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July 22, 2016

**BY HAND DELIVERY**

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

Re: Docket 4627 – In Re: Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project
Responses to PUC Data Requests – Set 1 (Part 2)

Dear Ms. Massaro:

On behalf of National Grid,[1] enclosed are National Grid's responses to Data Requests PUC-1-3 through PUC-1-11[2] issued by the Rhode Island Public Utilities Commission on July 5, 2016 in the above referenced matter. Also enclosed, please find a Motion for Protective Treatment with respect to National Grid's response to Data Request PUC-1-1 and Attachment PUC-1-2(d), filed by the Company on July 11, 2016.

Thank you for your attention to matter. If you have any questions, please contact me at (617) 951-1400, or Jennifer Brooks Hutchinson at 401-784-7685.

Very truly yours,

John K. Habib

John K. Habib

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1 The Narragansett Electric Company d/b/a National Grid.

2 The responses to Data Requests PUC-1-1 and PUC-1-2 were due and filed on July 11, 2016.

**STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS**

**RHODE ISLAND PUBLIC UTILITIES COMMISSION**

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| **Review of Precedent Agreement with Algonquin Gas Transmission LLC for Capacity on the Access Northeast Project Pursuant to R.I.G.L. § 39-31 *et seq.*** | **Docket No. 4627** |

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**NATIONAL GRID'S REQUEST**
**FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION**

National Grid[1] hereby requests that the Rhode Island Public Utilities Commission (PUC) provide confidential treatment and grant protection from public disclosure of certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by PUC Rule 1.2(g) and R.I.G.L. § 38-2-2(4)(B). National Grid also hereby requests that, pending entry of that finding, the PUC preliminarily grant National Grid's request for confidential treatment pursuant to Rule 1.2 (g)(2).

## I. BACKGROUND

On June 30, 2016, National Grid filed with the PUC its request for approval of a precedent agreement with Algonquin Gas Transmission LLC (Algonquin) for capacity on the Access Northeast Energy Project (ANE Project). In support of its request for approval, National Grid submitted initial testimony and supporting exhibits including a copy of the precedent agreement and the Company's analysis of the precedent agreement and ANE Project, including proprietary modeling information and analysis provided by

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[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

the Company's third-party consultants. For example, the testimony of Gary Wilmes of Black & Veatch Management Consulting LLC (Black & Veatch), provided detailed cost-benefit analysis related to the ANE Project that was created using Black & Veatch's proprietary modeling.

On July 11, July 21 and July 22, 2016 National Grid filed its responses to the PUC's First Set of Data Requests that reference these highly sensitive confidential terms. Specifically, the Company is seeking protective treatment of its response to Data Request PUC 1-1 and Attachment PUC 1-2 (d), which it filed on July 11, 2016. The Company's response to Data Request PUC 1-1 provides all responses to discovery issued in the related Massachusetts Department of Public Utilities (the Department) proceeding, D.P.U. 16-05. The response to Data Request PUC 1-1 is being updated by the Company on a rolling basis as additional discovery responses are filed in D.P.U. 16-05 and the Company requests that confidential treatment for any supplemental response to PUC 1-1 be protected pursuant to this motion.

As noted above, the Company's affiliates Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid have filed a similar request for approval of precedent agreements with Algonquin for capacity on the ANE Project with the Department. The Department has approved a two tier confidential document designation to provide an added layer of protective treatment in this related proceeding. This additional layer of protective treatment is necessary because certain intervenors granted full-party status in the Massachusetts proceeding are classified as bidders with respect to the request for proposals (RFP) that resulted in the precedent agreement that is the subject of this proceeding. The RFP was jointly simultaneously with the RFP issued by the Company's Massachusetts affiliates and Eversource Energy and, therefore, the Company expects that some or all of the parties who have intervened in the Massachusetts proceeding will also seek to intervene in this proceeding. Therefore, in order to ensure that confidential information is treated consistently across jurisdictions, the Company proposes to implement the same two-tier system for this proceeding. If the same parties intervene in this proceeding and the two-tier system is not utilized, the two-tier system being used in Massachusetts will be undermined and the Company (and its affiliates) will be placed at a competitive disadvantage. This result would be particularly problematic because it is expected that other pipeline projects will be proposed in the near future to address capacity restraint in the New England region.

In this proceeding, the Company proposed to adopt the same approach to ensure consistency across New England jurisdictions, and to prevent intervenors from gaining access to confidential information that has been restricted in Massachusetts. Each of the documents referenced in this Motion have been classified as either Confidential or Highly Sensitive Confidential Information, consistent with the Company's initial filing and as filed in Massachusetts. Although the PUC has declined to adopt the two-tier method of protective treatment proposed, the PUC has determined that National Grid can still mark documents as either HSCI or Confidential and enter into non-disclosure agreements appropriate for each classification.

The Company has provided redacted and unredacted versions of each of these documents. Each of these documents and/or files contains confidential and proprietary contractual or economic analysis information. Therefore, National Grid requests that the

PUC give the information contained in the unredacted version of the HSCI or Confidential Documents confidential treatment.

## II. LEGAL STANDARD

The PUC's Rule 1.2(g) provides that access to public records shall be granted in accordance with the Access to Public Records Act (APRA), R.I.G.L. §38-2-1 *et seq.* Under APRA, all documents and materials submitted in connection with the transaction of official business by an agency is deemed to be a "public record," unless the information contained in such documents and materials falls within one of the exceptions specifically identified in R.I.G.L. §38-2-2(4). Therefore, to the extent that information provided to the PUC falls within one of the designated exceptions to the public records law, the PUC has the authority under the terms of APRA to deem such information to be confidential and to protect that information from public disclosure.

In that regard, R.I.G.L. §38-2-2(4)(B) provides that the following types of records shall not be deemed public:

> Trade secrets and commercial or financial information obtained from a person, firm, or corporation which is of a privileged or confidential nature.

The Rhode Island Supreme Court has held that this confidential information exemption applies where disclosure of information would be likely either (1) to impair the Government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal Company v. Convention Center Authority, 774 A.2d 40 (R.I. 2001).

The first prong of the test is satisfied when information is voluntarily provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47.

## III. BASIS FOR CONFIDENTIALITY

The information contained in the un-redacted versions of the response to Data Request PUC-1-1 and Attachment PUC-1-2(d) includes confidential and proprietary bidder information, pricing information and bid-evaluation information. In addition, the response to Data Request PUC-1-1 and Attachment PUC-1-2(d) contain confidential contractual terms including pricing information that was negotiated by the Company with Algonquin. This information was obtained from bidders under a confidentiality agreement and contains their confidential pricing data. Disclosure of this information would impact the competitive position of these parties, and such disclosure would impede National Grid's future ability to obtain bids and/or favorable contractual terms. Such disclosure would have a negative impact not only on National Grid but on National Grid's customers by impeding National Grid's ability to obtain the best price for future capacity agreements.

## IV. CONCLUSION

Accordingly, the Company requests that the PUC grant protective treatment to the Company's response to Data Request PUC-1-1 and Attachment PUC-1-2(d).

**WHEREFORE**, the Company respectfully requests that the PUC grant its Motion for Protective Treatment as stated herein.

Respectfully submitted,

**NATIONAL GRID**

By its attorneys,

_________________________________
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Dated: July 22, 2016

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PUC 1-3

Request:

Please provide copies of all statutes in the other New England states authorizing electric distribution companies in those states to enter into contracts for gas capacity. If a state does not have an authorizing statute, please provide a copy of regulatory orders, regulations in place, or proposed for effect, that allow for the development of natural gas infrastructure to serve power generation through contract with electric distribution companies. (See Brennan & Allocca, p. 34, lines 8-13).

Response:

*Massachusetts*

Please see Attachment PUC-1-3(a)(1) for a copy of M.G.L. c. 164, § 94A. The Massachusetts Department of Public Utilities has determined in D.P.U. 15-37 (Attachment PUC-1-3(a)(2)) that M.G.L. c. 164, § 94A provides the Department authority to approve a gas capacity contract executed by a Massachusetts electric distribution company.

*Connecticut*

Please see Attachment PUC-1-3 (b) for a copy of Conn. Pub. Acts 15-107.

*Maine*

Please see Attachment PUC-1-3(c) for a copy of The Maine Energy Cost Reduction Act, Title 35-A, Chapter 19.

*New Hampshire*

The New Hampshire Public Utilities Commission (NH PUC) has accepted a Staff Report and Stakeholder Comments, and Outlining Review Process for Any Petitions for Capacity Acquisitions and Associated Competitive Bidding (Staff Report) (Attachment PUC-1-3(d)(1)), without making a determination regarding the statutory basis for the NHPUC to approve such capacity additions. The Staff Report, provided as Attachment PUC-1-3(d)(2), includes a legal analysis of the NHPUC's authority to approve such contracts. However, the PUC will ultimately make such determination in the context of its review of a specific electric distribution company contract to procure gas capacity. A proceeding is currently underway, as noted in the Company's response to data request PUC-1-4.

*Vermont*

The Company is not aware of any statutes, regulations or regulatory orders in Vermont that specifically address the procurement by electric distribution companies of gas capacity. However, the Company is also not aware of a legal analysis that has concluded that such authority does not exist.



## General Laws



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| PART I | ADMINISTRATION OF THE GOVERNMENT | NEXT |
| TITLE XXII | CORPORATIONS | PREV |
| CHAPTER 164 | MANUFACTURE AND SALE OF GAS AND ELECTRICITY | PREV NEXT |
| Section 94A | Contracts for purchase of gas or electricity; review of price paid | PREV NEXT |

Section 94A. No gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of one year without the approval of the department, unless such contract contains a provision subjecting the price to be paid thereunder for gas or electricity to review and determination by the department in any proceeding brought under section ninety-three or ninety-four; provided, that nothing herein contained shall be construed as affecting a contract for the purchase of gas or electricity from a person or corporation engaged in manufacturing, where the manufacture, sale or distribution of gas or electricity by such person or corporation is a minor portion of his or its business, and which contract is made in connection with a contract to supply such person or corporation with gas or electricity, or as affecting a contract for the purchase of electricity from an alternative energy producer. In any such proceeding the department may review and determine the price to be thereafter paid for gas or electricity under a contract containing said provision for review. Any contract covering a period in excess of one year subject to approval as aforesaid, and which is not so approved or which does not contain said provision for review, shall be null and void. The department is authorized to exempt any electric or generation company from any or all of the provisions of this section upon a determination by the department, after notice and a hearing, that an alternative process or incentive mechanism is in the public interest.

# The Commonwealth of Massachusetts

## DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 15-37 October 2, 2015

Investigation by the Department of Public Utilities on its own Motion into the means by which new natural gas delivery capacity may be added to the New England Market, including actions to be taken by the electric distribution companies.

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ORDER DETERMINING DEPARTMENT AUTHORITY
UNDER G.L. C. 164, § 94A

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## I. INTRODUCTION

On April 2, 2015, the Department of Energy Resources ("DOER") filed a petition with the Department of Public Utilities ("Department") requesting that the Department open an investigation into the means by which new natural gas capacity[1] may be added to the New England market, including actions that may be taken by the Massachusetts electric distribution companies ("EDCs") ("Petition"). On April 27, 2015, the Department issued an Order opening an investigation into whether: (1) there is an "innovative mechanism" for EDCs or other parties to secure new natural gas capacity into the region to benefit electric ratepayers; (2) it is appropriate for the Department to review for cost-recovery EDC contracts for natural gas capacity under G.L. c. 164, § 94A ("Section 94A"); and (3) the Department's established standard of review under Section 94A should be different for these contracts. See Investigation by the Department of Public Utilities on its own Motion into the means by which new natural gas delivery capacity may be added to the New England market, including actions to be taken by the electric distribution companies, D.P.U. 15-37, Order Opening Investigation (April 27, 2015) ("Order Opening Investigation"). The Department docketed this matter as D.P.U. 15-37.

As part of its Order Opening Investigation, the Department presented the questions posed by DOER in its Petition as well as additional questions developed by the Department. See Appendix A for all questions included in the Order Opening Investigation. The

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[1] Throughout this Order, the Department uses the terms "natural gas capacity," "gas capacity," and "pipeline capacity" interchangeably.

Department requested that interested persons address the questions and further encouraged individuals and stakeholders to submit relevant information even if not specifically requested in one of the questions. See Order Opening Investigation at 3. The Department provided for submission of initial comments by May 26, 2015, and reply comments by June 9, 2015. See Order Opening Investigation at 6. On May 6, 2015, the Department granted the Office of the Attorney General's ("Attorney General") request for an extension of time to file initial and reply comments. Accordingly, initial comments were due on June 15, 2015 and reply comments were due on July 6, 2015.

The Department received initial and reply comments from various individuals, customer groups, governmental entities, environmental organizations, EDCs, consumer interest groups, and interested industry entities. See Appendix B for list of individuals and stakeholders who filed initial and reply comments. The Department appreciates the thorough and thoughtful comments the participants submitted.[2]

In this Order, the Department determines its legal authority to review and approve contracts filed by EDCs for pipeline capacity, establishes a standard of review for such contracts, and sets forth filing requirements.

## II. DOER PROPOSAL

In its Petition, DOER highlights industry stakeholders' widespread conclusion that high winter electricity costs in Massachusetts are attributable to natural gas capacity constraints

[2] The Department has given all comments relating to the DOER Petition and associated issues full consideration even though not all comments are specifically addressed herein.

(Petition at 1). DOER asserts that new, creative solutions are needed to reduce natural gas capacity congestion and to make sufficient pipeline capacity available for electricity generation during peak demand periods (Petition at 1).[3] DOER further asserts that gains from additional natural gas capacity can reduce ratepayer costs, diversify the energy mix, and secure electric system reliability (Petition at 3).

DOER states that local gas distribution companies ("LDCs") contract for gas capacity to serve their customers and that the LDCs receive assurance of cost recovery in regulated rates for those contracts (Petition at 3). DOER explains that electricity generators with gas-fired power plants sell their output into a wholesale power market that is not price regulated and are unwilling or unable to commit to long-term gas capacity contracts to secure firm gas supply, because the generators cannot be reasonably assured of cost recovery (Petition at 3). Thus, DOER asserts that the LDCs' customers do not experience market volatility and higher winter prices as severely as electric distribution customers (Petition at 3).[4] For example, DOER cites to the 60 percent to 96 percent increase in electric basic service rates during the winter of 2014-2015, when compared to the prior year period, due to constraints on gas capacity, thereby increasing forward prices for natural gas and electricity (Petition at 3). Moreover, DOER claims that despite the increasing demand for natural gas for heating and

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[3] DOER cites several recent studies to support the view that New England needs additional natural gas capacity to reduce regional gas prices (Petition at 2, n.1).

[4] Power to serve retail electric customers is procured through the wholesale power market. Generally, changes in wholesale electricity prices are reflected in retail electricity prices.

fuel for electric power generation in Massachusetts and New England,[5] gas pipeline companies are not willing to build new gas capacity without long-term contractual agreements for the new capacity (Petition at 3-4). DOER argues that the absence of long-term contracts needed to stimulate necessary gas pipeline expansion and the unwillingness of gas-fired generators to supply those contracts are the problem (Petition at 4).

To address this problem, DOER proposes that the Department consider authorizing EDCs to contract for new natural gas capacity, enabling gas-fired electric generators to secure firm capacity and thereby serving the electric generation needs of the EDCs' customers (Petition at 4-5). According to DOER, the EDCs would seek Department approval of such contracts pursuant to Section 94A (Petition at 4). DOER maintains that the EDCs will have the burden of proof to demonstrate that such contracts meet the Department's standard of review, which requires that the contracts are consistent with the public interest, and provide a benefit to ratepayers (Petition at 4). According to DOER, such contracts will be consistent with the public interest if the economic and other measurable benefits[6] are materially higher than the underlying costs (Petition at 5). DOER suggests that the Department determine the application of the public interest standard to any filed contract (Petition at 5).

DOER argues that pre-approval under Section 94A is the appropriate regulatory vehicle for EDCs to obtain assurance that the costs of any contractual arrangement will be included in

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5 Refer to Section III for a discussion of market conditions.

6 DOER suggests that benefits could include reduced electric rate volatility, lower overall winter electric prices, and enhanced system reliability, as well as the revenue from capacity sales into the market (Petition at 5).

electric distribution rates (Petition at 4). DOER proposes that the EDCs will reconcile the net annual cost or savings of such contracts through electric distribution rates (Petition at 5).

DOER concludes by requesting that the Department investigate the means by which the EDCs can contract for gas capacity to the benefit of electric ratepayers, including a determination of the Department's authority pursuant to Section 94A to review and approve such contracts (Petition at 5).

## III. MARKET CONDITIONS

### A. Summary of Comments

#### 1. DOER

DOER argues that natural gas capacity constraints result in scarcity driven gas price spikes and corresponding electricity price spikes, particularly during seasonal peaking times (DOER Comments at 22). DOER points to the 99 percent positive correlation between regional average monthly gas and electricity prices in the winter months to support its view that electricity prices in the winter of 2013-2014 reached unprecedented high levels as a result of the gas price spikes (DOER Comments at 4, 22; DOER Reply Comments at 3, 15).[7]

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[7] Correlation refers to the degree of relationship between two variables (e.g., in this case, the movement of regional average monthly natural gas prices and regional average monthly electricity prices). The correlation statistic ranges from +1.0 to -1.0, with a value of 0.0 (no correlation) indicating that the relationship in the movement between the two variables is perfectly random, a value of 1.0 (perfect correlation) indicating that the two variables move exactly together, and the sign indicating that the variables move together in the same direction (positive) or in opposite directions (negative). Hence, a correlation of "99 percent" indicates that there is a strong positive relationship in the movement of regional average monthly natural gas and regional average monthly electricity prices.

DOER highlights the price differential for wholesale natural gas prices in New England versus the PJM Interconnection ("PJM")[8] during 2014, noting that the same volume of gas that New England generators used would have cost $600 million less in PJM due to lower gas prices (Petition at 2; DOER Comments at 22). DOER reports that in Pennsylvania, natural gas has averaged $7.21/MMBtu for the last three winters,[9] while in New England the average cost during the same period was $14.04/MMBtu (DOER Reply Comments at 3). Further, DOER claims that both the New York Independent System Operator ("NYISO")[10] and PJM have more adequate gas supplies than New England, and thus have experienced significantly lower electricity prices during the winter months (DOER Reply Comments at 18).

For the winter of 2014-2015, DOER lists three factors that mitigated regional gas capacity deficiency: (1) the implementation of the ISO New England Inc. ("ISO-NE")[11]

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[8] PJM Interconnection is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. See http://www.pjm.com/about-pjm/who-we-are.aspx.

[9] MMBTU is a standard measurement for natural gas. One MMBTU is equal to one million British Thermal Units ("BTU"). One BTU is the amount of heat required to increase the temperature of a pint of water by one degree Fahrenheit.

[10] NYISO coordinates the movement of wholesale electricity in New York State.

[11] ISO-NE is a not-for-profit, private corporation that has responsibility for the management of the New England region's electric bulk power generation and transmission systems and for administering the region's open access transmission tariff, pursuant to approvals granted by the FERC. D.P.U. 12-77, at n.1 (2013).

winter reliability program;[12] (2) low world-wide oil prices; and (3) the availability of a "short supply" of liquefied natural gas ("LNG") (Petition at 2). DOER cautions, however, that these factors do not provide a long-term solution for alleviating the regional gas capacity constraints that it maintains result in escalating electric prices facing New England (Petition at 2).

DOER references a number of studies that indicate the need for additional gas capacity in order to reduce the differential between the wholesale price of natural gas in New England and in neighboring regions (Petition at 2, n.1). DOER also cites ISO-NE support for DOER's assertion that solving natural gas capacity bottlenecks will enable access to lower priced gas from neighboring regions (DOER Comments at 4, 13; DOER Reply Comments at 4). DOER concludes that the Commonwealth should not take a "wait and see" approach to addressing the gas capacity constraints that create gas price volatility, because sufficient access to low-cost gas supply is needed now (DOER Reply Comments at 5).

2. Other Parties

The pipeline companies, EDCs, and several other commenters support DOER's view that the there is a lack of sufficient natural gas infrastructure and constrained pipeline capacity that result in higher electric prices (Spectra Comments at 2, 10; Tennessee Comments at 2, 18; ANGA Comments at 5; CLEC Comments at 2; Eversource Comments at 2; National Grid Comments at 3; Dynegy Comments at 2; MMWEC Comments at 2). Eversource Energy ("Eversource") asserts that reliability concerns and high retail electricity prices will not be

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12 ISO-NE's winter reliability program provides out–of-market payments to generators to ensure reliable winter operations.

alleviated until existing constraints on pipeline capacity are eliminated (Eversource Comments at 2). National Grid reports that typical residential customer electric rates effective November 1, 2014 were almost 50 percent higher than rates for October 2014 and approximately 37 percent higher than rates in effect November 1, 2013 (National Grid Comments at 3). Algonquin Spectra ("Spectra") states that New England increasingly is relying on gas-fired generation as the marginal unit and that natural gas-fired generators typically rely on interruptible and released gas capacity to supply their facilities (Spectra Comments at 10). Spectra notes that, for four to five years, it has operated on essentially a 100 percent load factor through the Southeast, New York and Cromwell, Connecticut compressor stations downstream of the gas generators on its system (Spectra Comments at 8). Spectra asserts that these operating conditions mean that it does not have spare capacity to supply electric generators (Spectra Comments at 8). Spectra also reports that competition for the scarce interruptible pipeline capacity places upward pressure on spot prices for natural gas and the higher natural gas spot market prices result in higher power costs, especially on natural gas pipeline peak days (Spectra Comments at 10).

Tennessee Gas Pipeline ("Tennessee") indicates that it receives requests nearly every day of the year for transportation service to or within New England that greatly exceed its operating capacity (Tennessee Comments at 13). In addition, according to Tennessee, on each day in the winter months, it has to restrict shippers' requested volumes for non-firm service (Tennessee Comments at 13). According to Tennessee, the extent of these restrictions over the past three winters ranges from an average low of approximately 0.7 Bcf/d,[13] to an average high of 1.4 Bcf/d, with sustained periods of significantly greater restrictions (e.g., restricting up to 2.6 Bcf/d of shipper requests during the winter 2014 -2015) (Tennessee Comments at 13). Tennessee states that Massachusetts and New England are experiencing the highest electricity and natural gas prices in the continental United States (Tennessee Comments at 2).

Other commenters disagree with various aspects of DOER's market view. The Conservation Law Foundation ("CLF") asserts that DOER is incorrect in concluding that "high winter electricity costs in Massachusetts are attributable to natural gas capacity constraints" given that wholesale energy markets did not experience the same level of seasonal price increase in 2014-2015 as occurred the prior year (CLF Comments at 2, 9; CLF Reply Comments at 2). Several commenters point out that wholesale electricity prices for 2015 declined in the range of 40-45 percent from the previous year and that prices in the spring of 2015 continued to decrease (CLF Comments at 10; EDF Comments at 17; NEPGA Comments at 24, 25). The Acadia Center cautions that high electricity prices are not necessarily linked to gas constraints, and that it would be reasonable to conclude that high winter prices are attributable to an inadequate supply of any resource that produces electricity or reduces electricity demand (Acadia Center Comments at 2).

With regard to current market conditions, the Attorney General requests that the Department undertake a full and careful analysis of the cause of high winter electricity prices

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13 Bcf is a measurement of natural gas in cubic feet equating to one billion cubic feet. Bcf/d represents one billion cubic feet per day.

and the need for potential solutions (Attorney General Comments at 1). The Attorney General and other commenters argue that the studies DOER cites regarding market conditions are flawed, as they rely in part on flawed price suppression metrics and that the studies fail to adequately explain assumptions and evaluate alternatives (Attorney General Comments at 16-17; NEPGA Comments at 17; Berkshire Photovoltaic Services Comments at 1). Further, both the Attorney General and Repsol note that natural gas price spikes only occur a few dozen days during the winter season (Attorney General Comments at 3; Repsol Comments at 3).

Other commenters observe that the market conditions witnessed in 2013-2014 were exceptional, and emphasize that both the wholesale market and energy policymakers are responding appropriately to address the concerns identified by DOER and others advocating for EDC gas capacity contracts (NEPGA Comments at 24, 25; GDF Suez Comments at 15-20; CLF Comments at 28-29; Acadia Center Comments at 5-7). GDF Suez states that LNG imports in winter 2014-2015 were double those in winter 2013-2014, and that increased LNG imports can mitigate the basis differential and relieve price volatility (GDF Suez Comments at 18). Various commenters note that LNG is being offered into the New England market at prices competitive with domestic gas supply options during cold winter months (Repsol Comments at 4,5; CLF Comments at 20, 23-26; GDF Suez Reply Comments at 13, 14).

B. Analysis

In its Petition, DOER points to industry stakeholders' widespread conclusion that high winter electricity costs in Massachusetts are attributable to pipeline capacity constraints.

DOER asserts that new means are needed to reduce pipeline capacity congestion and to make sufficient gas capacity available for electricity generation during peak demand periods (Petition at 1). Specifically, DOER asks the Department to consider authorizing EDCs to contract for new pipeline capacity and recover the costs through electric distribution rates (Petition at 4). DOER requests that the Department investigate the means by which the EDCs can contract for pipeline capacity to the benefit of electric ratepayers, including the applicability of Section 94A (Petition at 4-5).

DOER premises its Petition on several fundamental assumptions regarding New England's wholesale natural gas and electricity markets: (1) winter regional pipeline capacity constraints have been increasing and are expected to increase further; (2) pipeline capacity constraints have caused recent wholesale gas prices to rise above historical levels; (3) regional wholesale gas and power prices are near perfectly correlated and thus high wholesale gas prices have resulted in high wholesale electricity prices relative to historical levels; and (4) regional power generators lack sufficient financial incentives to contract for new gas capacity. DOER and some commenters point to industry studies and other information as support for DOER's market view and its conclusion that increasing regional gas capacity will lead to lower wholesale gas and electricity prices. Other commenters challenge DOER's market view, its conclusion regarding the need for EDCs to contract for gas capacity to lower regional wholesale electricity prices, and/or the form of gas capacity arrangements that would best accomplish this objective.

On balance, the Department finds that DOER and other parties to this proceeding have provided sufficient information to support DOER's assessment of current New England wholesale market conditions and to arrive at the conclusion that increasing regional gas capacity will lead to lower wholesale gas and electricity prices. While not making a finding in this Order that voices a preference for any particular project for gas pipeline infrastructure development over any other potential capacity constraint solution, the Department finds in this Order that innovative solutions and a menu of options are required to alleviate capacity constraints and the associated downstream market price impact experienced by Massachusetts ratepayers. Therefore, the Department will proceed to evaluate whether it has the requisite authority to approve EDC contracts for acquisition of new natural gas capacity and recover the costs through electric distribution rates, including the applicability of Section 94A. Accordingly, we undertake this evaluation below.

## IV. LEGAL AUTHORITY

### A. Section 94A

#### 1. Introduction

As a threshold matter in its review of the questions posed by DOER in its Petition and in consideration of the questions presented by the Department, the Department must determine whether it has the statutory authority to review and approve contracts entered into by EDCs for pipeline capacity. Section 94A provides, in relevant part, as follows:

> No gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of one year without the approval of the department . . . .

Several commenters argue that the plain language of Section 94A provides the Department with the authority to approve contracts entered into by EDCs for pipeline capacity. Other commenters contend that Section 94A, when interpreted using established canons of statutory construction, and when considered in light of the statute's legislative history, should not be construed as allowing the Department to review and approve such contracts.

Below, the Department (1) summarizes the comments addressing these topics and (2) determines that it has the authority, pursuant to Section 94A, to review and approve EDC gas capacity contracts. On the basis of that review, the Department then takes the opportunity to address other issues commenters raise in this proceeding associated with the Electric Restructuring Act of 1997 (St. 1997, c. 164), federal preemption, what standard of review should be applied, and what filing requirements should be required to warrant further review and approvals.

2. Summary of Comments

a. Commenters in Support of Section 94A As Providing Authority

DOER, the EDCs, and several other commenters argue that the plain language of Section 94A provides the Department with the statutory authority to approve pipeline capacity contracts entered into by EDCs (DOER Comments at 6-7; Eversource Comments at 3-4; National Grid Comments at 10-11).[14] To support this argument, these commenters highlight the first sentence of Section 94A – providing that "[n]o gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity . . . ." (emphasis added) - and argue

[14] Two EDCs filed comments in this matter: Eversource and National Grid.

that the statute plainly permits either gas or electric companies to enter into contracts for the purchase of gas capacity (DOER Comments at 6; Eversource Comments at 3-4; National Grid Comments at 10-11).[15] Several commenters point to the familiar maxim that when statutory language is clear and unambiguous, it must be given its ordinary meaning (see, e.g., Eversource Reply Comments at 15, citing Providence & Worcester R.R. v. Energy Facilities Siting Bd., 453 Mass. 135, 141 (2009); National Grid Reply Comments at 16; Spectra Reply Comments at 9).

A number of commenters also argue that because Section 94A clearly and unambiguously permits the Department to review contracts for the purchase of gas capacity entered into by EDCs, there is no need to consider the statute's legislative history to determine whether the Legislature intended for this to be the case (see, e.g., Tennessee Reply Comments at 16; CLEC Reply Comments at 4; Spectra Comments at 2). For the same reason, several commenters contend that, despite comments raised in opposition, there is no need to refer to or rely upon canons of statutory construction to determine Section 94A's plain meaning (see, e.g., Tennessee Reply Comments at 16-17; ANGA Comments at 2; Spectra Comments at 2).

Finally, several commenters contend that Section 94A must be read in the context of the Department's overarching regulatory authority, as well as the Department's reasoning and

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15 DOER further argues that the words "or" and "and" contained in the first sentence of Section 94A "are generally interchangeable and 'one may be substituted for the other, if consistent with the legislative intent'" (DOER Comments at 6, n.5, quoting Holyoke Water Power Co. v. FERC, 799 F. 2d 755, 761 (1986)). According to DOER, substituting the word "and" for "or" reinforces the fact that an EDC can enter into a gas contract, if approved by the Department (DOER Reply Comments at 11).

justification for taking action to approve EDC contracts (see, e.g., Eversource Reply Comments at 11; National Grid Reply Comments at 12-13).[16] Specifically, these commenters cite to the Department's broad authority to: (1) supervise all gas and electric companies, pursuant to G.L. c. 164, §§ 76, 94, 94A; (2) allow cost recovery of EDC contracts where it is consistent with the public interest to do so, pursuant to G.L. c. 164, § 94 and Section 94A; and (3) take steps to ensure a necessary energy supply at a reasonable cost, pursuant to G.L. c. 164, § 69*I* (Eversource Reply Comments at 12-13; National Grid Reply Comments at 12-14; DOER Reply Comments at 6-7).

b. Commenters in Opposition to Section 94A As Providing Authority

Conversely, a number of other commenters argue that Section 94A does not provide the Department with legal authority to authorize EDCs to contract for natural gas capacity (see, e.g., Attorney General Comments at 21; CLF Comments at 4-5; GDF Suez Comments at 3; NEPGA Comments at 4). In support of their position, these commenters rely upon: (1) canons of statutory construction; and (2) Section 94A's legislative history (Attorney General Comments at 21-23; CLF Comments at 4-5; GDF Suez Comments at 3-5; NEPGA Comments at 4-5).

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16 DOER and other commenters suggest that if Section 94A did not exist, there are other means by which an EDC could seek Department approval of pipeline capacity contracts (e.g., pursuant G.L. c. 164, § 76, the Department's general supervisory authority over EDCs; under G.L. c. 164, §§ 93, 94, the Department's authority to set rates) (DOER Reply Comments at 10). For the reasons stated below and based on the findings in this Order, the Department need not address those other means here.

The Attorney General, GDF Suez, and several other commenters contend that Section 94A should be interpreted using the statutory construction maxim reddenda singula singulis, which provides that "[w]here a sentence contains several antecedents and several consequents they are to be read distributively . . . [and] . . . [t]he words are to be applied to the subjects that seem most properly related by context and applicability" (GDF Suez Comments at 4, quoting Sutherland Statutory Construction § 47:25; Attorney General Comments at 22, citing Commonwealth v. Barber, 143 Mass. 560, 562 (1887); 2A Sutherland Statutory Construction § 47.26 (7th ed.)). GDF Suez argues that "[a]pplied here, the parallel uses of the word 'or' in the first sentence of Section 94A can only be read in a manner that authorizes the DPU to approve electric company contracts for the purchase of electricity, and gas company contracts for the purchase of gas" (GDF Suez Comments at 4). GDF Suez and other commenters contend that the Department "cannot mix and match among the antecedents and consequents in this clause of Section 94A" (GDF Suez Comments at 4; Attorney General Comments at 22).

