GDF SUEZ

May 30, 2014

Heather Hunt
Executive Director
New England States Committee on Electricity
4 Bellows Road
Westborough, MA 01581

RE: NESCOE Request for Comments on Governors' Infrastructure Initiative

Dear Ms. Hunt:

GDF SUEZ Gas NA LLC (GDF SUEZ) and Distrigas of Massachusetts LLC (Distrigas) appreciate the opportunity to respond to the New England States Committee on Electricity (NESCOE) April 30, 2014 Memorandum to NEPOOL and members of the New England Gas-Electric Focus Group, which invited comment on the "Governors' Infrastructure Initiative – Approach to Increasing Natural Gas Infrastructure."

Our company further appreciates NESCOE and staffs from each of the New England Governors' offices meeting with a number of stakeholders, including us, on this important issue. Respectfully, and consistent with all of our public comments to date, as well as the substance of our stakeholder meeting with NESCOE and States' staff, we continue to believe that the proposal to increase pipeline infrastructure is premature and perhaps misinformed when existing supply and delivery infrastructure is not being fully utilized. We find the expansion proposal puzzling given that existing infrastructure east of the pipeline constraint points would, if better utilized, greatly enhance natural gas and electricity delivery reliability and do so in a manner that would be economically beneficial and less disruptive to the region.

In this regard, we note again that the Distrigas regasification facility has the capacity to produce **435 MMcf per day of natural gas for power generation and/or local distribution company customers** that can be sent out at multiple pipeline pressures simultaneously, in addition to the facility's maximum send-out commitment to liquid delivery sales and the Mystic Power Plant. This means the Distrigas facility can provide a total sustainable delivery capacity of 715 MMcf per day of vaporized LNG and an additional capacity of approximately 100 MMcf per day of LNG loaded on trucks in liquid form.

It is also worth noting that, while the April 30 memo repeatedly comments that the competitive market has not satisfied the region's need in regard to natural gas delivery infrastructure, in fact multiple competitive market solutions, from new rules around generator performance incentives and strong FCM auction signals, to a number of pipeline expansion and transmission project

Francis J. Katulak
President and Chief Executive Officer

GDF SUEZ Gas NA LLC
1990 Post Oak Blvd., Suite 1900
Houston, TX 77056
tel. 713 636-1280 - fax 713 636-1247
email: frank.katulak@gdfsuezna.com
www.gdfsuezna.com

open seasons, are all presently being actively discussed in multiple venues within the region and at the Federal Energy Regulatory Commission (FERC). Undoubtedly, the potential for a mandated solution will stultify the development of those competitive solutions as market participants will hold back on taking affirmative action until it is clear where the state proposal will end up, thus creating a self-fulfilling prophecy of the market not resolving the problem.

Given our continuing view that the region would be best served for reliability and economic purposes by first utilizing existing natural gas infrastructure before investing in new increments of natural gas pipeline, we asked ICF International to update the report they prepared in October 2013, titled, ***"Options for Serving New England Natural Gas Demand."*** The update[1] includes an analysis of the experience of this past winter. Some of the report's conclusions include:

- While the winter of 2013/14 was very cold, New England's weather conditions were not unprecedented.
  - Evidence from this past winter supports the conclusion that New England experiences gas pipeline constraints about 30 days per year, and projected demand growth suggests these constraints will persist at least through the remainder of the decade.
- This past winter, in-bound pipeline capacity was over 90% full on 42 days and over 95% full on 10 days.
- Increased utilization of the Everett LNG import terminal is a relatively low cost way of meeting this short duration constraint.
  - A new, greenfield pipeline would cost about $2 billion, would need to be fully contracted, and would take three or more years to complete.
  - When annual pipeline costs are allocated over the 30-day period the capacity is needed, the cost per MMBtu of fuel demand served is higher than imported LNG.
- ISO New England's Winter Reliability program encouraged the use of fuel oil to meet winter fuel needs, but imported LNG would have cost less on a dollar per MMBtu basis.
  - This past fall, the cost of LNG was about 33% less per MMBtu than what generators spent on fuel oil.
  - Gas-fired units also have a better average heat rate than oil-fired units, yielding additional potential fuel cost savings.

GDF SUEZ/Distrigas is pleased to provide a copy of the updated ICF International report, ***"New England Natural Gas Supply and Demand: Post-Winter Review,"*** as an attachment to this letter.

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[1] The updated report titled, "***New England Natural Gas Supply and Demand: Post-Winter Review***," was prepared by ICF International based on assumptions from a variety of sources, including GDF Suez. The report must be considered in its entirety to understand the context, assumptions and conditions on which the conclusions are based.

With respect to the Incremental Gas for Electric Reliability (IGER) concept specifically, there is limited detail upon which to offer constructive guidance at this point. However, given this and the competing proposal offered by the EDCs, what is imminently clear is that under either approach, the strongest possible safeguards must be put in place to prevent even the appearance of conflicts of interest both in the selection and administration of duty on the part of both the contract entity and capacity manager. This is especially true if the prerequisite qualifications for the capacity manager and contract entity end up being as described in NESCOE's April 30 memo. While deep natural gas management experience is an obvious plus, if that experience was gained in the northeast market, it could be a disadvantage as well. While creditworthiness and strength of balance sheet are important attributes for a contract entity, it would be naïve to think that a current market participant could play that role and be agnostic to their own financial interests with respect to the administration of the program. Consequently, it would be helpful to stakeholders in the region to better understand NESCOE's view of how IGER or any proposal would be positioned to overcome the numerous legal, regulatory, legislative, and marketplace challenges that would have to be cleared in order for the proposal to be implementable.

Given the foregoing, GDF SUEZ is troubled by a number of potential intended and unintended consequences of the IGER concept and the EDC proposal. Fundamentally, we oppose using the ISO electricity tariff to subsidize construction of new natural gas pipeline as there is a basic disconnect between the purpose of the tariff and this intended application. Among other concerns, the proposal would require that the region socialize and subsidize the cost of substantially more natural gas pipeline than truly needed and consequently undermine the value of the firmness provided by other resources currently in the market. The concept leads to an outcome that explicitly picks winners and losers in many different respects. As structured, it ignores any other potential natural gas reliability solution to the states' concerns. For instance, newly constructed in-region natural gas liquefaction and storage can't compete on a level playing field under this structure – there is no mechanism to participate. Moreover, unless every pipeline project currently proposed gets some level of subscription, it is conceivable that those natural gas fired power plants along a pipeline with no incremental expansion will be unable to receive the same level of benefit envisioned by the program as those plants located along expanded pipeline systems. What is the market implication? How do the states intend to fairly adjudicate the appropriation of additional capacity through the capacity manager?

