KEEGAN WERLIN LLP

ATTORNEYS AT LAW
265 FRANKLIN STREET
BOSTON, MASSACHUSETTS 02110-3113

(617) 951-1400

TELECOPIERS:
(617) 951- 1354
(617) 951- 0586

September 14, 2016

BY HAND DELIVERY

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

Re: Docket 4627 – In Re: Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project
Responses to Division Data Requests – Set 5

Dear Ms. Massaro:

On behalf of National Grid,[1] enclosed are National Grid's responses to the Fifth Set of Data Requests issued by the Rhode Island Division of Public Utilities and Carriers in the above-referenced matter. Please note that the response to Data Request DIV 5-1 contains Highly Sensitive Confidential Information; a Motion for Protective Treatment is enclosed and the confidential versions of this response will be provided only the Public Utilities Commission and those parties that have executed the appropriate non-disclosure agreements.

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

Very truly yours,

John K. Habib

John K. Habib

Enclosures

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

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

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

NATIONAL GRID'S REQUEST
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

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

I. BACKGROUND

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

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

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

On September 14, 2016 National Grid filed its responses to the Division of Public Utilities and Carriers' (Division) Fifth Set of Data Requests that reference these highly sensitive confidential terms. Specifically, the Company is seeking protective treatment of its response to Data Request DIV 5-1 (the HSCI Document).

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

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

The Company has provided redacted and unredacted versions of the HSCI Document. This document contains confidential and proprietary contractual or economic analysis information. Therefore, National Grid requests that the PUC give the information contained in the unredacted version of the HSCI Document protective treatment.

II. LEGAL STANDARD

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

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

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

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

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

III. BASIS FOR CONFIDENTIALITY

The information contained in the un-redacted versions of the HSCI Document includes confidential and proprietary bidder information received in response to the Company's request for proposals. This information includes information that was obtained from bidders under a confidentiality agreement and contains their confidential pricing data. Disclosure of this information would impact the competitive position of these parties, and such disclosure would impede National Grid's future ability to obtain bids and/or favorable contractual terms. Such disclosure would have a negative impact not only on National Grid but on National Grid's customers by impeding National Grid's ability to obtain the best price for future capacity agreements.

IV. CONCLUSION

Accordingly, the Company requests that the PUC grant protective treatment to the Company's response to Data Request DIV 5-1.

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

Respectfully submitted,

NATIONAL GRID

By its attorneys,

Jennifer Brooks Hutchinson (RI Bar #6176)
National Grid
280 Melrose Street
Providence, RI 02907
(401) 784-7288

John K. Habib

John K. Habib, Esq. (RI Bar #7431)
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400

Dated: September 14, 2016

Division 5-1

Request:

Please create a revised PROMOD / GPCM base case that is the same as B&V's original base case but with the following specific changes made.

a. Update the PROMOD and GPCM inputs to reflect current market conditions for fossil fuels
b. Use the 2016 CELT reports for the forecast of electricity demand and annual consumption in New England.
c. Use the following annual growth rates for LDC demand from 2016 to 2040 per the 2016 AEO forecast
    i. Residential: 0.03%
    ii. Commercial: 0.82%
    iii. Industrial: 0.48%
d. Change the monthly LNG send-out assumed from Distrigas and Canaport to the value provided in the attached excel file named DIV 5-1 to NGRID attachment CONF.xlsx.

Response:

Black & Veatch acknowledges that proposed new Reference Case above (proposed in this Data Request, DIV 5-1) and scenarios (proposed in Data Request DIV 5-2) would potentially reduce the impact of the ANE Project on regional natural gas and electric prices, and the associated net benefits of the project.

It is Black & Veatch's expert opinion that the suggested monthly LNG send-out assumptions for the Distrigas and Canaport facilities provided in this Data Request, DIV 5-1, are not reasonable and do not warrant additional analysis.

Repsol Energy North America Corporation's (Repsol) ability to deliver 1 Bcf/d of regasified LNG from Canaport is limited. As stated by Repsol in the related Massachusetts docket D.P.U. 16-05, Canaport has peaked at approximately 700 MMcf/d over the past 3 winters. See Attachment DIV 5-1(a) (D.P.U. 16-05, Testimony of Vincent C. Morrissette on behalf of Repsol), at VCM-3. Canaport's ability to deliver into New England is restricted by its capacity on the Brunswick Pipeline and on Maritimes and Northeast, which are well below the 1 Bcf/d suggested. Respol also stated in D.P.U. 16-05 that absent gas sales agreements, it is unrealistic to assume significant long-term supplies at maximum regasification rates from Canaport. See Attachment DIV 5-1(b) (D.P.U. 16-05, Exh. NG-RENA-1-14).

In GDF Suez's Request for Proposal response, it states that its maximum daily quantity is [redacted]. See Exh. Attachment AG 1-4(a)(3) (HSIC) filed by the Company's Massachusetts affiliates in D.P.U. 16-05 and provided in response to Data Request PUC 1-1. After taking into consideration GDF Suez's (formerly Distrigas) ability to load LNG to trucks, it is short of the maximum monthly average volume of [redacted] suggested by the Division. While it may be possible to assume an additional offshore LNG regas facility to make up the difference, those imports are highly speculative and are not reasonable to be considered as part of the sensitivity reference case.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, for Approval of Firm Gas Transportation and Storage Agreements with Algonquin Gas Transmission Company, LLC, pursuant to G.L. c. 164, § 94A.	))))))))	D.P.U. 16-05

TESTIMONY OF

VINCENT C. MORRISSETTE
VICE PRESIDENT, MARKET DEVELOPMENT
REPSOL ENERGY NORTH AMERICA CORPORATION

ON BEHALF OF
REPSOL ENERGY NORTH AMERICA CORPORATION

June 17, 2016

Q: Please state your name and business address.

A: My name is Vincent ("Vince") C. Morrissette. My business address is 2455 Technology Forest Boulevard, The Woodlands, TX 77381.

Q. By whom are you employed and what are your professional qualifications?

A: I am employed by Repsol Energy North America Corporation ("RENA") as Vice President of Market Development. My responsibilities include managing a team that is responsible for developing new markets for RENA's existing natural gas commercialization business, which is very active in New England gas markets, and for managing state and federal regulatory affairs related to RENA's natural gas business. Prior to this role, I managed a team that was responsible for the origination of long-term natural gas sale, purchase, and transportation transactions, also with a strong focus on the New England market. In addition to my experience at RENA, I have held a variety of positions at natural gas infrastructure companies, including Tennessee Gas Pipeline Company, L.L.C. and Iroquois Gas Transmission System, LP. In total, I have over twenty-five years of relevant experience in the natural gas industry with a broad background in all aspects of the New England gas market, ranging from natural gas pipeline design and flow dynamics to the sale and purchase of natural gas.

Q: Have you presented testimony in any other state proceedings addressing the need for incremental pipeline capacity into the New England region?

A: Yes. I have presented testimony before this Commission in Docket No. D.P.U. 15-181, as well as before the Maine Public Utilities Commission in Docket No. 2014-00071.