A number of commenters also argue that Section 94A's legislative history demonstrates that the Legislature did not intend to permit the Department to review and approve EDC gas capacity contracts (see, e.g., Attorney General Comments at 22; Compact Comments at 9; GDF Suez Comments at 4-5). Several commenters note that when Section 94A was originally enacted, the statute addressed only the purchase of electricity by electric companies and made no reference to gas companies or gas contracts (see, e.g., GDF Suez Comments at 4-5, citing St. 1926, c. 298; NEPGA Comments at 4-6; Attorney General Comments at 22). Although the Legislature later amended Section 94A to include, inter alia, references to gas companies and gas contracts, GDF Suez notes that '[t]he Supreme Judicial Court has held that when interpreting an amended statute, the 'provisions of [an] amendatory act [are] to be considered together with the provision of [the] original act.'" (GDF Suez Comments at 4-5, quoting Foster v. Group Health Inc., 444 Mass. 668, 673-674 (2005)).

3. Analysis and Findings

a. Introduction

It is axiomatic that in order to define the scope of our authority under Section 94A, we must first consider the plain language of the statute. When interpreting a statute, the "statutory language should be given effect consistent with its plain meaning and in light of the aim of the Legislature unless to do so would achieve an illogical result." Welch v. Sudbury Youth Soccer Assoc., Inc., 453 Mass. 352, 354-355 (2009), quoting Sullivan v. Brookline, 435 Mass. 353, 360 (2001). The Supreme Judicial Court has also stated:

> None of the words of a statute is to be regarded as superfluous, but each is to be given its ordinary meaning without overemphasizing its effect upon the other terms appearing in the statute, so that the enactment considered as a whole shall constitute a consistent and harmonious statutory provision capable of effectuating the presumed intention of the Legislature.

Bolster v. Commissioner of Corps. and Taxation, 319 Mass. 81, 84-85 (1946); see also International Org. of Masters, Mates and Pilots, Atlantic and Gulf Maritime Region, AFL-CIO v. Woods Hole, Martha's Vineyard and Nantucket S.S. Authority, 392 Mass. 811, 813 (1984). Where ambiguities exist, the Court will interpret a statute:

> according to the intent of the Legislature ascertained from all its words construed by the ordinary and approved usage of the language, considered in

> connection with the cause of its enactment, the mischief or imperfection to be remedied and the main object to be accomplished, to the end that the purpose of its framers may be effectuated.

Commonwealth v. Welch, 444 Mass. 80, 85 (2005), quoting Commonwealth v. Galvin, 388 Mass. 326,328 (1983), quoting Board of Education v. Assessor of Worcester, 368 Mass. 511, 513 (1975); see also Sperounes v. Farese, 449 Mass. 800, 804 (2007), quoting Hanlon v. Rollins, 286 Mass. 444, 447 (1934).

Therefore, in our review in this Order, the Department must first look to the plain language of the statute itself to determine if the intent can be ascertained from all its words construed by the ordinary and approved usage of the language. The Department's statutory review is detailed below.

b. The Department's Authority To Review Contracts Under Section 94A

Section 94A authorizes the Department to review and approve contracts for "the purchase of gas or electricity" by "gas or electric companies." Specifically, Section 94A provides, in relevant part, as follows:

> No gas or electric company shall hereafter enter into a contract for the purchase of gas or electricity covering a period in excess of one year without the approval of the department . . . . (emphasis added)

As some commenters have noted, Section 94A, in its original form, did not mention gas companies or the purchase of gas capacity. See St. 1926, c. 298 ("No electric company shall hereafter enter into a contract for the purchase of electricity covering a period in excess of three years without the approval of the department . . . ."). The Legislature later amended

Section 94A to add, inter alia, language regarding gas. See St. 1930, c. 342 (adding gas companies and gas contracts to first sentence of statute).

"[A] statute is to be construed as written, in keeping with its plain meaning." eVineyard Retail Sales-Mass., Inc. v. Alcoholic Beverages Control Comm'n, 450 Mass. 825, 831 (2008). In this instance, the plain language of Section 94A provides the Department with its authority to review and approve "the purchase of gas or electricity" by "gas or electric companies." The use of the word "or" here is used to list the entities (gas and electric companies) and the products (gas and electric purchases) and does not limit one type of company or one type of product. Consistent with the overall structure of Chapter 164, the Legislature provides the Department with authority over both electric and gas distribution companies, and without direct limiting language. Accordingly, taken in the context of the words in their ordinary and approved usage, we find that the plain language of Section 94A provides the Department with the statutory authority to approve gas capacity contracts entered into by EDCs. Contrary to arguments raised by the Attorney General, GDF Suez, and others, the words of the statute are clear as to their plain meaning in the statute itself. As such, there is no need for the Department to consider the legislative history or doctrines of statutory construction to derive the meaning of the statute.

To the extent that commenters argue that the Department lacks authority to approve such contracts, commenters rely on inapplicable canons of statutory construction and strained assumptions from Section 94's legislative history. For example, the Attorney General, GDF Suez, and others rely on the canon of statutory construction known as reddenda singula singulis. But this canon of statutory construction is used in circumstances where textual construction would not make sense if the words of the statute were construed literally. This is not the case here. Additionally, to the extent commenters argue that the Legislature did not intend to alter or expand the meaning of Section 94A when it amended the statute to cover gas companies and gas contracts, these commenters overlook the fact that the very point of the amendment was to expand the scope of the Department's authority. In any event, where the statutory language is clear and unambiguous, as is the case for Section 94A, we need not consider extrinsic information to ascertain the Legislature's intent, as the intent is clear from the words of the statute. See Pyle v. School Committee of South Hadley, 423 Mass. 283, 285-286 (1996) ("Where the language of a statute is clear and unambiguous, it is conclusive as to legislative intent."), citing Boston Neighborhood Taxi Ass'n v. Department of Pub. Utils., 410 Mass. 686, 690 (1991); Bronstein v. Prudential Ins. Co., 390 Mass. 701, 704 (1984) ("When the use of the ordinary meaning of a term yields a workable result, there is no need to resort to extrinsic aids such as legislative history").

The Supreme Judicial Court has long recognized that the broad delegation of authority to the Department by the Legislature vests the Department with significant discretion to construe its enabling statutes. For example, the Court has found that where Chapter 164 does not define certain terms, "[t]he task of [statutory] interpretation is thus left to the discretionary authority and expertise of the department." City of Cambridge v. Department of Telecomm. & Energy, 449 Mass. 868, 875 (2007). The Court has elaborated that "[w]here, as here, the case involves interpretation of a complex statutory and regulatory framework, '[w]e give great deference to the department's expertise in areas where the Legislature has delegated its decision making authority.'" City of Cambridge, 449 Mass. at 875, quoting MCI Telecomm. Corp. v. Department of Telecomm. & Energy, 435 Mass. 144, 150-151 (2001), quoting Stow Mun. Elec. Dept. v. Department of Pub. Utils., 426 Mass. 341, 344 (1997). Most significantly, the Court has consistently held that "[a]n agency's interpretation of its own regulation and statutory mandate will be disturbed only if the interpretation is patently wrong, unreasonable, arbitrary, whimsical or capricious." Box Pond Ass'n v. Energy Facilities Siting Bd., 435 Mass. 408, 416 (2001) (internal quotation marks omitted). As such, our interpretation here in this regard is appropriate and well within the discretionary authority and expertise of the Department. In sum, the plain language of Section 94A provides the Department with the statutory authority to approve gas capacity contracts entered into by EDCs. Because Section 94A is clear and unambiguous, there is neither the need for, nor legal justification to require, further analysis of the statute's legislative history or interpretation of the statute using canons of statutory construction. As such, the Department in the sections below will address the other issues raised by commenters in this proceeding, chiefly those associated with the Electric Restructuring Act of 1997 (St. 1997, c. 164), federal preemption, the standard of review, and filing requirements for further review and approvals.

### B. Restructuring Act

#### 1. Introduction

The Electric Restructuring Act of 1997 (St. 1997, c. 164)[17] ("Restructuring Act"), restructured the electric industry in the Commonwealth by providing incentives to investor-owned EDCs to divest their generating assets and by adopting a competitive market structure for the purchase of electricity. In order to provide "affordable service" to all consumers, the Restructuring Act removed the generation of electricity from state regulation and set the purchase of electricity in a competitive market, while leaving the distribution and transmission systems of the EDCs subject to public regulation. See St. 1997, c. 164 § 193; G.L. c. 164, § 1A(a)(e).

Several commenters maintain that the DOER Proposal is inconsistent with the policies and provisions of the Restructuring Act (see, e.g., Attorney General Comments at 18-21; CLF Comments at 5; GDF Suez Comments at 6; NEPGA Comments at 6). Other commenters, however, respond that the DOER Proposal is, in fact, consistent with the Restructuring Act, and that, in the general paradigm DOER presents, no obligations would be imposed on wholesale market participants (see, e.g., DOER Reply Comments at 8-9; Eversource Reply Comments at 10; Tennessee Reply Comments at 19-20). The Department addresses this issue below.

[17] "An Act Relative To Restructuring The Electric Utility Industry In The Commonwealth, Regulating The Provision Of Electricity And Other Services, And Promoting Enhanced Consumer Protections Therein."

2. Summary of Comments

A number of commenters argue that allowing EDCs to enter into long-term contracts for natural gas capacity would violate the general purpose of the Restructuring Act. These commenters argue that the primary purpose of the Restructuring Act was to remove EDCs from the business of owning generation facilities, producing electricity, and buying fuel to produce electricity (see, e.g., Attorney General Comments at 18-19; GDF Suez Comments at 6; NEPGA Comments at 6; CLF Comments at 5). The Attorney General and others also argue that the Restructuring Act limits the Department's authority in regulating generation-related activities and shifts the risks of generation development from consumers to generators (Attorney General Comments at 19, citing Investigation by the Department of Public Utilities on its own motion into the need for additional capacity in NEMA/Boston within the next ten years, pursuant to Chapter 209, Section 40 of the Acts of 2012 and pursuant to G.L. c. 164, § 76, D.P.U. 12-77, at 30 (2013);[18] see also GDF Suez Comments at 7-8; NEPGA Comments at 9-10).

Several commenters maintain that approving the DOER Proposal is a reversal of established state policy that would expose ratepayers to another round of stranded costs as well as would produce unfair and anti-competitive distortions in the wholesale market (see, e.g.,

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18 As part of "An Act Relative to Competitively Priced Electricity in the Commonwealth," the Legislature directed the Department to "open a docket to investigate the need for additional [electric generating] capacity in the [Northeastern Massachusetts and Greater Boston ("NEMA/Boston")] region within the next 10 years." St. 2012, c. 209, § 40. On October 1, 2012, the Department issued an Order opening docket D.P.U. 12-77 for that purpose.

NEPGA Comments at 6; GDF Suez Comments at 7; CLF Comments at 5). Further, the Cape Light Compact ("Compact") argues that absent specific legislative authorization, the Department should not allow EDCs to enter into long-term pipeline capacity contracts in a restructured electric market (Compact Comments at 8).

In contrast, DOER, the EDCs, the gas pipelines, and others argue that allowing the DOER Proposal neither implicates nor violates the policies and provisions of the Restructuring Act (DOER Reply Comments at 8-9; National Grid Reply Comments at 18-19; Eversource Reply Comments at 10; Tennessee Reply Comments at 19-20). A number of commenters contend that in entering into long-term gas capacity contracts, the EDCs would not own, operate or control generation facilities or dictate the prices generators are bidding into the market in contravention of the Restructuring Act (DOER Reply Comments at 8-9; National Grid Reply Comments at 19; Eversource Reply Comments at 10).

Tennessee asserts that while the Restructuring Act required the EDCs to divest their non-nuclear generation assets, it did not remove either the EDCs' obligation to provide ratepayers reliable and least-cost service or the Department's oversight of that obligation (Tennessee Reply Comments at 19). Tennessee maintains that it is appropriate for EDCs, consistent with their obligation to provide least-cost service, to enter into long-term gas capacity contracts to lower or moderate ratepayer electricity costs, and for the Department to approve any such contract it finds is consistent with the public interest (Tennessee Reply Comments at 19).

In response to those commenters who assert that approving the DOER Proposal would be contrary to Department precedent in a post-Restructuring Act market, Tennessee notes that the Department has implemented a number of policy changes and associated ratemaking mechanisms for both gas and electric companies that could affect wholesale market prices (Tennessee Reply Comments at 19). For example, Tennessee states that the Department investigated and adopted ratemaking principles to "enhance the price-responsiveness of wholesale electricity markets" and to "moderate some of the impact of electricity and gas commodity price levels" in its decoupling ratemaking proceeding (Tennessee Reply Comments at 19, citing Revenue Decoupling, D.P.U. 07-50, at 1-2 (2007)). Tennessee contends it is "entirely appropriate" in this instance for the Department to review and approve EDC contracts for natural gas capacity in order to lower customer costs, if the Department finds such contracts are consistent with the public interest (Tennessee Reply Comments at 19).

DOER, the EDCs, and others argue that by increasing the availability of pipeline capacity to relieve pipeline constraints, and thereby improving reliability and decreasing price risk, DOER's proposal does not violate the Restructuring Act (DOER Comments at 3; DOER Reply Comments at 8-9; Eversource Reply Comments at 10-11; National Grid Reply Comments at 17-19; Tennessee Reply Comments at 19). Further, the EDCs contend that the DOER Proposal, as presented, will not cause EDCs to become engaged in producing, manufacturing, or generating electricity for sale at wholesale. Rather, proponents contend that the DOER Proposal affords the EDCs the opportunity to purchase gas capacity, not the actual commodity, which will then create the financial incentives needed to encourage additional resources into the market that wholesale generators may or may not choose to purchase (Eversource Reply Comments at 10; National Grid Reply Comments at 18-19)

3. Analysis and Findings

In this Order, the Department has found that, on balance, increasing regional pipeline capacity will lead to lower gas and electric prices for Massachusetts ratepayers. Further, the Department has determined that it has the authority under Section 94A to review and approve a long-term contract for natural gas capacity filed by an EDC. In addition, for the reasons stated below, the Department finds that comments in opposition to DOER's proposal overstate what that proposal is attempting to accomplish, and, in the construct proposed by DOER and the framework established by the Department, the Restructuring Act does not present an impediment to EDCs' contracting for natural gas capacity subject to Department review and approval.

By way of background, the Department is in complete agreement with commenters that the Restructuring Act was implemented to introduce competition in the retail electricity market with the overriding policy of providing affordable electric service to all Massachusetts consumers under reasonable terms and conditions. St. 1997, c. 164, § 1(b). Pursuant to the DOER Proposal, electric generators and others would have the option to acquire new incremental pipeline capacity from the EDCs, under oversight by the Federal Energy Regulatory Commission ("FERC"). Under this construct, ownership of generation facilities would remain with the merchant generators, and would not be shifted to the control of the EDCs. Further, as noted by several of the commenters, an EDC gas capacity contract under this framework will simply put a resource into the market that could operate to mitigate higher peak-period price electric prices. Nothing is being required of the generators, nor is there any direct intervention into the wholesale market by the EDCs. Wholesale generators will be free to purchase pipeline capacity from the market, and, in fact, if EDC gas capacity contracts are found needed and warranting Department approval in future filings, wholesale generators will have the opportunity to take advantage of this pipeline capacity. This opportunity would afford generators additional supply options in the marketplace, with the intended result of lower energy prices. Accordingly, the Department finds that the DOER Proposal and the framework established by the Department would not result in the EDCs' reentry to producing, manufacturing or generating electricity for sale at wholesale, as contemplated by the Restructuring Act. See St. 1997, c.164, § 193.

With respect to the comments from the Attorney General and others that rely upon the Department's ruling in D.P.U. 12-77 as grounds to state that the Department's actions here are somehow inconsistent with precedent, the Department's decision in that Order does not contradict our actions here. The Department's investigation in D.P.U. 12-77 was based on a specific directive of the Legislature into the electricity generation capacity needs of a particular capacity zone in Massachusetts: NEMA/Boston.[19] As a result of its investigation, the

[19] At the time of the Department's Order in D.P.U. 12-77, there were four capacity zones in New England: Connecticut, NEMA/Boston, Maine, and Rest of Pool. D.P.U. 12-77, at 5 (2013). Since that time, for the ninth Forward Capacity Market auction, the region was divided into four zones: Connecticut (CT); Northeast Massachusetts/Greater Boston (NEMA/Boston); Rest of Pool (ROP); and a new zone, Southeast Massachusetts/Rhode Island (SEMA/RI). The ROP zone includes western and central Massachusetts, Vermont, New Hampshire, and Maine. The CT, NEMA/Boston and

Department found a need for additional electric generating capacity in NEMA/Boston taking specific account, as required by the Legislature, the assessment of the capacity market in ISO-NE. D.P.U. 12-77, at 16-17. Regarding the issue of directing EDCs to solicit proposals for long-term generation resource contracts to meet this need, the Department declined, inter alia, to mandate the EDCs to solicit and enter into capacity generation contracts for the NEMA/Boston region. D.P.U. 12-77, at 29-31. The Department's actions by this instant Order are not inconsistent with our decision in D.P.U. 12-77. Consistent with the Department's decision in D.P.U. 12-77 not to mandate generation resource acquisition, by this Order the Department does not mandate that EDCs acquire pipeline capacity. Rather, the Department has established a framework for EDCs to enter into pipeline capacity contracts, subject to Department review and approval.

Furthermore, despite the efforts by some commenters to characterize it as such, the potential that an outcome of a Department action may have implications in the wholesale electricity market does not by itself render the action inconsistent with the Restructuring Act. Since the implementation of the Restructuring Act, the Department has initiated several investigations that have implications for wholesale electricity markets. See, e.g. Order Opening Investigation into Initiatives to Improve the Retail Electric Competitive Supply Market, D.P.U. 14-140 (2014); D.P.U. 07-50. The Department's review in this proceeding is

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SEMA/RI zones were created based on transmission limitations that restrict the level of power that can be imported into each area, as well as local resource levels and needs. See, http://www.iso-ne.com/static-assets/documents/2015/02/fca9_initialresults_final_02042015.pdf.

not inconsistent with its authority to undertake those previous reviews. In the instant case, the Department finds that establishing the framework set forth herein enables the Department to investigate the option of EDCs' entering into long-term pipeline capacity contracts as a means to moderate the recent volatility of retail electricity prices in Massachusetts and the region. Pertinent to our decision here is the Department's role pursuant to statute and precedent as the state entity responsible for the oversight of investor-owned electric companies and natural gas companies in the Commonwealth, and responsible for developing alternatives to traditional regulation and ensuring that utility consumers are provided with the most reliable service at the lowest possible cost. Based on this authority, the Department's review and conclusions regarding the applicability of the Restructuring Act to this proceeding are appropriate.

For the reasons stated above, the Department finds that an EDC contract for pipeline capacity would be consistent with the Restructuring Act if an EDC is able to demonstrate that entering into a contract would result in cost savings for EDC ratepayers and otherwise satisfies the standard of review for approving EDC gas capacity contracts set forth in Section V. C, below. Therefore, the Department finds that our actions by this Order do not violate the policies and provisions of the Restructuring Act.

C. Federal Preemption

1. Introduction

Pursuant to the Supremacy Clause of the United States Constitution,[20] federal preemption operates to invalidate any state action in a field of regulation that Congress intended the federal government to occupy exclusive jurisdiction or where a court determines that state action operates as an obstacle to achieving the objectives of the federal government. See, e.g., Crosby v. National Foreign Trade Council, 530 U.S. 363, 372 (2000) (even in the absence of an express preemption provision, however, state law is preempted "[w]hen Congress intends federal law to 'occupy the field'" or "to the extent of any conflict with a federal statute.") (citations omitted). Numerous commenters assert that the DOER Proposal for EDCs to purchase natural gas capacity is inconsistent with federal law and may be preempted by one of the following: (1) the Natural Gas Act, 15 U.S.C. § 717 et seq. ("Natural Gas Act") (see, e.g., CLF Comments at 6-7; Acadia Center Comments at 2); (2) the dormant Commerce Clause doctrine (see, e.g., Acadia Comments at 4; CLF Comments at 6-7);[21] and (3) the Federal Power Act, 16 U.S.C. § 824 et seq. ("Federal Power Act") (see, e.g., GDF Suez Comments at 12-15). The Department addresses each of these below.

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[20] U.S. CONST. art. VI, cl. 2.

[21] "The Congress shall have power . . . [t]o regulate Commerce with foreign Nations, and among the several Sates, and with Indian Tribes . . . ." U.S. CONST. art. I, § 8, cl. 3.

2. Natural Gas Act

a. Summary of Comments

Several commenters maintain that the DOER proposal to allow EDCs to contract for natural gas capacity may be preempted by the Natural Gas Act as an impermissible intrusion into the wholesale natural gas capacity release market that is within FERC's exclusive domain (see, e.g., CLF Comments at 6-7; Acadia Comments at 3-4; GDF Suez Reply Comments at 7; Compact Reply Comments at 3). NEPGA asserts that the Natural Gas Act and FERC regulations prohibit the EDCs and interstate pipeline companies from reserving pipeline capacity for the exclusive use of Massachusetts ratepayers (NEPGA Comments at 13). DOER also states that it is unclear how FERC would view any targeted offering of services involving interstate pipelines (DOER Comments at 28).

Eversource and National Grid argue that with no specific contract proposal before the Department, it is premature for the Department to determine that the DOER Proposal is preempted by federal regulation under the Natural Gas Act (Eversource Reply Comments at 20; National Grid Reply Comments at 6-8). Eversource, National Grid, and Tennessee also maintain that there are ways to structure a contract that would be compatible with FERC regulations, and the EDCs note that FERC has invited requests for waiver of its capacity release regulations (Eversource Reply Comments at 18-19; National Grid Reply Comments at 6-7; Tennessee Reply Comments at 11).

b. Analysis and Findings

In this Order, the Department has determined that it has authority under Section 94A to review and approve a long-term contract for natural gas capacity filed by an EDC. In establishing that authority and in setting the standard of review and filing requirements herein, the Department is not regulating (1) transportation of natural gas in interstate commerce, (2) the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial or any other use, or (3) natural gas companies so engaged, which are the purposes of the Natural Gas Act. 15 U.S.C. § 717(b). Therefore, the Department finds that our actions by this Order do not violate the Natural Gas Act.

3. Dormant Commerce Clause

a. Summary of Comments

The dormant Commerce Clause doctrine refers to the prohibition that is implied in the Commerce Clause of the U.S. Constitution that bars states from implementing policy or legislation that discriminates against or unduly burdens interstate commerce. See, e.g., Public Utilities Commission of Rhode Island. v. Attleboro Steam & Electric Company, 273 U.S. 83 (1927). Acadia and CLF raise concerns that any prospective state action, i.e., legislation that may be taken to restrict the DOER Proposal to intrastate markets would violate the dormant Commerce Clause of the U.S. Constitution (CLF Comments at 7; Acadia Center Comments at 4).

National Grid and Eversource maintain that the DOER Proposal can be implemented in a manner that does not raise preemption concerns triggered by the dormant Commerce Clause

(National Grid Reply Comments at 8; Eversource Reply Comments at 20). National Grid and Eversource contend that no aspect of the DOER's Proposal suggests that an EDC contract to procure pipeline capacity would benefit in-state economic interests by burdening out-of-state competitors (National Grid Reply Comments at 8; Eversource Reply Comments at 21). National Grid also notes that the DOER Proposal, in fact, seeks solutions to obtain new pipeline capacity that would benefit electric ratepayers in the region (National Grid Reply Comments at 8). National Grid concludes that, at most, the Acadia and CLF comments could be useful in the event that an EDC submits a proposal with terms that differ from the parameters set forth in the DOER proposal (National Grid Reply Comments at 8).

b. Analysis and Findings

In this Order, the Department has determined that it has authority under Section 94A to review and approve a long-term contract for natural gas capacity filed by an EDC. For the reasons stated above, this determination does not discriminate against out-of-state interests or unduly burden the free flow of commerce among the states or otherwise regulate interstate commerce. Therefore, the Department finds that our actions by this Order do not violate the Commerce Clause or the dormant Commerce Clause doctrine.

4. Federal Power Act

a. Summary of Comments

GDF Suez, CLF and others state that Congress has granted FERC exclusive jurisdiction over wholesale electric markets, and that any state action with a direct effect on wholesale energy price is preempted by the Federal Power Act (see, e.g., GDF Suez Comments at 12-15;

CLF Comments at 3, 6-7; NEMA Comments at 5). GDF Suez asserts that there is a significant likelihood that the DOER Proposal would result in intervention in the wholesale electricity market that is preempted by the Federal Power Act (GDF Suez Comments at 12, citing PPL Energyplus, LLC v. Nazarian, 753 F.3d 476 (4th Circ. 2014) ("Nazarian") and PPL Energyplus, LLC v. Solomon. 766 F.3d 241, 253 (3d Cir. 2014) ("Solomon")).

DOER, Eversource, and National Grid assert that the cases that GDF Suez relies upon fail to support its contention that the DOER Proposal is preempted by the Federal Power Act (DOER Reply Comments at 12-14; Eversource Reply Comments at 21-24; National Grid Reply Comments at 9-12). Specifically, these commenters argue that unlike the Nazarian and Solomon cases, where the federal appeals courts found that the Maryland and New Jersey programs set a price level for a generator's participation in the wholesale market, an EDC contract for pipeline capacity would not set rates or compensation levels a generator may receive for energy or capacity at wholesale (DOER Reply Comments at 12-14; Eversource Reply Comments at 22-23; National Grid Reply Comments at 11). DOER further asserts that by permitting EDCs to enter into contracts for gas capacity, the Department is not intervening in the wholesale electricity market as certain commenters suggest (DOER Reply Comments at 13).

Eversource asserts that the fact that the availability of incremental pipeline capacity could have an indirect effect on wholesale rates by increasing the ability of generators to acquire additional pipeline capacity is insufficient to invoke federal preemption (Eversource Reply Comments at 22-23). Therefore, Eversource contends that the impact on any wholesale energy market of an EDC contract to acquire pipeline capacity appears to be indirect and a legally permissible method of effectuating state policy without setting the wholesale price of energy (Eversource Reply Comments at 24).

b. Analysis and Findings

In this Order, the Department has determined that it has authority under Section 94A to review and approve a long-term contract for natural gas capacity filed by an EDC. As such, the Department is not regulating interstate electricity transmission or wholesale power sales, areas of federal regulation under the Federal Power Act. 16 U.S.C. § 824(b)(1). Therefore, the Department finds that our actions by this Order do not violate the Federal Power Act.

5. Conclusion

Electric and gas utilities and their operations are subject to regulation at both the federal and state level. In exercising its authority over EDCs and LDCs, the Department operates under this cooperative regulatory model.

Based on the DOER Proposal, the Department has established a framework for Massachusetts EDCs to procure new pipeline capacity to benefit electric ratepayers in Massachusetts. Pursuant to this Order, an EDC may file such a contract with details on the proposed transaction and the terms and conditions of the contract. At that time, depending on the specific details and terms, it may be necessary to consider the preemption issues and/or the federal statutory issues raised in this proceeding. It remains the burden of any petitioner submitting a pipeline capacity contract for Department review pursuant to Section 94A to structure a proposed contract that would overcome any federal preemption. Absent an actual proposed contract that sets forth the rights and obligations of the signatories, it is premature for the Department to determine or to speculate whether the terms of any such contract would be inconsistent with federal laws and regulation and subject to federal preemption.

As stated above, the Department does not voice a preference for any particular project, nor for gas pipeline infrastructure development over any other potential capacity constraint solution. Rather, the Department finds in this Order that innovative solutions and a menu of options are required to alleviate capacity constraints and the associated downstream market price impact experienced by Massachusetts ratepayers.

## V. STANDARD OF REVIEW AND FILING REQUIREMENTS

### A. Introduction

Having determined through the Department's review of Section 94A and the Restructuring Act that the plain language of the statute supports the ability of EDCs to enter into long-term contracts to procure needed gas capacity, subject to Department review and approval, the question then becomes what level of review for these contracts is warranted to ensure that the resulting resource is, reliable, and least cost for ratepayers. The Department addresses this question in this section by: (1) summarizing the comments on the appropriate standard of review to evaluate an EDC's contract for pipeline capacity filed pursuant to Section 94A; (2) setting forth the Department's standard of review; and (3) establishing filing requirements for any such proposed contract.

B. Summary of Comments

1. DOER

DOER contends that the Department should apply the same public interest standard that it applies to the review of gas contracts filed by LDCs with the Department for approval under Section 94A (DOER Petition at 4). DOER asserts that the Department has discretion to apply the public interest standard as it deems appropriate, and recommends that the Department, in applying the standard to EDCs, require EDCs to show: (1) the need for additional pipeline capacity; (2) that the proposed contract is the best of reasonably available alternatives, based on an evaluation of price and non-price factors; (3) that the pipeline capacity contracted is sufficient to meet the need; and (4) that there is a material net benefit to electric customers (DOER Petition at 5).

DOER maintains that for an EDC gas contract to satisfy the public interest standard, the contracted resource must (1) compare favorably to the range of alternative options reasonably available in the regional wholesale electric market, and (2) be consistent with an EDC's resource objectives as described in a filing accompanying the proposed contract (DOER Comments at 10). DOER states that the range of alternative options reasonably available to an EDC may include gas pipeline construction, import LNG, energy efficiency initiatives, and ISO-NE's Pay for Performance ("PFP")[22] and winter reliability programs (DOER Comments

[22] ISO-NE's PFP links electricity capacity payments to actual generator performance, thus providing an incentive to generators to undertake investments to ensure that they can perform when the power grid is stressed. See ISO Newswire: http://isonewswire.com/updates/2014/1/22/spi-news-iso-ne-submits-proposal-to-strengthen-performance-i.html

at 13). DOER maintains that the Department's assessment of alternatives should include both price and non-price factors (DOER Comments at 13). DOER recommends that an EDC must demonstrate that the new gas capacity will reduce regional electricity prices and that the dollar benefits for an EDC's ratepayers, including both the revenue generated from release of gas capacity and the impact the capacity has on price spikes driven by regional gas capacity constraints, will substantially exceed the cost of the gas capacity (DOER Comments at 13-15). DOER suggests that non-price factors could include electric grid reliability, greenhouse gas reduction, or other environmental benefits (DOER Comments at 13).

Regarding an EDC's resource objectives, DOER asserts that an EDC has an obligation to take any action within its control, as allowed by statute, to maintain the reliability of supply to its customers at least cost, including soliciting and entering into contracts that would reduce price spikes driven by gas capacity constraints (DOER Comments at 11). DOER suggests that an EDC should seek the support of ISO-NE in demonstrating the need for incremental gas capacity in the region (DOER Comments at 16, 17). Finally, DOER recommends that an EDC include in a filing for review and approval of a contract for gas capacity an implementation plan that demonstrates how an EDC will secure the benefits attributable to the contract (DOER Comments at 16).

2. Other Commenters

Eversource and National Grid concur with DOER that the Department has a level of discretion in determining whether an EDC gas capacity contract satisfies the Section 94A public interest standard (Eversource Comments at 6, 7; National Grid Comments at 18). The

EDCs assert that the Department should approve such contracts where an EDC is able to demonstrate that the electric reliability and supply pricing benefits generated by relief of capacity constraints warrant expenditure of the costs for gas capacity (Eversource Comments at 7; National Grid Comments at 19). As suppliers of last resort for all basic service customers, the EDCs argue that they have a responsibility to design resource portfolios that ensure reliable and least-cost supply for these customers (Eversource Comments at 8; National Grid Comments at 20). Thus, the EDCs conclude that the Department should approve a proposed gas contract where an EDC is able to demonstrate that (1) such contract compares favorably to the alternative options reasonably available to it at the time of the acquisition, including that the price is competitive, and (2) the contract satisfies non-price objectives for basic service supply such as reliability, feasibility, expected availability and minimal environmental impact (Eversource Comments at 8, 9; Eversource Reply Comments at 25; National Grid Comments at 20). Eversource further specifies that the EDCs would need to demonstrate that: (1) the proposed contract is the product of a fair and reasonable procurement solicitation process; (2) shareholder interests are not placed ahead of ratepayer interests, and (3) that the transaction is consistent with affiliate transaction rules (Eversource Reply Comments at 26).

Pipeline companies offer additional perspectives on the appropriate standard of review for EDC gas contracts. Spectra advises the Department to approve contracts that actually ensure gas delivery to gas-fired power generators during peak demand periods (Spectra Comments at 4). Tennessee urges the Department to: (1) require the EDCs to issue a request for proposals ("RFP") for additional pipeline capacity; (2) ensure that the EDCs' solicitation, evaluation, and negotiation of contracts reflect a competitive and fair process that does not give undue preference to an EDC's affiliates; and (3) evaluate contracts according to both price and non-price factors (e.g., flexibility, supply diversity, service offerings, ability to serve gas-fired generation) (Tennessee Reply Comments at 10). Portland Natural Gas Transmission System ("PNGTS") also cautions the Department to ensure that whatever contracts are filed for approval result from a transparent competitive process in order to alleviate concerns related to affiliate relationships between EDCs and potential bidders (PNGTS Comments at 2). The Coalition to Lower Energy Costs ("CLEC") similarly urges the Department to determine that a fair, open, and transparent competitive solicitation process is integral to meeting the public interest standard (CLEC Reply Comments at 43, 44).

