NATURAL GAS INFRASTRUCTURE AND ELECTRIC GENERATION: A REVIEW OF ISSUES FACING NEW ENGLAND

PREPARED FOR

The New England States Committee on Electricity

14 DECEMBER 2012

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In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

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1.0 Executive Summary

BACKGROUND

Innovations in production technologies and large shale gas discoveries in North America have ushered in an era of low-cost natural gas production. This has fueled an increased reliance on natural gas for electric generation, home heating, and industrial uses. In the power sector, specifically, natural gas has seen its market share as a power generation fuel increase in the United States from 20% of the power generated in 2006 to 25% of the power generated in 2011. This migration to natural gas-fired generation is driving increased scrutiny of the adequacy of the existing North American natural gas grid – absent new infrastructure – to reliably supply fuel to the electric industry.

In New England, increasing load factors on the natural gas pipelines serving the region and the potential for continued load growth suggest that physical constraints may emerge. Depending upon the configuration and location of natural gas-fired generation, local distribution companies ("LDCs"), and other end users, a constraint may have a range of impacts: from increases in the cost of electric supply to, potentially, electric service reliability concerns. Thus, New England policymakers have taken an interest in various industry studies, papers, and presentations that conclude that existing natural gas infrastructure is inadequate to meet New England's demand for natural gas in the future, particularly for electric generation.

SCOPE OF STUDY

Given the implications of natural gas infrastructure inadequacy for electric system reliability, the New England States Commission on Electricity ("NESCOE") commissioned Black & Veatch to provide an independent review of the studies, papers, and presentations in question. According to NESCOE, policymakers are interested in sufficiently granular information to determine whether New England's natural gas infrastructure is adequate to meet the region's needs over the long-term. Further, to the extent the region needs to implement solutions related to inadequate infrastructure, policymakers are interested in understanding the costs and benefits of potential solutions.

Accordingly, NESCOE requested that Black & Veatch review certain studies, identify common themes and findings, and then identify: 1) major assumptions and drivers; 2) any incorrect assumptions underlying major study findings; 3) available information to date about the adequacy of gas supply going forward; and 4) any information gaps that policymakers should seek to fill to inform their decision-making.

APPROACH

Black & Veatch reviewed thirty-five studies, papers, and presentations that discuss New England's natural gas supply infrastructure and issues related to the increasing prominence of natural gas as a power generation fuel. In answering the questions raised by NESCOE, Black & Veatch considered the scope, methodologies, assumptions, uncertainties, and analytical tools present in these studies, papers, and presentations.

This report provides an assessment of the adequacy of natural gas infrastructure in New England based on third-party studies and information available to date, in addition to our own expert knowledge of the regional energy market.

Black & Veatch believes that New England's natural gas infrastructure will become increasingly stressed as regional demand for natural gas grows, leading to infrastructure inadequacy at key locations.

In addition, Black & Veatch identifies information gaps and missing elements from current studies that policymakers may wish to consider addressing in order to inform any decisions that may be required.

KEY OBSERVATIONS AND FINDINGS OF EXISTING STUDIES

New England Faces Pressing Concerns Regarding Natural Gas Supply Reliability

New England faces unique natural gas supply issues because the region resides at the terminus of the North American pipeline grid with no indigenous production or underground storage facilities. The region receives its gas supplies through long line pipelines accessing Western Canada, Eastern Canada Maritimes, the US Gulf Coast, the Rockies, and emerging shale production from the Northeast US. New England has exceptional access to liquefied natural gas ("LNG") imports through several regional terminals, but these gas supplies are expected to be costly going forward as other countries also turn to LNG for their supply. For these reasons New England is among the most costly North American markets to serve[1].

The papers and presentations reviewed consistently focus on several key issues impacting electric-gas reliability in New England. The key issues identified by the papers and presentations are as follows:

Natural gas is expected to be relied upon as a major electric generation fuel source for New England going forward. The discovery of abundant natural gas resources and the expectation of stable natural gas prices, along with rising environmental costs associated with other fossil fuel generation are factors that make natural gas an attractive fuel choice for incremental capacity builds and the replacement of retiring coal and oil-fired plants[2].

Increased usage of natural gas as an electric generation fuel potentially raises reliability concerns due to logistical issues that, if unaddressed, will pose reliability risks to the electric grid. For the most part, natural gas-fired generators in New England do not hold firm natural gas pipeline transportation capacity and are largely dependent upon interruptible delivery capacity to meet their gas needs. Major issues include a lack of synchronization in natural gas and electric nomination schedules, constraints in the physical operation of natural gas pipelines in meeting the intraday swing of gas generators, and maintenance schedules for natural gas pipelines that reduce pipeline capacity during periods of peak electric demand[3].