We appreciate NESCOE's work in getting this concept out to stakeholders and subjecting in to vigorous debate. We look forward to contributing to the discussion and thank you for the opportunity to provide our perspective on these important issues for our region.

Sincerely,

Francis J Katulak

Francis J. Katulak
President and Chief Executive Officer

New England Natural Gas Supply and Demand: Post-Winter Review

Prepared for

GDF SUEZ Gas North America

May 29, 2014

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

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1 Introduction

In October 2013, GDF SUEZ Gas North America (GSGNA) engaged ICF to perform an assessment of alternate solutions to providing incremental natural gas supplies to the New England market.

In the 2013 study, ICF provided its assessments of New England's gas supply capabilities, and the projected growth in annual and daily gas loads. Based on that comparison, ICF estimated that New England will need additional gas supplies on about 30 peak winter days per year through 2020. ICF also compared the costs of meeting the need for incremental gas supplies on 30 days from new pipeline versus incremental imports of liquefied natural gas (LNG). ICF concluded that LNG imports to Distrigas appear to be a more cost-effective solution for meeting the region's gas supply needs, given the limited number of days when gas supplies are expected to be constrained.

Following the winter of 2013/14, GSGNA asked ICF to assess how the gas market reacted during the extreme weather events, as well as past and future drivers of gas demand growth in New England. ICF was also asked to compare the cost of fuel oil purchased by generators under ISO New England's (ISO-NE) Winter Reliability Program to imported LNG, as another means to meet a portion of the region's peak seasonal fuel demand.

2 Winter of 2013/14 Market Conditions

While the winter of 2013/14 was unusual in the extent and severity of cold weather across most of the eastern United States, it was not the coldest on record. This winter ranked as the 34th coldest winter in the past 119 years, and the coldest since 2009/10. The average temperature for the contiguous U.S. during the winter season (December 2013-February 2014) was 31.3°F, 1.0°F below the 20th century average.[1]

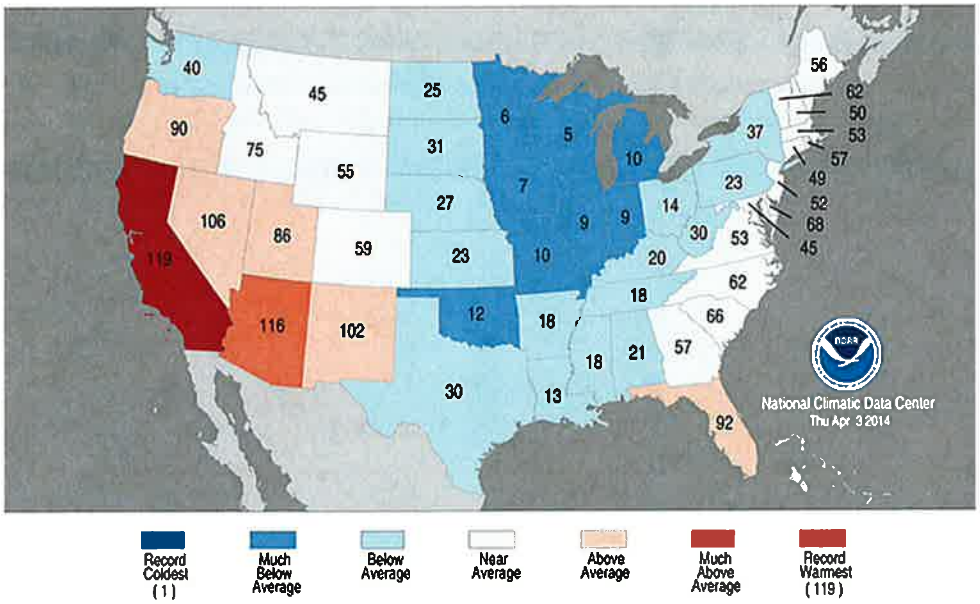
This winter was in sharp contrast to the previous two winters, and most winters of the past two decades, when temperatures were predominately warmer than the 20th century average. Below-average temperatures dominated east of the Rockies, with the coldest conditions occurring across the Midwest. Seven Midwestern states were much colder than average and had a top 10 cold winter season, though no state experienced record cold (Figure 1). Numerous cold Arctic air outbreaks impacted both the Midwest and Northeast during the winter season, particularly in January and February.

In the New England states, this winter's average temperature ranked near the middle of the 119 years of recorded temperatures, ranging from 49th to 62nd (Figure 1). Compared to the past 20 years, the range of daily temperatures New England experienced was near the low but not unprecedented. Between November 1 and March 31, New England temperatures averaged