Acadia urges the Department to interpret the Section 94A public interest standard to require EDCs to demonstrate that any proposed gas contract compares favorably to the range of alternative options available at the time of acquisition (Acadia Comments at 7). Acadia asserts that an analysis of alternative options should include a comparison of the benefits, costs, and risks of an EDC's proposed purchase and sale of pipeline capacity to the benefits, costs, and risks of other viable pathways that the Commonwealth could pursue, including energy efficiency, energy storage, renewable energy, hydroelectric imports, and other resources (Acadia Comments at 7). According to Acadia, the Department must then determine which option is most cost effective, reliable, and compatible with other public policy objectives such as environmental goals and protection of consumers (Acadia Comments at 7). Acadia further advises that the Department's Section 94A review should consider risks associated with self-dealing (Acadia Comments at 10).

Finally, GDF Suez asserts that if the Department determines that it has authority to review EDC gas contracts under Section 94A, the public interest standard must encompass Department review of all potentially relevant elements of the proposed gas capacity arrangement "simultaneously, rather than permitting the elements to come before the DPU seriatim over the course of multiple proceedings over multiple years." (GDF Suez Comments at 23). GDF Suez cautions that the Department will not be able to assess the true costs to ratepayers if it does not review the "full contractual scheme over the entire lifetime of the proposed rate" (GDF Suez Comments at 23). GDF Suez further urges the Department to interpret the Section 94A public interest standard applicable to its review of EDC gas contracts in a manner consistent with its interpretation of the public interest as articulated in D.P.U. 12-77 (2013) (GDF Suez Reply Comments at 5, 6).

C. Standard of Review

The Department seeks to define the standard of review it would apply for gas capacity contracts filed by EDCs. In establishing a standard of review to apply to the Department's evaluation of an EDC's pipeline capacity contract, the Department first examines our well-established standard for approving LDC contracts under Section 94A.

> In evaluating a gas utility's resource options for the acquisition of commodity resources as well as for the acquisition of capacity under G.L. c. 164, § 94A, the Department examines whether the acquisition of the resource is consistent with the public interest. Commonwealth Gas Company, D.P.U. 94-174-A at 27 (1996). In order to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources

> is consistent with the public interest, a local distribution [gas] company ("LDC") must show that the acquisition (1) is consistent with the company's portfolio objectives, and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27.
>
> In establishing that a resource is consistent with the company's portfolio objectives, the company may refer to portfolio objectives established in a recently approved forecast and supply plan or in a recent review of supply contracts under G.L. c. 164, § 94A, or may describe its objectives in the filing accompanying the proposed resource. D.P.U. 94-174-A at 27-28. In comparing the proposed resource acquisition to current market offerings, the Department examines relevant price and non-price attributes of each contract to ensure a contribution to the strength of the overall supply portfolio. D.P.U. 94-174-A at 28. As part of the review of relevant price and non-price attributes, the Department considers whether the pricing terms are competitive with those for the broad range of capacity, storage, and commodity options that were available to the LDC at the time of the acquisition, as well as with those opportunities that were available to other LDCs in the region. D.P.U. 94-174A at 28. In addition, the Department determines whether the acquisition satisfies the LDC's non-price objectives including, but not limited to, flexibility of nominations and reliability and diversity of supplies. D.P.U. 94-174-A at 28-29. In making these determinations, the Department considers whether the LDC used a competitive solicitation process that was fair, open, and transparent. <u>The Berkshire Gas Company</u>, D.T.E. 02-56, at 10 (2002); <u>Bay State Gas Company</u>, D.T.E. 02-52, at 8 (2002); <u>KeySpan Energy Delivery New England</u>, D.T.E. 02-54, at 9 (2002); <u>The Berkshire Gas Company</u>, D.T.E. 02-19, at 11 (2002).

In summary, the Department's standard of review for LDC gas contracts under Section 94A involves a consideration of whether a contract is consistent with the public interest. To demonstrate that a proposed acquisition of a resource is consistent with the public interest, an LDC must show that the acquisition (1) is consistent with an LDC's portfolio objectives demonstrated in a recently approved supply plan or as described in a filing, and (2) compares favorably to a range of alternative options reasonably available to the company at the time of acquisition or contract (re)negotiation. <u>See</u>, <u>e.g.</u> <u>NSTAR Gas Company</u>, D.P.U. 13-159, at 3 (2014). The Department finds that its standard of review for gas contracts entered into by LDCs provides an appropriate model for similarly reviewing gas contracts entered into by EDCs and submitted to the Department for review and approval under Section 94A. However, because of the different regulatory treatment of LDCs and EDCs, particularly regarding the approval of a forecast and supply plan pursuant to G.L. c. 164, § 69*I*,[23] the Department finds that some modifications to the existing standard of review under section 94A are necessary for review of an EDC gas capacity contract.

Under the modified standard of review, in order to determine that an EDC gas capacity contract filed pursuant to Section 94A is consistent with the public interest, an EDC must demonstrate that the proposed contract (1) results in net benefits for the Massachusetts EDCs' customers at a reasonable cost,[24] and (2) compares favorably to the range of alternative options reasonably available to the EDC at the time of acquisition of the resource or contract negotiation (e.g., pipeline capacity, local storage, electric transmission). An EDC must show that the price of the resource is competitive and that the contract satisfies other non-price

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23 Pursuant to G.L. c. 164, § 69*I*, an LDC must file for approval by the Department a biennial forecast and supply plan consisting of projected gas sendout and projected available resources for the ensuing five-year period. EDCs are exempt from the forecast and supply plan requirements of G.L. c. 164, § 69*I*. See In Re: (1) Rescinding 220 C.M.R. § 10.00 et seq. and (2) Exempting Electric Companies From Provisions of G.L. c. 164, § 69*I*, D.T.E. 98-84/EFSB 98-5 (August 8, 2003).

24 Under typical market conditions, lower retail electricity prices follow lower wholesale electricity prices.

factors such as reliability of service and diversity of supply.[25] In any such filing, the EDC will bear the burden of satisfying the standard of review, including providing appropriate and sufficient supporting information.

D. Filing Requirements

In satisfying the public interest standard set forth above, an EDC seeking Department review and approval of a gas contract must include with its filing materials that demonstrate a competitive and transparent procurement, that avoid conflicts of interest, and that allow for consideration of procurement by entities other than EDCs. So doing will ensure the conduct of a competitive, transparent procurement process that avoids conflicts of interest and further ensures the management of any procured capacity that achieves the goals stated above, for the benefit of ratepayers. In the event that an EDC chooses not to use a competitive solicitation process, it must justify its reasoning behind the decision. An EDC shall include in any filing for Department review and approval, at a minimum:

1. a complete description of and justification for the type, size, and timing of the contracted resource(s);

2. a complete description of the contract, including the following information:

   a. contracting parties;

   b. type of resource (e.g., pipeline capacity, local storage, electric transmission);

   c. type of service (e.g., firm, peak shaving);

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25 Increased natural gas availability can improve the performance of gas-fired generators during periods of both high electric demand and high heating requirements. Improved performance could produce lower electricity prices.

d. quantity (e.g., daily, seasonal, annual);

e. price (e.g., variable, demand, expected total annual cost);

f. commencement date and term;

g. receipt and delivery points;

h. evergreen/renewal terms;

i. performance, force majeure;

j. ability to serve electric generators; and

k. any other terms that are considered "industry-standard" for the type of proposed transaction.

In addition, in its filing an EDC must demonstrate that the proposed contract is the product of a fair and reasonable procurement process, such as a competitive solicitation.

Further, in the filing, an EDC must demonstrate that the proposed agreement compares favorably to the range of alternative reliable and least-cost resource options reasonably available to it at the time of acquisition or contract renegotiation. Such alternative options include all energy resources reasonably available in the market that have the potential to address the objective providing electricity at a reasonable cost and that compare favorably in terms of price and non-price factors. An EDC must demonstrate that its analysis evaluated all options using the same methodology and standards, with detail for all assumptions.

A filing must also include the EDC's strategy for maximizing ratepayer benefits associated with the acquisition and use of contracted gas capacity, including but not limited to, any capacity release activities. Such strategy should include a detailed explanation of how the EDC expects to trade all of the acquired gas capacity. A filing must also explain how the strategy for maximizing ratepayer benefits associated with the acquisition and use of any such contracted capacity complies with the Department's regulations in 220 C.M.R § 12.00 et seq., which govern affiliate transactions.

Further, the filing must demonstrate that the electric pricing benefits associated with the contract warrant expenditure of the contract costs. Such demonstration should be based on a quantitative analysis of the benefits and costs associated with the contracted resource(s) to the maximum extent practicable.

Finally, a filing must include a description of the method of ratemaking the EDC proposes for recovery of costs that it will incur under the proposed contract and, if applicable, the crediting of revenues that it will accrue pursuant to any capacity use/release strategy. A filing must also include a description of efforts that the EDC has undertaken or will undertake to recover contract costs regionally.

The Department puts EDCs on notice that they must make a complete and accurate filing to allow for a thorough, substantive examination by the Department. In its filing, an EDC must address any other filings or approvals that would be needed to make its proposal viable. The Department seeks to avoid expending resources on the review of a proposal that is not feasible. Further, EDCs and interested parties are on notice that in examining an EDC filing, the Department anticipates requiring time for a full adjudicatory process (e.g., direct prefiled testimony, intervenor prefiled testimony, discovery, evidentiary hearings (including any required interlocutory rulings), and briefing) and for deliberation. In this Order, the Department does not establish a specific schedule or timetable for its examination, but will address the particular review timeframes based on the complexity and novelty of the relevant issues.

VI. ORDER

Accordingly, after opportunity for comment and due consideration, the Department

FINDS: That the Department has authority pursuant to G.L. c. 164, § 94A to review and approve contracts for natural gas pipeline capacity filed by electric companies; and it is

ORDERED: That any electric company filing a contract for natural gas capacity with the Department for review and approval pursuant to G.L. c. 164, § 94A shall comply with all directives contained in this Order.

By Order of the Department,

/s/
Angela M. O'Connor, Chairman

/s/
Jolette A. Westbrook, Commissioner

/s/
Robert E. Hayden, Commissioner

## I. DOER QUESTIONS

1. Is there any legal impediment to the Department accepting and considering natural gas capacity contracts by EDCs under Section 94A and, if approved, providing reasonable assurance of cost recovery?

2. Is there an alternative mechanism available for EDCs or other parties to secure new gas delivery capacity for the region?

3. What would be the standard of review for such contracts?

4. How should affiliate relationships among EDCs and potential bidders be addressed?

5. What financial risk will be borne by ratepayers and EDCs? What mitigation tools are available to offset these risks?

6. Since the effects of any capacity contracts would have a regional impact, should any approvals be conditioned upon some or all New England states sharing in the contracting obligation?

7. How will the contracted-for capacity be made available to the market such that the benefits accrue to Massachusetts ratepayers?

8. Should there be a third party managing the sale of the capacity in the market?

9. If a contract is approved, how should costs be allocated in distribution rates?

## II. ADDITIONAL QUESTIONS

1. What specific natural gas delivery capacity constraints are causing high regional electricity prices? Please identify and characterize constraints with respect to geographic location, time of year and/or market condition when constraint is or will be binding, and the degree to which the constraint impacts local versus regional natural gas delivery capability.

2. What specific natural gas resources and/or commercial mechanisms could potentially alleviate each of the natural gas delivery capacity constraints identified above? What is the estimated cost and timing required to implement each potential resource/commercial mechanism?

3. What rules or standards should apply to any affiliate relationships among EDCs, potential bidders, and buyers of the natural gas capacity?

a) Please respond with regard to relationships between EDCs and affiliates who are, or may potentially be, partners in interstate pipeline projects; and

b) Address any other affiliate relationship conflicts not identified above that may affect the proposed contracts and bidding dynamic.

4. Apart from issues pertaining to Section 94A, are there any legal impediments to the contractual and cost recovery arrangements discussed by DOER?

5. How will EDCs acquire natural gas capacity and how will the amount of new natural gas capacity for each EDC be determined?

6. How will EDCs determine the length of contracts for natural gas capacity?

7. How will EDCs release or otherwise sell the natural gas capacity?

8. Could there be restrictions placed on the release of natural gas capacity so that the released capacity only can be acquired by electric generators serving the ISO New England market?

9. Please indicate the types of natural gas capacity that the EDCs would acquire.

10. If a contract is approved, will total contract costs collected from ratepayers be capped at a specific amount or threshold? If so, at what level should the cap be set? Over what time period will EDCs collect total contract costs through rates?

11. Should the EDCs collect costs through base distribution rates or through a separate reconciling mechanism? Discuss the benefits and disadvantages of each approach.

12. If costs are recovered through an annual reconciling mechanism:

a) Section 51 of An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209 requires that reconciliation factors recover costs from each rate class on cost-based criteria. If a contract is approved, what are the cost-based criteria?

b) Would the EDCs include such annual reconciliations in their annual retail rate adjustment filings for transition costs, transmission costs, etc. (e.g., D.P.U. 13-05)? If not, what process would be appropriate?

c) Would annual rate changes from such contracts be capped, and, if so, at what amount?

13. If the Department approves the costs, will the costs collected from ratepayers include only the costs of the contract, or will total costs include administrative costs associated with managing the contracts?

14. How are future changes in the gas market to be addressed if the EDC contract proposal is implemented? Specifically, is this mechanism designed to be a permanent or interim measure? How is this mechanism to be re-evaluated if energy alternatives are successful?

15. Are there regions or states with existing financial structures/regulations in place for electric distribution companies to contract for firm natural gas capacity? Please provide any information on how these regions or states implement and manage these contract arrangements.

16. If EDCs contract for new natural gas delivery capacity, how should they manage the capacity to best achieve policy objectives of making such capacity available for electricity generators and reducing electricity market costs for Massachusetts distribution ratepayers? How should the benefits associated with any such contracts be measured? How can the value embedded in any such contracts be monetized and captured for Massachusetts ratepayers?

## I. CITIZEN COMMENTS

John Berkowitz
Julia Blyth
Leslie Breeding
Nathalie Bridegam
James Carvalho
Barry De Jasu
Clifford Dornbusch
Darcy DuMont
Natani Hume
Katherine Keenum
Mark McDonald
Marty Nathan
John Nelson
Alisa Pearson
Rutilious B. Perkins, III
Arnold Piacentini
David Roitman
Carolyn Sellars
Rosemary Wessel

350 Massachusetts for a Better Future (including approximately 350 citizen comments)
Food and Water Watch (including approximately 225 individual comments and approximately 918 signatures)

## II. OTHER PARTICIPANTS

Acadia Center (et al.) ("Acadia Center")
Algonquin Gas Transmission, LLC and Spectra Energy Partners, LP ("Spectra")
America's Natural Gas Alliance ("ANGA")
Berkshire Photovoltaic Services
Cape Light Compact ("Compact")
Coalition to Lower Energy Costs ("CLEC")
Conservation Law Foundation ("CLF")
Direct Energy Services, LLC
Dynegy Inc. ("Dynegy")
Entergy Nuclear Power Marketing, LLC
Environmental Defense Fund ("EDF")
Environmental Entrepreneurs (E2)
Environmental League of Massachusetts
Essential Power Massachusetts, LLC

Gailanne M. Cariddi, State Representative
GDF Suez Gas NA LLC ("GDF Suez")
Low-Income Weatherization of Fuel Assistance Program Network
Mass Energy Consumers Alliance
Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid ("National Grid")
Massachusetts Department of Energy Resources ("DOER")
Massachusetts Municipal Wholesale Electric Company ("MMWEC")
Massachusetts Office of the Attorney General ("Attorney General")
National Energy Marketers Association ("NEMA")
New England Power Generators Association, Inc. ("NEPGA")
Northeast Energy Solution, Inc.
Northeast Municipal Gas Pipeline Coalition
NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy ("Eversource")
Portland Natural Gas Transmission System ("PNGTS")
RENEW Northeast, Inc.
Repsol Energy North America Corporation ("Repsol")
Stop the West Roxbury Lateral
Tennessee Gas Pipeline Company, LLC. ("Tennessee")
Town of Warwick, Buildings & Energy Committee
Town of Northfield Board of Selectman
Wal-Mart Stores East, LP and Sam's East Inc.

AN ACT CONCERNING AFFORDABLE AND RELIABLE ENERGY

Showing 1 of 51 CGA document(s) retrieved

**PA 15-107**—sSB 1078

**AN ACT CONCERNING AFFORDABLE AND RELIABLE ENERGY**

**SUMMARY:** This act allows the Department of Energy and Environmental Protection (DEEP) commissioner, in consultation with others, to solicit proposals from providers of energy and energy-related products and services and direct the electric companies to (1) enter into long-term agreements with these providers, subject to the Public Utility Regulatory Authority's (PURA) review and approval and (2) recover related costs and credit certain revenues, through a component of ratepayer electric bills. It specifies three categories for solicitations:

1. demand response measures and smaller renewable energy sources;
2. larger renewable energy sources and hydropower; and
3. natural gas resources.

It also allows the commissioner to seek proposals for energy storage, Class II renewable energy sources (see BACKGROUND), and existing hydropower in certain circumstances.

The act allows the commissioner to hire consultants to help evaluate proposals. If he finds proposals to be in the ratepayers' best interests, he may select one or more of them and direct the electric companies to enter into long-term contracts with energy providers. The act allows DEEP to recover from ratepayers certain costs associated with consultants and other reasonable costs associated with its solicitation and evaluation of proposals.

The act limits (1) all contract terms to 20 years; (2) selected proposals for demand response, renewable resources, and hydropower, in the aggregate, to 10% of the total load served by the state's electric companies; and (3) the total aggregate capacity of selected contracts.

EFFECTIVE DATE: Upon passage

RESOURCE TYPES

The act allows the DEEP commissioner to solicit proposals for multiple long-term contracts to (1) secure cost effective resources to provide more reliable electric service for the state's electric ratepayers and (2) meet goals and policies established in the state's integrated resources plan (IRP) and comprehensive energy strategy (CES). It establishes three categories and specifies the types of proposals that the commissioner must solicit in each category.

For solicitations for demand response measures and smaller renewable resources, the commissioner must seek proposals for (1) Class I renewable energy sources (e. g. , solar or wind power) and Class III source projects (e. g. , combined heat and power) with a capacity between two and 20 megawatts and (2) passive demand response measures capable of reducing electric demand by at least one megawatt, including energy efficiency, load management, and the state's conservation and load management programs. The act requires electric companies to consult with the Energy Conservation Management

Board (i. e. , the Energy Efficiency Board) to assess the feasibility of submitting a proposal for passive demand response measures that are in addition to existing and projected demand reductions obtained through the conservation and load management programs.

The act allows the commissioner to also seek proposals for energy storage systems of up to 20 megawatts. Under the act, "an energy storage system" is any commercially available technology capable of absorbing energy and storing it for a period of time before dispatching it. It must be capable of:

1. using mechanical, chemical, or thermal processes to store electricity generated at one time for use at a later time;
2. storing thermal energy for direct use for heating or cooling at a later time, avoiding the need to use electricity;
3. using mechanical, chemical, or thermal processes to store electricity generated from renewable energy sources for use at a later time; or
4. using mechanical, chemical, or thermal processes to capture waste electricity generated from mechanical processes and store it for delivery at a later time.

For solicitations for large renewable energy sources and hydropower, the commissioner must seek proposals for (1) Class I renewable energy sources with capacity of at least 20 megawatts and (2) verifiable large-scale hydropower. These proposals must include associated transmission (i. e. , use of high-voltage lines to carry electricity from where it is generated to local substations).

The act also allows him to seek proposals for energy storage systems of at least 20 megawatts. He may also seek proposals for Class II renewable energy sources and certain existing hydropower resources to balance the delivery of Class I renewable energy sources (which may be intermittent) and improve the economic viability of such proposals. Existing hydropower resources used for this purpose must not be considered large-scale, Class I, or Class II. Class II renewable energy sources and hydropower resources must be interconnected to associated transmission and either be (1) located in the control area of the regional independent system operator (generally, New England) or (2) imported from an adjacent regional independent system operator's control area.

For natural gas resources, the commissioner must solicit proposals for:

1. interstate natural gas transportation capacity,
2. liquefied natural gas,
3. liquefied natural gas storage,
4. natural gas storage, or
5. any combination of such resources.

Such proposals must provide incremental capacity, gas, or storage with a firm delivery capability to transport natural gas to natural gas-fired generating facilities located in the control area of the regional independent system operator.

SOLICITATION PROCESS

DEEP must consult with (1) PURA's procurement manager, (2) the Office of Consumer Council, and (3) the attorney general when soliciting proposals and evaluating any proposals it receives. It may issue solicitations on behalf of Connecticut alone or in coordination with other New England states.

The commissioner must base the evaluation on factors including:

1. reliability improvements to the electric system, including during peak demand;
2. whether the proposal's benefits outweigh the cost to ratepayers;
3. fuel diversity;
4. the extent to which the proposal meets requirements to reduce greenhouse gas emissions and improve air quality, including the state's renewable portfolio standard;
5. the ratepayers' best interests; and
6. alignment with IRP and CES policy goals, including environmental impact.

DEEP (1) must compare a proposal's costs and benefits to those of other resources eligible to respond to DEEP's solicitations authorized under the act and (2) may also consider economic benefits to the state.

The act allows the commissioner to hire consultants with expertise in (1) quantitative modeling of electric and gas markets and (2) physical gas and electric system modeling, as applicable, to assist with solicitations, including proposal evaluation. Under the act, DEEP may recover reasonable costs of up to $1. 5 million associated with solicitation and evaluation process through the non-bypassable federally mandated congestion charge, even if DEEP selects no proposals. Federally mandated congestion charges are generally collected on electricity bills to cover certain costs approved by the Federal Energy Regulatory Commission (FERC) and other costs approved by PURA. Customers must pay non-bypassable charges regardless of whether they choose a retail energy supplier, as these charges are considered reliability related.

If the commissioner finds proposals authorized by the act to be in ratepayers' best interests, he may select one or more proposals and direct the electric companies to enter into long-term contracts with the selected providers. Under the act, the contracts may be for:

1. passive demand response measures,
2. electricity,
3. electric capacity,
4. environmental attributes,
5. interstate natural gas transportation capacity,
6. liquefied natural gas,
7. liquefied natural gas storage,

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8. natural gas storage,
9. energy storage, or
10. any combination of such measures.

The act limits the total aggregate capacity of the selected contracts to 375 million cubic feet per day of natural gas capacity or the equivalent megawatts of any combination of electricity and electric demand reduction. (The conversion rate of cubic feet per day to megawatts is unclear. ) The act also limits selected proposals for demand response, renewable resources, and hydropower, in the aggregate, to 10% of the total load served by the state's electric companies.

Under the act, PURA must review and approve any agreement entered into as a result of a proposal. Electric companies must file an application with PURA for approval of any agreement, and PURA must approve it if it is cost effective and in electric ratepayers' best interests. If PURA does not issue a decision within 90 days, the agreement is deemed approved.

The electric companies must recover certain costs from ratepayers and credit ratepayers for certain revenue. Specifically, they must, through a fully reconciling component of electric rates for all the electric company's customers, (1) recover net costs on a timely basis, including costs incurred under the agreement and reasonable costs incurred in connection with the agreement, and (2) credit customers for any net revenue from the sale of products purchased in accordance with long-term contracts authorized by the act. The act allows the electric companies to contract with a gas supply manager to sell natural gas products procured as a result of long-term contracts into the wholesale energy markets at the best available rates and in compliance with FERC regulations.

RENEWABLE ENERGY CERTIFICATES

The act allows electric companies to sell any renewable energy certificates (REC) for any Class I renewable energy sources or Class III sources procured through solicitations authorized by the act to suppliers or other electric companies in the New England Power Pool Generation Information System renewable energy credit market so that these suppliers or companies may meet the state's renewable portfolio requirement. The electric company must credit the revenue of any REC sales to its customers. The act also allows the electric companies to retain such RECs to meet renewable portfolio requirements. The act requires the electric companies to choose whether to sell or retain RECs based on the best interests of the company's ratepayers.

BACKGROUND

By law, Class II renewable energy sources include energy derived from (1) trash-to-energy facilities, (2) certain biomass facilities, and (3) certain hydropower facilities not included as Class I resources and with a capacity of up to five megawatts (CGS § 16-1(a)(21)).

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# Title 35-A: PUBLIC UTILITIES HEADING: PL 1987, c. 141, Pt. A, §6 (new)

## Chapter 19: THE MAINE ENERGY COST REDUCTION ACT

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## Maine Revised Statutes

# Title 35-A: PUBLIC UTILITIES HEADING: PL 1987, c. 141, Pt. A, §6 (new)

## Chapter 19: THE MAINE ENERGY COST REDUCTION ACT

### §1901. SHORT TITLE

This chapter may be known and cited as "the Maine Energy Cost Reduction Act." [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

### §1902. DEFINITIONS

As used in this chapter, unless the context otherwise indicates, the following terms have the following meanings. [2013, c. 369, Pt. B, §1 (NEW).]

**1**. **Basis differential.** "Basis differential" means the difference between the so-called Henry Hub spot price for natural gas and the corresponding cash spot price for natural gas in New England.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**2**. **Energy cost reduction contract.** "Energy cost reduction contract" or "contract" means a contract executed in accordance with this chapter to procure capacity on a natural gas transmission pipeline, including, when applicable, compression capacity.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**3**. **ISO-NE region.** "ISO-NE region" means the region in which the New England bulk power system operated by the independent system operator of the New England bulk power system or a successor organization is located.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**4**. **Pipeline capacity holder.** "Pipeline capacity holder" means any person owning rights to natural gas pipeline capacity.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**5**. **Trust fund.** "Trust fund" means the Energy Cost Reduction Trust Fund established under section 1907, subsection 1.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

### §1903. LEGISLATIVE FINDINGS

The Legislature finds that: [2013, c. 369, Pt. B, §1 (NEW).]

**1. Electricity prices.** It is in the public interest to decrease prices of electricity and natural gas for consumers in this State; and

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**2. Natural gas expansion.** The expansion of natural gas transmission capacity into this State and other states in the ISO-NE region could result in lower natural gas prices and, by extension, lower electricity prices for consumers in this State.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1904. ENERGY COST REDUCTION CONTRACTS

The commission in consultation with the Public Advocate and Governor's Energy Office may execute an energy cost reduction contract in accordance with this section. In no event may the commission execute energy cost reduction contracts for the transmission of greater than a cumulative total of 200,000,000 cubic feet of natural gas per day or for a total amount that exceeds $75,000,000 annually. [2013, c. 369, Pt. B, §1 (NEW).]

**1. Prior to executing an energy cost reduction contract.** Before executing an energy cost reduction contract, the commission shall:

A. Pursue, in appropriate regional and federal forums, market and rule changes that will reduce the basis differential for gas coming into New England and increase the efficiency with which gas brought into New England and Maine is transmitted, distributed and used. If the commission concludes that those market or rule changes will, within the same time frame, achieve substantially the same cost reduction effects for Maine electricity and gas customers as the execution of an energy cost reduction contract, the commission may not execute an energy cost reduction contract; [2015, c. 329, Pt. E, §1 (AMD).]

B. Explore all reasonable opportunities for private participation in securing additional gas pipeline capacity that would achieve the objectives in subsection 2. If the commission concludes that private transactions, within the same time frame, achieve substantially the same cost reduction effects for Maine electricity and gas customers as the execution of an energy cost reduction contract, the commission may not execute an energy cost reduction contract; and [2015, c. 329, Pt. E, §1 (AMD).]

C. In consultation with the Public Advocate and the Governor's Energy Office, hire a consultant with expertise in natural gas markets to make recommendations regarding the execution of an energy cost reduction contract. The commission shall consider those recommendations as part of an adjudicatory proceeding under subsection 2. [2013, c. 369, Pt. B, §1 (NEW).]

[ 2015, c. 329, Pt. E, §1 (AMD) .]

**2. Commission determination of benefits.** After satisfying the requirements of subsection 1, the commission may execute or direct one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities to execute an energy cost reduction contract if the commission has determined, in an adjudicatory proceeding, that the agreement is commercially reasonable and in the public interest and that the contract is reasonably likely to:

A. Materially enhance natural gas transmission capacity into the State or into the ISO-NE region and that additional capacity will be economically beneficial to electric consumers, natural gas consumers or both in the State and that the overall costs of the contract are outweighed by its benefits to electric consumers, natural gas consumers or both in the State; and [2013, c. 369, Pt. B, §1 (NEW).]

B. Enhance electrical and natural gas reliability in the State. [2013, c. 369, Pt. B, §1 (NEW).]

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**3**. **Parties to an energy cost reduction contract.** The commission may execute, or direct to be executed, an energy cost reduction contract that contains the following provisions.

A. The commission may direct one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities to be a counterparty to an energy cost reduction contract. In determining whether and to what extent to direct a utility to be a counterparty to a contract under this subsection, the commission shall consider the anticipated reduction in the price of gas or electricity, as applicable, accruing to the customers of the utility as a result of the contract as determined by the commission in an adjudicatory proceeding.

Any economic loss, including but not limited to any effects on the cost of capital resulting from an energy cost reduction contract for a transmission and distribution utility, a gas utility or a natural gas pipeline utility, is deemed to be prudent and the commission shall allow full recovery through the utility's rates. [2013, c. 369, Pt. B, §1 (NEW).]

B. If the commission concludes that an energy cost reduction contract can be achieved with the participation of other entities, the commission may contract jointly with other entities, including other state agencies and instrumentalities, governments in other states and nations, utilities and generators. [2013, c. 369, Pt. B, §1 (NEW).]

C. The commission may execute an energy cost reduction contract as a principal and counterparty. [2013, c. 369, Pt. B, §1 (NEW).]

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**4**. **Approval by the Governor.** The commission may not execute or direct the execution of an energy cost reduction contract unless the Governor has in writing approved the execution of the energy cost reduction contract.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW). 2015, c. 329, Pt. E, §1 (AMD).

## §1905. FUNDING OF AN ENERGY COST REDUCTION CONTRACT

An energy cost reduction contract may be funded in accordance with this section. [2013, c. 369, Pt. B, §1 (NEW).]

**1**. **Assessments on ratepayers.** The commission may direct one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities to collect an assessment from ratepayers for the following purposes:

A. To finance the participation of a transmission and distribution utility, a gas utility or a natural gas pipeline utility in an energy cost reduction contract; and [2013, c. 369, Pt. B, §1 (NEW).]

B. To pay the costs of energy cost reduction contract evaluation and administration under section 1906, subsection 2. [2013, c. 369, Pt. B, §1 (NEW).]

All assessments must be just and reasonable as determined by the commission and must be identified as an energy cost reduction contract charge on a ratepayer's utility bill. When determining just and reasonable assessments, the commission shall consider the anticipated reduction in the price of gas or electricity, as applicable, accruing to different categories of ratepayers as a result of the contract.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**2**. **Assessments on utilities.** If the commission is the principal and counterparty on the contract, the commission may:

A. Assess one or more transmission and distribution utilities, gas utilities and natural gas pipeline utilities in proportion to the anticipated reduction in the price of gas or electricity, as applicable, accruing as a result of the contract to the customers of the utility for any and all net costs to the commission of the commission's performance of the contract as determined by the commission in an adjudicatory proceeding. The cost to the utility of the assessment may be recovered by the utility in rates in the same manner as any other prudently incurred cost. [2013, c. 369, Pt. B, §1 (NEW).]

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**3**. **Volumetric fee.** The commission may establish and direct the payment to the trust fund of a volumetric fee on the use of gas by a consumer of natural gas obtained from a source other than a gas utility or a natural gas pipeline utility of this State in proportion to the anticipated reduction in the price of gas accruing to that consumer as a result of the contract as determined by the commission in an adjudicatory proceeding.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1906. CONTRACT RESALE AND ADMINISTRATION

The following provisions govern the resale and evaluation and administration of an energy cost reduction contract. [2013, c. 369, Pt. B, §1 (NEW).]

**1**. **Resale of natural gas pipeline capacity.** The commission may negotiate and enter into contracts for the resale of all or a portion of the reserved natural gas transmission pipeline capacity acquired through an energy cost reduction contract. All of the revenue received as a result of the resale must be deposited into the trust fund.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**2**. **Contract evaluation and administration.** The commission is responsible for assessing, analyzing, negotiating, implementing and monitoring compliance with energy cost reduction contracts. The commission may use funds for this purpose from the trust fund or may collect funds for this purpose through just and reasonable assessments placed on a transmission and distribution utility, a gas utility or a natural gas pipeline utility pursuant to section 1905, subsection 1, paragraph B.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1907. REVENUES FROM ENERGY COST REDUCTION CONTRACTS

Revenues received from the resale of natural gas pipeline capacity acquired through an energy cost reduction contract must be used in accordance with this section. [2013, c. 369, Pt. B, §1 (NEW).]

