Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies

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Key Findings

New England's Independent System Operator (ISO-NE) commissioned ICF to compose a White Paper addressing the impacts of new and existing gas-fired power generation projects in eastern New York located on New England's natural gas supply access routes.[1]

Air emission regulations, low capital costs and better performance factors for gas-fired generation, as well as the increase in competitively priced natural gas supplies available to Northeastern markets has resulted in an increase in regional gas demand, particularly within the power sector. However, New England's gas-fired generators now increasingly compete for gas supplies with a growing number of consumers, including gas-fired generators located in New York. Many of the New York generators are located "upstream" of New England's generators, with electric market commitment schedules that currently provide them a timing advantage in acquiring gas supplies within the daily market.

New England's gas supply access issues have led to significant price volatility and price risk in the region.

During periods of peak gas consumption, generators in New York and New England compete for the available gas supply. For the generators in New England, the nature of this competition can create difficulties in obtaining gas when and where it is needed.

There are three main factors contributing to New England's gas supply access issues, leading to price volatility and increased price risk. These include pipeline infrastructure constraints and differences in interregional gas nomination scheduling. In addition, gas consumption that has not been scheduled and confirmed by gas consumers (such as power generators, LDCs, and industrial gas users), which is often a byproduct of an ISO/RTO generator dispatch timeline extension or schedule overrun, can create operational and reliability challenges for gas pipelines.

This paper highlights the following key findings:

- Increasing supply and low gas prices: The recent North American shale gas revolution has fundamentally changed the flow of natural gas in and around the U.S. Northeast, and has created an environment where natural gas is competitively priced versus other options.
- Increase in gas-fired power generation in the U.S. Northeast: Expansion of gas supply sources for Northeastern markets has led to gas demand increases from the region's gas-fired power producers, particularly in New England and other regional markets such as (eastern) New York.
- New England's gas supply access issues: While New England continues to increase its gas-fired generating capacity, competing gas demand sources, particularly those in eastern New York, will continue to stress the region's pipeline infrastructure, leading to supply access issues in New England.

Three main factors contributing to New England's gas supply access issues are pipeline infrastructure constraints, competing demand sources, and gas consumption that has not been nominated and scheduled by the pipeline.

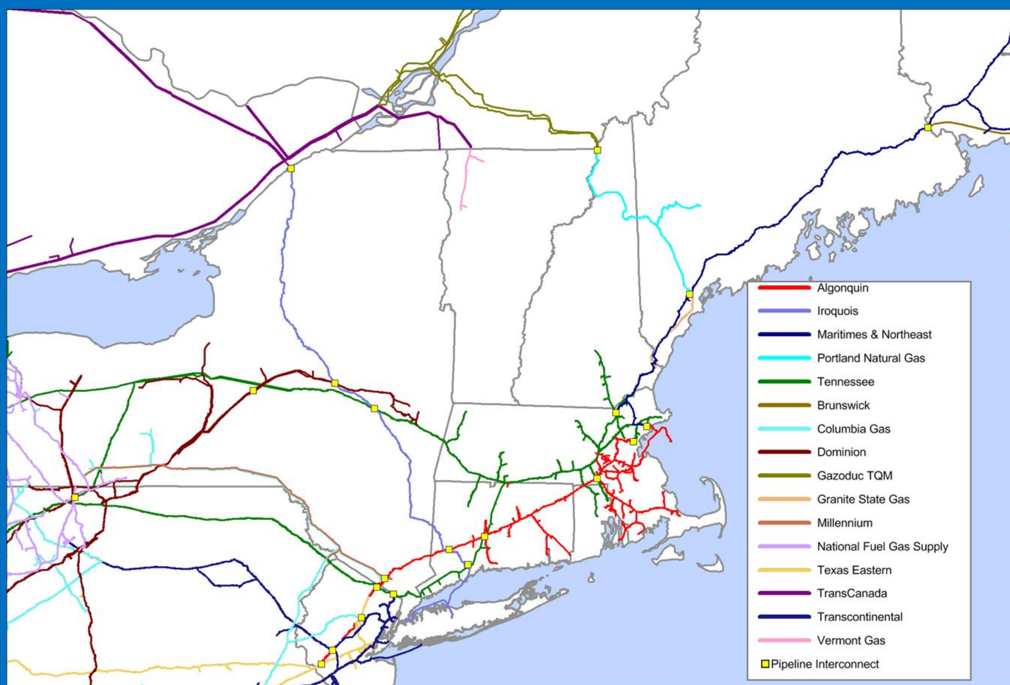
- Main factors affecting New England's gas supply access: Factors contributing to New England's gas supply access include pipeline infrastructure constraints, competing gas demand sources, and inappropriate gas consumption on the part of gas consumers. These factors contribute to the significant natural gas price spreads between New England and the Mid–Atlantic States (including New York).
    - *Pipeline infrastructure constraints:* Increasing New England's pipeline capacity has proven difficult, as pipeline expansions depend on firm capacity contracts, an uneconomic option for most gas-fired generators given the changing nature of gas demands during the year. As a result, pipelines have not expanded to meet the needs of power generators, and the generators have relied primarily on interruptible pipeline service or capacity release contracts rather than firm service contracts. The pipeline constraints, coupled with more stringent U.S. Department

[1] This paper approaches New England's gas supply access issues strictly from the electric utility's perspective, looking only at gas-fired generation and supply access impacts on regional gas-fired generation.

of Transportation (DOT) Pipeline Hazardous Materials Safety Administration (PHMSA) maintenance and inspection requirements, will continue to plague New England's markets, likely leading to persistent gas price volatility.

- *Competing demand sources:* Three of the six pipelines that serve New England - Algonquin, Iroquois, and Tennessee - also provide service to markets in New York. Several eastern New York gas-fired power generators that are located upstream of New England generators but downstream of existing pipeline constraints on the pipelines serving New England, compete for regional gas supply and transportation services along with New England's generators. As a result, physical conditions that influence pipeline deliveries into and within New England will be impacted by gas use by generators and other loads located "upstream" in New York.

New England and Northeast Natural Gas Pipelines



Source: ICF using Ventyx Velocity Suite mapping software

- *A mismatch in scheduling that disadvantages New England generation:* Because of the differences in the wholesale electric market schedules between the New York Independent System Operator (NYISO) and ISO-NE, New England generators learn of their gas requirements after the New York generators have already learned of theirs. As a result, New England generators compete for gas supply and transportation in a less liquid gas market. Likewise, the earlier electric market timing advantage for NYISO allow New York markets earlier access to gas trading. As a result, ISO-NE's gas-fired power generators may not be able to access necessary gas supplies and are exposed to significant gas price volatility, particularly on cold winter days.

- *Occasional events where gas that has not been scheduled and confirmed by the pipeline is consumed*: On any given day, a gas shipper on a pipeline may find itself "out of balance" to some degree for the entire gas day. The pipeline's tariff contains penalty and payment provisions for these types of events. From the perspective of the gas pipelines, however, these tariff provisions are intended to address occasional and unavoidable events. They are not intended to be used as "services" available for use at a shipper's discretion. At the same time, gas-fired generators in New England are under pressure to make competitive power commitments despite uncertainty regarding pipeline deliverability. Thus, there are days when gas-fired generators make gas nominations in excess of their final needs to ensure fuel supplies, contributing to gas price volatility and inefficient use of gas infrastructure.

- To elaborate on this point, if a generator is dispatched more than anticipated over the course of a day, the generator may attempt to continue operation and pay the corresponding charges for an “unauthorized overrun.” Such behavior can create pressure problems at locations downstream of the location. As such, generators in New England can be adversely affected unless the pipeline physically closes the flow control valves to stop the flow of gas to the generator that is taking unauthorized gas. Simply put, the use of unauthorized (gas) volumes could potentially translate to lower pressures all along the pipeline. During peak demand periods on cold winter days, such reduction of pressure can be more problematic. Because New England’s generators are located downstream of New York’s generators, and are already subject to pipeline constraints, they are more exposed to the pressure reductions created by the type of behavior discussed here.

Key Conclusion: While consumers have benefitted from relatively low gas prices, New England is still facing a number of challenges as its reliance on gas-fired power generation continues to grow. New England’s gas supply access continues to be limited by pipeline infrastructure constraints and interregional electric-day issues. Though New England’s power market regulatory environment supports building gas-fired capacity, gas pipeline regulations employed by FERC require firm contract underpinning for new pipeline capacity that is not directly supported with cost recovery in the organized electricity markets in the Northeast. Thus, operational challenges during peak demand periods are likely to persist.

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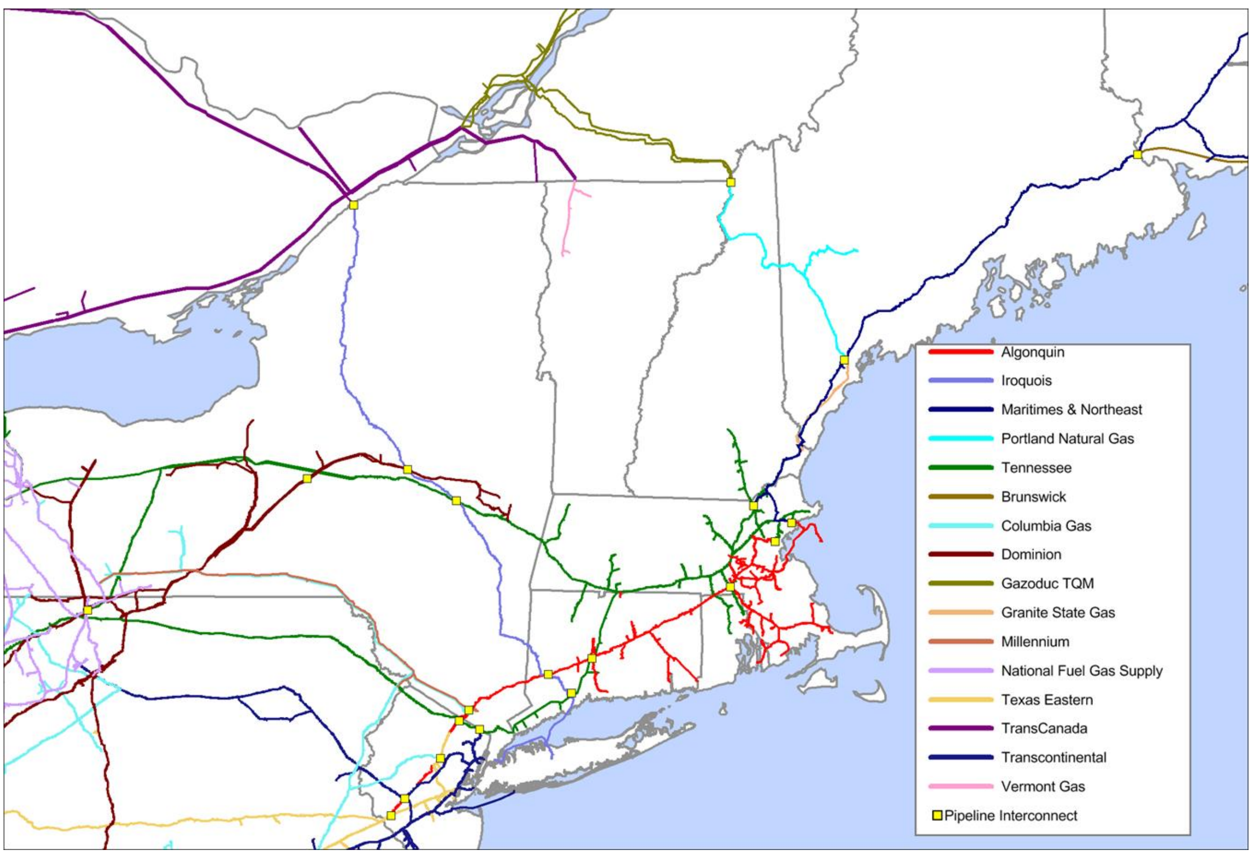
1 Introduction

New England's Independent System Operator (ISO-NE) commissioned ICF to compose a White Paper addressing the impacts that new and existing gas-fired power generation projects in eastern New York can have upon New England's access to gas supplies. These eastern New York generators are located downstream of existing pipeline constraints on the regional pipelines serving New England and directly compete for regional gas supply and transportation services with New England generating units. This paper approaches New England's gas supply access issues strictly from the electric utility's perspective, looking only at gas-fired generation and supply access impacts on regional gas-fired generation.

Expansion of gas supply sources for Northeastern markets has led to demand increases among the region's gas-fired power producers. While New England continues to expand its gas-fired generating capacity, competing demand sources, particularly those in eastern New York, will continue to stress the region's pipeline infrastructure, leading to supply access issues within New England. Exhibit 1-1 shows all interstate and regional natural gas pipelines (including Vermont Gas System) that deliver gas into New England or have upstream connections to New England pipelines. Major interconnections between pipelines are represented by yellow squares.

Exhibit 1-1: New England and Northeast Natural Gas Pipelines



Source: ICF using Ventyx Velocity Suite mapping software

Natural gas is delivered into New England from seven pipelines and one liquefied natural gas (LNG) import terminal, which receive natural gas from four regional gas supply markets.[2] They include the following:

1) *The Maritimes & Northeast Pipeline U.S. (M&N U.S.)* receives natural gas at the border between Maine and New Brunswick, Canada, and can deliver into Maine, New Hampshire, or Massachusetts. At the Baileyville Border interconnect, M&N U.S. can receive offshore Canadian production from Maritimes & Northeast Canada, or imported LNG delivered at Canaport LNG (St. John, New Brunswick) and shipped through the Brunswick Pipeline.
2) *The Portland Natural Gas Transmission System (PNGTS)* receives gas from the Trans Quebec & Maritimes Pipeline (TQM), which receives gas exclusively from the TransCanada Pipeline (TCPL). This gas could ultimately be sourced from pipeline interconnects or underground storage located in Ontario, or traditional flow along the vast TCPL Mainline from western Canada. PNGTS shares joint pipeline facilities with M&N U.S. in Maine, southern New Hampshire, and Massachusetts.
3) *The Tennessee Gas Pipeline Co. (Tennessee)* is a long-haul gas transmission system stretching from the Gulf of Mexico, connecting with more than 20 interstate and regional pipelines, making it a premium carrier into the New England market. Tennessee can access underground storage on the U.S. Gulf Coast and in New York and Pennsylvania. Tennessee also has access to Canadian supplies.
4) *Algonquin Gas Transmission (Algonquin)* is a regional interstate pipeline that receives gas from a number of interconnecting pipelines in New York and New Jersey, with access to natural gas produced in the Marcellus Shale, as well as traditional gas supply sources from the Gulf of Mexico and Canada. Algonquin interconnects with Iroquois Gas Transmission System (Iroquois) in Connecticut, where it currently delivers gas bound for Long Island and New York City (Bronx). Algonquin interconnects with Tennessee, M&N U.S., and PNGTS, where it generally receives gas bound for the New England market it serves. The Algonquin Hub Line pipeline, under Boston harbor, also has the capability of receiving supplies from regas vessels docking at Northeast Gateway or Neptune Deepwater Port LNG terminals.
5) *The Iroquois Gas Transmission System (Iroquois)* was built to receive gas from TCPL near the Ontario/Quebec border and delivers gas into the northeastern United States. Traditionally, Iroquois has supplied Canadian gas to upstate New York consumers and transferred gas to Tennessee and Algonquin through interconnects in New York and Connecticut. Iroquois can also deliver gas to Connecticut consumers before crossing the Long Island Sound to serve loads in New York.
6) *Distrigas in Everett, Massachusetts* can transport regassified LNG directly to end-use consumers, such as the Mystic Generating Station, local gas utility customers, and into the eastern end of Algonquin and Tennessee pipelines.
7) *Vermont Gas* is a state-regulated local gas distribution company (LDC), which receives gas exclusively from TCPL. Vermont Gas does not interconnect with the broader New England pipeline network.
8) *Granite State Gas Transmission*, an additional line into the region, is an interstate pipeline regulated by FERC, which delivers gas from M&N and Portland pipelines into New Hampshire and Maine. The pipeline does not bring gas into New England or receive gas at the Canadian border like the other pipelines listed.