[1] National Climate Data Center, http://www.ncdc.noaa.gov/sotc/national/2014/2/

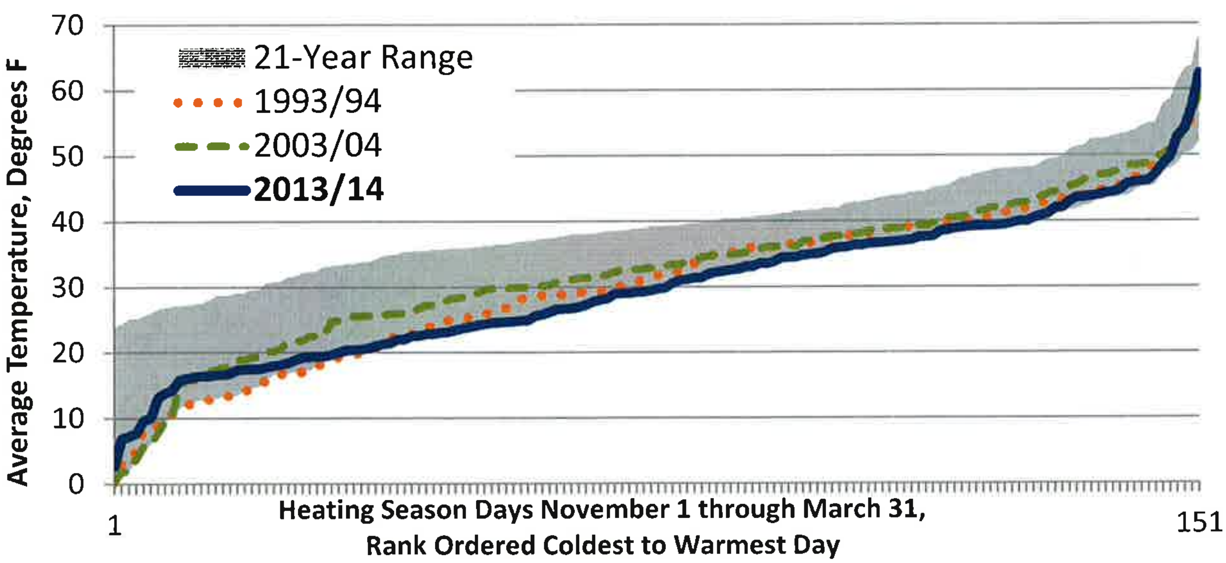
about 30° F; on the coldest day (January 3), temperatures averaged less than 3° F. Over the prior 20 years, New England has experienced two winters with similar "cold snaps". The winters of 1993/94 and 2003/04 both had 7 or more days with average temperatures below 10° F, and coldest days at or near 0° F (Figure 2).

Figure 1. State-wide Temperature Ranks, December 2013-February 2014 (Ranking based on years 1895-2014)



Source: National Climate Data Center

Figure 2. New England November-March Daily Temperatures, 1993/94 through 2013/14[2]



Source: ICF International, derived from NOAA data

[2] Population weighted average of mean daily temperatures from 6 weather stations across New England.

There have been no changes to New England's in-bound natural gas pipeline capacity since ICF's 2013 study for GDF SUEZ. New England shippers currently have firm contracts for about 3.7 billion cubic feet per day (Bcfd) of capacity on five pipeline systems (Figure 3). Planned expansions on the Algonquin and Tennessee systems will add slightly over 400 million cubic feet per day (MMcfd) of additional pipeline capacity into New England in November 2016.

Figure 3. Firmly Contracted Pipeline Capacity into New England, MMcfd[3]

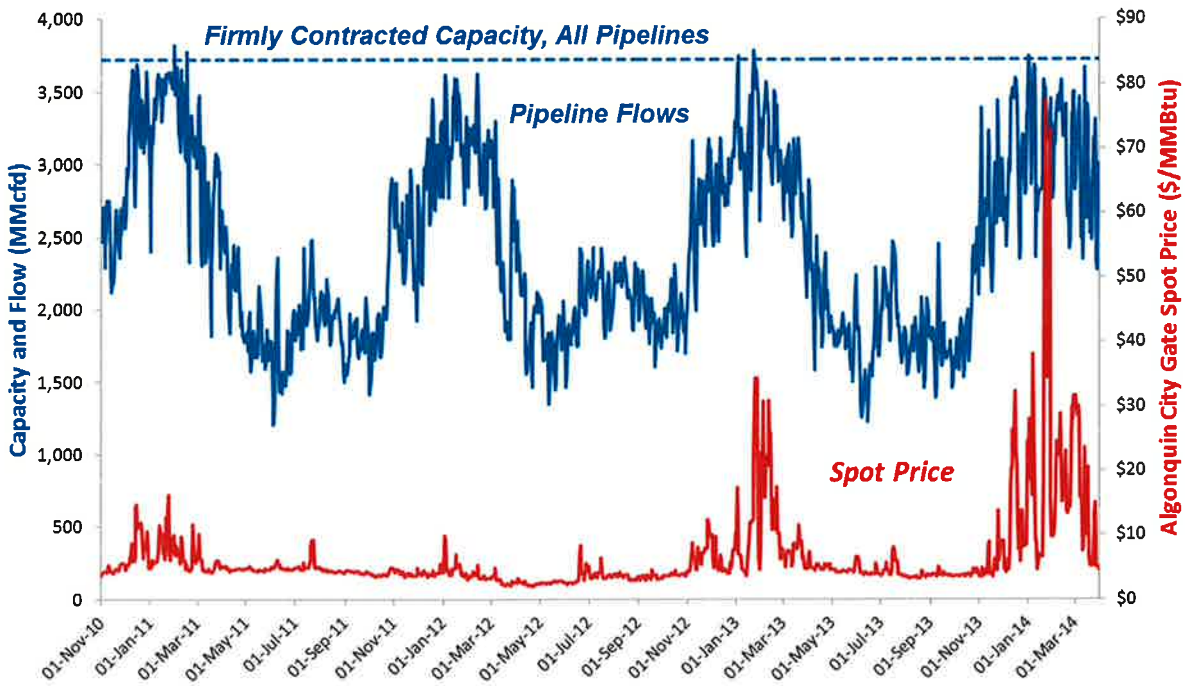
Pipeline System	Current Contracts	With 2016 Expansions[4]
Tennessee Gas Pipeline	1,290	1,362 (+72)
Algonquin Gas Transmission	1,120	1,462 (+342)
Iroquois Gas Transmission	230	230
Portland Natural Gas Transmission System	250	250
Maritimes and Northeast (M&N)	830	830
Total Firmly Contracted Capacity	**3,720**	**4,134 (+414)**

While the physical capability of the pipelines entering New England is somewhat greater that the firmly contracted capacity, contracted and interruptible deliveries to upstream shippers on cold winter days effectively limit total deliveries to New England shippers to firmly contracted volumes. This pattern of pipeline constraints on winter peak day pipeline deliveries can be seen in the daily in-bound flows and regional spot prices over the past 4 years, as shown in Figure 4.

[3] Current contracts based on ICF's assessment of each pipeline's reported firm capacity contracts with receipt points outside of New England and delivery points within New England.

[4] Expansion capacities based on announce capacities for the Algonquin Incremental Market (AIM) project and the Tennessee Gas Connecticut Expansion project, both due online in November 2016.

