GDF SUEZ

February 10, 2014

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

RE: NESCOE Request for "Additional data or analysis in connection with adequacy of increased pipeline capacity"

Dear ~~Ms. Hunt~~: Heather

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) January 27, 2014 Memorandum to members of the New England Gas-Electric Focus Group, which requested submission of "Additional data or analysis in connection with adequacy of increased pipeline capacity," to better inform NESCOE's request to the New England ISO for tariff assistance in supporting proposed new pipeline infrastructure in New England.

As background, Distrigas owns and operates the Everett LNG Import Terminal, the longest-operating facility of its kind in the United States. Since receiving our first shipment of LNG in November 1971, we have been a driving force in the adoption of this safe, clean-burning fuel in North America. In the 1970s, the company employed LNG to mitigate New England's regional energy crisis. Today, we continue to build on our reputation for developing innovative, flexible solutions that meet a wide range of energy needs of a growing and diverse customer base. Our parent company GDF SUEZ S.A. is a leading purchaser and supplier of liquefied natural gas (LNG) to the United States and countries around the world, and has a proven history of safety, reliability, and innovation.

For more than 40 years, the Everett LNG terminal has been the primary supplier of LNG to a network of 46 utility-owned, above-ground LNG storage tanks (shown on next page) that support New England's peak-shaving natural gas storage needs. Underground natural gas storage in the region is not feasible due to its geological conditions.

**Francis J. Katulak**
President and Chief Executive Officer

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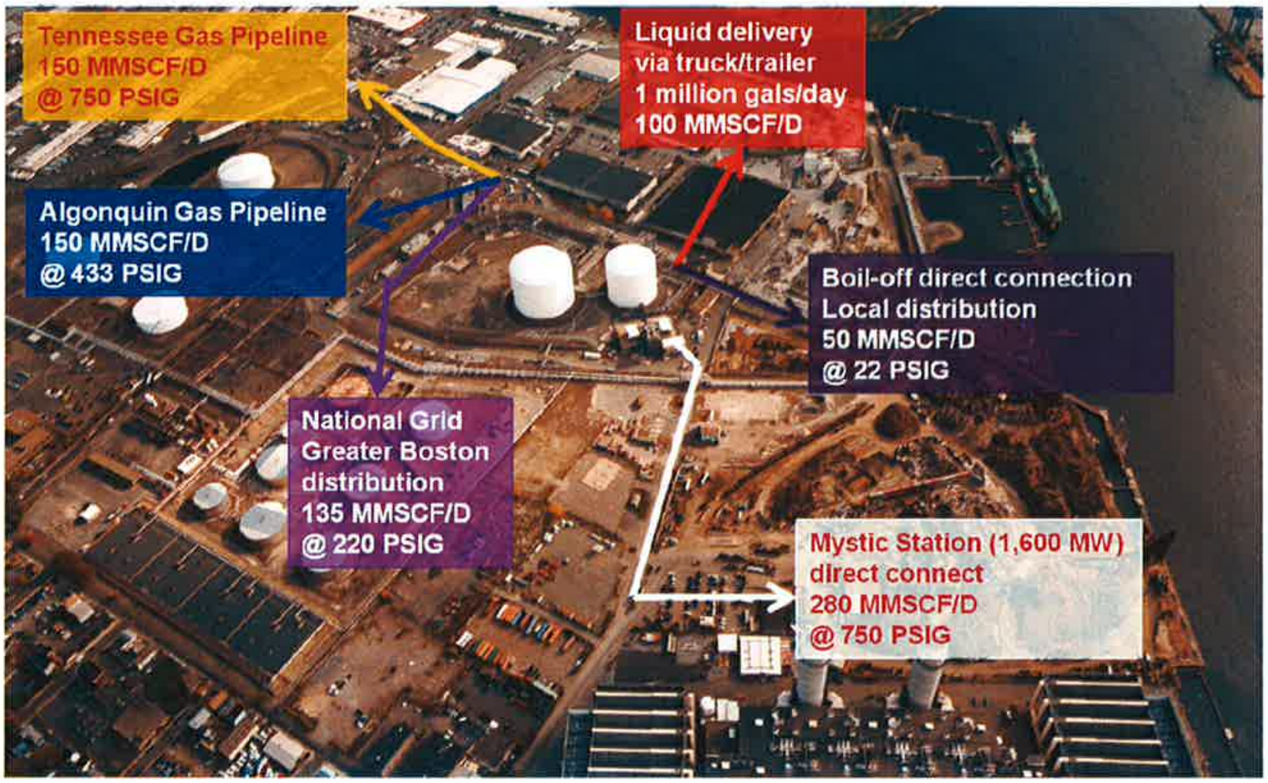
# Everett LNG Terminal is Well Connected to Serve NE Gas Demand


The Distrigas facility (shown on next page) is ideally located, connecting with not only two interstate pipeline systems, but also National Grid's distribution system and a neighboring 1,550-megawatt power plant capable of generating enough electricity for about 1.5 million homes. In addition, the Distrigas facility serves nearly all of the gas utilities in New England as well as key power producers. As illustrated below, the Distrigas facility has the available throughput capacity of **435 MMcf/day for power generation and local distribution company customers** of vaporized LNG that can be sent out at multiple pipeline pressures simultaneously, exclusive of the facility's maximum send-out commitment to liquid delivery sales and Mystic Station, for a total sustainable capacity of 715 MMcf/day of vaporized LNG and approximately 100 MMcf/day of LNG loaded on trucks in liquid form.

## Everett Can Provide 435 mmcf/day for Power Generation and LDCs



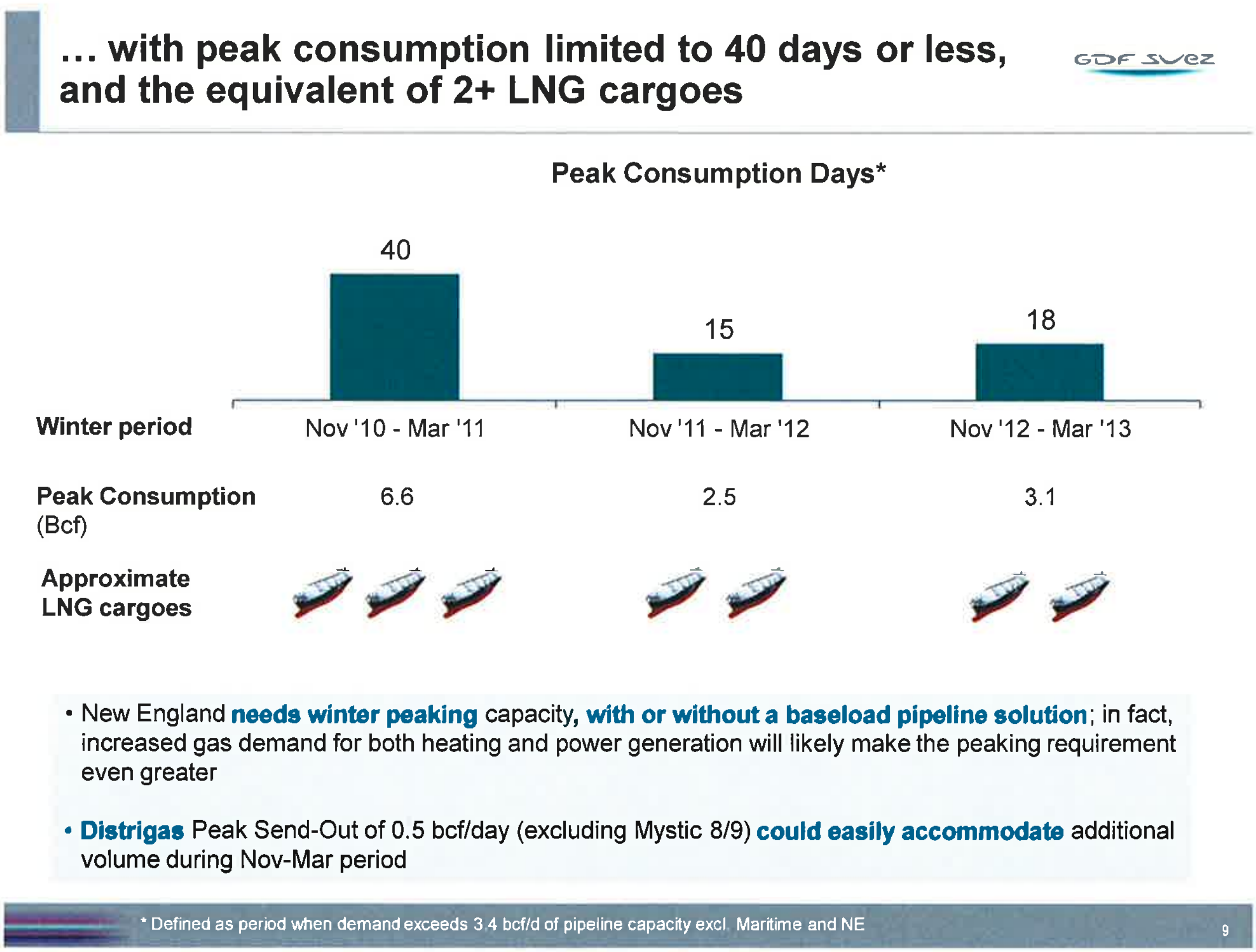

According to the December 2013 statement of the New England Governors, they are, as a group, committed to pursuing an initiative that "diversifies our energy supply portfolio while ensuring that the benefits and costs of transmission and pipeline investments are shared appropriately among the New England States." Distrigas commends the New England Governors, NESCOE, and ISO-NE for elevating the issue of energy infrastructure in our regional dialogue, and we appreciate the fact that a market exists for additional west to east pipeline infrastructure as evidenced by the successful subscription to Spectra's AIM project.

