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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 16-___

PETITION FOR APPROVAL OF A LONG-TERM CONTRACT FOR NATURAL GAS INTERSTATE PIPELINE CAPACITY

DIRECT TESTIMONY OF JAMES G. DALY

February 18, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is James G. Daly. My business address is One NSTAR Way, Westwood, Massachusetts 02090.

Q. By whom are you employed and in what capacity?

A. I am the Vice President, Energy Supply for Eversource Energy Service Company, which provides services to the operating companies of Eversource Energy including Public Service Company of New Hampshire d/b/a Eversource Energy (hereinafter "Eversource" or the "Company").[1]

Q. Please describe your education and professional background.

A. I graduated from Trinity College in Dublin, Ireland with a Bachelor's Degree in Electric Engineering and from University College in Dublin, Ireland with a Master's Degree in Industrial Engineering. From 1980 through 1988, I held the position of Regional Marketing Engineer/Senior Engineer with responsibility for supply arrangements with large industrial customers for the Electricity Supply Board in Dublin, Ireland. I joined Unitil Service Corporation in 1988 and served in various positions including Senior Vice President and President of Unitil Power Corporation. During my tenure at Unitil, I was responsible for the procurement, operations and management of the electric power and natural gas portfolios for various Unitil subsidiaries. From 1998 through 2000, I was President of Unitil Resources, Inc., developing an energy consulting business to major energy companies. In 2000 through 2001, I held the position of Executive Vice

[1] The term "Eversource Energy" will refer to the parent company of Eversource in this proceeding.

President, Network Operations for Enermetrix.com, Inc., where I was responsible for developing an Internet-based network for large retail customers to procure electricity and natural gas. From 2001 through 2003, I was Vice President/Director of Power Market Development for Sprague Energy Corporation where I was responsible for developing a start-up retail electricity business servicing large commercial and industrial customers. I joined NSTAR Electric and Gas Corporation in July 2003. Following the merger of NSTAR and Northeast Utilities, I was promoted to my current position.

Q. Please describe your current responsibilities.

A. As Vice President, Energy Supply, I am responsible for securing a reliable and least-cost energy supply on behalf of customers served by Eversource along with other Eversource Energy distribution affiliates in Connecticut and Massachusetts. My responsibilities include the management of the natural gas resource portfolio and Basic Service supply.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes, I have testified in various proceedings before the New Hampshire Public Utilities Commission (the “Commission”), the Massachusetts Department of Public Utilities (the “Department”), the Connecticut Public Utilities Regulatory Authority (“PURA”) and the Federal Energy Regulatory Commission (“FERC”).

Q. What is Eversource requesting in this proceeding?

A. In this proceeding, Eversource is requesting the Commission’s approval of a 20-year transportation contract between Eversource and Algonquin Gas Transmission Company (“Algonquin” or “AGT”) in securing interstate pipeline capacity on the proposed “Access

Northeast" project (the "ANE Contract"). In total, the Access Northeast project will provide 500,000 MMBtu/day of gas transportation and 400,000 MMBtu/day of LNG storage deliverability, along with 6,400,000 MMBtu of LNG storage capacity. Under the ANE Contract, Eversource will hold contractual entitlements for firm transportation and storage services up to a Maximum Daily Transportation Quantity ("MDTQ") of 66,600 MMBtu/day. Eversource will pay a negotiated rate for services taken pursuant to the contracts based on an initial recourse rate for the Access Northeast facilities. Eversource will release this capacity to the electric market in accordance with an Electric Reliability Service ("ERS") tariff that will be approved by FERC. Eversource customers will be the direct beneficiaries of the incremental release of gas-transportation capacity to the market, with improved electric reliability and price relief expected to result from the procurement. The expert analysis prepared on behalf of Eversource to support contract approval demonstrates that contract benefits are projected to outweigh costs on a 3/1 ratio, excluding any consideration of capacity-release revenues or reliability improvements. The benefits of the capacity made possible through the proposed ANE Contract are significant, sustaining and necessary.

Q. What is the purpose of your testimony?

A. My testimony is designed to support the request by Eversource for approval of the ANE Contract. To demonstrate that the ANE Contract is in the public interest, this testimony accomplishes the following: (1) provides an overview of the filing and its component parts; (2) summarizes the energy market conditions that are giving rise to the need for incremental interstate gas pipeline transportation and storage services; (3) describes the

ANE Contract that Eversource is proposing to enter into with AGT and discusses the net-benefits analysis prepared for Eversource in relation to the ANE Contract; (4) describes the process conducted by Eversource to identify resource alternatives for addressing pipeline capacity constraints, including the request for proposals ("RFP") process conducted in furtherance of the Eversource contracting efforts; (5) summarizes possible alternatives to the Access Northeast project and the economic and non-economic factors used to evaluate the Access Northeast project; (6) discusses the manner in which the retained contract manager will manage the contract quantities and maximize the release revenues received by customers; and (7) provides an overview of the proposed ratemaking mechanism for the costs and revenues attributable to customers in relation to the proposed ANE Contract.

With this filing, Eversource will demonstrate that the proposed ANE Contract is consistent with the public interest, and that the proposed contract: (1) will result in net benefits for Eversource customers at a reasonable cost; and (2) compare favorably to the range of alternative options reasonably available to Eversource at the time of acquisition of the resource or contract negotiation (e.g., pipeline capacity, local storage, electric transmission). Eversource will also show that the price of the resource is competitive and that the proposed ANE Contract satisfies other non-price factors such as reliability of service and diversity of supply.

Q. Aside from your testimony, what are the components of the Eversource filing?

A. In addition to my testimony, this filing includes the following:

Mr. James M. Stephens, of Sussex Economic Advisors, LLC ("Sussex" or "Sussex Advisors"), provides testimony and supporting attachments on: (1) the market and policy factors that influenced the Eversource decision to acquire firm natural gas transportation and storage capacity; (2) the process that Eversource followed to confirm that the proposed contract would provide an appropriate solution to market dynamics that have produced reliability concerns and high electric retail prices; (3) the terms and operation of the contractual arrangement executed by Eversource for pipeline and storage service capacity; and (4) the Eversource evaluation and analysis of potential resource alternatives.

Mr. Kevin R. Petak, of ICF International ("ICF"), is sponsoring the report titled, "*Access Northeast Project - Reliability Benefits and Energy Cost Savings to New England Consumers*," which was prepared in relation to the ANE Contract (the "ICF Report"). The ICF Report focuses on the impact that new infrastructure is expected to have on regional gas and electricity prices, and the associated economic impacts for consumers. The assessment includes an independent evaluation of the electric consumer benefits expected to arise from the lower gas prices available as a result of the proposed Access Northeast project.

Mr. Tilak Subrahmanian, Vice President, Energy Efficiency for Eversource Energy Service Company provides testimony on the Eversource Energy Efficiency programs and the role those programs played in the evaluation of alternatives.

Mr. Christopher J. Goulding, Manager of Revenue Requirements – New Hampshire and Ms. Lois B. Jones, Team Leader – Rates for Eversource Energy Service Company, provide testimony and attachments explaining the mechanism by which the Companies' will recover contract-related costs and flow back to customers the net revenues associated with the release of capacity and any associated sale of storage made by the electric distribution company ("EDC") or its Capacity Administrator/Manager. The testimony and attachments also present potential bill impacts for Eversource customers relating to the contract costs.

Q. What attachments are you sponsoring in your testimony?

A. I am sponsoring several attachments including my testimony. The attachments that I am sponsoring are designated as follows:

Attachment EVER-JGD1:	Presentation to U.S. Department of Energy Advisory Committee (Sept. 25, 2014)
Attachment EVER-JGD-2:	Eversource Precedent & Service Agreement
Attachment EVER-JGD-3:	Regional Coordination
Attachment EVER-JGD-4:	Request for Proposals, Issued October 23, 2015
Attachment EVER-JGD-5:	Proposed Electric Reliability Service Program

Q. How is the remainder of your testimony organized?

A. After this Introduction section, Section II briefly summarizes the market supply and demand imbalance conditions that gave rise to the need for Eversource along with other EDCs in New England to contract for interstate gas pipeline transportation and storage services. Section III describes the proposed Access Northeast project; discusses the ANE Contract that Eversource is proposing to enter into with Algonquin; and reviews the regulatory approvals necessary for the project to move forward. Section III also provides an overview of the net-benefits analysis prepared by ICF in relation to the ANE Contract. Section IV discusses the procurement process conducted by Eversource to identify an appropriate contract solution. Section V analyzes the alternatives to the Access Northeast project and demonstrates the basis for the Eversource determination that the proposed project should be undertaken to achieve greater reliability and lower prices for the retail electric market in New Hampshire. Section V also describes the economic and non-economic factors used to evaluate the alternatives and demonstrates that the Access Northeast project has the highest level of capabilities to have an impact on the reliability and wholesale market price issues that are creating the imperative for incremental transportation capacity. Section VI describes how Eversource will obtain and maximize the release revenues obtained by Eversource customers. Section VII discusses the ratemaking mechanism that will be used to recover contract-related costs and to credit net release revenues to customers, offsetting the cost of the contracts. Section VIII is the conclusion.

II. PREVAILING MARKET TRENDS AND PORTFOLIO OBJECTIVES

Q. From an overall perspective, why is the proposed ANE Contract needed to meet portfolio objectives to provide a safe and reliable energy supply to customers?

A. Eversource is presenting an in-depth analysis of market conditions in the testimony of Mr. James M. Stephens of Sussex Advisors. As discussed in Mr. Stephens' testimony, New England electric consumers currently pay the highest electric rates of any part of the contiguous United States. One of the principle reasons for this circumstance is that in recent years there has been a shift in the New England electric generation mix from oil, coal and nuclear, to natural gas without a corresponding increase in gas infrastructure to deliver the fuel reliably. This shift is occurring as older less efficient units are coming out of service and are replaced with natural gas facilities and intermittent renewable resources, such as solar and wind that require backup resources.

Although there has been a substantial increase in the demand for natural gas as a fuel for generating electricity, only limited expansions of interstate pipeline capacity serving the region have been implemented in recent years, with the expansion projects tailored narrowly to the requirements of the region's natural gas local distribution companies ("LDCs"). Under the market rules of ISO New England ("ISO-NE"), gas-fired generators have no guarantee that they will be able to recover the fixed costs of long-term pipeline transportation contracts, which are required by the interstate pipelines in order to get approval from FERC to construct expansions. Therefore, gas-fired electric generators are dependent upon the limited availability of pipeline capacity released by the LDC capacity holders, who rely heavily on the capacity to serve their firm customers when the temperature gets cold. The combination of limited pipeline capacity and high demand for gas from gas-fired generators is driving inordinately high market prices for gas delivered to New England, despite the abundance of new gas discoveries in the Marcellus Shale region less than a few hundred miles away.