The current electric market does not provide financial incentives for generators to purchase firm natural gas capacity, which would, in turn, produce incentives for infrastructure development. Current electric market factors have generally worked to discourage new gas infrastructure construction; generators do not receive compensation for investments in costly firm fuel supplies that could ensure they are able to dispatch electricity during periods of capacity constraints when it is needed the most[4].

Multiple natural gas infrastructure projects have been proposed to connect growing Marcellus Shale natural gas production to markets in the Northeast US, Southeast US, and Canada. However, only one proposal (Spectra's AIM project) has been made to build incremental capacity directly from Marcellus Shale production into New England[5].

The construction of interstate natural gas pipeline capacity requires FERC regulatory approval that is highly contingent on the demonstration of market need. Such "need" is typically evidenced by long-term (10+ year) firm contract customer commitments. As LDC demand growth in New England generally lags growth experienced by the electric sector, without proper incentives in place to encourage power generators to purchase firm natural gas transportation capacity, it will become increasingly difficult for proposed pipeline projects to gain the requisite firm capacity commitments for regulatory approval[6].

Significant Scope Differences Exist between Studies

Significant differences exist between the scopes of each of the papers and presentations reviewed. These differences and lack of comparability between the papers and presentations present challenges to forming a clear and consistent understanding of the adequacy of the natural gas infrastructure in serving the New England market. Although each study may add value to the discussion, the absence of a common scope frustrates efforts of industry and policymakers to consider a range of views on a complex subject and coalesce around a set of solutions as may be appropriate.

Current Studies Do Not Provide In-Depth Assessment of Infrastructure Adequacy

The most notable observation from our review is that only one report attempts to quantify New England's potential capacity shortfall[7]. That report was commissioned by ISO-NE, which may be seen as a leader among its peers in analyzing gas-power adequacy. Its 2011 request for proposals on this topic was issued a year in advance of FERC technical conferences and subsequent rulemaking concerning the issue[8]. However, this report is limited in its scope: it does not fully address the nuances of the natural gas market or consider the nature and duration of potential inadequacies. For example, the study does not differentiate "supply", which refers to available natural gas supplies, and "capacity", which refers to the pipeline infrastructure available to deliver that gas. This aggregation obscures the effect of capacity usage and gas production changes taking place in the Mid-Atlantic and Canadian markets upstream of New England. Further, the study's focus on the winter design day and summer peak day assessment does not provide insights into the potential seasonal infrastructure inadequacy.

No Studies Undertake a Comprehensive Cost-Benefit Analysis

What constitutes gas supply adequacy for power generators (and a regional grid in the aggregate) is typically a location-specific determination affected by numerous factors including load characteristics, geography, power infrastructure, and fuel alternatives. For this reason, having “adequate natural gas supplies” does not necessarily require that the natural gas infrastructure must meet the last unit of peak natural gas demand. There can be a variety of alternatives available to optimize the investments in gas and power reliability as the systems get closer to meeting 100% of peak natural gas demand.

An assessment of the costs and benefits associated with investments made to alleviate constraints will be central to good decision making. Our review indicated that only one study, commissioned by Spectra Energy[9], specifically focuses on the estimated costs that pipeline capacity constraints impose on New England consumers and economic benefits for incremental capacity builds. This study, however, does not discuss costs of alternative options, and is too reliant on historical data to quantify the benefits of incremental infrastructure.

ASSESSMENT AND RECOMMENDATIONS

Black & Veatch believes that the natural gas infrastructure serving New England will become increasingly stressed as regional demand for natural gas grows. The increasing prominence of natural gas as a power fuel in the New England generation fleet raises electric reliability concerns. Given that New England relies almost exclusively on natural gas supplies and storage from outside the region, natural gas infrastructure constraints could develop at key locations across the region. However, as previously stated, studies conducted to date do not confirm the extent or explore the ramifications of potential inadequacies.

The inability of gas-fired generators to meet dispatch obligations for lack of fuel could place the reliability of electric service at risk. This is especially true during periods in which the region is tight on generation capacity and faces localized congestion. Accordingly, a full understanding of the extent of natural gas infrastructure inadequacy and a comprehensive assessment of possible solutions is important. For example, more detailed information on the timing and magnitude of any natural gas deficiency would inform consideration of appropriate strategies to relieve inadequacies. The following graphic illustrates the integrated framework that Black & Veatch utilizes when assessing natural gas infrastructure adequacy for the electric sector.

A material observation based upon our review of the studies to date is that no study has approached the problem in a comprehensive manner that integrates each of the elements outlined above. As a whole, the studies reviewed consider some of these elements, but most likely due to the limited topics covered in their scopes, none concurrently include each element in a single study.

Black & Veatch finds that the studies reviewed do not fully consider the ramifications of New England's infrastructure adequacy in several key areas and recommends that these critical gaps be addressed in order to provide a complete picture of the adequacy of the natural gas infrastructure serving New England:

Definition of Adequacy for Natural Gas Infrastructure

No study or other benchmark specifically articulates what level of natural gas infrastructure could be considered "adequate" to alleviate the electric reliability challenges facing New England. A benchmark specific to the region is needed to identify the level of infrastructure required to achieve an acceptable balance of costs, benefits, and systemic reliability risk.

