundamentals. Such efficient investment benefits ratepayers by ensuring they will be served by the most efficient source factoring in all cost components, including fuel. Here, by

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109 For example, the Commission carefully scrutinizes RTO proposals to create tariff mechanisms designed to relieve congestion based upon construction of new electric transmission. *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Pub. Util.*, Order No. 1000, 136 FERC ¶ 61,051 at P 2 (2011) (adopting transmission planning reforms to "support the development of those transmission facilities identified by each transmission planning region as necessary to satisfy reliability standards, reduce congestion, and allow of consideration of needs driven by public policy"), *on reh'g*, 139 FERC ¶ 61,132, *on reh'g*, 141 FERC ¶ 61,044 (2012), *aff'd, S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014); *see also PJM Interconnection, LLC*, 123 FERC ¶ 61,051 at P 63 (2008) (accepting "PJM's proposal to weigh production cost savings and load payment 70/30 in the benefits formula as a reasonable basis for deciding whether specific economic transmission projects should be included in the [Regional Transmission Expansion Plan]"), *reh'g denied*, 126 FERC ¶ 61,152 (2009); *Midwest Indep. Sys. Operator, Inc.*, 118 FERC ¶ 61,209 at P 30 (2007) (accepting proposal to use production cost savings and LMP reductions to calculate project benefits as "accepted measures of the economic benefits (and costs) of new investments."), *reh'g denied*, 120 FERC ¶ 61,080 (2007).

contrast, the State Pipeline Scheme pre-selects natural gas as the fuel source of choice, without regard to efficiency or neutrality.

In this regard it also bears pointing out that while all agree that there will be price suppression, there is substantial dispute whether the reduction in wholesale prices will actually outweigh the costs of the pipeline expansion.[110] The only entities that have submitted analysis at the state level indicating that retail ratepayers will realize such a net "benefit" are affiliated with the entities collectively owning a majority interest in the pipeline. And strikingly, the same Eversource witness gave a cost estimate for the Access Northeast Project in Massachusetts that was about a third higher than the cost estimate he gave for the same project in New Hampshire.[111] That creates significant questions about the credibility of the EDC analysis. While the MDPU has determined that it should be the arbiter in Massachusetts of whether there is a "net benefit," its obligations are to EDC ratepayers in Massachusetts. The same is true of other states. Commission intervention is necessary to ensure all interests are considered and balanced and that *de facto* market rules are not being developed without regard to market fundamentals and Commission policy.

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110 *See, e.g.*, Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi on behalf of NextEra Energy Resources, LLC, D.P.U. Docket 15-181 at 8:3-6 (June 13, 2016) (noting that "the [EDC] contracts would require ratepayers to pay on a present value basis somewhere from several hundred million to several billion dollars more in a gas pipeline surcharge on their electric bills than they would experience in the form of a reduction to electric energy charges attributable to the ANE project."); Maine Public Utilities Commission, Examiners' Report, *Investigation of Parameters for Exercising Authority Pursuant to the Maine Energy Cost Reduction Act, 35-A.M.R.S. § 1901*, Docket 2014-00071 at 1 (Oct. 1, 2014) ("Based on the evidence in this proceeding, we find that it is unlikely that the benefits to Maine consumers will exceed the costs of pipeline capacity"); *see also* the June 8, 2016 Examiner's Report in the same proceeding at 1 (concluding that Energy Cost Reduction Contract proposals presented in the proceeding "are not in the public interest [and] are not reasonably like[ly] to be cost-beneficial").

111 *See* Eversource MDPU Petition at Exhibit EVER-KRP-3 at 37 (noting the "$3.2 billion investment required for the project"); *compare* Eversource Energy, Petition for Approval of Gas Infrastructure Contract with Algonquin Gas Transmission, LLC, NHPUC Docket 16-241, Attachment EVER-KRP-2 at 33 (Feb. 18, 2016).

(4) The State Pipeline Scheme will upset Commission policy to promote fuel neutrality through use of market-based solutions and unduly discriminate against Indicated Generators and others

The Commission has emphasized in New England that out-of-market solutions must be short term in nature[112] and, where possible, fuel neutral.[113] The State Pipeline Scheme is neither of those things. It will materially affect wholesale markets over the course of at least 20 years. There is no foreseeable end. It favors gas-fired generators to the detriment of all other resources in ISO-NE.

Undue discrimination occurs when similarly situated customers receive different rate treatment.[114] Here, the Commission's policies favoring fuel neutrality and market-based solutions intend generators of all fuel types to be similarly situated, particularly over the long term, but the State Pipeline Scheme will nullify those policies, and produce incentives that favor some users of natural gas, for twenty years at least, over generators that use other fuels, such as nuclear and renewable generation. That is undue discrimination. A similar problem arises for natural gas fired generators who would not be able to use this new pipeline capacity because they

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[112] *See, e.g.*, *ISO New England, Inc.*, 144 FERC ¶ 61,204 at P 42 (2013) (approving 2014-2015 winter program "for the limited period requested") and P 72 ("The instant proceeding and the Winter 2005-2006 proceeding are similar in that they are both time-limited, out-of-market mechanisms"), *reh'g denied*, 147 FERC ¶ 61,026 (2014), *aff'd sub nom. Transcanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (D.C. Cir. 2015).

[113] *See ISO New England Inc.*, 151 FERC ¶ 61,052 at P 17 (2015) (Commission noting that it expected ISO-NE to "abide by its commitment to work with stakeholders to expand any future out-of-market winter reliability program to include 'all resources that can supply the region with fuel assurance', such as nuclear, coal, and hydro resources") (quoting ISO-NE rehearing request at 13). The Commission subsequently rejected a more "fuel-neutral" winter reliability program, finding that that expanding the program to other fuel types would not provide additional reliability benefits. *ISO New England Inc.*, 152 FERC ¶61,190 (2015), *reh'g denied*, 154 FERC ¶ 61,133 at P 13 (2016). Here, as we have discussed, fuel neutrality will preserve reliability through Pay for Performance just as well – and in fact more efficiently – than the fuel-biased State Pipeline Scheme.