Energy Efficiency programs, including through a potential energy efficiency resource standard, and renewable generation are playing an increasingly important role in the region and will continue to do so as part of the overall portfolio of resources available to supply electricity to New Hampshire consumers. However, these resources cannot reasonably address the scale of the existing market imbalance, leaving the construction of incremental pipeline capacity as the most effective way to reduce the cost of electricity in the region. Because gas-fired generators are unwilling to contract for pipeline capacity due to the uncertainty of cost recovery, the EDCs are the only entities with a long-term vested interest in the reliability and cost of electric service for retail customers connected to the distribution system, and with the financial and ratemaking capability to pay for and recover the costs of capacity procured to protect the interests of those customers.

Through a careful evaluation process, Eversource determined the best way to improve the reliability and cost of electric supply for retail electric customers is to participate in Algonquin’s Access Northeast project. To that end, Eversource has contracted for 66,600 MMBtu/day of pipeline transportation delivery capacity, which includes 29,600 MMBtu/day of deliverability from a new regional domestic liquefied natural gas (“LNG”) storage facility in order to serve Eversource’s share of the New England electric market. The incremental infrastructure available through the development of the Access Northeast project will increase reliability and lower the cost of electricity by ensuring the availability of lower cost supply of natural gas for generators to use.

Q. Please provide a high level overview of the New England wholesale generation market.

A. The New England wholesale electric market consists of merchant, non-utility electric generators operating in a competitive market managed by ISO-NE under rules approved by FERC. The New England generation portfolio encompasses natural gas, nuclear, coal, oil, wind, solar, biomass and hydro facilities. All New England states except Vermont have deregulated their retail markets for customers of investor-owned utilities, which is the driver of market behavior and risks in the wholesale market. The testimony of James M. Stephens, Sussex Advisors, provides more information on the wholesale market.

Q. How has the natural gas industry historically served the New England wholesale electricity market?

A. The New England energy market has existed at the physical termination point of the U.S. natural gas transmission system since natural gas pipelines were first constructed in the New England region in the early 1950s. From the time the interstate pipelines first extended into the New England region, LDCs have provided the contractual support for the facilities, which replaced previous LDC reliance on locally manufactured gas derived from coal and oil. Because LDC firm loads are highly temperature sensitive, LDC resource portfolios were designed to meet peak day and peak winter season loads, which put the LDCs in a position to make low-cost, interruptible sales of gas to dual-fuel customers (such as electric generators) during the off-peak season.

Pipeline expansions that took place in the 1980s and 1990s were primarily supported by the LDCs and for a relatively short period by Independent Power Producers ("IPPs"), who sold electricity to EDCs under long-term purchased power contracts.[2]

Q. Please explain why there has been a recent change in the generation mix of the New England electricity market.

A. There are several reasons that there has been a shift in the generation mix in the New England electric generation market since the year 2000. The shift has come about as a result of the retiring of fossil fuel and nuclear generators, improvements in the efficiency of new gas-fired generating facilities, and stricter environmental regulations, all of which are covered in the testimony of Mr. James M. Stephens.

Q. What is the reason that the owners of New England gas-fired generation do not enter into contracts for firm pipeline capacity to serve their facilities, and why is this dynamic a problem for pipelines serving the New England market?

A. Under ISO-NE rules, gas-fired generators have no guarantee that they will be able to recover the costs associated with long-term pipeline transportation contracts. The New England electric-market structure calls for the dispatch of generation units based on competitive bidding. A gas-fired generator that includes all or a portion of its pipeline fixed costs in its bid is less likely to get dispatched because it would be competing with generators that do not include fixed pipeline costs but instead contract for non-firm service from the secondary capacity market.

[2] With electric restructuring, New England's EDCs were generally required to divest their generation assets and their IPP contracts. Without long-term contracts with EDCs for the purchase of their electric output, the IPPs divested their long-term pipeline contracts, many of which were permanently released to LDCs that needed incremental capacity to serve growing loads.

Conversely, interstate pipelines are not willing or able to construct incremental pipeline capacity unless that construction is supported by associated long-term transportation contracts. Long-term contracts obligate shippers to pay the fixed costs of the pipeline for terms of up to 15 or 20 years. Shippers enter into these contracts because the contracts are needed to ensure reliability of supply deliverability to end-use customers. Thus, the execution of these contracts demonstrates "market need" and is both a requirement of the FERC certificate process and a financial requirement of the FERC regulated pipelines.

Q. Are there other market factors that have increased the demand for natural gas in New England?

A. Recent changes in the gas market are discussed in the testimony of Mr. Stephens. However, it is very clear that the rapid development of gas production in the prolific Marcellus shale region has had a dramatic downward impact on the price of Marcellus and Utica shale supplies; however, there is currently a lack of pipeline capacity available to transport the gas to markets. Multiple pipeline projects have been completed to allow more Marcellus and Utica gas to be transported to the U.S. Gulf Coast, back to the mid-western U.S. market, and into eastern Canada, with more projects planned. Other projects have been proposed to deliver Marcellus supplies to the New England area.

Q. What is the consequence of the change in the ISO-NE generation mix; the lack of incentives for gas-fired generators to contract for firm capacity; and the availability of low-cost gas from the Marcellus region?

A. These combined changes have produced very high costs of gas delivered during the winter season to the New England market and have also raised considerable reliability concerns for ISO-NE. Gas-fired generators do not hold firm pipeline capacity contracts, and are therefore dependent upon the availability of capacity released by firm capacity holders who do not need all their capacity on a given day. As the weather gets colder, less capacity is released by the LDCs and the price of the limited available capacity is forced up through the competitive bidding process. Because all generators are paid based on the highest accepted bid in the ISO-NE bidding process, they are able to recover their cost of fuel (as long as bidders incorporate the full cost of fuel in their bids).

Q. What is the most direct and effective way to reduce the cost of wholesale electricity in New England?

A. Because of the region's dependence on natural gas as the source of electricity generation, the most direct and effective alternative to ensure reliability and lower electricity prices is to construct incremental pipeline capacity. Natural gas prices are high because those prices are bid up by the generators who do not have access to firm capacity. However, 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. The EDCs have the long-term financial capability and institutional willingness to support the pipeline contracts on behalf of their customers as long as they have the ability to recover the associated costs. Cost recovery from retail electric customers is warranted because EDC customers will be the principal beneficiaries of the lower-cost electricity and increased reliability that will result from the availability of incremental capacity.

Q. Has Eversource provided additional detail in this filing regarding market imbalances driving reliability and price disparities for electric customers?

A. Yes. The testimony of Mr. James M. Stephens, Sussex Advisors, provides an in-depth analysis of the market demand and supply trends motivating the proposals in this case. With respect to market demand, Mr. Stephens discusses the historical levels of natural gas demand in New England; changes occurring over the past 10 years in regional demand for natural gas; the characteristics of existing natural gas and dual-fuel electric generation; and, expected changes in the generation mix.

With respect to market supply, Mr. Stephens describes the production and supply areas from which New England's gas is sourced; the market dynamics associated with imported LNG and constrained interstate pipeline facilities; and the resulting impact for electric retail prices. Mr. Stephens also demonstrates that New England customers are paying a significant premium for natural gas supplies and that this premium is increasing. For example, Mr. Stephens shows that the average winter-basis differential between the Algonquin City Gates price index and the adjacent Mid-Atlantic region (as represented by the TETCO M3 price index) over the 2012/2013 to 2014/2015 period was approximately $5.41/MMBtu as compared to the average differential of $0.70/MMBtu over the 2010/2011 to 2011/2012 period. This differential is significant, and when coupled with insufficient gas capacity to electric demand, has the effect of causing severe price impacts for New Hampshire retail customers.

Q. What was the overall impact on wholesale prices due to gas shortages?

A. Attachment EVER-JGD-1 is a presentation made to the U.S. Department of Energy, Advisory Committee on Sept. 25th 2014. Page 5 shows a calculation of the wholesale cost of electricity for the prior four winter seasons and shows that wholesale prices increased by over $3 billion during the 2013/14 winter season alone. As demonstrated in the ICF Report and associated testimony of Mr. Kevin Petak, most of these price impacts are eliminated with the construction of the Access Northeast project.

III. THE ACCESS NORTHEAST PROJECT AND PROPOSED ANE CONTRACT

A. Description of Access Northeast Project and ANE Contract Terms

Q. Please describe the Access Northeast project.

A. The Access Northeast project is designed to provide increased natural gas deliverability to the New England market to directly serve the gas-fired electric generating plants on the Algonquin and Maritimes and Northeast Pipeline ("M&NP") pipeline systems. The project is designed to provide delivery-point flexibility to serve generators in four separate sub-regions of the 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. The Northern New England PPAA includes a portion of New Hampshire as well Maine served by the M&NP pipeline.

The Access Northeast project will provide customers in these markets with: (1) 500,000 MMBtu/day of indirect 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.[3] 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; thereby enabling net benefits to electric customers.

A new level of service will be provided under the customized ERS tariff rate, which will provide fuel certainty and performance flexibility critical to the electric generators by virtue of a reserved "no-notice" transportation service with an hourly supply option.

Q. Would you please describe the proposed Precedent Agreement with Algonquin?

A. Yes. The proposed Precedent Agreement sets forth the rights and obligations of Algonquin and Eversource during the pre-approval process before FERC and requires Eversource to execute an actual Service Agreement upon satisfaction of all conditions precedent, including acceptable FERC and state regulatory approvals. A copy of the executed Precedent Agreement between Algonquin and Eversource, and the related Service Agreement that will be executed by the parties upon the fulfillment of all of the conditions precedent, is provided as Attachment EVER-JGD-2 [CONFIDENTIAL].

3 Based on net storage capacity of 6,373,592 Mcf after adjusting for the heel and an assumed BTU content of 1,030 BTU/cubic foot.

The Eversource Precedent Agreement provides a Maximum Daily Receipt Quantity ("MDRQ") of 37,000 MMBtu/day of capacity from Mahwah, Ramapo and/or Brookfield and a Maximum Daily Withdrawal Quantity ("MDWQ") of 29,600 MMBtu/day from the LNG storage service. This will result in the ability to deliver up to a maximum of 66,600 MMBtu/day of natural gas to New England gas-fired generators.

The Eversource contract provides a 20-year term beginning on the in-service date of the first of four planned phases. The project is scheduled to go into service beginning with the first phase starting on November 1, 2018, the second phase starting on November 1 2019, the third phase commencing on November 1, 2020, and the fourth and final phase commencing on May 1, 2021. Eversource and the other EDC customers have negotiated a levelized cost for the 20-year duration of the contract.[4] The rate paid by the EDCs will be based on the actual cost of construction subject to a cap.

Q. Would you please explain the phasing aspect of this project?

A. Yes. Due to the size and scope of the project's construction components, the in-service time line for the project is divided into four phases, accommodating earlier firm deliverability to the extent possible. Phase 1 anticipates [redacted] to be available on November 1, 2018; Phase 2 anticipates an additional [redacted] on November 1, 2019; Phase 3, an additional [redacted] on November 1, 2020; and Phase 4 completes the project with the estimated in-service of the LNG facility on

[4] Under current FERC regulations, pipelines are not required to file rate cases on any particular schedule. FERC allows pipelines to negotiate rates with customers under certain guidelines under non-discriminatory conditions. Levelized rates are one of the features that most customers of incremental pipeline expansion insist upon.