GDF SUEZ/Distrigas respectfully suggests that, before the New England states endeavor to share the cost of expensive new infrastructure, the region should first consider how to better utilize the billions of dollars in existing infrastructure that can alleviate significant capacity and gas supply shortfalls by flowing natural gas east to west. Indeed, in addition to the Distrigas Terminal, the Repsol Canaport LNG import terminal and the Northeast Gateway and Neptune deep-water port LNG receiving terminals could all be better utilized east of the pipeline bottlenecks and within the most constrained area.

To be sure, the lack of utilization is attributable to the fact that LNG, unlike domestic pipeline natural gas, is a global commodity and can access various global markets. But the global market is always in flux, and just five years ago, as a result of a weak global market and strong domestic US price, there were dozens of LNG import terminal applications filed at FERC. Today, it's just the opposite; there are almost as many export terminal applications pending at the DOE. Nevertheless, there are contractual arrangements that can be negotiated to lessen the gap between current global and domestic market prices.

GDF SUEZ has made several offers to provide short-notice and flexible natural gas services to the New England market over the past two winters. While we have signed a limited number of contracts, potential power generation buyers have lacked appropriate cost recovery mechanisms under existing wholesale electric market design to justify purchase of such services. With appropriate market signals in place and commitments made in advance to facilitate logistics, we are confident that LNG can be economically delivered to the New England market during peak periods.

The chart below illustrates that, particularly during winter peaks, LNG utilization is a flexible and right-sized solution for the region and, regardless of whether additional costly infrastructure projects come online, can accommodate easily additional winter volumes next winter and beyond.



Sending the correct market signals is a critically important aspect of the conversation in New England. To that end, GDF SUEZ/Distrigas appreciates the work of ISO-NE to improve market design, most notably through its Forward Capacity Market Pay for Performance Incentive (FCM-PFP) Proposal currently before the Federal Energy Regulatory Commission (FERC). We believe those proposed market reforms will enhance the prospects for additional peak LNG supply as well as new regional pipeline capacity.

While it will take time to implement those reforms, existing LNG infrastructure can respond to the pressing challenges facing New England much sooner, and very likely much more efficiently. The critical role LNG is playing this winter in New England was recently highlighted in the **U.S. Energy Information Administration's** *In the News* segment of its ***Natural Gas Weekly Update*** publication for the week ending January 22, 2014[1], which noted "Within the United States, the importance of LNG sendout varies greatly by region. It plays a particularly significant role in New England, which utilizes LNG sendout when demand peaks to levels that exceed available capacity to bring gas on pipelines from inland production areas." The *In the News* segment also noted that:

> "The Distrigas LNG terminal in Everett, Massachusetts, accounts for the highest LNG sendout volumes in the United States, accounting for more than half of all sendout last year. Through the first three weeks of 2014, Everett sendout totaled 0.30 Bcf/d, or 7% of total New England consumption. This was a 34% increase over the same dates in 2013, when it accounted for 5% of total New England consumption, but 31% below sendout for these dates in 2010-12, when it accounted for 9% of total New England consumption, according to Bentek data. In recent years, Everett has received a relatively high share of its LNG cargoes contracted on a long-term basis. This has partially mitigated the effect on imports of relatively higher global spot prices."

We thought it might also be helpful to share the data and analysis contained in a report prepared for GDF SUEZ/Distrigas by ICF International this past October. We asked ICF to test the theory that utilizing existing natural gas infrastructure to meet peak winter demand in New England is economically justified.

The report, titled ***Options for Serving New England Natural Gas Demand***, 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. In brief, however, the report concluded the following:

- New England currently experiences a tight supply/demand balance on about 30 days per year, and natural gas demand is projected to grow significantly over the remainder of the decade.

[1] ***"LNG satisfies less U.S. natural gas consumption, although helpful in New England."***

- Compared to 2013 levels, ICF projects that winter peak day gas demand will increase by more than 500 MMcfd by 2015 and more than 1,000 MMcfd by 2020, exacerbating the existing gas supply constraints.

- The projected growth in LDC firm demands justifies some new pipeline capacity. ICF assumes that Algonquin's AIM expansion will add an incremental 450 MMcfd of capacity, but it is not expected until late-2016. Even after the AIM expansion, New England will still need incremental gas supplies on about 30 peak winter days a year by 2020.

- New England gas demand is very seasonal, so there will be sufficient supply capability to meet off-peak loads.

- Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution.

GDF SUEZ/Distrigas is pleased to provide a copy of the ICF International report, *"Options for Serving New England Natural Gas Demand,"* as well as the information referenced in EIA's recent Natural Gas Weekly Update and our own data which demonstrate Distrigas' ability to provide 435 mmcf/day of throughput capacity for NE power generators and LDCs in response to NESCOE's request for additional data and analysis. It is unclear whether or not the Governors' request for analysis concerning a range of between 600 mmcf/day and 1000 mmcf/day have fully accounted for the available capacity at Distrigas, Canaport and other existing LNG infrastructure or are instead using as data points the more recent lower sendout volumes which reflect limited firm contracting.

The Distrigas terminal is a unique asset that resides in a unique location; with the right policies and incentives in place, we believe LNG, and more importantly the Distrigas terminal, can be an instrumental part of the solution to New England's near term and long term natural gas supply and capacity constraints. And it's worth noting that as existing infrastructure, the Distrigas terminal can satisfy this need without incremental environmental impact from construction or the sunk cost of infrastructure that goes unutilized all but a few months out of the year.

Thank you for the opportunity to provide our perspective on these important issues for our region.

Sincerely,

Francis J. Katulak
President and Chief Executive Officer

# Options for Serving New England Natural Gas Demand

Prepared for

**GDF Suez Gas North America**

October 22, 2013

Prepared by

**ICF International**
9300 Lee Highway
Fairfax, VA 22031

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# Executive Summary

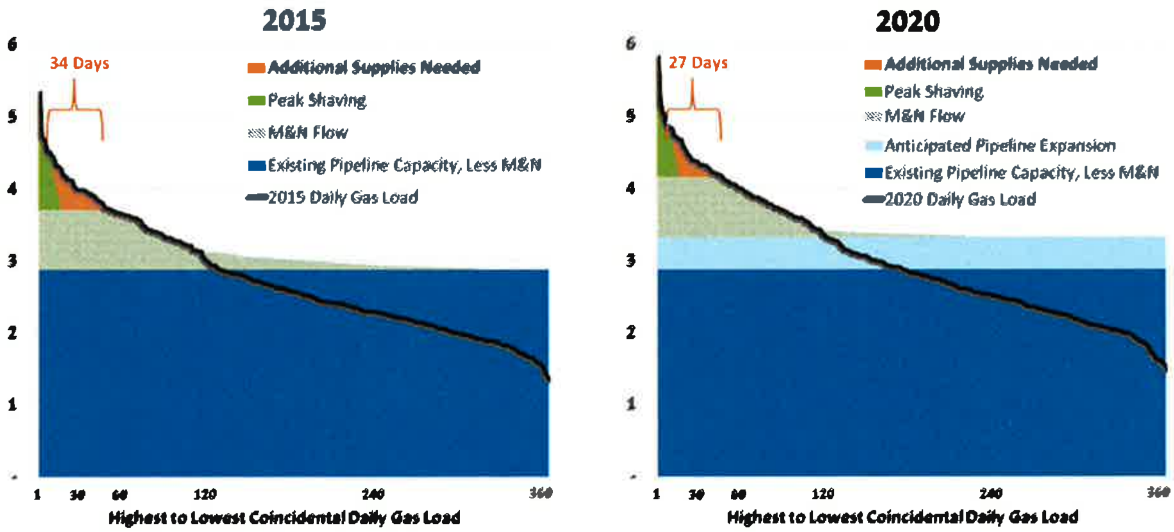
Over the past 10 years, U.S. natural gas production has surged due to the development of shale gas supplies. Despite the overall increases in domestic production, some markets like New England remain supply constrained during peak demand periods. New England has no in-region gas production, so the region depends on interstate pipelines and liquefied natural gas (LNG) terminals for all its gas supplies. New England gas demand has been steadily increasing, primarily due to an increase in gas-fired electricity generation, but also due to increases in residential and commercial loads served by the region's local distribution companies (LDCs).

As New England's gas demand continues to increase, it will need new gas supplies on peak demand days. ICF was engaged by GDF Suez Gas North America (GSGNA) to assess the costs of different options for meeting projected gas demand in the New England market. ICF assessed New England's current gas supply capabilities, the projected growth in annual and daily gas loads, and the comparative costs of meeting the need for incremental gas supplies. The projections for annual demand growth, gas prices, and daily loads are based on results from ICF's September 2013 Base Case gas market forecast, developed using ICF's Gas Market Model (GMM) and Daily Gas Load Model (DGLM).