[114] *See e.g.*, *Transwestern Pipeline Co.*, 36 FERC ¶ 61,175 at 61,433 (1986) ("[u]ndue discrimination is in essence an unjustified difference in treatment of similarly situated customers" (citations omitted)).

are not connected to the Access Northeast Project (estimated to be 43% of the gas-fired generators in the ISO-NE market[115]).

2. Wholesale markets are threatened right now

Timing is an important consideration because once the MDPU approves the EDC contracts, which it is expected to by the end of this year, potentially by October, it may be difficult or even impossible to unwind the mess that will result. The Commission has acted before in similar circumstances to remedy a tariff flaw in the face of a planned scheme to manipulate jurisdictional markets,[116] and should do so here as well. The Commission should not wait until the market is irrevocably harmed to take action. As described above, prompt Commission action will not only mitigate the price suppressive effect, but may also prevent the scheme from being implemented. Because the states have been plain in stating that their objective is price suppression, they will likely have no reason to go forward by approving EDC contracts for the Access Northeast Project if that objective is neutralized.

If the states do go forward, the State Pipeline Scheme will have an immediate impact. The process for the upcoming FCA 11 will begin in February 2017 for the 2020-2021 Capacity Commitment Period. The Access Northeast Project is scheduled to go into service in the fourth quarter of 2018. Because the upcoming FCA 11 will commit capacity for a time period after the schedule in-service date for Access Northeast, market rules changes to mitigate the price suppressive effect of the State Pipeline Scheme should be in place before the auction is run.

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[115] *See* Stephens Testimony at 6:8-10 & n.2.

[116] *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022 at P 139 (2011) (finding that "mounting evidence of risk from what was previously only a theoretical weakness in the MOPR rules that could allow uneconomic entry has caused us to reexamine our acceptance of the existing state exemption"), *reh'g denied*, 137 FERC ¶ 61,145 (2011), *aff'd*, *N.J. Bd of Pub. Utils. v. FERC*, 744 F.3d 74 (3rd Cir. 2014).

3. The requested relief is necessary to mitigate market manipulation

The effects of the State Pipeline Scheme, if left unmitigated, will constitute market manipulation under FPA Section 222 and the Commission's Anti-Manipulation Rule.[117] These rules prohibit any entity from: (1) using a fraudulent device, scheme, or artifice, or making a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule, or regulation, or engaging in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter; (3) in connection with the purchase, sale or transmission of electric energy subject to the jurisdiction of the Commission.[118]

Applying this rule, the Commission has initiated enforcement actions where it found that a market participant intentionally engaged in behavior designed to affect prices, including tactics designed to artificially lower commodity prices, instead of acting based on the fundamentals of supply and demand.[119] The State Pipeline Scheme has all of the elements of market manipulation. The first prong is met because the EDCs will make a purchase and below-market-resale of pipeline capacity that has no legitimate business purpose, but instead will benefit two related positions: it will lower wholesale prices, and divert revenues from generators to the pipeline affiliate of the EDCs. [120] The second prong – scienter – is met because the express

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[117] 16 U.S.C. § 824v(a); 18 C.F.R. § 1c.2.

[118] 18 C.F.R. § 1c.2 (2015); *Prohibition of Energy Market Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202, *reh'g denied*, 114 FERC ¶ 61,300 (2006).

[119] *See, e.g.*, *Deutsche Bank Energy Trading, LLC*, 142 FERC ¶ 61,056 at P 5 (2013) (describing alleged scheme to trade a physical product in a manner to benefit a financial position at the same location); *Constellation Energy Commodities Grp., Inc.*, 138 FERC ¶ 61,168 at P 21 (stipulation and consent agreement) (finding that alleged manipulative scheme involved plan to decrease day ahead price).

[120] As discussed, the underlying purpose of the capacity release scheme is to suppress wholesale power prices, not to maximize profits for EDC ratepayers through releases into the secondary capacity release market. Even Eversource has admitted that secondary capacity releases will cover no more than 50% of the pipeline costs. *See* Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi on behalf of

admitted intent of the parties involved in the scheme is to use the EDC contracts as a means to lower wholesale power prices in ISO-NE, contrary to the fundamentals of supply and demand.[121] The third prong is met because the price the scheme seeks to affect is the price for purchase of wholesale electricity by the EDCs.

The Indicated Generators are not requesting that the Commission direct its Office of Enforcement to take action against the state agencies at this time. Because this is a case where the nature of the manipulation is known in advance, it can be mitigated by the remedies proposed in this Complaint, without direct federal-state confrontation. This was the path followed in the MOPR cases.[122] But the manipulative nature of the anticipated state actions here can and should inform the Commission's action on the requested relief. And, we wish to be clear that we do believe that the anticipated state actions here are market manipulation that, if left unchecked, will violate Section 222 of the FPA. If need be, we will ask the Commission to address such claims. We raise this now because it is important that the MDPU, as well as others in states considering similar manipulative schemes, understand all potential ramifications in deciding whether to go forward.

NextEra Energy Resources, LLC, D.P.U. Docket 15-181 at 17:14-18:2 (June 13, 2016) (citing MDPU Case No. 15-181, Eversource Response to Information Requests NEER-1-39 and NEER-1-41 (Mar. 22, 2016), *available at* http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fNEER139.pdf and http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fNEER141.pdf).

121 *See*, *e.g.*, Stephens Testimony at 4:9-11 ("Eversource anticipates that the Access Northeast Project will result in increased natural gas supply and reduced wholesale natural gas and power prices").

122 *See*, *e.g.*, *New England Power Generators Assn' v. ISO New England, Inc.*, Docket Nos. EL10-50-000, *et al.*, "Complaint Requesting Fact Track Processing by New England Power Generators Association" at 3-4 (Mar. 23, 2010) (stating that "[g]iven the appropriate intent, and assuming a valid factual basis, buyer-side price suppression could constitute market manipulation" and that "market design should not create incentives for such conduct" but not asking Commission to act on market manipulation).