**1. Establishment of Energy Cost Reduction Trust Fund.** The Energy Cost Reduction Trust Fund is established as a nonlapsing fund administered by the commission for the purposes of this chapter. The commission is authorized to receive and shall deposit in the trust fund and expend in accordance with this section revenues received from an energy cost reduction contract and revenues received from the resale of natural gas pipeline capacity acquired through an energy cost reduction contract.

The funds in the trust fund are held in trust for the purpose of reducing the energy costs of consumers in the State and may not be used for any other purpose, except as described in subsection 2.

[ 2013, c. 369, Pt. B, §1 (NEW) .]

**2. Distribution of funds.** The commission shall distribute funds in the trust fund in the following order of priority:

A. As a first priority, to the costs of monitoring and administering a contract pursuant to section 1906, subsection 2; and [2013, c. 369, Pt. B, §1 (NEW).]

B. As a 2nd priority, to utilities and other entities to reduce energy costs for electricity and natural gas ratepayers and consumers subject to a volumetric fee under section 1905, subsection 3. The commission may distribute funds to benefit ratepayers of one or more transmission and distribution utilities, gas utilities or natural gas pipeline utilities or consumers subject to a volumetric fee under section 1905, subsection 3 in a manner that the commission finds is equitable, just and reasonable. [2013, c. 369, Pt. B, §1 (NEW).]

[ 2013, c. 369, Pt. B, §1 (NEW) .]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1908. EXEMPTION FROM STATE PURCHASING AGENT RULES

Notwithstanding any other provision of law, agreements and contracts entered into pursuant to this chapter are not subject to the competitive bid requirements of the State Purchasing Agent. [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1909. MARKET POWER INVESTIGATION

The commission may on its own motion, with or without notice, summarily investigate the exercise of market power by a gas utility, natural gas pipeline utility or pipeline capacity holder. If, after the summary investigation, the commission determines it to be necessary, it may hold a public hearing in accordance with section 1304. Notwithstanding section 1304 and Title 5, section 9052, the commission shall notify the utility under investigation in writing of the matter under investigation and 7 days after the commission has given notice the commission may set the time and place for the public hearing. [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1910. RULEMAKING

The commission may adopt rules to implement this chapter. When adopting rules, the commission shall consider the financial implications of this chapter for transmission and distribution utilities, gas utilities and natural gas pipeline utilities. Rules adopted pursuant to this section are routine technical rules as defined in Title 5, chapter 375, subchapter 2-A. [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1911. REPORTS

The commission shall include in its annual report under section 120, subsection 3 a description of its efforts to pursue, in appropriate regional and federal forums, market and rule changes that will reduce the basis differential for natural gas coming into New England. [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

## §1912. LIMITATION

The commission may not execute an energy cost reduction contract under this chapter after December 31, 2018. The commission may continue to administer existing contracts and enter into agreements regarding the resale of natural gas pipeline capacity purchased through an energy cost reduction contract after December 31, 2018. [2013, c. 369, Pt. B, §1 (NEW).]

SECTION HISTORY
2013, c. 369, Pt. B, §1 (NEW).

**STATE OF NEW HAMPSHIRE**
**PUBLIC UTILITIES COMMISSION**

**IR 15-124**

**ELECTRIC DISTRIBUTION UTILITIES**

**Investigation into Potential Approaches to Ameliorate Adverse Wholesale Electricity Market Conditions in New Hampshire**

**Order Accepting Staff Report and Stakeholder Comments, and Outlining Review Process for Any Petitions for Capacity Acquisitions and Associated Competitive Bidding**

**O R D E R N O. 25,860**

**January 19, 2016**

## I. BACKGROUND

On April 17, 2015, the Commission issued an Order of Notice announcing an investigation, pursuant to RSA 365:5, RSA 374:3 and :4, and RSA 374-F:8, into potential approaches involving New Hampshire's electric distribution utilities (EDCs) to address cost and price volatility issues affecting wholesale electricity markets in New Hampshire. In general terms, the Commission ordered the Commission Staff (Staff) to prepare a report regarding the natural gas resource constraint issues facing the New England electricity market to be filed no later than September 15, 2015. A report by Commission Staff was filed as ordered on September 15, 2015, under the direction of Electric Division Assistant Director George McCluskey (Staff Report).[1] In advance of the Staff Report's filing, Staff engaged in a series of collective stakeholder meetings with interested persons and organizations, including the three New Hampshire EDCs, and also met bilaterally with certain stakeholders to clarify their proposals for resolving gas constraint issues and related data responses. This process resulted in a large volume of written materials, including bilateral data requests and responses between Staff

[1] The Staff Report is available here: http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-124/LETTERS-MEMOS-TARIFFS/15-124%202015-09-15%20STAFF%20REPORT.PDF

and certain stakeholders, which are posted for public inspection on the Commission's website at: http://www.puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html. Also, the Commission granted leave for interested persons to file comments directly with the Commission regarding the Staff Report by October 15, 2015. Those comments are posted at: http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-124.html

## II. ACCEPTANCE OF STAFF REPORT AND STAKEHOLDER COMMENTS

The Staff Report is an overview of the natural-gas capacity constraints in the New England energy market from a multi-disciplinary perspective: economic, legal, financial, engineering, and environmental. Interested persons are urged to read the Staff Report and the other primary-source materials generated by Staff and stakeholders through this investigation to inform themselves of the issues at hand. We will not attempt to condense or summarize the broad scope of material available for public inspection, or distill the many varied perspectives presented by Staff and stakeholders. With one exception (discussed below), the Commission will also not make judgments at this time regarding the factual content and policy positions outlined in the Staff Report, the submissions by the various stakeholders, and the data requests/responses available for inspection. That said, it is clear that Staff engaged in a thorough analysis of the questions presented in the Order of Notice and the factual information at its disposal. The Commission will therefore accept the Staff Report as compliant with the directives set out by the Commission for the investigation in Docket No. IR 15-124, and accept the companion stakeholder comments.

## III. FUTURE REVIEW PROCESS FOR GAS CAPACITY-RELATED PETITIONS

The Staff Report indicated that, in Staff's view, there exists a path under New Hampshire law for the approval of acquisitions of natural gas capacity resources by New Hampshire EDCs for the economic benefit of their customers and the customers of other regional EDCs. *See* Staff Report at 9-13. As indicated by their comments, this position was accepted by certain stakeholders and opposed by others. It is clear to the Commission, from a review of the Staff Report, stakeholder comments, and ancillary materials made publicly available through this investigation, that no consensus exists regarding the potential legality of such an acquisition of gas capacity by a New Hampshire EDC. Furthermore, we expect that such a capacity acquisition would be highly controversial.

The Commission thus intends to rule on the question of whether a New Hampshire EDC has the legal authority to acquire natural gas capacity resources to positively impact electricity market conditions, only within the context of a full adjudicative proceeding conducted pursuant to the New Hampshire Administrative Procedure Act, RSA Chapter 541-A, and only in response to an actual (as opposed to hypothetical) petition. Such a proceeding would be opened if and when a New Hampshire EDC files a petition for a proposed capacity acquisition, and related cost recovery. The Commission would consider the petition in separate phases. In the first phase, the Commission would review briefs submitted by the petitioner EDC, Staff, and other parties regarding whether such capacity procurement is allowed under New Hampshire law. If the Commission were to rule against the legality of such acquisition, the petition would be dismissed. If the Commission were to rule in the affirmative regarding the question of legality, it would then open a second phase of the proceeding to examine the appropriate economic, engineering, environmental, cost recovery, and other factors presented by the actual proposal. This second phase would involve the usual procedural features of discovery, testimony, rebuttal testimony, and cross-examination, provided in any adjudicative proceeding before the Commission.

## IV. EXPECTED COMPETITIVE BIDDING FOR CAPACITY

As is clear from the Staff Report and the extensive comments filed in this docket, there is no New Hampshire precedent for EDCs to purchase gas pipeline capacity for electric generators. That is different from the situation with local gas distribution companies (LDCs) which sell gas on the retail market. An essential part of an LDC's business is the procurement of gas supply for its customers. In New Hampshire, our two gas LDCs are required to file Least Cost Integrated Resource Plans under RSA 378:37 *et. seq*. that lay out how they expect to fulfill their obligations to customers. It is not unusual for an LDC to make a firm commitment to purchase capacity on a gas pipeline. The LDCs know they must follow appropriate competitive processes for their gas supply and capacity purchases. Each such procurement is subject to scrutiny to make sure that the decision is consistent with prudent utility practice.

As indicated, the Commission is not going to rule on substantive questions at the present time regarding the legality or specific attributes of a natural gas capacity related procurement. Nonetheless, due to the practicalities of private-sector contracting for such capacity taking place in advance of petitions for regulatory approval, the Commission will outline one policy directive to EDCs and stakeholders related to the terms under which such acquisitions would be made. Under the Commission's Affiliate Transactions Rules, N.H. Code Admin. Rules, Chapter Puc 2100, there exists a strong policy preference against self-dealing in relations between New Hampshire EDCs and their unregulated affiliates.

Functionally, this would tend to militate against the use of a sole-source acquisition approach by a New Hampshire EDC seeking to only acquire a gas capacity product from its competitive, unregulated affiliate. Also, there is a recognition in private industry and regulatory bodies throughout the United States that competitive bidding acquisition processes provide powerful benefits for ensuring prudency in utility expenditure and, by extension, cost savings for utility customers, through the introduction of cost discipline, open participation by competitors, and choices in product acquisition. Those benefits were identified in the Staff Report, which strongly advocated in favor of requiring that any gas capacity acquisition program by a New Hampshire EDC be predicated on competitive evaluation and selection processes undertaken by entities unaffiliated with the project sponsors. Staff Report at 11-12, and 46-47. We agree. The Commission expects 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 EDC's corporate affiliates or business partners would also be able to participate. Furthermore, this competitive solicitation process should be open to all categories of gas capacity product, including pipeline, Liquified Natural Gas, and Compressed Natural Gas capacity. It would also include storage solutions to ensure maximal choice and potential cost savings. In addition, in recognition of various state gas capacity procurement efforts occurring throughout the New England region, the Commission would accept a New Hampshire EDC's participation in another state's RFP platform where the evaluation and selection of competing projects is the responsibility of entities that have no affiliation with any of the project sponsors.

## V. CONCLUSION

The Commission wishes to thank the Staff for its hard work during this investigation, and for the preparation of the Staff Report and ancillary materials. The Commission also extends its appreciation for the various stakeholders' engagement with this process, for their comments, and for their ongoing interest in this matter of great importance to our State.

**Based upon the foregoing, it is hereby**

**ORDERED**, that the Staff Report and companion stakeholder comments in this instant investigation are ACCEPTED, and that future petitions for gas capacity acquisition programs be governed by the policy approaches outlined in this Order.

By order of the Public Utilities Commission of New Hampshire this nineteenth day of January, 2016.

Martin P. Honigberg
Chairman

Kathryn M. Bailey
Commissioner

Attested by:

Debra A. Howland
Executive Director

**SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED**

**Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.**

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Docket #: 15-124-1 Printed: January 20, 2016

**FILING INSTRUCTIONS:**

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

IR 15-124

# Report on Investigation into Potential Approaches to Mitigate Wholesale Electricity Prices

Prepared by:

The Staff of the New Hampshire Public Utilities Commission

September 15, 2015

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## EXECUTIVE SUMMARY

In April of this year, the New Hampshire Public Utilities Commission announced in an Order of Notice the opening of a non-adjudicative investigation, to be conducted by its Staff, into potential approaches involving New Hampshire's electric distribution companies (EDCs) to mitigate the high and volatile electricity prices that have affected electricity markets in New Hampshire and other New England states in recent winters. On June 2, Staff received twenty five sets of comments from stakeholders in the investigation, some of which include detailed solutions to the high electricity price problem. Two such solutions (Access Northeast and PNGTS) propose to expand existing New England natural gas pipelines whereas a third (Northeast Energy Direct) is based on the construction of a new "greenfield" pipeline that runs through Massachusetts and New Hampshire. All three pipeline-based solutions propose to deliver significant volumes of incremental natural gas supplies to New England from the Marcellus Shale gas formation in Northeastern Pennsylvania. Another stakeholder (CLF) proposes to address the problem not by adding incremental pipeline capacity but by increasing the utilization of the region's existing LNG infrastructure, which it defines as the combination of local gas distribution company (LDC)-owned satellite liquefied natural gas (LNG) storage and vaporization facilities and LNG import terminals. Other stakeholders have suggested the introduction of a combination of energy efficiency, demand response, and distributed generation solutions, without specifying the costs and benefits of such an approach.

In addition to the above referenced comments and solutions, Staff and several stakeholders submitted memoranda addressing the legal question set forth in the Order of Notice; namely, whether New Hampshire EDCs, under existing New Hampshire law, have the authority to enter into contractual arrangements with sponsors of regional projects to acquire pipeline and/or LNG related products and services to benefit their customers and, if so, whether the associated costs can be recovered from EDC customers through Commission-approved rates.

In this executive summary we summarize our key findings regarding the legal question and the detailed solutions proposed to mitigate the high and volatile wholesale electricity prices. In brief, we view Access Northeast and Northeast Energy Direct (NED) as two very cost-effective projects that will moderate future winter electricity prices though the numbers clearly indicate that NED will provide the greatest benefits to regional electricity customers. Nonetheless, Staff's principal recommendation in this report is that if the Commission chooses to participate in a regional procurement of gas capacity (whether pipeline or LNG) for the benefit of electricity consumers it should condition that participation on the procurement being conducted through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. Our key findings are as follows:

1) From a legal perspective, Staff has concluded that the Commission may hold that New Hampshire EDCs have authority to enter into gas capacity contracts for the benefit of gas-fired generators, if such a proposal were to be made by a New Hampshire EDC.

2) All three of the pipeline-based projects will enhance electric grid reliability by providing gas generators access to firm fuel supplies through the provision of firm transportation and no-notice services. The sponsors of the Access Northeast project even assert that their solution is designed first and foremost to enhance electric grid reliability rather than mitigate high and volatile electricity prices; a statement Staff finds difficult to understand given that the region already has 6,000 MW of gas generation capacity with dual-fuel capability to

protect against gas supply interruptions.[1] In addition, ISO-NE's Pay for Performance capacity market redesign, which is expected to become fully operational in June of 2018, will provide both financial incentives and penalties to existing generators to improve generator performance and to new gas generators to improve fuel assurance. For these reasons, Staff places less weight on reliability benefits and more weight on the benefits of price mitigation.

3) In a report prepared for the sponsors of the Access Northeast project, ICF International projects that under normal weather conditions and without Access Northeast January average natural gas prices will increase steadily from about $15/MMBtu in 2019 to about $23/MMBtu in 2028 due to expected growth in the demand for natural gas for heating and electric generation and decreased gas supplies from Atlantic Canada.

4) With Access Northeast but without taking into account the positive effects of reduced price volatility, ICF projects January average natural gas prices to remain at relatively high levels ranging from $12/MMBu to $20/MMBtu over the 2019 through 2028 period, a result that reflects an expectation of continued bottlenecks on the Algonquin pipeline. The $3/MMBtu reduction in average January gas prices, which together with smaller average price reductions in other months, translates to an annual average wholesale energy cost saving of $450 million over the first ten years after the project is placed in service.

5) When the effects of reduced price volatility are taken into account, ICF estimates wholesale energy cost savings to increase by an additional $330 million annually under a low price volatility scenario and by $750 million annually under a high price volatility scenario. Overall, the total annual average wholesale energy cost savings are estimated at $780 million to $1.2 billion for the low and high volatility scenarios respectively. The corresponding annual cost to achieve these savings is estimated at about $600 million.

6) Based on these savings and cost estimates, Staff estimates the benefit to cost ratio for the Access Northeast project to be in the range of 1.3 to 2.0. Further, in order to allow such a cost-effective project to proceed, we estimate that the Commission would need to approve a distribution surcharge on all New Hampshire electricity consumers of about 4.8 mills per kWh. Revenues received from the release of the pipeline capacity to gas generators or to secondary market participants could result in a lower distribution surcharge.

7) Tennessee Gas Pipeline's NED project will deliver up to 1.3 Bcf/day of firm gas supplies from Wright, New York to several existing New England pipelines in the vicinity of Dracut, Massachusetts. Upon completion of the NED project, TGPwill have the ability to physically deliver into every pipeline system serving New England as well as to incrementally serve markets along its own pipeline system. In addition, because of the location the NED pipeline relative to the Central Massachusetts Hub (Mass Hub) area, TGP could play a critical role in serving future new generation expected to be located in that area.

[1] Or 1,000 MW more than the sponsors of Access Northeast contend is needed to supply load reliably.

8) In a report prepared for TGP on the impact of the NED project on New England gas and electricity markets, ICF[2] projects that under normal weather conditions and without NED in place January average natural gas prices will increase steadily from about $15/MMBtu in 2019 to about $30/MMBtu in 2028.[3] To put these prices in context, the average Algonquin citygate price for January 2014, an extremely cold month, was about $23/MMBtu and February 2015, the coldest Febuary on record, was $17/MMBtu.

9)With NED but without taking into account the positive effects of reduced price volatility, ICF projects January average natural gas prices to range from about $10/MMBu to $18/MMBtu over the 2019 through 2028 period, equivalent to January average price reductions of $5/MMBtu to $12/MMBtu. These average price reductions when combined with smaller average price reductions in other months translates to an annual average wholesale energy cost saving of $2.1 billion over the first ten years after the project is placed in service.

10) When the effects of reduced price volatility are taken into account, ICF estimates total annual average wholesale energy cost savings for NED to range from $2.1 billion to $2.8 billion assuming zero volatility and high volatility scenarios respectively. The corresponding annual cost of the electric portion of the NED project is estimated at $400 million.

11) Based on the above savings and cost estimates, we estimate the benefit to cost ratio for the NED project to be in the range 5.25 to 7.0 not including the value of enhanced electric grid reliability and the investment cost to provide enhanced transportation services. Further, in order to allow such a cost-effective project to proceed, we estimate that the Commission would have to approve a distribution surcharge on all New Hampshire electricity consumers of about 3.3 mills per kWh. Revenues received from the release of the pipeline capacity to gas generators or to secondary market participants would further lower the distribution surcharge

12) While Staff has no reason to believe that the new pipeline expansion project proposed by Portland Natural Gas Transmission System (PNGTS) will not also enhance electric grid reliability and mitigate winter electricity price spikes, the magnitude of the potential improvements is unknown because PNGTS is in a fairly early stage of its project-development process, and has not been able to convey cost estimates as of this present time.

13) According to CLF, the most cost-effective way to address the current shortage of pipeline capacity is not to construct new or expanded pipelines from the west but to increase the utilization of the region's existing LNG infrastructure, which it defines as the combination of LDC-owned satellite LNG storage and vaporization facilities and onshore and offshore LNG import facilities. Under CLF's proposal, the LNG import facilities would be used in conjunction with expanded truck deliveries to refill the satellite LNG facilities to effectively base-load

[2] That is, the same consulting firm used by sponsors of the Access Northeast project but under a separate engagement. ICF used the same methodology for both reports.
[3] See footnote 56 for an explanation of why the ICF gas price projection in the NED report differs from the corresponding projection in the Access Northeast report.

these LDC assets. This would create, a winter-only LNG "pipeline" for LDCs to supply gas customer demands on 50 days each winter when the demand for natural gas is projected to exceed pipeline capacity with excess supply available for release to gas generators. Though Staff does not take a position on CLF's proposal at this time, we do note that ICF has recently projected that under normal weather conditions daily gas demands in 2020 will exceed daily supply capacity on 63 days and in 2035 by 113 days. Further, under design weather conditions the duration of capacity deficits is projected to increase from 78 days in 2020 to 122 days in 2035. Assuming ICF's projections to be accurate, the volume of LNG required to meet the capacity deficits (under both normal and design weather conditions) will be far greater than CLF has estimated, thus significantly reducing if not eliminating the claimed cost savings relative to pipeline capacity purchases.

14) In the event the New England states decide as a group to proceed with the procurement of incremental pipeline capacity on a regional basis, Staff strongly recommends that procurement not be based on the results of pipeline open seasons. Given that the capacity purchased by EDCs will be paid for by the customers of those companies and not by the shareholders, Staff believes that it is incumbent on regulators to ensure that the needed capacity be allocated among pipeline projects through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. Because most of the largest EDCs in New England are affiliated with the sponsors of one of the competing pipeline projects, we believe it will be difficult if not impossible for EDCs to make a convincing case that pipeline open seasons qualify as fair, open and transparent competitive processes. For this reason, Staff believes it is imperative that the states develop and post for comment an alternative competitive solicitation process (i.e., a Request for Proposals). In Staff's opinion, the terms and conditions for a gas capacity RFP including the criteria for bid evaluation should be the responsibility of the states assisted by an independent consulting firm with extensive expertise in gas and electricity procurement matters.

Absent a demonstrably competitive solicitation, Staff foresees a significant risk that the negotiations between a project sponsor and potential customers will not be at arms-length and thus will not produce the most advantageous cost and commercial terms for consumers. We also foresee the prospect of lengthy and costly delays due to litigation initiated by aggrieved project sponsors.

## INTRODUCTION

On April 17, 2015, the New Hampshire Public Utilities Commission (Commission) announced in an Order of Notice (Order) the opening of a non-adjudicative investigation, to be conducted by its Staff, into potential approaches involving New Hampshire's electric distribution companies (EDCs) to mitigate the high and volatile winter electricity prices affecting electricity markets in New Hampshire and other New England states.[4] As noted in the Order, competition in wholesale and retail electricity markets had, until recently, kept electricity prices at reasonable levels for New Hampshire consumers. The past two winters, however, have seen significant changes in New Hampshire's wholesale and retail electricity markets, and those of the New England region generally; changes that some have attributed to the increasing dependence on natural gas generation plants to supply the region's electricity requirements.

On May 12, 2015, Staff met informally with interested stakeholders regarding its investigation and invited them to propose specific detailed solutions to the problem, no later than June 2, 2015. Detailed guidance on the content of submissions including commercial and analytical data was communicated to stakeholders through a May 14 letter from Staff, a copy of which was placed on a public website created especially for the investigation. In addition, written comments that do not offer specific solutions but instead provide advice on how the state and the region should address the winter price problem were welcomed. Staff also advised that it could issue written questions to stakeholders that make submissions, and also potentially schedule bilateral meetings with certain stakeholders. Staff questions and stakeholder responses were also placed on the public website.

On June 2, 2015, Staff received twenty five submissions including two solutions that propose the expansion of existing New England natural gas pipelines and one solution that is based on the construction of a new "greenfield" natural gas pipeline that runs through Massachusetts and New Hampshire. All three pipeline-based solutions propose to deliver to New England significant volumes of incremental natural gas supplies from the Marcellus Shale deposit in Pennsylvania. In addition, two stakeholders proposed that the problem be solved through the use of existing or new LNG storage facilities located within New England. Others have proposed to address the problem through a combination of expanded energy efficiency programs, increased importation of Canadian hydroelectricity and increased development of renewable resources. All submissions are available for public inspection on the Commission's website, as are Staff's written questions and stakeholder responses, here:
http://www.puc.nh.gov/Electric/Investigation_into_Potential_Approaches_to_Mitigate_Wholesale_Electricity_Prices.html.

During the course of our investigation, we conducted a number of interviews with nine stakeholders to better understand how the proposed solutions will work in practice including obtaining better information on the potential costs and benefits of each project.

In addition, Staff and several stakeholders submitted memoranda addressing the legal question set forth in the Order; namely, whether New Hampshire EDCs, under existing New Hampshire law, have the authority to enter into contractual arrangements with project sponsors to acquire pipeline and/or LNG-

[4] Staff's investigation is limited to issues relating to the high and volatile electricity prices that have affected regional electricity markets over the past few winters and therefore does not address other important issues like project siting and the impacts to the environment and landowners that are the responsibility of other state and federal agencies.

related capacity to benefit their customers and, if so, whether the associated costs can be recovered from EDC customers through Commission-approved rates. Staff also hereby requests that the Commission grant leave for stakeholders to file comments with the Commission on Staff's report, which summarizes the investigation and the findings based on that investigation. Staff suggests that stakeholders be given one month after the filing of our report, until October 15, 2015, to submit their comments.

## LEGAL ANALYSIS OF EDC AUTHORITY TO ENTER INTO PIPELINE CAPACITY CONTRACTS

As an initial matter, Staff wishes to clarify that in its analyses of the legal questions related to potential acquisition of gas infrastructure capacity by New Hampshire EDCs, Staff is not proposing any solution to the Commission. In actuality, Staff is analyzing the potential solutions that have been proffered by certain stakeholders. Therefore, characterizing Staff's discussion of such potential solutions in the context of this Investigation as a "Staff proposal," or a "proposal favored by Staff"[5] is not adequately precise, nor is it accurate.

Staff engaged in an initial discussion of legal issues related to this Investigation in a memorandum dated July 10, 2015 (July 10 Memorandum), which was made available to stakeholders and the public via the NHPUC website.[6] In response, several stakeholders (the Conservation Law Foundation (CLF)[7], the Office of the Consumer Advocate (OCA)[8], Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource)[9], Algonquin Gas Transmission, LLC/Spectra Energy Partners, LP (Spectra)[10], Tennessee Gas Pipeline Company, L.L.C (TGP)[11], the New England Power Generators Association, Inc. (NEPGA)[12], and the Coalition to Lower Energy Costs (CLEC)[13]) issued responses to the July 10 Memorandum on August 10, 2015. These responses presented a wide diversity of views regarding the potential legality of New

[5] *See* OCA Response to Staff, August 10, 2015 at p. 2.
[6] *See* Memorandum of Alexander Speidel to George McCluskey, July 10, 2015, at http://www.puc.nh.gov/Electric/Wholesale%20Investigation/20150710%20IR%2015-124%20Staff%20Legal%20Memorandum%20on%20Authorities%207-10-15.pdf
[7] CLF August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/2015-08-10%20CLF%20Comments%20on%20Staff%20Legal%20Memorandum.pdf
[8] OCA August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/OCA%20Comments%20re%20Staff%20Memo%208-10-15.pdf
[9] Eversource August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Cover%20Letter%20to%20August%2010%20Reply%20Comments.pdf
[10] Spectra August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Spectra%20Energy%20comments%20on%20Staff%20Legal%20Memorandum%2015-124%20(3).pdf
[11] TGP August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Comments%20of%20TN%20Gas%20Pipeline%20Co.%20on%20Staff%20Legal%20Memo%208-10-15.PDF
[12] NEPGA August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/NEPGA%20Comments%20to%20Staff's%207-10-15%20Memo%20IR%2015-124%20(8-10-15).pdf
[13] CLEC August 10 Response, at: http://www.puc.nh.gov/Electric/Wholesale%20Investigation/Comments%20of%20CLEC%20to%20Staff%20Memo%208_10_15.PDF

Hampshire EDCs acquiring gas pipeline capacity for the ultimate use of gas generators. Having reviewed the responses of these stakeholders, and having considered the matter further, Staff re-adopts the conclusions of the July 10 Memorandum, with the following expansions and clarifications.

*On the question of whether the New Hampshire Electric Restructuring Statute (RSA Chapter 374-F) allows or prohibits New Hampshire EDCs to engage in such activities*:

In their responses to the July 10 Memorandum, certain stakeholders supported the proposition that RSA Chapter 374-F allows for the acquisition of pipeline capacity by New Hampshire EDCs (CLEC, Eversource, Spectra, TGP), and others (CLF, NEPGA, OCA) opposed this proposition. In its July 10 Memorandum, Staff indicated that the Commission could conceivably hold that RSA 374-F allows such activity by EDCs. Staff re-affirms this position.

In Staff's view, the Commission could determine that the Restructuring Policy Principle delineated in RSA 374-F:3, III, regarding the functional separation of generation services from transmission and distribution services, could be complied with by an EDC acquiring gas capacity on behalf of merchant generators, insofar as separate ownership of the actual generation plants will remain in the hands of merchant generation companies, rather than the EDCs. The Commission could therefore find that an adequate level of "functional separation" for the purposes of RSA 374: F-3, III is thereby maintained.

Furthermore, Staff continues to recognize that the Commission could reasonably find that the functional-separation principle of RSA 374: F-3, III should be read in concert with the other Restructuring Policy principles of RSA Chapter 374-F. RSA 374-F: 3, I states: "Reliable electricity service must be maintained while ensuring public health, safety, and quality of life." RSA 374-F: 3, VI: "A nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system may be used to fund public benefits related to the provision of electricity. Such benefits, as approved by regulators, may include, *but not necessarily be limited to*, programs for low-income customers, energy efficiency programs, funding for the electric utility industry's share of commission expenses pursuant to RSA 363-A, support for research and development, and investment in commercialization strategies for new and beneficial technologies" (emphasis added). RSA 374-F: 3, XII: "New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process." RSA 374-F: 3, VIII: "Continued environmental protection and long term environmental sustainability should be encouraged….As generation becomes deregulated, innovative market-driven approaches are preferred to regulatory controls to reduce adverse environmental impacts."

Staff considers these other Restructuring Policy Principles to be of similar importance to the functional separation principle, and therefore, Staff believes that the Commission could rule, in response to a proposal being made by a New Hampshire EDC, that the potential benefits of a gas-capacity acquisition project would foster the overall goals of the Restructuring Policy Principles of RSA 374-F. These goals include, but are not limited to: cost savings for distribution customers of EDCs; enhanced reliability for New England's increasingly gas-dependent electric generation fleet and electric transmission system; and environmental benefits from the displacement of inefficient coal and oil generation units by highly efficient gas generation units. Staff believes that quality evidence of such benefits will be of critical importance in gauging the appropriateness of a given proposal under RSA 374-F.

*On the question of statutory/corporate authority for New Hampshire EDCs to engage in such activities*:

In its July 10 Memorandum, Staff indicated that RSA Chapter 374-A offered the most foursquare authorization for New Hampshire EDCs to acquire gas pipeline capacity on behalf of merchant generators. In response, Eversource stated that RSA Chapter 374-A "is not directly applicable to the potential solution described by Eversource."[14] Instead, Eversource pointed to RSA 374:57, relating to the "Purchase of Capacity" as the "most appropriate" basis for potential Commission review of Eversource's proposal.[15] CLEC stated, in its August 10 response, that "there is no need to find specific language in NH law authorizing EDCs to purchase pipeline capacity," as the general corporate powers delineated in RSA Chapter 295 granted such authority.[16] TGP concurred generally with Staff's analysis of RSA 374-A in its August 10 response, while CLF and NEPGA directly opposed Staff's conclusion regarding RSA 374-A.[17]

Staff re-affirms its July 10 Memorandum analysis of RSA Chapter 374-A. Staff does note, however, that the New Hampshire EDC most likely to submit an actual proposal for Commission review, Eversource, has indicated that it would likely rely upon RSA 374:57, not Chapter 374-A, as its primary statutory authority in its proposal. In its July 10 Memorandum, Staff characterized the 374:57 statute as providing "additional indirect statutory support."[18] Staff views the applicability of RSA 374:57 to gas capacity acquisitions, in addition to electric capacity acquisitions, to be the key question for Commission resolution regarding the applicability of this statute to the activities being proposed by Eversource. Given that the plain language of the statute does not specify the type of capacity (the term "capacity" being in common use in both the gas and electric industries), the Commission could rule that gas capacity purchases were contemplated by RSA 374:57, and therefore allowed.

Staff also takes note of the disallowance and public-interest review standards of RSA 374:57 ("The commission may disallow, in whole or part, any amounts paid by such utility under any such agreement if it finds that the utility's decision to enter into the transaction was unreasonable and not in the public interest"), to which the following criteria (delineated in the July 10 Memorandum) should be applied by the Commission: (1) There must be a clear, verifiable cost-benefit advantage for EDC customers that would result from enactment of the gas capacity program. Such an advantage should be demonstrated through hard pricing data and quality studies. If the program is limited to recovery from Default Service customers (authority sought pursuant to RSA 374-F:3, V(e)), rate reductions for Default Service must be demonstrated. If rate recovery is sought from all EDC customers, through distribution rates, electricity cost savings for all customers, including those taking competitive supply, must be demonstrated; (2) in order for rate recovery to be held just and reasonable, and the program costs in rates to be considered prudently incurred, it is imperative that EDC gas capacity-acquisition arrangements with pipeline and/or LNG counterparties be accomplished at arm's length, in compliance with affiliate transaction rules, and through RFP-based project selection processes applying least-cost and reliability criteria in EDC decision-making; (3) an EDC seeking Commission authority to engage in gas-capacity acquisition should demonstrate that such activity would not result in "re-vertical integration" of the ISO-New England wholesale electricity market, would not result in undue competitive harms to New Hampshire

[14] Eversource August 10 Response at p. 11.
[15] Eversource August 10 Response at pp. 11-14.
[16] CLEC August 10 Response at pp. 2-6.
[17] *See* TGP, CLF, and NEPGA August 10 Responses.
[18] July 10 Memorandum at 5.

competitive electric suppliers, nor impair the ability of the Commission to manage New Hampshire's competitive electric and gas markets; (4) an EDC seeking authority to engage in such gas-capacity arrangements must demonstrate that the proposed program will not result in stranded, or deferred, costs for EDC customers.