Q: Please describe RENA.

A: RENA is a fully owned subsidiary of Repsol S.A. ("Repsol"), one of the world's leading integrated oil and gas companies. Repsol spans the entire energy value chain including exploration, production, refining, marketing and new energy research and development.

RENA and its affiliate Repsol Energy Canada Ltd ("REC") are key players throughout the natural gas value chain with a strong upstream portfolio and direct access to storage and transportation capacity within the U.S. and Canada. RENA provides a full range of natural gas trading and origination services including baseload gas purchases and sales, structured and daily natural gas transactions, seasonal and peaking gas supply services, daily natural gas trading and asset management. In addition, RENA recently commenced trading power and began providing gas management services for power generation facilities in the New England region.

RENA's affiliate REC has contracted for 100% of the 1,000,000 dekatherms per day ("Dth/d") of capacity at the Canaport™ LNG facility at Saint John, New Brunswick, Canada ("Canaport LNG").[1] With REC having a long-term contract in place for 100 percent of this capacity and RENA having a corresponding long-term contract in place for 730,000 Dth/d of firm transportation capacity on Maritimes & Northeast Pipeline, L.L.C. ("M&NP"), RENA has the ability to serve New England gas markets with significant volumes of natural gas through direct deliveries off M&NP's system and through deliveries into the eastern ends of Algonquin Gas Transmission, LLC ("AGT") at Beverly-Salem, MA and Tennessee Gas Pipeline Company, L.L.C. ("TGP") at Dracut, MA.

[1] Canaport LNG is jointly owned by Repsol Partners (75%) and Irving Partners (25%).

RENA has been selling gas into New England gas markets since 2008. Since 2009, RENA has been providing base-load and winter peaking services utilizing the Canaport LNG facility and its corresponding pipeline capacity on M&NP. During the winters of 2013/2014, 2014/2015, and 2015/2016 RENA supplied approximately 20 Bcf, 21Bcf, and 12 Bcf of natural gas, respectively from Canaport LNG to New England markets, with daily deliveries peaking at approximately 700 million cubic feet per day ("MMcf/d") each winter.

Q: Did RENA submit a proposal in response to the October 23, 2015 *Notice of Requests for Proposals (RFP) for Natural Gas Capacity, Liquefied Natural Gas (LNG) and Natural Gas Storage Procurement* issued jointly by Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid ("National Grid"); and NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource ("Eversource")?

A: Yes. RENA submitted proposals to both National Grid and Eversource. With respect to its bid submitted to National Grid, RENA was one of eight entities that submitted proposals in response to the RFP. RENA's proposal consisted of an eighteen-year term agreement for up to 500,000 Dth/d with a maximum annual quantity of 22,500,000 Dths. RENA's bid included a U.S. gas index-based price and a demand charge that would be in effect for the full term of the agreement. While RENA's proposal was not selected by National Grid, RENA remains convinced that the use of imported liquefied natural gas ("LNG"), along with already existing pipeline infrastructure can best meet the gas supply needs of gas-fired electric generation facilities located in the region more efficiently and cost effectively, and without environmental disturbance. Such a solution will have a much less overall cost to New England's electricity ratepayers than new, expensive incremental pipeline capacity that will remain underutilized for the bulk of the year.

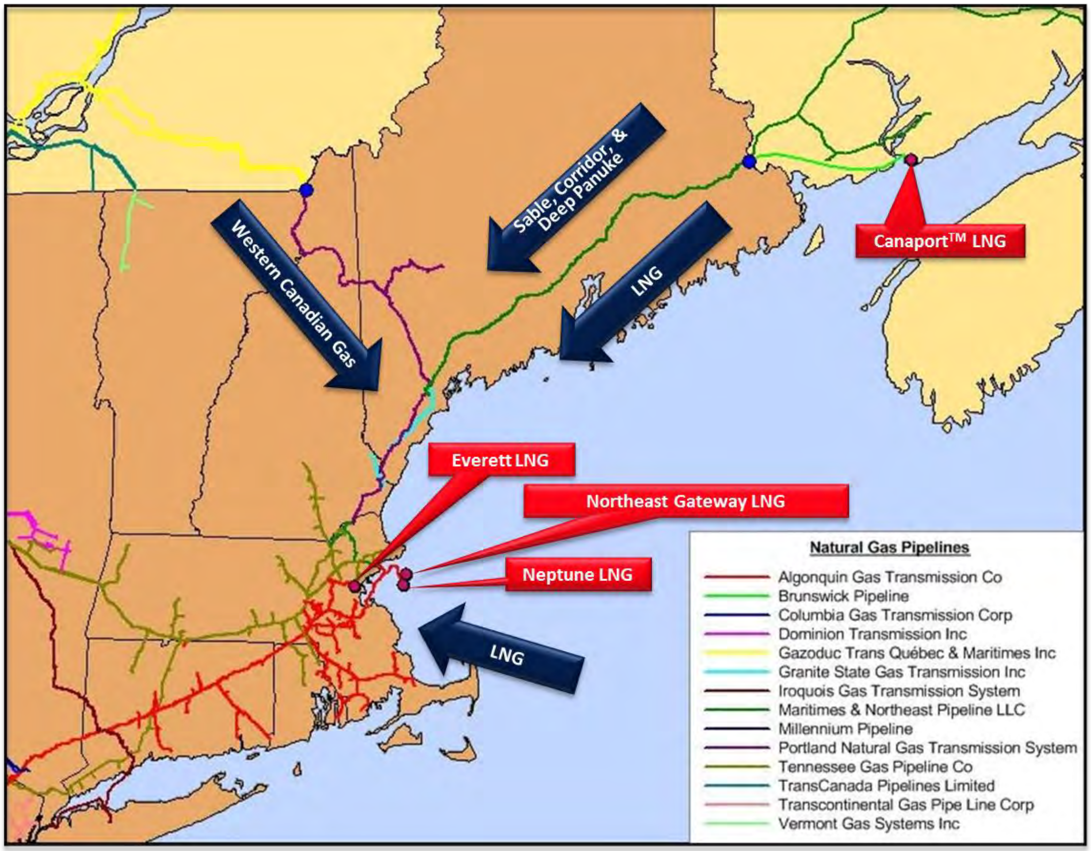
Q: Please summarize your testimony.

A: My testimony provides evidence to support the position that better utilization of existing natural gas infrastructure and gas supply resources, such as LNG import facilities, is the most cost effective, implementable, and reliable solution for electric reliability in lieu of expensive new natural gas pipeline infrastructure.

Q: Please provide an overview of New England's natural gas requirements.

A: New England's natural gas requirements are characterized by a generally increasing level of average daily natural gas usage punctuated by winter peak-day spikes primarily related to the residential heating load during periods of extreme cold. Historically, supplemental gas supplies to meet New England's peak-day requirements have reliably been met by imports of Canadian production and re-gasified LNG from Canaport LNG and other regional LNG facilities (i.e., "back-feed supply"). *See* Figure 1 on the following page.