While we do not request action against the states at this time, the Commission could chose to initiate an investigation of the conduct of the Eversource EDCs and the National Grid EDCs.[123] In past cases in Maryland and New Jersey, local utilities were unwilling participants in state manipulation schemes – they were required to participate under state law, and in some cases opposed the state law through litigation.[124] Here, by contrast, the EDCs are voluntary actors. No state law required them to submit price suppression proposals, but they did so anyway, complete with testimony calculating the price suppressive effect. The EDCs' affiliates have a collective 60% ownership interest in the Access Northeast Project. Without the capacity purchases funded by the manipulative State Pipeline Scheme voluntarily proposed by the EDCs, the affiliated Access Northeast Project likely would not be built.[125] Under the Commission's Penalty Guidelines, if the Commission were to find the scheme is manipulative, the EDCs could be liable for civil penalties.

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[123] The Commission has previously referred issues to enforcement when concurrently acting on complaints or initiating FPA Section 206 investigations that raised market manipulation concerns. *See, e.g., N.Y. Indep. System Operator, Inc.*, 120 FERC ¶ 61,024 at P 1 (2007) (establishing paper hearing procedures and referring to the Office of Enforcement whether any entity engaged in manipulation of the in-city ICAP market); *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 at P 1 (2014) (requiring PJM to change tariff rules related to payment of reactive power capability payments to deactivated units or show cause why it should not be required to do so, and noting that the Commission had referred to the Office of Enforcement the concern that certain resources had continued to receive such payments even after they could no longer provide Reactive Service).

[124] *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, at 88 (3rd Cir. 2014) (describing New Jersey and Maryland programs, both of which required EDCs to enter into long-term contracts to purchase new capacity). Of note, several New Jersey EDCs (*e.g.*, Public Service Electric & Gas Company, Atlantic City Electric Company) successfully challenged the state law on preemption grounds. *See PPL Energyplus, LLC v. Solomon*, 766 F.3d 241 (3rd Cir. 2014).

[125] *See* Eversource MDPU Petition, Testimony of James G. Daly, Exhibit EVER-JGD-1 at 39:13 (irrespective of MDPU approval, the Access Northeast Project "will not move forward as a project unless and until there is sufficient subscription (*i.e.*, a total of 900,000 MMBtu/day) evidenced through execution of long-term contracts by EDCs operating throughout New England"); *see also id.* at 15:21-16:1-2 ("because gas-fired generators do not have the capability to sign the long-term pipeline contracts, the most logical parties to sign long-term pipeline contracts to reduce the wholesale cost of electricity are the EDCs").

B. Requested Action: The Commission should direct ISO-NE to submit Tariff revisions, to be evaluated at a technical conference with Commission action on the ISO-NE proposal on or before January 31, 2017

The Commission should require ISO-NE to amend its Tariff in a way that prevents the anticipated state actions from artificially suppressing prices in the ISO-NE market. The Indicated Generators recognize that such a fix will have a market-wide impact. Thus, amendments to the ISO-NE Tariff should be vetted through a technical conference, to be conducted in time to implement the solution before the upcoming FCA 11.[126] Below, the Indicated Generators first discuss in broad terms the types of mitigation solutions that could be developed for ISO-NE markets, and then offer a procedural schedule for ISO-NE to either adopt these fixes or propose its own, followed by a technical conference, a comment period, and Commission review.

More specific examples of potential solutions are provided in Appendix A. As discussed previously, due to the importance of prompt issuance of an initial order, we are not asking the Commission to review these potential fixes on the merits at this time, but rather simply to order ISO-NE to submit a proposed fix that fully mitigates the price suppressive effect of the State Pipeline Scheme for subsequent Commission consideration. This bifurcation more than meets Complainants' burden of showing the existing ISO-NE Tariff to be unjust and unreasonable, while also providing a path forward for the Commission to meet its responsibility of determining a replacement rate.[127]

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[126] As Access Northeast proposes to commence operations by the end of 2018, two annual FCAs have already passed through which the reduction in energy and ancillary services revenues have not been reflected in net cost of new entry calculations. To the extent that ISO-NE chooses to mitigate the market through changes to the FCM, effectuating these actions prior to FCA 11 will be most appropriate.

[127] *See Consol. Edison Co. of N.Y., Inc., v. N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,139 (Commission granting in part complaint regarding NYISO buyer side-market mitigation rules and stating: "[h]aving found that the Complainants satisfied the initial burden under section 206 to show that NYISO's existing tariff is unjust and unreasonable without a competitive entry exemption, we must

1. Potential measures to mitigate the price suppressive effects of the State Pipeline Scheme

The price suppressive effect of the State Pipeline Scheme can and should be mitigated. The Indicated Generators believe that Tariff changes should be based on the principles that have informed MOPR cases. While we believe the anticipated state action here is manipulative, appropriate solutions should not prevent Massachusetts or other states from subsidizing pipeline construction if they really believe that there is a reason to do so other than suppression of market prices, such as increased reliability. Rather, like the MOPRs, Tariff changes should focus on neutralizing the price suppressive effect of the state action, while allowing the state action to go forward, if desired for other reasons.

Tariff changes also should be narrowly tailored backstops that will only apply when a state subsidy occurs, and only to the extent necessary to mitigate manipulation. If there is no subsidy, such mechanisms should never be applied. Furthermore, the solution chosen by ISO-NE should be a market-based solution, in that it should restore the ability of markets to operate according to market fundamentals, free of manipulative interference. The solution also should continue the Commission policy of promoting fuel-neutral market rules where possible.

While we do not wish to stir debate, at this juncture, on the appropriate form of a solution, we nonetheless recognize that it may help the Commission's decision-making process to see that there are at least some possible solutions. For that reason, in Appendix A hereto we provide examples of potential solutions. These potential solutions meet the criteria set out above. If solutions like these are adopted by ISO-NE, they would neutralize the State Pipeline

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determine the just and reasonable replacement rate."), *order on clarification*, 152 FERC ¶ 61,110 (2015); *New England Power Gen. Assn. v. ISO New England, Inc.*, 153 FERC ¶ 61,222 (2015) denying complaint, but finding that, had the complainant "met its section 206 burden to show that the existing tariff provisions were unjust and unreasonable, the Commission would have then determined a just and reasonable replacement rate, whether by accepting NEPGA's proposal, if supported by record evidence, or implementing its own solution").