Dynamic Natural Gas Demand Projections

A static projection of future demand on a single average, peak, or design day, as examined in the ISO-NE Gas Study, does not fully consider issues related to the probability or duration of potential natural gas infrastructure inadequacies. ***No study has examined the seasonality, daily and hourly fluctuations of demand in an effort to identify the nature and duration of potential infrastructure constraints.***

Identification of Localized Constraints

No study considers the intra-regional constraints and unique characteristics of New England's natural gas and electric infrastructure. Constraints develop in specific locations due to the complex nature of New England's natural gas infrastructure and location of gas generators that require certain parameters (such as pressure of gas deliveries) to dispatch. Such constraints must be identified in order to formulate effective solutions.

Costs and Benefits of Incremental Infrastructure

No study examines the costs of constructing any kinds of incremental infrastructure. An infrastructure solution is expected to yield social and economic benefits, but its implementation will not be supported by market participants if it levies unreasonable costs on those participants.

Estimation of the benefits of incremental infrastructure through the exclusive use of statistical analysis of historical data, as utilized in the Spectra study, does not account for a number of uncertainties caused by the dynamics of market fundamentals. Fundamental modeling of the natural gas and electric markets, however, can serve as an effective means of quantifying the benefits of incremental infrastructure investments. Any resulting lowering gas and electric prices will provide the basis for quantifying the potential benefits of the project. ***No study has quantified the benefits of additional infrastructure in a way that accounts for the uncertainties attributable to market fundamentals.***

2.0 Introduction

New, advanced drilling techniques for extracting natural gas from shale formations have led to explosive growth in North America's natural gas production and reserves over the last five years. As a result, the average US price for wellhead natural gas has dropped from a high of $10.79/MMBtu in 2008 to $1.89/MMBtu in 2012, and has remained in the $2.00/MMBtu to $3.00/MMBtu range through 2012. The expectation for low, stable natural gas prices has led to a wide range of impacts to those consuming, processing, and transporting natural gas within North America.

One of the most fundamental changes resulting from the increase in natural gas reserves and production is being experienced by the wholesale power sector. Natural gas-fired generation, traditionally utilized as an intermediate or peaking resource in many parts of North America, is now cost competitive with coal-fired generation for baseload generation, challenging coal's half century of dominance as the baseload fossil fuel of choice. A number of gas-fired generators have begun to experience increased capacity factors. This is largely at the expense of, and in response to, decreased utilization of coal units because of shifts in economics and the anticipation of environmental regulation. Moreover, a majority of announced North American electric generation projects are natural gas-fired, which is reflective of the long-term market consensus regarding construction costs, commodity prices, and overall market risk.

In New England, the increase in natural gas-fired generation is even more pronounced than seen through the US generally. Natural gas-fired generation is the dominant electric supply resource in New England, supplying more than 43% of the electricity purchased from the grid[10]. Natural gas-fired generation enjoys an advantage over coal-fired generation in the region due to the challenges and costs of transporting coal into the region from distant coal fields by barge or rail. At current and forecasted natural gas price levels, most experts believe that natural gas-fired generation will likely remain the preferred resource for supplying incremental load growth in the region. Pressures on natural gas as the fuel of choice will increase with the retirement of coal and oil units that have become uneconomic to operate.

This increased reliance on natural gas to produce electricity also raises electric supply reliability risks, especially in New England where natural gas supplies must be imported from other regions. Specifically, concerns regarding reliability have been raised due to the possible inadequacies of natural gas delivery capacity into the region as well the absence of electric market incentives to induce generators to purchase firm natural gas pipeline transportation capacity. Many North American natural gas-fired plant owners contract for natural gas for interruptible delivery, meaning physical delivery of contracted volume of natural gas only occurs if the delivery capacity is not otherwise committed to serve holders of "firm" transportation capacity. The purchase of interruptible transportation capacity allows generators to avoid the costs of reserving "firm" gas supply, but also creates the risk that a gas-fired generator is willing to serve load but cannot access the fuel supply required to do so. In isolation, this circumstance may have little impact on electric costs and reliability; the generator is simply on outage and internalizes these opportunity costs.

When extended to a larger population of gas-fired units, however, the same circumstance may challenge the ability of the electric grid to generate enough power to meet demand.

This electric reliability challenge has attracted the attention of federal and state policymakers. The FERC has established a rulemaking to gather comments on the issue and many regional and state-level regulatory bodies have initiated formal discussions with stakeholders[11]. In addition, many stakeholders have independently issued policy papers or commissioned studies to evaluate these market conditions.