During the last winter, gas pipeline infrastructure constraints complicated the dispatch of generation. The lack of an apparent cost recovery mechanism that would allow merchant generation to contract for firm gas pipeline service has resulted in growth in gas-fired generation capacity in New England and New York without a commensurate increase in gas pipeline capacity. The construction of gas pipeline capacity in the Northeast has been recently supported by *"supply-push"* projects to allow for new gas production from the Marcellus region or by contract support from gas LDCs to primarily meet the needs of residential, commercial, and industrial gas consumers, including those wishing to covert to gas from higher cost petroleum fuels. While the policy issues regarding these conditions and economic incentives are not the

[2] The four primary gas supply sources are Marcellus, WCSB, Eastern Canada, and LNG..???

specific focus of this White Paper, understanding these issues is important to understanding the focus of this document.

This White Paper assesses the impact of new and existing demand sources, located downstream of existing pipeline constraints, and their impacts to the New England markets. In addition, this paper evaluates similar power plants and methods in which they compete for firm and interruptible transportation (IT) capacity and capacity released by firm contact holders (primarily LDCs), as well as impacts to natural gas flowing into New England. This paper also includes a discussion of ramifications to gas flows into and within New England from use of ***unauthorized overruns*** by gas consumers where a gas consumer takes gas in excess of the scheduled volumes either upstream of or within New England, and assesses the conflicting requirements and incentives/disincentives that natural gas-fired generators face as they compete within these electric and gas markets.[3] The paper concludes with a discussion of measures that ensure compliance with established pipeline operating tariffs and applicable independent system operator (ISO) /regional transmission operator (RTO) market and operating rules.

The paper is organized as follows:

- Section 1: Introduction – provides an overview of the White Paper
- Section 2: U.S. Northeast Supply Overview – provides a snapshot of U.S. Northeast natural gas production trends and reviews infrastructure development
- Section 3: U.S. Northeast Demand Overview – provides an overview of key natural gas demand growth areas in the U.S. Northeast, including power generation growth in eastern New York and New England, as well as a discussion of impacts from changes in ISO-NE's nomination schedule and resulting implications for gas–electric reliability issues
- Section 4: Supply Access Implications for New England's Gas-Fired Power Generators – includes a discussion of infrastructure, gas-electric coordination, and other issues affecting New England gas-fired power generators, as well as the ongoing efforts on behalf of regional power generators to secure fuel supplies and incentives/disincentives to ensure compliance
- Section 5: Conclusion – provides a discussion of the key conclusions from this White Paper

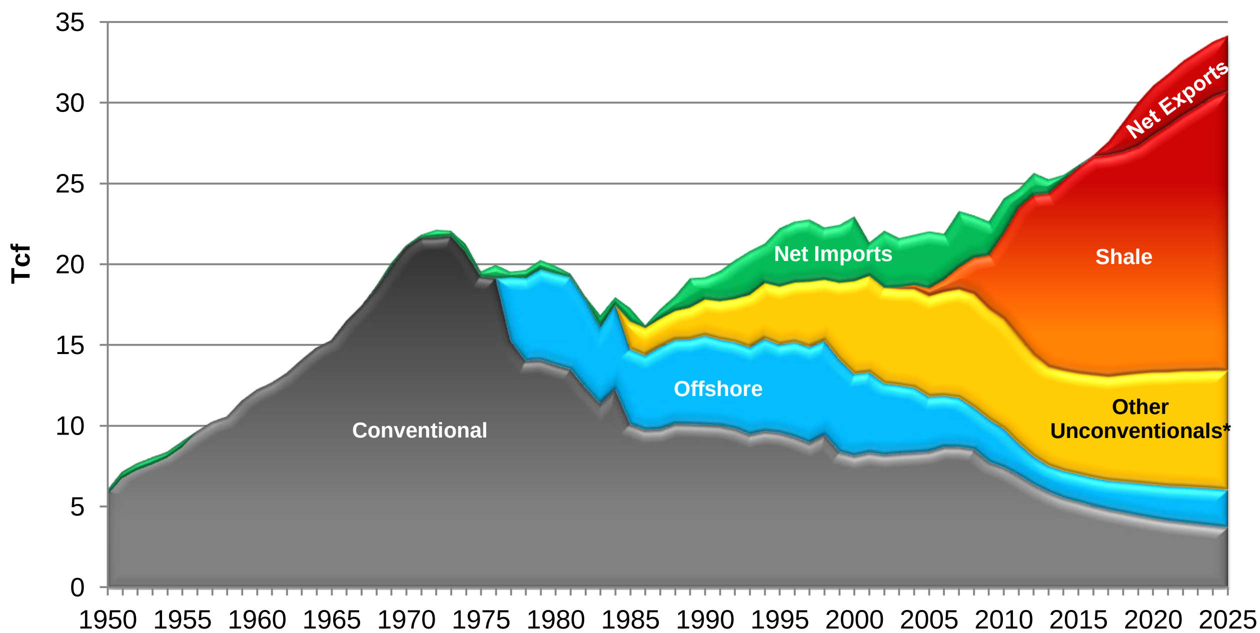
[3] "Bad behaviors refer to inappropriate gas consumption on the part of gas consumers (e.g., gas-fired power generators, LDCs, industrial gas consumers) and the resulting imbalances.

2 U.S. Northeast Supply Overview

2.1 U.S. Natural Gas Supply Trends

Over the past several years, the United States and Canada have experienced a resurgence in natural gas production, attributable to upstream production technologies, including hydraulic fracturing and horizontal drilling. Exhibit 2-1 shows the fundamental shift in natural gas production from declining conventional production to production of unconventional natural gas supplies. The most notable source of unconventional supply is shale gas, although other sources include coalbed methane, tight gas and gas associated with tight oil. The development of these resources has fundamentally changed the nature of North American oil and gas supplies. ICF estimates that annual U.S. natural gas production will grow from 24 trillion cubic feet (Tcf) in 2012 to more than 34 Tcf in 2025, with shale gas production comprising 61 percent of total production in 2025 (up from 41 percent in 2012).

Exhibit 2-1: Historical and Projected U.S. Natural Gas Production and Trade Trends

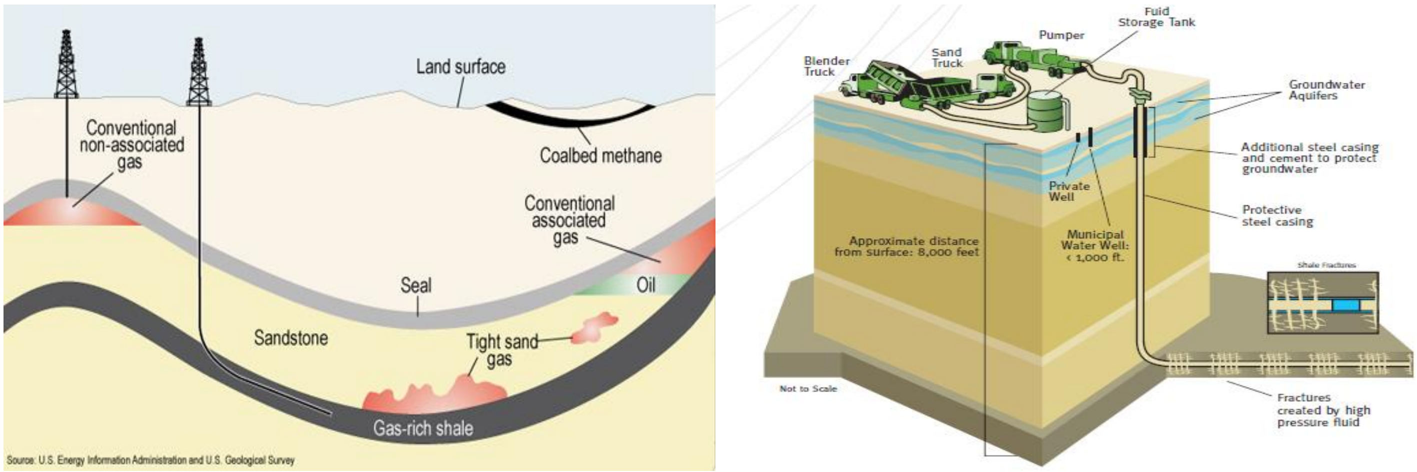


Sources: EIA (1950-1999), ICF Gas Market Model (GMM)® Q2 2013 (2000-2025)

** Includes tight gas, associated gas from tight oil, and coalbed methane*

These technologies together allow producers access to previously uneconomic sources of gas, oil, and other hydrocarbons trapped inside rock thousands of feet below the earth's surface. Exhibit 2-2 shows natural gas resources on the left, including the process of horizontal drilling (used to access a large area of shale gas layers), and on the right, the process of hydraulic fracturing, used to crack open the shale gas layers.

Exhibit 2-2: Natural Gas Resources and Hydraulic Fracturing Process



Sources: U.S. EIA and USGS (left) and Bipartisan Policy Center and American Clean Skies Foundation (right)

According to ICF estimates, the lower 48 States hold nearly 3,600 Tcf in technically recoverable natural gas, the equivalent of 140 years of 2012 U.S. natural gas consumption.[4] Shale gas comprises roughly 55 percent of the lower-48 recoverable gas, at nearly 2,000 Tcf, production of which is attributable to the upstream production technologies mentioned earlier, without which, significant shale gas production would be infeasible.

Exhibit 2-3: U.S. Lower-48 Technically Recoverable Resources

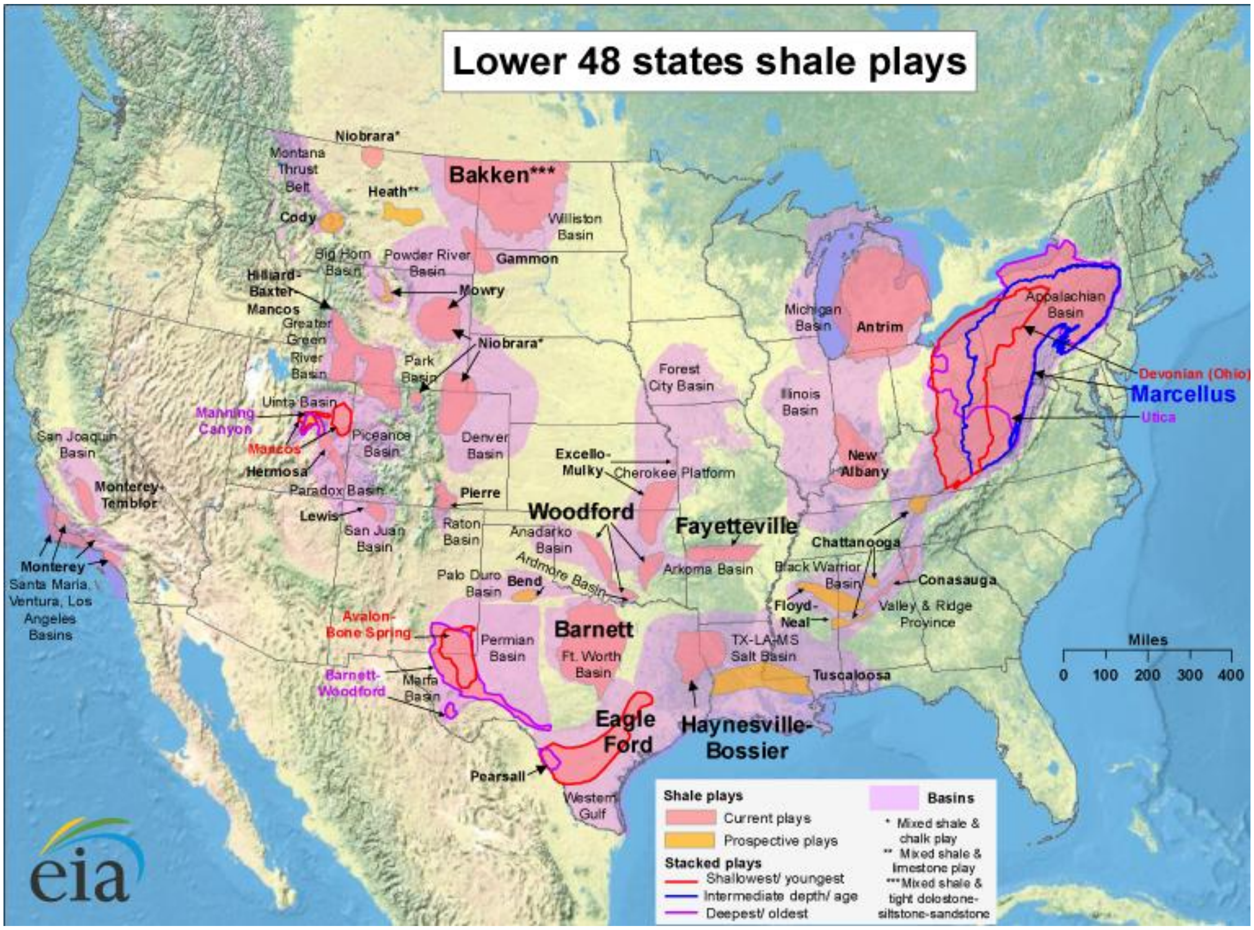
Resource	Dry Total Gas (Tcf)	Crude and Cond. (Bn Bbl)
Conventionals Total	***989***	***154***
Proven reserves	297	21
Reserve appreciation	204	23
Stranded frontier	0	0
Enhanced oil recovery	0	42
New fields	488	68
Unconventionals Total	***2,594***	***71***
Shale gas and condensate	1,964	31
Tight oil	126	36
Tight gas	438	4
Coalbed methane	66	0
Lower-48 Total	**3,583**	**225**

Source: ICF estimates, updated February 2013, proven resources as of 2010

[4] 2012 U.S. natural gas consumption totaled 25.5 Tcf. Energy Information Administration (EIA). "Natural Gas Consumption by End Use." EIA, May 31, 2013: Washington, DC. Available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

As shown in Exhibit 2-4, the United States has shale and other unconventional deposits around the country, with significant resources found in the Marcellus and Utica shales, which are located in the U.S. Northeast (spanning from West Virginia to Pennsylvania, southern New York, and eastern Ohio). ICF estimates that the Marcellus Shale holds 698 Tcf in technically recoverable natural gas; while the smaller and deeper Utica Shale holds 322 Tcf. The Utica Shale, however, is much deeper and covers more subsurface area than the Marcellus Shale. Production from the Marcellus and Utica shales has fundamentally altered the natural gas supply-demand dynamic in the U.S. Northeast.