Scheme's unjustified, unreasonable, long-term, out-of-market, preferential proposal, and retain the pre-manipulation status quo.

2. Proposed Process for implementing market solution before price suppression can occur

As explained above, the Indicated Generators propose a bifurcated process. First, due to the urgency of a Commission order putting the states on notice that their manipulative scheme will fail, because a price suppressive effect will be fully mitigated, we request an order directing ISO-NE to develop such mitigation by August 23, 2016. Second, we propose a technical conference and comment period for review of the ISO-NE proposal. Our proposed procedural schedule is as follows:

August 23, 2016	Order directing ISO-NE to submit Tariff revisions to fully neutralize the price suppressive effect of the State Pipeline Scheme
November 21, 2016	ISO-NE to file proposed Tariff revisions (90 days)
November 29, 2016	Technical Conference on proposed Tariff revisions
December 20, 2016	Initial Comments on Tariff revisions based on Technical conference (21 days)
January 4, 2017	Reply Comments (15 days)
January 31, 2017	Order on Tariff proposals, to be effective January 31, 2017

This process will provide sufficient time to consider and adopt changes to the ISO-NE Tariff so such changes can be in place before the manipulative effects of the State Pipeline Scheme can influence the outcome of FCA 11. However, as the timeline shows, we are concerned that ISO-NE may fail to meet its deadline to propose a fix. Accordingly, **we request that the Commission expressly retain jurisdiction under Section 206, pursuant to this**

Complaint, to consider a proposal submitted by the Indicated Generators if ISO-NE fails to meet its deadline. While that may be a belt-and-suspenders approach, we wish it to be clear that it will not be necessary to file a new complaint at that time – the submission of the proposal for consideration at the Technical Conference would simply be a continuation of the proceeding commenced by the filing of this Complaint, and it would be in aid of the Commission's responsibility to adopt a just and reasonable replacement rate.

C. Request for Fast-Track Processing

Indicated Generators respectfully request Fast-Track Processing.[128] Expedited action is appropriate to ensure that market solutions are in place in time to ensure that the justness and reasonableness of the outcome of FCA 11. If the Commission issues an order by August 23, 2016, and implements the procedure described in Section III.B.2, the necessary Tariff amendments can be implemented prior to FCA 11.

D. Compliance with Rule 206

The specific information required under Rule 206(b)(1) through (10)[129] of the Commission's Rules of Practice is set forth below. The basis for the complaint is set forth in more detail in Section III.A above. The relief requested is set forth in Section III.B.

1. **Action or inaction alleged to violate statutory standards:** As a result of the State Pipeline Scheme, the ISO-NE Tariff will no longer be just and reasonable, and not unduly discriminatory or preferential.

2. **Explanation of how the action or inaction violates such standards:** Without a mechanism to neutralize the effects of the State Pipeline Scheme, prices under the ISO-NE Tariff will be artificially and harmfully suppressed.

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128 18 C.F.R. § 385.206(b)(11).

129 18 C.F.R. § 385.206(b).

3. **Business, commercial, economic or other issues presented by the action or inaction:** The central economic, commercial and business issue here is whether a state, acting through its EDCs, should be permitted to manipulate and reduce market prices to an extent that is materially harmful to generators.

4. **Financial impact or burden on complainant:** The Indicated Generators own gas and non-gas fired generation that they offer into the ISO-NE energy and electric capacity markets. It is undisputed that the State Pipeline Scheme will reduce revenues to the Indicated Generators, though there is disagreement as to the level of price suppression.

5. **Practical, operational, or other non-financial impacts:** Aside from harmful effects on markets, this case presents the question whether the Commission should act to neutralize state efforts to set wholesale rates, as the Commission did in the MOPR cases.

6. **Other pending proceedings and explanation why timely resolution cannot be achieved in that forum:** As described in Section II, the MDPU is currently considering two long-term firm transportation contracts filed by EDCs in MDPU Case Nos. 15-181, 16-05 and 16-07.[130] The Commission is considering proposals filed by Algonquin related to the Access Northeast Project in Docket Nos. PF16-1-000 and RP16-618-000. These cases may result in timely resolution, but they may not. With the MDPU considering requests to approve pipeline capacity purchases with a 20-year term by the end of the year and possibly as early as October, failure by

130 Two parties have filed an appeal with the Supreme Judicial Court of Suffolk County, Massachusetts asking the Court to reverse the *MDPU Order*. *See* Petition on Appeal, Conservation Law Foundation v. Dep't of Public Utilities, SJ-2015-0437 (Oct. 26, 2015); Petition on Appeal, GDF Suez Gas NA LLC v. Dep't of Public Utilities, SJ-2015-0448 (Nov. 2, 2015).

the Commission to act in a timely manner could render the problem largely or completely unsolvable at a later date. By contrast, prompt action would remove the state's incentive to proceed and may result in termination of the state proceedings.

7. **Specific relief requested:** That the Commission find that the ISO-NE Tariff has become unjust, unreasonable, and unduly discriminatory, and order ISO-NE to revise its Tariff to neutralize the price suppressive effect of the State Pipeline Scheme.

8. **Documents in support of complaint:**

    1. Eversource MDPU Petition, as Exhibit A;
    2. MDPU Order, as Exhibit B;
    3. Eversource MDPU Petition, Exhibits JGD-1 and JGD-2, as Exhibit C;
    4. Eversource MDPU Petition, Exhibits KRP-1, KRP-2, KRP-3, as Exhibit D;
    5. Eversource MDPU Petition, Exhibit JMS-1, as Exhibit E;
    6. National Grid ANE Petition and corresponding exhibits, as Exhibit F;
    7. MDPU Case No. 15-181, Eversource Response to Discovery Request NEER-3-5, as Exhibit G;
    8. MDPU Case No. 15-181, Eversource Response to Discovery Request NEER 1-041, as Exhibit H; and
    9. Direct Testimony of Joseph P. Kalt and A. Joseph Cavicchi on behalf of NextEra Energy Resources, LLC, MDPU Case No. 15-181, as Exhibit I.