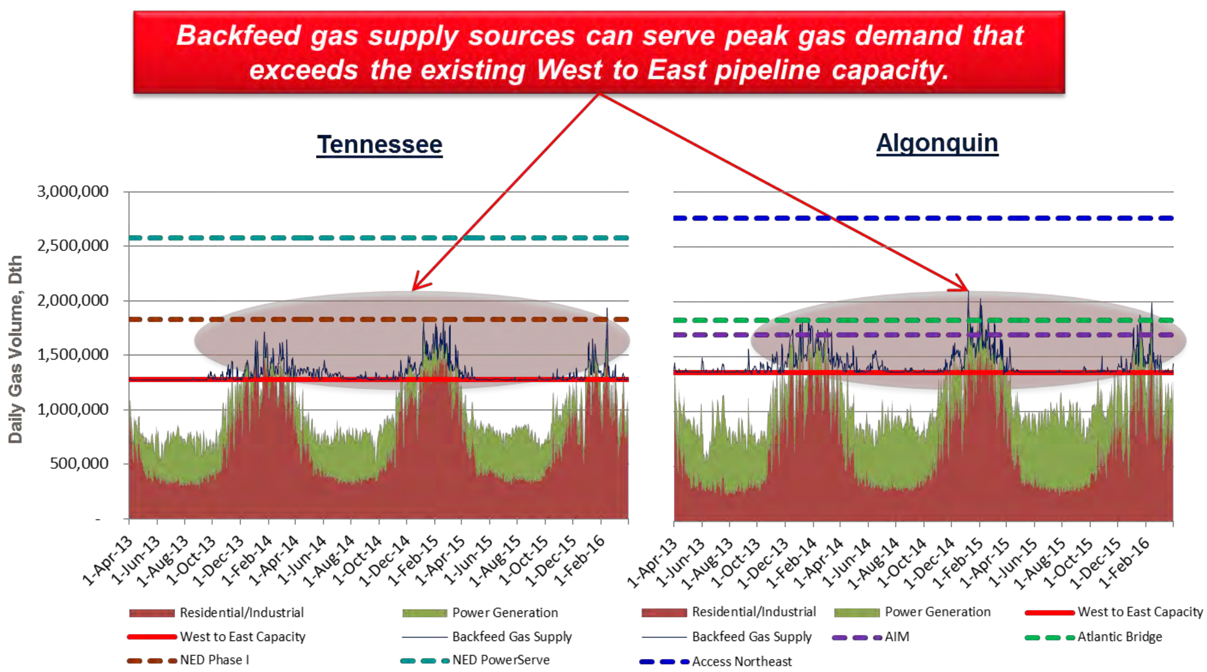
Figure 1
Back-Feed Supply Sources



The principal pipelines serving New England include TGP, AGT, M&NP, Portland Natural Gas Transmission System ("PNGTS"), and Iroquois Gas Transmission ("IGT"). AGT and TGP serve the majority of the New England market primarily from the south and west, while the other pipelines serve this market primarily utilizing gas supplies from Canada. In addition to re-gasified LNG delivered from Canaport LNG through M&NP, re-gasified LNG is also available from Engie Gas & LNG LLC's ("Engie"; formerly GDF Suez) Everett LNG facility in Everett, MA, and Excelerate Energy's ("Excelerate") Northeast Gateway Deepwater Port facility offshore Salem, MA.

New England's peak winter days can best be defined as those days when the firm capacity holders on AGT and TGP, primarily local distribution companies ("LDCs"), are fully utilizing their west-to-east pipeline capacity to serve residential, industrial and commercial markets such that discretionary markets (those without firm transportation capacity - primarily power generators) must rely on back-feed supply. The gas delivery profile for AGT and TGP for the period April 1, 2013 through March 31, 2016 is shown in Figure 2 below. The solid red horizontal lines represent existing west-to-east capacity on TGP (1.27 Bcf/d) and AGT (1.36 Bcf/d). As shown in Figure 2, on those days when demand exceeds available west-to-east capacity, back-feed supply sources (such as Canaport LNG) are utilized to serve this excess demand.

Figure 2



Source: Ventyx

Figure 2 also shows the incremental west-to-east pipeline capacity additions that have been announced by TGP[2] and AGT, including AGT's Access Northeast project ("ANE").

---

[2] TGP recently announced it was suspending the NED project. However, RENA believes that a TGP "reconfigured" project will still go forward that will satisfy the approximate demand (approximately 0.550 Bcf/d) associated with LDC forecasted requirements in "NED Phase I" .

AGT's Algonquin Incremental Market Expansion ("AIM") has been approved by the Federal Energy Regulatory Commission (the "FERC") and is projected to be in-service by November 1, 2016. AIM will provide 342,000 Dth/d of new west-to-east incremental capacity. AGT's Atlantic Bridge Expansion, which is currently pending before the FERC, is anticipated to provide an additional 136,000 Dth/d of incremental capacity by the winter of 2017. In addition to this new incremental capacity, the Access Northeast project ("ANE") is proposed to provide an <u>additional</u> 900,000 Dth/d of incremental west-to-east capacity through expansion of AGT's existing pipeline facilities and the construction of a new LNG storage facility located in Acushnet, MA.

Q: In your opinion, is there sufficient demand to satisfy the almost 1 Bcf/d of incremental capacity being proposed as part of ANE?

A: No. As explained later in my testimony, and as graphically shown above in Figure 2, this new incremental capacity is not supported by market realities. Further, even if the incremental capacity was needed on winter peak days, it would lay unutilized for the bulk of the year, leaving New England electric ratepayers picking up the tab. In contrast, by virtue of its ability to deliver firm gas supplies at the terminus of the TGP and AGT systems into the middle of the market centers where gas is needed most, back-feed supply sources (such as LNG) have the ability to meet the peak-day requirements of the market when it is needed most without the requirement for expensive and duplicative facilities that would remain unutilized for most of the year. In addition, due to their proximity to the market centers and their rapid send-out ramp-up capabilities, the LNG import facilities (i.e., Canaport LNG, Everett, and Northeast Gateway) are very responsive to the market during periods of peak demand. Collectively, the back-feed peaking supply capability currently available to serve the New England market is almost 2.4 Bcf/d (exclusive of Engie's contractual commitment to the Mystic Development, LLC power plant) and deliveries of greater than 1.6 Bcf/d have actually been realized to date.

Q: Are there sufficient LNG supplies available at competitive prices to satisfy New England's peak day needs?

A: Yes. To explain, let's start with putting the size of the worldwide LNG market in perspective: The entire worldwide LNG market is in the range of the equivalent of approximately 35 Bcf/d. By comparison, the average daily U.S. gas market is in the range of approximately 75 Bcf/d, and it peaks to almost twice that during periods of very high demand in the winter. There are approximately 13 Bcf/d (gas equivalent) of new LNG supply projects that are under construction and proposed to come online by the end of 2018, which is almost 40% of current worldwide demand. *See* Figure 3. This growth in the supply of worldwide LNG is expected to outpace LNG demand for the foreseeable future, increasing competition between LNG suppliers for market and putting further downward pressure on LNG prices. Sufficient supplies of LNG at competitive prices for the peak demand market in New England for the long term, therefore, will likely result.

