

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

IR 15-124

Report on Investigation into Potential Approaches to
Mitigate Wholesale Electricity Prices

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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/MMBtu 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, 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, 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, ICF² 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 February 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/MMBtu 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](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](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, prudence, 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 up to 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.

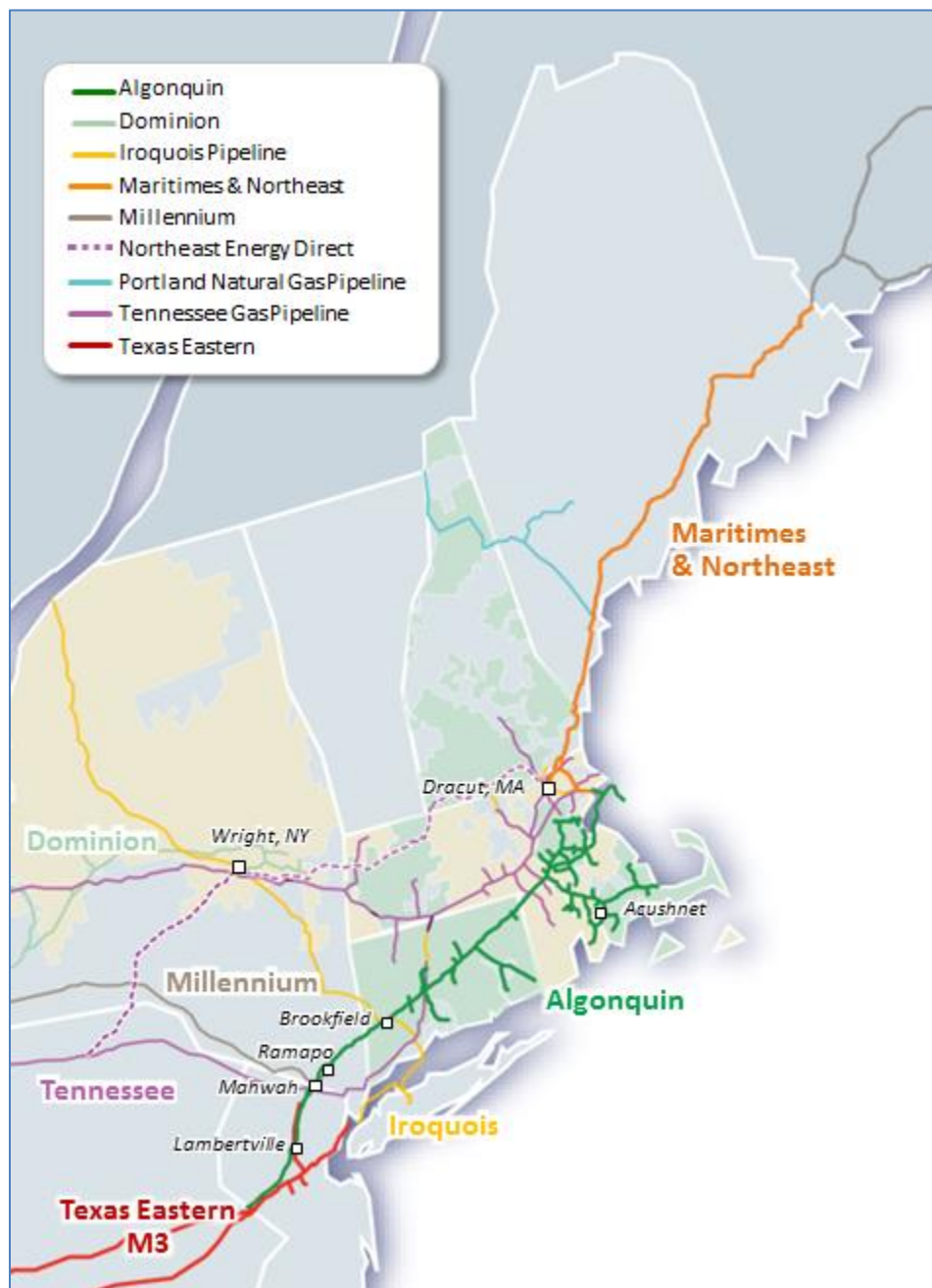


Figure 1: Algonquin and Maritimes & Northeast Pipelines

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-for-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 capacity³³ 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.