9. **Whether the Enforcement Hotline, Dispute Resolution Services, tariff-based dispute resolution mechanisms or other informal procedures were used, and if**

not, why: No such processes were used. None of these processes are appropriate given the time-sensitive nature of this matter.

10. Whether ADR could successfully resolve the complaint: No.

11. Form of notice: A copy of a form of notice is attached hereto.

VI. Conclusion

The Indicated Generators respectfully urge the Commission to promptly issue an order by August 23, 2016, directing ISO-NE to submit Tariff revisions within 90 days, to be followed by a technical conference as described in Section III.B.2. Any Tariff revisions should be made effective no later than January 1, 2017, to ensure that proper safeguards are in place prior to FCA 11, held on February 6, 2017.

Respectfully Submitted,

/s/ Noel Symons

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June 24, 2016

APPENDIX A

Examples of Potential Market Solutions for ISO-NE Consideration

Appendix A – Examples of Potential Market Solutions for ISO-NE Consideration

I. Potential Energy Market Solutions

The Indicated Generators provide two potential alternative fixes to the energy market. The first is the "Energy Bid Mitigation" example. It is essentially a form of MOPR for energy markets. The second we refer to as the "Supplier Make-Whole" example. It uses a form of uplift payment as a means of restoring the pre-manipulation status quo by causing customers to pay generators a charge that would leave both customers and generators in financially about the same position they would have been in but for the manipulation. Both examples are aimed at neutralizing price suppressive effect, rather than barring the construction of the Access Northeast Project, such that it could go forward if the State Pipeline Scheme is approved by regulators.

A. Energy Bid Mitigation Example

The Access Northeast Project would create gas transportation infrastructure dedicated to electric generation, paid for by EDC ratepayers, and then provided to generators in quantities and rates that are not intended or expected to cover the cost of the infrastructure.[1] This below-cost gas transportation service is designed to reduce the cost of natural gas delivered to gas generators in New England and thereby suppress the price of electricity. It is an archetypical subsidy to generation cost intended to distort wholesale electricity markets.

One potential approach to offset the distortion caused by the subsidy is for the price of electricity to reflect the full anticipated, unsubsidized cost of the Access Northeast Project during

[1] Eversource's responses to discovery in the MDPU procedure demonstrate that it does not know what the capacity release revenues will be and that for modelling purposes it considered them to be "zero." *See* MDPU Case No. 15-181, Eversource Response to NEER-1-041 (Mar. 22, 2016) (stating that "[b]ecause it is difficult to precisely quantify or foresee what the offset revenues may be, Eversource has approached its proposal **without consideration** of those offsetting revenues" and that "customers will experience net benefits over and above the cost of the capacity even with **zero** revenue obtained through capacity release"), available at http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=15-181%2fNEER141.pdf.

those days when natural gas prices would have otherwise been elevated if Access Northeast was not built. The Access Northeast Project is designed to provide additional gas transportation to and storage in New England to allow generators to obtain natural gas on the coldest winter days. For the rest of the year, the additional capacity is anticipated to be surplus to existing gas transportation capacity and effectively unneeded and unused, as explained by an Eversource witness.[2] As such, consistent with market principles and principles of cost causation, the full cost of the Access Northeast Project could be reflected in the operating cost of gas-fired generation during the cold winter period targeted by the State Pipeline Scheme.

Essentially the State Pipeline Scheme treats the $3.2 billion Access Northeast Project as a peaking resource[3]—it is likely needed, at most, only 30 days per year.[4] In a market operating consistent with market fundamentals, a generator would purchase such a resource if the anticipated additional margin earned in the energy markets during the peak period would compensate for the cost of the gas transportation capacity (plus the cost of the gas purchased using that capacity) relative to the generation margins earned absent access to that gas capacity.[5] Because the "peaking" pipeline capacity would essentially be unused surplus during the non-winter months, the full cost of the resource – the cost of gas in the source markets, plus the variable cost of gas transportation (i.e., cost to compress and flow the gas), plus the full cost of

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[2] *See* May 29 ICF Report at 13 ("New England is likely to need additional fuel supplies about 30 days per year").

[3] *See, e.g.*, *MDPU Order* at 26-27 (purpose of the EDCs' capacity purchase is to "simply put a resource into the market that could operate to mitigate higher peak-period electric prices.").

[4] *See supra* note 2 and accompanying text.

[5] This consideration would include anticipated electric capacity revenues in addition to energy revenues. The marketplace has demonstrated the State Pipeline Scheme is not needed to meet electric capacity obligations and the purported benefits identified by Eversource arise from suppression of delivered gas prices in New England. We address capacity market issues below and focus this discussion instead on energy market fixes. While we believe that an approach that recovers most of the "missing money" from the energy market makes the most sense in this context, ISO-NE is free to propose something different if the Commission agrees with our procedural recommendation.

the gas transportation capacity amortized during the period during which that capacity was needed – would need to be recovered through the expected margins during the limited peak winter period.

Put differently, in a market operating consistent with market fundamentals, a rational actor making a decision whether to purchase a peaking resource would compare the expected cost of the peaking resource against the incremental revenues that the resource would be expected to bring in. This would be done by comparing expected energy market revenues based upon energy market bids that reflect the actual cost of the resource. Here, unfortunately, we do not have such rational action consistent with market fundamentals. If we did, the pipeline capacity would not be purchased.

Instead, the additional pipeline/storage resources are procured by EDCs (at the expense of their ratepayers) and provided to generators below cost, such that energy market bids will not reflect the actual cost of the additional pipeline/storage resources. If the proposal was not a manipulative subsidy, the generators would be expected to be willing to pay at least the anticipated cost of the proposed pipeline/storage project and these costs would be reflected in the energy market bids of the generators. Therefore, in order to restore the status quo as nearly as possible we could treat the cost of the pipeline resource as part of energy market bids just as if the subsidy had not occurred. And because the revenue from the use of pipeline/storage would (in a rational market) be recovered during the "peak" period of expected use in the winter, under this approach adjustments to energy market bids would occur during that same period.