Figure 3

Over 13 Bcfd (99 MMtpa) of new liquefaction capacity is under or near construction worldwide with anticipated start-up by 2018. This is very significant considering that the average worldwide LNG trade volume is only ~35 Bcfd (270 Mmtpa).

Project	# of Trains	Capacity MMtpa	Capacity Bcfd	Est. Start-up	Status
Queensland Curtis T1 and T2 (Australia)	2	8.5	1.1	Q1 and Q3 2015	Under Construction
DS LNG (Indonesia)	1	2.0	0.3	Q2 2015	Under Construction
Pacific Rubiales	1	0.5	0.1	Q4 2015	Under Construction
Australia Pacific T1 and T2 (Australia)	2	9.0	1.2	Q1 and Q2 2016	Under Construction
GLNG T1 and T2 (Australia)	2	7.8	1.0	Q1 and Q3 2016	Under Construction
Sabine Pass T1-4 (USA)	4	18.0	2.4	Q1/Q3 2016, Q2/Q3 2017	Under Construction
Gorgon T1-3 (Australia)	3	15.6	2.1	Q1/Q3 2016, Q1 2017	Under Construction
Petronas FLNG (Malaysia)	1	1.2	0.2	Q3 2016	Under Construction
MLNG T9 (Malaysia)	1	3.6	0.5	Q4 2016	Under Construction
Ichthys T1 and T2 (Australia)	2	8.4	1.1	Q2 2017	Under Construction
Wheatstone LNG T1 and T2 (Australia)	2	8.9	1.2	Q2 and Q4 2017	Under Construction
Prelude FLNG (Australia)	1	3.6	0.5	Q3 2017	Under Construction
Elba Island T1-8 (USA)	8	2.5	0.4	Q2 2017 (T1-6), Q2 2018 (T7-8)	Near Construction
Rotan FLNG (Malaysia)	1	1.5	0.2	Q2 2018	Under Construction
Cameron LNG T1 and T2	2	8	1.1	Q4 2018	Under Construction
TOTAL	33	99.1	13.1		

Source: Waterborne LNG

Figure 4 below shows the worldwide LNG capacity versus demand through 2025 as estimated by Cambridge Energy Research Associates ("CERA"). It is anticipated that it will take the worldwide market many years to absorb this abundant new supply and therefore, future LNG price expectations have been drastically reduced from the abnormally high peak levels experienced a few years ago when the LNG markets endured the unforeseen and extremely rare nuclear power generation shutdown in Japan due to the earthquake and subsequent tsunami that destroyed the Fukushima nuclear power generation facility in addition to a long-term drought in Brazil that caused an increase in gas-fired power generation due to the reduction in hydroelectric generation.

Figure 4

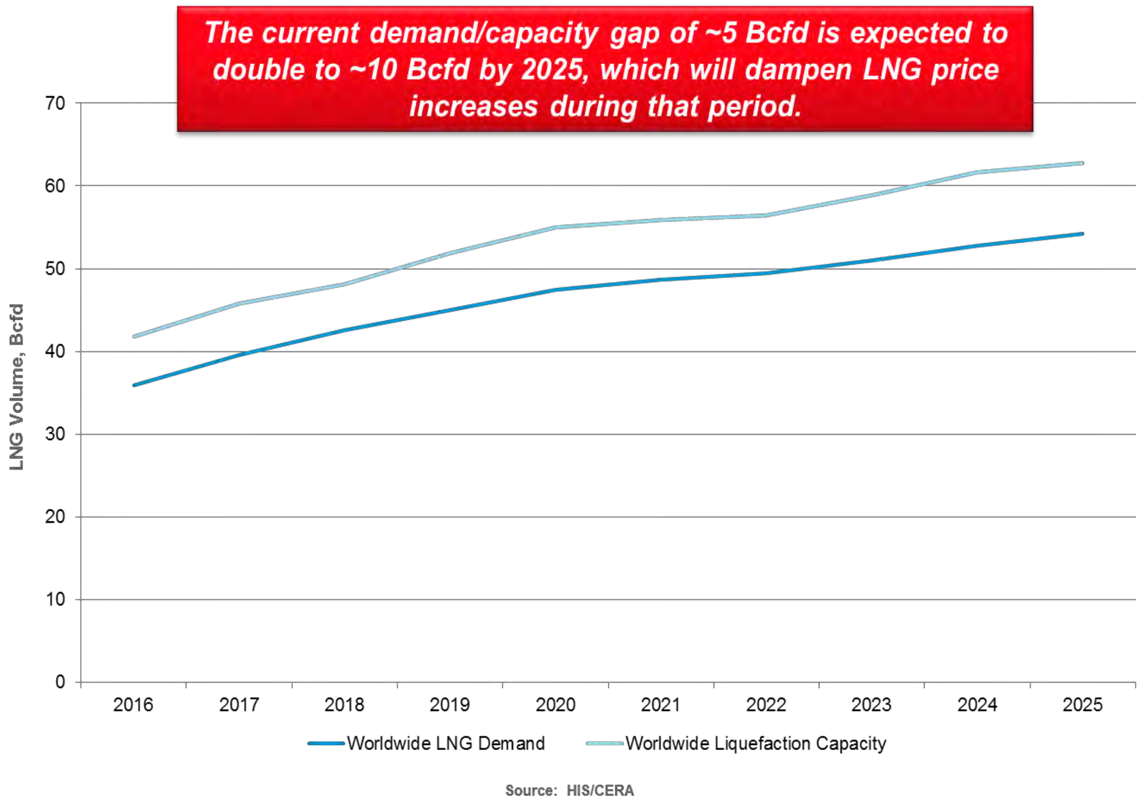
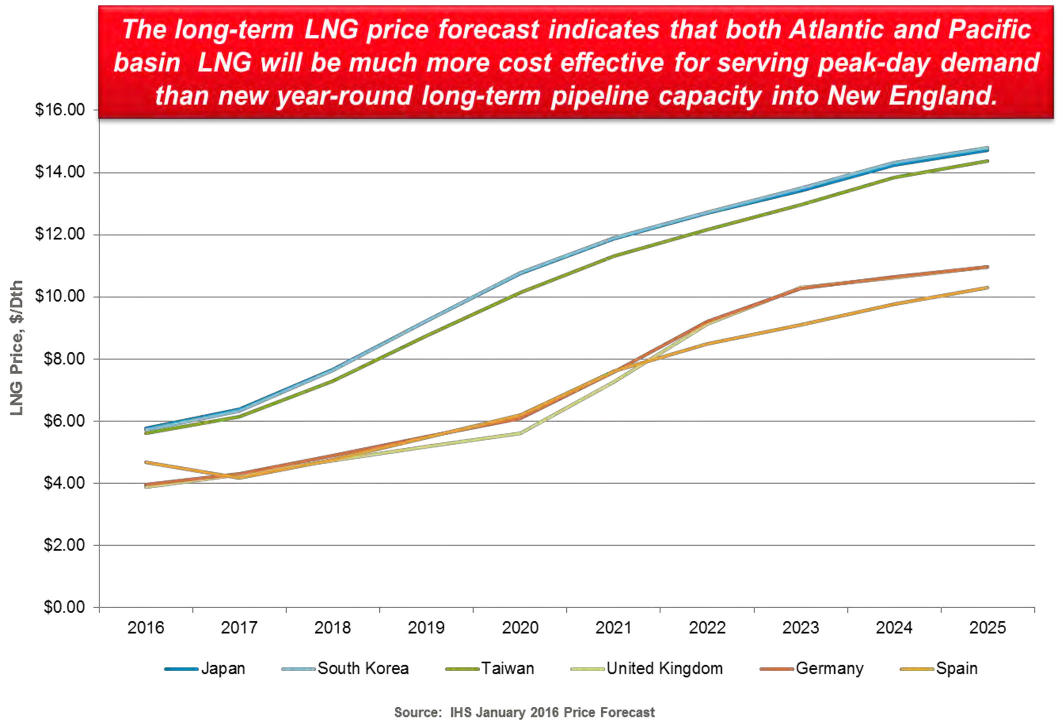