Exhibit 2-4: U.S. Lower-48 Shale Gas Plays



Source: EIA. "Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays." EIA, July 2011: Washington, DC. Available at: http://www.eia.gov/analysis/studies/usshalegas/

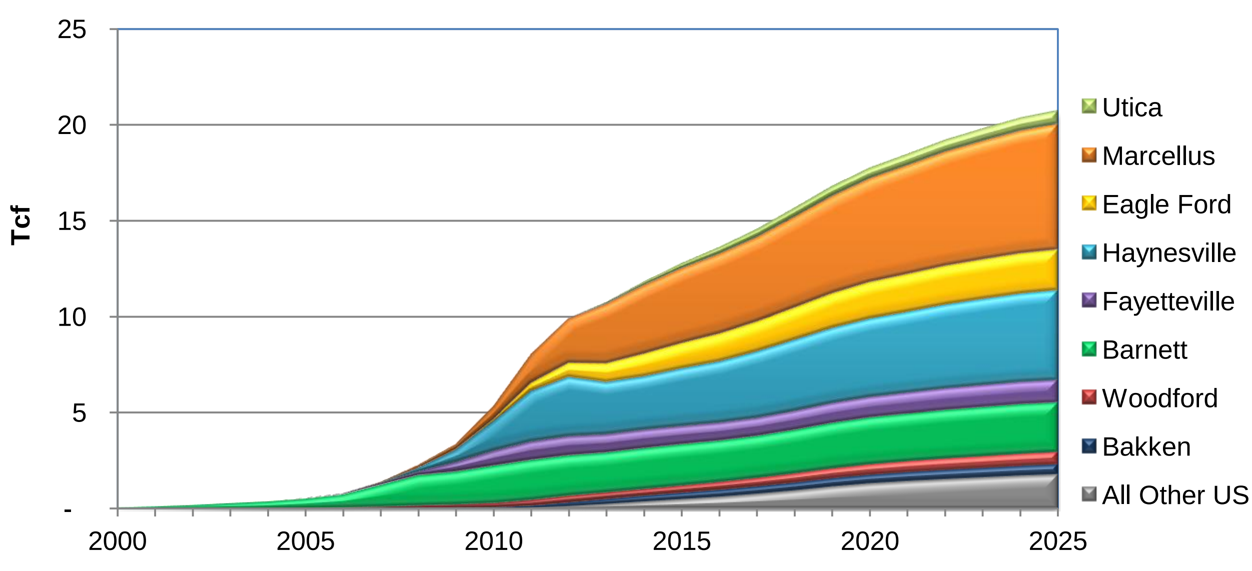
2.2 Marcellus and Utica Development

Natural gas production in the Marcellus Shale has grown significantly since the mid-2000s, with production concentrated in Pennsylvania. Marcellus production has grown from 143 billion cubic feet (Bcf) annually in 2008 to nearly 2.3 Tcf in 2012. Despite relatively weak natural gas prices in 2012, Marcellus gas production continued to grow throughout the year, reaching approximately 8 billion cubic feet per day, or an annualized rate of 2.9 Tcf, by the beginning of 2013.

While uncertainties regarding future production rates of the Marcellus and Utica shales persist, rates continue to trend upward. The Marcellus Shale production is expected to reach 6.5 Tcf by 2025, up from 2.3 Tcf in 2012, indicating an average annual growth rate of 8 percent. The Utica Shale began production in 2011, and is expected to reach 700 Bcf in 2025, up from 14 Bcf in 2012, indicating an average annual growth rate over the period of 35 percent. While the Utica Shale is expected to see significant increases in production over the foreseeable future, production will be dwarfed by large shale plays such as the nearby Marcellus.

The Marcellus shale, and to a lesser extent, the Utica formation, are particularly important to New England and New York because of the close proximity to the region’s demand markets. In fact, the Marcellus formation extends into New York. However, there has not been development of shale gas in New York because of a moratorium on the use of high-volume, multi-stage hydraulic fracturing that makes shale gas production economic. The ICF projection of Marcellus shale production is not contingent upon removal of New York’s ban on hydraulic fracturing (thereby precluding Marcellus and Utica development within the state).

Exhibit 2-5: Projected U.S. Shale Gas Production (Tcf)



Source: ICF Gas Market Model (GMM) Q2 2013

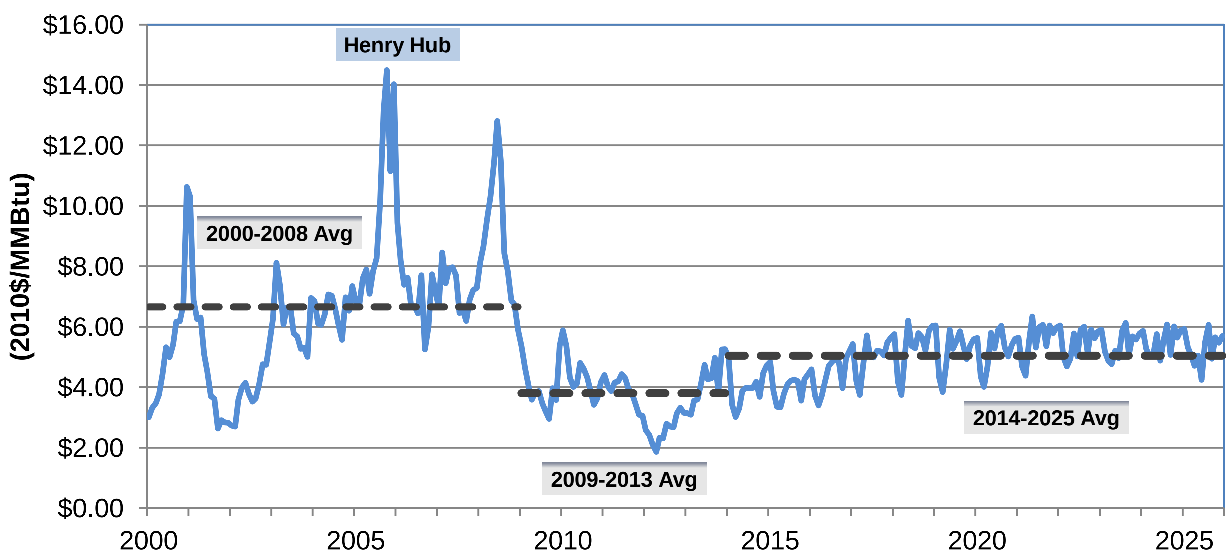
Note: Haynesville production includes production from other formations in the vicinity (e.g., the Bossier sands).

3 U.S. Northeast Demand Overview

3.1 Low Natural Gas Pricing Driving Demand

Expanding unconventional gas production has led to a significant and sustained drop in natural gas prices, a trend expected to continue over the foreseeable future (see Exhibit 3-1). While prices are expected to increase moderately over the next decade, ICF estimates that prices will remain below $5.00 per million British thermal units (MMBtu) through 2016, with much less nationwide price volatility than previously seen over the past decade. As shown in Exhibit 3-1, the early 2000s were characterized by significant natural gas price volatility, attributable in large part to uncertainties in natural gas supplies and weather events. Recent years have seen a historic drop in natural gas prices, as natural gas production has grown 20 percent between 2008 and 2013, and is expected to increase another 40 percent by 2025. Recognizing the long-term potential of this domestic resource, power companies throughout the United States are increasingly turning to gas-fired generation. As demand increases, the recent supply glut continues to dissipate, and gas prices are expected to increase modestly over the next few years, remaining in the $4.00 - $6.00/MMBtu range through 2025.

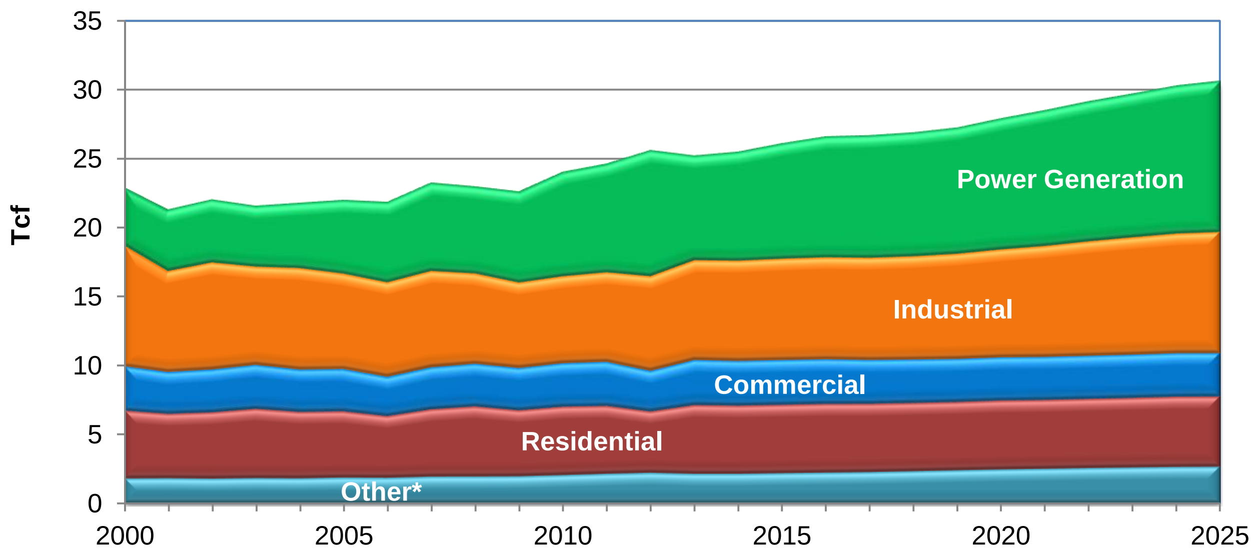
Exhibit 3-1: Monthly Average Natural Gas Prices at Henry Hub



Source: ICF GMM Q2 2013

Low gas prices have led to a renaissance in U.S. industrial manufacturing (particularly petrochemical manufacturing and gas-intensive manufacturing such as ammonia products), as well as significant gas-fired power sector investments and coal-to-gas switching among a number of power producers. As shown in the exhibit below, gas used for power generation is expected to see the fastest growth, comprising nearly 40 percent of total U.S. domestic natural gas consumption within the next 10 years (up from 36 percent in 2012).

Exhibit 3-2: U.S. Domestic Natural Gas Consumption by Sector



Source: ICF GMM Q2 2013

* Includes pipeline fuel and lease & plant (lease & plant refers to natural gas used in drilling operations and as a fuel in processing plants)

3.2 New England Price Volatility

Despite the significant increase in U.S. natural gas supply, infrastructure issues will create volatility in markets such as New England over the near-term. An increasing number of New England power generators are turning to gas-fired power generation, highlighting the need to ensure unfettered access from the Marcellus and Utica shales.

Exhibit 3-3 highlights the expected volatility in New England through 2025, as New England is anticipated to see larger natural gas price swings than at Henry Hub, which is the main natural gas hub in the U.S.[5] The price swings shown in the New England prices (during the winter months) illustrate the infrastructure constraints on New England's markets for the next few years as additional infrastructure is constructed to meet changing supply-demand trends. The dotted gray lines on the Exhibit indicate the average New England price premium over Henry Hub. While New England's price premium averaged $0.98/MMBtu between 2000 and 2008, the region's recent infrastructure issues are reflected in the much higher premium currently seen, estimated to average annual $1.38/MMBtu over 2009 to 2013[6]. While improved supply access over the long-term will mean lower volatility, the precarious nature of the region's current

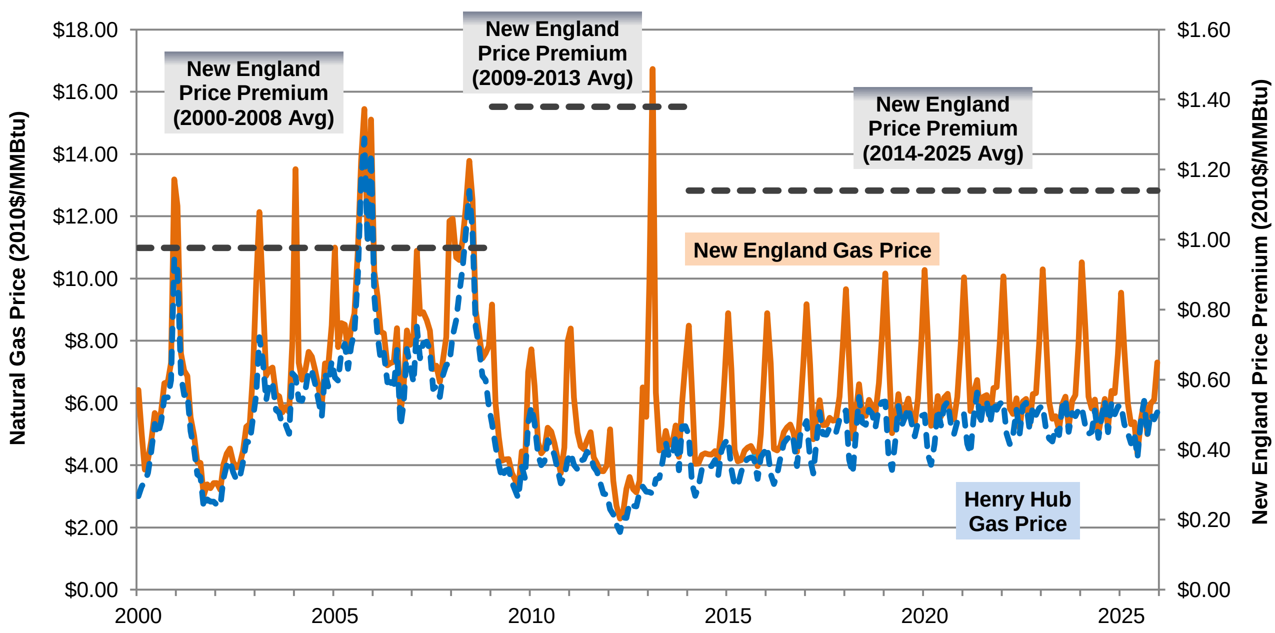
[5] ICF GMM Q2 2013.

[6] The annual premium is driven largely by a small number of days where the premium exceeds $12.00 per MMBtu averaged with a large number of days where the premium is less than $0.70 per MMBtu.

gas supply issues will mean higher price premiums than historically, averaging $1.14/MMBtu between 2014 and 2025.