Generators operating on natural gas would be required to submit bids into ISO-NE energy markets that include, on certain cold weather days, an adder to reflect the inclusion of the costs of the Access Northeast Project as if the project had been built without subsidies. There could be eight components for determining the amount of such an adder, and for determining when and how to apply it to bids: (1) determination of the targeted annual dollar amount of mitigation – essentially the annual carrying costs of the Access Northeast Project ("Fixed Annual Target"); (2) determination of generators whose bids should be mitigated ("Mitigated Generators"); (3) determination of the number of winter peak days to be subjected to mitigation (i.e., the amortization period for the Fixed Annual Target) ("Mitigation Period"); (4) determination of which winter peak days should be mitigated ("Mitigation Days"); (5) determination of variable costs (costs of gas in source markets plus variable costs of transportation) ("Variable Fuel Cost"); (6) determination of the amount of mitigation to apply to determine the mitigated bids of Mitigated Generators on Mitigation Days, i.e., amortized portion of Fixed Annual Target plus Variable Fuel Cost ("Mitigation Adder"); (7) development of each generator's Minimum Bid by adding the Mitigation Adder to other variable costs determined in consultation with the IMM; and (8) making adjustments to the Mitigation Period, Mitigation Days and/or Mitigation Adder, if tracking indicates that the Fixed Annual Target is likely to be under- or over-achieved ("Tracking Adjustment"). We address each in turn.

Fixed Annual Target. The Indicated Generators believe an appropriate Annual Target for mitigation could be $526 million or more.[6] This amount is based upon the annualized costs to be borne by New England electric ratepayers upon completion of the Access Northeast Project.

Mitigated Generators. To neutralize the expected effect of the distortive subsidy inherent in the State Pipeline Scheme gas generators would be subject to a Minimum Bid requirement reflecting the unsubsidized fuel cost.

[6] $526 million represents the current estimate of the annualized, levelized cost that electric ratepayers in New England would be required to pay to compensate the owners of the Access Northeast Project.

Mitigation Period. The mitigation period would be the number of days that the Access Northeast Project is expected to be used to artificially and inefficiently suppress wholesale power prices. Because this resource is essentially intended as a peaking resource, and this period could be thought of as its "peak shaving" period, the annual carrying costs of the resource – the Fixed Annual Target – would be amortized over this period. If the amortization period is too long, it will lose its effectiveness in mitigating price suppression because the adder will be too small to change clearing prices. A similar problem arises if the amortization period is too short because mitigation will not occur on all days where there is material price suppression. So the challenge is to try to match the mitigation as closely as possible to the actual days when material price suppression will occur.

As indicated above, estimates of the number of days of use vary, with the Massachusetts Attorney General stating it would be 9 days per year, and Eversource saying it would be about 30. The Indicated Generators believe it would be reasonable to split the difference and choose an initial Mitigation Period of 20 days, which corresponds well with those days when New England experiences its coldest weather and natural gas prices in New England would be expected to be elevated above upstream locations where gas is sourced, absent the Access Northeast Project. As discussed below, this period would be subject to a potential Tracking Adjustment during the course of the year to increase the likelihood of achieving the Fixed Annual Target of mitigation.

Mitigation Days. It would be anomalous to expect all of the cold weather days in a winter to occur sequentially, and in any event, it is impossible to predict, far in advance, when those days will occur. Accordingly, if the 20 days of the Mitigation Period were assigned on a calendar basis and did not change from year to year, the 20 days of the Mitigation Period almost certainly would not capture the 20 coldest days, i.e., the days when prices are being suppressed. The mitigation will only be effective if it matches those days.

Accordingly, Mitigation Days would be designated by ISO-NE on a Day Ahead basis based upon a trigger tied to predicted low temperature for peak hours of the next day. The low temperature trigger would be developed by ISO-NE each year based upon historical data for the three prior years. Because the goal would be to predict the 20 coldest days, the low temperature trigger would be based on an average of the low temperatures of the twentieth-coldest days in each of those three years.

If the ISO-NE forecasts Day Ahead that the low temperature trigger will be tripped the next day, it would declare the next day a Mitigation Day, such that Mitigated Generators would be required to make energy bids at or above Minimum Bid levels.

Variable Fuel Costs. As discussed, the concept here is to reverse the effects of the manipulative subsidy by treating gas-fired generators as if they had made a rational, non-subsidized investment in the pipeline. Under those circumstances, the generators in question would not be purchasing gas at the city gate – as shippers they would be purchasing gas at the source market. And as shippers they would anticipate revenue adequate to cover the interruptible costs of source gas and variable cost of pipeline transportation, in addition to the cost of the pipeline capacity. These costs should be determined and utilized in developing a minimum bid in lieu of the subsidized cost of delivered gas actually paid by the generators. ISO-NE's IMM can determine on a daily basis the applicable costs for Mitigated Generators. This Variable Fuel Cost would reflect the cost of gas upstream of transportation on Access Northeast, plus the variable cost component—fuel and variable charge—on the Access Northeast Project.

Mitigation Adder. The Mitigation Adder would be a component of each Mitigated Generator's Minimum Bid for each hour of each Mitigated Day for both the day-ahead and real-time hourly markets. The Mitigation Adder would consist of the Variable Fuel Costs plus an amortized portion of the Fixed Annual Target. The amortization would assume, conservatively, that the Access Northeast facilities would be fully utilized over the Mitigation period, so that the Access Northeast Project transportation capacity (500 MMcf/d) is assumed to be 100% utilized during the number of Mitigation Days, plus the full 6 Bcf of storage capacity is also assumed to be utilized over those days.[7] The amortized value of the Fixed Annual Target, per mcf of gas, would equal the Fixed Annual Target divided by the sum of 1) the daily pipeline capacity into New England of the Access Northeast Project (500 MMcf/d) times the number of Mitigation Days, and 2) the storage capacity that can be delivered from the project during that period (6 Bcf). Using $526 million as the Fixed Annual Target, the fixed portion of the Mitigation Adder would equal $32.88 per mcf.