Solutions to this challenge can take many forms, from demand-side measures to the construction of additional natural gas transportation capacity. In New England, stakeholders have focused on incentives and market mechanisms needed to meet this reliability challenge. These include recommendations for increased emphasis on demand side management, new rules in the Forward Capacity Market to value duel fuel capability (meaning burning fuel oil to serve as an emergency backup fuel when natural gas is scarce) or other fuel supply investments (such as short-notice and/or non-interruptible gas supply agreements), and improved coordination of scheduling and trading practices for electricity and natural gas. To date, only one study has been commissioned to assess the adequacy of existing natural gas infrastructure to meet future natural gas demand in the New England region.

To assist New England policymakers in their response to this issue, NESCOE commissioned Black & Veatch to provide an independent review of the most relevant studies, papers, and presentations related to the question of natural gas supply and electricity production in New England. In particular, NESCOE asked Black & Veatch to summarize and provide an opinion on the conclusion reached in several studies that the existing natural gas infrastructure is inadequate to meet forecasted near term demand. In addition, NESCOE asked Black & Veatch to discuss the current financial incentives and disincentives that influence electric generators' practices relative to gas supply.

Section 3 provides background information on New England's natural gas infrastructure. The Study Review is described in Section 4, while our Conclusions and Recommendations are described in Section 5.

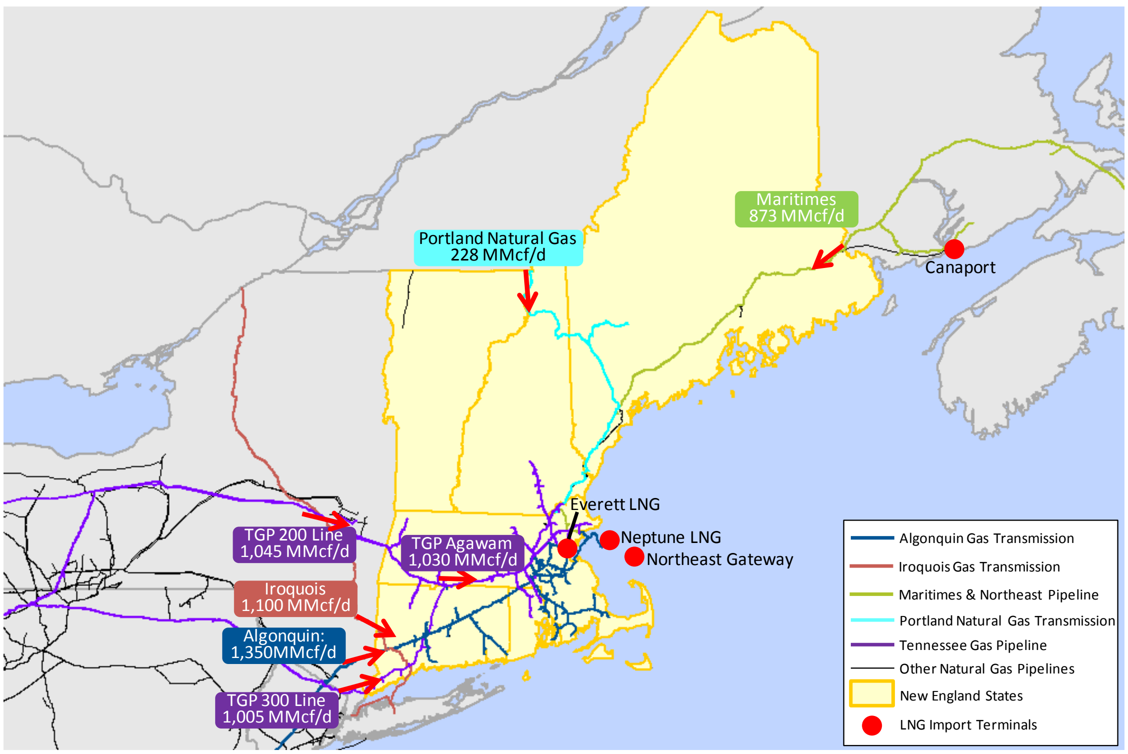
3.0 New England Natural Gas Market Overview

Numerous studies and presentations available in the public domain provide information about the New England gas market. This section provides a digest of recent market developments most relevant to the issue of gas-power inter-dependency.

NEW ENGLAND NATURAL GAS INFRASTRUCTURE

New England is located at the terminus of several interstate pipelines. With no indigenous production or underground storage, the region receives natural gas supplies from outside the region via interstate pipelines and liquefied natural gas ("LNG") import terminals. An overview of interstate pipelines and LNG import terminals serving New England is included in Figure 1.

Figure 1: New England Natural Gas Infrastructure



Source: Energy Velocity, LCI Energy Insight, Pipeline Electronic Bulletin Board Data

Major interstate pipelines that deliver natural gas supplies to the region include the Algonquin Gas Transmission ("AGT"), Iroquois Gas Transmission System ("Iroquois"), Portland Natural Gas Transmission System ("PNGTS"), Maritimes & Northeast Pipeline ("M&NE"), and Tennessee Gas Pipeline ("TGP").