The New England gas market has become increasingly constrained in the winter, as peak winter demand has gradually increased while transport capabilities into the region have not. The power sector has been and will continue to be the biggest source of demand growth, as New England electric generators have become increasingly dependent on natural gas. At the same time, New England's LDCs continue to expand into previously unserved areas and steadily increase their customer counts as residential and commercial customers convert from fuel oil to natural gas furnaces for space heating. ICF projects that New England's peak day demand will increase by about 1 billion cubic feet per day (Bcfd) by 2020.

Currently, New England consumers contract for about 3,700 million cubic feet per day (MMcfd) of interstate pipeline capacity. ICF's Base Case anticipates that about 450 MMcfd of new pipeline capacity will come online by the end of 2016, and Spectra's NY–NJ expansion will free up some capacity on the Iroquois pipeline for New England consumers. Peak shaving facilities operated by New England's LDCs can provide additional supplies on limited number of days each winter, but this still leaves the New England market in need of additional supplies on about 30 days per year between 2015 and 2020 (Figure 1).

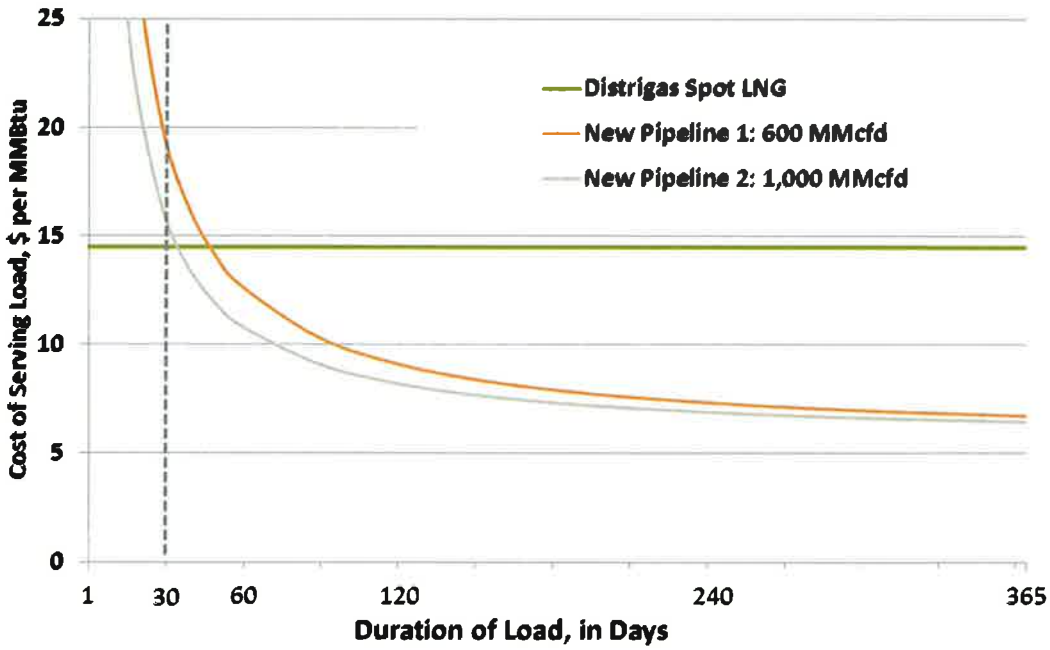
**Figure 1. Projected Daily Gas Loads versus Pipeline Capacity and Peak Shaving, in Bcfd**




The primary options for meeting **New England's need for** incremental peak day gas supplies are additional pipeline capacity (beyond the incremental 450 MMcfd projected in the ICF Base Case) and LNG imports into Everett. Based on recent historical prices, ICF anticipated that additional spot LNG supplies at Distrigas terminal would cost about $14.50 per million British thermal units (MMBtu). Additional LNG shipments into the Neptune and Northeast Gateway LNG terminals would cost approximately $1 dollar more (around $15.50 per MMBtu) due to the higher charter cost of the specialized tankers required to deliver gas to those buoy-based terminals.

To compare the cost of adding incremental pipeline capacity to the cost of spot LNG deliveries, ICF developed cost duration curves to represent the per-unit cost (in $ per MMBtu) of serving daily loads over the course of a year (Figure 2). While Marcellus-area gas is attractively priced, a new greenfield pipeline to connect New England to the Marcellus Shale would cost about $2 billion. Since the additional capacity would have to be fully contracted to be built but needed only about 30 days per year, the per-unit cost of this option is $16 to $20 per MMBtu, significantly higher than the cost of incremental spot LNG shipments.

**Figure 2. Cost per Day of Serving Incremental Gas Load, New Pipeline versus Spot LNG**




It is typically more cost effective to increase utilization of an existing asset rather than build new capacity, as the capital cost of existing assets can be treated as a sunk cost and therefore not subject to capital recovery. Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution **to meet this portion of New England's gas demand**.

# 1 Introduction

Over the past 10 years, U.S. natural gas production has surged due to the development of shale gas supplies. Despite the overall increases in domestic production, some markets, like New England, remain supply constrained during peak demand periods. New England has no in-region gas production, so the region depends on interstate pipelines and LNG terminals for all its gas supplies. New England gas demand has been steadily increasing, primarily due to an increase in gas-fired electricity generation, but also due to increases in residential and commercial loads served by the region's LDCs.

On peak demand days in the winter, New England's in-bound pipelines are fully utilized, resulting in price spikes at trading hubs within the region. As recently as January 2013, daily spot prices at the Algonquin Citygate rose to more than $30 per MMBtu, a premium of $25 more than the Henry Hub price. However, during the shoulder and summer months when regional demand is much less than the available in-bound pipeline capacity, New England's basis is far lower. Between April and September 2013, the Algonquin Citygate basis averaged about $0.56; and between July 28 and September 30 there were 11 trading days when the Algonquin price was actually below the Henry Hub price.

As New England gas demand continues to increase, it will need new gas supplies on peak demand days. ICF was engaged by GSGNA to assess the costs of different options for meeting projected gas demand in the New England market. ICF assessed New England's current gas supply capabilities and the projected growth in annual and daily gas loads, and the comparative costs of meeting the need for incremental gas supplies. The projections for annual demand growth, gas prices, and daily loads are based on results from ICF's September 2013 Base Case gas market forecast, developed using ICF's GMM and DGLM. ICF also assessed four different scenarios based on alternate projections for New England power generation gas demand and alternate projections for gas production from eastern Canada (a critical source of incremental supplies for the New England market).

This assessment of the New England gas market is based on the total pool of gas supply resources available to the area and total daily demands within the area. In reality, the ability of individual consumers within New England to receive gas from any one supply source (e.g., a particular pipeline or LNG terminal) is limited by intra-regional infrastructure constraints; however, this "pooled" approach is a reasonable representation of the region's overall supply/demand dynamics.

The remainder of this report is divided into three sections: a discussion of ICF's outlook for the North American gas market, the outlook for New England gas supply and demand, and an assessment of options to meet New England's near- to mid-term (through 2015 and 2020) projected gas supply needs.

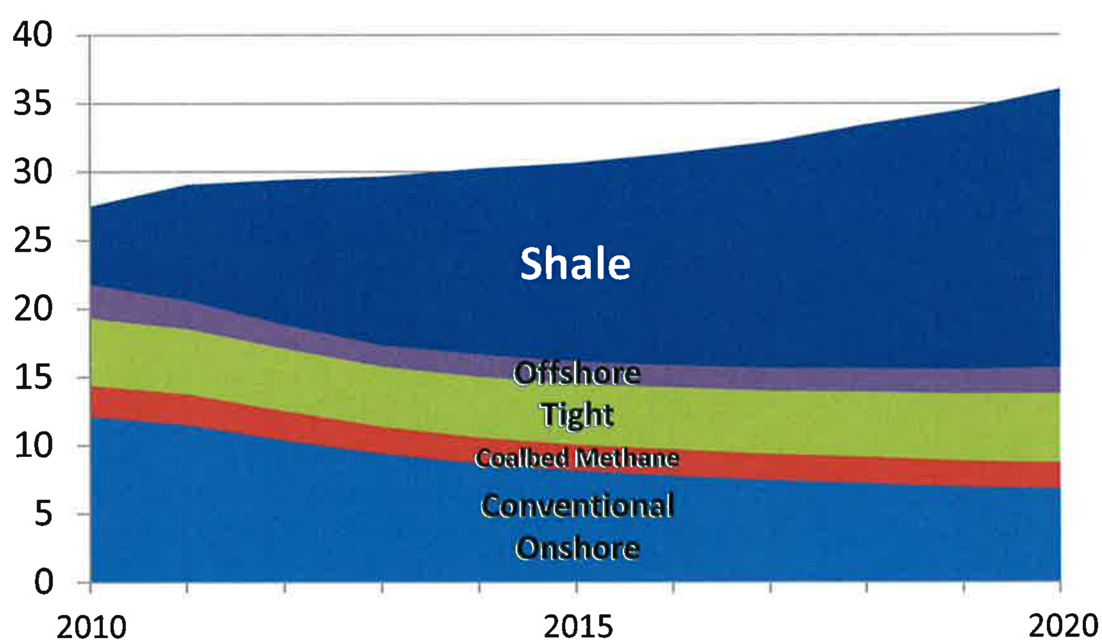
# 2 Overview of ICF's Outlook for the North American Natural Gas Market

To provide context for the more detailed discussion of the New England gas market (provided in Section 3), this section of the report provides an overview of **ICF's projection for the North** American gas market.