While New England has seen prices drop over recent years reflecting Henry Hub pricing trends, 2013 in New England began with price spikes attributable to a combination of infrastructure-related factors. First, extremely cold weather on certain days during January and February 2013 meant pipelines into New England from the Mid-Atlantic and Central Canada (e.g., Algonquin, Iroquois, PNGTS, and Tennessee) were operating at or near full capacity with little flexibility to alter shipping to accommodate additional gas demands.[7] Second, offshore Nova Scotia natural gas production (declining over the past two years) from SOEP[8] was at the lowest gas production level in the project's 13 year history. While the completion of the Deep Panuke project will provide some additional supply, it will not be sufficient to fill the M&N U.S. While Canaport LNG (St. John, New Brunswick) recorded the highest gas send-outs since January/February of 2011, the M&N U.S. pipeline gas flowed well below capacity.[9] Third, cold weather in Europe may have bid away LNG that might have come to New England at the Everett, Massachusetts LNG terminal. LNG imports into Everett were at their lowest levels during January and February 2013, with no cargos imported under short-term or spot provisions, compared with five such cargos during the same period in 2012. While firm cargos to Everett arrived from Trinidad & Tobago as expected, cargos from Yemen have not come to New England in 2013 with the same frequency as seen in previous years, in part due to terrorist attacks on Yemeni gas gathering facilities.[10] New England is expected to see continued pricing volatility due primarily to persistent pipeline infrastructure constraints.

Exhibit 3-3: Monthly Average Natural Gas Prices at Henry Hub and in New England



Source: ICF GMM Q2 2013

Note: The projected prices likely understate the impact of price spikes that occur during particularly cold days

[7] LCI Energy Insight databases compiled from regional pipeline informational postings.

[8] Sable Offshore Energy Project (SOEP) monthly production reports.

[9] LCI Energy Insight databases compiled from regional pipeline informational postings.

[10] LNG import/exports shipments data compiled by DOE Office of Fossil Energy.

3.3 U.S. Northeast Power Sector Gas Consumption Trends

Power producers in the U.S. Northeast have increasingly turned to gas-fired generation, given the sustained increase in supply and strict air regulations, coupled with the projected low, long-term prices. Despite the unprecedented growth in gas supplies available to Northeastern markets, pipeline capacity into the region remains insufficient, as gas-fired generation continues to grow.

Power generation using natural gas in New England has grown from about 100,000 GWh per year pre-2010 to about 125,000 GWh per year in 2011 and 2012. This growth has primarily come about from power generators switching from using coal and petroleum to lower priced natural gas. The exhibit below shows monthly generation by fuel type for New England since 2005. Gas generation growth in New England has been modest compared to the growth exhibited in the Mid-Atlantic region

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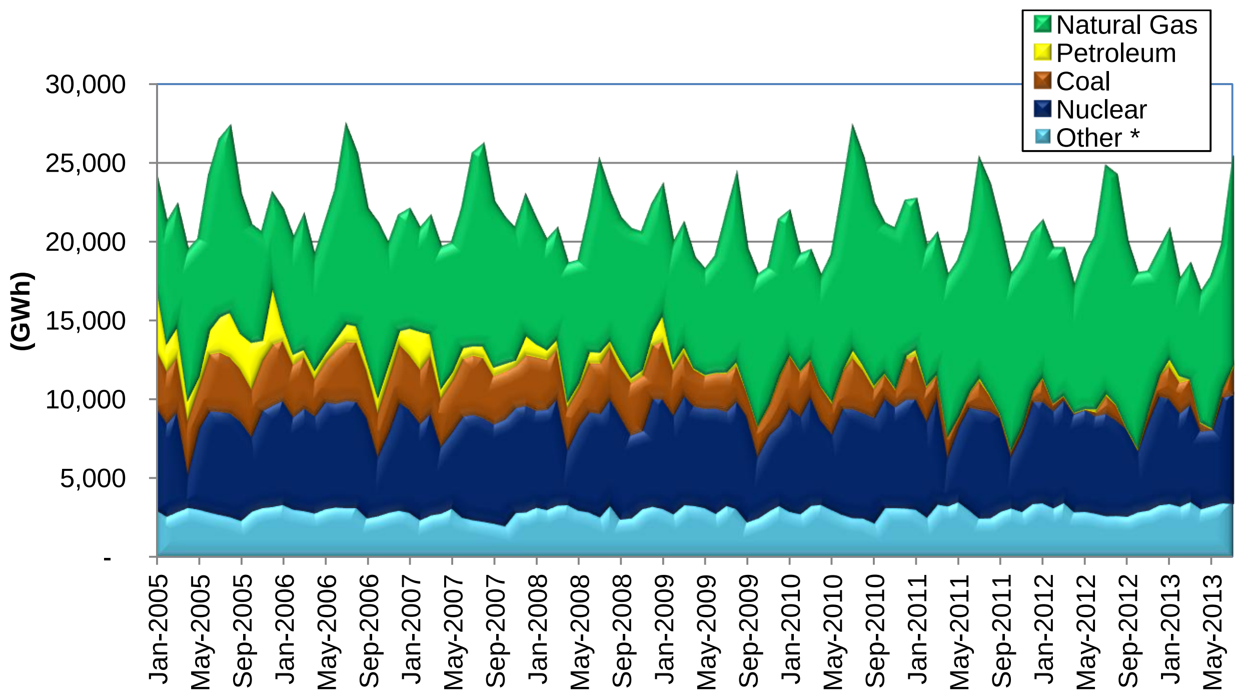
Exhibit 3-4: New England Generation by Fuel Source (GWh)

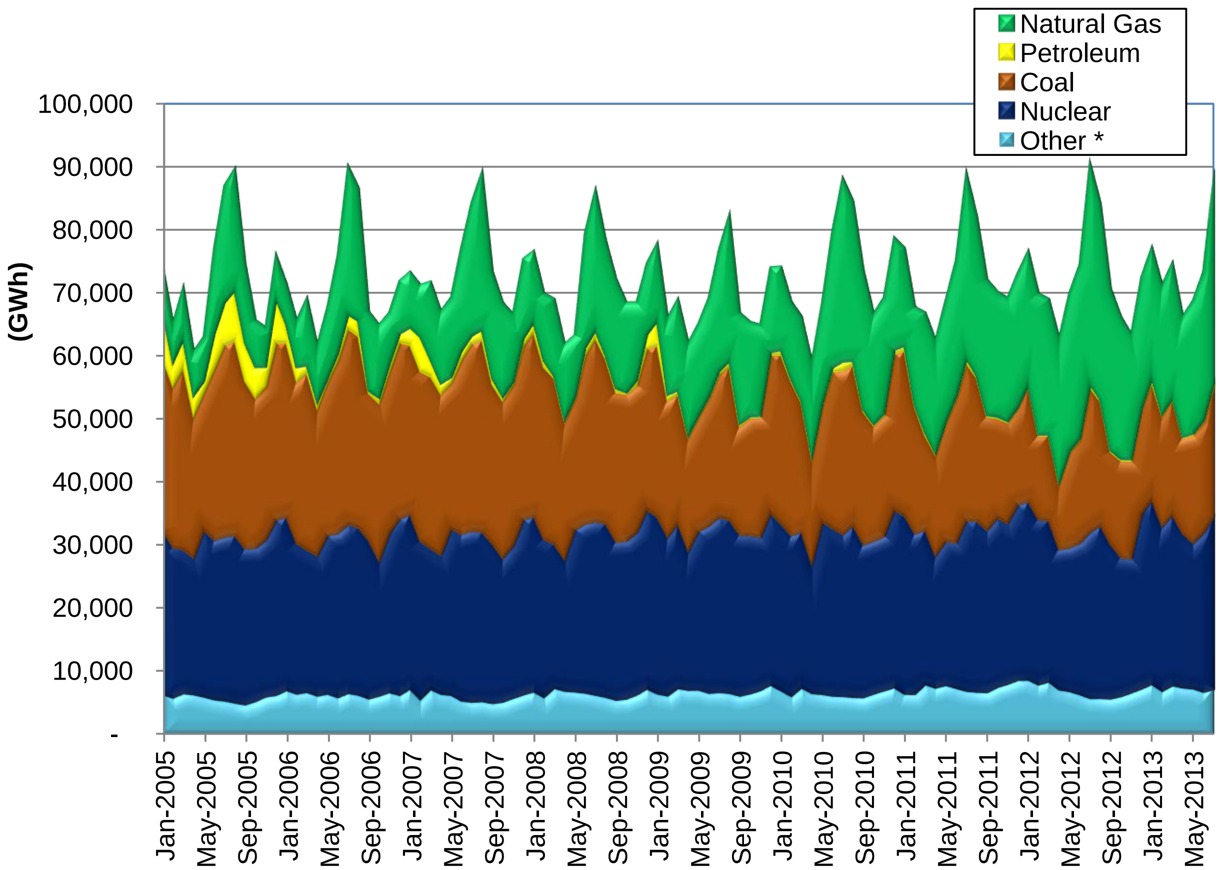


Source: EIA Forms 905, 920, and 923.

‘ Other generation includes Biomass, Hydroelectric, Solar, Wind and other renewable generation,*

The exhibit below shows monthly generation by fuel type for the Mid-Atlantic region.[11] Power generation from natural gas more than doubled in the Mid-Atlantic from about 120,000 GWh per year in 2005 to 295,000 GWh in 2012, or approximately 14 percent growth per year. From 2005 to 2012, Mid-Atlantic gas generation grew by 175,000 GWh per year, including 56,000 GWh in the state of New York. Much of the growth in the Mid-Atlantic region can be attributed to the addition of new - and more efficient - gas generation plants, along with the development of large amounts of Marcellus shale gas within the region.

Exhibit 3-5: Mid-Atlantic Generation by Fuel Source (GWh)



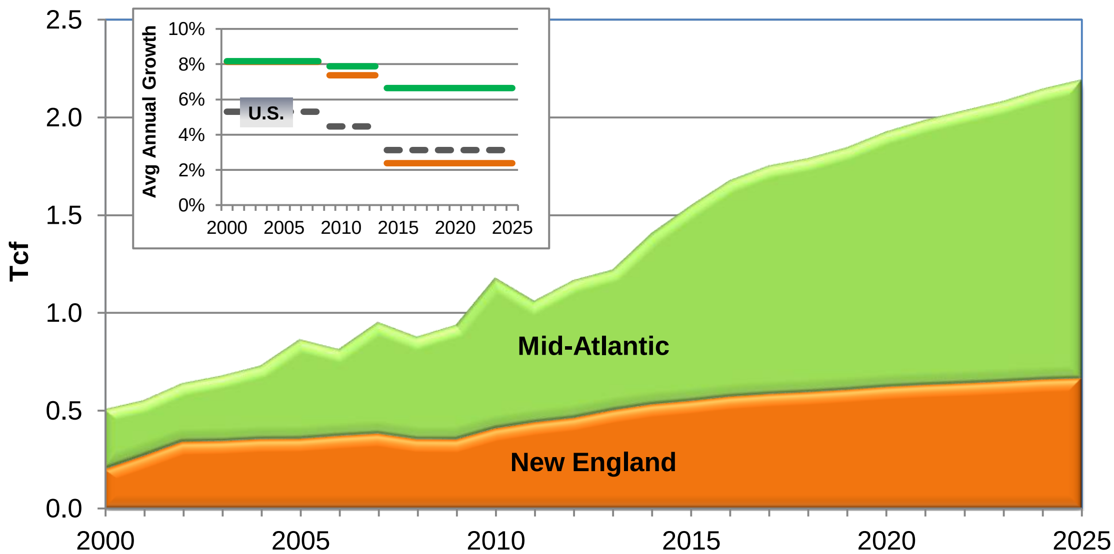
Source: EIA Forms 905, 920, and 923.

' Other generation includes Biomass, Hydroelectric, Solar, Wind and other renewable generation,*

[11] Mid-Atlantic region includes New York, New Jersey, Pennsylvania, and Delaware.

Exhibit 3-6 shows historical and projected power sector gas demand for New England and the Mid-Atlantic regions. Mid-Atlantic power sector gas demand was significantly larger than that of New England in 2012, exceeding 750 Bcf, relative to 460 Bcf for New England. Mid-Atlantic power sector gas demands will more than double that of New England by 2025. This indicates that competition for the regional gas supplies will intensify; meaning continued pricing uncertainty and volatility.

Exhibit 3-6: Power Sector Gas Consumption for New England and the Mid-Atlantic



Source: ICF GMM Q2 2013

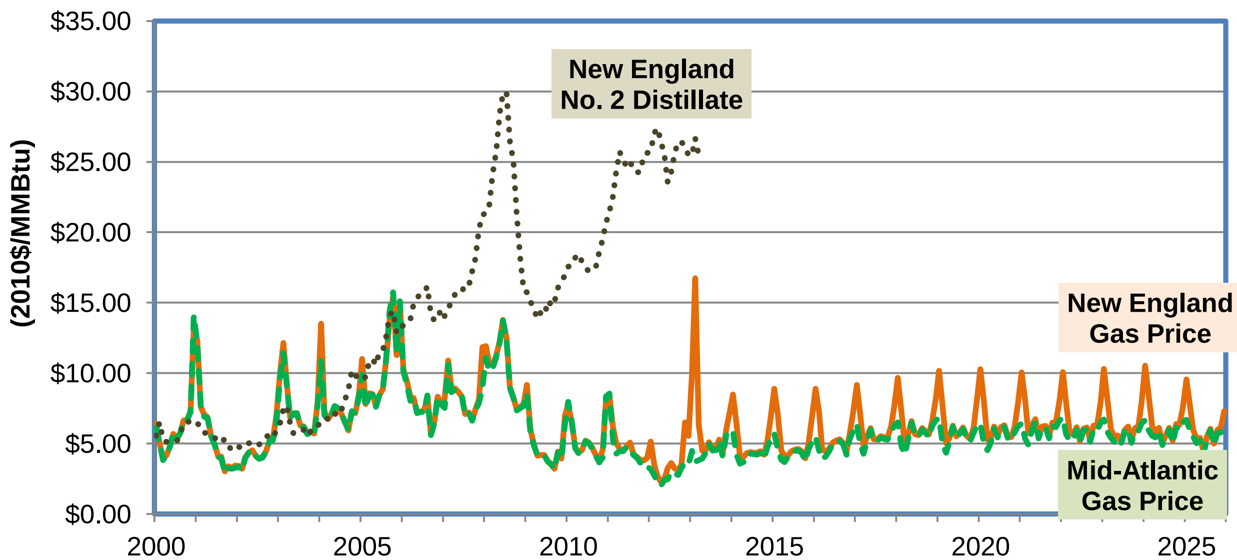
Note: Average annual growth averages over 2000-2008, 2009-2013, and 2014-2025 periods for the Mid-Atlantic, New England, and the United States.

Although New England has several interstate pipelines carrying gas into the region, the region cannot simultaneously meet the wintertime gas requirements of LDCs and all its gas-fired generators. Compounding these issues is competition from eastern New York and other regions, which will continue putting upward pressure on regional prices in an effort to draw gas into New England during peak periods. Given the structure of ISO-NE's electric market, New England power generators on peak or constrained days have paid up to $75/MMBtu, creating pricing uncertainties, despite the nationwide drop in natural gas prices.[12]

[12] Hederman, William. "Investigation of New England Gas-Electric Market Events, January 13-16, 2004." The Federal Energy Regulatory Commission (FERC), presented to the New England Conference of Public Utilities Commissioners, May 2004: Brewster, MA.