Table 1 provides an overview of the physical and firm contracted pipeline delivery capacity available to serve the New England market.

Table 1: New England Gas Supply Sources

Supply Sources	Physical Pipeline Capacity at New England State Borders	Firm Contracted Capacity Serving New England Demand[1,2]
Pipeline	(Bcf/d)	(Bcf/d)
Tennessee Gas Pipeline	2.0	1.3
Algonquin Gas Transmission	1.4	1.3
Iroquois Gas Transmission	1.1	0.2
Maritimes & Northeast Pipeline	0.9	0.9
Portland Natural Gas Transmission	0.2	0.2
LNG Imports (Firm Supplies)		
Everett LNG	0.7	0.7
LNG Import (Non-Firm Supplies)		
Neptune LNG	0.4	0.0
Northeast Gateway	0.8	0.0
LNG Peak Shaving	1.4	1.4
Total	**8.9**	**6.1**

[1]Source: 2012 Quarter 4 FERC Index of Customers

[2]Firm contracted capacity originating outside of New England

	Nameplate Capacity (MW)
Dual - Fired Generation Capacity	10,118

Source: *Black & Veatch Analysis, Energy Velocity, Energy Information Administration Form 860,EPA Continuous Emission Monitoring (CEMS) data*

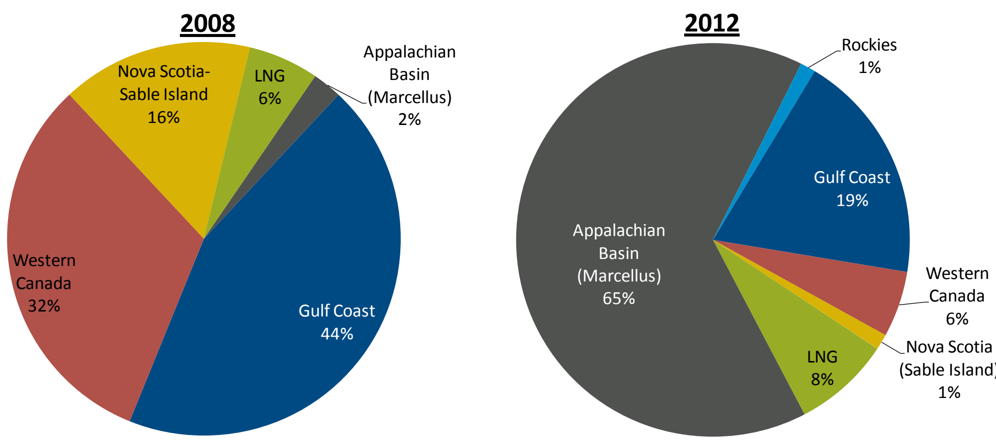
GAS SUPPLY SOURCES AND PIPELINE UTILIZATION

Until recently, the majority of natural gas supply serving New England was produced in the Gulf of Mexico or Canada and transported to regional consumers through the TGP, AGT, and Iroquois pipelines, but this trend has shifted in recent years due to the emergence of shale resources in the Northeast US. In their delivery of natural gas supplies to New England, TGP and AGT have replaced supplies from the Gulf of Mexico and Western Canada with newly developed Appalachian production from what is commonly referred to as the Marcellus Shale. This increased reliance on Appalachian supplies has been exacerbated by declines in natural gas production in the Gulf of Mexico and Western Canada.

Eastern Canadian supplies augmented the regional supply portfolio beginning in December 1999 with the onset of production from Nova Scotia's Sable Offshore Energy Project ("SOEP") and the construction of the M&NE pipeline. In recent years, however, these natural gas supplies have served a decreasing share of New England gas demand as production has declined. Deep Panuke, another offshore Nova Scotian gas play under development by Encana, could potentially offset SOEP declines, but has experienced numerous production delays and cost overruns. Deep Panuke production is expected to commence in 2013, with Repsol, the majority owner of the Canaport LNG terminal, owning the production capacity. Shale exploration in New Brunswick and Newfoundland is still in its early stages, with limited exploratory drilling activity.

Figure 2 summarizes the recent rapid and sizable shift in the origin of natural gas supplies serving New England. As recently as 2008, approximately three quarters of the natural gas supplying the region was from the Gulf Coast and Western Canada. Supplies from those sources now comprise approximately 25% of total supply, while Marcellus shale production accounts for more than half (65%) of total supply to the region.