In the past 10 years, the North American natural gas market has undergone dramatic changes. The rise of shale gas production combined with weak economic growth has led to lower and less volatile gas prices. Before the rise of shale, most projections assumed that in the future, the United States would rely on LNG imports to meet a significant portion of its gas demand. Now, it appears that U.S. and Canadian production growth will exceed domestic demand, and there are multiple LNG export terminals under construction or being planned in the United States and Canada, as well as expansion of pipelines exporting gas from the United States to Mexico.

ICF projects that combined U.S. and Canadian gas production will increase by more than 20 percent to 36 trillion cubic feet (Tcf) per year by 2020 (Figure 3). Conventional onshore production is expected to continue declining, but shale gas production is projected to nearly double, reaching more than 20 Tcf per year by 2020. About one-third of the projected growth in shale gas production comes from the Marcellus shale, where production is expected to increase to 5.7 Tcf per year.

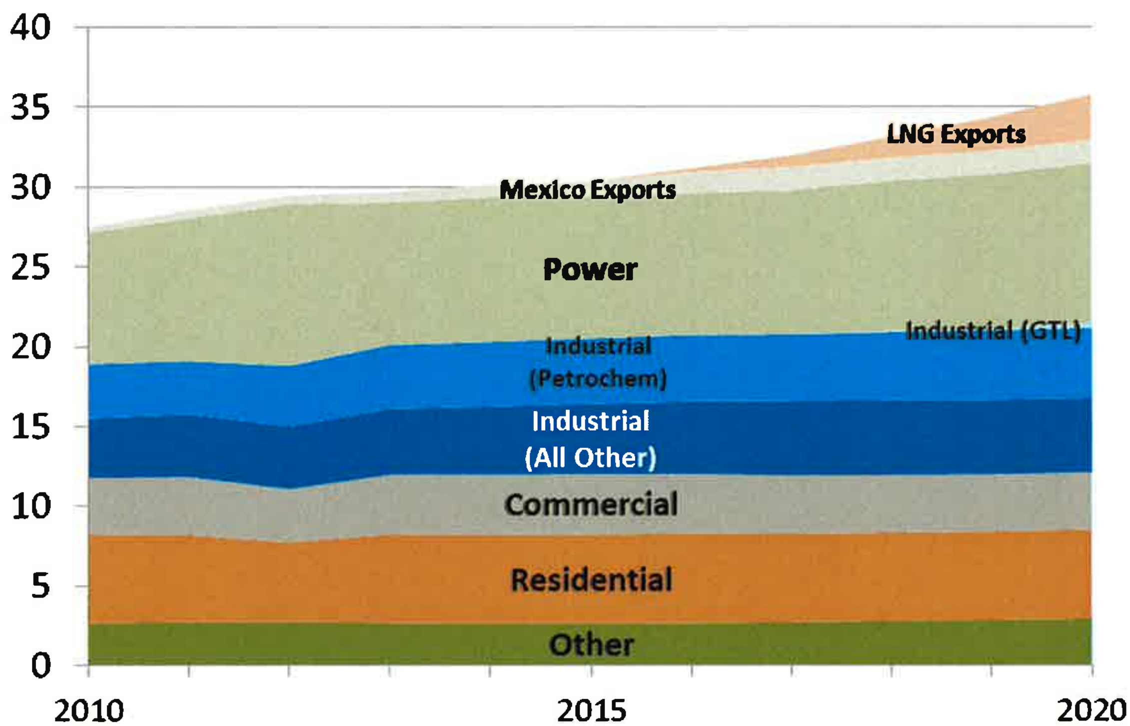
**Figure 3. Projected U.S. and Canadian Natural Gas Production, in Tcf per Year**



Over the same period, demands for natural gas (both domestic consumption and imports) are expected to increase rapidly (Figure 4). Long-term growth in domestic gas consumption is primarily driven by the power sector. Electric load growth, combined with coal and nuclear plant retirements drive power sector gas consumption up by more than 1 Tcf per year by 2020. Industrial gas consumption is expected to increase rapidly. In the United States, new petrochemical plants are being developed to take advantage of the abundant shale gas resources; in Canada, industrial consumption growth is primarily driven by increased use of natural gas for oil sands development. And toward the end of the decade, Shell and SASOL are planning new gas-to-liquids (GTL) plants, which could create additional demand. By 2020, combined U.S. and Canadian industrial gas consumption is projected to increase by about 1 Tcf per year. While residential and commercial sector gas consumption is expected to increase very little for the United States and Canada as a whole, demands in New England are expected to increase at a higher rate due to continued conversions by space heating customers from oil fuel to natural gas.

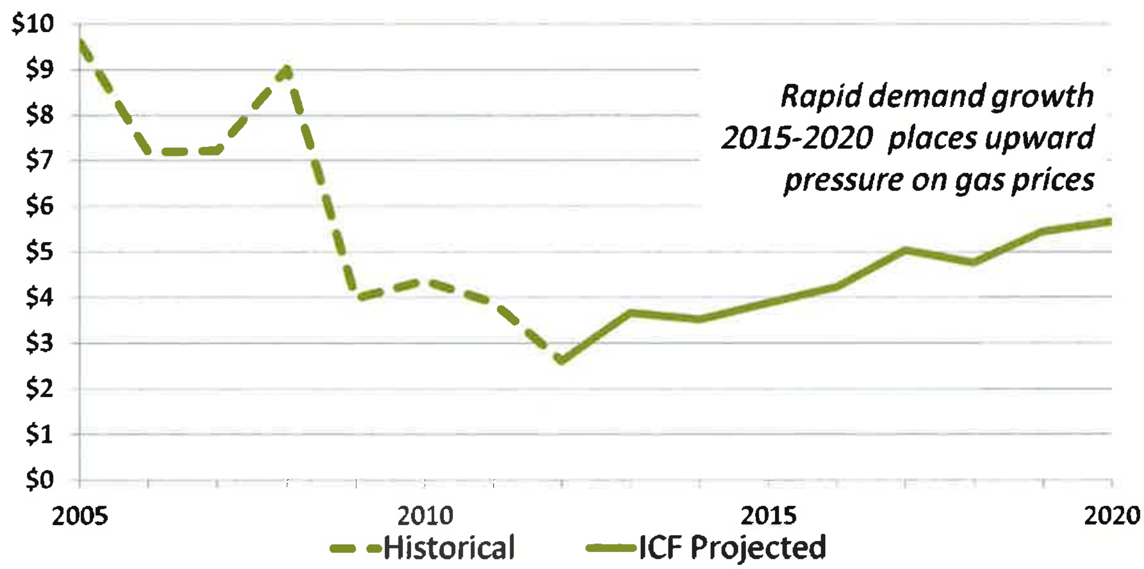
In addition to the domestic consumption growth, both LNG exports and pipeline exports to Mexico are also expected to increase. By 2020, LNG exports from the United States and Canada are expected to reach 2.9 Tcf per year (about 9 Bcfd) and exports to Mexico increase by 1 Tcf per year (about 3 Bcfd).

**Figure 4. Projected U.S. and Canadian Natural Gas Demand, in Tcf per Year**



While gas prices are expected to remain around $4 per MMBtu through 2014, prices this low are not sustainable in a rapidly growing market. ICF projects Henry Hub gas prices (in 2010$) averaging $4.00 per MMBtu through 2015, then rising to between $5.00 and $6.00 per MMBtu by 2020 (Figure 5).

**Figure 5. Annual Average Natural Gas Prices at Henry Hub, in 2010$ per MMBtu**




Despite the growth in domestic gas supplies and the relatively low gas price environment, basis differentials to the New England market are expected to remain relatively high (Figure 6 and Figure 7). Before 2013, basis between Henry Hub and the Algonquin Citygate averaged about $1 per MMBtu. Even though winter temperatures during these years were relatively mild (2012 was one of the warmest winters on record), basis during peak months ranged from $2 to $4 per MMBtu. In 2013, winter temperatures were significantly colder, and basis averaged nearly $7 per MMBtu, with basis on peak days spiking to more than $25.

In ICF's Base Case (which assumes forecast weather consistent with the average of the median of the last 20 years), annual basis between Henry Hub and Algonquin is expected to average about $1 per MMBtu, and January basis averages about $3.50 per MMbtu. While there is some dip in basis in 2014 (after Spectra's NY–NJ expansion) and again in 2017 (after the assumed 450 MMcfd of pipeline expansion into the New England market), continued market growth is expected to keep basis values relatively high. In Section 3 we provide additional details on ICF's Base Case projections for New England gas demand and supplies.