Minimum Bid. The Minimum Bid would consist of a Mitigated Generator's non-fuel variable costs, as determined in consultation with the IMM consistent with the IMM's protocol for establishing cost-based reference bids for generating units, plus the Mitigation Adder, converted into an energy Minimum Bid utilizing the applicable generating unit heat rate curve. The Minimum Bids would be developed consistent with the current timeline for submitting offers into the day-ahead and real-time markets.

Tracking Adjustment. Weather, of course, varies from year to year. Some years will be colder than others. Some years will have more than 20 cold days. Some will have less. Nonetheless, consistent with the view that the Fixed Annual Target represents recovery of the

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[7] Amortizing the Fixed Annual Target using less than 100% of the available capacity would generate a higher adder.

carrying costs of the Access Northeast Pipeline, adjustments could be made each year to keep actual mitigation as close as possible to the Fixed Annual Target. This will have the effect of smoothing weather related volatility, a potential benefit to both consumers and investors.

Each year, ISO-NE would develop a weather pattern, based upon the previous three years, showing how much of the Fixed Target Amount is expected to be recovered in each two week segment from December 1 through March 30. At the conclusion of each two week segment, ISO-NE would compare actual results with predicted results. If mitigation was occurring ahead of schedule, ISO-NE would decrease the number of Mitigation Days and/or the Mitigation Adder. If mitigation was behind schedule to achieve the Annual Target Amount, ISO-NE would add Mitigation Days and/or increase the Mitigation Adder.

B. Supplier Make Whole Example

Our alternative example for an energy market fix is the Supplier Make-Whole example. The concept here is to reverse the effective cost shift that will occur as a result of the manipulative subsidy. The subsidy will divert revenues from generators to load, in the form of artificial savings. Under this example, the amount of those diverted funds would be quantified, and returned from load to generation in the form of a charge to load serving entities. This would correct for the uneconomic investment in gas-pipeline by neutralizing the price suppressive effect of the State Pipeline Scheme. It would restore investment incentives in the wholesale market to the pre-manipulation status quo because the make-whole payments reflect the efficient allocation of capital resources necessary to support system reliability.

There is not a present need for the Access Northeast Project because system reliability can be maintained by more cost effective means. ISO-NE's Pay for Performance structure incentivizes resources to make cost-effective investments in reliability to avoid penalties for poor performance. Generators can secure the level of performance that ISO-NE needs with lower cost investments than procurement of firm transportation on gas pipelines, primarily through addition of dual fuel capability to existing gas generation. But the EDCs, on behalf of their load, have decided to invest in the Access Northeast Project and have committed to pay for it through a charge to their load, with the expectation that load will be compensated by the resulting suppressed energy prices. As we have discussed, the same plan is proceeding in most of the New England states, and the State Pipeline Scheme contemplates that load throughout New England will pay less for electric energy.

Load is not entitled to the savings that will result from those suppressed prices – it is a windfall that will result from the manipulative actions of the EDCs and their state regulators. Accordingly, for rates in ISO-NE to remain just and reasonable, the effect of the price suppression must be reversed: load must pay to generators the money that generators would have received absent manipulation. If the project satisfies standard economic cost-benefit criteria, load will retain a net benefit after the payment to generators.

Under our Supplier Make-Whole Example, ISO-NE network load (*i.e.*, load serving entities such as EDCs) would be assessed a monthly fee. This fee would be assessed at the end of the delivery month along with other fees allocated to network load, such as transmission charges. This payment would place the cost of the Access Northeast Project on the group on whose behalf the unneeded expansion was undertaken, rather than on generators participating in ISO-NE's wholesale energy markets. To best align incentives for resources to follow dispatch and maximize their performance, we recommend that such a payment be linked to the Pay for Performance structure. We discuss this payment in two parts: first the calculation of the market-wide amount necessary to reverse the price suppressive effect of the subsidy, and second, the way in which the make-whole payment would be allocated to individual generators.

Calculation of Market-Wide Make-Whole Amount. ISO-NE first would calculate the market-wide amount necessary to provide generators with the amount they would have received but for the manipulative subsidy and resulting suppressed wholesale energy revenues. Specifically, ISO-NE would calculate seasonal rates: winter and summer. The rate would be based on a function of: 1) an estimate of the natural gas basis price for the upcoming year with and without the Access Northeast Project;[8] and 2) an estimate of the average system heat rate for each season with and without the project. The rate would be the *difference* between the heat rate without the project times the gas price without the project *and* the heat rate with the project and the gas price with the project. The appropriate seasonal rate would be multiplied by the actual MWh produced in each delivery month to derive the regional amount, and charged to load on the basis of consumption of MWh of energy.

Allocation to generators. As discussed above, the regional amount charged to load would be based upon actual MWh produced. It is a performance based charge. Because costs are charged to load based on generator performance, revenues likewise should be allocated on the basis of generator performance. Fortunately, ISO-NE has an existing mechanism designed to calibrate revenues with generator performance: Pay for Performance. While that is of course a capacity market payment mechanism, the Indicated Generators believe that the concept of rewarding performance is the same, and that it can be translated for this purpose to avoid reinventing the wheel.

Specifically, generators participating in the wholesale power market would receive a *pro rata* share of the side payment available to all generators. Each generator's share will be based on the ratio of its FCM payments to all FCM payments, taking into account adjustments based on

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8 The estimation of gas prices without the project would be based on historical gas prices. The actual natural gas hub price (*i.e.*, with the project) would be taken from the futures market.

the Pay for Performance mechanism. Thus, a given generator's share of the total monthly make whole payment would be determined by dividing its capacity payments for that month, plus or minus any Pay for Performance payments/penalties, by total FCM payments for that month. This approach would ensure that incentives to perform are maintained, and would follow principles of cost causation, because the underlying charge to load also would be based upon generator performance.

II. Capacity Market Examples

Capacity market solutions also may be needed, in addition to an energy market solution, because wholesale electric energy markets and capacity markets are inextricably linked. The Forward Capacity Market captures energy market margins by calculating and imputing an energy and ancillary services markets offset ("E&AS Offset") in association with the estimation of new and existing generation capacity market resource offer prices. When making these estimates ISO-NE relies on detailed cost data it compiles on different types of generation capacity resources. It uses this cost data and E&AS Offset values to estimate capacity resource market offer prices. When making these calculations, ISO-NE carefully incorporates an estimate of the E&AS Offset. To the extent that the Access Northeast Project suppresses wholesale electric energy prices in New England, the project would also lower the E&AS Offset and raise the Net CONE.