Figure 5 below shows several different price forecasts for the Atlantic and Pacific basin LNG markets through 2025. As shown, European LNG prices are anticipated to increase from the current price range of \$4.00 to \$4.50/Dth to a range of \$10.00 to \$11.00/Dth by 2025 while Asian LNG prices are anticipated to increase from the current price range of \$5.50 to \$6.00/Dth to a range of \$14.00 to \$15.00/Dth during the same period, all of which prices are well below the imputed total cost for gas on peak winter days if an incremental pipeline capacity solution is selected.

Figure 5



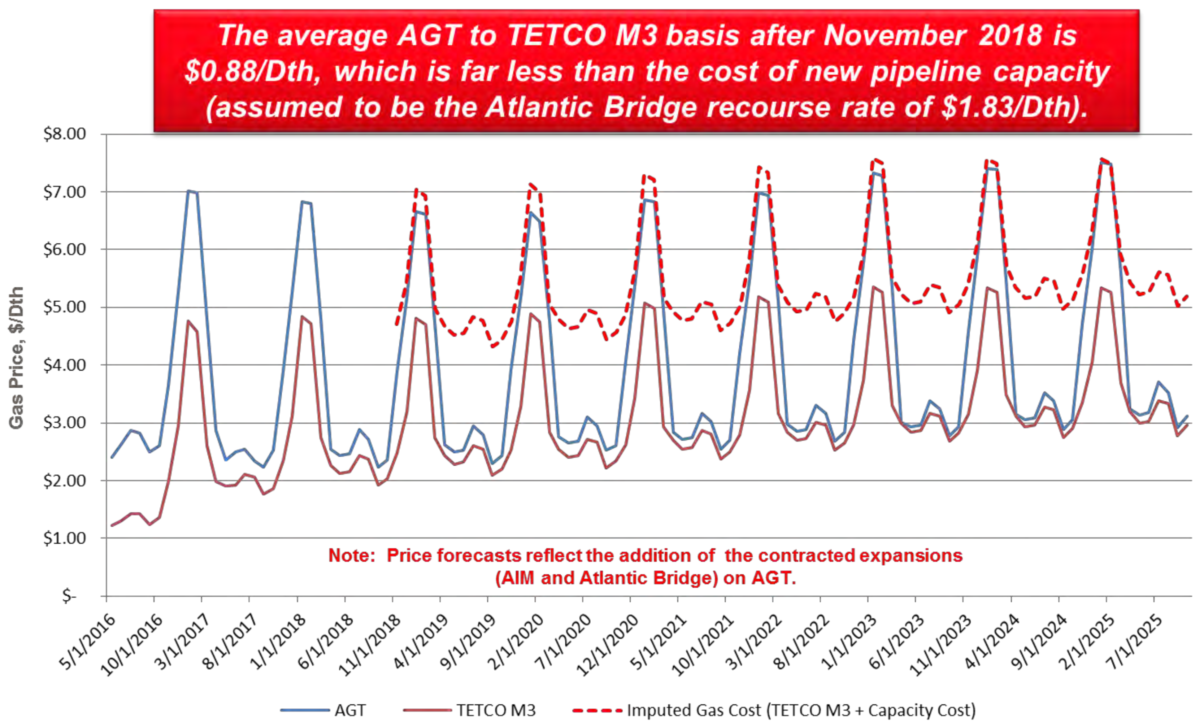
Q: Please explain what you mean by the "imputed total cost for gas" on peak winter days for incremental pipeline capacity.

A: Incremental pipeline capacity is sized to meet peak day demand. By its inherent design, that peak day capacity is available 365 days a year. However, it is well recognized and accepted that New England's electric generation gas supply problem is a winter peak day problem, when the gas demand of the residential sector surges on very cold days. Because the pipeline capacity is actually only needed on those peak days during the winter heating season, the actual equivalent per-unit cost of that capacity on the days when it is needed is much greater than its 365 design-day unit cost. This actual per-unit cost of capacity plus the commodity cost of gas is the "imputed total cost for gas".

Q: Please explain how such an imputed total cost for gas actually needed and consumed on a peak demand day that is purchased only when needed (up to approximately 60 days in a winter heating season) compares to the cost of 365-day firm pipeline capacity that must be purchased under a long-term (>15 years) contract.

A: The high cost of new natural gas pipeline capacity relative to the cost of utilizing imported LNG through existing pipeline capacity to serve peak demand loads seems to be downplayed—and even ignored—in many reports and other stakeholder outreach venues that are attempting to justify the straight pass-through of these high and unpredictable costs to the natural gas and/or electric consumers in the New England region. However, fairly simple yet accurate aggregate cost analyses show the true real cost of this new pipeline capacity based on how often this capacity is actually used. Figure 6 below shows current forward price forecasts for the AGT City-gate Index and the Texas Eastern Transmission Company ("TETCO") M3 Index. The TETCO M3 Index is an indicative index for the market price of gas delivered into AGT on the far western end of its system where AGT receives the majority of its gas supply. As the graph shows, there is typically a positive basis differential between these two pricing points during the winter months that reflects a positive value for the transportation capacity between the two points, which ranges from approximately $2.00 to $2.20 per Dth. However, during the majority of the year when demand is not near its peak and traditional west-to-east transportation capacity is not constrained, the basis differential drops dramatically to a range of between $0.0 to $0.30 per Dth, which reflects the low market value of that capacity. Assuming that the cost of capacity on the new pipeline is in the same range as the Atlantic Bridge recourse rate of $1.83/Dth, the combined cost of the gas (at the TETCO M3 price) and the transportation capacity cost (the $1.83/Dth Atlantic Bridge rate) is greater than the AGT to TETCO M3 basis differential as forecasted without the proposed pipeline expansion for the majority of the year, and it far exceeds the average basis differential of $0.88/Dth.