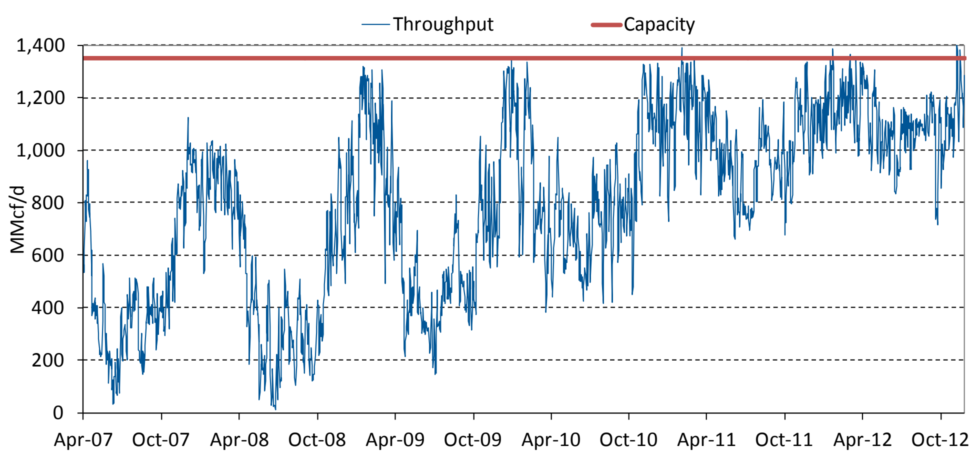
Figure 2: New England Natural Gas Supply by Source



Source: *Black & Veatch Analysis, LCI Energy Insight, Pipeline Electronic Bulletin Board Data*

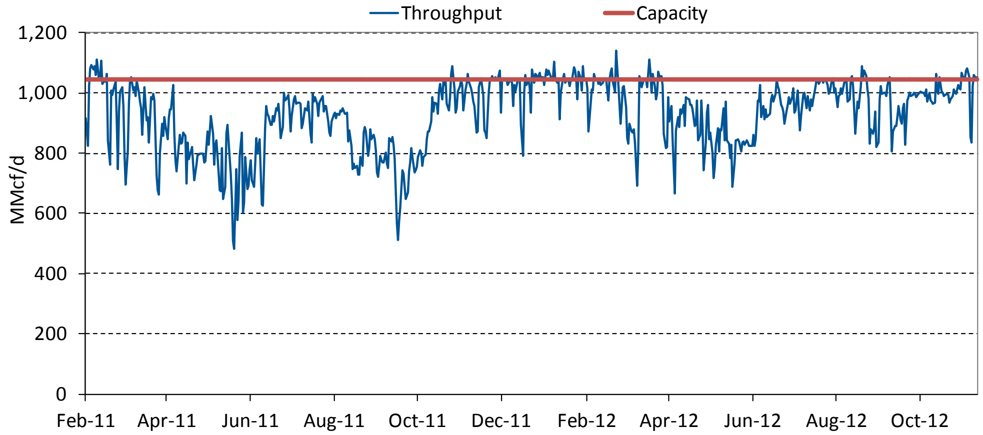
This supply realignment has caused a shift in interstate pipeline flow patterns into New England. Interstate pipelines that bring Marcellus Shale production to the New England market have recently approached 100% utilization of their capacities over the last year, as illustrated in Figure 3, Figure 4, and Figure 5 . In recent years, flows on AGT and TGP have increased in both summer and winter, increasing year-round utilization. This will affect interruptible transportation capacity and hourly flexibility available to power generators during periods of peak demand.

Figure 3: Historical Algonquin Pipeline Utilization



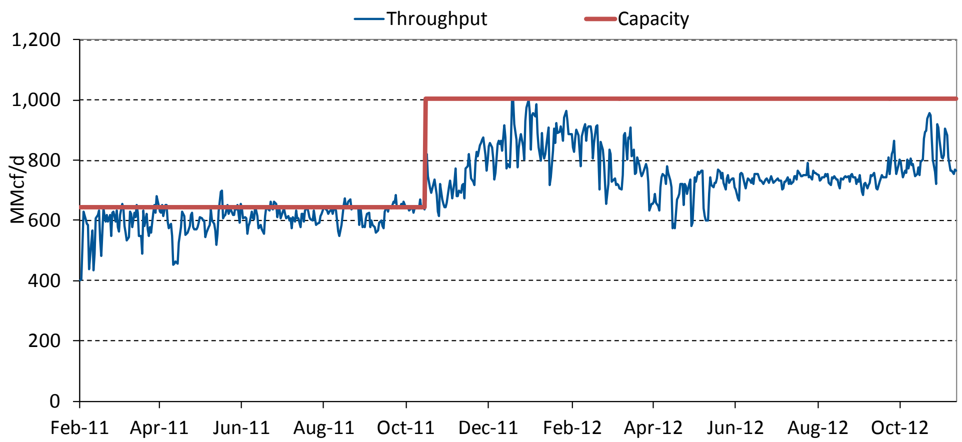
Source: *LCI Energy Insights*

Figure 4: Historical Tennessee Gas Pipeline Station 245 (200 Line) Throughput



Source: *Pipeline Electronic Bulletin Board Data*

Figure 5: Historical Tennessee Gas Pipeline Station 325 (300 Line) Throughput



Source: *Pipeline Electronic Bulletin Board Data*

LIQUEFIED NATURAL GAS IMPORTS

LNG import volumes also serve New England natural gas demand and have traditionally been considered a supplemental supply source to pipeline deliveries. However, given that the US market price is perceived as less competitive compared to other global markets, the future of these imports is uncertain.