*On the question of cost recovery for such EDC investments*:

In its August 10 response, Eversource indicated that it would not seek to place its proposed investments of gas capacity, made pursuant to RSA 374:57, into its EDC rate base.[19] Eversource generally indicated that "[s]imilar to the manner in which power purchase agreements ('PPAs') have been handled in New Hampshire, the expenses of the [gas capacity] contract would be reduced by the revenues generated when the capacity was released and sold, and the resulting amounts would either be credited to, or recovered from, customers from their rates. It would not be an item in the EDC's rate base subject to traditional cost-of-service ratemaking."[20]

Staff points to RSA 378:8, which establishes the general principle that a utility seeking higher rates bears the burden of proving the necessity of the increase. Staff would expect the Commission to apply the traditional ratemaking criteria of least-cost procurement, prudency, and allocation fairness to any surcharge sought by an EDC for gas capacity activities, and that any surcharge should be justified by a proposing EDC under a specific statutory provision, or provisions, of New Hampshire law.

*On the need for competitive bidding for pipeline capacity*:

Staff, in its July 10 Memorandum, strongly advocated for the requirement that New Hampshire EDCs seeking to acquire gas pipeline capacity do so through a competitive bidding (Request for Proposals, or RFP) process, in which different pipeline companies would compete for the EDCs' contracts.[21] Staff also pointed to the need by EDCs to maintain compliance with affiliate transaction rules within any gas-capacity acquisition program, an issue also discussed by NEPGA in its August 10 response.[22] Staff reiterates, in the strongest terms, that Staff views RFP-based competitive processes to be critical to the economic procurement of gas capacity at the lowest cost by EDCs from pipeline developers, and Staff will not support any EDC proposal that fails to incorporate such a competitive process in its capacity procurement structure. Staff strongly disagrees with Spectra's conclusion that there is an "absence of a legal mandate for an RFP"[23]; such processes are critical for protecting ratepayer interests, and ensuring that cost recovery of such investments are just, reasonable, and in the public interest.

*On federal preemption, and litigation risk generally*:

Staff acknowledges that the role of the states in overseeing wholesale electricity and gas markets, in parallel with the primary jurisdiction of the Federal Energy Regulatory Commission (FERC), is currently in flux, and subject to challenge. A minimalist position, shared by some industry advocates and others, has developed which holds that states cannot act directly in shaping wholesale market outcomes through mandatory procurement programs, nor can states even approve, through their regulatory bodies'

[19] Eversource August 10 Response at pp. 14-15.
[20] Eversource August 10 Response at p. 15.
[21] July 10 Memorandum at p. 7.
[22] NEPGA August 10 Response at p. 11.
[23] Spectra August 10 Response at p. 7.

adjudicative processes, initiatives which could impact prevailing wholesale market prices and/or competitive conditions. This minimalist position, which fundamentally rejects any "dual responsibility" by both the FERC and states in wholesale market oversight, has been bolstered by recent (2014) decisions by the Third and Fourth Circuit U.S. Courts of Appeals in the *PPL EnergyPlus, LLC* cases, regarding New Jersey and Maryland mandates and incentives for specific generation-resource siting. These decisions, upholding the U.S. District Courts' decisions to strike down the state programs under the Supremacy Clause of the U.S. Constitution, on the basis that the states' incentive programs for generation violated FERC's jurisdiction over wholesale transactions and rate-setting under the Federal Power Act, were very broad in their language, implying that states' wholesale market activities would be subject to close judicial scrutiny going forward.[24] (Maryland and New Jersey have each sought Writs of Certiorari from the U.S. Supreme Court regarding the Circuit Courts' decisions, and similar litigation is pending before U.S. District Courts in Connecticut and Rhode Island).

Staff recognizes that state programs mandating acquisition of gas capacity by EDCs could face challenge under the *PPL EnergyPlus* line of reasoning. However, Staff does not share the view that a Commission adjudication, approving the elective acquisition of gas capacity by EDCs, would somehow trigger Supremacy Clause preemption. If the proposition that no Commission action that had an "impact" on wholesale electric and/or gas rates was allowed under the Federal Power Act or Natural Gas Act were to stand, many routine Commission approval processes (such as acceptances of precedent agreements by New Hampshire gas LDCs) could be purportedly disallowed as "preempted." Staff rejects this approach, and believes that Commission approval of a procurement investment decision by a market participant subject to its jurisdiction, that is, a New Hampshire EDC, does not run afoul of federal preemption.

Staff cannot predict how FERC would approach an innovative program such as that proposed by Eversource under the Federal Power Act and the Natural Gas Act. FERC could accept this program as a timely solution to gas-electric coordination problems, or it could reject it as unacceptable under principles such as FERC's "open-access" gas capacity allocation structure established pursuant to the Natural Gas Act and FERC precedent. Staff would expect that any Commission approval for a New Hampshire EDC would be subject to a condition of FERC/federal approval of the program.

That said, it can be expected that vigorous litigation, within and beyond the Commission, would arise from any Commission review of an EDC proposal to acquire gas capacity for the ultimate use of merchant generators. CLF, NEPGA, and OCA were clear in their August 10 responses that they did not see any legal basis for Commission action to approve such activities, or to grant rate recovery for such activities, and other stakeholders have expressed their dismay with the prospects of such a program. At every decision point, parties could challenge Commission determinations in either direction, and Staff does not expect that an approval process would prove to be as abbreviated as certain stakeholders expect (e.g., Spectra: "Spectra Energy recommends that the Commission accepts EDC contracts for filing so that review and approval may be obtained no later than the end of this calendar year.")[25]

[24] Fourth Circuit Decision (re: Maryland), dated June 12, 2014, available at:
https://statepowerproject.files.wordpress.com/2014/03/4th-cir-opinion-060214.pdf ;
Third Circuit Decision (re: New Jersey), dated September 11, 2014, available at:
https://statepowerproject.files.wordpress.com/2014/03/3rd-cir-nj-decision.pdf

[25] Spectra August 10 Response at p. 7.

## THE CAUSE OF HIGH AND VOLATILE ELECTRICITY PRICES

The May 14 guidance issued by Staff on the content of submissions began by inviting stakeholders to identify the root cause of the high and volatile winter period wholesale and/or retail electricity prices. Almost all of the stakeholders that addressed this issue directly expressed the opinion that cause of the problem can be attributed to a wholesale market imbalance of supply and demand for natural gas. Eversource, for example, asserted that this issue has been extensively studied in the last few years, with the studies reaching the almost universal conclusion that increased reliance on natural gas as a fuel for electric generation without a corresponding expansion of natural gas capacity resources into New England leads to pipeline constraints during the winter months and in turn high and volatile wholesale gas and electricity prices. Elimination of these pipeline constraints will require, according to Eversource, the construction of incremental pipeline capacity resources "as no other comparable resource is reasonably available in an adequate quantity to alleviate the supply and demand imbalance in the wholesale electricity market."

Spectra agreed that the lack of adequate natural gas pipeline infrastructure to supply regional electric generation is the primary cause of the high gas and electricity prices and, moreover, of diminished electric reliability in New England. The reason for the high prices, according to Spectra, is that the increased utilization of natural gas for home and commercial heating, industrial uses and electric generation has made the demand for firm interstate pipeline capacity in New England extremely competitive. This increasing demand has placed additional burdens on an infrastructure that was already constrained resulting in natural gas and electricity prices that are higher in New England than in markets elsewhere in North America.

CLEC noted that the Low Demand Study prepared for the Massachusetts Department of Energy Resources in early 2015, which took into account all technologically and economically feasible alternative energy resources, concluded that "[i]nsufficient natural gas capacity for the electric sector has contributed to high wholesale gas prices to generators and thus high electricity prices."

Even CLF, which appears to question in its comments whether the region actually has a high winter period electricity price problem, says in a report submitted on its half that the dramatic gas and electricity price spikes of winter 2013/14 were the result of not enough natural gas to meet demand.

Only one stakeholder, Ms. Martin, appears to question that the cause of the high price problem rests with natural gas supply winter shortages. Ms. Martin argues that the EIA electric price data cited in the Order relate to early 2015 and therefore takes no account of the lower rates in effect during the second half of the year. According to Ms. Martin, all New Hampshire utilities announced significant default service rate reductions for the second half of 2015. Averaged over the course of the year, New Hampshire electric bills have not risen dramatically above the bills paid in previous years.

Ms. Martin also argues that customers do not pay rates, but rather bills based on usage, and New England and New Hampshire customers use less electricity than most regions and states. In the case of New Hampshire residential households, Ms. Martin argues that the most recent full year price data, from 2014, when combined with the most recent average usage data, from 2013, show that New Hampshire residential electric bills were 29th highest in the United States and the District of Columbia, below the national average. Residential bills in New England overall were very consistent with the national average, and less than in the regions often cited for lower energy costs such as the South and the Middle Atlantic.

The May 14 guidance then invited stakeholders to propose solutions to the high electricity price problem and to explain in detail how the solutions would reduce prices at the wholesale and/or retail levels. Each of these project proposals are described below beginning with the Access Northeast project. These are followed by brief summaries of comments from stakeholders that do not offer specific solutions.

## ACCESS NORTHEAST

### Project Overview

Spectra, Eversource and National Grid, the joint owners of the Access Northeast project, have submitted a solution that they contend is designed first and foremost to enhance electric grid reliability through the provision of a new Energy Reliability Service (ERS) tariff for firm transportation customers that depends in part on the supply of natural gas from new LNG storage facilities.[26] The key features of the ERS are described below. In addition to enhancing electric grid reliability, the sponsors assert that Access Northeast will mitigate the expected future high and volatile winter period gas and electricity prices.[27]

The Access Northeast project will provide incremental firm transportation service to gas generators through a 0.5 billion cubic feet per day (Bcf/day) expansion of the existing Algonquin and Maritimes pipelines largely through the use of the "lift and lay" method, which requires the removal of smaller diameter pipe and its replacement with larger diameter pipe in the existing pipeline right of way. The expansion will also include looping in areas where extra capacity is needed.[28] As noted, Access Northeast also includes new LNG storage facilities with a combined usable capacity of 6.0 Bcf, which when combined with liquefaction and vaporization equipment will deliver up to 0.4 Bcf /day of gas on peak winter days.

Together these facilities will provide <u>up to</u> 0.9 Bcf/day of incremental capacity, sufficient according to the sponsors to supply approximately 5,000 MW of generating capacity.[29] According to the sponsors, 5,000 MW is the amount of gas-fired generation capacity that must have firm fuel supplies on peak winter days in order for load to be served reliably.[30] Although Access Northeast has been marketed to electric (rather than gas) distribution companies, one of the sponsors has been quoted as saying that the project has received interest from both EDCs and LDCs and that negotiations on long-term contracts with both have begun. Staff understands that any long term commitments with LDCs will be met from an expansion of the project above the 0.9 Bcf/day level. The proposed in-service date for the project is November 1, 2018.

[26] Spectra owns the Algonquin pipeline and is the majority owner of the Maritimes pipeline.
[27] See Spectra Response to Initial Staff Question 5, July 6, 2015.
[28] Looping is the addition of a parallel pipe laid next to a segment of the existing pipeline. Since Access Northeast has yet to announce the project route, the location and extent of these parallel pipelines is currently unknown.
[29] Staff questions the claim that the project can supply 5,000 MW of generating capacity. While the claim would be accurate if the project was a pipeline expansion of 0.9 Bcf/day, the fact that it comprises a storage element limits its continuous supply capability. ICF modeled Access Northeast as project capable of providing 0.6 Bcf/day capacity, which would be capable of supplying between 3,100 MW and 3,500 MW depending on heat rate.
[30] A 2014 ICF International study for ISO-NE indicates a need for up to 1.1 Bcf/d of additional gas supply by 2020 to meet projected power plant fuel requirements on a design day. This, according to ICF, equates to roughly 5,700 MW of capacity.

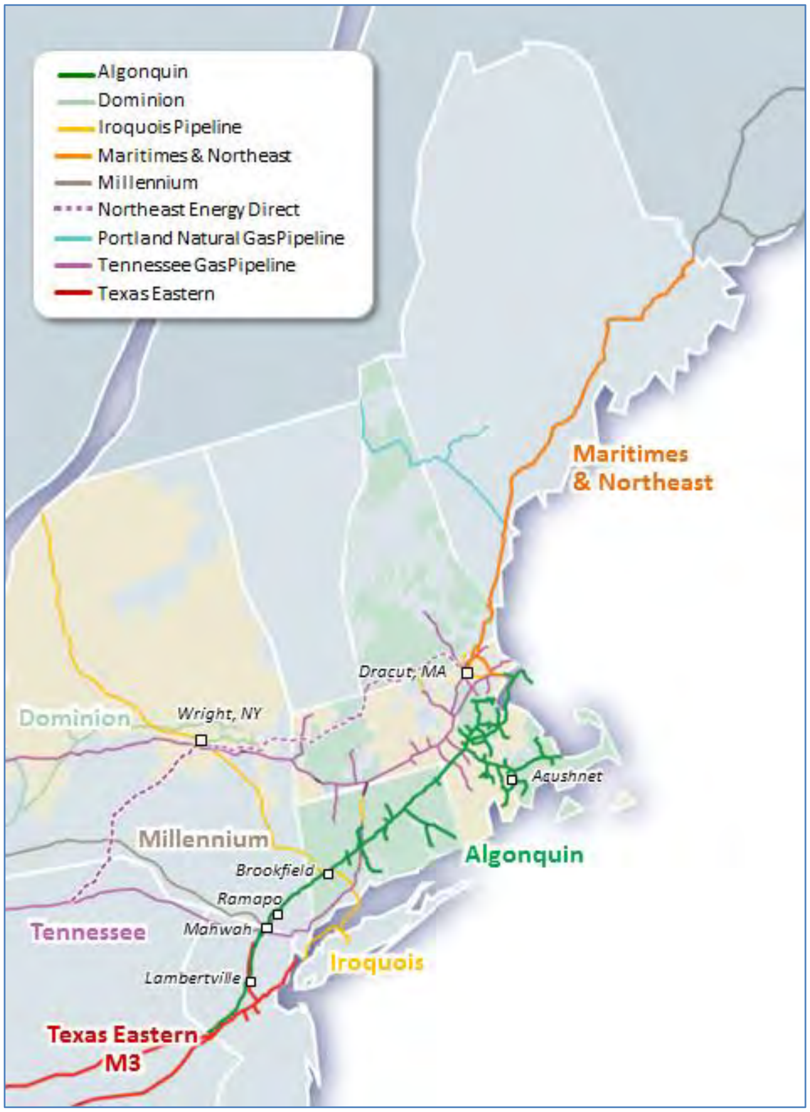


**Figure 1: Algonquin and Maritimes & Northeast Pipelines**

## Energy Reliability Service

The Energy Reliability Service (ERS) tariff is designed to work in tandem with incremental pipeline capacity to provide the flexibility gas generators need to accommodate large swings in electrical load and hence gas demand. ERS will be available as part of the integrated transportation/storage service provided by the Algonquin and Maritimes pipelines (see below under Firm Transportation Service). ERS is designed to provide two complimentary features that the sponsors claim are highly valued by the gas generation market.

The first feature is the reservation of pipeline transportation capacity. Under the current nomination and scheduling rules for requesting space on natural gas pipeline, a generator must comply with specific timelines established by the natural gas industry. At the timely nomination cycle, which ends 11:30 am Central Clock Time (CCT) on the day before gas flows at 9:00 am CCT, generators nominate their specific transportation capacity requirements. Pipelines evaluate those requirements in aggregate and schedule their pipelines based on the priority of services nominated. If there are potential choke points on a particular pipeline or, as is the case with Algonquin, the pipeline is fully subscribed, a particular transportation request may not be scheduled at the timely cycle or any subsequent nomination cycle that has been established. Under the ERS, the primary firm transportation capacity procured by an EDC and transferred to gas generators is reserved so that it can be nominated at the timely cycle or any subsequent nomination cycle. In essence, the primary firm transportation capacity will be available to be nominated 24/7 and, as long as gas supply is confirmed, gas deliveries can be ramped up or down based on the expected generator loads.

The second feature of ERS is the ability of a generator to ramp up its electrical output on short notice: commonly referred to as the "quick start" feature. With the transportation space already reserved on the pipeline, this quick start feature allows the generator to start flowing gas before it has submitted a nomination or has had a nomination confirmed. A generator simply has to notify Algonquin or Maritimes that it will be using the ERS before taking gas off the pipeline. The ERS allows the generator to take gas for up to two hours without having a nomination confirmed by the pipeline. This is referred to as no-notice firm transportation service. The source of this no-notice gas supply will be a combination of pipeline line pack and LNG storage withdrawals.

### LNG Storage Facilities

As noted, the LNG component of Access Northeast is designed to meet the large fluctuations in demand that generators experience on a daily basis. At the present time, the sponsors contemplate that domestically sourced natural gas will be placed into storage during off-peak periods (typically, spring, summer and fall) at a cost equal to the sum of the price of gas at the receipt point where it is purchased,[31] the variable cost of transportation to the LNG storage facility, the variable cost of liquefaction, and the variable cost of storage. On peak demand days during the winter or during operating reserve deficiencies, the stored LNG would be vaporized and released to generators first and foremost at the daily spot price of natural gas in New England on the day of delivery. Any positive margin between the selling price of natural gas and the actual delivered cost of LNG to generators (i.e., cost in storage plus the variable costs of vaporization and transportation to generator delivery meters) would be credited to EDC customers.

In the event of negative margins, the sponsors contend that the Capacity Manager would likely decide not to sell gas and instead hold on to it until such time as either the market price appreciates enough to sell gas at a positive margin or the supply is needed for reliability purposes. If the negative margin scenario were to occur, sponsors argue that power prices which have typically tracked gas prices will be lower and electric customers would realize the benefit of lower electricity prices. Taken to its logical conclusion, this argument suggests that if the variable costs of LNG turn out to be higher in most hours than the spot price of gas and LNG remains in storage, Access Northeast will be incapable of fulfilling one of its primary design objectives, which is to address the unique requirements of gas generators.

[31] The gas may be purchased inside New England at spot market prices or outside New England and transported to the region at an appropriate firm or interruptible transportation rate. Optional natural gas receipt points for Access Northeast are Brookfield, Connecticut, Mahwah, New Jersey , Ramapo, New York and Wright, New York. These receipt points connect with the following upstream pipelines: TGP, Millennium and Iroquois. See Figure 1 above.

In addition, Staff does not understand the sponsors' argument that the project was conceived with the primary goal of enhancing electric grid reliability by providing fuel assurance to gas generators. As Spectra itself acknowledges, the regional power system already has 6,000 MW of gas-fired generation with dual-fuel capability to protect against gas supply interruptions, or 1,000 MW more than Spectra contends is needed to supply load reliably. In addition, ISO-NE's Pay-for-Performance capacity market redesign, which is expected to become fully operational in June of 2018, will provide both financial incentives and penalties to existing generators to improve generator performance during times of system emergencies and new generators to acquire dual-fuel capability. To be clear, Staff is not suggesting that construction of the Access Northeast project, or for that matter the NED and PNGTS projects, will not enhance reliability. They will. Rather, we question Access Northeast's focus on system reliability at a time when ISO-NE has only recently received FERC approval of its Pay-for-Performance program, which was designed to address among other things the reliability risks associated with New England's growing dependence on natural gas and attendant vulnerability to interruptions in gas supply. The Pay-fo-Performance program will provide strong incentives for the installation and operation of dual-fuel capable generation to improve gas generator performance – if a dual-fuel generator cannot get natural gas (or if the price of natural gas is too high), the generator can instead use fuel oil or LNG as back-up fuel sources to meet its capacity obligations.[32] While the resulting increase in dependence on back-up fuel for generation can also present reliability risks, as demonstrated by the difficulties of replenishing oil supplies in winter 2013/14, Staff believes the system of incentives and penalties that constitute the Pay for Performance capacity market redesign will compel dual-fuel generators to address these risks through appropriate fuel supply planning.

## Power Producer Aggregation Areas

Under the Access Northeast proposal, gas will be delivered via transportation on a primary firm basis to four Power Producer Aggregation Areas (PPAAs) as depicted in Figure 2 below. These are geographical areas that include 9,200 MW of existing gas generation capacity[33] directly or indirectly served by the Algonquin and Maritimes pipelines, which according to Spectra is equivalent to 60% of all natural-gas fired generation in New England.[34] These four areas include Connecticut, Massachusetts, Maine, and the G System on the Algonquin pipeline system. The G System is a segment of the Algonquin pipeline system from Mendon to Bourne in Massachusetts that is often fully utilized throughout the heating season. The upgraded facilities that comprise the Access Northeast project have been designed to provide all gas generators within a specific PPAA the opportunity to receive firm transportation service. However, the capacity of the generators that will actually receive such firm service in a specific PPAA will be limited by that PPAA's sub-total capacity as shown in Figure 2. As can be seen, the sub-totals sum to 5,000 MW, the amount of generation capacity the sponsors claim will be supplied by the Access Northeast project.

[32] These incentives already appear to be producing the intended market response, as evidenced by NEPGA's comments which state that six gas-fired units have committed to install dual-fuel capability including four totaling 1,039 MW in winter 2014/15 and two next winter for an additional 735 MW. In addition, two new dual-fuel units totaling 920 MW cleared the ninth FCA in February 2015.
[33] 6,900 MW is directly connected to Algonquin and the remaining 2,300 MW to Maritimes.
[34] The inference that the Algonquin/Maritimes system plays a greater role than the TGP system in meeting the needs of New England's gas generation market is disputed later in this report.

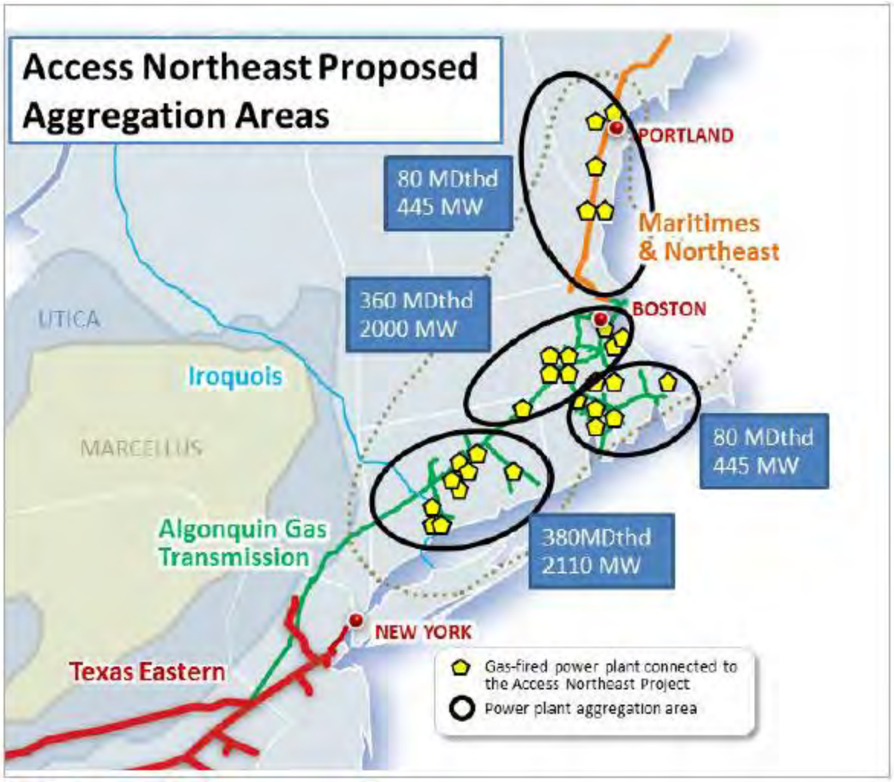


**Figure 2: Access Northeast Proposed Aggregation Areas**

### Firm Transportation Service

Pipeline transportation service and LNG storage service will be offered as an integrated service under the Access Northeast project. Also, the Access Northeast rate for this integrated firm transportation service will be a "postage stamp" rate that applies to all generators regardless of Power Plant Aggregation Area and will cover all costs of providing transportation directly to generators including so-called "last mile" costs. The postage stamp rates will also apply to any LDC that elects to procure firm transportation service under the project.

### Reliability Benefits and Energy Cost Savings

#### A. Reliability Benefits

As noted, the sponsors of Access Northeast view the project principally in terms of its ability to enhance grid reliability by increasing the deliverability of natural gas to electric generators. Reducing or eliminating winter period natural gas and electricity price spikes is considered to be a secondary benefit of the project.

The project sponsors assert that reliability will be improved in three ways. First, gas generators will be given the opportunity to enhance natural gas deliverability by allowing them to make firm transportation arrangements. Second, gas generators that have executed firm transportation arrangements will be given the flexibility to increase or decrease gas supplies in order to accommodate large swings in electrical load. As explained above, this will be achieved through the provision of a "no-notice" transportation service, which among other things allows gas generators to commence delivery of gas supplies to their facilities for a period of time not to exceed two hours prior to submitting a formal request for transportation space on the pipeline to deliver gas between receipt and delivery points – a process known as nomination. The importance of this "no-notice" service is that it ensures the generator is able to immediately come online when dispatched by ISO-NE. Third, the sponsors assert that the Access Northeast project has been sized to provide approximately 5,000 MW of generation capacity with firm transportation service, which is close to the amount of generation capacity that studies indicate need firm gas supplies in order to maintain power system reliability under extreme weather conditions.

## B. Energy Benefits

In support of its contention that the Access Northeast project will also bring substantial economic benefits to the region, Spectra attached to its comments a February 2015 study by ICF International prepared for Eversource and Spectra of the potential impacts of the project on New England gas and electricity prices under both normal and abnormal weather conditions.[35]

### (i) Normal Weather Analysis

There are two components to ICF's normal weather analysis: one that excludes the impact of reduced price volatility and the other that includes it. As can be seen in Figure 3 below, which is a plot of average monthly Algonquin citygate gas prices with and without Access Northeast but excluding the effects of price volatility, ICF projects January average natural gas prices without Access Northeast to increase steadily from about $15/MMBtu in 2019 to about $23/MMBtu in 2028 due to expected growth in the demand for natural gas for heating and electric generation and decreased gas supplies from Atlantic Canada. That is, without additional pipeline capacity in the region, the growth in the demand for gas is expected to drive up the spot market price of natural gas. Note also that over the four year period 2016 through 2019, January average prices are projected to decline due to the effects of the AIM, TGP Connecticut Expansion, and Atlantic Bridge pipeline expansion projects. In other words, ICF expects the decline in prices caused by these expansion projects to be slowed and eventually reversed by the growth in the demand for natural gas.

With Access Northeast, January average natural gas prices are projected to remain at relatively high levels ranging from $12/MMBu to $20/MMBtu over the 2019 through 2028 period, suggesting that Algonquin citygate prices will continue to reflect high basis differentials if no further pipeline capacity investments are made. According to ICF, these high citygate prices are not the result of winter price spikes on upstream pipelines feeding the Algonquin system. On the contrary, ICF's modeling assumes existing constraints on upstream pipelines will be resolved over time with investments in new pipeline capacity expansion projects. The high Algonquin citygate prices are a reflection of continued bottlenecks on the Algonquin pipeline.

Under the with Access Northeast scenario, ICF assumes the project will add 0.6 Bcf/day of incremental capacity comprising 0.5 Bcf/day of new pipeline capacity and 0.1 Bcf/day of LNG storage capacity.[36] The incremental capacity reduces January gas prices by about $3/MMBtu on average, which together with even smaller average price reductions in other months translates to an annual average wholesale energy

[35] Access Northeast Project – Reliability Benefits and Energy Cost Savings to New England, ICF International, February 18, 2015.
[36] The assumed incremental LNG capacity is less than 0.4 Bcf/day because the stored LNG must be managed judiciously given that abnormal weather conditions can occur at any time during the coldest winter months.

cost saving of $450 million over the first ten years after the the project is placed in service. It must be emphasized, however, that the changes in natural gas and electricity prices summarized above do not take into account the effect of reduced price volatility benefits.

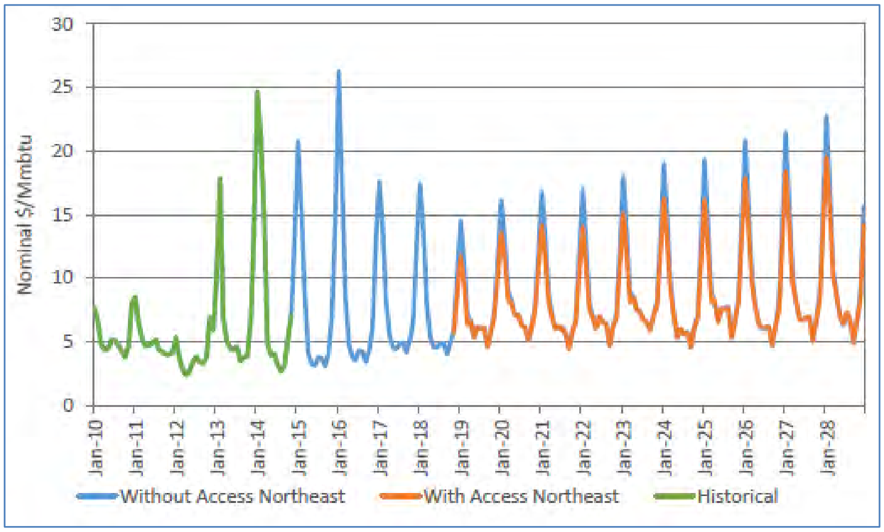


**Figure 3: ICF's natural gas price forecast for New England (excluding volatility reduction benefits)**

In addition to the above described average annual energy cost savings, ICF asserts that the project will produce other energy cost savings that relate to reductions in daily natural gas price volatility, i.e., reductions in the frequency and magnitude of daily gas price spikes. For this analysis, ICF analyzed two volatility reduction levels: low and high. Under the low volatility analysis, ICF assumed that the frequency and size of price spikes would be reduced by half from a moderate volatility level similar to that experienced in the 2010/11 or 2012/13 winter. This analysis resulted in an additional $330 million in annual average wholesale energy cost savings over the first ten years of the project. In contrast, the high volatility analysis, which was based on a high volatility level similar to that experienced in the 2013/14 winter, produced an additional $750 million in annual average wholesale energy cost savings. Overall, the total annual average wholesale energy cost savings is $780 million to $1.2 billion for the low and high volatility scenarios respectively.[37]

Regrettably, the ICF report does not include a projection of wholesale electricity prices that correspond to the energy cost savings estimate of $780 million to $1.2 billion. As a result, Staff is unable to provide the Commission with a complete assessment of Access Northeast's ability to mitigate future winter electricity prices. We consider this to be a major weakness of the ICF analysis. Further, because ICF used the same methodology to develop the cost savings estimates in its report on the NED project, this criticism applies to that report also.

[37] Given the weather conditions in 2013/14 were abnormal, the $1.2 billion energy cost savings estimate can reasonably be interpreted as being consistent with some hybrid of normal and abnormal weather conditions.

### (ii) Abnormal Weather Analysis

ICF estimates that had the Access Northeast project been in operation during the abnormally cold winter of 2013/14, it could have eliminated gas price spikes on 49 days resulting in wholesale energy cost savings totaling about $2.5 billion. ICF attributes this cost saving to 0.5 Bcf/day of incremental pipeline capacity plus daily withdrawals of LNG that vary depending on the actual load factor on New England's pipeline system. On days when the actual load factor was at or above 95%, higher LNG withdrawals were assumed to bring the load factor below 75%. When load factors on New England pipelines are at or below 75%, natural gas price spikes and associated electric price spikes are much less likely to occur, according to ICF.

## Benefit-Cost Analysis

Whether during normal or abnormal weather conditions, ICF asserts that the potential annual energy cost savings from adding new gas infrastructure to the region will exceed by a large margin the levelized annual cost of constructing that infrastructure, which it estimated at approximately $400 million.[38] To be conservative, we use a levelized annual cost of $480 million. Based on this cost estimate and the wholesale energy cost savings as described above, the Access Northeast project would produce benefit to cost ratios of 1.63 and 2.5 not including the value of enhanced electric grid reliability associated with providing secure winter fuel supplies to 5,000 MW of gas generation capacity. The total cost to consumers of the project under our annual cost estimate would be $9.6 billion.[39]

However, ICF's estimate of the levelized annual cost of the project was prepared at a time when the sponsors were considering providing the proposed LNG storage service out of upgraded LNG storage facilities owned and operated by affiliated LDCs. Since that time, Eversource has decided not to upgrade those facilities and instead is proposing to construct two new LNG storage tanks and associated liquefaction and vaporization facilities at an existing site in Acushnet, Massachusetts. The cost of this project is reported to be $600 million which may include the cost of a new, three-mile pipeline from the Acushnet facility to an interconnection with Algonquin, raising the total investment cost for the Access Northeast project to about $3 billion.[40] Although Eversource has declined to provide an updated estimate of the levelized annual cost of the project, Staff estimates the new cost could be about $600 million based on the same 20% carrying charge rate. A levelized annual cost of $600 million would lower the benefit to cost ratios to 1.3 and 2.0.