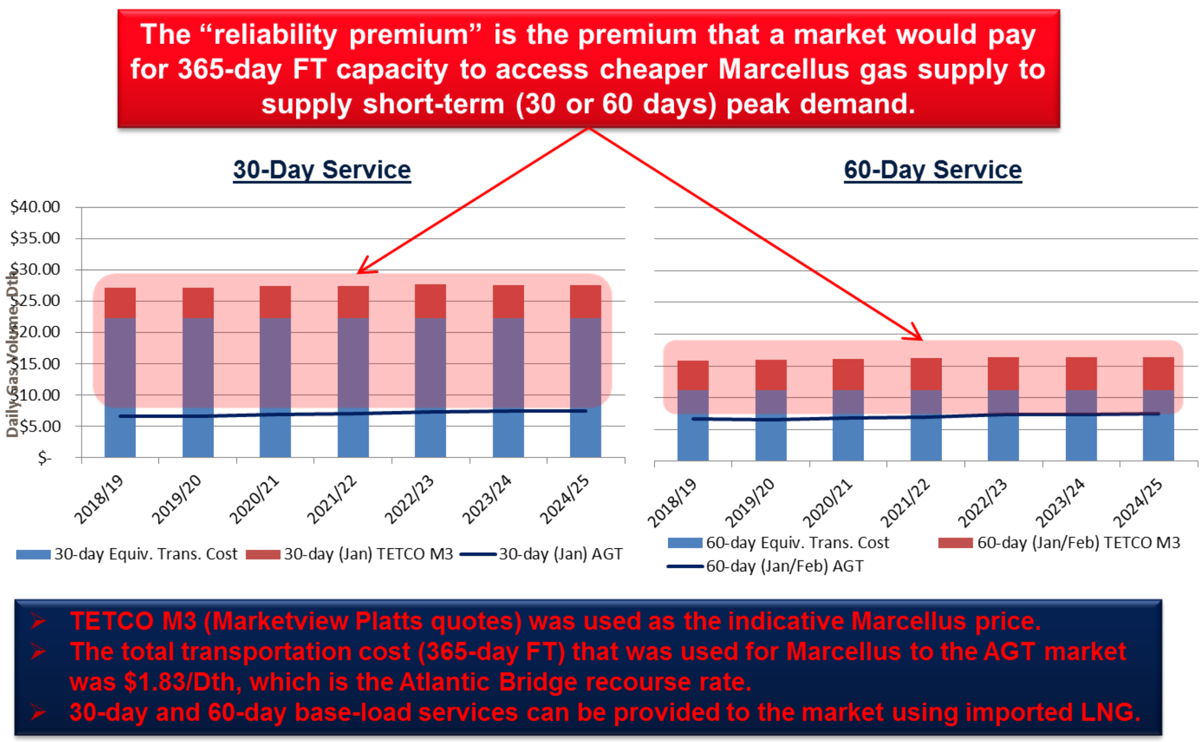
Figure 6



Source: Platts

Figure 7 below further exemplifies the magnitude of the cost of new pipeline capacity to serve short-term (up to 60 days) peak markets. It shows that if you took the annual cost of the new pipeline capacity and only allocated that cost to 30 or 60 days of potential utilization during winter, the total unit cost would be in excess of $25/Dth for the 30-day scenario and in excess of $15/Dth for 60-day scenario. Imported LNG competes quite favorably with these costs since current worldwide market prices for LNG are well below $10/Dth and are continuing to drop due to an abundance of new LNG supply sources coming online over the next several years that will put the worldwide LNG market in an over-supplied state for the foreseeable future.

Figure 7



Q: The cost/benefit analysis prepared by Black & Veatch (*See* Exh. NG-JNC-3), includes certain assumptions for gas demand and supply that were included in its Base Case. With regard to its Base Case assumptions for LNG supply on page 13 of Exh. NG-JNC-3, Black & Veatch states that, "Supplies received at the Canaport LNG terminal (Saint John, New Brunswick) are expected to decline relative to historical norms as no new firm supplier has emerged since the firm supply agreement with Qatar expired in 2013." Further, again on page 13, it states, "Black & Veatch does not expect significant LNG import volumes at Canaport, Neptune, or Northeast Gateway beyond 2017." What impact does the level of LNG import volumes in the Base Case have on Black & Veatch's cost/benefit analysis?

A: The level of LNG volumes included in the Base Case will affect the Base Case projection of wholesale gas prices from which the benefits of the ANE expansion will be measured. Assuming more LNG volumes in the Base Case will decrease the Base Case projection of wholesale gas prices (in turn, reducing the benefits to be realized from the ANE expansion) and assuming less LNG volumes will increase the Base Case projection of wholesale gas prices (in turn, increasing the benefits to be realized from the ANE expansion).

Q: Does the Black & Veatch reference to the expiration of the firm supply agreement with Qatar have any bearing with respect to the future levels of LNG supply available to the market from the Canaport LNG facility?

A: Absolutely not. The supply of imported LNG is a function of the market. First and foremost, RENA will always procure enough LNG supply to meet any and all contractual gas sales obligations that are supported or back-stopped by such LNG supply. In addition, RENA continually assesses gas demand, supply, and transportation conditions in New England to determine if additional LNG supply procurement is justified, as it has done in the past (e.g., the deliveries by Canaport LNG of 20 Bcf and 21 Bcf in the winters of 2013/2014 and 2014/2015, respectively). As discussed above, with the oversupply of LNG in the market, LNG supplies are expected to be both plentiful and competitively priced for the foreseeable future. To arbitrarily assume low levels of LNG imports as reflected in Black & Veatch's Base Case without consideration for market realities is disingenuous and self-serving. Further, the projection of low levels of LNG volumes in the Base Case actually undercuts National Grid's argument that incremental pipeline capacity is needed at all (i.e., if LNG is not required to meet peak winter demand, then why would additional pipeline capacity be required?).

Q: Are there any other fallacies with Black & Veatch's analysis?

A: Yes, Black & Veatch wrongly concluded that the proposal submitted by RENA included unforeseen LNG supply disruptions upstream of the Canaport facility (i.e. shipping, LNG supply source disruptions in the country of origin, etc.) as force majeure events. RENA did not include such disruptions as events of force majeure.

Q: Is there a risk that the costs for new pipeline construction could be greater than that projected?