May 1, 2021, achieving the final [redacted] of the project volumes of 900,000 MMBtu/day.

Q. Would you please explain how the contract quantities were determined?

A. The contract quantities were determined through a computation of New England load share and represent the Eversource load share within the load served by investor-owned EDCs in New England. New England load share for investor-owned EDCs including Eversource was derived by determining the respective shares of the 2014 Annual Average of the Monthly Network Load Peak Value in kW reported by ISO-NE. This information is filed annually with FERC as part of the Participating Transmission Owner Administrative Committee Annual Informational Filing ("PTO AC Annual Informational Filing"). Attachment B of Attachment EVER-JGD-2 CONFIDENTIAL shows the share allocation by New England EDC.

Q. What are the key aspects of the Precedent Agreement?

A. The key aspects of the Algonquin Precedent Agreement are as follows:

<u>Cost and Cost Caps</u> - [redacted]

Regulatory Approvals - The proposed ANE Contract is subject to state regulatory approval and a decision is necessary before October 1, 2016 in order to meet the schedule of planned in-service dates. Should such approval not occur, the EDC may exercise an option to terminate the agreements at no cost to EDC customers.

Other Provisions –The proposed ANE Contract requires Algonquin to propose a FERC tariff change to allow capacity-release allocations specific to gas-fired generation. The approach and context of the proposed FERC tariff changes is further described in detail below in Section VI of this testimony. The ANE Contract also provides for a process to adjust the final allocations of volumes associated with the contracts, subject to Commission review and approval.

Right of First Refusal (“ROFR”) and Discount for Contract Extensions - [redacted]

[redacted]

<u>Sunset Date</u> – [redacted]

<u>Most Favored Nation Provision</u> – [redacted]

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[5] This clause is subject to any necessary FERC approvals.

B. Overview of Services, Price Terms and Benefits

Q. Please identify the price and service terms encompassed in the Precedent Agreement and the Negotiated Rate Agreements.

A. As indicated above, the Precedent Agreement provides for a negotiated rate of [redacted] The Precedent Agreement facilitates access to liquid receipt points and peak-period access to market area storage, injected using summer priced commodity to provide a reliable and flexible delivery service to meet the needs of generators.

Q. Please provide a summary of the ERS Rate Schedule.

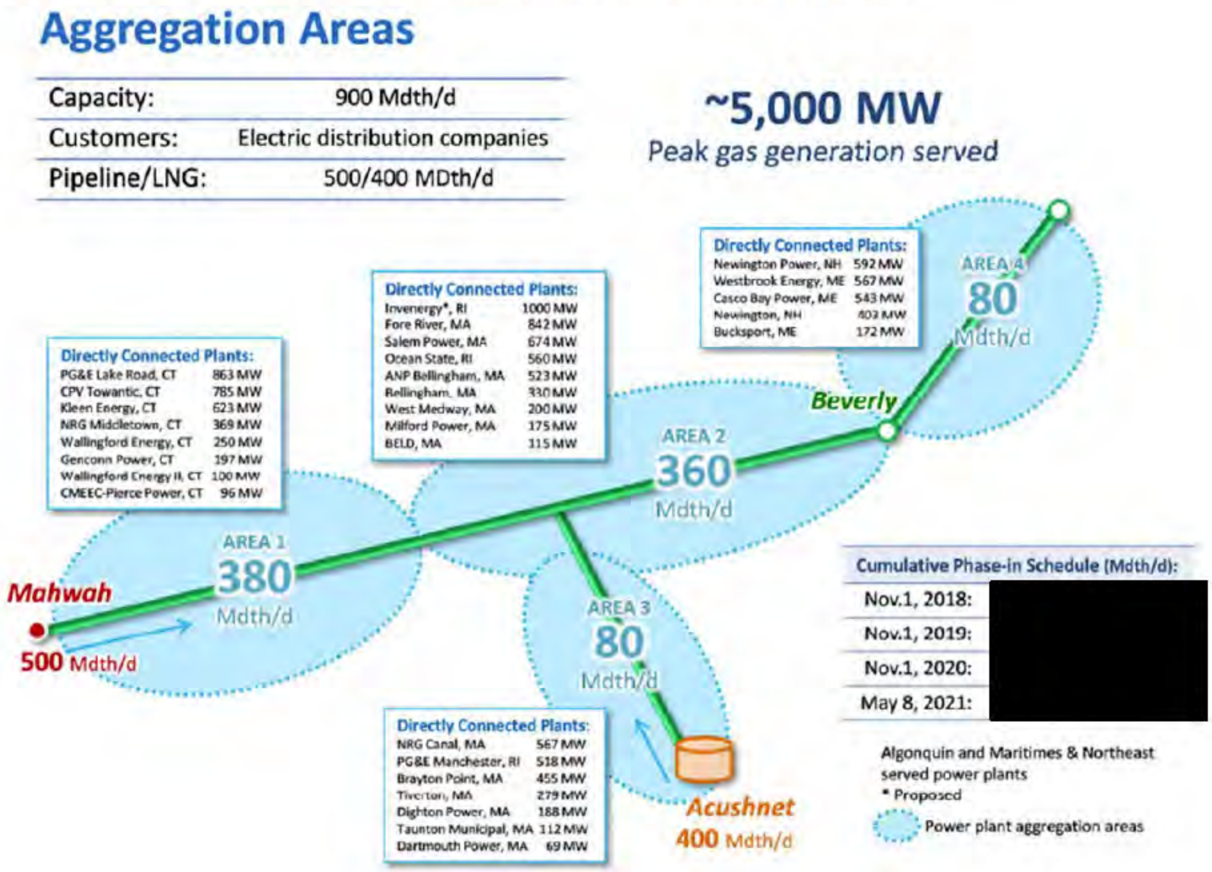
A. The ERS Rate Schedule transportation service provides the ability to receive flowing gas at the primary receipt point(s) and to deliver gas to multiple primary delivery points. The Rate Schedule also provides an LNG storage service that the EDCs will use to liquefy gas into storage, and to vaporize liquid out of storage for delivery to generators. The LNG storage facility will be constructed on the strategically located AGT G-system in Southeastern MA. The LNG service will provide access to supplies on days when flowing supplies from the primary receipt points are fully utilized or otherwise not available. In addition, the service will provide for hourly no-notice service for both transportation and storage services. The service also includes a “fast start” service that will allow generators to begin taking gas for up two hours prior to having gas nominated with the pipeline. This service will provide generators the ability to vary the amount of gas delivered to their facility on an hourly basis and allow generators the ability to better manage gas supply in order to match the fluctuating demand of the ISO-NE dispatch orders.

Q. Please describe the transportation service component provided in the Service Agreement.

A. The transportation component allows each EDC to deliver its portion of the 500,000 MMBtu/day of flowing gas available from the upstream pipelines and to deliver their portion of the 400,000 MMBtu/day of LNG deliverability from the regional LNG facility to the generating facilities. The service provides for multiple Primary Receipt points including AGT's Mahwah, NJ, Ramapo, NY, and Brookfield, CT interconnections with upstream pipelines. The storage receipt point will be the LNG facility in Acushnet, MA located on AGT's G-Lateral. For both transportation and storage services, multiple delivery points will be available. Those delivery points are allocated by four, distinct PPAAs, as shown in Figure 1 – Access Northeast Project – Receipts and Deliveries by Phase, below, showing the final project volumes.

The Connecticut aggregation area will have 380,000 MMBtu/day of daily deliverability; the AGT G-System aggregation area, which includes Southeastern Massachusetts and Rhode Island, will have access to 80,000 MMBtu/day; the Massachusetts aggregation area will have access to 360,000 MMBtu/day; and the Northern New England aggregation area will have access to 80,000 MMBtu/day.

Figure 1 – Access Northeast Project – Receipts and Deliveries by Phase



There are several generators located within each aggregation area so the capacity will reach any generator within the respective PPAAs on a primary basis. This will ensure that gas will be available to those generators who utilize the capacity or service on the coldest days of the year.

Q. Please describe the storage service component provided in the Service Agreement.

A. The storage component of the Service Agreement will provide the EDC with the ability to inject into the storage facility during two non-peak periods in order to withdraw from the facility during the winter and summer peak periods. The first injection period will begin

April 1 and conclude on July 20 of each year. The remainder of July and all of August, is the summer withdrawal season, which coincides with the ISO-NE peak summer demand for electricity. The second injection period is September 1 through November 30, which will allow EDCs to top off their storage inventories for the winter peak season.

The LNG facility will have the ability to liquefy 54,000 MMBtu/day during the injection season. During the withdrawal season, the facility can withdraw up to 400,000 MMBtu/day.

Q. Please describe the no-notice service component provided in the Service Agreement.

A. The Service Agreement provides for hourly scheduling where the EDC or generator has the right to adjust the scheduled quantities to better match the expected use for the day. Any gas that has not been scheduled up to the maximum daily receipt and/or delivery obligation will be reserved by the pipeline. The reserved capacity will be available for the shipper to access additional supplies for intra-day nomination changes.

The no-notice service will allow generators to better match gas utilization with unpredictable dispatch requests from ISO-NE. Many days, gas-fired generators are required to run only for part of the day after the pipeline "timely" nomination period has passed and this "no-notice" flexibility will allow those facilities to adjust their gas requirements to fit the load requirements from ISO-NE.

Q. Please describe the cost structure of the Service Agreement.

A. The transportation service has a [redacted]

[redacted]

The storage service has a [redacted]

Q. Please discuss the non-price attributes of the ANE Contract.

A. The increase in incremental capacity and supply associated with the Access Northeast project (900,000 MMBtu/day) will improve electric reliability and mitigate price volatility associated with market-area price spikes caused by gas infrastructure constraints.

A major non-price attribute of the ANE Contract is the flexibility inherent in the ERS Rate Schedule, which will allow generators to take gas under a "no-notice" service and follow their generation load requirements and avoid scheduling penalties. The unique combination of a regional LNG facility located on the Algonquin G-system in Southeastern Massachusetts provides the pipeline the operational flexibility required to provide this type of service. This is described in more detail below.

Another non-price attribute of the Access Northeast project is the fact that it is based primarily on an expansion of existing pipeline and does not involve construction in new right of ways. As a result, the Access Northeast project creates relatively less environmental impact than other alternatives that involve new construction. The project includes the development of a new LNG facility; however, the new facility will be constructed adjacent to an existing LNG satellite facility at a site with adequate land. The phasing of the project also allows parts of the project to go into service as early as November 2018, pending the development of the LNG facilities.

The Access Northeast project will be capable of serving the majority of New England's electric gas-fired generation capacity (nearly 70 percent) that is directly connected to an interstate pipeline.[6] This includes 24 power generating facilities that are directly connected to the Algonquin and M&NP facilities, including the 101-mile pipeline from Westbrook, ME to Dracut, MA that is jointly owned by M&NP and Portland Natural Gas Transmission System ("PNGTS") (the "Joint Facilities"). In its RFP, Algonquin identified four plants that, if built, would directly connect an additional 2,760 MW to Algonquin by 2020.