Figure 4. New England In-bound Pipeline Capacity, Daily Flows, and Daily Spot Gas Price



Sources: Pipeline bulletin board data (flow), SNL (Algonquin spot prices)

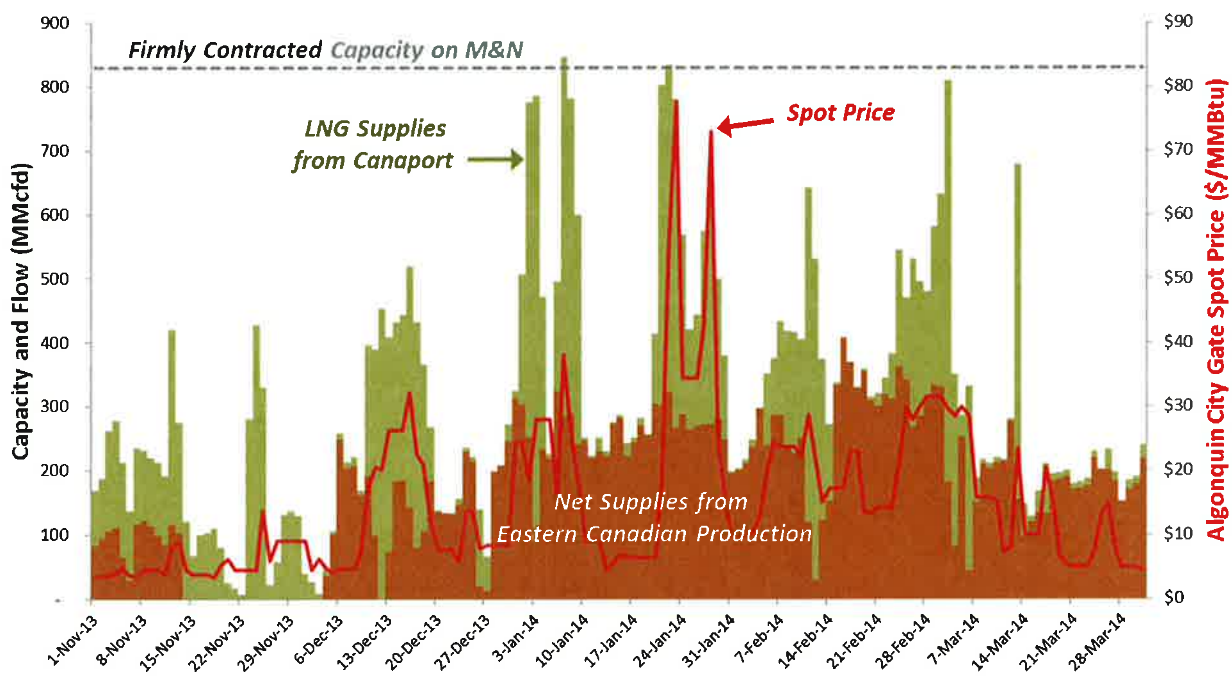
During this past winter, pipeline utilization (the ratio of total in-bound flows to firm pipeline capacity) was above 90% on 42 days, and above 95% on 10 days. As the pipelines approached their limits, the price of remaining spot supplies increased. As a result, spot prices spiked to over $70/MMBtu on two days, and averaged over $23/MMBtu for the entire month of January.

One of the five pipelines serving New England is the Maritimes and Northeast (M&N) Pipeline. Firmly contracted capacity on M&N is slightly over 0.8 Bcfd, representing about 22% of the region's total in-bound pipeline capacity. M&N relies on gas supplies from eastern Canada's two offshore platforms, Sable Island and Deep Panuke, as well as LNG from the Canaport import terminal in New Brunswick. Production from the Deep Panuke platform began in August 2013. Deep Panuke has a nominal capability of 300 MMcfd, but output from this platform was interrupted several times during the winter. Projection from the Sable Island, which has a nominal capacity of as much as 500 MMcfd, has been declining in recent years, averaging less than 200 MMcfd.

Canaport LNG is jointly owned by Irving Oil (25%) and Repsol (75%), and is connected to M&N via the Brunswick Pipeline. Due to the rapid growth of Marcellus shale gas production, shoulder and summer month gas prices in New England and eastern Canada have been far below Atlantic basin LNG prices. As a result, the overall utilization of the facility has been very low. In February 2013, Repsol reached an agreement to sell its LNG supply contracts and ship charters to Shell. As part of the deal, Shell will continue to supply the Canaport terminal with approximately 1 million tons (approximately 48 Bcf) of LNG per year over the next ten years.

While Canaport currently provides little if any gas supplies to Northeast markets during the shoulder and summer months, it was an important supply source this past winter. Over the 90 days from December 1, 2013 through February 28, 2014, supplies from Canaport LNG made up over 40% of the total flows to the U.S. on M&N Pipeline (Figure 5). On several days when output from the eastern Canadian offshore fields was not available, Canaport LNG was the sole source of M&N gas supplies to the U.S.

Figure 5. Maritimes and Northeast Pipeline Capacity and Flows



Sources: Pipeline bulletin board data (flow), SNL (Algonquin spot prices)