## Cost to Electric Consumers

Based on a $600 million levelized annual cost for the project and assuming only Eversource and National Grid EDCs choosing to enter contracts with project sponsors, New Hampshire's Eversource affiliate Public Service Company of New Hampshire (PSNH) would be allocated 9% of the total capacity of the project at an annual cost of $54 million.[41] If this cost is recovered from all PSNH customers via a per kWh distribution surcharge, we estimate the surcharge would be about $0.0068 per kWh or 6.8 mills per kWh. To put this surcharge in context, this is 106% higher than New Hampshire System Benefit Charge

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[38] This annual cost is based on a total investment cost for the project of $2.4 billion and a 16.667% carrying charge rate. To be conservative when calculating the benefit to cost ratio for the project, we adopted the 20% carrying charge rate recommended by Black & Veatch for interstate natural gas pipelines employing 20-year firm transportation contracts. This produces an annual cost of $480 million.

[39] $9.6 billion is the product of a $480 million levelized annual cost and a 20-year contract term.

[40] The two new tanks would have a combined useable storage capacity of 6.0 Bcf.

[41] See Eversource's August 20, 2015 response to Staff Follow-Up Question.

(SBC). However, we consider 6.8 mills per kWh to be a worst case outcome assuming of course the $600 million annual cost estimate is reasonable. If all other EDCs in the region (including the region's consumer-owned municipal and cooperative utilities) agreed to shoulder their load ratio shares of project costs, then the size of the surcharge could be reduced. However, because the Eversource and National Grid affiliated EDCs account for approximately 71% of all retail sales by EDCs in New England, the surcharge would not fall below 4.8 mills per kWh.

The discussion thus far has assumed that retail electricity consumers incur the full cost of the project and gas generators, the ultimate users of the purchased capacity, none. However, under the NESCOE model adopted by Eversource in its comments, capacity contracted by EDCs would be released to gas generators through an auction administered by a capacity manager. Revenues received by the capacity manager from winning bidders would be returned to the EDCs as an offset to the cost of the project as would any revenues received from capacity sales in the secondary market if generators choose not to purchase all of the capacity in the auction. Clearly, the higher the price paid by generators (or by end users in the secondary market) for released capacity, the greater the offset to project costs and the lower the distribution surcharge.

In this regard, it is worth considering the comments of CLEC on the potential for gas generators to benefit from purchasing the rights to firm transportation capacity. CLEC estimates that as long as the incremental pipeline capacity of the NED project does not exceed 1 Bcf/day, the throughput from this new capacity will be less than the combined electric and non-electric market demand for natural gas in New England on most days of the year and certainly on winter days. This means that the remaining gas demand must be met by existing and other new pipelines at prices based in large part on the price of gas at higher cost receipt points. And it will be the prices at these higher cost receipt points that will set the clearing prices in the New England natural gas market. Moreover, CLEC believes that if a generator shipping gas on NED is able to secure gas delivered to its facility at a lower price than other generators shipping gas on other pipelines, then the bid price of the higher gas cost generator will set the LMP of electricity, and the difference between the LMP and the bid of the lower gas cost generator will be retained by that generator as a form of energy-market rent. Staff believes this energy-market rent could function as an incentive to gas generators to not only bid for EDC capacity but to bid prices higher than otherwise, potentially producing a larger offset to project costs and a reduced distribution surcharge.

## NORTHEAST ENERGY DIRECT

### Project Overview

Tennessee Gas Pipeline Company (TGP), a Kinder Morgan subsidiary, currently plays a significant role in transporting gas to generators that supply the ISO-NE electric grid. While TGP is directly connected to only 27% of total installed gas capacity, or about 4,900 MW, ICF estimates that during 2012-14 TGP was responsible for supplying gas to over 9,000 MW of generation capacity or about 50% of total gas capacity.[42] TGP was able to achieve this level of coverage by delivering gas on behalf of customers directly connected to Algonquin via the Mahwah, New Jersey and Mendon, Massachusetts interconnections. Upon completion of the Northeast Energy Direct (NED) project, those specific pipeline

[42] New England Energy Market Outlook – Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project, ICF International, 2015, Page 10.

interconnections will be maintained and, importantly, TGP will have the ability to deliver additional volumes to Portland Natural Gas Transmission Service (PNGTS), Maritimes and Northeast (Maritimes), Iroquois Gas Transmission (Iroquois) and Algonquin.[43] Therefore, as a result of the NED project, TGP will have the ability to physically deliver into every pipeline system serving New England as well as to incrementally serve markets along its own pipeline system. In addition, the NED project will play a critical role in serving future new generation expected to be located in proximity to the Central Massachusetts Hub (Mass Hub) area.[44]

The NED project comprises two separate segments or paths: the Supply Path and the Market Path. The Supply Path will supply up to 1.2 Bcf/day of Marcellus Shale gas from one or more receipt points on TGP's 300 Line[45] in Northeast Pennsylvania and extend to Wright, New York where it will interconnect with TGP's existing 200 Line, the proposed Constitution pipeline,[46] and the Iroquois pipeline. Figure 4 shows the existing TGP pipeline system and the proposed route for the NED project.

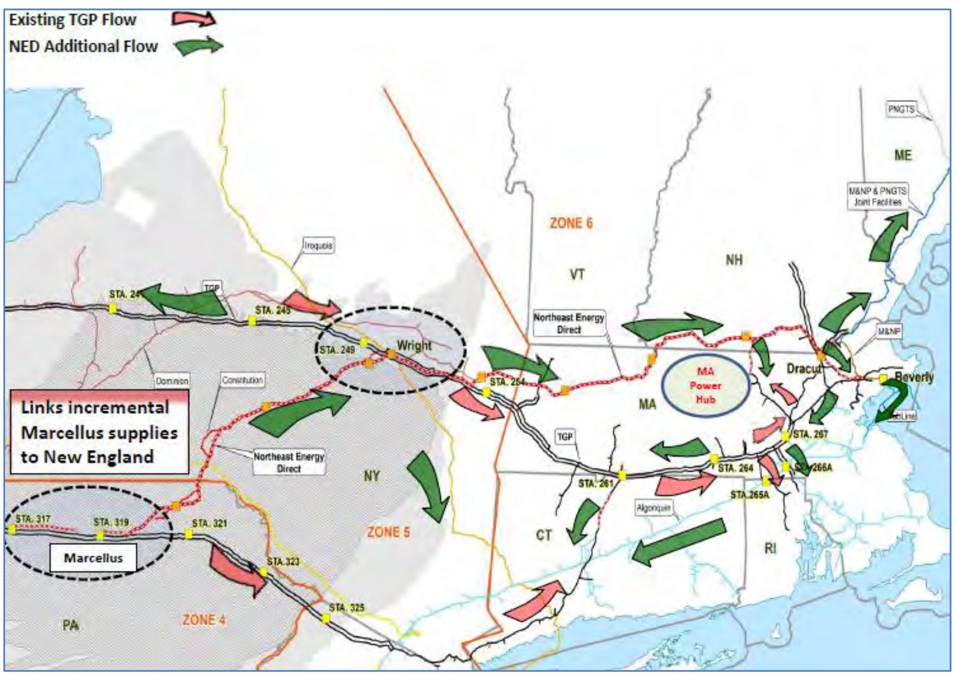


**Figure 4: Tennessee Gas Pipeline Company's Northeast Energy Direct Project**

The Market Path will be able to deliver up to 1.3 Bcf/day of incremental gas supplies from its receipt point at Wright, New York to interconnections near Dracut, Massachusetts with PNGTS, Maritimes, and TGP's 200 Line. Although the NED project is technically classified as a greenfield project, TGP asserts

[43] TGP states that existing gas generators currently served by Algonquin and Maritimes will be free to contract for firm transportation services on the Market Path.
[44] TGP contends that ISO-NE has identified the Mass Hub as an area on the electric grid with few constraints and therefore ideal for adding new gas generation to replace retiring old and inefficient non-gas generation.
[45] See NED's Open Season for PowerServe, September 8, 2015.
[46] The Constitution pipeline has already received the necessary FERC certification to deliver gas to Wright, New York.

that 91% of the Market Path route will be co-located along existing electric utility rights of way or adjacent to the existing 200 Line. TGP initiated the FERC pre-filing process in September 2014 and expects to begin construction on the Market Path in January 2017 and be fully operational by November 2018.[47]

Because the primary delivery point for the Market Path will be located at the eastern end of the New England pipeline system, the NED project will be capable of flowing gas from an easterly direction into the TGP's existing 200 Line and the Algonquin pipeline[48] via the Joint Facilities and the Hubline. The NED project will also allow generators directly connected to the Algonquin pipeline to receive incremental gas supplies via TGP's interconnection with Algonquin at Mendon, Massachusetts provided such generators enter into firm transportation contracts with TGP and Algonquin.

As noted, the NED project is designed to interconnect near Dracut, Massachusetts with TGP's 200 Line and the Maritimes and PNGTS pipelines. The interconnection with TGP's 200 Line will enable natural gas supplies to flow south from Dracut to LDCs and gas generators directly connected to TGP's existing system in Massachusetts, Connecticut, and Rhode Island. The interconnection with the Maritimes and PNGTS pipelines through the Joint Facilities, together with the anticipated reversal of gas flow along those facilities from south to north, will enable the NED project to access more New England customers in New Hampshire, Maine and in the Atlantic Canada region.

Currently, TGP has secured long-term commitments from nine New England LDCs for approximately 0.55 Bcf/day of the NED Market Path capacity, leaving approximately 0.75 Bcf/d of incremental capacity available to EDCs for release to gas generators, enough to supply between 3,900 MW and 4,500 MW of generation depending on the heat rates of such generators.[49] TGP has announced that it will meet its LDC commitments by constructing a 30-inch pipeline and sufficient compression to meet those firm commitments.[50] Subject to additional long-term commitments with New England EDCs, TGP will increase the capacity of the Market Path up to 1.3 Bcf/day by adding incremental compression.[51]

## Receipt Points

While the rates for firm transportation service largely determine a project's cost, the point of receipt of natural gas plays an important though not conclusive role in determining project benefits. This is because the price of natural gas often varies depending on where each project interconnects to the rest of the natural gas pipeline network. As noted, the primary receipt point for the NED project is Wright, New York, though EDCs and LDCs may elect to receive some or all of their gas supplies upstream of that point within the Marcellus Shale production area if they expect the price of natural gas at Wright to materially exceed the price in the production area plus the cost of firm transportation on the Supply Path for a significant portion of the contract term.

[47] See TGP response to Staff Initial Question 14.
[48] Spectra asserts that NED deliveries to the Algonquin pipeline from the east are limited by constraints on the Hubline.
[49] See TGP response to Question 11 in Second Set of Staff Questions.
[50] TGP states that it has also executed binding precedent agreements for firm transportation service on the NED Supply Path and is in the final stages of negotiations with other LDCs, gas producers and other market participants. See NED Open Season for PowerServe Firm Service, September 8, 2015.
[51] See July 16, 2015 press release from Kinder Morgan announcing its decision to proceed with the Market Path segment of the NED project.

According to TGP, the option to purchase gas in the Marcellus Shale production area provides EDCs and LDCs direct access to abundant supplies of low-cost natural gas from more than twenty different producers at an incremental cost equal to the firm transportation rate on the Supply Path. Moreover, TGP contends this is a significant advantage over other proposed pipeline projects including Access Northeast that only offer access to natural gas at downstream interconnects supplied by only a few producers. In support, TGP points to a study prepared on its behalf by Competitive Energy Services (CES) that compared natural gas prices at points that could be accessed by various New England pipeline expansion projects. That study found that the price of gas at Wright, New York could be purchased at a price equal to the price of gas in the Marcellus Shale production area plus transportation on the Supply Path whereas the price of gas at the Mahwah and Ramapo receipt points on Access Northeast would be substantially higher equivalent to TETCO M3 pricing.

Spectra argues that the analysis performed by CES is fundamentally flawed. In summary, Spectra asserts CES reached its conclusion by focusing on only two factors: (1) the current depressed price of natural price in the Marcellus Shale production area and (2) a transportation charge for a project that has no announced commitments. Additionally, Spectra claims that CES neglected to factor in real influences on the future price of gas at Wright such as the current and future demand on Iroquois, the current premium pricing for Iroquois supplies that primarily originate from Canada, and the likelihood that those premium Canadian supplies and markets through reverse flow on Iroquois could result in a price at Wright that may trade at a significant premium to TETCO M3. Finally, Spectra contends that CES ignored what it believes could be a significant flattening of TETCO M3 prices relative to Marcellus production area prices through the construction of substantial pipeline expansion projects, into, within and around TETCO M3.

### Firm Transportation Services

Firm transportation rates on the Market Path will vary depending on the delivery point. For example, generators that select Dracut, Massachusetts as the primary delivery point will pay the "Wright to Dracut" rate whereas generators that select delivery points on the 200 Line in Massachusetts will pay a "Wright to downstream of Dracut'' rate. The "Wright to Dracut" rate will be set at a discount to the "Wright to downstream of Dracut'' rate to reflect the fact that generators directly connected to the Market Path will not incur the cost of transportation on TGP's existing 200 Line including the costs of any new investments on that line to reach generators. The "Wright to downstream of Dracut'' rate will also apply to generators directly connected to TGP's 300 Line in Connecticut or the Rhode Island lateral off of the 200 Line. Finally, generators located in the Mass Hub area will pay either the "Wright to Dracut" rate if they are directly connected to the Market Path pipeline or the higher "Wright to Downstream of Dracut" rate if they are connected to the 200 Line.

### Enhanced Transportation Service

The rate for firm transportation service will also vary depending on whether the customer is an LDC or an EDC releasing capacity to gas generators. Gas generators may require enhanced transportation services to accommodate large load swings as they respond to rapid changes in power system demand or system contingencies, often with little no time to notify pipelines of their transportation needs. In order to ensure gas generators have access to natural gas transportation services when needed, TGP intends to offer an optional no-notice transportation service[52] that utilizes the NED facilities, reserved

[52] LDCs generally receive gas on a uniform basis throughout the gas day.

capacity on TGP's existing system and regional storage and/or line pack. Generators may select from the following no-notice service options: (a) a supply service option supported by regional storage or (b) an auto park and loan service supported by regional storage and/or line pack. TGP will reserve capacity on the pipeline to provide the no-notice service. Importantly, as currently envisaged by TGP, gas generators will be responsible for maintaining sufficient quantities of gas in storage to satisfy their no-notice service requirements. Staff interprets this language to mean that the commodity cost of gas withdrawn from storage will equal the weighted average cost of gas in inventory. Naturally, the rates charged to generators for these no-notice services are expected to be higher than the rate charged to LDCs. The higher rate for EDCs will recoup the incremental capital costs TGP incurs to provide a higher quality service that enhances electric reliability.

## Reliability and Energy Cost Savings Benefit

### A. Reliability Benefits

The New England region as a whole stands to benefit from the NED project in two significant ways: by improving electric grid reliability and lowering gas and electricity prices to consumers. As regards the first benefit, the problem of non-firm gas supplies to gas generators has been particularly acute in New England in recent years, resulting in impaired electric grid reliability on the coldest winter days when gas is scarce and service interruptions become more common. According to TGP, the NED project will provide enhanced delivery of firm gas supplies to between 3,900 MW to 4,500 MW of existing generation on the coldest winter days and potentially large quantities of future gas generation in and around the Mass Hub area where new generation would most conveniently be located to ensure reliability in the regional power market.[53] This future gas generation would replace some of the 8,300 MW of existing nuclear, oil and coal generation expected to retire by 2020. In addition, by providing deliveries to Dracut, Massachusetts, NED could enhance reliability for generators on the Algonquin, PNGTS and Maritimes pipelines assuming appropriate modifications to those pipelines and available transportation capacity on NED.

### B. Energy Benefits

Regarding energy benefits, TGP engaged ICF to analyze the potential energy cost savings that might arise from the construction of the NED project. The principal objectives of ICF's analysis were to quantify future differences between the region's demand for natural gas and existing gas supply sources and the financial benefits for consumers if new pipeline capacity is added to narrow those differences.

Even though TGP serves a smaller proportion of the region's existing gas generation market than Algonquin and Maritimes pipelines combined, ICF estimated that on average New England's wholesale energy costs could be reduced by $2.1 billion to $2.8 billion a year for the ten-year period after NED is placed in service: substantially higher than the $780 million to $1.2 billion per year cost savings estimated for the Access Northeast project, which we discussed in detail above.[54] The difference is explained by the much larger NED project, which adds 1.3 Bcf/day of incremental pipeline capacity to

[53] If the proposed 0.75 Bcf/day of incremental capacity on NED is accounted for by existing generators directly or indirectly connected to TGP or other New England pipelines, additional supplies to future gas generation in the Hub area would require an expansion of NED above the currently proposed 1.3 Bcf/day level.
[54] Both estimates were prepared by ICF using the same methodology but under separate engagements.

the New England pipeline system whereas Access Northeast adds the equivalent of 0.6 Bcf/day of incremental pipeline capacity.[55]

### Normal Weather Analysis

As with the analysis conducted for the Access Northeast project, ICF conducted a normal weather analysis with and without NED and without consideration of volatility effects. The results of that analysis are presented in Figure 5 below, which shows considerably larger reductions in average peak winter month natural prices due to NED compared to Access Northeast. Without NED, average January gas prices steadily increase over time from about $15/MMBtu in 2019 and $30/MMBtu in 2028.[56] To put these prices in context, the average Algonquin citygate price for January 2014, an extremely cold month, was about $23/MMBtu and for February 2015, the coldest month on record according to ISO-NE, about $17/MMBtu.

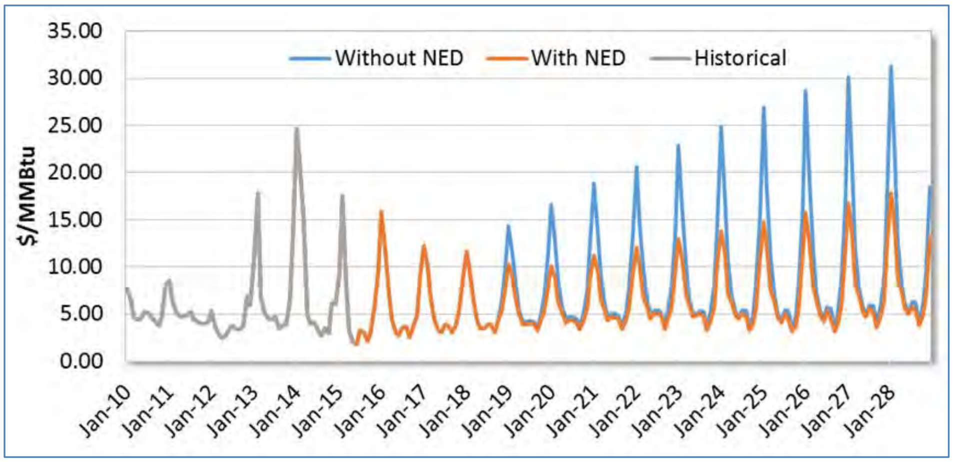


**Figure 5: ICF's natural gas price forecast for New England (excluding volatility reduction benefits)**

With NED, average January gas prices are projected to range from about $10/MMBtu to about $17/MMBtu over the same time period.

### (ii) Abnormal Weather Analysis

In order to estimate the impact of the NED project under abnormal weather conditions, ICF analyzed New England's natural gas and electric markets during the "polar vortex" winter of 2013/14. It found that NED could have eliminated gas price spikes on 86 days during the 2013/14 winter resulting in wholesale energy cost savings totaling about $3.7 billion. ICF attributes this cost saving to the 1.3 Bcf/day of incremental pipeline capacity reducing the load factor on New England pipelines to levels equal to or below 75%. When load factors are at or below 75%, ICF asserts that natural gas price spikes and associated electricity price spikes are much less likely to occur.

[55] The fact that 0.55 Bcf/day of the NED capacity will be contracted to LDCs rather than gas generators does not diminish the potential for that portion of the project to reduce natural gas prices for the benefit of regional electricity consumers.

[56] The projection of natural gas prices absent incremental capacity has increased relative to the projection in ICF's Access Northeast report. ICF attributes this to the use of an updated gas demand forecast that reflects increased growth in the demand for gas in the power sector and higher than previously expected demand for gas in Atlantic Canada.

### Benefit-Cost Analysis

According to ICF, the investment cost for the electric portion of the NED project is $2.0 billion,[57] equivalent to a levelized annual cost of $400 million over a 20-year contract term.[58] At $400 million per year, electric customers would pay $8 billion over the contract term. Based on the above benefits and costs, we estimate the NED project would produce a benefit to cost ratio in the range 5.25 to 7.0 not including the value of enhanced electric grid reliability or the annual costs of providing enhanced transportation services.

### Cost to Electric Consumers

Based on a $400 million levelized annual cost for the electric portion of the NED project and the assumption that only Eversource and National Grid EDCs choose to enter contracts with TGP, New Hampshire's Eversource affiliate PSNH would be allocated 9% of the total capacity of the project at an annual cost of $36.0 million.[59] If this cost is recovered from all PSNH customers via a per kWh distribution surcharge, we estimate the surcharge would be about $0.0046 per kWh or 4.6 mills per kWh. For context, this is about 40% higher than the New Hampshire System Benefit Charge (SBC). If all other EDCs in the region (including the region's consumer-owned municipal and cooperative utilities) agreed to shoulder their load ratio shares of project costs, we calculate the size of the distribution surcharge could be reduced to about 3.3 mills per kWh.

However, as noted above in the section addressing the cost to consumers of the Access Northeast project, the surcharge can be reduced further by offsetting the electric portion of the project cost with revenues received from releasing capacity contracted by EDCs to gas generators through an auction process. As explained, the higher the price paid by generators for released capacity the greater will be the offset to protect costs and the lower will be the distribution surcharge.

## PORTLAND NATURAL GAS TRANSMISSION SYSTEM NEW EXPANSION

### Project Overview

Portland Natural Gas Transmission System (PNGTS), a subsidiary of TransCanada and Gaz Metro, is a high pressure interstate natural gas pipeline providing transportation services to LDCs, paper mills, and electric generation plants throughout New England. PNGTS' pipeline extends in a southeasterly direction from a point on the border between the United States and Canada near Pittsburg, New Hampshire, where it interconnects with the TransCanada Pipeline. The PNGTS pipeline passes through New Hampshire, Vermont, and Maine to interconnections with Maritimes at Westbrook, Maine and TGP near Dracut and Haverill, Massachusetts. Figure 6 is a map of the existing PNGTS pipeline. The pipeline between Westbrook, Maine and Dracut, Massachusetts is known as the Joint Facilities because they are jointly owned by PNGTS and Maritimes.

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[57] Staff believes this estimate excludes investments to provide firm transportation customers with enhanced or no-notice transportation services.
[58] $400 million is equivalent to a carrying charge rate of 20% for pipelines 20-year firm transportation contracts. This is the same carrying charge rate used to calculate the levelized annual cost for the Access Northeast project.
[59] See Eversource's August 20, 2015 response to Staff's Follow-Up Question.

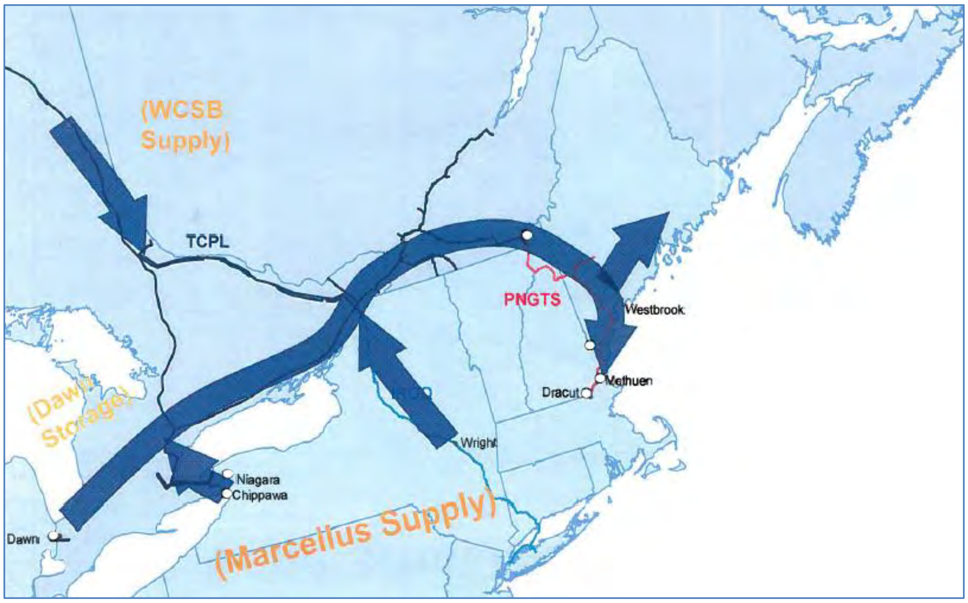


**Figure 6: PNGTS Supply. Storage Access Options**

PNGTS is in the early stages of developing a new expansion of its system that would be in addition to the capacity added as a result of its recent Continent-to-Coast (C2C) expansion project. By efficiently expanding its existing pipeline system, PNGTS believes it can offer EDCs a competitive alternative to the Access Northeast and NED projects. PNGTS is presently considering two scenarios. The first scenario is a scalable medium-sized project with incremental firm capacity up to 0.6 Bcf/day over a level that includes the C2C project. The new expansion would run from Pittsburg, New Hampshire to either Westbrook, Maine or Dracut, Massachusetts depending on the delivering points selected by expansion customers and provide firm transportation service to EDCs, LDCs and other markets in New England through the addition of three new compressor stations. The second scenario is a large expansion project up to 0.9 Bcf/day of incremental firm capacity over a level that includes the C2C project. This project would serve the same markets as the smaller project and would be based on the addition of two new compressor stations and 130 miles of looping of the existing 24" line. PNGTS states that any expansion of the Joint Facilities would depend on an analysis of existing facilities performed in conjunction with other changes proposed by co-owner Maritimes.

In addition to the above mentioned improvements on the PNGTS pipeline, incremental capacity would be required upstream on the TransCanada and Iroquois pipelines. TransCanada will add compressor and pipeline facilities from its interconnection with Iroquois at Waddington, New York to Pittsburgh, New Hampshire. Under the 0.6 Bcf/day scenario, TransCanada will add new compressors at 5 locations but looping would not be necessary. Under the 0.9 Bcf/day scenario, TransCanada will add new compressors at 5 locations and 143 miles of 30 inch looping.

In contrast, Iroquois appears to have firm capacity available that PNGTS could utilize to reverse flow and access Marcellus gas at the Wright, NY trading point. PNGTS could also access Mid-Continent and Marcellus gas at Dawn, Niagara and Chippawa receipt points off of TransCanada. According to PNGTS, the gas supply diversity these receipt points offer will provide substantial benefits to shippers. For example, if the price of gas at Wright were to change over time, access to supplies from Dawn and Alberta could prove valuable to shippers.

That said, PNGTS expects Wright to be a liquid and reliable source of Marcellus Shale supply following the completion of the Constitution pipeline and TGP's proposed "Supply Path", which initially will deliver 0.65 Bcf/day and 1.2 Bcf/day respectively into the Iroquois pipeline. In addition, there is potential for expansion of both the Constitution and Supply Paths.

## Enhanced Transportation Service

PNGTS does not currently offer generators on its system a no-notice service nor has it committed to do so in the future. The most it would say is that it is currently evaluating with counterparties the possibility of offering generators a no-notice service based on peaking facilities. That said, PNGTS currently has a firm transportation Hourly Reserve Service (HRS) rate schedule that would be available to any future expansion customers. According to PNGTS, HRS was specifically designed to help electric generation customers manage variations in hourly load needs. It does so by providing a generator the flexibility to contract for firm transportation service up to a specified Maximum Hourly Quantity (MHQ), as well as a specified Maximum Daily Quantity (MDQ). The MHQ allows the generator to receive delivery of its MDQ at an accelerated rate over a specified number of hours during the gas day, which is likely to be particularly useful to electric generators with loads that vary significantly during the gas day. PNGTS uses line pack as the basis of its HRS.

PNGTS states that a generator may contract for one of five different firm hourly flow options, ranging from 4.16% of its MDQ (which translates into uniform deliveries over a 24-hour gas day) up to 8.33% of the generators MDQ, which translates into full daily deliveries over 12 hours. By electing to receive firm higher hourly deliveries during a gas day, the generator will pay a higher reservation rate for the additional firm capacity required to provide the higher hourly deliverability. Also, the reservation rate will vary based on the firm hourly flow rate elected by the generator. The higher the firm hourly flow rate, the higher the reservation charge.

PNGTS also has a Park and Loan (PAL) service which generators can use to balance on a daily basis gas supplies and loads. PAL customers can request available capacity to "park" gas they have already scheduled and will not use, or receive a "loan" of gas from PNGTS to supplement their requirements. hourly or NAESB cycle basis.

## Reliability Benefits and Energy Cost Savings

Unlike the Access Northeast and NED projects, PNGTS presented no studies of the potential energy cost savings associated with its proposed new expansion project. Nor was PNGTS willing to share with Staff its estimate of the total investment cost of the project, the associated annual cost, or details of the firm transportation rates that potential generators might pay to transport gas from receipt point to delivery point, citing the early stage of its project development cycle. For these reasons, Staff is unable to provide the Commission with any of the most basic information associated with this or any expansion project including its total investment cost, the associated annual cost, the required distribution surcharge, the estimated benefit to cost ratio, the potential reduction in wholesale electricity prices, or even the amount of new firm capacity that would be available to generators. Without such information, Staff can offer no quantitative assessment of the project's ability to mitigate wholesale electricity prices.

## COALITION TO LOWER ENERGY COSTS

### Introduction and Cost Savings Analysis

The Coalition to Lower Energy Costs (CLEC) is a non-profit association of individual consumers, large energy consumers, labor unions and institutions seeking to eliminate the threat to New England's families and economy from skyrocketing natural gas and electric prices. CLEC advocates for increased renewable energy, energy efficiency, demand response and new energy infrastructure to give natural gas and electricity consumers access to an adequate gas supply, a cleaner energy portfolio and lower energy costs.

CLEC contends that the best available information shows that the region will require large amounts of additional pipeline capacity from two major new or substantially new pipelines to fully solve the high electricity price problem. This pipeline capacity cannot, according to CLEC, be provided by the region's electricity market, which is designed on principles of theoretical short term "efficiency" that ISO-NE itself acknowledges cannot support the investment needed to remedy the problem. In this investigation, CLEC advocates for the creation of mechanisms to require each EDC in New England to contract to purchase capacity from interstate natural gas pipelines in an amount equal to the EDC's pro rata share of New England electricity consumption.

According to CLEC, the NED and Access Northeast projects benefit New England separately and then synergistically, providing 2.2 Bcf/d in additional capacity. Access Northeast serves southern New England directly whereas NED delivers low cost gas to the Dracut trading point where it can be delivered to generators directly connected to TGP's existing system and other pipelines.

CLEC's claim that the region will need the capacity from two major new pipelines to fully solve the high electricity price problem, it submitted a February 2014 study prepared by Competitive Energy Services (CES).[60] That study was updated by CES in a December 5, 2014 report titled Report to Tennessee Gas Pipeline Company L.L.C. and included in this investigation as part of a TGP discovery response. In that updated study, CES estimated the economic value (i.e., wholesale energy cost savings) of hypothetical 0.2 Bcf/day increments of pipeline capacity and found that between 2.0 to 2.4 Bcf/day of pipeline capacity was needed to completely eliminate the constraints on regional pipelines. Absent such capacity additions, CES estimates that regional electricity consumers would pay approximately $3.0 billion annually in additional wholesale energy costs; costs that will place the region at a severe economic disadvantage relative to neighboring regions of the country. As can be seen in Appendix 1, Page 1 below, with each 0.2 Bcf/day increment of capacity the cumulative power cost savings increase but at a diminishing rate suggesting that as the additional capacity approaches 2.4 Bcf/day the pipeline constraints become insignificant and the cumulative annual savings level off at about $3 billion.

Applying the results of CES' work to NED, which as noted is a 1.3 Bcf/day project, produces cumulative annual wholesale energy cost savings of about $2.5 million,[61] well within the range of cost savings projected by ICF for the NED project.

[60] "Assessing Natural Gas Supply Options for New England and their Impacts on Natural Gas and Electricity Prices" February 17, 2014.
[61] This estimate assumes NED is the first project built.