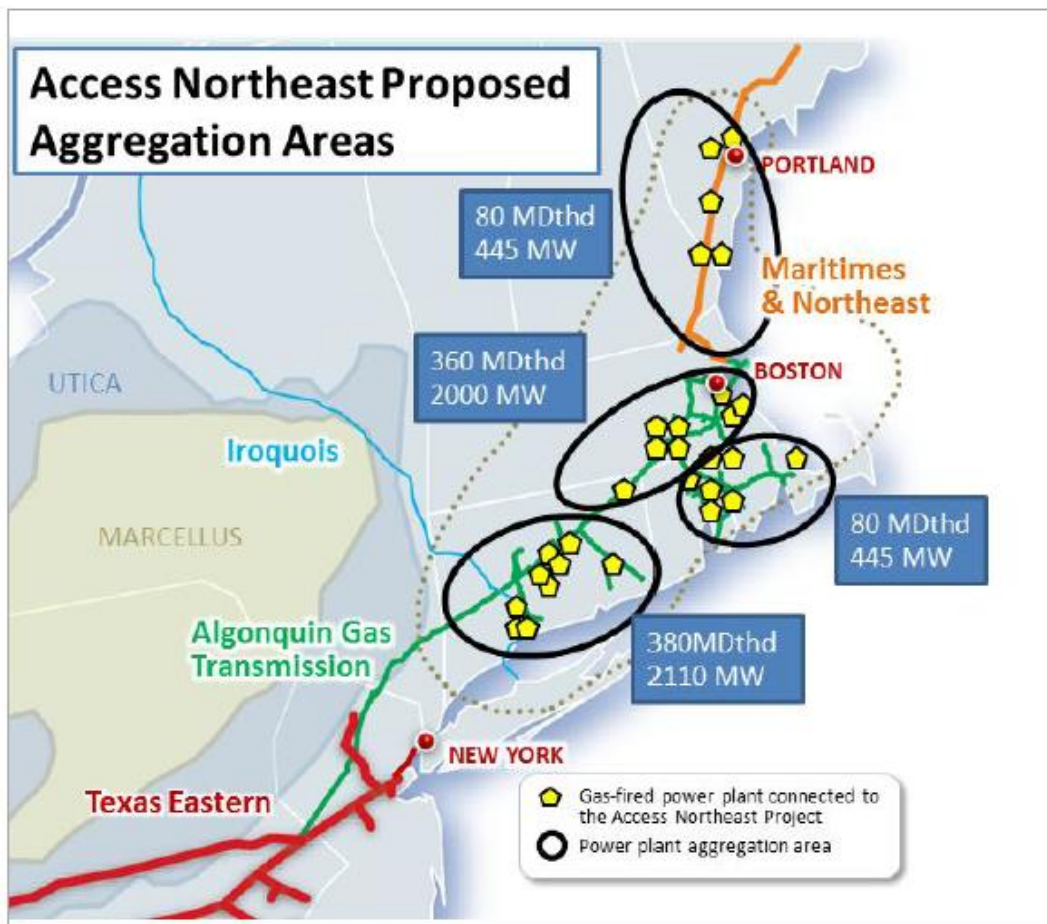


Figure 2: Access Northeast Proposed Aggregation Areas

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/MMBtu 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.