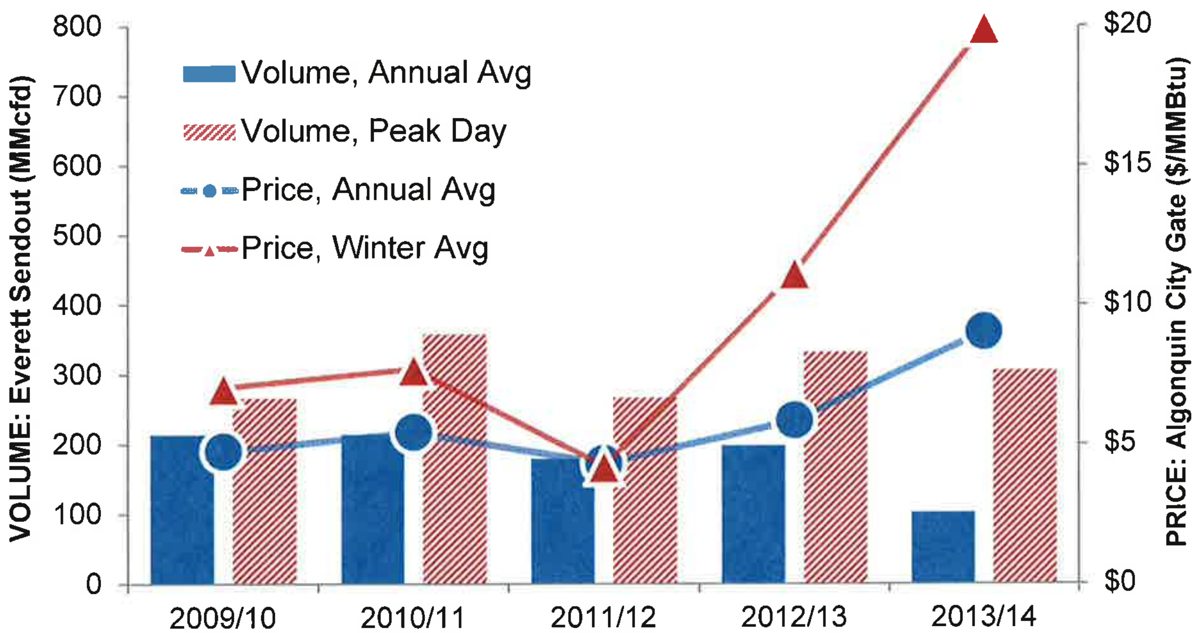
The Distrigas LNG terminal in Everett, MA (operated by GDF SUEZ NA) is the region's only other source of natural gas supplies currently in use.[5] The Everett facility has a total storage capacity of 3.4 Bcf and a sustained vaporization capacity of 715 MMcfd. Everett can deliver up to 300 MMcfd to Algonquin and Tennessee pipelines (150 MMcfd each), in addition to direct connections to the Mystic Generating Station and National Grid/Boston Gas. Everett also provides up to 100 MMcf per day of trucked shipments of LNG to 46 satellite peak shaving facilities operated by the local distribution companies (LDCs). The LDCs rely on these facilities to meet up to 30% of their peak day loads. However, the peak shaving facilities do not represent a separate supply source into the region; they are merely a way of redistributing LNG supplies received at Everett.

Over the past 5 years, New England natural gas prices have been relatively low compared to LNG prices, leading to a decline in imports to the Everett terminal (Figure 6). Since 2010, daily spot gas prices at the Algonquin City Gate during the shoulder and summer months (March through October) have averaged only about $4.50 per MMBtu, compared to Atlantic Basin LNG

[5] New England's two offshore LNG terminals, Neptune and Northeast Gateway, have not received any shipments since 2010.

prices of $14 to $15 per MMBtu. Over that same period, sendout from the Everett LNG has declined from over 200 MMcf to only 100 MMcfd.

Figure 6. Everett LNG Sendout and New England Spot Prices



Sources: LNG sendout based scheduled deliveries from Everett to Algonquin and Tennessee pipelines and estimate deliveries to Mystic units 7 and 8; Algonquin daily spot prices provided by SNL

While gas prices have been low in shoulder and summer months, New England gas prices often rise well above global LNG prices during the winter. 2011/12 was an exception, as gas prices remained lower due to record warm winter weather. However, during the winter of 2012/13, spot prices were over $15 per MMBtu on 17 days and averaged $12 per MMBtu. This past winter, prices were above $15 per MMBtu on 36 days and averaged nearly $20 per MMBtu, well above global LNG prices.

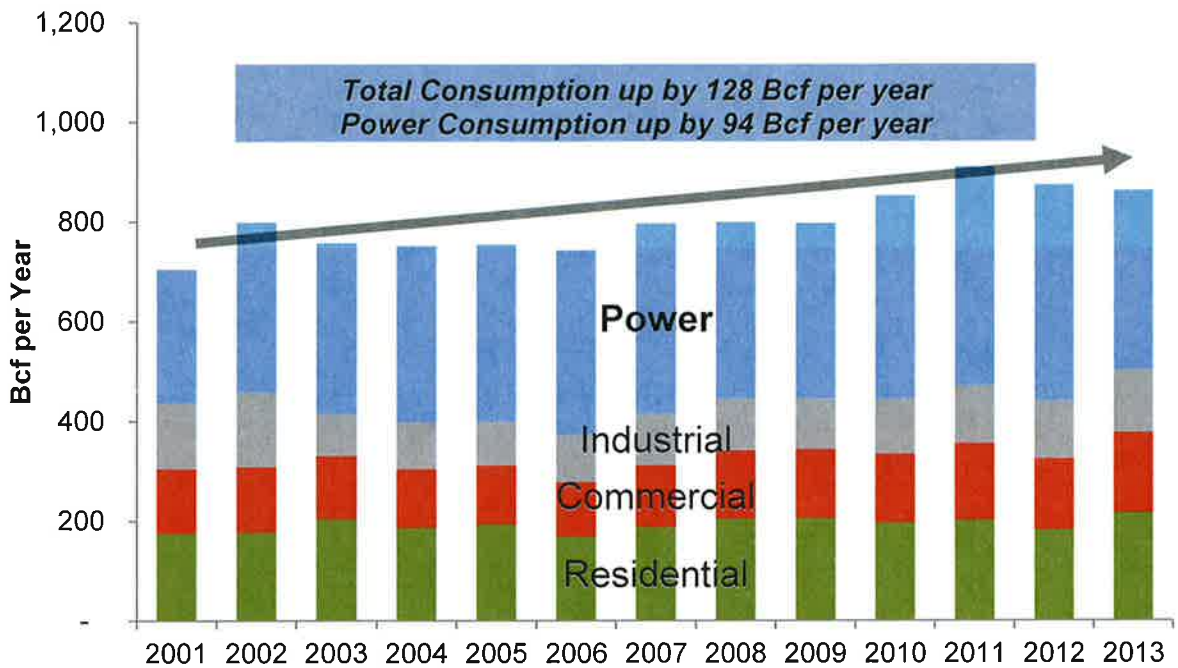
During these periods of supply constraints, additional LNG imports could have eased regional supply constraints and reduced gas prices in New England. However, under the current market system, electric generators have no way to recover costs for this service. As a result, generators continue to rely on interruptible pipeline capacity, and are exposed to potential gas supply shortages and high prices during peak demand periods.