In 2011, total LNG imports into the New England LNG terminals averaged approximately 470 MMcf/d, compared to approximately 249 MMcf/d for 2012 to date.

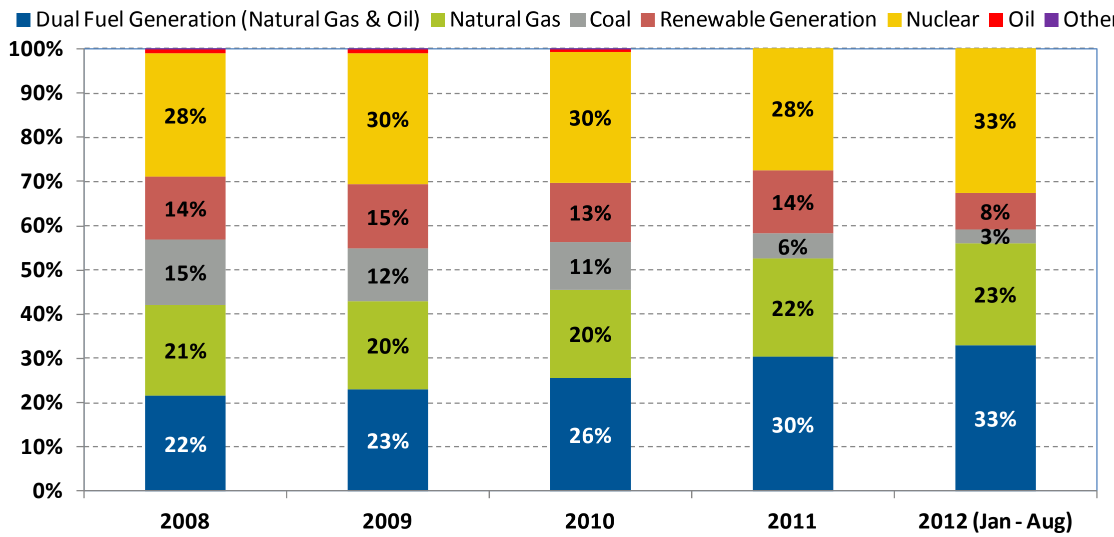
LNG PEAK SHAVING FACILITIES

New England's LNG peak-shaving facilities can deliver up to 1.36 Bcf/d with about 16 Bcf of total storage capacity[12] from locations in Connecticut, Massachusetts, New Hampshire, and Rhode Island. LNG peak-shaving facilities supplement supplies from interstate pipelines and LNG terminals during days of peak winter demand, and are accordingly only utilized on days of extremely high demand.

DUAL-FIRED CAPACITY

Over 10,000 MW of dual-fired generation capacity resides in New England that can use oil as an alternative fuel if natural gas supply is not readily available[13]. The dispatch of New England's dual-fired capacity has steadily increased from 22% of total New England generation in 2008 to 33% by 2012, as shown in Figure 6. Over the same period, dual fired generation units have relied more heavily on natural gas than oil, limiting the oil generation of these units from 9.1%to less than 0.7% of total dual fired generation in 2011.