**Figure 6. Annual Average Basis Henry Hub to Algonquin Citygate, 2010$ per MMBtu**

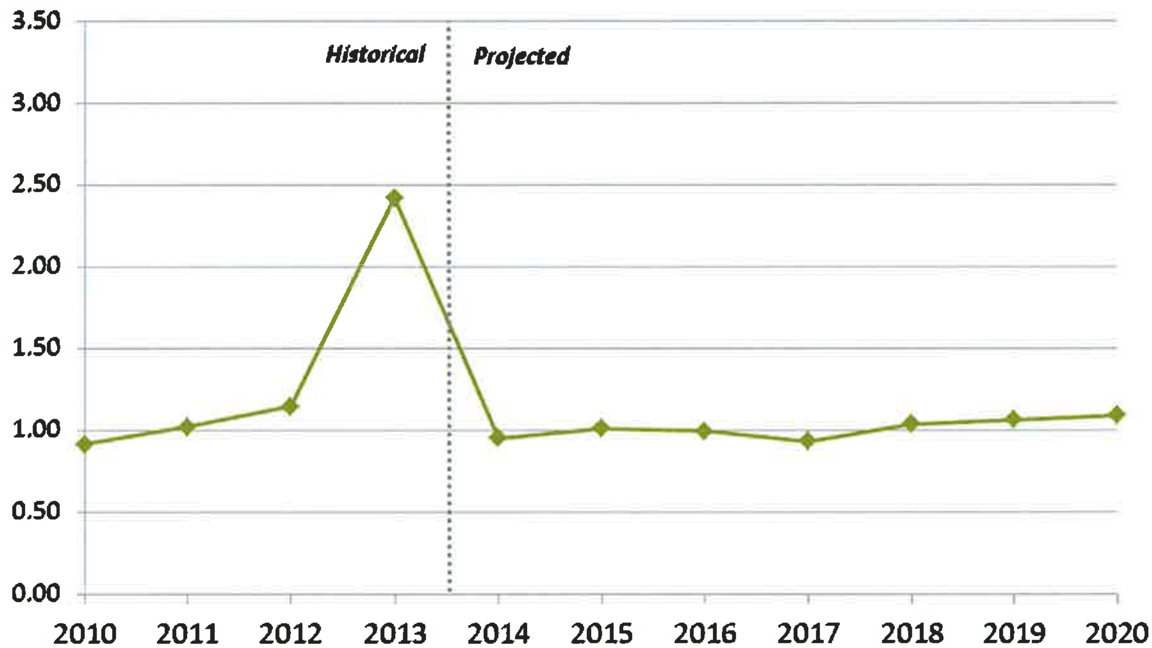
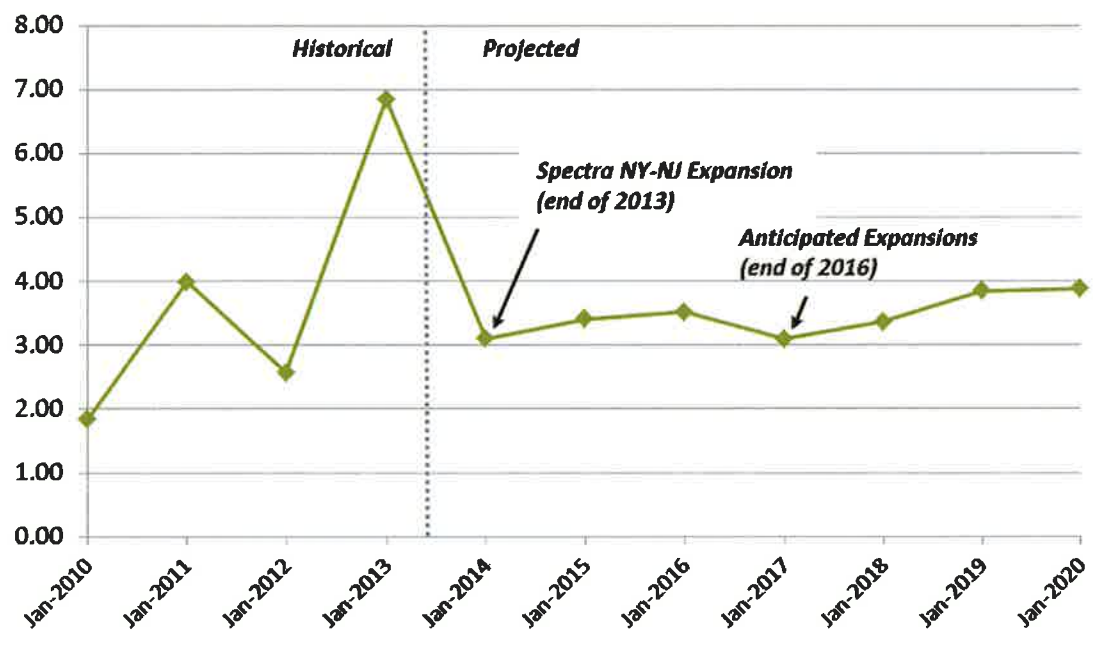



**Figure 7. January Average Basis Henry Hub to Algonquin Citygate, 2010$ per MMBtu**



# 3 Outlook for the New England Market

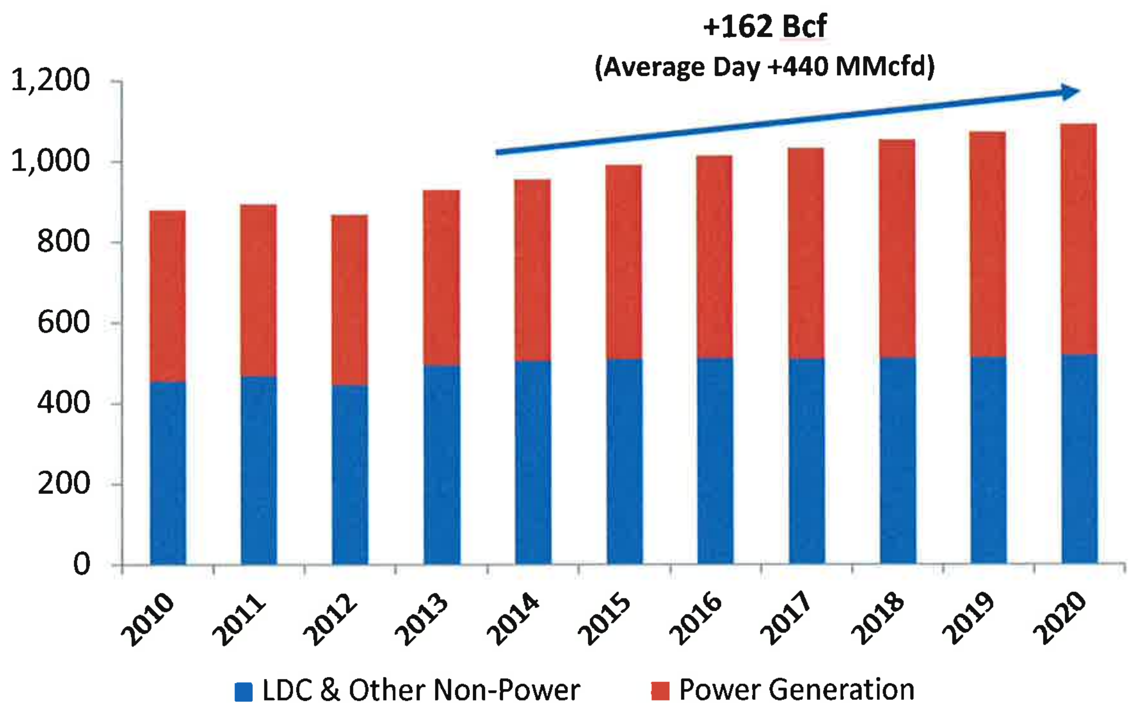
Gas Demand

The New England gas market has become increasing constrained in the winter, as peak winter demand has gradually increased while transport capabilities into the region have not. The power sector has been the biggest source of demand growth, as New England electric generators have become increasingly dependent on natural gas. Between 2004 and 2012, about half **(5,000 MW) of New England's dual**-fuel capable capacity was either mothballed or retired. The recently announced shutdown of Vermont Yankee nuclear power plant in 2014 will further increase gas demand for electricity generation by approximately 110 MMcfd.

LDCs have expanded into previously unserved areas and have steadily increased their customer counts as residential and commercial customers convert from fuel oil to natural gas furnaces for space heating. Relatively mild winter weather over the past decade has obscured the rate of market growth; three of the last five years have been much warmer than normal, and the winter of 2011–2012 was the warmest on record. In fact, New England has not experienced **very cold "design day" winter conditions the past 10 years.** When the weather did turn relatively cold in January–February 2013, spot gas prices at the Algonquin Citygate soared past $30 per MMBtu, even as other Northeast price points remained relatively stable around $4 per MMBtu, indicative of the regional supply constraints.

**ICF's** Base Case projects that total New England annual natural gas demand will increase by more than 160 billion cubic feet (Bcf) by 2020 (Figure 8). The majority of the increase in annual demand is expected to come from the power sector, which increases by 140 Bcf; the remainder of the increase is from LDC demand (residential and commercial) and a small amount of industrial demand. **ICF's projections for annual gas demand assume "normal" weather, based** on the median of the past 20 year.