While several eastern New York gas-fired power producers have dual-fuel capabilities, and are able to draw upon natural gas or distillate fuels, New England's gas-fired power producers are typically single-fuel operators. As explained later in **Section 3.5**, New York power producers operate within the jurisdiction of the NYISO. Under the NYISO, power producers must submit fuel needs by 4 a.m., whereas, as of May 2013, New England's producers submit fuel needs by 10 a.m.[13] This alternate schedule indicates that although New York gas-fired generators have dual-fuel capabilities, New York producers will elect for significantly cheaper natural gas supplies, relative to recent distillate prices (see Exhibit 3-7). In times of extreme weather or heavy usage, this means that New England gas-fired producers cannot access needed gas supplies, as New York power producers have already made their gas supply purchases and transportation nominations. As shown in Exhibit 3-7, these factors contribute to the significant natural gas price spreads anticipated between New England and Mid-Atlantic gas markets.

Exhibit 3-7: Monthly Average Natural Gas Prices at Henry Hub and in New England



Source: Natural gas prices: GMM Q2 2013, Distillate No. 2: EIA. "New England (PADD 1A) No. 2 Distillate Retail Sales by Refiners." EIA, June 3, 2013: Washington, DC. Available at: *http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMA_EPD2_PTG_R1X_DPG&f=M*

[13] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

3.4 Gas Nomination Schedules and Impact on Gas-Fired Power Generators

3.4.1 Natural Gas Pipeline Service Contracts

Firm service contracts are the foundation for natural gas pipeline development and construction. In order to obtain the Certificate of Public Convenience and Necessity, which is required to construct gas pipeline facilities in interstate commerce, the Federal Energy Regulatory Commission (FERC) requires that a pipeline demonstrate the "market need" through binding precedent agreements that commit to firm service contracts for ten years or more for the new capacity.[14,15,16,17] As a result, pipelines do not and cannot build new capacity to meet the needs of customers (e.g. power generators) that rely on interruptible pipeline service or capacity that is released by firm shippers when not otherwise required.

That said, under normal operating conditions during much of the year when gas LDC capacity used to serve peak heating load is not fully utilized, pipelines have some level of unused capacity that can be sold as IT or sold by the firm capacity holders within the capacity release market. On constrained pipelines, such as Algonquin, there has been little or no capacity available as IT, and the only way in which a generator that has no firm capacity can receive gas is with released capacity or capacity that is obtained by a natural gas marketer.

When pipeline capacity is obtained, the generator (or the marketer obtaining gas for the generator) is required to nominate gas utilizing the standardized NAESB procedures for nomination, confirmation, and scheduling. In order to comply with FERC regulations, the nomination and confirmation must be communicated to the pipeline within the nomination cycle timelines that are in the pipeline's tariff that is approved by FERC.

3.4.2 Power Sector Gas Nomination Procedures

Within the electric sector, power generators serve hourly system needs, with some generation units reserved for satisfying peak demands. Firm gas transportation services purchased under fixed fees (i.e., do not vary by volumes delivered and do not provide daily usage rates) are expensive and not always necessary. In markets where excess pipeline capacity is available, interruptible service is often used. In the U.S. Northeast, however, pipelines currently operate at or near capacity, leaving little leeway for interruptible gas service. Gas-fired generation capacity in CC/CT units in the U.S. Northeast[18] represents 35 percent of installed capacity in 2012, and is projected to grow to 42 percent by 2025. Total CC/CT capacity will grow from 55 GW in 2012 to 94 GW in 2025, or approximately 4.3 percent per year, according to ICF estimates.

[14] FERC. "Order Clarifying Statement of Policy," docket no. PL-99-3-000. FERC, September 15, 1999: Washington, DC.

[15] FERC. "Order Clarifying Statement of Policy," docket no. PL 99-3-001. FERC, February 9, 2000: Washington, DC.

[16] FERC. "Order Further Clarifying Statement of Policy," docket no. PL 99-3-002. FERC, July 28, 2000: Washington, DC.

[17] FERC. "Statement of Policy on Maximizing the Quality, Objectivity, Utility, and Integrity of Disseminated Information and Request for Comments," docket no. PL 02-3-000. FERC, April 30, 2002: Washington, DC.

[18] The U.S. Northeast includes all New England States and coastal States down to MD and Washington, DC.

The increasing role that natural gas plays in power markets throughout the U.S. Northeast highlights the pressing gas-electric integration issues, including the following:

1) How do the various timelines for the gas pipelines, gas LDC nominations, and power market timelines mesh?
2) Can gas pipeline nomination schedules better accommodate gas demands to improve infrastructure utilization?
3) How and when do generators communicate whether or not they have successfully obtained the appropriate level of gas supply needed to operate when dispatched by the ISO/RTO?

As gas-fired power generation is expected to see significant growth over the next couple of decades, improving coordination between natural gas pipelines and electricity markets is key to ensuring power reliability and managing price risks. While "Electric-Days" throughout North America vary, natural gas pipelines throughout North America operate on a single "Gas-Day" to ensure standard gas transportation across multiple pipelines in the path to serve the ultimate gas consumer.

3.4.3 Gas-Day versus Electric-Day Schedules

Gas-Day Schedules

The Gas-Day, as dictated by regulations established by the North American Energy Standards Board (NAESB) and FERC, begins at 10 a.m. Eastern Standard Time. The Gas-Day is divided into four default cycles per day, with each cycle including three steps:[19]

- Nomination: A process in which firm capacity holders or shippers request a certain volume of pipeline service for the next cycle or the next gas day. Primary firm service is scheduled first, followed by secondary firm. Interruptible capacity is schedule last. If there is insufficient capacity to meet all service requests in the priority categories, service will be met on a *pro-rata* basis for lowest priority categories. Thus, a pipeline may schedule interruptible service on one portion of the pipeline (where capacity is allocated on a *pro-rata* basis), while requesting secondary firm capacity on other segments of the pipeline.
- Confirmation: Confirmation from the producer selling the gas to the shipper that the gas will be delivered into the pipeline at the designated receipt point.
- Scheduling: Communication to the shippers that the scheduled gas volumes can be removed at the designated delivery point.

While electricity supply and demand happens instantaneously, natural gas typically moves through a pipeline at a maximum speed of 30 miles per hour. To further complicate gas delivery, pressure must be maintained at all times to ensure reliable service. Thus, a shipper will remove gas at the delivery point at the same time as gas is delivered to the pipeline receipt point (up to 1,000 miles upstream). The nomination, confirmation, and scheduling steps are crucial to ensure reliable pipeline operation and pressure maintenance. Exhibit 3-8 shows the standard NAESB timeline (in Eastern Standard Time) for the three steps described above.

[19] NAESB. "NAESB Governance Documents." NAESB, 2013: Houston, TX. Available at: http://www.naesb.org/materials/gov.asp

Exhibit 3-8: Pipeline Nomination Cycles (EST)

Nomination Cycle	Nomination Deadline	Third-Party Confirmation Deadline	Pipeline Scheduled Quantity Deadline	Flow Time
Timely *(Cycle 1)*	12:30 p.m. *(day before gas flows)*	4:30 p.m. *(day before gas flows)*	5:30 p.m. *(day before gas flows)*	10 a.m. *(next day)*
Evening *(Cycle 2)*	7 p.m. *(day before gas flows)*	10 p.m. *(day before gas flows)*	11 p.m. *(day before gas flows)*	10 a.m. *(next day)*
Intraday 1 *(Cycle 3)*	11 a.m. *(Gas Day)*	2 p.m. *(Gas Day)*	3 p.m. *(Gas Day)*	6 p.m. *(same day)*
Intraday 2 *(No Bump - Cycle 4)*	6 p.m. *(Gas Day)*	9 p.m. *(Gas Day)*	10 p.m. *(Gas Day)*	10 p.m. *(same day)*

Source: NAESB

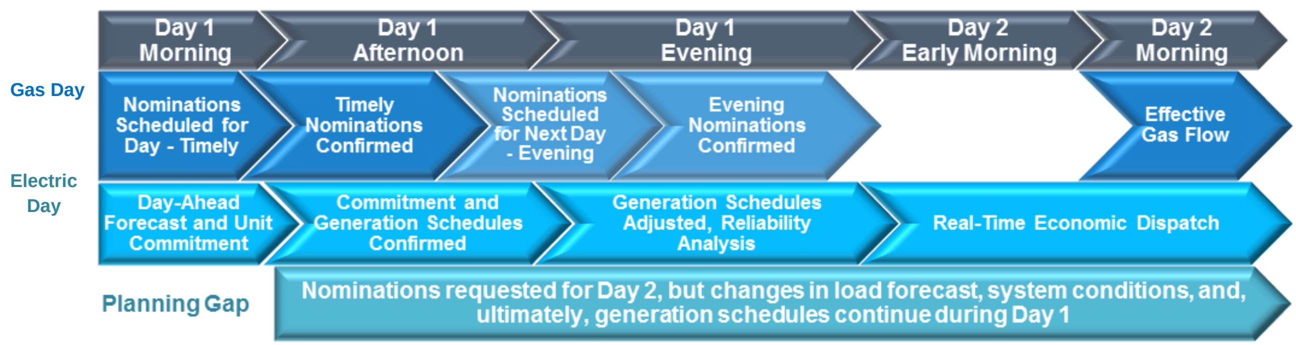
The NAESB timeline dictates to the pipeline the minimum number of nomination “windows” that all pipelines must offer. Each individual pipeline, however, can offer additional nomination windows. For example, Tennessee and Algonquin both offer gas shippers additional opportunities to nominate different levels of service. The fact that the pipeline is offering additional nomination cycles can only assist a generator if: 1) there is capacity available that has not been previously scheduled; and 2) if there is gas supply available at the pipeline receipt point that supports the nomination.

This last point is extremely important and will be discussed in depth later in this White Paper. The liquidity in the gas commodity market is largely concentrated prior to and around the timely nomination cycle. Even if the pipeline may have some ability to reallocate capacity in other periods, a generator may not be able to find “intraday” gas supplies to utilize such capacity. Moreover, the lack of liquidity is likely to make the purchase of any gas supply that may be available more expensive and less predictable.

Gas nominations are initially made based on fuel requirements for individual utilities for the next day. However, there is a significant gap between utilities' estimated fuel needs and actual gas nominations, meaning that while utilities' fuel needs may change significantly due to weather or other unforeseen events, gas nominations are already locked in. In addition, given that gas nominations are based on individual customers' fuel needs, rather than the ISOs/RTOs final electric day plan, gas nominations can differ considerably from actual gas requirements. This is particularly true given that individual utilities will often overestimate fuel needs, rather than risk imbalance penalties.[20]

Exhibit 3-9 shows the general steps for Gas-Days, relative to that for Electric-Days. It highlights the scheduling gaps between the two in that gas nominations are finalized for the next day earlier than final plans for the electric day. Note that Electric-Day timing differs by ISO/RTO region, though all follow the same general steps.

Exhibit 3-9: Description of the Interaction of Gas-Day and Electric-Day Scheduling Cycles



Source: North American Electric Reliability Corporate (NERC).“2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States.” p. 98. NERC, December 2011: Washington, DC. Available at: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

3.4.4 Changes in ISO-NE's Electric Nomination Schedule and Impacts on Regional Gas Markets

Over the past several years, gas-electric coordination has become a key focus to ensure electric and gas system reliability. A 2004 jump in gas and electricity prices brought on by extreme winter weather in New England precipitated FERC Order 698, which began to address gas-electric interdependence issues, improving communication between gas pipelines and power markets and allowing gas shippers greater procurement flexibility.[21, 22]

[20] North American Electric Reliability Corporate (NERC). "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States." p. 98. NERC, December 2011: Washington, DC. Available at: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf

[21] FERC (2012). Standards for Business Practices of Interstate Natural Gas Pipelines. 18 CFR Part 284. Docket No. RM96-1-037; Order No. 587-V. Available at www.ferc.gov/whats-new/comm-meet/2012/071912/G-1.pdf

[22] NAESB. "Order 698 Effort." NAESB, September 10, 2007: Houston, TX. Available at: www.naesb.org/pdf3/update091207w5.doc

New England's gas-electric coordination has become a key issue for the region's power market participants, given the ever increasing role natural gas plays in electricity production. In an effort to address these issues, in February 2013, ISO-NE and the New England Power Pool (NEPOOL) each submitted proposed electric day changes to FERC to move the power market's day-ahead schedule earlier, allowing for earlier gas procurement (i.e., facilitating increased reliance on gas-fired generation during times of low pipeline capacity).[23]

The NEPOOL proposal moved the day-head bidding window deadline to 10 a.m., with the market clearing at 1:30 p.m. It also proposed completing the initial Reserve Adequacy Analysis (RAA) process by 5 p.m.[24] The ISO-NE proposal would have moved the bidding window deadline to 9 a.m., with market clearing at 12:30 p.m. and completion of the initial RAA by 4 p.m. to allow for earlier gas procurement.[25]

According to ISO-NE, market participants are already working early in the morning to assess gas pricing, volumes, and market dynamics that affect the day-ahead market and these participants will adjust to the 9 a.m. bidding timeline without subjecting the market to significant risks. For example, the NYISO day-ahead bidding currently closes at 5 a.m.