## Assessment of CES's Energy Cost Savings Analysis

Staff has reviewed CES' description of its dispatch model and concluded that some of the simplifying assumptions understate the estimated energy cost savings while others overstate the savings. For example, CES assumed that the spot price for natural gas in New England would be $5/MMBtu during any hour when the combined demand for natural gas from LDCs and gas generators was less than the combined capacities of the region's pipelines. Other consulting firms such as ICF and Black & Veatch assert there is strong empirical evidence for natural gas prices to spike whenever pipeline utilization rates exceed 75%. This suggests that CES' $5/MMBtu gas price assumption understates gas prices and hence energy costs under the base case scenario and as result understates the potential cost savings associated with incremental pipeline capacity.

The updated dispatch model used by CES to estimate cost savings reflects changes in several important variables including an expected decline in north-to south gas flow on Maritimes out of Canada; increased pipeline capacity into New England to reflect the likelihood that the AIM and TGP Connecticut Expansion project will get built; increased peak day LDC gas demands; and reduced oil and LNG prices to reflect changes in energy markets. Despite these changes, it is important to note that the modeling results depend in large part on two critical variables: the number of hours LNG-fueled generation is estimated to be on the margin prior to the addition of incremental capacity; and the assumed price of LNG. Changes in these variables can significantly impact the modeling results.

Because energy cost savings are directly proportional to the difference between the price of LNG and the price of natural gas assumed in the dispatch model, the expected future price of LNG is critically important to the modeling exercise. For example, had CES assumed that the price of LNG going forward was $10/MMBtu instead of $14/MMBtu, the cumulative annual cost savings at the 1.3 Bcf/day and 2.4 Bcf/day capacity levels are reduced to about $1.4 billion and $1.7 billion respectively. These results are shown in Appendix 1, Page 2. Because world LNG prices have fallen since CES completed its update, we believe the reduced cost savings may be more indicative of future benefits, all other things being equal.

However, all other things are rarely equal. If the addition of new pipeline capacity significantly reduces the demand for LNG during winter months it may be difficult for the region to maintain multiple LNG regasification facilities. In the event one of the two major LNG facilities closes, LNG prices may increase as the sole supplier seeks to recover its fixed costs over a smaller volume. Since this potential increase in LNG prices is not reflected in CES' estimate of energy costs under the incremental capacity scenarios, the cost savings estimates may be understated.

Finally, as noted, cost savings are driven in part by reductions in the number of hours LNG-fueled generation is on the margin. Data provided by CES shows that the modeled daily LNG requirements are higher than actual daily injections from Canaport in 2013, suggesting the cost savings are overstated. However, CES states that the model injections may be higher than Canaport deliveries during the winter months because it assumed that dual-fuel generators operate on LNG before they operate on oil when pipeline gas is un available, an assumption that may not hold under ISO-NE's Winter Reliability Program. That notwithstanding, CES states that since the delivered prices of oil and LNG are similar, the effect on energy cost savings should be small.

## CONSERVATION LAW FOUNDATION

### Initial Comments

Despite Staff's May 14 guidance letter encouraging stakeholders to submit non-pipeline as well as pipeline solutions to the high winter wholesale electricity price problem, the Conservation Law Foundation (CLF), a non-profit environmental advocacy organization, elected not to include in its submission a fully developed alternative to incremental pipeline capacity stating that the Commission appears to have already concluded that a pipeline solution is needed and that alternatives such as LNG natural gas are unreliable.

CLF believes that it is not necessary or wise for New Hampshire or the region to take actions that would promote construction of a new natural gas pipeline. CLF suggests that the volatility of the wholesale gas and electric markets argues against any intervention that requires funding by electricity consumers through significant subsidies. While Staff acknowledges there are risks to consumers of financing energy infrastructure projects through electric rates, we also recognize there are risks to consumers of continuing with the way things are now. For this reason, Staff disagrees with the contention that risk necessarily argues against market intervention. Clearly, state policy makers will have to weigh the potential benefits and costs of projects designed to reduce high winter electricity prices when deciding whether to have consumers fund those projects.

In support of its contention that the winter 2014/15 price reductions do not support state intervention in electricity markets, CLF notes that the futures markets for wholesale electricity are predicting another moderately priced winter. Specifically, it states that as of June 1, 2015 the CME Group's 5 MW day-ahead on-peak product for ISO-NE's internal hub for the six months December 2015 to May 2016 was trading at an average price of less than 8 ¢/kwh, significantly lower than the retail rates paid by some New Hampshire customers last winter. However, CLF was unable to provide any studies that show that wholesale electricity futures prices are a good predictor of future wholesale electricity prices. In fact, when asked to provide the corresponding CME Group futures market prices as of June 1, 2013 and June 1, 2014 in order to test their predictive ability, all CLF would say was that it does not have access to the requested information. The fact is that wholesale electricity prices are the result of many factors including weather conditions, the availability and price of LNG, fuel oil prices, and power plant outages, none of which can be predicted with great certainty. So, for CLF to suggest that prices for this coming winter could be far lower than last winter is completely contrary to what it says just two paragraphs later, which is that future wholesale prices are very uncertain.

CLF also contends that neither new pipeline capacity nor proximity to Marcellus Shale wellheads ensures protection from cold-weather price spikes. While it is true that the addition of incremental pipeline capacity in New England will have no effect on the constraints that drive price spikes on upstream pipelines such as those that deliver to the Texas Eastern M-3 trading point,[62] it is completely false to say that that incremental capacity will have no effect on prices at, say, Algonquin ciygates. The addition of incremental capacity to the regional pipeline system, whether through the expansion of existing pipelines or the construction of new pipelines, will reduce the constraints on Algonquin and TGP pipelines and lower gas and electricity market prices, particularly during the coldest winter days.

[62] The elimination of these price spikes will be resolved over time with investments in new upstream pipeline capacity expansion projects.

Furthermore, the extent of these price reductions depends on the amount of capacity added, as is so clearly demonstrated in the testimony of CES filed on behalf of CLEC, the report of ICF on behalf of Eversource and Spectra, and the report of ICF on behalf of TGP all of which are part of the record in this investigation. To be clear, Staff is not saying that the Access Northeast project or the NED project will eliminate the existing pipeline constraints. We are saying, however, that the benefits of each project will substantially exceed the project's implementation costs even ignoring the benefits of enhanced electric grid reliability.

On the potential role of LNG in addressing winter peak prices, the Commission in its FERC Fuel Assurance filing acknowledged that the reduction in electricity prices in winter 2014/15 compared to winter 2013/14 can be attributed in large part to a surge in gas sendout from the region's LNG import terminals, including previously idled offshore terminals. That surge, however, was made possible by a reduction in world LNG prices that enabled terminal operators to successfully compete with fuel oil and high priced pipeline natural gas to supply gas generators. Unfortunately, as ISO-NE has so clearly stated, there is no guarantee that the market conditions that enticed LNG tankers to New England in winter 2014/15 will recur in future winters. This means the very high prices of 2013/14 could reappear just as quickly as they disappeared in 2014/15 assuming of course similar extreme weather conditions. Finally, it is important to note that the increased availability of LNG in winter 2014/15 did not eliminate price spikes or energy cost premiums as CLF seems to imply. As can be seen in Figure 7 below, which is copied from Attachment 2 to Eversource's filing in this investigation, wholesale electricity prices continued to exhibit substantial volatility though not as high as in winter 2013/14. This volatility resulted in wholesale electricity costs in winter 2014/15 about $2 billion higher than winter 2011/12.

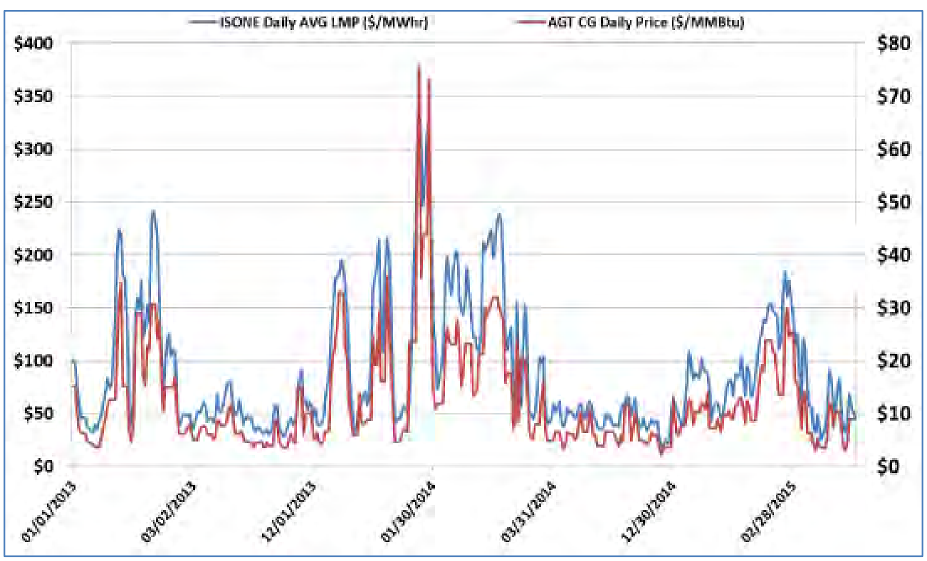


**Figure 7: ISO-NE Winter Energy Market Prices (2013-2015)**

Staff now turns to CLF's claim that the over 400,000 Dth/day of new LDC capacity associated with the Spectra AIM and TGP Connecticut Expansion projects, expected to be in service by November 2016, could achieve all or most of the objectives that special Commission action may target. If by this statement CLF is suggesting that the above referenced projects will alone result in a long-term reduction in winter period wholesale gas and electricity prices, Staff would dispute that claim. As Figure 3 in this report shows, and as we explain below in our response to similar comments by Unitil, under normal weather conditions and without the Access Northeast project peak winter gas prices are projected by ICF to fall during the 2016 through 2019 period as a direct result of the capacity added by the AIM, Connecticut Expansion and Atlantic Bridge projects. However, from 2019 through 2028 peak winter gas prices are projected to increase significantly due to expected strong growth in the demand for gas for heating and electric generation and associated growing supply constraints. That is, while gas and electricity consumers will continue to benefit from the new capacity throughout the term of the contracts, the forecast growth in the demand for gas is projected to result in price increases over time rather than decreases. In short, the new LDC capacity will not produce the long-term reduction in gas and electricity prices that presumably would be the goal of any regional pipeline capacity initiative.

CLF notes that LDCs currently release surplus pipeline capacity on the secondary market, and use the resulting revenues to reduce gas rates to residential and business customers. However, state intervention in the gas market that results in the procurement by generators of incremental pipeline capacity and lower natural gas prices will reduce the revenues available from the release of capacity and in turn raise the rates paid by gas customers, according to CLF.

Staff has several concerns with this argument. The first is that CLF's inability to quantify the alleged negative rate impact makes it difficult to determine whether this is an issue worthy of consideration. The second and far more important concern is that CLF fails to take into account the positive impact on natural gas prices and hence rates resulting from adding incremental pipeline capacity to the regional pipeline system. That is, the reduction in natural gas prices associated with new pipeline capacity will benefit gas consumers as well as electricity consumers.

Finally, CLF contends that Commission action to add new pipeline capacity to the region "is emphatically not a positive step for achieving the needed reductions in carbon emissions from the electric sector to achieve New England and New Hampshire's climate goals." However, when questioned on this issue, CLF was less emphatic and appeared to agree that displacing an existing non-gas generator that has a high $CO_2$ emissions rate with a new combined cycle gas generator that has a low $CO_2$ emissions rate would lower the average system-wide emissions rate and in the process contribute to reductions in carbon emissions.

## Winter Only LNG "Pipeline" Solution

### A. Project Overview

On August 31, just two weeks before Staff's report to the Commission was due, CLF supplemented its comments in the investigation with a 46 page report prepared by the consulting firm Skipping Stone that proposes a solution to what it terms New England's natural gas deliverability problem.[63] Because the report was presented by CLF in this investigation, Staff naturally assumed that the proposed solution was submitted as an alternative to the procurement of incremental pipeline capacity to solve the gas and electricity prices spikes that have plagued New England over the past few winters. However, it quickly became apparent that the principal purpose of the proposed solution was not to offer an incremental LNG capacity solution but instead to modify the gas supply procurement practices of New England's LDCs in order to reduce the cost of meeting peak winter gas demands and only secondarily

[63] *Solving New England's Gas Deliverability Problem Using LNG Storage and Market Incentives, Skipping Stone (undated).*

solve the high winter period electricity price problem. While a case could possibly be made that such a proposal is consistent with the Commission's Order, or at least Staff's broad interpretation of that Order, it would appear that our investigation is missing some obvious parties of interest including but not limited to LDCs, LDC consumers and the Commission's gas division. Those concerns notwithstanding, we summarize in the following pages the proposal put forth by Skipping Stone and offer our initial observations. Clearly, a proposal of this magnitude and complexity requires far more time and consideration than we have been able to devote to it over the past two weeks.

According to Skipping Stone, the most cost-effective way to address the current shortage of pipeline capacity is not to construct new or expanded pipelines from the west but to increase the utilization of the region's existing LNG infrastructure, which it defines as the combination of LDC-owned satellite LNG storage and vaporization facilities and onshore and offshore LNG import facilities. Under this solution, the LNG import facilities are used in conjunction with expanded truck deliveries to refill the satellite LNG facilities to effectively base-load what Skipping Stone claims are currently underutilized LDC assets.[64] This different use of existing satellite LNG facilities would create, according to Skipping Stone, a winter-only LNG "pipeline" for LDCs to meet their gas demands on peak days while maintaining excess supply available for sale on the secondary market to gas generators and other spot market consumers.

Skipping Stone contends that this different use of the satellite LNG assets would require advance contracting of approximately eight cargoes or 24 Bcf of LNG delivered over a 90 day winter period to meet 2020 gas demands, during which time LNG would be vaporized 50 days each winter when the demand for natural gas is projected to exceed pipeline capacity from the west with the excess supply available for release to gas generators.[65] Fifteen cargoes or 45 Bcf of LNG would be needed to meet forecasted 2030 gas demands.

Skipping Stone asserts that its solution is not only technically feasible, but would save LDC consumers initially over $340 million a year and as much as $4.4 billion over twenty years, as compared to new pipeline capacity, while also providing peak winter deliverability that will lower wholesale electricity prices on a scale comparable to new pipeline capacity additions.

### B. Economics of Winter-Only LNG "Pipeline" vs. New Pipeline

For the purposes of this comparison, Skipping Stone assumes an LDC is faced with the option of entering into a precedent agreement to purchase 160,000 Dth/day (i.e., 0.16 Bcf/day) of incremental pipeline capacity[66] at a rate of $1.5 Dth/day or alternatively contract for 160,000 Dth/day of LNG for just 50 days.[67] While the former would cost $87.6 million per year in fixed cost exclusive of commodity costs, the latter would cost $76.7 million inclusive of gas cost.[68] After adding commodity costs[69] to the pipeline

[64] According to Skipping Stone, the increased utilization of the region's LNG facilities will free up existing pipeline capacity under contract to LDCs that can in turn be released to the secondary market for the use of gas generators.
[65] On a September 11 conference call with Staff, Skipping Stone attributed the 50 day capacity deficit projection to a 2014 report by ICF International. It also stated that the 50 day capacity deficit applies to the years 2020 and 2030.
[66] The new or expanded pipeline is assumed to have a total capacity of 0.8 Bcf/day.
[67] That is, 8 Bcf of LNG gas supplies.
[68] Assumes an average landed LNG cost of $9.59/Dth (inclusive of margin for terminal operator) over the first 5 years and 8 Bcf of gas supply.
[69] Calculated as the product of 3.2 million Dth and an average natural gas price of $3.60 per Dth. The 3.2 million Dth is Skipping Stones estimate of the amount of gas actually needed.

option, the LDC cost saving would be about $22.4 million per year. Scaling this annual savings up to the full capacity of the pipeline would produce an annual savings of about $112 million for New England LDCs or approximately $2.2 billion over the 20-year life of transportation capacity contracts under the pipeline option**.** Skipping Stone asserts that only 3 Bcf of the 8 Bcf is actually needed to meet LDC capacity deficits leaving 5 Bcf for generators. That is, when scaled up to the full capacity of the pipeline, 9 Bcf of LNG is used to meet the capacity deficits.

Importantly, Skipping Stone says that "in order to facilitate this solution" regulators should permit LDCs to treat the difference between the landed cost of LNG and the cost of pipeline gas[70] (i.e., in the hypothetical $9.59/Dth of LNG on average over the 5 year period versus an assumed $3.60 /Dth winter average pipeline gas price over the same period) the same way they treat pipeline capacity payments: that is, as a fixed cost for accounting purposes.[71] This accounting treatment would allow the price of the surplus LNG to be sold to generators a price at least equal to the cost of pipeline gas, a result that means electric market clearing prices would be the same as if the LDC had purchased incremental pipeline capacity and released the rights to that capacity to gas generators. That is, the proposed accounting treatment is fundamental to achieving the wholesale energy cost savings that accrue to electric consumers under the pipeline capacity option.

While Staff does not take a position on the proposal at this time, we have one major concern. Our concern relates to the claim that the demand for natural gas exceeds pipeline capacity on just 50 days during the winter. If the region is capacity deficit on more than 50 days each winter then clearly the unmet electric sector demand for gas would increase as would the cost of the Skipping Stone proposal. In other words, the cost savings relative to the pipeline option would shrink. In this regard, it is important to note that ICF projects that in winter 2020 daily gas demand will exceed supply capacity under normal weather conditions on 63 days.[72] By 2035, the projected duration of capacity deficits lengthens to an estimated 113 days. Further, under design weather conditions ICF projects the duration of capacity deficits to be even longer ranging from 78 days in 2020 to 122 days in 2035. Clearly, if ICF's projections of capacity deficits are accurate, the volume of LNG required to meet the unmet electric sector gas demands (under both normal and design weather conditions) will be far greater than Skipping Stone has estimated, thus significantly reducing the cost savings relative to the pipeline option and decreasing the surplus gas supplies available for resale to gas generators.

Finally, because LDCs use the satellite LNG facilities to maintain gas distribution system reliability and help meet firm customer demands on peak winter demand days, Staff believes they will be very reluctant to use the associated capacity to mitigate non-firm gas and electricity price spikes.

## NEW ENGLAND POWER GENERATORS ASSOCIATION

The New England Power Generators Association (NEPGA) is the trade association representing competitive electric generating companies that own approximately 25,000 MW of capacity throughout New England including 2,700 MW in New Hampshire. Most of these electric generators are fired by gas

[70] The cost of pipeline gas is defined as the price of gas at Henry Hub.
[71] Equivalent to $18 million per year.
[72] New England Energy Market Outlook – Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Projects, ICF International, September 2015.

alone or by a combination of gas and oil. According to NEPGA, New Hampshire's member companies provide over $46 million annually in state and local taxes and jobs for nearly 800 skilled employees.

NEPGA urges the Commission not to intervene in the competitive energy marketplace in support of out-of-market energy infrastructure initiatives that seek to subsidize interstate natural gas pipeline expansion projects and large-scale hydroelectric and wind energy purchases via the construction of high voltage transmission lines. NEPGA's principal argument in support of its recommendation is that New England's electricity and fuel supply markets are performing efficiently as evidenced by the significant investments being made in new power plants, the development of new pipelines, and the implementation of new and creative concepts to increase energy supplies, all without consumers bearing the risks associated with those investments. Undercutting those efforts through subsidized out-of-market initiatives could have significant unintended consequences for the power system and electricity consumers, according to NEPGA.

In the electric sector, NEPGA contends that the markets are responding appropriately and aggressively to price signals by making necessary investments to support reliability and enhance competitive pricing while continuing to meet or exceed state and federal environmental mandates. NEPGA notes that over 1,700 MW of new power plants have been selected in recent Forward Capacity Market (FCM) auctions and a further 16,000 MW of new resources have provided expressions of interest for the next auction commencing in early 2016. Subsidized initiatives of the type described above could undermine those investments as well as investments in power plants already operating and providing services to consumers, says NEPGA.

NEPGA also contends that LNG can play an important role in meeting winter electricity demands and reducing natural gas prices, presumably as an alternative to out-of-market pipeline expansion initiatives, although this argument does not actually appear in its comments. Instead, NEPGA seems content to draw attention to the 31 Bcf of LNG injections during the December 2014 through February 2015 period, almost double the 16 Bcf of gas from LNG imports the previous winter.

In the natural gas sector, NEPGA states that several natural gas pipeline projects have recently been proposed in New England with the potential to bring up to 2.74 Bcf/day of new capacity into service between 2016 and 2018, of which over 0.8 Bcf/day has already been subscribed and potentially available to generators during the winter months.

Turning to NEPGA's claim that three pipeline projects totaling 2.74 Bcf/day of new capacity have been proposed with the potential to reduce winter constraints, it is important to note that the Northeast Energy Direct project has been reduced in size from 2.2 to 1.3 Bcf/day. More importantly, that scaled down project will not go forward without regulatory commission approval of LDC and EDC customer charges to pay for the new capacity. Furthermore, the 0.642 Bcf/day of Spectra AIM and PNGTS Continent-to-Coast capacity is subscribed by LDCs and therefore completely dependent on gas customer approved rates for their development. Thus, to the extent NEPGA is offering these projects as examples of investor financed projects without the support of regulated rates, that obviously is not the case. Also, as demonstrated by the ICF study attached to Spectra's comments in this investigation and in particular Figure 18, while these and other LDC based pipeline expansion projects will benefit the region throughout their terms they are not sufficiently large to prevent the expected increase in demand for gas from driving prices up over the long term.

NEPGA also makes reference to four major high voltage electric transmission lines each capable of delivering 1,000 MW of clean energy to the region - the Green Line, Northern Pass, the Northeast Energy Link and the New England Clean Power Link – again presumably as examples of market-based energy projects developed in response to market signals and without out-of-market subsidies. However, none of these projects are likely to be implemented absent long-term contracts with regional EDCs.

Finally, regarding the potential role of LNG in mitigating future winter gas and electricity prices, Staff agrees with the implication that the reduction in wholesale energy prices and costs during the 2014/15 winter compared to winter 2013/14 can be attributed in part to increased supplies of lower cost LNG to the region.[73] However, as noted by ISO-NE in its April 2015 review of winter 2014/15 power system performance, "LNG is a globally-priced commodity and its availability in New England is dependent on worldwide demand. New England's record-high natural gas and wholesale energy prices during winter 2013/14, along with high forward prices late last year, provided strong economic signals to LNG suppliers to bring tankers to the region this winter." Unfortunately, there is no guarantee that the same market conditions that enticed tankers to New England in winter 2014/15 will recur in future winters. As ISO-NE concluded in its review, lower LNG supplies in future winters would exacerbate New England's gas pipeline constraints, and heighten the potential for a return to the high wholesale energy prices experienced in winter 2013/14. Furthermore, because the landing price of LNG is unlikely to come close to the price of natural gas in the Marcellus Shale production area, we believe winter electricity prices will continue to reflect sizable basis differentials even when LNG supplies are plentiful. It is for these reasons that Staff does not share NEPGA's view that LNG is a dependable long-term alternative to pipeline expansion for mitigating future winter gas and electricity prices.

## UNITIL ENERGY SERVICES AND LIBERTY UTILITIES

Unitil Energy Systems (Unitil) recognizes the key role that natural gas plays in today's regional electric market and that during periods when access to gas becomes scarce wholesale electric prices may become high and volatile. The ideal solution, according to Unitil, is to change regional electric market rules to enable and require gas generators to secure firm access to gas supply but regulatory and political barriers appear to have stalled efforts to implement such rule changes.

However, Unitil does not believe having EDC play the role of counterparty in long term contracts with pipelines is the next best alternative. If EDCs are required to enter contracts to backstop natural gas infrastructure, Unitil contends that other parties who might otherwise decide to contract for pipeline capacity (such as generators and the merchants who supply them) would not do so. State regulators and policy makers should, according to Unitil, exercise patience to see how the electric market responds to over 1 Bcf/day of recently announced pipeline expansion projects before decisions are made on 15 or 20 year commitments by EDCs.[74] In addition to these expansion projects, Unitil contends that there is the prospect of new electric transmission projects which could bring an incremental year-round electric supply to the region, which would reduce the demand for gas and hence gas and electricity market prices.

[73] The drop in oil prices also helped moderate wholesale energy prices and costs.
[74] The 1 Bcf/day of publicly announced capacity expansions is made up of 0.342 Bcf/day from Spectra's AIM project, 0.072 Bcf/day from TGP's Connecticut Expansion, 0.153 Bcf/day from Spectra's Atlantic Bridge project, and 0.5 Bcf/day from TGP's NED project.

To the extent the Commission directs New Hampshire EDCs to contract for pipeline capacity, Unitil says that no single pipeline project should be presumed to be the best solution. While pipeline demand costs, project viability and access to liquid supplies are critical considerations, maintaining a preference for diversity among projects will improve the likelihood that all or most gas generators will be able to access the additional natural gas supplies.

In the event the states chose to go ahead with a region-wide solution and purchase pipeline capacity under long term contracts with EDCs, Unitil declined to directly answer the question of whether it would voluntarily agree to pay a portion of such capacity costs even if it were not required to contract for capacity. The most Unitil would say was that "it would seem feasible to allocate a share of net capacity costs from an EDC who does contract for pipeline capacity to an EDC that does not." In contrast, Liberty Utilities states that it "would be willing to pay its portion of any region-wide solution that may be implemented provided such costs would be fully recoverable from all of its customers during the period Liberty is obligated to pay for such costs."

Regarding Unitil's contention that the over 1 Bcf/day of publicly announced pipeline expansion projects will meaningfully reduce winter period natural gas prices and in turn wholesale electricity prices, we direct the Commission's attention to ICF's report for Eversource and Spectra on the Access Northeast project. That report, which is discussed above in the section addressing energy cost savings associated with the Access Northeast project, shows in Exhibit 18 that under normal weather conditions and without Access Northeast peak winter gas prices are projected to fall during the 2016 through 2019 period as a direct result of the capacity added by the AIM, Connecticut Expansion and Atlantic Bridge projects. However, from 2019 through 2028 peak winter gas prices are projected to increase due to expected strong growth in the demand for gas for heating and electric generation purposes. Even with Access Northeast, which adds approximately the same amount of capacity as the LDC portion of NED, ICF projects peak winter gas prices to increase throughout the 2019 through 2018 period. In summary, Unitil's instinct that the recently announced pipeline expansion projects will reduce winter period gas and electricity prices is not supported by careful analysis.

## STAKEHOLDER MARTIN

Ms. Martin is an active member of the Town of Rindge Energy Commission but notes that her comments in the investigation are not submitted on behalf of any organization, company, lobbying group or special interest.

Unlike many stakeholders in the investigation, Ms. Martin does not subscribe to the view that the root cause of New England's high winter period wholesale and retail electricity prices is caused by a shortage of gas infrastructure. Rather, she seems to hold the view that New Hampshire, and presumably the region, does not have an electricity price problem at all. Her rationale appears to be that the focus on electricity prices is wrong. If the focus was on electric bills, New Hampshire would not have a major problem because it is ranked close to the middle of the pack.

Ms. Martin also believes power generation within the region should be more rather than less diverse. She infers that had the region had a more diverse generation portfolio in the winter of 2013/14, like PSNH and the state of Vermont (which supplies a significant portion of its load with fixed price contracts with non-gas resources that act as a hedge against volatile gas and electricity prices), it would have been better able to withstand the worst of the winter.

The above notwithstanding, the core of Ms. Martin's opposition to an expanded regional pipeline system and more gas generation appears to be her strong belief in and support for more demand response to reduce natural gas demand during the heating season through the use of smart meters and customer incentives; more distributed generation (i.e., behind the meter solar PV systems) made possible by legislative fixes that provide for the expansion of net metering regionally; increased financial support for low income homeowners unable to pay the cost of rooftop solar installations; an expansion of weatherization and energy efficiency programs; and greater development of renewable resources including onshore and offshore wind projects.

Staff does not dispute that energy efficiency and renewable resources have an important role to play in solving the problem of high and volatile electric prices in New England, which we believe is a real problem that many businesses and residences in the region are struggling to overcome. Indeed, the Commission has said on several occasions that there is no single solution to the problem of high electricity prices and that expanded energy efficiency programs, increased importation of Canadian hydroelectricity and increased development of renewable resources can all contribute to mitigating high prices. However, Ms. Martin's suggestion that whatever is ailing the region can be solved with these resources alone does not withstand scrutiny as was clearly demonstrated by the Massachusetts Low Gas Demand Analysis prepared by Synapse Energy Economics in January 2015 for the Massachusetts Department of Energy. Synapse was tasked with answering two key questions:

A. What is the current demand for and capacity to supply natural gas in Massachusetts?
B. If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

In order to answer these questions, Synapse evaluated eight scenarios some of which took into account all technically and economically feasible energy efficiency and renewable resources as well as 2,400 MW of incremental Canadian hydroelectric imports. Notwithstanding the inclusion of these alternative energy resources, Synapse found that in order to balance supply and demand for natural gas in Massachusetts in 2020, natural gas pipeline additions that range from 0.6 Bcf/ day to 0.8 Bcf/day were needed. In 2030, the range of required pipeline additions increased slightly to 0.6 Bcf/day to 0.9 Bcf/day. When scaled up to the whole of New England, the equivalent range for 2020 would be 1.1 Bcf/day to1.5 Bcf/day, higher than the 1.1 Bcf/day estimated by ICF in its 2014 Phase II study conducted for ISO-NE.

## OTHER STAKEHOLDERS

Many stakeholders chose not to submit concrete solutions and instead focused on related issues such as New Hampshire's historically high energy costs, compared to the rest of the nation, and the damage those costs do residents, businesses, non-profit organizations, and the state's overall economy. BAE Systems, for example, claims that the cost of doing business in New Hampshire is not competitive with other regions of the country, largely because our highest-in-the nation cost of electricity. In terms of actions, some such as the Greater Londonderry Chamber of Commerce urge the Commission to take whatever steps it deems necessary to ensure more affordable sources of energy are available to the state while others like the Business & Industry Association and BAE Systems recommended forging ahead on specific energy infrastructure projects such as pipeline expansion to deliver incremental supplies of natural gas and new electrical transmission lines to transport low cost hydroelectric and wind energy from remote locations. Failure to do so will only deepen and extend the energy crisis and stifle economic growth, says BAE Systems.

Mr. Howard Moffett, a member of the Science, Technology & Energy Committee of the New Hampshire House of Representatives, submitted comments that reflect his own views (rather than those of the Committee) on the causes of and solutions to the high winter period wholesale electricity prices. In summary, Mr. Moffett asserts that there is a strong consensus that the problem is caused by insufficient pipeline capacity feeding the region from west to east and that that consensus is entitled to overwhelming weight. As regards solutions, Mr. Moffett advocates for a region-wide approach that results in the construction of sufficient new gas pipeline capacity to eliminate the "basis differential" but does not see a need for New Hampshire EDC's or their customers to finance the expansion. This, he contends, is the responsibility of LDCs. Also, Mr. Moffett does not see LNG imports as part of the regional solution. LNG prices, he says, are simply too unpredictable and the reliance on more LNG cargoes in future winters would risk regional blackouts.

In the long-term, Mr. Moffett believes the region needs to transition away from fossil fuels and decentralize its electric grid. Achieving these policy goals will require development of a strong Energy Efficiency Resource Standard, the promotion of indigenous renewable energy sources, support for demand response programs, and incentives for distributed generation.

The Office of the Consumer Advocate (OCA), in its initial comments and response to the July 10 Staff Memorandum on legal authorities, took a holistic approach to the question of winter price spikes, and cautioned against market interventions in the first instance. OCA expressed confidence in the ability of the New England energy markets to respond to the price signals being generated, and the benefits of the forthcoming roll-out of ISO-NE reforms such as Pay-for-Performance, in upcoming years. OCA did delineate some criteria for consideration if its preferred course of non-intervention at the market level were not taken: no long-term commitments from rate payers, such as that for pipeline capacity; a resource-neutral approach; a recognition of the benefits of energy efficiency and other demand-side management tools; the need to avoid regulatory duplication across state boundaries and between the federal and state authorities; and the potential benefits of rate smoothing approaches designed to spread out the impact of winter rates for consumers throughout the year. OCA's response to Staff's July 10 Memorandum, as mentioned previously, strongly opposed any conclusion that existing New Hampshire statutory authority existed for the EDCs to acquire pipeline capacity, and also pointed to the issue of potential stranded costs as being a potential ratemaking problem of great concern to OCA.