3 New England Natural Gas Demand Growth

When adjusted for fluctuations in weather, New England natural gas consumption has increased by about 130 Bcf per year since 2001 (Figure 7). Over this same time period, the total number of residential and commercial (R/C) gas customers has grown from 2.3 million to 2.6 million, an increase of 12%.[6] However, increases in end-use efficiency have reduced per-customer consumption, offsetting some of the impacts of customer growth. As a result, over the same time period R/C gas consumption has increased by only 9 percent (about 40 Bcf per year). Industrial gas demand has rebounded somewhat since the recession, but is still down versus 2001 levels. Currently, industrial gas consumption in New England averages less than 120 Bcf per year, as output from energy-intensive industries in New England (e.g., paper and chemicals) have all declined from 2001 levels.

Most of the growth in New England gas consumption since 2001 has come from the power sector, which has increased by about 94 Bcf per year. Currently, the power sector accounts for just under half of the region's total annual gas consumption, and over 40% of New England's total electric generating capacity is fueled by gas.

Figure 7. Historical New England Gas Consumption by Sector



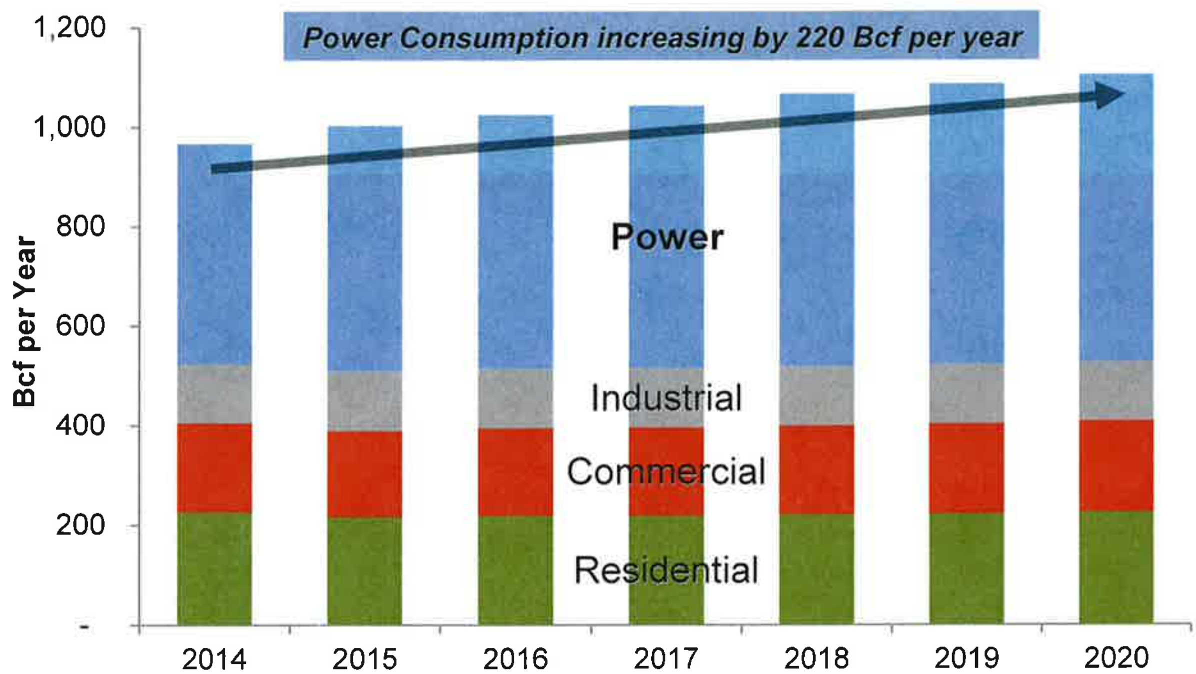
Source: EIA

Future gas demand growth in the region will continue to be driven primarily by the power sector. ICF currently projects that annual New England power generation gas consumption will increase by 220 Bcf through 2020, accounting for 90% of the region's total projected gas demand growth (Figure 7). As in the past, incremental electric load growth is likely to be met by increases in gas-fired generation. Additionally, pending retirements of coal, oil, and nuclear capacity will increase New England's dependency on gas-fired generation. Based on ISO New England's most recent Forward Capacity Auction (FCA8), retirements of Salem Harbor Units 3 and 4 and Vermont Yankee will remove 1,201 MW of non-gas capacity from the market by the winter of 2015/16. Assuming the full output of these units is replaced with gas-fired capacity, these

[6] Based on residential and commercial customer counts reported in EIA Form 176.

retirements could increase peak power generation gas demand by 0.23 Bcfd. By the winter of 2017/18, addition retirements of Brayton Point units (another 1,535 MW) could increase peak gas demand by another 0.32 Bcfd (0.55 Bcfd total).[7]

Figure 8. Projected New England Natural Gas Consumption



Source: ICF International Q2 2014 Natural Gas Strategic Outlook; assumes normal weather

[7] Estimates for incremental peak gas demand from non-gas unit retirements are based on replacing all the potential MWh of generation from this capacity with gas-fired generation at the fleet average heat rate of 8.2 MMBtu/MWh.

Figure 9. Capacity Exiting the New England Wholesale Electric Market, 2014-17

Plant and Unit Number	Primary Fuel	Year Retiring	Capacity (MW)
Salem Harbor 3	Coal	2014	150
Salem Harbor 4	Oil	2014	431
Vermont Yankee	Nuclear	2014	620
Brayton Point 1	Coal	2017	244
Brayton Point 2	Coal	2017	244
Brayton Point 3	Coal	2017	612
Brayton Point 4	Oil	2017	435
Total Retirements			**2,736**