Q. What are the specific fuel-supply issues for New England gas-fired generators that will be addressed by the Access Northeast project?

A. The generation portfolio in the New England region relies substantially on natural gas for electric generation, which is a fuel resource that requires pipeline capacity for delivery.

[6] The Access Northeast project will be capable of providing service to those generating facilities directly connected to the Algonquin and M&NP pipelines, including those power plants directly connected to the Joint Facilities of M&NP and PNGTS.

Because there is no indigenous gas storage capacity in the region, gas typically flows hundreds of miles from the production areas and storage fields to the New England market region, which ISO-NE has described as a "just-in-time" fuel delivery system.[7]

Demands on these supplies are greatest during the coldest periods of the year when heating requirements are at their highest level and the LDCs are utilizing their firm pipeline capacity and on-system LNG peaking facilities to meet firm customer demand. ISO-NE gas-fired generation is often called on short notice to dispatch power during peak gas demand periods to meet the hourly variations in power load throughout the day, which have coincident peaks during the mornings and evenings. Gas-fired generators have the ability to start up quickly to meet unexpected load fluctuations on the grid. The ISO-NE depends heavily on this capability to achieve reliability and it is anticipated that the ability to start and ramp up quickly will be even more important as new intermittent resources such as wind and solar are added to the system. However, in order for these generators to provide this service, the generators must have access to gas supplies on short notice and for short durations.

It should also be noted that there are numerous generation plants that have been specifically designed as "peaking" facilities and that run only a few hours each day to assist the regional system operator in managing the hourly power load fluctuations. This creates a difficult situation because gas is often needed in real-time on short notice but

[7] http://www.iso-ne.com/nwsiss/pr/2013/2013_winter_outlook_press_release_final.pdf

the normal "day ahead" trading and scheduling process does not accommodate these short term variations in load. At times, these generators may not be able to perform on such short notice due to the unavailability of firm pipeline capacity or insufficient fuel supply. If these generators can acquire gas, those opportunities exist only in the secondary market on an intra-day basis, which typically involves more expensive fuel sources. In most cases, the necessary gas and pipeline capacity has already been allocated to shippers who own the capacity and therefore it is not available in the secondary market.

In FERC Docket No. RM14-2-000,[8] ISO-NE provided FERC with information showing the number of times the gas-fired generators day-ahead market commitments were reduced as a result of the inability to acquire natural gas. Numerous generators and regional system operators attempted to remedy these issues by making changes to the timing of the Gas Day. The final rule did not change the Gas Day scheduling requirements on the basis that there was not sufficient evidence and industry consensus to indicate that changing the Gas Day scheduling requirements would resolve these issues. Some changes were made to portions of the nominations and scheduling rules in an attempt to accommodate some of these unique gas-fired generation requirements. However, the fundamental problem arising from the fact that gas-fired generators do not hold firm pipeline capacity for their fuel requirements, which is the root cause of the price volatility and reliability concerns in New England, was not addressed.

[8] FERC, 18 CFR Parts 157, 260, and 284[Docket Nos. RM96-1-038 and RM14-2-003; Order No. 587-W issued October 16, 2015.

Q. Please describe the type of gas service that would be tailored to the unique characteristics of gas-fired generation demand on the natural gas pipelines in New England.

A. Combining primary firm pipeline capacity of scale from liquid supply areas with local domestic peaking supplies/facilities and associated on-site storage to serve the dynamic load requirements of New England gas consumers is a well-established practice of the regional LDCs.[9] Standard pipeline services require substantially even hourly flows of supplies, with the matching of receipt quantities and delivery quantities. As gas-fired generators acquire gas from pipelines to serve their requirements, these facilities will find that portfolio resources providing access to LNG vaporization and storage will likely be required to serve their highly variable requirements.

A physical gas service that could provide generators with the ability to take gas prior to actually having nominated or scheduled gas would be the ideal service to accommodate the hourly, real-time, highly variable requirements of power generation. In order to provide this service, pipelines need to have access to variable sources of supply (such as an LNG facility or an underground storage facility). Some pipelines currently offer "no-notice" services that can be nominated later in the day to accommodate changes in load requirements for shippers on the pipelines, but often a generator is called to generate power with little notice and may not be able to acquire gas for several hours. A "fast-start" service provides this unique type of service by combining the primary firm pipeline capacity to the generator's plant with a regional storage facility that can deliver gas in a

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[9] Yankee Gas Services Company - Connecticut Public Utility Regulatory Authority Docket 14-10-01, NSTAR Gas Company, D.P.U. 14-63 (2015).

"real-time" manner allowing the pipeline to operate in a balanced state, while accommodating the needs of the generator to take gas prior the generator's ability to have the gas actually delivered to the pipeline.

Q. Please describe the benefits of having a regional storage facility sited in New England.

A. The pipeline capacity in the region is at or near capacity on nearly every day of the year in New England and particularly during the winter period, as explained in the testimony of Mr. James M. Stephens. During these times, the LDCs are often utilizing their on-system LNG facilities, which were filled during the summer period to meet the daily and hourly fluctuations in load. A local LNG facility would be able to liquefy domestically produced gas from the Marcellus region at relatively lower costs when gas prices are typically lower during the off-peak summer period. This would insulate the facility from the volatility of world LNG markets as the cost of imported LNG for summer refills is more reflective of winter prices. The facility's proximity to generators allows for the "fast-start" capability where the generator can take gas prior to nominating it from a receipt point. These facilities also provide a critical reliability function as the facilities can support a portion of the loads during any potential disruptions to the pipeline systems, which are rare but can and have occurred. In these circumstances, the power generation fleet would have access to a strategically located market area LNG facility with a scale sufficient to impact supply and demand imbalances.

C. Regulatory Approvals Needed

Q. Please describe the FERC regulatory process that applies to pipeline construction projects.

A. Pipeline companies engaged in the interstate transportation and storage of natural gas in interstate commerce must receive a "Certificate of Need and Public Necessity" ("CNPN") from FERC in order to construct a major project. The regulatory process includes a comprehensive environmental impact analysis, along with opportunities for public involvement from concerned citizens and state and federal regulatory agencies. FERC is directly involved in evaluating the costs of the projects; the rates to be charged by the sponsor; and compliance with FERC regulations. The U.S. Department of Transportation is involved in safety issues. A specific FERC concern is that the project must be supported by long-term contracts. Therefore, like other interstate pipeline projects, Access Northeast will require state-approved, long-term contracts as a prerequisite for its FERC approvals.

Q. Will the Access Northeast project require approval in New England states other than New Hampshire?

A. Yes. The bulk power market in New England is a regional market, with generating facilities throughout the six New England states operating within the oversight of ISO-NE. Within the region, the electric and gas delivery systems are increasingly interrelated with common infrastructure components serving all retail customers in New England so that the electric reliability and cost challenges facing New Hampshire customers are not unique to New Hampshire customers. On December 5, 2013, the Governors of the six New England states jointly acknowledged the need for new natural gas infrastructure serving the New England region, setting in motion a coordinated effort to advance a regional energy infrastructure initiative (see, Attachment EVER-JGD-3-A). The commitment to infrastructure development encompassed within the New England Governors' joint statement is the impetus for the Access Northeast project. Infrastructure development requires financial commitment through the execution of long-term contracts. Therefore, in the two-year period since the joint statement of the New England Governors acknowledging the need for incremental pipeline capacity, efforts have moved forward in each of the New England states to establish a structure for regulatory review of anticipated infrastructure contracts.

At this point, all New England states except Vermont have laws or regulations in place, or proposed, that allow for the development of natural gas infrastructure to serve power generation. Attachment EVER-JGD-3-B provides a summary of the state regulatory structures allowing for the state approval of gas infrastructure contracts. Consistent with the established regulatory structures, efforts are underway in each of the states to consider participation and support for infrastructure contracts that will alleviate reliability and cost concerns for New England's retail electric customers. Consequently, a regional solution will require regulatory approvals by New England state jurisdictions in addition to New Hampshire. The Eversource Energy electric distribution companies operating in

Massachusetts (the "Eversource Massachusetts EDCs") have also requested approval of similar PAs with Access Northeast.[10]

Q. Will the Commission's approval of the proposed ANE Contract be contingent on approvals in other states?

A. Yes, effectively. The solution proposed by Access Northeast is sized as a regional solution and will require other New England states to take responsibility for a proportional share of the costs of the project, which are necessary to achieve the benefits of lower electricity rates and increased reliability across the New England region. Even with the Commission's approval of the proposed ANE Contract, Access Northeast 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 the execution of long-term contracts by EDCs operating throughout New England.

Q. Will the Eversource Massachusetts EDCs and other Eversource Energy operating affiliates seek contract approvals in other states?

A. Yes, as indicated earlier, a process is underway in Massachusetts for approval of the two PAs entered into with Access Northeast by the Eversource Massachusetts EDCs. In Connecticut, the Department of Energy and Environmental Protection is expected to conduct an RFP and direct the EDCs to enter into precedent agreements for gas transportation capacity.

[10] The Massachusetts electric distribution companies are NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy. *See* Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC, D.P.U. 15-181.

Q. What will happen if Access Northeast precedent agreements are not approved in each of the six New England states?

A. The development of regional infrastructure on a coordinated basis is a hugely complex undertaking as the legislative, regulatory and political processes in each state jurisdiction are different. Eversource anticipates that it will take time for all of the concurrent processes to be completed and that there could be challenges that arise through the process. With the high level of complexities involved, it is not possible to predict the outcome or precise timing of infrastructure decisions in each of the six New England states. In this case, Eversource is focused on New Hampshire. Timely approval from the Commission for the New Hampshire load share is critical in moving the entire process forward.

If other approvals do not follow in one or more New England states, Access Northeast will need to make a determination whether to proceed with fewer precedent agreements; to reconfigure the project and renegotiate the existing precedent agreements; or terminate the project. Given the significant benefits available to New Hampshire customers as a result of project implementation, it will be important for New Hampshire to monitor developments and allow for adaptations and adjustments to achieve project implementation. The proposed ANE Contract contemplates an expedited process for the Commission's review and approval of adjusted contract quantities should it be necessary to make adjustments to the load share computation to account for final subscriptions levels.

D. *Net Benefits Analysis*

Q. Has Eversource performed a net-benefits analysis of the proposed ANE Contract?

A. Yes. There is a need to address the imbalance of supply and demand for natural gas that is jeopardizing electric reliability and driving high electric retail prices and the solution to this imbalance requires the execution of long-term contracts that no other market participant can or will execute. The EDCs are the only creditworthy entities in a position to procure this capacity through long-term contracts; however, the motivation for the EDCs to enter into these contracts is to alleviate reliability and price impacts for their retail customers. As a result, the contracts and the contract benefits are inextricably linked.