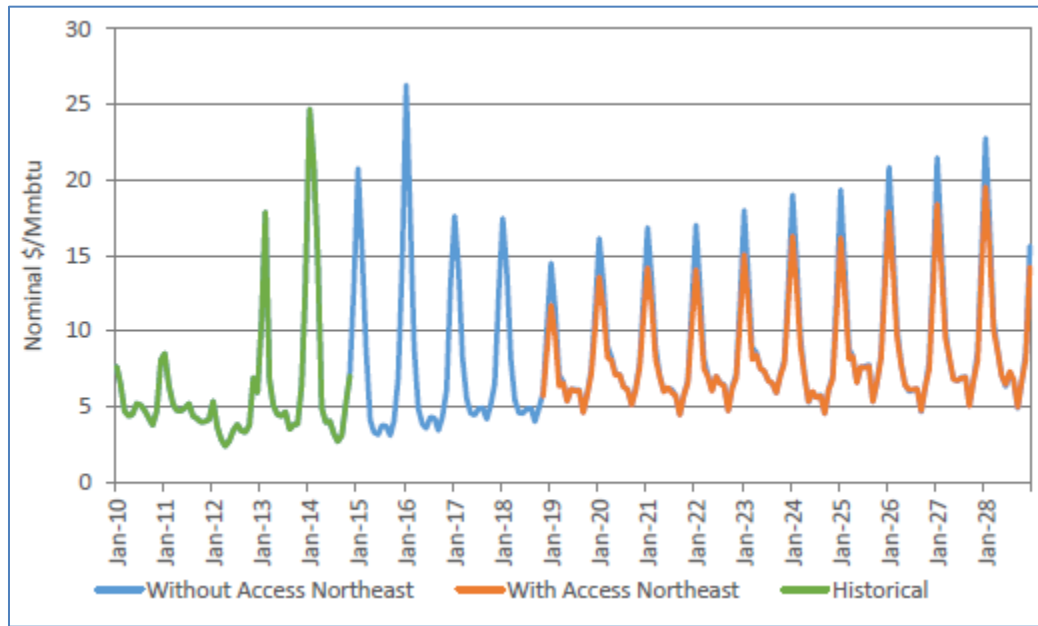


Figure 3: ICF’s natural gas price forecast for New England (excluding volatility reduction benefits)

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

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 Line⁴⁵ in Northeast Pennsylvania and extend to Wright, New York where it will interconnect with TGP's existing 200 Line,⁴⁶ 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.

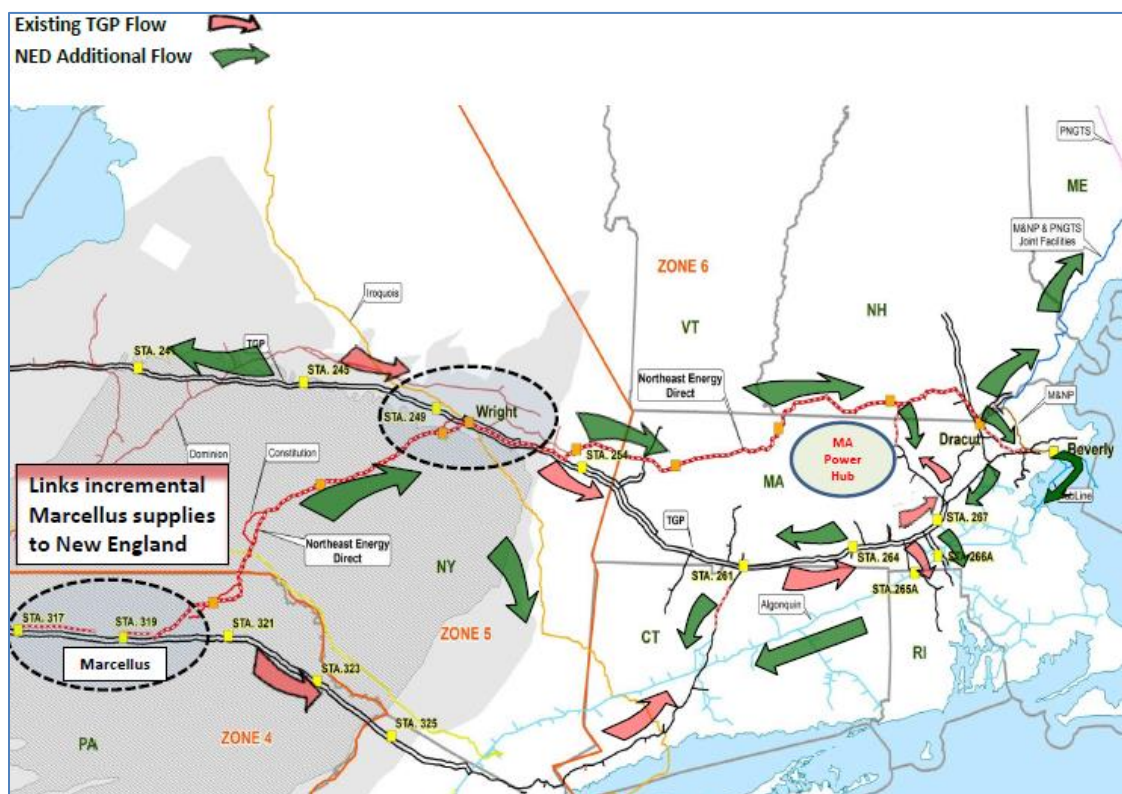


Figure 4: Tennessee Gas Pipeline Company's Northeast Energy Direct Project

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 pipeline⁴⁸ 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 service⁵² 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.