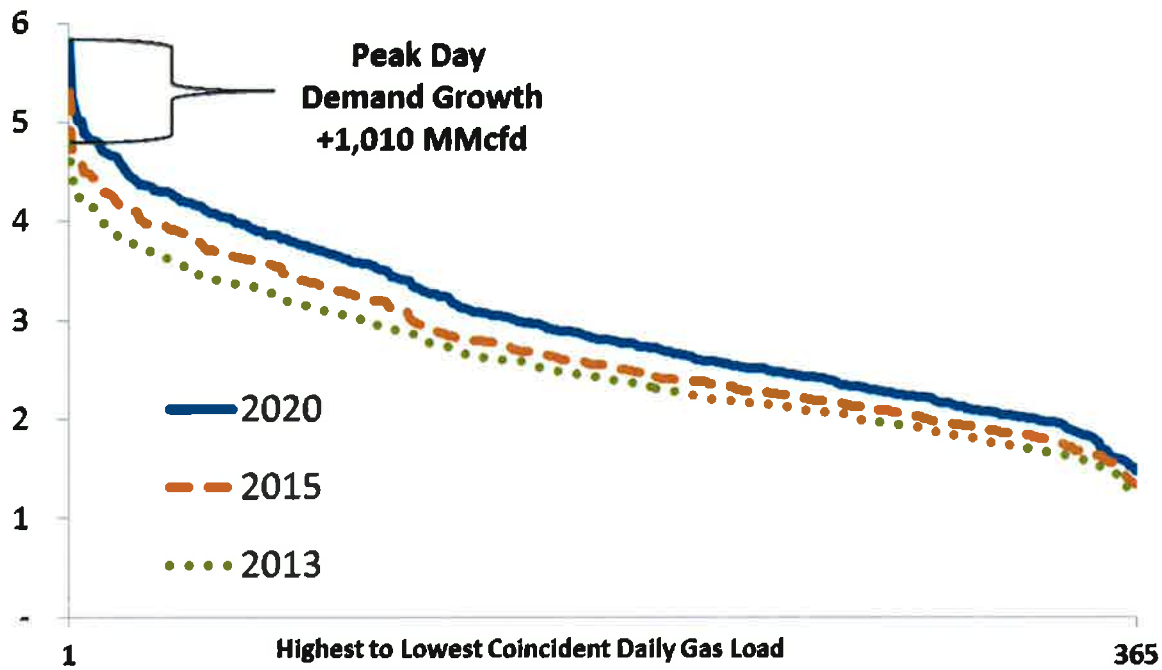
**Figure 8. New England Annual Natural Gas Demand, in Bcf per Year**




While the growth in LDC demand is modest on an annual basis, the impact on peak day demand is much greater, since the majority of LDC load is for space heating. Growth in daily load due to increased power sector gas demand is spread more evenly throughout the year, as much of the increase in gas-fired generation is for based load use, such as the replacement of generation from the Vermont Yankee plant. Also, about 6 gigawatts (GW) of the gas-capable units in the region have the ability to switch to fuel oil, which helps limit power sector gas consumption on peak winter days.[1] Figure 9 shows ICF's projection for total daily gas loads. By 2020, peak day demand is projected to increase by about 1 Bcfd.

[1] "CELT Report: 2013–2022 Forecast Report of Capacity, Energy, Loads, and Transmission," ISO New England, May 2013.

**Figure 9. Projected New England Daily Natural Gas Demand, in Bcfd**




ICF also examined two alternate projections for New England power sector demand, based on potential change in the region's capacity mix. In the higher demand scenario, ICF projects there could be an additional 0.16 to 0.17 Bcfd of incremental demand growth if New England's coal or nuclear capacity were reduced by another 1,000 MW. In the lower demand scenario, if 1,000 MW of coal capacity retirement anticipated in the ICF Base Case did not occur, then demand growth would be reduced by about 0.1 Bcfd.

<u>New England Pipeline Capacity</u>

New England has no in-region gas production, so it depends on deliveries via pipeline and LNG terminals for all its gas supplies. There are five interstate pipelines that supply the New England market—Tennessee Gas Pipeline, Algonquin Gas Transmission, Iroquois Gas Transmission, Portland Natural Gas Transmission System (PNGTS), and Maritimes and Northeast Pipeline (M&N) (Figure 10). Based on ICF's analysis of Index of Customer data for each of these pipelines, a total of approximately 3,700 MMcfd of pipeline capacity is contracted for by consumers in New England (Table 1).[2] The vast majority of the firmly contracted pipeline

[2] ICF's analysis of the Index of Customers data was performed in the fourth quarter of 2012.

capacity is held by the region's LDCs; less than 8 percent of the firm pipeline capacity is held directly by electric generators in New England.[3]

**Figure 10. Map of New England Interstate Pipelines and LNG Terminals**

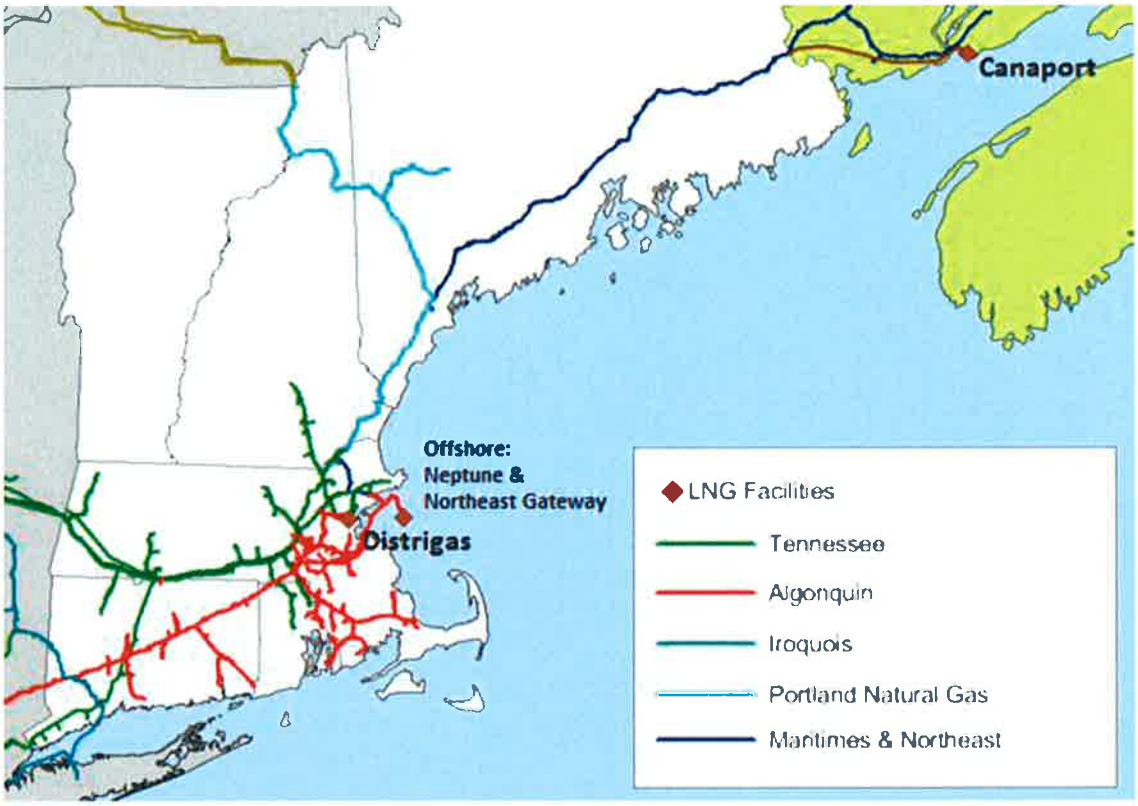



**Table 1. Firm Pipeline Capacity Held by New England Shippers, in MMcfd**

| Tennessee | Algonquin | Iroquois | PNGTS | M&N | Total |
|---|---|---|---|---|---|
| 1,290 | 1,120 | 230 | 250 | 830 | **3,720** |

About two-thirds of the capacity contracted by New England shippers is on the Tennessee and Algonquin systems. Iroquois has a total of more than 1,500 MMcfd of firm contracts, but the majority of this capacity is contracted for by shippers further downstream in New York. New England shippers contract for only about 230 MMcfd of firm capacity on Iroquois.

[3] ICF analysis of the Index of Customers data indicates about 280 MMcfd of firm capacity is directly held by New England electric generators; however, generators may contract for additional firm capacity through marketers.

On PNGTS, New England shippers contract for approximately 250 MMcfd, but the system's physical capacity is greater; on peak winter days PNGTS has flowed more than 300 MMcfd. While PNGTS has proposed an expansion to offer additional capacity to the New England market, it will likely be increasingly difficult to get gas supplies to the system. Declining production and increasing demand in Alberta has reduced flows on the TransCanada and TransQuebec systems, which supplies PNGTS.

M&N has a capacity of 830 MMcfd, essentially all of which is contracted for by Repsol's gas marketing division. While M&N does flow full on peak demand days (when New England prices are very high), the annual capacity utilization of the system has been declining due to declining Sable Island offshore production, reduced LNG imports to Canaport, and demand growth in eastern Canada.

<u>Potential Pipeline Expansions</u>

Several pipeline systems have proposed expanding capacity into New England. In July 2013, Tennessee Gas Pipeline launched an open season for its Connecticut Expansion Project, which would provide an additional 72 MMcfd from Tennessee's existing interconnect with Iroquois Gas Transmission in Wright, New York, to zone 6 delivery points on Tennessee's 200 and 300 lines in Connecticut through upgrades and modifications to its existing system in New York, Massachusetts, and Connecticut. The Algonquin Incremental Market (AIM) expansion project was proposed to add as much as 450 MMcfd of capacity by the end of 2016. As of late September 2013, the response to Algonquin's open season indicates the expansion would be sized at less than 400 MMcfd. ICF projects that by the end of 2016, contracted pipeline capacity into the New England market will increase by 450 MMcfd, most likely on some combination of expansions on the Tennessee and Algonquin system.

Spectra's NY–NJ expansion of its Texas Eastern Transmission and Algonquin lines in the New York City metropolitan area is due online in November 2013. While these expansions do not directly provide any additional capacity into the New England market, they may make additional capacity available to New England shippers by displacing flows from New England to Long Island on the Iroquois system.