Q. Please describe the net benefits analysis performed by Eversource?

A. Eversource retained the services of ICF to perform the net-benefits analysis for the ANE Contract for Eversource and the Eversource Massachusetts EDCs. The ICF Report demonstrates that Access Northeast would generate significant cost savings to New England electric consumers by reducing the price of natural gas delivered to New England power generators, and in turn, the wholesale and retail energy prices prevailing in the New England region. ICF estimates wholesale power price reductions of up to $12/MWh, with the total cost of the Access Northeast project equating to $4/MWh and net savings for customers of approximately $8/MWh. On an aggregate basis, Access Northeast, as proposed, could save New England retail electric customers between $1.4 to $1.9 billion per year on average from 2019 through 2035 under normal weather conditions, and about $3.1 billion annually if New England experiences a winter with design conditions and a nuclear plant outage (exclusive of net capacity-release and LNG sales revenues). About 10 percent of the benefits accrue to consumers in New Hampshire. Taking into account the cost of the pipeline, the net benefits to New England electric consumers could range from **$0.9 to $1.3 billion per year on average**, under normal weather conditions with capacity-release and LNG sales revenues only increasing that count. The details of the ICF analysis are provided in the testimony and attachments of Mr. Petak.

Q. Are there any other benefits associated with the Access Northeast project?

A. Yes. As explained further in the ICF Report and the testimonies of Mr. Petak and Mr. Stephens, New England has been steadily increasing its reliance on natural gas-fired electricity generation over the past 15 years. Currently, about 50 percent of New England's power comes from gas-fired generation, compared to roughly 15 percent in 2000. In addition, the projected retirements of regional nuclear and coal-fired power plants is expected to result in the construction of new gas-fired generation. Many observers, including ISO-NE, have noted that New England faces the risk of persistent and growing natural gas supply constraints without any new sources of capacity. Of particular concern is whether the network of gas production, pipelines, and storage capacity serving New England will be adequate to supply power generators under winter gas demand conditions. A press release by ISO-NE dated December 1, 2015 states:

> "Winter has become a challenging time for New England grid operations," said Vamsi Chadalavada, executive vice president and chief operating officer of ISO New England Inc. "Especially during the coldest weeks of the year, the natural gas infrastructure in New England is inadequate to meet the demand for gas for both heating and power generation. In fact,

> we've identified over 4,000 megawatts (MW) of natural-gas-fired generating capacity at risk of not getting sufficient fuel on any given day."

The Access Northeast project would enhance New England's grid reliability and complement the ISO-NE's market improvements to motivate generation availability. Access Northeast can potentially serve approximately 8500 MW, or nearly 70 percent of the region's existing natural gas-fired and dual-fueled power generation capacity interconnected to the pipeline system and operating without back-up fuel capability, including capacity served on Algonquin, M&NP, and the Joint Facilities.

By providing secure fuel supplies to these generators, the Access Northeast project would significantly improve electric reliability across the grid and potentially help the region avoid costly load shedding measures under extreme circumstances. In addition, Access Northeast would provide services that are designed to follow hourly gas load variation of power plants as electric load and gas-fired generation fluctuate throughout the day. By allowing generators to better follow hourly gas load variations, Access Northeast would help ISO-NE meet its system reliability mandate and help power plants avoid shortage penalties associated with ISO-NE's "Pay for Performance" program. ISO-NE's winter reliability and "Pay for Performance" programs are discussed in greater detail below.

IV. EVALUATION AND PROCUREMENT PROCESS

A. Procurement Process

Q. When did Eversource commence the process to identify an interstate delivery infrastructure solution?

A. Commencing with the New England Governors' joint statement of commitment to a cooperative regional initiative in December 2013, Eversource Energy has been actively engaged in an effort to identify a solution to the market imbalance of natural gas supply and demand, with particular reference to electric generation. The joint statement of the New England Governors raised the possibility of facilitating the development of gas pipeline capacity infrastructure through a collaborative process involving ISO-NE and the New England State Committee on Electricity ("NESCOE") (Attachment EVER-JGD-3-A).

By letter dated April 22, 2014, Northeast Utilities (the predecessor company to Eversource Energy), National Grid and UIL Holdings outlined an approach whereby electric distribution companies would, under certain circumstances, consider entering into long-term contracts with interstate pipeline companies for new firm gas transportation capacity. The approach acknowledged that, in addition to the construction of new pipeline capacity, solutions that include increased availability of domestic LNG supplies, gas storage and no-notice pipeline services should be explored in order to address the central issue of electric reliability and retail price volatility for electricity. Consistent with this outlined approach, the process commenced by the New England Governors' joint statement continued in the interests of identifying a solution that would support electric generation and facilitate the attainment of increased grid reliability and retail price stability.

Q. How did these efforts progress in furtherance of the goals outlined in the New England Governors' joint statement?

A. Throughout 2014, efforts that commenced with the issuance of the New England Governors' joint statement continued evolving with EDC involvement and within the context of a growing recognition that the EDCs would need to take the initiative to underwrite the construction of incremental pipeline capacity for the New England states. Early in this process, the entities involved in the effort, including Eversource Energy, recognized the need to follow certain protocols to ensure that:

- Any eventual solicitation and evaluation process would be conducted in a fair, transparent and competitive manner;
- All laws, regulations, rules and standards and codes of conduct would be observed
- All potential bidders would be treated equally;
- No potential bidder would receive preferential treatment or non-public information not available to other potential bidders, enabling it to gain an unfair advantage; and
- Efforts of the EDCs in the solicitation process would not create any actual or apparent conflict of interest to the extent that the EDCs (or their affiliates) may seek to submit a proposal and may participate in the solicitation and/or evaluation of proposals.

Ultimately, Eversource Energy announced plans to develop incremental capacity on Algonquin's Access Northeast project as part of a joint venture. Planning for the Access Northeast project was conducted by a project team kept separate from the supply procurement function. In April 2015, the Eversource Energy Project/Bid team and EDC Evaluation and Procurement team began negotiating precedent agreements to support the project.

Q. You mentioned a "Project/Bid team" and "EDC Evaluation and Procurement team." Could you provide more detail regarding the process Eversource Energy followed to assure that contract negotiations were conducted on a transparent "arms-length" basis?

A. On September 16, 2014, Eversource Energy announced a joint venture with Spectra Energy to develop the Access Northeast project. In conjunction with this decision, Eversource Energy formally identified a cross-functional group of employees to support the Access Northeast Project, led by the Eversource Energy Vice President of Energy Planning and Development. In parallel, the Eversource Energy regulated gas and electric utilities (responsible for obtaining gas supply and transportation resources to serve utility customers) identified a group of employees to support the transaction with respect to the evaluation of the various New England gas infrastructure initiatives. The Eversource Energy Project/Bid Team was engaged in the planning and development of the Access Northeast project, and the EDC Evaluation and Procurement Team was separately engaged in the assessment of portfolio objectives and identification and evaluation of resource alternatives and net benefits associated therewith.

Q. What are the specific codes of conduct procedures that Eversource Energy employed for Access Northeast project development and evaluation and procurement activities?

A. In deciding to participate in the joint venture, Eversource Energy recognized that it would need to establish an internal framework to assure the transparency and fairness of the procurement process. These standards of conduct generally require fairness and transparency in affiliate transactions and the transfer of assets or services at a fair value (generally defined as the higher of net book value or fair market value). These standards also generally prohibit preferential treatment and/or sharing of confidential or competitively sensitive information among transacting affiliates.

To avoid an actual or apparent conflict of interest regarding the Access Northeast project and the activities and obligations of the Eversource Energy distribution companies with respect to the New England gas infrastructure initiatives, Eversource Energy established Standard of Conduct Guidelines, which were similar to the Utility Standards of Conduct developed for the Regional Clean Energy RFP. As is the case with the Utility Standards of Conduct, written certification is required from each team member acknowledging he/she will follow and be bound by the Standards of Conduct Guidelines. Questions regarding compliance with the Standards of Conduct Guidelines are directed to the Chief Compliance Officer ("CCO"), who maintains electronic copies of all signed certifications and updated team rosters. In general, these standards of conduct are consistent with the requirements of the Commission's regulations in PART Puc 2100 on affiliate transactions.

Q. Were Eversource Energy employees provided with any training on the applicable Standards of Conduct Guidelines?

A. Yes. The Standards of Conduct Guidelines are relatively intuitive but team members are encouraged to ask questions and the CCO has fielded a number of questions. The EDC Evaluation and Procurement team was trained on the Standards of Conduct Guidelines by the CCO. The CCO circulated the team rosters and Standards of Conduct Guidelines to each team member and has kept the team leads up to date with roster changes. The CCO has also conducted internal meetings with various management groups to review the standards and has presented the Standards of Conduct Guidelines at an internal leadership meeting. The CCO has followed up by circulating electronically copies of the Standards of Conduct Guidelines and team rosters to all participating employees.

Q. Please describe the sequence of events that led to the RFP and Access Northeast PA.

A. Between April 2015 and October 2015, the separate teams involved in the contract negotiation made progress on a number of key issues. Throughout this period, Eversource also monitored industry developments regarding other potential alternatives and participated in pipeline open seasons for both Access Northeast and the Northeast Energy Direct ("NED") projects. Negotiations on the ANE Contract were not concluded and, in fact, were suspended as a result of the RFP jointly issued on October 23, 2015 by the Eversource EDCs and National Grid. As a result, there was never a complete or final agreement resulting from the pre-RFP efforts to bring a resource alternative to the marketplace.

B. <u>Procurement Process</u>

Q. Did the decisions of state authorities relating to potential contractual commitments for interstate pipeline capacity for the benefit of electric customers in New Hampshire affect Eversource's efforts?

A. On October 2, 2015, the Department of Public Utilities in Massachusetts issued an Order in its investigation in D.P.U 15-37 that determined its legal authority to review and approve contracts filed by EDCs for pipeline capacity, established a standard of review for such contracts, and set forth filing requirements.

That Order also required, among other things, that EDCs must demonstrate a fair and reasonable procurement process. Based on these findings, the Eversource EDCs decided that an RFP process would be useful in confirming the range of alternatives meeting the criteria for relief of electric reliability and retail price volatility concerns. Therefore, the Eversource EDCs immediately commenced efforts to develop an RFP for resource alternatives to be jointly issued by the Eversource EDCs and National Grid. Ultimately, the same requirements were supported in the September 15, 2015 Staff Report in Docket No. IR 15-124, and in the Commission's order accepting that report. Specifically, the Commission's Order No. 25,860 (January 19, 2016) in Docket No. IR 15-124 at page 5 noted that it expected that "any acquisition of gas capacity by a New Hampshire EDC for the ultimate benefit of electric customers would be undertaken through an open, transparent, and competitive bidding/Request for Proposals (RFP)-type process, in which competitors of the New Hampshire EDCs corporate affiliates or business partners would also be able to participate." The process contemplated by both Massachusetts and New Hampshire is, in all material respects the same process, and is therefore satisfied by the RFP process conducted by the Eversource EDCs and National Grid.