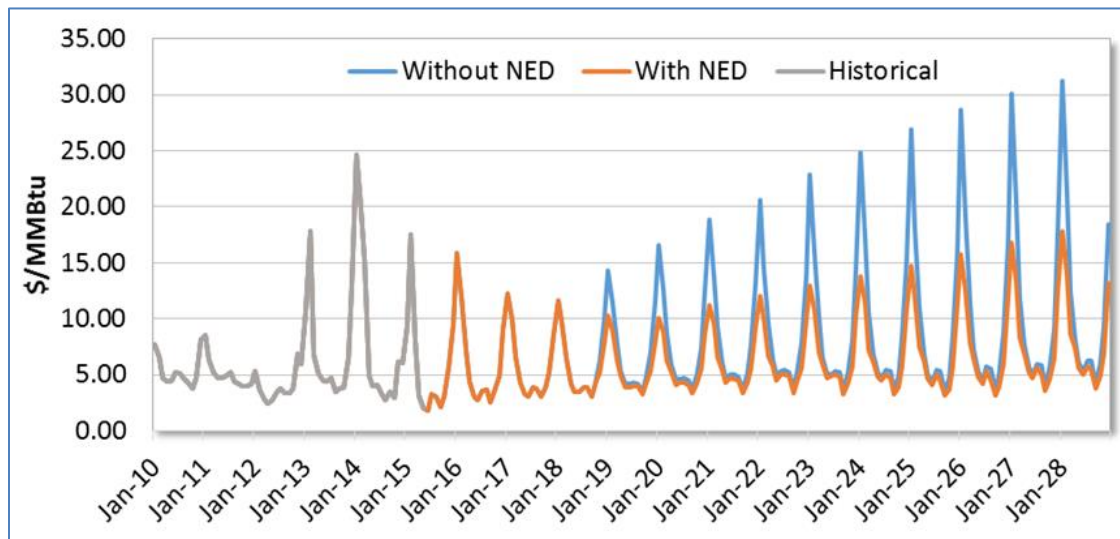


Figure 5: ICF's natural gas price forecast for New England (excluding volatility reduction benefits)

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.

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.