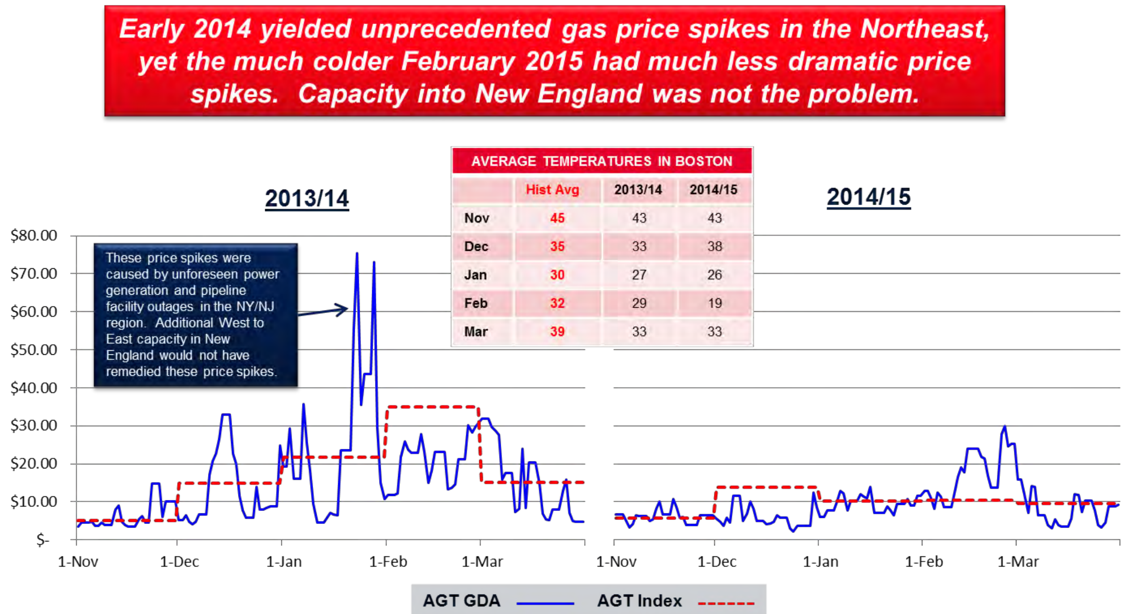
A: The magnitude of the cost of new pipeline capacity to serve a very short-term peak market is substantial. Pipeline infrastructure costs in the Northeast region are among the highest in the nation due to high labor costs, rocky terrain, expensive rights-of-way, high population density along existing pipeline rights-of-way, and well organized/funded public opposition, among other factors. For example, AGT's recent FERC 7(c) application for its proposed Atlantic Bridge project showed a total cost of $188.1 million for 6.3 miles of 42-inch diameter pipeline, which equates to a unit cost of approximately $30 million/mile. By comparison, the ninety-mile, 30-inch diameter Brunswick Pipeline constructed in 2008/2009 from the Canaport LNG facility in Saint John, NB to an interconnection with M&NP at the U.S./Canada border near Calais, ME cost approximately $450 million (50% over its original estimated cost of $300 million), which equates to approximately $5 million per mile. Based on the aforementioned regional construction challenges and persistent local opposition, it is quite reasonable to anticipate that the new pipeline expansion projects will cost significantly more than currently estimated.

The simple conclusion is that if there is a reliable and economically competitive gas supply source such as imported LNG that can serve the peak market demand without the need for expensive new pipeline capacity that will be subject to potential delays and cost overruns, then the market should rely on those resources to the maximum extent practicable before making a costly long-term commitment to new capacity that will be fraught with opposition.

Q: Would the ANE project have eliminated the winter price spikes realized in the winter of 2013/2014?

A: No. Much of the current impetus for adding incremental pipeline capacity into New England originated from the gas price volatility during this period. For example, during a cold period in January 2014, New England experienced large spikes in the price of natural gas (~ $70/Dth for spot market gas on AGT on a few days). Figure 8 below shows these price spikes during the 2013/14 winter and compares them to the prices during the same period in 2014/15, which had even colder temperatures for a longer period of time.

Figure 8

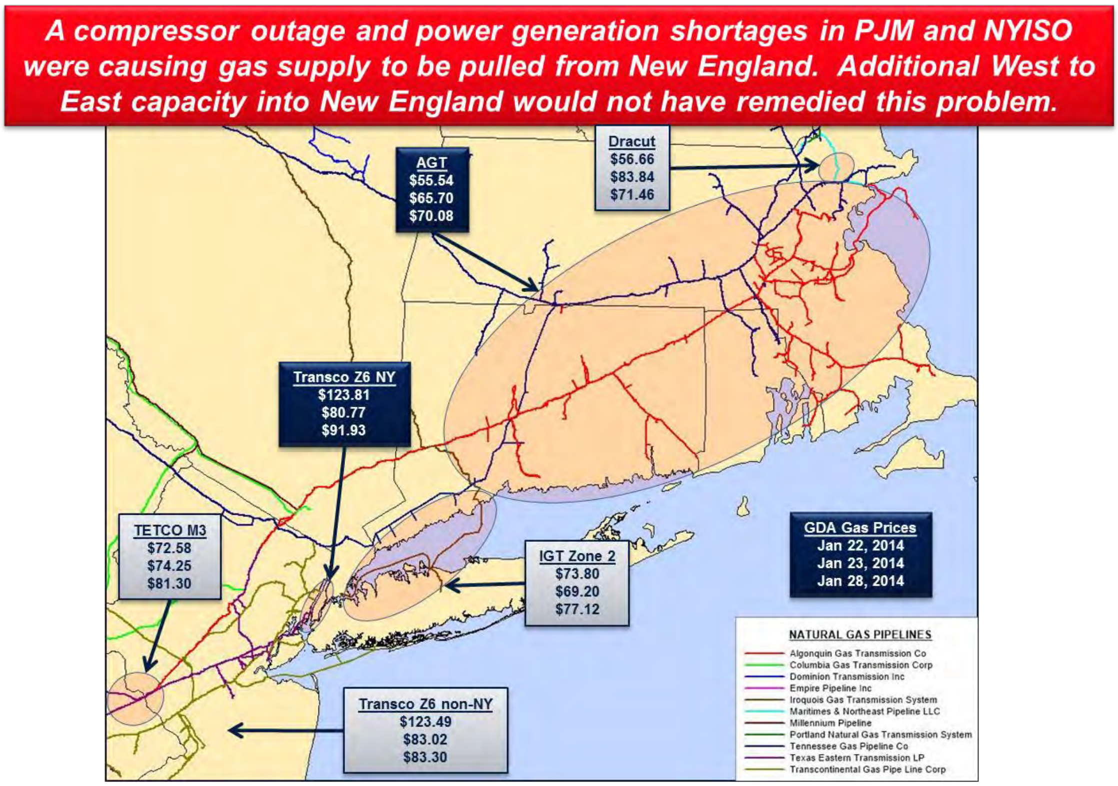


It has been stated in several of the pipeline capacity studies prepared for some sponsors of incremental pipeline projects that the addition of more pipeline capacity into New England would have remedied these price spikes and would have resulted in huge cost savings to New England gas and electric rate-payers.[3] However, it was actually pipeline and power generation shortages in the NJ/NY markets (as depicted by the Transco Z6 NY prices shown in Figure 9 below) that were the cause of higher price spikes in those regions (>$120/Dth) and, as a result, those markets had to procure gas from New England to meet their shortfalls. Therefore, the high natural gas prices in New England were more a result of market demand in NJ/NY than market demand in New England, and since gas was being pulled East-to-West from New England to NJ/NY, additional West-to-East pipeline capacity into New England would not have remedied this phenomenon.

[3] For example, *see New England Energy Market Outlook, Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project*, prepared by ICF International, dated 2015.