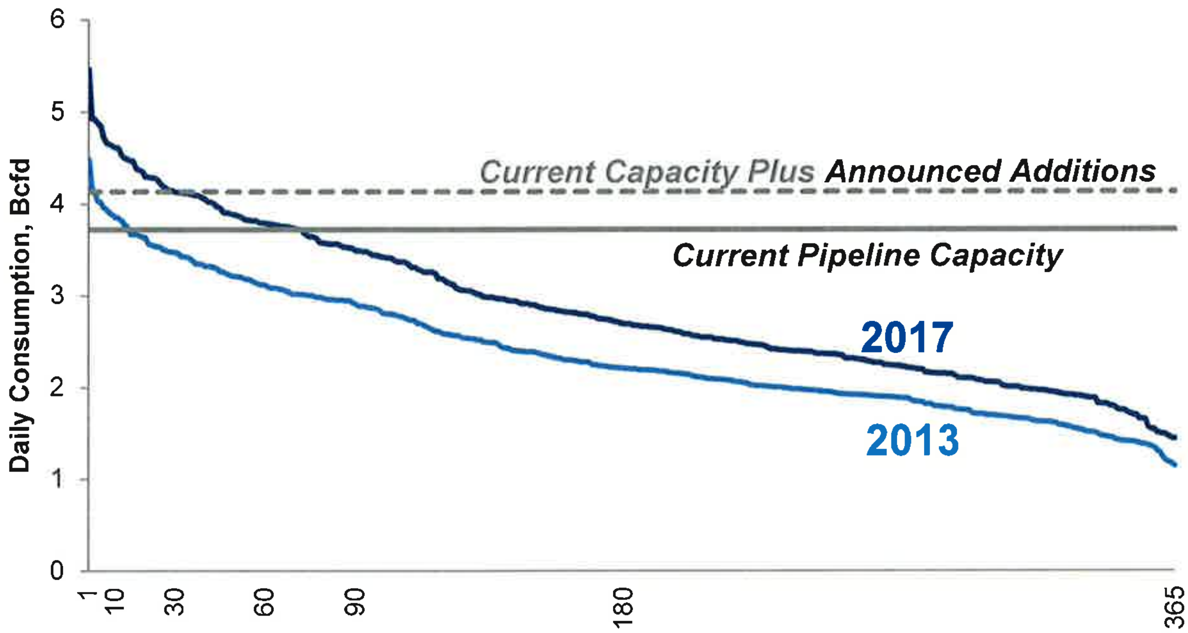
Source: Based on ISO New England Forward Capacity Auction (FC8)

Given expected demand growth, ICF projects that winter peak day loads will reach 5.5 Bcfd by 2017, an increase of almost 1 Bcfd over the 2013 peak (Figure 10). This projection for peak day load is based on 20-year average temperatures; colder-than-normal weather (similar to what was experienced this past winter) would yield a peak day load projection that is about 20% higher than a typical peak winter day. A significant portion of New England's peak day gas load is met by peak-shaving facilities. These facilities are owned and operated by regional LDCs, which use them to insure reliable service to their firm customers. As such, these peak shaving resources are not available to serve customers that rely on interruptible gas service, including the majority of gas-fired electric generators.

As discussed above, planned expansions of the Algonquin and Tennessee systems will provide over 400 MMcfd of new pipeline capacity into the region by the winter of 2016/17, but this will not be available in time to meet the incremental gas demand created by the 1,201 MW of non-gas generation retirements scheduled to occur before 2016. And even after the new pipeline capacity is built, it will not necessarily be available to interruptible shippers (i.e., the gas-fired generators) on cold winter days, since the LDCs hold the firm rights and will use this capacity to meet their customers' demand. As a result, it is likely that New England's total daily gas load will exceed in-bound pipeline capacity on about 30 days per year.

Upstream supply issues on M&N Pipeline may also exacerbate New England's gas supply constraints. Production from the Sable Island offshore platform has been steadily declining, Canaport's firm LNG supply contracts are limited, and gas consumption in eastern Canada is increasing. Based on these conditions, M&N Pipeline (which represents over 20% of the region's in-bound firm capacity) is unlikely to flow full on more than a few days per winter.

Figure 10. New England Daily Natural Gas Consumption, 2013 and 2017



Source: ICF estimate for 2013; 2017 projection assuming 20-year average temperatures

4 ISO New England's Winter Reliability Program and the Cost of Fuel Oil

In 2013, ISO-NE instituted its Winter Reliability program to address electric system reliability concerns arising from constraints on the interstate pipeline system into New England, increased reliance on natural gas-fired generation, and generating resource performance during periods of stressed system conditions.[8] As a short-term means to reduce these risks, ISO-NE offered to procure up to 2.4 million MWh of energy this winter from a combination of oil-fired generators, dual-fuel generators, and demand response assets. In exchange for their commitment to maintain oil inventories needed to provide power when called upon, the selected oil-fired and dual-fuel generators receive monthly payments regardless of whether they were actually dispatched. These payments reduced the financial risk to the generators holding oil inventories that might not be used. ISO-NE ultimately accepted bids from 20 participants for 1.95 million MWh of energy (83% of the original target). While the program included demand response, only one demand response bid was accepted, amounting to less than 1% of the total program MWh. LNG inventories at Everett and Canaport were not included in the Winter Reliability program.

The Winter Reliability program required that generators have the fuel oil in inventory by December 1, 2013. Data from the U.S. Energy Information Administration (EIA) indicates that the delivered cost of fuel oil to electric generators in New England averaged about $22 per

[8] ISO-NE's FERC filings related to the Winter Reliability program: http://www.iso-ne.com/key_projects/win_relblty_sol/iso_ne_filings/

MMBtu from September to November 2013, the period when oil for the program would most likely have been purchased.[9] Assuming an oil fleet average heat rate of 12 MMBtu/MWh[10], ICF estimates the total amount of fuel oil purchased for the program was approximately 23.3 trillion Btu at a total cost of over $500 million.

In its 2013 study for GDF SUEZ, ICF assumed that the cost of incremental LNG delivery to Everett would be $14.50 per MMBtu; global landed LNG prices in November 2013 appear to support this assumption (Figure 11). Given the reported cost of fuel oil, LNG would have cost about 33% less, a potential savings of about $175 million based on ICF's estimate of fuel oil expenditures related to the Winter Reliability program. Shifting from oil-fired to gas-fired generation could also yield additional fuel cost savings, as New England's gas-fired units have a significantly better average heat rate than the oil-fired units.

Figure 11. Estimated Landed Prices for LNG in November 2013, Dollars per MMBtu

Source: FERC Natural Gas Market Overview, October 2013

As discussed above, evidence from this past winter supports the conclusion that New England is likely to need additional fuel supplies about 30 days per year, during the peak winter demand period. In its 2013 study for GDF SUEZ, ICF compared the cost of serving this relatively short duration load with either new ("greenfield") pipeline capacity or incremental LNG imports. In March 2014, ICF completed a study of gas, oil and natural gas liquids midstream infrastructure

[9] EIA Electric Power Monthly, Table 4.11.A. Average Cost of Petroleum Liquids Delivered for Electricity Generation.
[10] The oil-burning fleet average heat rate is based on data from EIA-923 Monthly Generation and Fuel Consumption Time Series.