Q. When was the Massachusetts RFP issued?

A. The Eversource EDCs and National Grid jointly issued an RFP on October 23, 2015, to solicit proposals to further the goals of increased reliability of the New England electric system and reduced electricity costs for the benefit of electric distribution customers. The RFP was issued to six interstate pipeline companies serving the New England region and two LNG providers. Bid recipients are identified in Attachment EVER-JMS-3, which is presented with the testimony of Mr. James M. Stephens. The RFP was also posted on each EDC's website. Bid questions were received October 30, 2015 with bids due November 13, 2015. All bid questions were received and answered in written form to all potential participants. The RFP issued on October 23, 2015 is provided herewith as Attachment EVER-JGD-4.

Q. Please describe how the RFP was structured, including the criteria for responsive bids.

A. The purpose of the RFP was to confirm the range of resource alternatives for incremental gas infrastructure that would be operationally feasible, commercially reasonable, cost-effective and sufficiently sized to have a significant impact on generation-related reliability and cost concerns. The Eversource EDCs and National Grid worked together to develop appropriate bid guidelines for the RFP to achieve the goal of the RFP. The bid guidelines encompassed threshold criteria, as well as contractual parameters, that would need to be met to be considered a viable solution. Specifically, the following key criteria were set for bidding parties:

1. <u>Regional Scale</u>: Project solutions were required to have a regional scale, ranging from a minimum of 500,000 MMBtu/day to a maximum of 2,000,000 MMBtu/day.

2. <u>Delivery and Receipt Points</u>: Identification of specific receipt and delivery points was a critical prerequisite for conforming bids. Receipt points are critical to ensure that the point of purchase allows access to a long-term liquid supply. Delivery points must be primary firm and delivered to meter-specific ISO-NE generation facilities

in multiple load zones. The receipt and delivery points are critical components of a solution because, if the gas is not available and able to get to where it is needed on the coldest days, there would be no incremental reliability benefit nor ability to reduce the cost to customers.

3. Service: Flexible service offerings providing hourly flexibility in a cost effective and reliable manner would be beneficial to electric generators and should be an element of the solution to assure that the resource alternative is economically and operationally attractive to generation facilities.

4. Price: Each responder was required to provide all relevant information and cost breakdowns to allow for a comparison of options.

5. Contract Terms and Renewal Rights: Contract terms were required to be for a minimum of 15 years and a maximum of 20 years.

6. Contract/Precedent Agreements: Each bidder was provided a sample/draft precedent agreement to use as a guideline for the contract terms acceptable to the EDCs. The bid guidelines also allowed bidders to rely on a precedent agreement previously tendered to an EDC as part of negotiations ongoing prior to the issuance of the RFP, or to provide a precedent agreement that was previously accepted by a New England regulatory jurisdiction. Specific to LNG imports, the EDCs additionally requested respondents remove the country risk of origin and LNG shipping risk from the force majeure provisions. This was necessary to ensure reliability over the long term and to mitigate known imported LNG supply risk factors.

7. Service Agreements/Tariffs: Bidders were required to submit Service Agreements and all associated Tariffs.

8. Experience and Expertise: Bidders were required to specify their experience with developing and managing natural gas resources. For the EDCs, this element is vital as the process to develop incremental resources is very complex and requires unique and specific experience to succeed. The interests of customers will not be served where time and resources are spent without timely in-service dates. Due to the nature of the market imbalance, time is of the essence and therefore, experience and expertise is a critical prerequisite.

9. Approvals: Bidders were required to list all necessary approvals that would be necessary to complete the proposed project/facilities.

10. Financial Statements/Business Reports: Bidders were required to submit financial and business-related information to demonstrate that their proposed project is viable and can be carried out to completion. Preference was indicated for credit ratings of investment grade or above with a positive outlook.

12. Legal Matters/Conflicts: Bidders were required to discuss and identify any legal matters and/or conflicts of interest that the EDCs would need to be aware of.

Q. What resources were considered in the RFP?

A. Consistent with the Commission's expectations as expressed in Order No. 25,860, resources were considered that would meet the RFP criteria as described above and included LNG, pipelines, and gas storage. The resources that were considered did not, however, include compressed natural gas because the Eversource EDCs and National Grid determined that this resource was not capable of addressing the regional reliability and resultant pricing issues in a viable manner.

V. ANALYSIS OF RESOURCE ALTERNATIVES

A. <u>Analysis of Responses to RFP</u>

Q. How many bids were received?

A. Responses to the RFP were received on Friday, November 13, 2015. The Eversource EDCs received seven bids, encompassing four interstate pipeline companies and three LNG suppliers. The pipelines included Tennessee, Algonquin, PNGTS (jointly with TransCanada and Iroquois), and Iroquois (Constitution supply delivered to Algonquin). The LNG suppliers included Repsol, GDF Suez and one additional bid for LNG liquid from Stolt LNGaz of Canada. Some bidders identified multiple options within their bid resulting in the Companies' evaluation of approximately 20 resource alternatives.

Q. How were the bids evaluated?

A. The bids were evaluated by the Eversource EDCs with the assistance of Sussex Advisors in a three-step process. In the first step, a screening analysis was undertaken to determine whether the respective bid conformed with the requirements and objectives of the RFP. Several bids were eliminated from consideration at this stage due to the fact that the bids were "non-conforming" in terms of satisfying the threshold bid criteria. For example, certain bids were eliminated for failure to meet the minimum size to implement a regional solution or did not offer fixed-price proposals for transportation service. The projects remaining after the preliminary screening included the Tennessee NED project; the 600,000 MMBtu/day PNGTS proposal from Wright; several GDF Suez alternatives; the Repsol supply alternative; and the Access Northeast project.

The second step of the process involved organizing the bids by the Pipeline Delivery Area served (i.e., Algonquin or Tennessee) and then by category of project (i.e., Pipeline Only, Pipeline with LNG Storage (Hybrid), and Imported LNG). The quantitative analysis performed in this second step of the process by Sussex Advisors was based on a "landed-cost" analysis, as discussed in Mr. Stephens' testimony and as shown on Attachment EVER-JMS-4 (Sussex Landed Cost Analysis). The qualitative analysis was based on the assessment of certain risk categories including: generation capacity served; peak day deliverability; flexibility; receipt point liquidity; construction risks; sponsor financial consideration; and potential capacity mitigation opportunities. The projects remaining after the second-step analysis included the Tennessee NED project and the Access Northeast project. Specifically, Access Northeast was identified as the best option for generation served by Algonquin, and the Tennessee NED project proposal without optional LNG storage and with receipts at the Tennessee Zone 4 300 Line was identified as the best option for generation served by Tennessee Gas Pipeline ("TGP").

The qualitative analysis of pipeline projects performed by Sussex Advisors is provided in Mr. Stephens' Attachment EVER-JMS-5 (Sussex Evaluation of Pipeline Proposals). The qualitative analysis of the LNG proposals performed by Sussex Advisors is provided in Mr. Stephens' Attachment EVER-JMS-6 (Sussex Evaluation of LNG Proposals). The qualitative analysis of the hybrid proposals performed by Sussex Advisors is provided in Mr. Stephens' Attachment EVER-JMS-7 (Sussex Evaluation of Hybrid Proposals).

Q. Is the "landed cost" developed by Sussex Advisors to facilitate its analysis of the resource alternatives the key factor for distinguishing the relative benefits of project proposals?

A. No. The landed cost analysis was developed as a threshold component of the decision-making process, but is not the key factor for differentiating the relative benefits of the project proposals or determining resource selection. The resource selection, in this case, is not purely a function of "least cost" procurement principles. Here, the overriding objective of the resource procurement 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*. Therefore, while price is always an important consideration, other attributes may have a higher priority in relation to ultimate selection of a particular resource alternative, such as physical location and access to electric generating plants that have the greatest impact on wholesale market prices. Within this context, "landed cost" is only one piece of the puzzle, and if viewed in isolation, could produce misleading or erroneous conclusions. Other critical factors have to be taken into account such as the respective project's ability to deliver to generators of scale, access to liquid supply sources, project viability and, in short, the ability to impact wholesale power prices. Consequently, the Companies' objective in making its resource determination was to select the resource alternative possessing a competitive cost combined with the highest capability to have an impact on reliability and price volatility in the wholesale electric market. This ultimate determination was made in the third step of the process.

Q. What was the third step of the bid-evaluation process?

A. The third step of the bid evaluation process was a comparative assessment of the Access Northeast project and the Tennessee NED project, which finished as the top proposals for projects serving the Algonquin Delivery Area and the Tennessee Delivery Area, respectively.

Q. Please summarize the third-step evaluation analysis performed by Sussex Advisors.

A. In the third step, the Access Northeast and Tennessee NED projects were each evaluated in relation to their respective capabilities to improve reliability and to have a meaningful impact on wholesale market prices. This evaluation process is described in Mr. Stephens' testimony and involved a comparative assessment based on the same quantitative and qualitative factors described above.

Q. What are the physical or operational capabilities that would lead to a greater potential to have an impact on reliability and price volatility in the wholesale market?

A. The capability to have an impact on reliability and wholesale electric prices is greatest where there are firm, primary delivery rights to electric generating plants having the highest potential to run on peak. Each of the pipeline proposals provided for deliveries to plants on its respective system and additionally provided deliveries to interconnects either with other pipelines or further on its own system. Figure 18 of Mr. Stephens' testimony shows that approximately 12,400 MW of winter generation capacity is directly connected to the interstate pipelines located in New England, with the vast majority located within the Algonquin delivery area (57 percent). The Tennessee delivery area is connected to 24 percent of the generation capacity, and the remainder is spread across Iroquois, PNGTS, M&NP and the MN&P/PNGTS Joint facilities. The Tennessee NED project stretches across northern Massachusetts and southern New Hampshire with no existing generation plants in its path until it terminates in the Dracut, MA area. The Tennessee NED project would require additional facilities and capacity on its own system or on other pipeline systems to reach other generating facilities in Connecticut, Rhode Island and Massachusetts. The PNGTS proposal provided for deliveries to plants in New Hampshire and Maine, as well as interconnects with other pipelines, but would also require further facilities or downstream capacity to reach Connecticut, Rhode Island or Massachusetts. Algonquin's Access Northeast proposal provided for deliveries to plants in Connecticut, Rhode Island, Massachusetts, New Hampshire and Maine along its existing infrastructure path, which it is utilizing in this proposal to reach plants spanning the entire region.

Q. Which resource alternative was determined to have the highest capability to impact reliability and pricing issues affecting the New England region?

A. Sussex Advisors identified the Access Northeast project as the option with the highest capability to impact the reliability and pricing issues affecting the New England region. The key capabilities of the Access Northeast project that position it to have a major impact on regional reliability and wholesale market prices are: (1) the project reaches the largest number of power plants; (2) the project provides access to liquid supplies of scale and is designed to minimize the need to reach back further to more liquid points with larger demand charges; and (3) the project is designed to provide operational flexibility through a market area domestic LNG facility that will support no-notice and fast-start services for electric generators.