NEPOOL argued that closing the bidding at 9 a.m. (as ISO-NE suggested) could lead to larger challenges in coordinating gas-electric markets, leading to market inefficiencies. NEPOOL stated that the ISO-NE proposal moves the deadline too early in the day, requiring gas-fired generators to make day-ahead offers on very limited information, increasing price risk significantly (due to lack of market liquidity). It asserted that load servers would be in a riskier position, because the larger differences between the cleared day-ahead loads and actual loads would mean greater financial variance between the day-ahead market and the real-time market. According to NEPOOL, the next-day trading in northeastern gas markets generally starts between 8:30 and 8:45 a.m., rather than 7 a.m., as ISO-NE asserted, with greatest liquidity occurring between 9:00 and 10:30 a.m. NEPOOL further argued that if gas markets had liquidity at 9 a.m., day-ahead bidders cannot fully capitalize on limited information, as gas market participants usually need at least 30 to 60 minutes to complete and verify trades and accurately submit them into the ISO-NE market system.[26]

NEPOOL stated that the additional hour in the morning allotted for in its proposal will allow gas-fired generators to provide more price information during a key part of the gas trading day. NEPOOL stressed that its proposal enables gas-fired units to benefit from both transparency and price discovery for day-ahead bidding, while the earlier timing of the ISO-NE proposal would lead to illiquid natural gas markets, meaning higher risk premiums which would subsequently translate into higher energy prices.[27]

In April 2013, FERC announced that it had chosen the NEPOOL proposal over ISO-NE's. FERC stated that it chose the NEPOOL proposal because the benefits of moving the market closing up one hour outweighed the market inefficiencies associated with the earlier submission times required for the day-ahead market. According to FERC, under ISO-NE's earlier timeline, gas-fired generators may add risk premiums to day-ahead bids, leading to inefficient in market-clearing and erroneous price signaling. The new day-ahead energy market schedule became

[23] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

[24] Marsh, Rachael. "Changes in ISO-NE's Day-Ahead Energy Market Schedule To Take Effect Next Week." Bracewell & Giuliani, May 16, 2013. Available at: http://www.energylegalblog.com/archives/2013/05/16/4571

[25] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

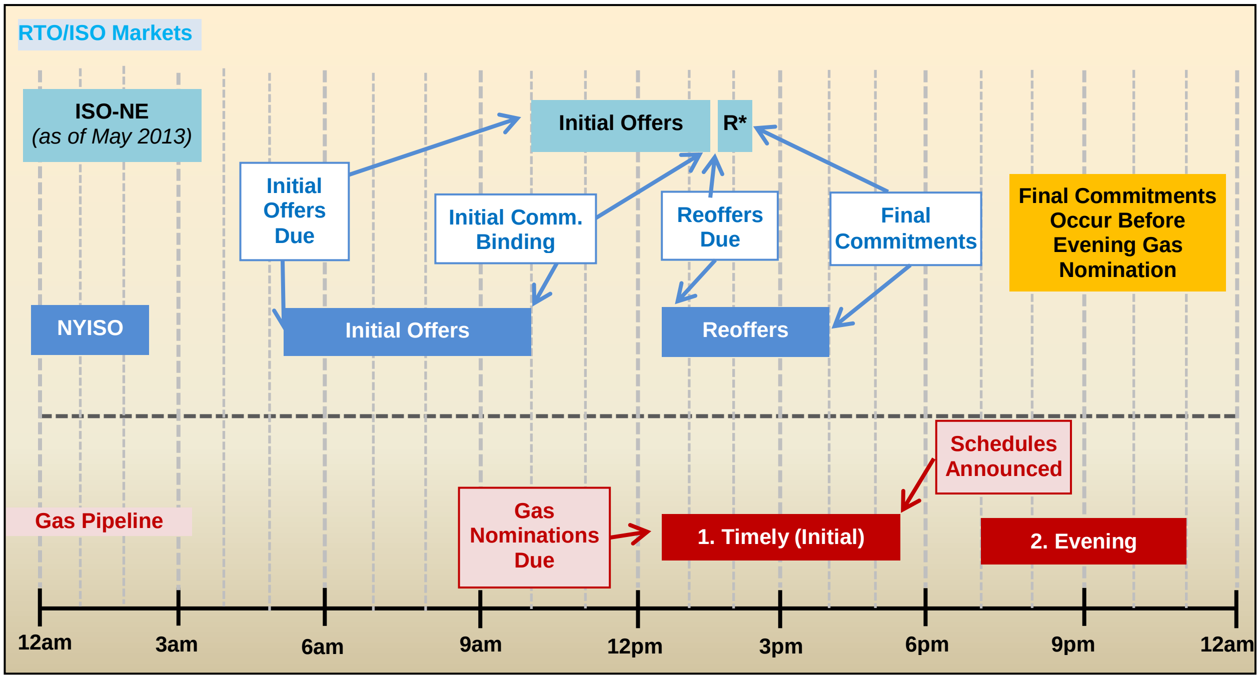
[26] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

[27] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

effective May 23, 2013. ISO-NE stated in its proposal that it would revisit day-ahead market changes within one year, to assess possible future changes (in the case neither of the proposals was chosen).[28]

Exhibit 3-10 illustrates the electric day schedules for ISO-NE (as of May 2013) and NYISO, relative to that for regional gas pipelines. The new ISO-NE electric day schedule moves final electric day commitments ahead of the evening gas schedule, allowing for additional gas scheduling within the intraday cycles, similar to that for NYISO.

Exhibit 3-10: Commitment Timing versus Gas Market Nominations for ISO-NE and NYISO



R*: ISO-NE reoffer period

Source: Revised from http://www.hks.harvard.edu/hepg/Papers/2012/Schatzki_Todd_Oct2012.pdf

[28] ISO New England and New England Power Pool. "Order on Proposed Tariff Revisions," docket no. ER13-895-000. FERC, April 24, 2013: Washington, DC. Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13242580

4 Supply Access Implications for New England's Gas-Fired Power Generators

The increase in competitively priced natural gas supplies available to Northeastern markets has resulted in an increase in regional gas demand, particularly within the power sector. New England's gas-fired generators now increasingly compete for gas supplies with a growing number of consumers in New York, including gas-fired generators. Many of these New York generators are located "upstream" of New England's generators, with electric market commitment schedules that currently allow New York generators a timing advantage in acquiring gas supplies within the daily market.

During periods of peak gas consumption, generators in New York and New England compete for the available gas supply. For the generators in New England, the nature of this competition can create difficulties in obtaining gas when and where it is needed. There are three main factors contributing to New England's gas supply access issues, leading to price volatility and increased price risk:

- Pipeline infrastructure constraints
- Interregional gas nomination scheduling
- Inappropriate gas consumption and other "bad behavior" on the part of gas consumers (such as power generators, LDCs, industrial gas users), which is often a byproduct of an ISO/RTO generator dispatch timeline extension or schedule overrun

These factors, as well as implications for New England's gas-fired power generators, are discussed below.

4.1 Pipeline Infrastructure Constraints

As mentioned in **Section 3**, pipeline service contracts honor firm service requirements before the scheduling of both interruptible and capacity release contracts. However, firm service contracts are not typically an economic choice for New England's gas-fired generators, given the significant variation in generation requirements throughout the year and corresponding low load factors for intermediate and peaking generators. Interruptible service and capacity release contracts are typically utilized by gas-fired generators. Thus, during times of high demand (e.g., cold winter days), decreased pipeline capacity available to gas-fired power generators leads to significant price risk to generators who have committed to or have been dispatch by the ISOs/RTOs to serve daily electric loads, but typically depend on interruptible or capacity release services.

The following subsections identify a number of New York demand sources and pipeline constraint areas that directly influence the availability of gas to reach New England markets.

4.1.1 Eastern New York Demand Sources and Impacts on Pipeline Access

While gas-fired power generation growth in the U.S. Northeast is expected to outpace U.S. averages over the foreseeable future, pipeline constraints into New England and competing New York gas-fired power generation may inhibit growth within New England's gas-fired generation fleet.

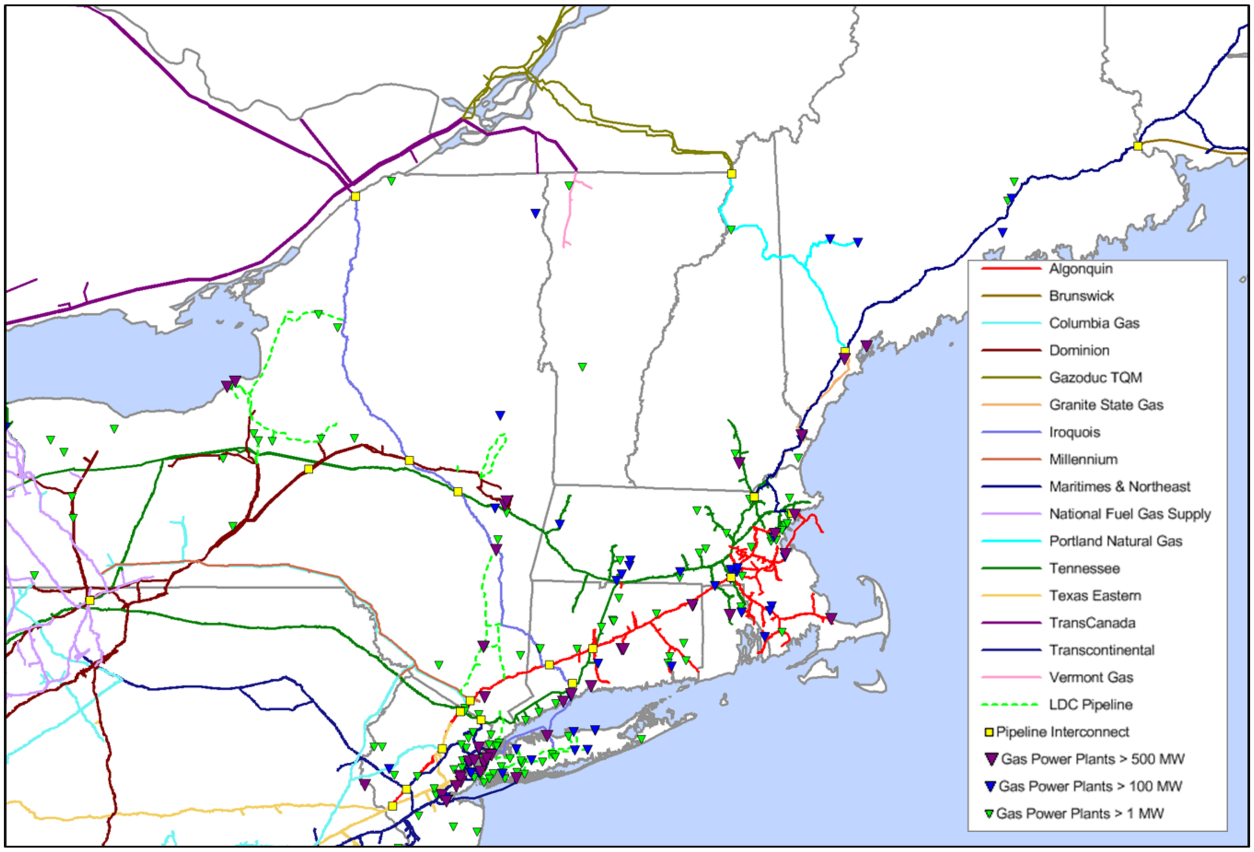
As discussed below, three of the six pipelines that serve New England (i.e., Algonquin, Iroquois, and Tennessee) also providing service to markets in New York. In addition to the gas loads from the LDCs in New York upstream of New England, these pipelines extend into New England to serve the LDC loads and generation in these states. The physics and engineering of a natural gas pipeline will impact downstream deliveries on a pipeline segment when there are no additional options to add gas through another pipeline interconnect. As a result, the physical conditions that influence pipeline deliveries in New England will be the result of gas use by generators and other loads located "upstream" in New York.

This section will focus on the power plants in New York that can have the greatest influence on the availability of gas supplies targeted for New England. The focus is on gas-fired generators rather than gas LDCs since, in virtually all cases, the LDCs utilize firm capacity, storage, and peak shaving facilities to meet their peak load requirements and are typically not competing with regional power generators for released capacity or IT services.

When a generator is on a segment of the pipeline that is upstream of a pipeline interconnection where the pipeline can access gas, gas received will have less of a direct impact than deliveries to a generator that is downstream of the interconnections. The additional interconnect provides an alternative path for gas to reach the generator. To be an effective option, however, there needs to be a source of gas available on the alternative path. Without that source of gas, the pressure and volume of deliveries to the generator will fall regardless of the attempts to obtain gas from the alternative path. Gas-intensive power producers in New York that could draw away gas from New England markets include Selkirk Cogen (365 MW), Bethlehem Energy Center (759 MW), Empire Generating Co. (592 MW), and Athens Generating Plant (1,138 MW) in eastern central New York; Northport (1,593 MW) in eastern southern New York; and Sithe Independence (914 MW) in western New York. In the case that the Indian Point nuclear facility is closed, additional gas-fired capacity in the Lower Hudson Valley (LHV) Zone, including Advanced Power in Cricket Valley, NY (1,000 MW) and Competitive Power Ventures (CPV) in Wawayanda, NY (630 MW).

Exhibit 4-1 shows natural gas pipelines and all gas-fired power plants in the U.S. Northeast. The map highlights the difficulties New England may encounter, as a growing number of gas-fired power plants may draw off significant gas supplies from the Algonquin and Iroquois pipelines, reducing New England's supply access on those pipelines.

Exhibit 4-1: New England and Northeast Major Natural Gas Pipelines and Gas-Fired Power Plants



Source: ICF International using Ventyx Velocity Suite mapping software

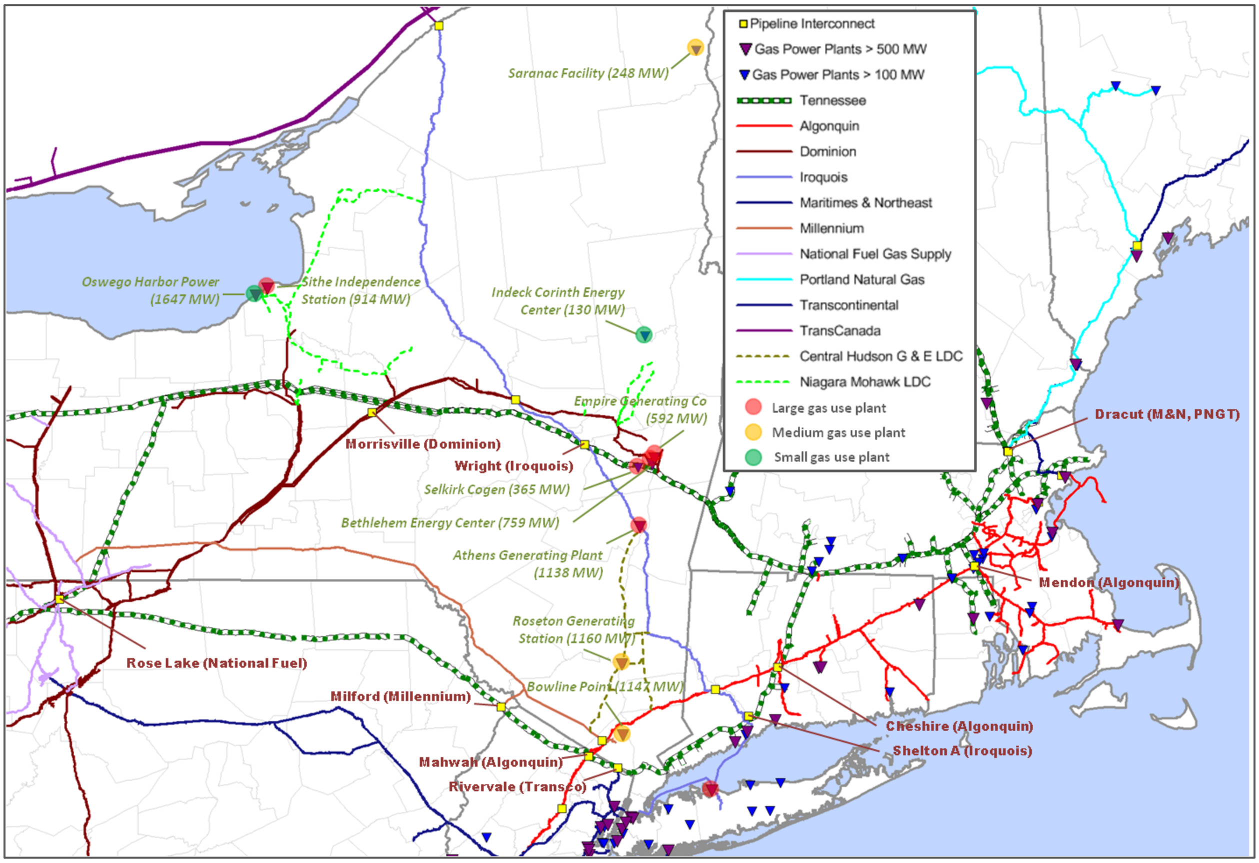
4.1.2 Key Pipeline Infrastructure Analysis

The following subsection discusses the key infrastructure issues of each major pipeline into New England.