<u>New England LNG Terminals</u>

The Distrigas LNG terminal in Everett, MA (operated by GDF Suez NA) is the only terminal in the region currently receiving shipments. Distrigas has a sustainable vaporization capacity of 715 MMcfd and can distribute another 100 MMcfd via truck; it has two storage tanks with a combined capacity of 3.4 Bcf. The combined sendout from Distrigas to interstate pipelines (Tennessee and Algonquin) and Mystic Generating Station averaged about 215 MMcfd in 2012, with a peak day sendout of about 440 MMcfd. Distrigas also delivers additional volumes directly to the local LDC system (National Grid/Boston Gas) and via truck to LNG peak shaving facilities across New England.

Two other offshore LNG terminals, Neptune and Northeast Gateway, have not received any shipments since 2010. The offshore terminals can only receive deliveries from specialized tankers with on-board regasification and buoy-docking systems. Also, since the offshore terminals have no LNG storage capacity, they are only able to send out gas when a LNG tanker is docked at one of their buoys.

New England Peak Shaving Facilities

In addition to the pipeline and LNG import terminals, LDCs in New England also operate about 45 LNG and propane-air peak shaving facilities. The peak shaving facilities are used by the LDCs to maintain system reliability and help meet firm customer demand during the 10 to 15 peak demand days of winter. The peak shaving facilities have a total send-out capability of about 1,450 MMcfd and a total storage capacity of about 16 Bcf.[4] **Some of the facilities are "full-cycle" LNG peak shaving (i.e., they can liquefy pipelin**e gas to refill the storage tanks), but the majority are supplied by truck shipments from the Distrigas facility.

Upstream Gas Supplies and Supply Scenarios

The closest major production area to New England is the Marcellus Shale; the Marcellus shale is centered in Pennsylvania but also stretches across portions of West Virginia, Ohio, and New York. Producers began drilling in the Marcellus Shale just six years ago, but production has already reached 9 Bcfd. Marcellus shale gas has become a major new source of gas supply for the entire northeast, including the New England market, displacing flows from traditional supply sources such as the Gulf Coast and western Canada. Despite the increase in Marcellus production, the availability of pipeline capacity into New England limits the availability of these supplies to the market, particularly on peak demand day. There have been pipeline system expansions and reconfigurations within the Marcellus play area, but no new pipeline capacity built directly into the New England market since the last M&N system expansion in 2009.

New England also receives gas from eastern Canada via the M&N pipeline. Gas production in eastern Canada has been declining and that has reduced supplies available on M&N. Most eastern Canada production comes from the Sable Island offshore field and the new Deep Panuke offshore field, which began production in August 2013. Production from Deep Panuke may improve average annual M&N flows in the near-term, but there have been a number of problems in the field since the start of production. There are also on-shore shale gas resources in New Brunswick, but producers have not announced any plans to develop them.

**The M&N pipeline also transports supplies from New Brunswick's Canaport LNG terminal**. Repsol, which owns both Canaport and the M&N pipeline, sold the majority of its LNG assets, including interest in the gas liquefaction facility in Trinidad and Tobago, which have provided **most of Canaport's supplies. Canaport's current LNG supply contracts** with Shell will allow it to **continue operations, but at only a small fraction of its nominal capacity; Repsol's current**

[4] **"NGA 2012 Statistical Guide", Northeast Gas Association, 2012.**

contract with Shell equates to about 5 Bcf per year. Utilization of both M&N and Canaport have been on the decline; in the past year, M&N only flowed full on a limited number of peak winter days, supported by sendout from Canaport.

ICF projects that eastern Canadian production will increase to approximately 0.5 Bcfd in the near-term, due to the startup of Deep Panuke production. After 2014, total production from eastern Canada (primarily Sable Island and Deep Panuke offshore fields, plus a small amount of additional onshore production) is expected to resume its decline, and reach about 0.18 Bcfd by 2020. Canaport is currently operating **as a "swing supply" for the New England market,** increasing sendout up to the available remaining capacity on M&N during peak demand periods when gas prices are very high, and sending out minimal volumes during the rest of the year; it is expected to continue operating this way through the projection.

ICF also examined two alternate supply scenarios for eastern Canadian gas production. In the higher supply scenario, eastern Canada production peaks at 0.51 Bcfd in 2014 and is maintained at 0.44 Bcfd through 2020. The lower supply scenario assumes Deep Panuke production is less than in the Base Case; eastern Canada production peaks at only 0.33 Bcfd in 2014 and declines to less than 0.1 Bcfd by 2020.

Conclusions from Demand and Supply Outlook

**ICF's Base Case** projection indicates that the New England market is likely to remain supply constrained during peak winter demand periods through 2020. Figure 11 and Figure 12 show **ICF's projected daily gas loads for New England in 2015 and 2020**, respectively, versus projected pipeline and peak shaving resources.

In summer and shoulder months, space heating gas use is minimal and LDC loads average about 80 percent lower than on a peak winter day. As a result, much of the pipeline capacity held by LDCs is available to other consumers (mostly electric generators) in the shoulder and summer months. On the 15 highest demand days, regional peak shaving facilities supplement the pipeline supplies to help meet loads. However, because the storage capacity of these facilities is limited, they cannot be relied on to provide additional supplies for extended periods. As indicated by the orange area in Figure 12, between the days when pipeline supplies and peak shaving facilities can meet daily loads is a period of approximately 30 peak demand days when additional gas supplies are needed. Even after expected expansion increases pipeline capacity by 450 MMcfd, the projected growth in daily load indicates that by 2020 there will still be about 30 days per year during which the New England market will need additional gas supplies beyond the expected pipeline and peak shaving capabilities (Figure 12).

In Section 4, we compare the cost of two options for meeting the need for additional gas capacity—additional pipeline capacity and LNG imports into Distrigas.

Figure 11. Daily Gas Load in 2015 versus Pipeline Capacity and Peak Shaving, in Bcfd

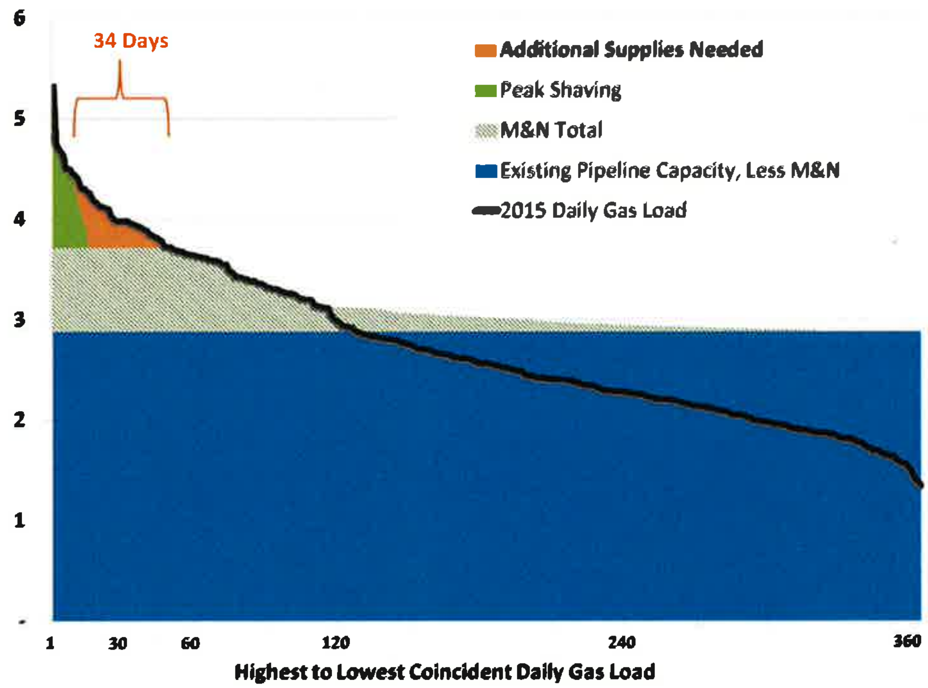
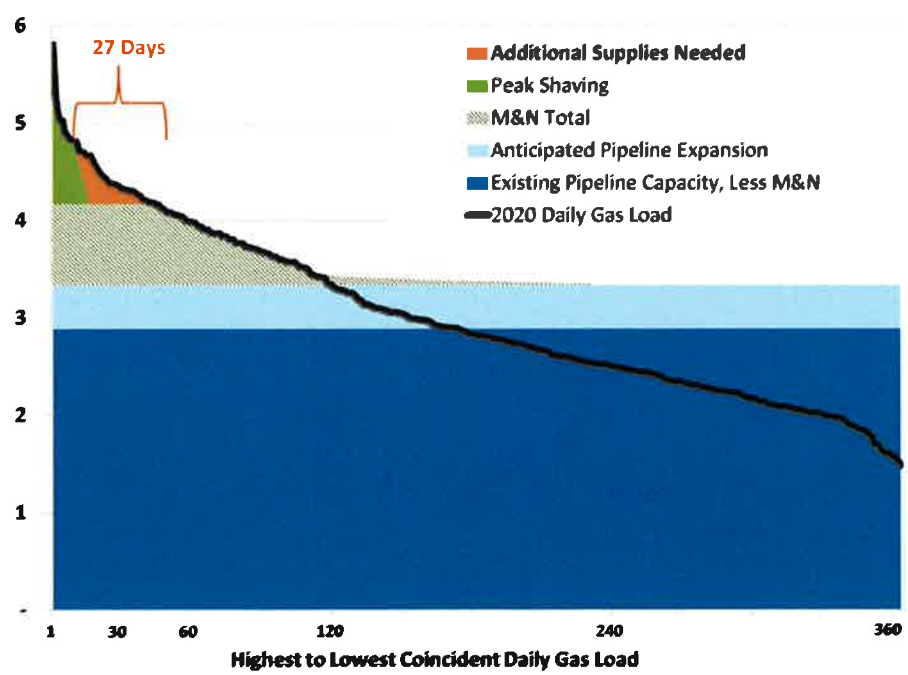



Figure 12. Daily Gas Load in 2020 versus Pipeline Capacity and Peak Shaving, in Bcfd



# 4 Cost of Supply Options to Meet New England's Near- to Mid-term Needs

Section 3 identifies additional pipeline capacity (beyond the incremental 450 MMcfd projected in the ICF Base Case) and LNG imports into Everett as the primary options to meet the need for incremental peak day gas supplies.