Net CONE is used by ISO-NE to establish the demand curve pricing schedule used in its capacity market auctions and represents the range of capacity market prices that can result in ISO-NE's capacity auctions. Net CONE is estimated triennially and was last calculated on behalf of ISO-NE in early 2014.[9] The calculation of the E&AS Offset occurs as part of the Net-

9 *See* Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve,

CONE analysis and is an important input to the study. Although ISO-NE is revising the Net CONE calculation this year.

The E&AS Offset is significant. The ISO-NE Net-CONE Study reports that the E&AS Offset for the 2018-2019 Forward Capacity Market was equal to $3.33/kW-Month, or about 25% of the total estimated CONE of $14.04/kW-Month. Because the ISO-NE capacity market demand curve pricing schedule is based upon Net CONE, a reduction in the E&AS Offset (which would result if the State Pipeline Scheme is not mitigated) will cause an increase in Net CONE. It should also be noted that the ISO-NE Net CONE Study shows that monthly E&AS margins during winter months – the very months the State Pipeline Scheme seeks to suppress – are a significant source of earnings for generation resource owners.[10] The reduction in winter E&AS Offset margins caused by the Access Northeast Project thus would raise the Net CONE in the demand curve pricing schedule. Accordingly, one potential fix would be for Net CONE be revised for FCA 11 (for the 2020-2021 Capacity Commitment Period), unless ISO-NE adopts energy market mitigation that would make such modifications to Net CONE unnecessary. It is important to note that, while the need for this particular capacity market fix in theory could be mooted if ISO-NE adopts energy market mitigation such as the Energy Bid Mitigation alternative discussed above, a timely order is still required in case ISO-NE adopts an energy market fix, such as the Supplier Make Whole option discussed above, that does not moot the need for a Net CONE adjustment.

In addition, when ISO-NE calculates its estimate of the an acceptable offer-price floor (the "Offer Review Trigger Price") for what it expects to be its less frequently operated

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Federal Energy Regulatory Commission Docket No. ER14-1639-000, April 1, 2014, (hereinafter "ISO-NE Net-CONE Study").

[10] *Id.* at Figure 5.

generation capacity resources, but likely still needed (such as oil-based fossil units), it also incorporates an estimate of the E&AS Offset in calculating net going forward costs.[11] The net going forward costs are equal to the generating unit's variable cost (fuel and operations and maintenance) plus avoidable capital expenditures and overhead, less revenue from energy and ancillary service market (i.e., the E&AS Offset). This calculation is used for both new resources in the Offer Review Trigger Price and existing resources in the review of static de-list bids. Thus, as is the case with the Net CONE, the resulting decease in the E&AS Offset from the Access Northeast Project should result in an increase in Offer Review Trigger Prices. So another potential fix is for ISO-NE to revise Offer Review Trigger Prices for FCA 11 in advance of the auction.

Finally, artificially suppressed natural gas prices might also be reflected in capacity supply offers by new resources and static de-list bids by existing resources. The Internal Market Monitor already reviews the reasonableness of the assumptions underlying these bids. However, offers by new and existing resources relying on suppressed prices from the Access Northeast Project might well fall below the triggering levels for review. The only way to ensure that retail buyer market power is not affecting the wholesale capacity market is to review offers by all new and existing resources with access to the Algonquin City Gates. Accordingly, another potential fix is for ISO-NE to revise its Tariff to incorporate a requirement that all new and existing gas-fired resources with access to the Algonquin City Gates be required to submit new and static de-list offers for review by the Internal Market Monitor, and that the Internal Market Monitor's review ensure that offers are not too low, in light of the subsidy.

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11 *See* ISO New England, Increasing the Dynamic De-list Bid Threshold, Robert Laurita, Manager, Market Monitoring, NEPOOL Markets Committee at 4 (Mar. 10, 2015), *available at* http://www.iso-ne.com/static-assets/documents/2015/03/a03b_imm_presentation_03_10_15.pptx.

CERTIFICATE OF SERVICE

I hereby certify that on this 24th day of June, I have caused to be served a copy of the foregoing upon all persons in accordance with the requirements of Rule 206(c) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206(c) (2015).

*/s/ Nelli Doroshkin*___
Nelli Doroshkin

June 24, 2016

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NextEra Energy Resources, LLC,	**)**	
PSEG Companies,	**)**	
	)	
Complainants,	**)**	**Docket No. EL16-___ -000**
	)	
v.	**)**	
	)	
ISO New England Inc.	**)**	
	)	
Respondent.	**)**	

NOTICE OF COMPLAINT

(June __, 2016)

Take notice that on June 24, 2016, NextEra Energy Resources, LLC and the PSEG Companies filed a formal complaint against ISO New England Inc. pursuant to Section 206 of the Federal Power Act and Rule 206 of the Commission's Rules of Practice and Procedure, seeking revision of the ISO New England Inc.'s Transmission, Markets and Services Tariff to ensure that prices in ISO New England energy and capacity markets remain just and reasonable in light of anticipated actions aimed at artificially suppressing wholesale energy market prices in New England.

NextEra Energy Resources, LLC and the PSEG Companies certify that copies of the complaint were served on the contacts for ISO New England Inc. as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the “eFiling” link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the “eLibrary” link and is available for review in the Commission’s Public Reference Room in Washington, DC. There is an “eSubscription” link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Kimberly D. Bose,
Secretary.

State of Rhode Island
Public Utilities Commission
Docket 4627
Response of NextEra Energy Resources to
The Lieutenant Governor's
First Set of Data Requests

CERTIFICATION

I hereby certify that on September 9, 2016, I sent a copy of the within to all parties set forth on the attached Service List by electronic mail and copies to Luly Massaro, Commission Clerk, by electronic mail and regular mail.

Name & Company	E-mail	Phone
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