In addition, Algonquin, as sponsor of the Access Northeast project, has ample experience constructing, operating, and expanding natural gas transportation in New England. That experience includes the currently underway Algonquin Incremental Market project and the Atlantic Bridge project, which similarly expand the capacity of the Algonquin system.

B. *ISO-NE Initiatives as Potential Alternatives to Capacity Procurement*

Q. Did Eversource consider whether ISO-NE reliability initiatives represent alternatives to obviate the need for incremental pipeline resources?

A. Eversource is familiar with initiatives taken by ISO-NE to reinforce the reliability of electric supply. However, these initiatives do not represent alternatives to the construction of incremental pipeline capacity and will not have the impact that is needed to resolve market imbalances.

For example, ISO-NE's Winter Reliability Program is designed to provide fuel assurance during each winter period, December through mid-March, prior to the implementation of ISO-NE's Pay-for-Performance market design in June 2018. This program is in response to a concern that arose from operations during the 2012/13 winter season when ISO-NE sought to dispatch a number of oil-fired units more frequently than in recent years, but instead discovered that the facilities had run out of usable inventory. Although the program details have changed somewhat since December 2013, the program is designed to: (a) compensate resources for firming up supplies of oil, LNG and demand response;

and (b) provide some compensation to natural gas-fired units that install dual-fuel capability. ISO-NE has indicated that the program has lessened its concerns about having adequate fuel resources during winter periods. Program costs to date have been $68 million for 2013/14 and $46.4 million for 2014/15.[11] This is an unsustainable and out-of-market solution. The most reliable and economical solution will not be achieved unless adequate fuel delivery infrastructure is in place.

Q. What is ISO-NE's "Pay for Performance" capacity-market design?

A. ISO-NE's "Pay for Performance" market design is intended to reform the penalty provisions of the Forward Capacity Market. Through its operation, ISO-NE expects to see capacity prices increase with the hope that these higher revenues will either be used to improve performance or forfeited to good performers who have taken actions to be the good performers. During scarcity events, pay for performance compares each resource's provision of generation and operating reserves to its capacity supply obligation adjusted for load and operating reserve requirements at the time versus peak requirements. The difference between what the resource is generating and what it is expected to generate at the time is multiplied by the capacity performance payment rate in effect at the time. If performance is better than expected the resource receives an additional performance payment; if performance is worse than expected it pays. All resources performing during the scarcity event regardless of having a capacity supply obligation are subject to the pay for performance calculation, except Energy Efficiency during certain months of the year.

[11] See, May 2014 PC materials http://www.nepool.com/uploads/NPC_20140502_Composite4.pdf; April 2015 PC materials http://www.nepool.com/uploads/NPC_20150410_Composite4.pdf, respectively.

Generally, scarcity events are defined as any five-minute interval in which reserve constraint penalty factors are triggered. Scarcity events can be pool-wide or in load zones. The capacity performance payment rate is being phased in over time. Specifically, the performance rate will be $2,000/MWh June 1, 2018 through May 31, 2021 (three years); $3,500/MWh June 1, 2021 through May 31, 2024 (three years) and $5,455/MWh thereafter subject to periodic review. Total payments are capped through stop-loss provisions with shortfalls recovered from other resources. Energy Efficiency resources are subject to the pay for performance calculation only during the months used to establish their capacity value. In other months those resources are exempt from the calculation. In addition to the pay for performance, as part of this reform reserve constraint penalty factors were changed. Reserve Constraint Penalty Factors for 30-Minute Operating Reserves were changed from $500/MWh to $1,000/MWh, and for 10-Minute Non-Spinning Reserves they were changed from $850/MWh to $1,500/MWh.

Q. Has ISO-NE indicated that its Pay for Performance market design will eliminate the need for incremental natural gas transportation capacity into New England?

A. No. ISO-NE stated in its 2015 regional system plan (at page 138) that:

> By creating incentives for generators to firm up their fuel supply, pay for performance may indirectly provide incentives for the development of oil or LNG fuel storage or gas pipeline infrastructure. However, PFP will not take effect until 2018 and will not reach full effectiveness until the seven-year phase-in of the new performance payment rate is complete. Until that time, the region may be challenged to meet power demand any time pipeline capacity is constrained. PFP may also hasten the retirement of inefficient resources with poor historical performance and the entrance of new, efficient, better-performing resources. Ultimately, PFP is an efficient and effective way to promote investments necessary to improve performance, to provide a stable revenue stream to high-performing resources for maintaining their viability, and to ensure continued

> predictable capacity prices and long-term reliability for consumers.

As noted, pay for performance will not be fully implemented until 2024, nine years from now, and even then, ISO-NE admits it will not necessarily lead to incremental natural gas transportation capacity in New England. According to ISO-NE, at least in the short term, most gas-fired generators would likely turn to limited dual-fuel capability additions to their plants, which would not only *increase* emissions, but would also have minimal impact, if any, on high electricity prices.

Moreover, pay for performance does not change the ISO-NE market rules with respect to requiring firm fuel supplies. ISO-NE stated the following in its answer to the New England Power Generators complaint to FERC that ISO-NE was imposing firm fuel supply requirements:

> In fact, the Tariff does not impose a "firm fuel obligation" or any other specific obligation with respect to fuel procurement, and the ISO has not made the assertion or interpretation – in the November 5 Memo or otherwise – that the Tariff does impose a firm (or other) fuel obligation. Because the entire Complaint is therefore premised on a faulty accusation, it should be rejected.[12]

Additionally the New Hampshire Commission has also recognized that Pay for Performance has limitation:

> …the NHPUC expects that Pay for Performance has limitations that will prevent ISO-NE from fully meeting the FERC's twin goals of system reliability at just

12 See, section B page 10 of this link: http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jun/el13_66_000_6_6_13_ans_nepga_complaint.pdf (page 13 of 50 of pdf).

and reasonable wholesale rates (FERC Docket Nos. AD13-7-000, AD14-8-000. Comments of the New Hampshire Public Utilities Commission at 5-6.

C. *Energy Efficiency as a Possible Project Alternative*

Q. Did Eversource consider whether increased implementation of Energy Efficiency initiatives represent an alternative to obviate the need for incremental pipeline resources?

A. Eversource is familiar with the range of Energy Efficiency resources available to reduce the demand for electric supply. However, these types of initiatives do not represent alternatives to the construction of incremental pipeline capacity and will not have the impact that is needed to resolve market imbalances.

Q. What role does Energy Efficiency play as an alternate solution?

A. The testimony of Mr. Tilak Subrahmanian, Vice President of Energy Efficiency for Eversource Energy Service Company, discusses New Hampshire's efforts to date in it Energy Efficiency ("EE") programs. Mr. Subrahmanian's testimony further discusses that while New Hampshire has significant potential for additional EE deployment, EE cannot suffice to resolve the market imbalance of supply and demand due to the scale of natural gas capacity needed in New England. There is simply no reasonable or feasible implementation of EE that would reduce the demand for natural gas in a quantity to offset the need for incremental gas capacity.

D. Transmission and Renewable Resources as Potential Project Alternatives

Q. Please explain how renewable energy alternatives and/or transmission imports of hydropower impact the selection of alternative to expanding natural gas supply.

A. Increases in renewable generation can and should augment the regional diversity of generation. Eversource Energy is a strong supporter of increased regional diversity of generation, particularly in relation to hydro resources. Eversource Energy is a partner in the Northern Pass project, which is a 192-mile transmission line that will bring 1,090 megawatts ("MW") of clean, affordable energy from Hydro-Québec's hydroelectric plants in Canada to New Hampshire and to the rest of New England. However, with approximately 8,300 MW of generation identified by ISO-NE as either scheduled for, or at risk of, retirement, the region remains in need of a significant expansion of natural gas capacity to augment what is reasonably available from a renewable portfolio.

Q. Could you be more specific about the reasons that increased reliance on renewable generation cannot suffice as the solution to the current market imbalance of supply and demand for natural gas?

A. The reasons that renewable resources cannot suffice to resolve regional supply issues is two-fold. First is the magnitude of the gap. In that regard, the testimony of Mr. Stephens discusses the fact that natural gas and dual-fuel (natural gas/oil) generating units currently account for nearly 60 percent of the total generating capacity in ISO-NE's portfolio, with natural gas representing approximately 28 percent of the total electric generation in 2001, and 46 percent of the total generation in the most recent 12 months. In a 2012 study, ISO-NE identified approximately 8,300 MW of oil and coal-fired generating units that were "at-risk" of retirement by 2020. Some of these have already retired, the Vermont

Yankee plant, which was not on the list, also has retired, and more are planned for retirement, including the Pilgrim Nuclear Plant no later than June 1, 2019. There are 92 proposed generation projects in the ISO-NE interconnection queue, which represent approximately 10,600 MW of proposed generating capacity additions. Proposed generation projects are fueled by natural gas or dual-fuel (natural gas/oil), accounting for the majority (approximately 60 percent) of the total net capacity additions, with wind projects accounting for approximately 35 percent of the total capacity additions.

Moreover, the planned addition by Footprint Power at the Salem Harbor facility is natural gas fueled only and is not permitted as dual fuel. The ability to permit generation facilities using ultra low sulfur diesel ("ULSD") for extended periods of time should gas be unavailable, is questionable from an environmental perspective and would result in higher carbon and other emissions. In addition, reliance on ULSD leaves consumers exposed to high and volatile prices driven by world oil prices. The logistics of moving large quantities of oil to power plants during cold winter conditions also raises risks to reliability.

Second, renewable resources cannot be procured or reasonably implemented on the scale necessary to fill the gap. Moreover, although wind and solar generation is growing, these resources are *intermittent*, which makes these resources unsuitable for heavy reliance in certain times of the year or under certain weather conditions routinely occurring in New England. For example, in New England there is a significant shortfall in gas supply during winter peak demand conditions, which occur late in the day when the sun has set and gas heating demand is peaking. Solar therefore cannot mitigate demand for natural gas. Similarly, wind power cannot be relied upon to generate at all times. Without a firm source of natural gas, the system will be at risk at a time when reliability of supply is paramount.

Q. What role should large hydro imports and associated transmission play in the resource mix?

A. Large hydro via new transmission imports is a viable and important source of diversity to the region. In addition to the new shale gas discoveries in the Marcellus and Utica, New England is next door to large hydro resources in Canada. These sources, in addition to renewable resources such as wind and solar generation can serve as complementary resources to help the region meet a clean and diversified supply of electricity. The process to determine the desirability of adding large scale transmission and hydro power is currently under way under the Clean Energy RFP, which was issued on November 12, 2015 by Massachusetts, Connecticut and Rhode Island.[13]

VI. MAXIMIZING PRICE RELIEF FOR EDC CUSTOMERS

Q. Would you please explain how Eversource will administer the release of natural gas pipeline capacity and LNG to the electric market so as to maximize reliability and price-relief benefits for electric customers?