Based on recent historical prices, ICF anticipated that additional spot LNG supplies at Distrigas terminal would cost about $14.50 per MMBtu; this estimate is based on a landed cost for the LNG of $14.25 and an additional terminal fee of $0.25. The Distrigas terminal fee is relatively low since it only covers marginal operating costs and does not include any capital recovery. Additional LNG shipments into the Neptune and Northeast Gateway LNG terminals would cost approximately $1 dollar more (around $15.50 per MMBtu) due to the higher charter cost of the specialized tankers required to deliver gas to those buoy-based terminals.

ICF also assessed the option of adding additional oil backup/fuel switching capability (beyond the approximately 6 GW of switchable capacity currently in-place) as a means of reducing incremental gas demand growth, and thereby lessening the need for additional gas supplies. Assuming the price of crude oil is $95 per barrel (similar to recent historical prices), this equates to a distillate fuel oil price of more than $20 per MMBtu, significantly higher than the fuel cost of incremental spot LNG. In addition to the higher cost per MMBtu, adding new oil switching capability would require new oil storage tanks and other modifications at power plants which would further increase the cost. Since oil switching would be more costly than incremental spot LNG supplies, we concentrated the cost comparison analysis on the pipeline option.

To compare the costs of adding incremental pipeline capacity to the cost of spot LNG deliveries, ICF first assessed the cost of building a new pipeline to New England from the Marcellus Shale. Based on a recent survey of pipeline construction costs, ICF estimates the cost of building a new "greenfield" pipeline to New England would be approximately $200,000 per inch-mile.[5] Right-of-way and construction costs in New England are significantly higher than the national average.

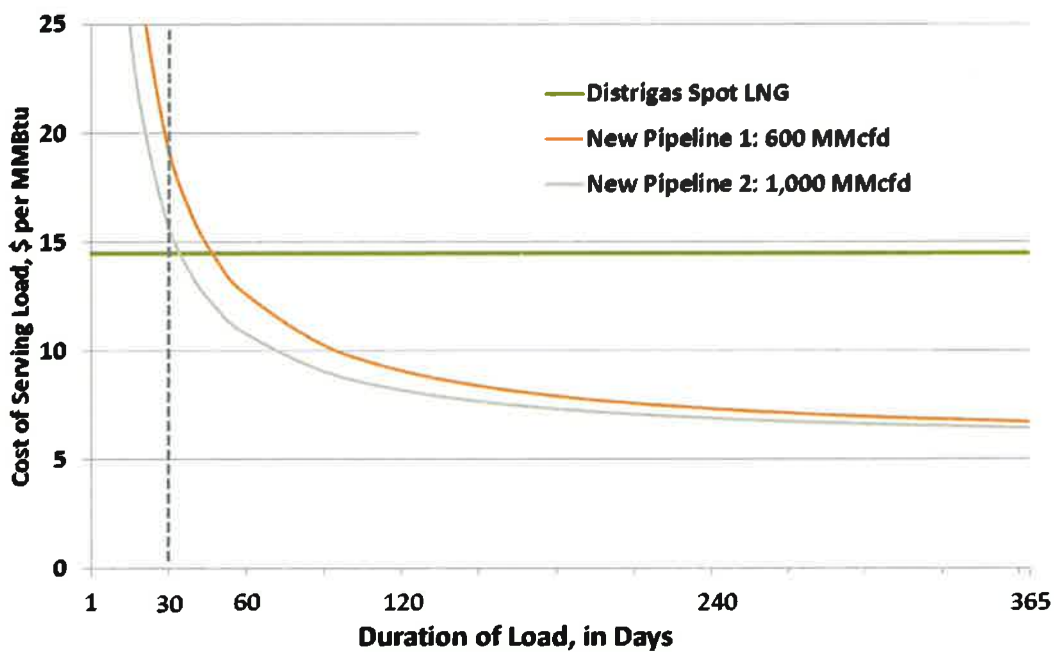
To connect to a liquid trading point within the Marcellus play area would require a pipeline length of about 300 miles. Given economies of scale, the new pipeline's capacity would be between 600 MMcfd (30-inch diameter) and 1,000 MMcfd (36-inch diameter); this range of capacity is similar to proposals for new pipeline capacity to serve New England. Given these potential diameters and the mileage required to connect to Marcellus supplies, the total pipeline costs would be between $1.8 billion (for a 600 MMcfd pipeline) and $2.2 billion (for a 1,000 MMcfd pipeline).

[5] Annual Pipeline Economics Report. Oil & Gas Journal, September 2, 2013.

A new pipeline would have to be fully contracted to be built. This means that shippers on this **hypothetical pipeline would have to contract for the pipeline's full capacity throughout the year** before the Federal Energy Regulatory Commission could approve it. Assuming a capital recovery factor of 14 percent, the annual capital charge would be between $260 and $360 per thousand cubic feet (Mcf) of capacity; fuel charges would add $0.05 per Mcf (assuming fuel use of 1 percent and a gas price of $5 per MMBtu), and other variable operations and maintenance (O&M) costs would add an additional $0.01 per MMBtu.

To create the cost duration curve, the annual capital charge is divided by the number of days the pipeline is used, and added to the variable costs and projected cost of gas (around $5 per MMBtu) to arrive at cost of service curves based on the number of days of load being served. Figure 13 shows the per-unit cost of the service as a function of the number of days the capacity is needed (e.g., the more days over which the load is spread, the lower the per-unit cost). 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 $16 and $20 per MMBtu, significantly higher than the cost of incremental spot LNG shipments.

**Figure 13. Cost Duration Curves: Cost per Day of Serving Incremental Gas Load**



Conclusions and Implications from the Cost Duration Analysis

The existing interstate pipelines serving New England are already fully utilized during peak **demand periods, as are the LDC's peak shaving facilities.** It appears likely that about 450 MMcfd of new pipeline capacity will be added by the end of 2016 to meet LDC incremental demand growth, but even with that additional capacity ICF projects that the New England market will still need additional gas supplies about 30 days per year.

While the proposed incremental expansion of the Algonquin system appears to be moving forward, the new capacity is not likely to be available until late 2016 or early 2017. Even after that expansion, continued market growth will likely result in continued supply constraints on peak winter days.

A new greenfield pipeline from the Marcellus Shale to New England would cost between $1.8 and $2.2 billion; since the incremental supplies are only needed on a limited number of days, the effective cost would be $16 to $20 per MMBtu. Supplies from additional spot LNG shipments are expected to available for between $14 and $15 per MMBtu; **Distrigas' variable operating** costs (exclusive of the LNG itself) are only about $0.25 per MMBtu, so this adds very little to the anticipated cost.

It is typically more cost effective to increase 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. Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution **to meet this portion of New England's gas demand**.

# 5 Summary of Conclusions

- New England currently has a very tight supply/demand balance on about 30 days per year, and demand is projected to grow significantly over the remainder of the decade.
    - Compared to 2013 levels, ICF projects that winter peak day demand will increase by more than 500 MMcfd by 2015 and more than 1,000 MMcfd by 2020, exacerbating the existing gas supply constraints.
    - The projected growth in LDC firm demands justifies some new pipeline capacity. **ICF assumes that Algonquin's AIM expansion will add an incremental 450 MMcfd** of capacity, but it is not expected until late-2016. Even after the AIM expansion, New England will still need incremental gas supplies on about 30 peak winter days a year by 2020.

- New England gas demand is very seasonal, so there will be sufficient supply capability to meet off-peak loads.

- Given that the duration of the expected supply constraint is approximately 30 days per year, incremental LNG imports at Distrigas appear to be the most cost-effective solution.
    - Based on current Atlantic Basin LNG prices, the landed price of LNG at Distrigas is likely to be less than $15 per MMBtu; terminal fees add only about $0.25 per MMBtu. In recent years, Distrigas has been operating well below its rated capacity.
    - While Marcellus-area gas is attractively priced, a new pipeline to connect New England to the Marcellus Shale would cost about $2 billion. Since the additional capacity would have to be fully contracted but needed only about 30 days per year, the per-unit cost of this option is relatively high at $16 to $20 per MMBtu.
- New production from Deep Panuke will increase supplies into the M&N Pipeline, but LNG imports at Canaport would still be needed to fill the pipeline; importing LNG at Distrigas would be a lower cost option.
    - The landed price of spot LNG cargos at Canaport would about the same as at Distrigas, but New England shippers also have to pay the transportation costs on M&N.