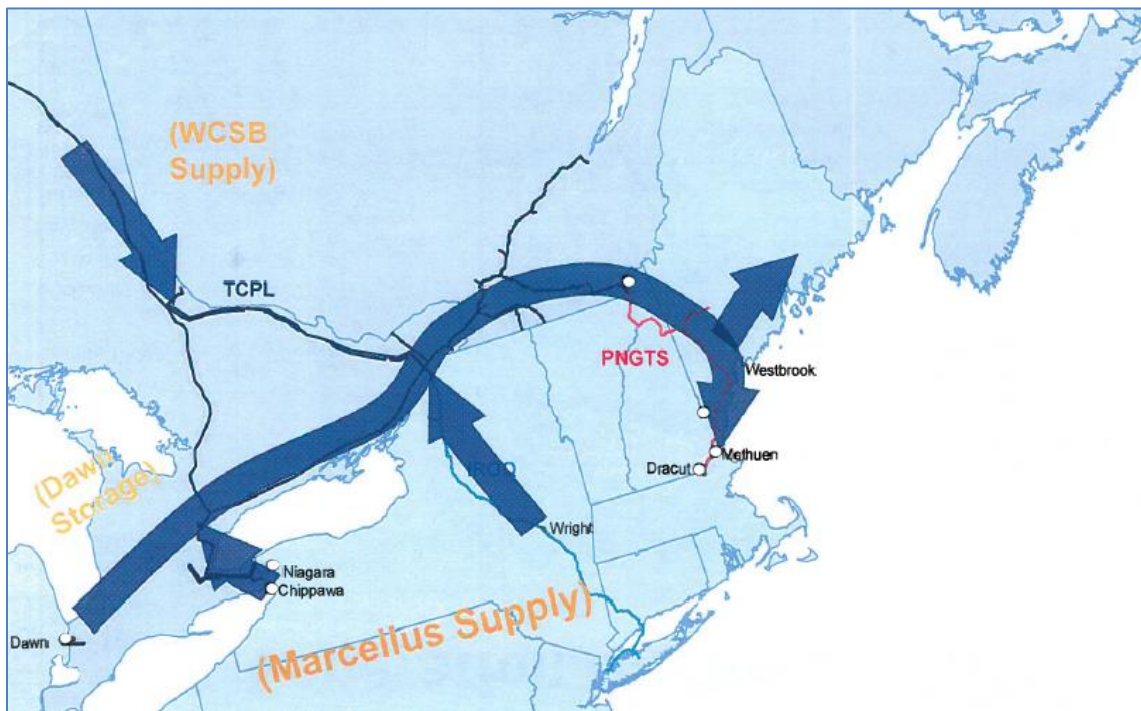


Figure 6: PNGTS Supply. Storage Access Options

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 Pittsburg, 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 unavailable, 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.

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.

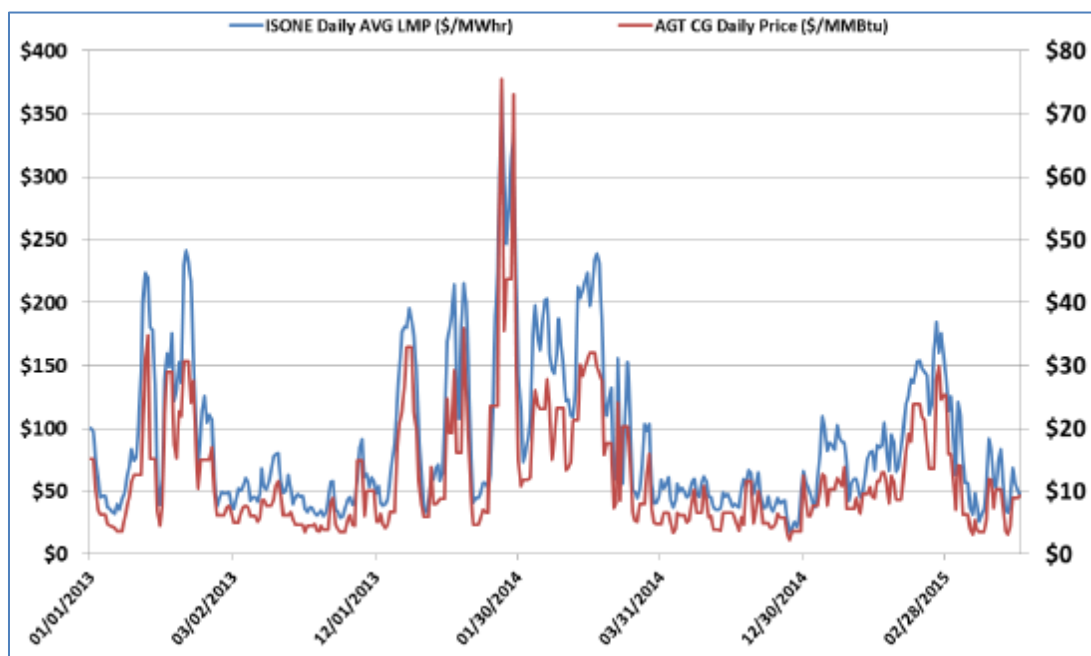


Figure 7: ISO-NE Winter Energy Market Prices (2013-2015)

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 CO₂ emissions rate with a new combined cycle gas generator that has a low CO₂ 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 capacity⁶⁶ 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 costs⁶⁹ 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 gas⁷⁰ (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 to 1.5 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 understanding⁷⁵ 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 EDCs 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.

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.

Base Case – LNG Priced at \$14/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers				
	Pipeline Capacity	Hours of Generation by Fuel Type		
Pipeline Capacity	bcf/d	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

LNG Priced at \$10/mmbtu

Summary - Economic Value of Incremental Natural Gas Pipeline Capacity to New England Electric Consumers				
	Pipeline Capacity	Hours of Generation by Fuel Type		
Pipeline Capacity	bcf/d	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

	Annual Energy Costs	Incremental Savings	Cumulative Savings	Load Weighted Avg. Energy Price
Pipeline Capacity	(\$)	(\$)	(\$)	(\$/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