<u>Tennessee Gas Pipeline</u>

The exhibit below shows only the Tennessee Gas Pipeline and the pipelines with which it interconnects. The plants with red circles are likely to have the largest impact on New England producers based on historical gas use (i.e., Selkirk Cogen, Bethlehem Energy, Empire, Athens Generating Plant, Northport, and Sithe Independence). The Tennessee line cuts east through New York before reaching New England, meaning that eastern New York power plants are able to access Gulf of Mexico, Marcellus/Utica, and Canadian gas volumes coming into the region before New England consumers.

Exhibit 4-2: Analysis Focus on Tennessee Gas Pipeline



Source: ICF International using Ventyx Velocity Suite mapping software

<u>Algonquin Gas Transmission</u>

Algonquin Gas Transmission is a regional interstate pipeline that receives gas from a number of interconnecting pipelines in New York and New Jersey with access to natural gas produced in the Marcellus Shale, as well as traditional gas supply sources from the Gulf of Mexico.

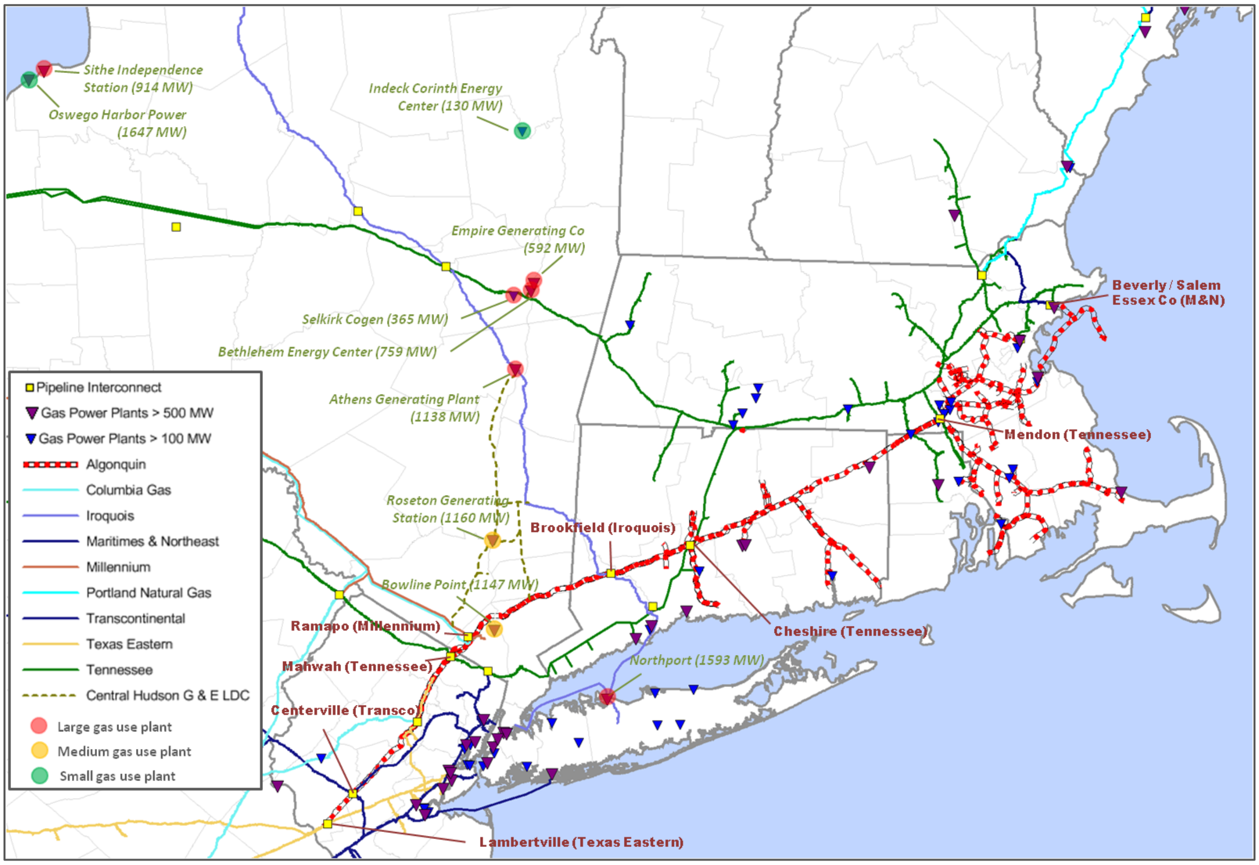
Algonquin does not directly connect to any power plants in New York. The Bowline Point plant is directly served by the shared Columbia/Millennium pipeline that terminates at the plant located on the Hudson River. The Ramapo interconnect between Millennium and Algonquin primarily flows gas from Millennium to Algonquin, but any change in power gas demand on Millennium, could directly impact Algonquin receipts at Ramapo.

Algonquin interconnects with the Iroquois Gas Transmission System in Brookfield, Connecticut, where it currently delivers gas bound for Long Island and Hunt's Point, located in the Bronx borough.

Algonquin interconnects with Tennessee, M&N U.S., and PNGTS where it generally receives gas bound for the New England markets it serves. The Algonquin Hub Line under Boston Harbor also has the capability of receiving (regassed) LNG from floating vessels docking at Northeast Gateway or Neptune Deepwater Port LNG terminals located off Gloucester, MA.

The exhibit below shows only Algonquin and the pipelines with which it interconnects.

Exhibit 4-3: Analysis Focus on Algonquin Gas Transmission



Source: ICF International using Ventyx Velocity Suite mapping software

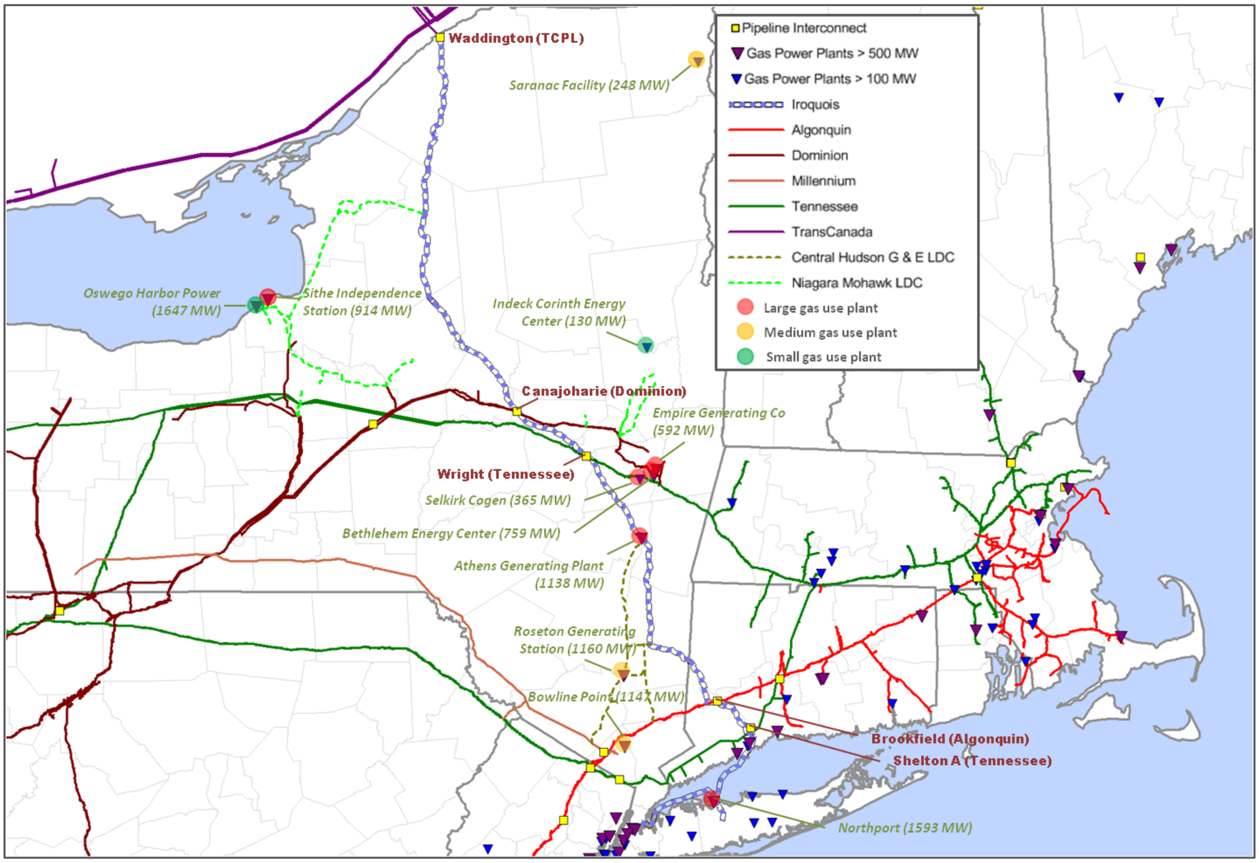
<u>Iroquois Gas Transmission</u>

New England has long viewed Canadian gas imports delivered into the PNGTS and Iroquois pipelines as a critical component of gas supply. Given the declining nature of the western Canada conventional production, as well as competing demand for western Canadian natural gas from (upcoming) LNG exports and current oil sands development and the declining volumes on TCPL eastward, Iroquois volumes have been decreasing from historical flow, turning it primarily into a seasonal pipeline.[29]

The exhibit below shows the Iroquois pipeline and the pipelines with which it interconnects. Plants with red circles are likely to have the biggest impact on New England consumers based on historical gas use. Iroquois has a direct connection to the Athens Generating Plant. It can also supply other gas-fired plants using facilities operated by the Niagara Mohawk and Central Hudson Gas and Electric LDCs. In addition, Cricket Valley's gas-fired power generation project is a front runner for the New York State's Energy Highway Initiative.

[29] Overall throughput volumes on IGTS have been declining, but do reach maximum flows primarily during winter and summer peak load conditions.

Exhibit 4-4: Analysis Focus on Iroquois Gas Transmission



Source: ICF International using Ventyx Velocity Suite mapping software

<u>Maritimes & Northeast U.S. Pipeline</u>

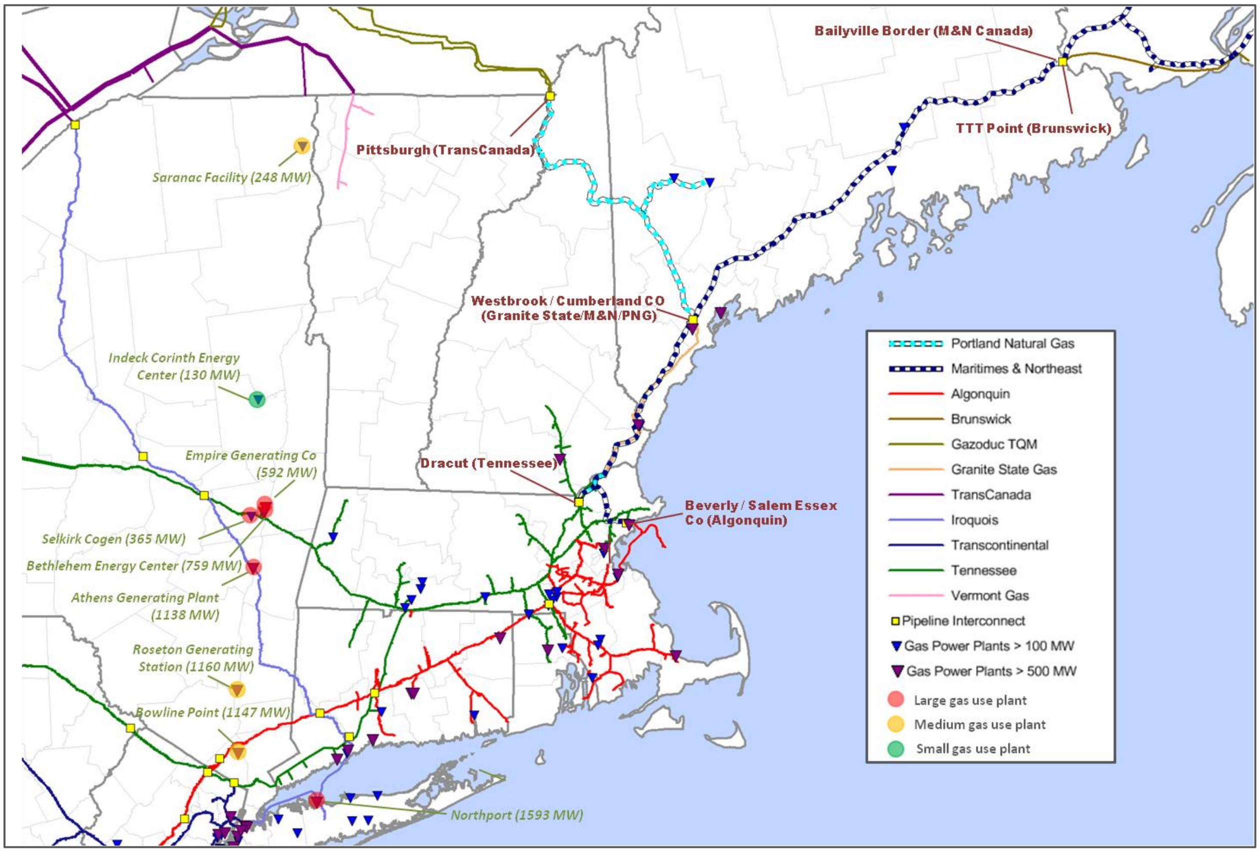
New England was expected to see expanding gas supplies from offshore Nova Scotia in eastern Canada, although recent lower production rates has occurred in offshore Sable Island, which is connected to the M&N U.S. Pipeline (connecting supply to New England). The Deep Panuke offshore gas project, another Nova Scotia project, has also contributed to supply uncertainties in the region, though Encana (Deep Panuke operator) announced that it will begin production in late 2013. The deepwater project is expected to provide up to 300 MMcf/d of gas to New England markets.[30] Built more than 12 years ago and expanded as recently as 2009, the M&N U.S. Pipeline originally promised continuous and growing natural gas supplies into New England from offshore Nova Scotia in eastern Canada. When first discovered, the waters around Sable Island were predicted to hold vast gas reserves, but only the Deep Panuke discovery is being developed more than 10 years later than originally expected. The Sable Offshore Energy Project (SOEP), which had peak production around 500 MMcf/d has showed significant production decline over the last two years. The Deep Panuke offshore gas project was slated to enter service in 2012, but an accident towing the production platform has delayed startup over a year. Encana (Deep Panuke operator) announced that it will begin production by the end of September 2013, and is expected to provide up to 300 MMcf/d of gas production into the M&N U.S. pipeline.31

[30] Chronicle Herald. "At long last, Deep Panuke to produce gas." Chronicle Herald, 9 August 2013: Halifax. Available at: http://thechronicleherald.ca/editorials/1146839-editorial-at-long-last-deep-panuke-to-produce-gas

[31] Platts. "Gas Daily." McGraw Hill Financial, June 12, 2013: New York, NY. pp. 1, 6.