The map in Figure 9 shows the gas prices in different parts of the Northeast region on the days of the price spikes (January 22, 23, and 28 of 2014). As it shows, prices in NY (as indicated by Transco Z6 NY prices) and NJ markets (as indicated by Transco Z6 non-NY and TETCO M3 prices) were much higher than in the New England area (as indicated by AGT prices) even though those markets are upstream of New England based on the traditional West-to-East flow of the pipelines in the region. As stated above, this unusual pricing situation was caused by a compressor outage on one of the pipelines that serves this region coupled with weather-related power generation outages that were caused by, among other things, frozen coal piles and fuel oil unavailability in addition to gas supply/capacity constraints on the pipelines that serve the NY/NJ markets from the West. Incremental pipeline capacity into New England would not have mitigated this issue since East-to-West gas flow movement (i.e., New England to NY/NJ) was not constrained. During the 2014/15 winter, availability of additional imported LNG (using existing LNG import capacity) and the ISO New England Winter Reliability Program, which ensured that oil-fired power generation facilities would be available during the winter, were the primary factors that kept gas prices relatively low, in addition to the lack of the unusual coincidental circumstances in NJ/NY that occurred during the 2013/14 winter.

Figure 9



Q: In your opinion, would the 900,000 Dth/d ANE project actually provide 900,000 Dth/d of incremental gas supply to the region?

A: No. The proposed receipt points for the ANE project include Brookfield, Lambertville, Mahwah, and Ramapo. There are no expansions currently proposed on the respective upstream pipelines (i.e., Iroquois, TETCO, TGP, and Millennium) to provide additional capacity to these receipt points that would truly allow incremental gas supply to flow into AGT and fulfill the ANE capacity. Although there may be some amount of excess gas supply currently at some of these receipt points, and the proposed Acushnet LNG facility will provide 400,000 Dth/d of incremental gas supply for a limited period of time (due to its storage capacity limitation), there will not be an incremental 900,000 Dth/d of gas supply available to fill this capacity on a peak demand day. This incremental gas supply shortfall will then put upward pressure on the gas prices at those receipt points where such shortfalls occur.

Q: You indicated earlier that market realities do not justify the ANE project. Please elaborate.

A: AGT's ANE proposal would place 900,000 Dth/d of new capacity into the region that is neither needed nor is anticipated to be necessary unless there is substantial growth in the gas market served by AGT. To determine market need, AGT looked at the amount of megawatts required "on a peak day in January 2014," which they determined to be 5,000 MW.

The generators within the ANE aggregation areas identified by AGT already receive their gas from market participants using existing transportation capacity, and growth is projected to only include four new plants with a combined total of 2,159 MW of new natural gas-fired generation need. Furthermore, none of the new plants proposed within the AGT aggregation areas are conditioned on ANE's implementation, nor is the market experiencing electricity curtailments or reliability issues as a result of natural gas shortfalls. It is also important to note that ISO New England has approximately 33 GW of total electric generation capacity, and the New England market only peaks at approximately 22 GW during the winter. Summer is the peak electricity market in New England, when demand can get as high as approximately 29 GW. In other words, AGT proposes to increase year-round capacity at levels that far exceed the peak day requirements during one of the coldest days of the year, with no identified imminent need or growth in market demand anticipated to justify the implementation of such substantial capacity increases within the region.

Q: Does this conclude your testimony?

A: Yes it does.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, for Approval of Firm Gas Transportation and Storage Agreements with Algonquin Gas Transmission Company, LLC, pursuant to G.L. c. 164, § 94A	))))))))	D.P.U. 16-05

AFFIDAVIT OF VINCENT C. MORRISSETTE

I, Vincent C. Morrissette, do attest and swear to the following:

The attached testimony and accompanying exhibits, on behalf of Repsol Energy North America Corporation, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury,

/s/ Vincent C. Morrissette

Vincent C. Morrissette

Date: June 17, 2016

INFORMATION REQUEST NG-RENA-1-14:

Please refer to the testimony of Mr. Morrissette, at VCM-15, lines 14-15. Please provide Canaport's projected or planned LNG import volumes and associated prices over the next 10 years in a fully functional Excel file with formulas intact.

a. Currently, how many cargoes are guaranteed under long-term supply contract and what is the duration of such obligation?
b. How many cargoes are potentially available under flexible contractual arrangements that may be delivered and who controls the decision whether such cargoes will be delivered?
c. How many cargoes are projected or planned to be procured through short-term contracting or spot purchases,
d. Please describe RENA's (or its affiliates) business activities in procuring and trading LNG cargoes/
e. Does RENA has any long-term natural gas sales obligations that are backed by firm LNG supplies in other markets?
f. Please provide RENA's (or its affiliates) business plan for its projected business activities for the next 5-10 years

RESPONSE:

a. RENA's contractual arrangements for the purchase of LNG (or any other commodity) are confidential.
b. Please see the response to NG-RENA-1-14 a. above.
c. Please see the response to NG-RENA-1-14 a. above.
d. Generally speaking, RENA continuously evaluates future (near-term and long-term) New England gas prices versus LNG prices to determine if and when to procure LNG for Canaport. At a minimum, RENA (through its Canadian affiliate) will procure enough LNG to fulfill any gas sale obligations that are back-stopped by LNG. Beyond that, RENA's assessment of the gas market and LNG pricing/availability is the sole determinant for the quantity of LNG that it will procure for Canaport. This is why RENA consistently and emphatically states in regulatory proceedings and other public forums dealing with this topic that gas sales agreements are the key to ensuring that gas will be available from Canaport when the market needs it. The lack of contracting for gas service that is back-stopped by imported LNG is a much bigger issue (and one that can be easily remedied) than gas supply or infrastructure deficiencies when it comes to serving peak-day demand in New England.
e. Please see the response to NG-RENA-1-14 a. above.
f. RENA's business plans are confidential and proprietary.

Division 5-2

Request:

Using the revised base case from question 1 above, please re-analyze the ANE project under the following scenarios. For each scenario, provide an update estimate of NPV savings due to the ANE project from the PROMOD/GPCM, NPV savings from an updated volatility analysis, and total savings.

e. New base case with DEA changes; no NPT or MREI.
f. New base case with DEA changes; with NPT; no MREI.
g. New base case with DEA changes; with NPT and MREI.

Response:

Please see the response to Data Request DIV 5-1.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

---

Division 5-3

Request:

In other studies that B&V has performed in the last five years, how did B&V model the supply from Distrigas and Canaport in its GPCM analyses? If B&V modeled these supply nodes any differently than it did in this case, please provide the details of how these supply nodes were modeled, including but not limited to the GPCM inputs assumed.

Response:

In previous publically available studies in the past five years, Black & Veatch has used a similar approach to model the Distrigas and Canaport facilities where LNG import volumes are assumed to be inframarginal.

Please refer to Exhibit NEER-6-1 filed by the Company's Massachusetts affiliates in D.P.U. 16-05 for the LNG import volumes assumed in other publically available studies from Canaport and Distrigas. This exhibit was provided in response to Data Request PUC 1-1.