The New Hampshire Electric Cooperative's (NHEC) primary contribution to the debate over solutions to the high electricity price problem is that for infrastructure projects paid for by consumers, such projects should be chosen and implemented in a manner that minimizes costs to consumers. In this regard, NHEC and other public power systems contend they should be offered the option to participate as equity partners in both pipeline and electric transmission infrastructure projects, allowing the injection of lower cost public power debt financing. Interestingly, Eversource believes that even if such alternative financing mechanisms were feasible, interstate pipelines are unlikely to build infrastructure for others to own, as such activities depart from their established business models of building, owning and operating these facilities for the long term. That said, if this is the price for public power systems agreeing to pay some of the costs of new gas infrastructure projects, Staff urges the representatives of public power systems to make their case to one or more of the project sponsors.

The New Hampshire Pipeline Awareness Network (NHPLAN) contends in its comments that LNG has an important role to play in meeting the peak day demands each winter when "fuel adequacy is seasonably challenged." In support of this position, NHPLAN compared the full cost of the NED pipeline with two LNG storage options; one based on domestically sourced natural gas and the other on LNG imports. Under the pipeline option, NHPLAN calculated a typical annual cost to supply 6 Bcf of gas over 60 winter peak demand days inclusive of gas commodity costs and 365 days of pipeline transportation charges. Under the domestically sourced LNG option, the annual cost comprised the cost to purchase 6 Bcf of natural gas plus the variable cost to liquefy that gas prior to placing it in storage. Under the imported LNG option, the annual cost is simply the product of the 6 Bcf of gas and the landed price of LNG. Based on the results of these calculations, NHPLAN asserts that the LNG alternatives are significantly less costly than purchasing pipeline capacity year round to meet winter peak demands.

Staff, however, contends that NHPLAN's calculations are seriously flawed. While NHPLAN appropriately included fixed pipeline costs in the pipeline option, under the domestically sourced LNG option it excluded the fixed costs associated with storage, liquefaction and vaporization facilities. In addition, it excluded the variable costs of storage and vaporization. As regards the imported LNG option, NHPLAN excluded the fixed costs of the import terminals, the fixed and variable costs of vaporization, and the fixed costs of the pipelines to transport the vaporized gas to gas generators. It also assumed unreasonably that the operator of the facilities would sell the commodity at its landed cost exclusive of margin. For all of these reasons, Staff contends that NHPLAN's assertion is deficient because it is not supported by factual analysis.

National Grid, a joint sponsor of the Access Northeast project, submitted comments that among other things support the idea of EDCs playing the role of counterparties to long-term contracts that enable pipeline construction. National Grid asserts, however, that this role is conditional on the EDCs recovering "total costs (including administrative costs and remuneration) associated with the incremental gas pipeline capacity through a fully reconciling, non-bypassable retail electric cost recovery mechanism." While Staff understands and supports National Grid's position that EDC participation in pipeline construction must be subject to the necessary cost recovery assurances from regulators including the recovery of monthly pipeline demand charges and EDC administrative costs, we question National Grid's insistence that EDCs must also be compensated for the use of their balance sheets.

Our concern relates to the Access Northeast project, which as we have explained includes both Eversource and National Grid as joint sponsors with Spectra. Although the financial details of their partnership with Spectra have not been disclosed, we believe it is reasonable to assume that both parent utility companies will be adequately rewarded for what we think is a relatively low risk undertaking. We base this assumption on ICF's estimate that a $2.4 billion capital investment will produce a levelized annual cost of $400 million assuming a 20-year contract term. That is, electric consumers would pay $8.0 billion over the life of the contract. We estimate that about one quarter of those revenues could be retained by the project partners as profit, while the rest would cover depreciation expenses, debt costs, and income and property taxes. While Staff acknowledges that the willingness of the EDCs to take on the role of counterparty in the long-term contracts exposes them to some financial risk, we believe that risk is small given the cost recovery assurances they are seeking. For these reasons, we urge the Commission to reject any request for such remuneration related to the Access Northeast project.

That said, Staff believes there may be a case for EDC compensation whenever long-term capacity contracts are entered into with TGP or PNGTS projects.

The Office of Energy and Planning (OEP) sent in initial comments setting out the proposition that another Commission docket, that in IR 14-338 related to rate smoothing, should be combined with this Investigation, that an expert should be retained to assist Staff in its Investigation, and that "OEP cautions the PUC against attempting to address wholesale issues on its own."

## COMPETITIVE SELECTION PROCESS

Sponsors of new or expanded natural gas pipelines generally employ open seasons to determine market interest in their projects. An open season is a process by which the sponsor of a pipeline project solicits prospective natural gas customers to bid on the available transportation capacity, evaluate the bids submitted, and award or allocate the capacity among customers that have met the qualification requirements. As a result of this process, project sponsors and selected customers typically enter into binding or non-binding precedent agreements that specify, among other things, the amount of transportation capacity to be purchased and the rates to be paid per unit of firm transportation. It is common practice for project sponsors and potential customers to negotiate the rates that customers pay for pipeline services, although the pipelines also must make available FERC-approved cost-based recourse rates that can be used in the event negotiations prove unsuccessful.

Access Northeast completed an open season May 1, 2015 and executed memoranda of understanding[75] with three EDC affiliates of National Grid and four EDC affiliates of Eversource, which together account for approximately 71 percent of the retail electric load in New England. As explained above, National Grid and Eversource are two of the three sponsors of the Access Northeast project and therefore the affiliated EDCs are not disinterested observers.[76] In addition, the sponsors of Access Northeast have also had discussions with unaffiliated New England ECDs to gauge their interest in participating in the project with the goal of spreading the project fixed costs more broadly. The outcome of those discussions has not been shared with Staff.

NED has completed an open season for New England LDCs and executed precedent agreements with nine companies for a total firm transportation capacity of approximately 0.55 Bcf/day on the Market Path segment, leaving approximately 0.75 Bcf/d of additional capacity available for EDCs. On September 9, 2015 TGP began a second open season for EDCs only. Finally, PNGTS has made it known that it expects to hold an open season for its new expansion project in the 4th Quarter of 2015 or the 1st Quarter of 2016.

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[75] It is important to note that the MOUs were entered into prior to EDCs meeting with the sponsors of competing pipeline projects. Furthermore, Eversource declined to provide Staff with a copy of the MOU executed with PSNH, claiming its terms contain commercially sensitive information that must remain undisclosed while precedent agreements are under negotiation. The key terms of a precedent agreement typically include the amount of capacity to be purchased, the rates for firm transportation, and the term of the contract.

[76] Although Access Northeast has been marketed to electric (rather than gas) distribution companies, Eversource been quoted in the press as saying that the project has also received strong interest from LDCs and that the company has started the process of negotiating long-term contracts with those companies. The implications of this development are addressed elsewhere in this report.

Despite the significant work done by project sponsors in organizing and hosting the open seasons, and by the participating EDCs in evaluating the various projects, Staff strongly recommends that if the New England states decide as a group to proceed with the procurement of incremental pipeline capacity on a regional basis that procurement not be based on the results of open seasons. Given that the capacity purchased by EDCs will be paid for by the customers of those companies and not the shareholders, Staff believes that it is incumbent on regulators to ensure that the target capacity be allocated among pipeline projects without favor through an open and transparent process that is demonstrably competitive and results in the lowest possible cost to consumers. As long as a significant number of the New England EDCs are affiliated with the sponsors of one of the competing pipeline projects, we believe it will be difficult if not impossible for EDCs to make a convincing case that pipeline open seasons qualify as fair, open and transparent competitive processes. For this reason, we believe it is imperative that the states develop and post for comment an alternative competitive solicitation process (i.e., Request for Proposals ("RFP")) much like the three southern New England states did when they developed a joint Clean Energy RFP. As is the case here, the purchasers of clean energy products will include New England EDCs that are affiliated with sponsors of one or more of the projects that are expected to submit bids. However, unlike the Clean Energy RFP, we do not believe it would be appropriate to have the EDCs play a significant role in the development of the RFP or in evaluating the bids. In Staff's opinion, the terms and conditions for the pipeline capacity RFP including the criteria for evaluating the bids should be the responsibility of the states assisted by an independent consulting firm with extensive expertise in gas and electricity procurement matters. Such independent consultant could also play the important role of primary bid evaluator. As CLEC correctly observes in its comments, the procurement of pipeline capacity "is a fundamentally public decision" that should not be delegated to EDCs and certainly not EDCs that have corporate relationships with project sponsors, and thus are likely to be burdened with conflicting interests.

The pipeline capacity RFP should be issued on behalf of New England EDCs that volunteer to participate in the procurement of incremental capacity and should solicit bids for firm transportation services from pipeline developers that offer such services. We anticipate that the aggregate amount of pipeline capacity to be purchased would be decided by the New England states through a collaborative effort, but hopefully somewhat less than the aggregate capacity of Access Northeast and NED projects in order to maximize the competitive pressures on bidders to offer their best prices. The RFP should also request binding bids on the ground that if developers are not held to their bids, the competitive process loses its integrity. Non-binding bids or bids with cost overrun provisions should be discouraged. In addition, the designers of the RFP may wish to consider requesting bids for relatively small increments of capacity that sum to the agreed aggregate amount in order to eliminate the problem of evaluating bids for projects of different sizes. Finally, requiring the competitive solicitation process to be transparent, thorough and overseen by independent evaluators will promote robust competition among pipeline sponsors to the ultimate benefit of consumers. Absent a demonstrably competitive solicitation, Staff foresees a significant risk that the negotiations between a project sponsor and potential customers will not be at arms-length and thus will not produce the most advantageous cost and commercial terms for consumers.

As regards the criteria for bid evaluation, we agree with CLEC that an important criterion is price. And by price we mean the delivered price of natural gas. Gas infrastructure projects, whether pipeline or LNG based, should be graded primarily on the basis of the delivered price of gas. This, however, raises the difficult question of how to determine in the context of an RFP the average price of gas at a specific receipt point over a 15- to 20-year contract term. While current market conditions may indicate some receipt points can access lower cost gas than others, those conditions are likely to change over time making such comparisons unreliable. Perhaps the best an evaluator can do is assume that market forces will eliminate over time any price differential between receipt points, which leads to the conclusion that the evaluation of competing projects should be based in large part on the rates for firm transportation service. That is, projects with lower transportation rates should be ranked higher than projects with higher transportation rates, all other things being equal. For projects with multiple transportation rates, we recommend that the weighted average rate be used for evaluation purposes.

There is, however, another criterion that some may argue should be ranked as high as the level of transportation rates in the evaluation process and that is a project's benefit to cost ratio. While pipeline capacity increments of the same size should produce the same wholesale energy cost savings, the cost to implement and hence the benefit to cost ratio may differ if, for example, a portion of the construction cost is allocated to LDCs rather than EDCs. This allocation of costs to LDCs should, however, enable the project sponsor to bid a lower transportation rate. Thus, in a truly competitive solicitation process, the relative firm transportation rates should determine in large part which projects are awarded capacity contracts.

Additional weight could be given to pipeline capacity proposals that can be readily expanded through the addition of compression or similar incremental investments – as opposed to replacement of actual pipe. Further, since delays in pipeline in-service dates are extremely costly to electricity consumers, additional weight could be given to pipeline capacity proposals that have realistic earlier in-service dates.

Finally, Staff anticipates that capacity purchased from pipeline projects based on a demonstrably competitive solicitation process would be allocated among participating EDCs (potentially including municipal and cooperative utilities) on a pro-rate load share basis. The EDCs would then engage in negotiations with the winning projects and execute precedent agreements for pipeline transportation service, which would become effective only after regulatory review and approval.

## REGULATORY APPROVAL PROCESS

Any New Hampshire EDC that chooses to purchase capacity under one or more infrastructure projects would be responsible for seeking Commission approval of its capacity purchases, assuming of course the Commission must determine that New Hampshire EDCs have the legal authority to enter into long-term contractual arrangements to benefit their customers. Capacity purchased on the basis of a demonstrably competitive solicitation process should be regarded by the Commission as satisfying any statute or regulation requiring the use of least cost procurement practices, meaning that the winning bids will be those that provide the highest value to electricity consumers. This does not mean, however, that capacity contracted by EDCs is necessarily in the public interest. In order to meet that standard, we believe each EDC seeking regulatory approval of its contract must establish that the associated wholesale energy cost savings will exceed by an appropriate margin the costs of the purchase. To meet this burden, we anticipate that each EDC or the EDCs as a group will need to hire the services of a consulting firm with extensive experience in gas industry modeling.

## APPENDIX 1, Page 1

Base Case – LNG Priced at $14/mmbtu

**Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers**

| Pipeline Capacity | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,136 | 2113 | 374 | 296 |
| + 0.2 bcf/d Capacity | 3,336 | 1723 | 267 | 217 |
| + 0.4 bcf/d Capacity | 3,536 | 1316 | 198 | 158 |
| + 0.6 bcf/d Capacity | 3,736 | 993 | 144 | 120 |
| + 0.8 bcf/d Capacity | 3,936 | 750 | 104 | 78 |
| + 1.0 bcf/d Capacity | 4,136 | 550 | 71 | 56 |
| + 1.2 bcf/d Capacity | 4,336 | 391 | 53 | 46 |
| + 1.4 bcf/d Capacity | 4,536 | 288 | 41 | 35 |
| + 1.6 bcf/d Capacity | 4,736 | 206 | 34 | 28 |
| + 1.8 bcf/d Capacity | 4,936 | 152 | 27 | 22 |
| + 2.0 bcf/d Capacity | 5,136 | 111 | 17 | 12 |
| + 2.2 bcf/d Capacity | 5,336 | 74 | 11 | 9 |
| + 2.4 bcf/d Capacity | 5,536 | 54 | 7 | 6 |

| Pipeline Capacity | Annual Energy Costs ($) | Incremental Savings ($) | Cumulative Savings ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|---|
| Base Case | $7,683,828,621 | | | $60.38 |
| + 0.2 bcf/d Capacity | $7,196,238,670 | $487,589,951 | $487,589,951 | $56.55 |
| + 0.4 bcf/d Capacity | $6,662,968,905 | $533,269,765 | $1,020,859,716 | $52.36 |
| + 0.6 bcf/d Capacity | $6,215,782,492 | $447,186,412 | $1,468,046,128 | $48.84 |
| + 0.8 bcf/d Capacity | $5,862,015,565 | $353,766,927 | $1,821,813,055 | $46.06 |
| + 1.0 bcf/d Capacity | $5,556,608,801 | $305,406,764 | $2,127,219,819 | $43.66 |
| + 1.2 bcf/d Capacity | $5,302,503,435 | $254,105,366 | $2,381,325,185 | $41.67 |
| + 1.4 bcf/d Capacity | $5,129,825,208 | $172,678,227 | $2,554,003,412 | $40.31 |
| + 1.6 bcf/d Capacity | $4,986,336,567 | $143,488,641 | $2,697,492,053 | $39.18 |
| + 1.8 bcf/d Capacity | $4,887,791,007 | $98,545,560 | $2,796,037,613 | $38.41 |
| + 2.0 bcf/d Capacity | $4,809,857,588 | $77,933,420 | $2,873,971,033 | $37.80 |
| + 2.2 bcf/d Capacity | $4,737,106,541 | $72,751,047 | $2,946,722,080 | $37.22 |
| + 2.4 bcf/d Capacity | $4,696,129,285 | $40,977,255 | $2,987,699,335 | $36.90 |

APPENDIX 1, Page 2

LNG Priced at $10/mmbtu

## Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers

| Pipeline Capacity | Pipeline Capacity bcf/d | Hours of Generation by Fuel Type LNG | Propane | Oil |
|---|---|---|---|---|
| Base Case | 3,136 | 2113 | 374 | 296 |
| + 0.2 bcf/d Capacity | 3,336 | 1723 | 267 | 217 |
| + 0.4 bcf/d Capacity | 3,536 | 1316 | 198 | 158 |
| + 0.6 bcf/d Capacity | 3,736 | 993 | 144 | 120 |
| + 0.8 bcf/d Capacity | 3,936 | 750 | 104 | 78 |
| + 1.0 bcf/d Capacity | 4,136 | 550 | 71 | 56 |
| + 1.2 bcf/d Capacity | 4,336 | 391 | 53 | 46 |
| + 1.4 bcf/d Capacity | 4,536 | 288 | 41 | 35 |
| + 1.6 bcf/d Capacity | 4,736 | 206 | 34 | 28 |
| + 1.8 bcf/d Capacity | 4,936 | 152 | 27 | 22 |
| + 2.0 bcf/d Capacity | 5,136 | 111 | 17 | 12 |
| + 2.2 bcf/d Capacity | 5,336 | 74 | 11 | 9 |
| + 2.4 bcf/d Capacity | 5,536 | 54 | 7 | 6 |

| Pipeline Capacity | Annual Energy Costs ($) | Incremental Savings ($) | Cumulative Savings ($) | Load Weighted Avg. Energy Price ($/MWh) |
|---|---|---|---|---|
| Base Case | $6,358,806,914 | | | $49.97 |
| + 0.2 bcf/d Capacity | $6,071,331,989 | $287,474,925 | $287,474,925 | $47.71 |
| + 0.4 bcf/d Capacity | $5,762,959,523 | $308,372,466 | $595,847,391 | $45.28 |
| + 0.6 bcf/d Capacity | $5,505,725,096 | $257,234,427 | $853,081,818 | $43.26 |
| + 0.8 bcf/d Capacity | $5,302,777,297 | $202,947,799 | $1,056,029,617 | $41.67 |
| + 1.0 bcf/d Capacity | $5,128,848,329 | $173,928,969 | $1,229,958,586 | $40.30 |
| + 1.2 bcf/d Capacity | $4,984,670,631 | $144,177,697 | $1,374,136,283 | $39.17 |
| + 1.4 bcf/d Capacity | $4,886,506,519 | $98,164,112 | $1,472,300,395 | $38.40 |
| + 1.6 bcf/d Capacity | $4,805,074,015 | $81,432,504 | $1,553,732,900 | $37.76 |
| + 1.8 bcf/d Capacity | $4,748,977,913 | $56,096,101 | $1,609,829,001 | $37.32 |
| + 2.0 bcf/d Capacity | $4,704,714,006 | $44,263,907 | $1,654,092,908 | $36.97 |
| + 2.2 bcf/d Capacity | $4,663,784,289 | $40,929,717 | $1,695,022,625 | $36.65 |
| + 2.4 bcf/d Capacity | $4,640,646,097 | $23,138,192 | $1,718,160,817 | $36.47 |

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PUC 1-4

Request:

For each statute or regulation referenced in PUC-1-2, please indicate the status of approval or consideration of contracts with Algonquin and the electric distribution companies under those statutes or regulations.

Response:

*Massachusetts*

The Massachusetts Department of Public Utilities (MA DPU) is currently reviewing agreements with Algonquin executed by: (1) Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, in D.P.U. 16-05; and Eversource Energy, in D.P.U. 15-181, respectively. Discovery in both dockets is near completion. Evidentiary hearings in both dockets will occur between July 26, 2016 and August 12, 2016, with briefing to follow through October 4, 2016. Responses to discovery issued in D.P.U. 16-05 have been submitted in Docket No. 4627 in response to PUC Data Request 1-1. A link to the MA DPU website is http://web1.env.state.ma.us/DPU/FileRoom/dockets.

*Connecticut*

On March 9, 2016, the Connecticut Department of Energy and Environmental Protection (CT DEEP) issued a draft request for proposals (RFP) for public comment, seeking bids for natural gas resources under Section 1(d) of PA 15-107. See http://www.ct.gov/deep/

A final RFP was scheduled to be issued April 11, 2016, with proposals due May 6, 2016. CT DEEP is scheduled to identify final gas projects between May and July 2016. The CT electric distribution companies are scheduled to submit contracts for CT Public Utility Regulatory Authority (CT PURA) review by October 31, 2016. The CT PURA decision is scheduled to be issued within 90 days thereafter, i.e., by January 30, 2017. The final execution of contracts would be scheduled at a future date.

*Maine*

The Maine Public Utilities Commission (ME PUC) is currently reviewing several proposals for gas capacity, including a potential contract with Algonquin, in Docket. No. 2014-00071.

See http://www.maine.gov/mpuc/. Hearings have been held and briefs have been filed. On June 8, 2016 the ME PUC staff issued a recommendation (Examiners' Report), and exceptions to the Examiners' Report have since been submitted. It is the Company's understanding that on July 19, 2016, the ME PUC voted to move forward with a contract with ANE, contingent upon participating by the electric distribution companies in Massachusetts, Rhode Island, Connecticut and New Hampshire (but not Vermont).

*New Hampshire*

On February 18, 2016, Public Service of New Hampshire d/b/a Eversource Energy (Eversource) filed a Petition for Approval of Gas Infrastructure Contract between Eversource and Algonquin, which among other things provides for the release of contracted capacity to New England gas-fired electric generators. See http://www.puc.state.nh.us/

The New Hampshire Public Utilities Commission (NH PUC) docketed the petition as DE-16-241. A technical session was scheduled to be held on May 4, 2016. Briefs have been filed by stakeholders on the question of the NH PUC's legal authority to approve the contract.

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PUC 1-5

Request:

For each order or regulation referenced in PUC-1-2, please indicate whether same has been challenged in any court of law, the status of such challenge, and an expected decision date.

Response:

The Company is aware of a challenge in only one state, Massachusetts. The D.P.U. 15-37 order was appealed to the Massachusetts Supreme Judicial Court (SJC) and has been docketed as SJC 12051 and SJC 12052. Oral arguments before the SJC were made on May 5, 2016. The SJC generally issues rulings within 130 calendar days after oral arguments.

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PUC 1-6

Request:

Please provide a status of the reviews in Connecticut, New Hampshire and Maine together with links to any websites containing documentation related thereto (Brennan & Allocca p. 16, n. 9).

Response:

Please see the Company's response to data request PUC 1-4.

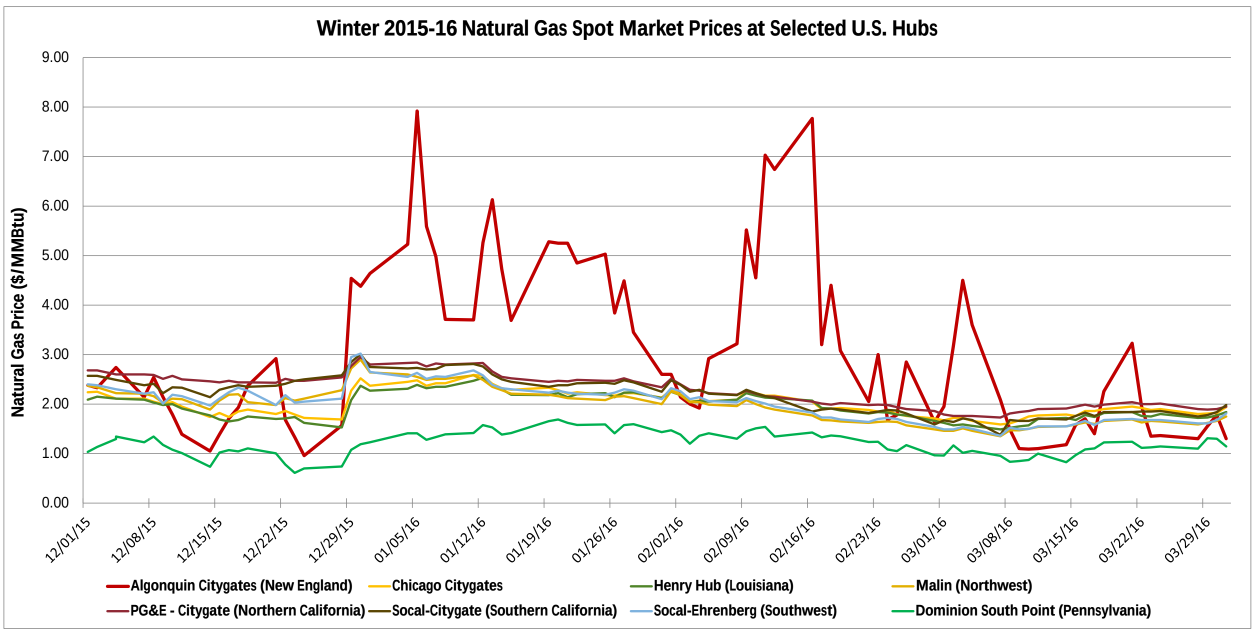
## PUC 1-7

Request:

Please provide a new chart updating the chart on page 17 of Messers. Brennan and Allocca's testimony for the winter 2015-2016.

Response:

Please refer to the chart provided below.



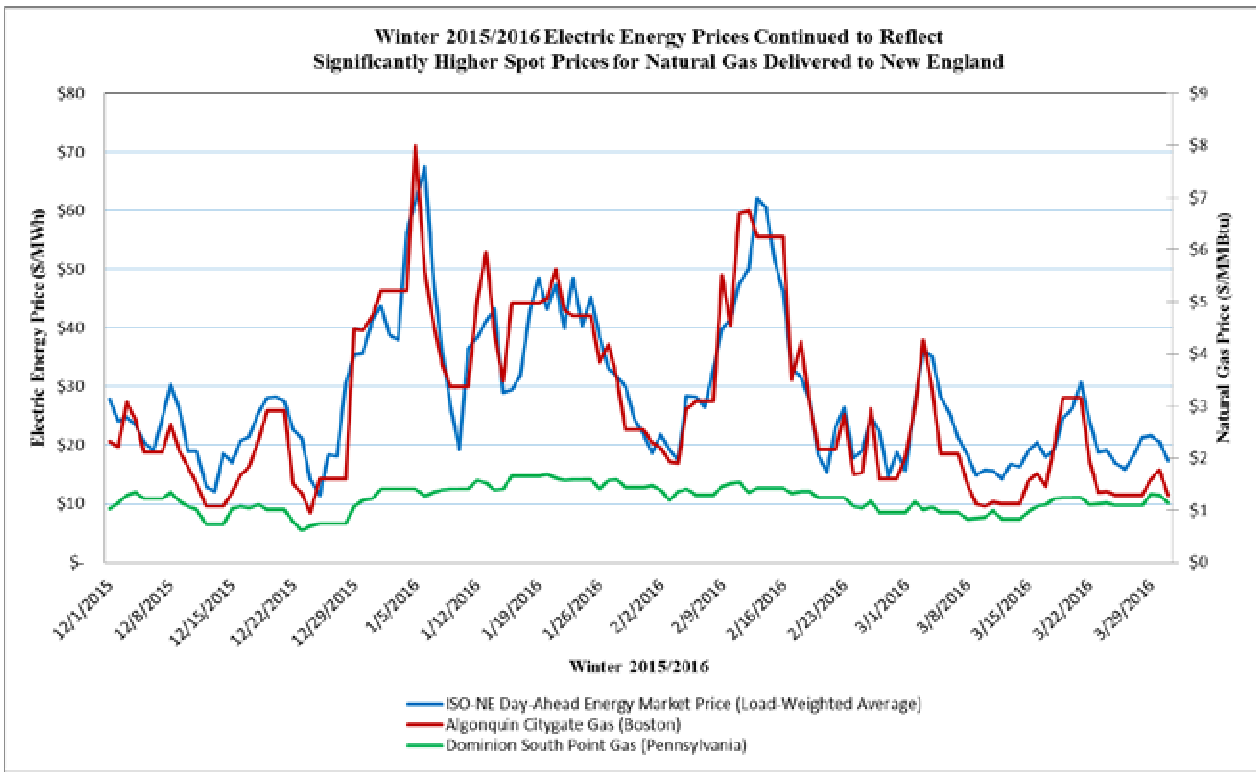
PUC 1-8

Request:

Please provide a new chart updating the chart on page 18 of Messers. Brennan and Allocca's testimony for the winter 2015-2016.

Response:

Please refer to the chart provided below.



PUC 1-9

Request:

Please provide a new chart updating the chart on page 19 of Messers. Brennan and Allocca's testimony to add a column for the winter 2015-2016.

Response:

Please refer to the updated table below.

| Algonquin City Gate vs. Henry Hub Basis Differential | Number of Days - Winter (Dec -Feb) | | | | |
|---|---|---|---|---|---|
| | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
| Greater than $2/MMBtu | 21 | 65 | 77 | 72 | 32 |
| Greater than $5/MMBtu | 4 | 41 | 64 | 53 | 1 |
| Greater than $10/MMBtu | 0 | 28 | 51 | 21 | 0 |
| Greater than $20/MMBtu | 0 | 10 | 20 | 9 | 0 |
| Greater than $30/MMBtu | 0 | 1 | 7 | 0 | 0 |
| Greater than $40/MMBtu | 0 | 0 | 3 | 0 | 0 |

Prepared by or under the supervision of: Timothy J. Brennan

PUC 1-10

Request:

Please provide a new chart updating the chart on page 20 of Messers. Brennan and Allocca's testimony to add a column for the winter 2015-2016.

Response:

Please refer to the updated table provided below.

| | Winter (Dec -Feb) | | | | |
|---|---|---|---|---|---|
| | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 |
| Avg. Gas Price @ Algonquin City Gate ($/mmBtu) | $ 4.40 | $ 11.26 | $ 19.56 | $ 10.73 | $3.40 |
| Total Cost of ISO-NE Electric Energy Market ($Billions) | $ 1.2 | $ 2.9 | $ 5.0 | $ 2.8 | $ 1.0 |

Prepared by or under the supervision of: Timothy J. Brennan

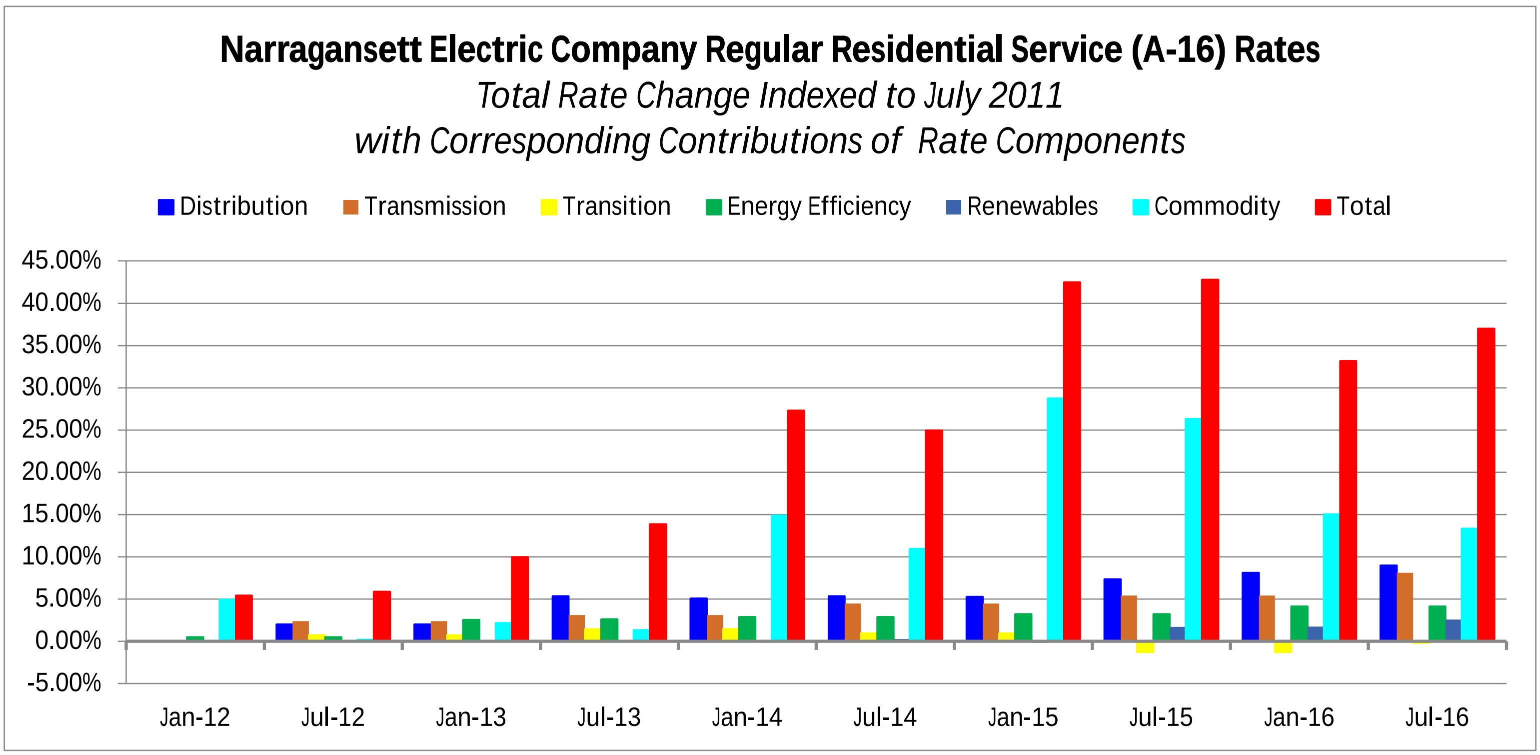
PUC 1-11

Request:

The label on the chart on page 21 of Messers. Brennan and Allocca's testimony is unclear. Please update the chart to include columns for January 2016 (if not already there) and July 2016.

Response:

Please refer to the chart provided below, updated to include columns for July 2016.




Prepared by or under the supervision of: Timothy J. Brennan