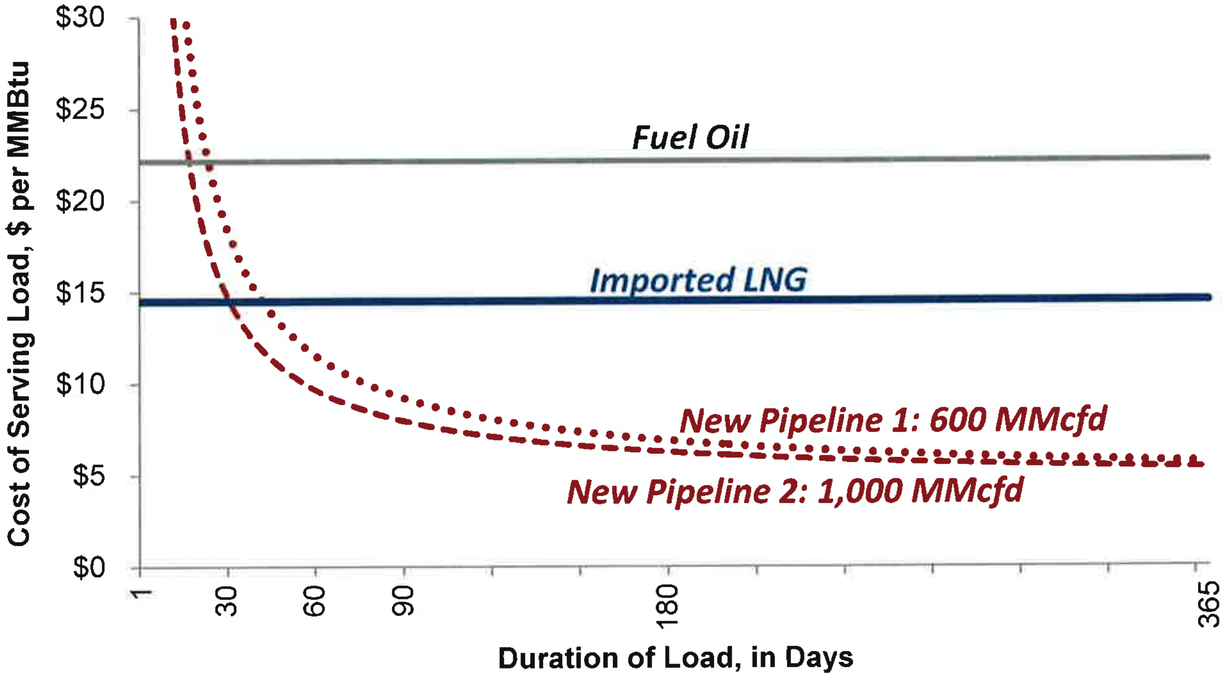
requirements for the INGAA Foundation.[11] For that study, ICF collected extensive data on recent natural gas pipeline projects and compiled new regional cost estimates for pipeline construction. Based on new data collected during the INGAA study, ICF currently estimates that a greenfield pipeline from the Marcellus Shale (the most likely source of incremental domestic gas supplies) to New England would cost between $1.7 billion (for a 600 MMcfd pipeline) to $2.1 billion (for a 1,000 MMcfd pipeline).

Using these new cost estimates, ICF created revised "cost duration curves" to illustrate the cost of pipeline service (in dollars per MMBtu) versus the number of days the capacity is needed (Figure 12). The cost duration curves for the two new pipeline options are derived by dividing the annual capital charge ($310 to $425 per Mcf annually, assuming a capital recovery factor of 14.6%) by the number of days the pipeline is needed, and then adding the variable costs, including the cost of gas supplies (assumed to be $4.50 per MMBtu). Since the incremental capacity is only needed for about 30 days per year, the effective per-unit cost of the pipeline-delivered supply would be between $15 and $19 per MMBtu.

For comparison, Figure 12 also shows the costs of fuel oil at $22 per MMBtu (consistent with last fall's delivered price, and also with the current world crude oil price of over $100 per barrel) and the assumed cost of incremental LNG imports at $14.50 per MMBtu. This illustrates the point that LNG imports are a more cost-effective option to serve incremental fuel demand with a duration of 30 days or less per year. As was pointed out in ICF's 2013 report for GDF SUEZ, it is typically more cost effective to increase the utilization of an existing asset rather than build new capacity, as the capital cost of existing assets can be treated as sunk cost and therefore not subject to capital recovery.

[11] "North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance," INGAA Foundation Report prepared by ICF International, March 2014.

Figure 12. Cost Duration Curves: Cost per Day to Serve Incremental Fuel Demand, Dollars per MMBtu



Source: ICF International

5 Summary of Conclusions

- While the winter of 2013/14 was very cold, New England's weather conditions were not unprecedented.
  - During the prior 20 years New England experienced two other very cold winters, so it is prudent to plan for similar events in the future.
  - Evidence from this past winter supports the conclusion that New England experiences gas pipeline constraints about 30 days per year, and projected demand growth suggests these constraints will persist at least through the remainder of the decade.
- This past winter, in-bound pipeline capacity was over 90% full on 42 days and over 95% full on 10 days.
  - Planned pipeline expansions will increase gas supplies into the region, but gas demand will also continue to increase.
  - Pending retirements of coal, oil, and nuclear generating capacity could create up to 0.23 Bcfd of additional peak demand within the next two years (prior to the AIM expansion), and up to 0.55 Bcfd by the winter of 2017/18.
- Increased utilization of the Everett LNG import terminal is a relatively low cost way of meeting this short duration constraint, and one of the few options available over the next two to three years.

    - A new, greenfield pipeline would cost about $2 billion, would need to be fully contracted, and would take at three years to complete.
    - When annual pipeline costs are allocated over the 30-day period the capacity is needed, the cost per MMBtu of fuel demand served is higher than imported LNG.
- ISO New England's Winter Reliability program encouraged the use of fuel oil to meet winter fuel needs, but imported LNG would have cost less on a dollar per MMBtu basis.
    - This past fall, the cost of LNG was about 33% less per MMBtu than what generators spent on fuel oil.
    - Gas-fired units also have a better average heat rate than oil-fired units, yielding additional potential fuel cost savings.
    - Pending retirements of some oil-fired capacity will limit the ability to switch to oil in the future.