Exhibit 4-5 shows the M&N U.S. and PNGTS, and the pipelines with which they interconnect. The major interconnection points for the two pipelines that share facilities in lower Maine and New Hampshire are named on the map. While it is not likely that eastern New York power producers will impact New England's supply access on these lines to a significant extent, lower than anticipated gas production from offshore Nova Scotia will mean supply uncertainties.[32]

Exhibit 4-5: Analysis Focus on Maritimes & Northeast and Portland Natural Gas



Source: ICF International using Ventyx Velocity Suite mapping software

[32] Uncertainties include the volume of gas available in from LNG from Canaport and Distrigas.

4.2 Interregional Gas Nomination Scheduling Differences

Compounding pipeline capacity issues in New England are eastern New York demand sources, which draw natural gas from certain pipelines. The amount of gas nominated, scheduled, and confirmed by these generators in New York on any given day will affect the amount of service that will be available to New England generators. Additionally, if any of the upstream (New York) generators take more gas than they actually nominated[33], which can and has occurred for limited periods as an unauthorized overrun, the actions can impact pipeline pressures downstream. The impact of this type of behavior is discussed in **Section 4.3**.

While power markets throughout the country, including ISO-NE's jurisdiction, continue to improve gas-electric discussions to address and improve coordination and communications issues, in order to improve both electric and gas sector reliability, there continue to be challenges. One such issue arises from the differences in the timing for the generation unit commitments within NYISO and ISO-NE jurisdictions.

As mentioned in **Section 3**, gas pipelines throughout North America offer a uniform (NAESB) nomination schedule and minimum (four) number of nomination "windows" that all pipelines must offer. Power market schedules, however, differ by region. While ISO-NE recently moved its nomination schedule earlier, ISO-NE's initial offers are due much later than are NYISO's (10 a.m. versus 5 a.m., respectively). While market participants debate over when optimal offer times should be made to optimize market liquidity (i.e., lowest price and volume risks), NYISO's earlier electric offer schedule means its gas-fired generation needs will be met before that of ISO-NE's. The implications of this are that during the coldest days of the year (i.e., peak-days), ISO-NE's gas-fired power generators may not be able to access needed gas supplies, or risk paying significant price to access limited supplies.

During the 2013 FERC Technical Conference, as part of the series of technical conferences on Coordination between Gas and Electric Markets (AD12-12-000), the issue of the timing differences was discussed.[34] FERC staff posed a question as to whether it would be better for ISO-NE and NYISO to operate on the same unit (day-ahead) commitment timeline. The answer offered by some generators was that problems could be created by that approach because some units can bid into either of the two markets. If the timelines were the same, the generator would need to choose to bid into only one market. With the differences in the two timelines, a generator could bid into the NYISO market and then subsequently bid into the ISO-NE market if the unit was not selected to be dispatched by the NYISO. The generators described this as superior, since it would make additional supply-side resources available by virtue of market sequencing.

As long as differences in the sequencing exist, there will be an inherent advantage to the units that receive their unit commitments earlier in the day, particularly during cold weather months when natural gas pipeline capacity constraints have the greatest impact on the availability of gas to generators. As discussed below, the lack of liquidity in the gas commodity market at the time a generator is attempting to obtain gas supplies also affects the price of the gas or the ability to procure it at all.

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[33] This could be due to a dispatch order from the ISO/RTO for post-contingency recovery or keeping a unit that is in economics on line to serve un-forecast electrical loads….(or some text like this..)

[34] FERC. "Notice of Commission Meeting: Coordination between Natural Gas and Electricity Markets," docket no. AD12-12-000. FERC, May 9, 2013: Washington, DC. Available at: http://www.ferc.gov/EventCalendar/Files/20130509182217-AD12-12-000.pdf

Even as some individual pipelines have allowed for additional nomination windows beyond what is required by the NAESB Standards and FERC (e.g., Algonquin and M&N) or a process for the continuous ability to accept (changing) nominations and award capacity if it is available (e.g., Tennessee), the ability to obtain the gas for generators is influenced by the liquidity in the gas commodity market within the region. As the day progresses, gas marketers tend to have committed more of the total amount of gas than the marketer was expecting to be sold on that day – i.e. “short” on gas for the day. Marketers sometimes must buy more gas than originally anticipated, requiring them to seek out gas supplies. When this occurs, gas prices within the day can move very quickly. Eventually, there is little, if any, gas that has not already been committed to other end-use customers.

The dynamics described above can work in the other direction, as well. There are instances where the anticipated gas load for the day exceeds the actual volume consumed, and a marketer finds itself “long” on gas for the day. At that point, the marketer may seek out a generator and offer additional gas at a favorable price. But that pricing is “back stopped” by the ability of the marketer to offer gas supplies or leave volumes of gas on the pipe or in storage. As a result, the price volatility in these instances is asymmetric, with generators that are short on gas subject to relatively high prices.

Because of these dynamics, the generators in ISO-NE face two choices. Either they can acquire gas supplies in the market without knowing if they will be dispatched by the ISO, or they can wait until later in the day, after being notified by the ISO of their next day commitment, to obtain gas, thereby risking price exposure do to a lack of liquidity that can result in an inability to obtain gas at prices consistent with their prior electrical bid.

4.3 Unauthorized Overruns, Imbalances, and “Bad Behavior”

Northeastern gas-fired generators have taken note of the increasing pipeline constraints seen in the region, which has led to some changes in supply procurement and power generator behaviors. Behaviors on the part of certain gas-fired generators contribute to price volatility in the region, exacerbating the region’s supply access issues. A coherent set of compliance measures is needed to curb such behavior. The following subsections discuss some “bad behaviors” on the part of regional gas consumers, as well as market incentives and disincentives to alter such behavior.

4.3.1 Gas Consumption of Volumes that have Not Been Scheduled and Confirmed by the Gas Pipeline

On any given day, a gas shipper on a pipeline may find itself “out of balance” to some degree for the overall gas day. The pipeline’s tariff contains penalty and payment provisions for these types of events. From the perspective of the gas pipelines, however, these tariff provisions are intended to address occasional and unavoidable events. They are not intended to be used as “services” available for use at a shipper’s discretion.[35]

[35] Some pipelines do offer “Park and Loan” or authorized overrun services at certain locations. These are distinctly different from charges for unauthorized overruns or imbalances. Most often Park and Loan services operate in conjunction with gas storage and pipeline interconnect options that allow the pipeline to meet these requests through exchanges of gas on the pipeline. A Park and Loan service can be offered as either a

During periods of peak requirements, the pipeline will issue a "Critical Notice" or "Operational Flow Order" ("OFO") on the pipeline or a segment of the pipeline. During such periods, the charges and penalties associated with imbalances are increased significantly. FERC allows these increases because of the desire to provide the strongest financial measures to keep all shippers in balance during these periods. Maintaining tight tolerances for imbalances is necessary to ensure that all of the scheduled transport of gas can be accommodated. Critical Notices or OFOs are issued only when the pipeline is approaching the engineering limits of the physical infrastructure.

Gas-fired generators in New England are under pressure to make competitive power commitments despite uncertainty regarding pipeline deliverability. Thus, gas-fired generators often make gas nominations in excess of their final needs to ensure fuel supplies, leading to high electricity and gas prices, as well as the inefficient use of gas infrastructure. As described earlier, generators in this situation may be forced to sell gas at a loss to a marketer with storage.

In addition to the generator's economic loss, imbalances created by gas left on the pipeline can present challenges for the pipeline. The ability to handle the situation by increasing "line pack" is limited by the maximum allowable operating pressure (MAOP) condition on the pipeline, which are imposed to ensure safe operation. At the extreme of this scenario, the pipeline might be forced to vent gas directly into the atmosphere. Fortunately, such events are rare, and the pipeline usually handles such events by moving gas to other locations on the system whenever possible.

The more troubling situation for pipeline operations occurs when a shipper, generator, marketer, or LDC takes more gas off the pipeline than has been confirmed and scheduled.[36] Over the past several years, in response to a dispatch order from ISOs/RTOs to generate for more hours than had been originally scheduled, some generators have taken more gas from the pipeline than originally scheduled. In these instances, the pipeline can experience low pressure conditions that are below gas delivery requirements. When this occurs, generation on the grid can be lost due to low gas pressure "turbine trips."

Some gas-fired generators habitually require gas volumes above their scheduled levels. Although the gas volumes are managed through pipeline balancing provisions, replacement of the gas that occurs at a later time does not always prevent pressure changes along the pipeline (as pipelines operate on a pressure basis to move volumes through the pipe, thus disruption or alteration of those levels interrupts service elsewhere on the pipeline). Thus, the taking of unauthorized (gas) volumes translates to lower pressures all along the pipeline. During periods of peak utilization, such as during cold winter days, pipelines are at particular risk for these types of supply disruptions.[37]

Because New England's generators are located downstream of the New York generators and pipe constraints, they are particularly susceptible to the pressure disruptions created by this type of behavior at upstream delivery points. The physics of gas pipeline operations dictate that the delivery points near the end of the pipe are subject to the greatest pressure deviations due to imbalances between receipt and delivery volumes.

firm or interruptible service. As is the case of firm transportation, firm Park and Loan service requires the payment of a monthly demand charge. Importantly, the lack of storage in New England would make the development of firm Park and Loan service expensive.

[36] The confirmation ensures that the volume of gas to be delivered to the pipeline at the receipt point is equal to the volume of gas scheduled to be removed from the pipeline at the delivery point.

[37] NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012: Washington, DC.

In California, there have been instances where a generator has attempted to include pipeline imbalance charges in their supply bid to the CAL-ISO, even those levied during periods where Critical Notice or OFO provisions are in place. Such behavior during critical periods can threaten the ability of the pipeline to provide scheduled service to all shippers Some market participants in the northeast have raised concerns that similar imbalances may become commonplace in Northeastern electricity markets. If this behavior were to become customary to any degree, it would create very unstable operating conditions on the pipeline as well as "overpriced" wholesale electricity prices, which FERC would soon investigate.

Ultimately, the pipeline's only response to persistent use of unauthorized overruns as used as a pipeline "service" is for the pipeline to physically close the (flow control) valve to the offending power plant. Historically, pipelines have been reluctant to take this drastic step. The sudden and unanticipated shut off of gas supply can cause damage to a generator, which would likely result in litigation, along with potential ramifications to electrical system reliability. Nevertheless, pipelines have increasingly indicated a willingness to close valves when the ability to deliver scheduled volumes is placed at risk by unauthorized overruns or inappropriate gas consumption.[38]

4.3.2 Incentives and Disincentives Facing New England's Gas-Fired Generators

While pipeline service contracts honor firm service requirements before both interruptible and capacity release contracts, gas-fired power generators in New England lack a cost recovery mechanism for procurement of firm capacity. Thus, firm service contracts, which ensure reliable deliveries and stable pricing, are not an economic option for most gas-fired generators, given the unpredictability of generation requirements throughout the year, as well as the low load factors for intermediate and peaking generators.

As gas-fired generation throughout New England and New York continues to grow without the corresponding levels of construction of new natural gas pipeline capacity, gas (and electric) price volatility will continue to grow. With natural gas pipeline increases dependent upon firm service contracts, the region will continue to face pipeline constraints, despite the pressing need for natural gas to support burgeoning gas-fired power generation growth. Thus, while New England's regulatory environment supports building gas-fired electric generation, gas pipeline regulations, as currently designed, inhibit midstream growth to satisfy overall power sector needs.

[38] Anecdotally, pipelines have described instances where personnel have been dispatched to close valves. When the generator was informed of that, the operators began an orderly shutdown of the generator.

5 Conclusion

Expansion of gas supply sources for Northeastern markets has led to demand increases among the region's gas-fired power producers. While New England continues to expand its gas-fired generating capacity, competing demand sources, particularly those in eastern New York, will continue to stress the region's pipeline infrastructure, leading to supply access issues in New England.

Power producers in the U.S. Northeast have increasingly turned to gas-fired generation, given the sustained increase in supply, coupled with projections of low long-term prices. Despite the unprecedented growth in gas supplies available to Northeastern markets, pipeline capacity into the region remains insufficient, as gas-fired generation continues to grow. Due to persistent pipeline infrastructure constraints and competition with upstream demand sources, New England is expected to see continued price volatility.

While gas versus electric-day issues will likely persist, increasing gas-fired power generation will exacerbate New England's supply access problems due to a combination of infrastructure issues, interregional electric-day issues, and regulatory barriers.

There are three main factors contributing to New England's gas supply access issues. These factors include pipeline infrastructure constraints, competing demand sources, and inappropriate gas consumption on the part of upstream and in-region power generators. These factors directly contribute to the significant natural gas price spreads observed and projected between New England , New York and Mid-Atlantic natural gas markets.

Pipeline infrastructure constraints: Although New England has several interstate pipelines transporting gas into the region, the region cannot simultaneously meet the gas requirements of LDCs and all its gas-fired generators. Firm service contracts, which LDCs rely upon, are the foundation for natural gas pipeline development and construction. FERC does not allow new pipeline capacity construction without firm capacity contracts. However, firm service contracts are not typically an economic choice for gas-fired generators, given the significant variation in generation requirements throughout the year and low load factors for intermediate and peaking generators. As a result, pipelines cannot build new capacity to meet the needs of non-firm power generators. Competing demand sources: New England competes for regional gas supply with industrial, consumer, and gas-fired loads in eastern New York and other regions. This competition will continue to put upward pressure on regional prices in an effort to draw gas into New England during peak periods. Many of these New York generators are located "upstream" of New England's generators, with electric market commitment schedules that allow them a timing advantage in procuring gas supply and transport in the daily market. The implications are that during the coldest days of the year (i.e., peak-days), ISO-NE's gas-fired power generators may not be able to access needed gas supplies, or risk paying significant price risks to access limited supplies.

Inappropriate power generator consumption of gas: The amount of gas nominated, confirmed, and scheduled, by certain generators in New York, which draw from pipelines going to New England, will affect the amount of service that will be available to New England generators. Thus, if any of the upstream (New York) consumers or generators takes more gas than actually nominated, the pipeline's pressure downstream may be impacted. Gas-fired generators are under pressure to make competitive power commitments despite uncertainty regarding pipeline deliverability. In order to minimize the risk of a pro-rata reduction, gas-fired generators often make gas nominations in excess of final needs to ensure fuel delivery, leading to high electricity and gas prices as well as inefficient use of gas infrastructure. As a result, generators in this situation may be forced to sell gas at a loss to a marketer that has storage. In addition to the generator's economic loss, imbalances created by gas left on or taken from the pipeline can present reliability challenges for the pipeline. The taking of unauthorized volumes translates to lower pressures all along the pipeline, and during peak periods, pipelines are at particular risk for supply disruptions. Because New England generators are located downstream of New York, they are particularly susceptible to the pressure condition disruptions created by this type of disruptive behavior at upstream delivery points.

As gas-fired generation throughout New England and New York continues to grow without the corresponding levels of construction of new natural gas pipeline capacity, regional gas, particularly in the daily spot market and electric price volatility will continue to grow. With natural gas pipeline increases dependent upon firm service contracts to obtain FERC approval, the region will continue to face pipeline constraints, despite the pressing need for natural gas to support electric sector growth. Thus, while New England's regulatory environment supports building gas-fired electric generation, gas pipeline regulations currently inhibit midstream growth to meet non-firm power sector needs. In addition, a coherent set of compliance measures is needed to curb the habit of inappropriate gas consumption on the part of all gas-fired generators.

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