A. Eversource has collaborated with the Eversource Massachusetts EDCs and National Grid to develop an "Electric Reliability Service Program" ("ERSP"), which will utilize a Capacity Manager to administer the release of contracted gas capacity to the electric generation market. The ERSP is contemplated to be a state-approved program, and the

[13] https://cleanenergyrfpdotcom files.wordpress.com/2015/11/clean-energy-rfp-final-111215.pdf.

details of the proposed ERSP are provided in Attachment EVER-JGD-5. Conceptually, an agreement between participating EDCs and the Capacity Manager would facilitate the transfer of procured capacity to electric generators on a priority basis to ensure reliability and promote liquidity. The priority release enhances reliability to the region as the generators will have access to the highest level of service provided by interstate natural gas pipelines in the form of primary firm transportation capacity. The EDCs are providing this priority of service structure to match natural gas infrastructure specifically designed to serve the power generation with its dynamic demand profile.

Under the agreement, the Capacity Manager would aggregate the assets owned by the EDCs and would be directed by an EDC Working Committee ("EDC-WC") comprised of representatives of each EDC that has contracted for gas infrastructure assets as part of this program. The EDC-WC would directly report to an EDC Executive Committee ("EDC-EC") comprised of one executive from each EDC, who will make all final decisions regarding asset management. The EDC-EC will coordinate with regulatory authorities annually to report on the program activity. The agreement would stipulate that the Capacity Manager is to make capacity available to generators prior to releasing any capacity to the secondary market. These parameters are essential to ensure that reliability and other benefits are achieved. These parameters also emulate in many respects the manner in which a gas LDC provides its customers with a reliable and reasonable cost supply. The capacity would be released to generators in a similar fashion as is currently allowed under FERC rules, but under FERC-approved tariff provisions that would enable the Capacity Manager to accomplish this service priority for generators similar to FERC-approved release rules related to LDC retail unbundling programs.

Specific controls, policies and procedures would be developed to ensure appropriate management controls are in place for the Capacity Manager to effectively administer the capacity and LNG to improve fuel deliverability to generators. Those EDCs who have affiliated Gas LDCs are highly experienced in developing and operating under such controls, policies and procedures and will leverage this experience as part of administration of this program. Again, a more detailed explanation of the process is provided in Attachment EVER-JGD-5.

Q. Can you please explain how the Capacity Manager will be selected?

A. The EDC-WC will conduct a competitive bidding process with a request for proposals to select a Capacity Manager. The Capacity Manager will not be allowed to have any conflicts of interest that could distract or conflict with their requirement to serve the EDCs' interests. The EDCs envision a model that would involve a single purpose entity that performs the intended services with very specific roles and responsibilities. The Capacity Manager's responsibilities would include releasing the capacity in a manner consistent with the EDC guidelines, which include effectively releasing capacity to the generators to ensure reliability and maximizing the credits received from the releases of capacity to help offset the cost of the EDC capacity. The Capacity Manager would also report on results to the management committee. The Capacity Manager would be compensated in the form of a fixed fee.

Q. Can you please explain how the revenues generated by the sales of capacity or LNG will be returned to customers?

A. The revenues generated by releasing the capacity would be credited back to the EDCs' customers net of the administrative costs required to compensate the Capacity Manager. Capacity will be released to the highest price bid by generators in the competitive process for longer term releases (i.e., greater than one month) or during the "real-time" bidding process for shorter term transactions. LNG would be sold by the EDCs to generators at market-based prices and will be reflective of an objective index such as the Daily AGT City Gate index. The margin from the LNG sales will be defined as revenue less the cost of the LNG, which will include the commodity price of gas injected plus all of the variable charges associated with injecting, transporting, storing and withdrawing the LNG from the storage facility.

The revenues collected from capacity releases and the margins from LNG sales would then be returned to EDC customers in a tracking mechanism to offset the costs of the capacity. Each EDC would receive a share of those net dollars proportionate to their respective share of the total pipeline [and LNG] capacity under this program. These values in the gas market will fluctuate over time.

Q. What are the "FERC-approved" release rules that you referred to earlier?

A. As part of its Order No. 636 program for unbundled open access natural gas pipeline transportation, FERC adopted capacity release regulations that allow firm shippers to release their capacity entitlements to replacement shippers. The regulations were designed to assure a transparent and non-discriminatory allocation of pipeline capacity to those who valued it the most. Thus, with limited exceptions, the regulations excluded preferential treatment for replacement shippers by requiring that shipper offers to release capacity be posted on a pipeline's internet website and that offers below the pipeline's maximum lawful rate be subject to competitive bidding. The initial limited exceptions/exemptions to the competitive bidding requirement were for short-term releases of thirty-one (31) days or less and releases at a pipeline's maximum lawful rate.

These generic exemptions to the competitive bidding requirement were expanded under FERC Order No. 712 to include capacity releases to asset managers and capacity releases in connection with state retail competition programs.[14] The pipeline on behalf of the EDCs would need to seek FERC approval for priority release of capacity to electric generators as the EDCs are proposing here.

Q. Has FERC previously recognized that flexibility in its capacity release regulations might be appropriate for the public interest purpose of assisting natural gas-fired generators in obtaining access to firm transportation service?

A. FERC has declared itself to be open to considering deviations from its capacity release regulations and/or the shipper-must-have-title rule on a case-by-case basis, where it is shown to be in the public interest, and FERC has acknowledged such public interest in, and provided the specific example of, assisting natural gas-fired generators in obtaining

[14] Promotion of a More Efficient Capacity Release Market, Order No. 712, 123 FERC ¶ 61,286 (2008) (Order No. 712), order on reh'g, Order No. 712-A, 125 FERC ¶ 61,216 (2008), order on reh'g, Order No. 712-B, 127 FERC ¶ 61,051 (2009).

access to firm transportation service in a transparent and not unduly discriminatory manner.[15]

Q. How will EDCs manage any FERC approvals needed to effectuate the ERSP?

A. The EDCs have required that Algonquin request FERC approval for release of capacity on a priority basis to generators under a state approved program. Algonquin will be making a tariff filing as part of its General Terms and Conditions to effectuate this FERC approval. Obtaining FERC approval would be a condition precedent to the EDCs being required to pay for the capacity. Since this is a tariff filing approved by the FERC, the EDCs have been in discussions with project developers on the terms of the capacity-release program, the main elements of which are contained Attachment EVER-JGD-5, referenced above. Final approval of the ANE Contract would be conditioned on the approval of the Algonquin tariff provision by FERC consistent with the state regulatory approvals of EDC precedent agreements. FERC has already recognized that granting retail gas marketers priority access to released capacity under state retail competition programs is in the public interest and has approved such priority access; the ERSP will accomplish similar goals.

[15] Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, Order No. 809, 151 FERC ¶ 61,049 (2015) Par. 146. See also Georgia Pub. Serv. Comm'n, 107 FERC ¶ 61,024, at P 36 (2004), reh'g granted in part, denied in part, 110 FERC ¶ 61,048 (2005), reh'g denied, 111 FERC ¶ 61,178 (2005), and Promotion of a More Efficient Capacity Release Market, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284, at P 146 (2008), order on reh'g and clarification, Order No. 712-B, 127 FERC ¶ 671,051 (2009).

Q. Absent FERC approval, will the incremental pipeline capacity and LNG supply provide benefits to EDC customers?

A. Yes. Although the EDCs prefer that electric generators access the pipeline and storage assets prior to competing in the open market, substantial benefits will be realized from the Access Northeast project even if "priority" releases are not allowed by the respective state commissions or FERC. In the absence of approval to accomplish priority releases, Access Northeast project capacity can and would be released consistent with FERC's existing rules for non-discriminatory capacity release. The EDCs are seeking approval for "priority" releases only to have the most direct impact possible on electric retail prices. However, with or without the ability to conduct priority releases, the Access Northeast project will increase the amount of gas available in the competitive marketplace. The incremental capacity creates increased liquidity and market depth for sellers to find bidders, which ultimately leads to lower retail prices. Lower gas prices have shown to be highly correlated to electricity prices in the region and therefore should lead to lower power prices.

VII. RATEMAKING MECHANISM

Q. What is the Eversource proposal for recovery of the costs and crediting the revenues associated with the proposed ANE Contracts, if approved?

A. The ratemaking mechanism that Eversource is proposing for recovery of the contracts costs and the crediting of net release revenues to customers is described in detail in the testimony of Mr. Christopher J. Goulding and Ms. Lois B. Jones. The mechanism is designed similar to contract cost recovery mechanisms previously approved by the Department for renewable generation contracts. From a high level, the mechanism is designed to net costs against expected revenues so that customers are charged a net cost that is recovered from all customers through a uniform per kWh rate.

The cost elements of the ANE Contract include: (1) fixed and variable transportation charges; (2) storage inventory costs including injection and withdrawal charges as necessary; and (3) administration charges, which would encompass fees paid to the Capacity Manager and consulting fees or other similar administrative and general costs incurred by the EDCs to effectuate the contracts and achieve mitigation revenues. Revenues offsetting those costs would be obtained from capacity releases and sales from LNG inventory. Eversource estimates that market revenues (combined capacity release and LNG sales) will vary, but 50 percent average recovery of Access Northeast demand costs is reasonable.

Q. Would you be more specific about the types of costs that would be recovered through the Administrative cost category?

A. Eversource anticipates that there will be a category of costs that are necessarily incurred to complete the contracting process and to carry out the activities that will be necessary to bring the contract resources to the market place, similar to the types of costs companies incur in order to provide default energy service to customers. For example, Eversource will incur costs in this proceeding to present the analysis required by the Commission to support contract approval. The Commission's approval of the ANE Contract will rest on the determination that procurement of this contract is in the public interest and will provide a net benefit to customers. Eversource is not requesting remuneration or any type of profit margin from its activities to bring these resources to the market and obtain reliability and price relief for electric retail customers. However, in lieu of any margin to help cover the incremental costs related to these contracts for the benefit of customers, it is necessary for there to be a provision for recovery of administrative costs on a pass-through basis, similar to cost recovery for providing default energy service.

VIII. SUMMARY AND CONCLUSION

Q. Please summarize your testimony and conclusion.

A. The composition of New England generation is moving away from coal, oil and nuclear generation and towards cleaner generation resources, including natural gas and renewable generation. The joint statement of the New England Governors issued in December 2013 highlighted the existence of regional infrastructure constraints and acknowledged that the future of the New England economy and environment requires strategic investments in the region's infrastructure. Infrastructure development requires financial commitment through the execution of long-term contracts. EDC contracts for gas infrastructure has emerged as the only feasible alternative to achieve the development of the necessary infrastructure as no other market participant possesses both the creditworthiness and customer connection to enter into the infrastructure contracts and to establish a mechanism for associated costs and revenues. Among other alternatives, the Access Northeast project has the highest capabilities to have a sizeable impact on the reliability and wholesale price issues serving as the impetus for the New England Governors' joint statement. Electric customers will be the primary beneficiaries of an increased supply of natural gas and lower electric prices. These benefits should be achieved on an expeditious basis because customers will incur higher electric costs unless and until incremental capacity resources are actually put into service. Therefore the Commission should approve the proposed ANE Contracts with Access Northeast and authorize the associated ratemaking mechanism.

Q. Does this conclude your testimony?

A. Yes.