Figure 6: New England Net Generation by Fuel Type



Source: *Energy Information Administration Form 860*

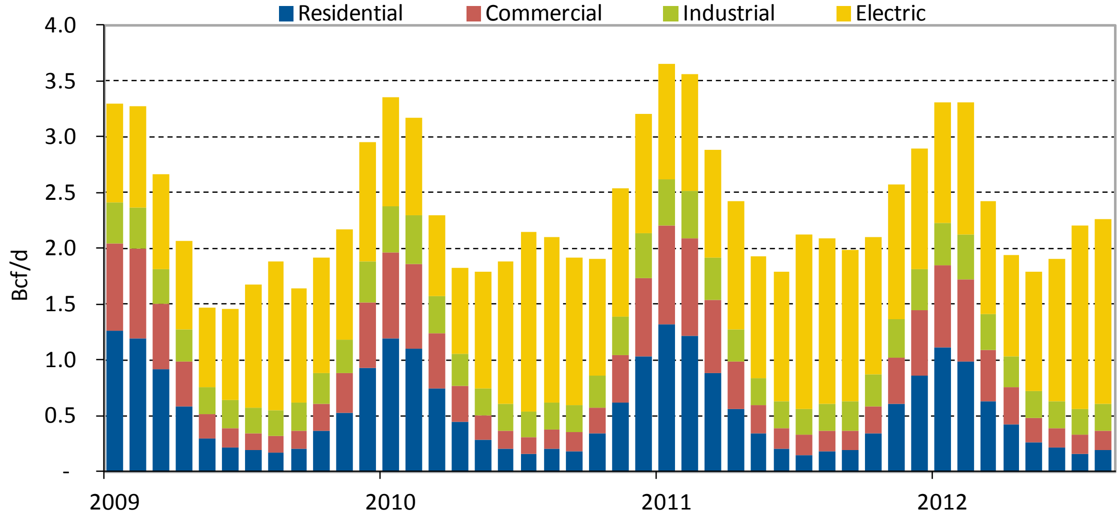
NATURAL GAS DEMAND

Natural gas demand in New England has grown at a robust pace in recent years, with average daily consumption growing from 2.04 Bcf/d in 2005 to 2.35 Bcf/d in 2011. Winter demand observed during "core" winter months (December through February) has grown at an even greater rate, with consumption in January 2011 0.9 Bcf/d greater than peak winter consumption observed in February 2006. When factoring winter weather conditions into demand growth, the average daily consumption for a given heating degree day is generally rising year over year during these core winter months.

On an annual basis, as a percentage of New England's natural gas demand, the residential and commercial sectors comprise approximately 40%, the electric sector comprises 50%, and the industrial sector comprises 10%.

New England's natural gas demand from the electric sector has experienced more robust growth than demand from other sectors. As illustrated below, electric sector demand has experienced average annual growth of nearly 8% from 2009 to 2011 as compared to New England natural gas demand from all other sectors, which has experienced a more modest growth rate of approximately 4.3% per annum from 2009 to 2011.

Figure 7: New England Natural Gas Demand



Source: *Energy Information Administration*

4.0 Study Review

STUDIES REVIEWED

Black & Veatch and NESCOE jointly identified thirty-five papers and presentations that directly or indirectly consider New England's natural gas infrastructure adequacy. These papers and presentations were authored by a variety of industry stakeholders, including market operators, natural gas pipeline companies, electric generators, transmission companies, energy service providers, and gas and electric utilities. Table 2 summarizes the thirty-five papers and presentations organized by the stakeholder groups that authored them.

Table 2: Overview of Studies Reviewed

Stakeholder	Count	Topics Addressed
Natural Gas Pipelines, Natural Gas Industry Associations	**18**	• Recent pipeline operational developments caused by Marcellus production growth and increased electric sector demand • Proposed projects to add incremental transportation capacity and their associated benefits
Natural Gas Suppliers (Producers, LNG Importers)	**4**	• Natural gas production trends and projected natural gas prices • Assert that Canadian supplies can back-feed the New England market
Electric Generators	**4**	• Operational concerns of electric generators related to increasing use of natural gas as a power fuel • Reliability concerns due to market incentives
ISO-New England	**5**	• Potential reliability risks associated with the interface of natural gas and electric markets • Quantify the potential shortage in near-term natural gas capacity available to New England power generators • Proposed revisions in market design to encourage investments in fuel supply reliability
Federal Energy Regulatory Commission	**2**	• Concerns of gas and electric industry participants regarding natural gas-electric interdependency as raised in several regional meetings • New England 2012-213 winter outlook - potential for natural gas constraints
NERC and MISO	**2**	• NERC - potential issues associated with gas-electric interdependency • MISO - outlook on pipeline capacity needs in the MISO region

COMMON STUDY TRENDS

The objectives, approaches, and relevance of the studies and presentations we reviewed vary. Nonetheless, these studies consistently focus on several key issues impacting electric-gas reliability in New England.

The following are the key issues as identified by the studies we reviewed.

First, robust growth in demand for natural gas from New England's electric sector is expected to continue. There are abundant natural gas resources in shale plays across the US that can be produced at reasonable costs and with limited environmental impacts[14]. It is generally expected that natural gas prices will rise from the lows reached in 2012, but remain stable in the near term due to gains in production efficiency and revenue uplifts granted by petroleum liquids. In addition, rising environmental compliance costs for coal and oil fired generation capacity will make natural gas the fuel of choice both for incremental capacity build and the replacement of retired oil and coal fired capacity[15].

Second, traditional differences in investment, marketing and operations between the natural gas and the electric industries could result in generator outages caused by lack of economic fuel supply. This increases reliability risk. The increased prominence of natural gas as an electric generation fuel raises a number of logistical issues that, if unaddressed, pose reliability risks to the electric grid. Some studies indicate that these issues are largely the result of New England generators not holding firm natural gas transportation capacity on interstate pipelines and instead relying on interruptible capacity to meet their gas needs. Major issues include a mismatch between electric and natural gas nomination schedules, constraints in the physical operation of natural gas pipelines in meeting the intraday swing of gas generators, and maintenance schedules for natural gas pipelines[16].

Third, New England's electric market, as currently designed, does not provide sufficient financial incentives for generators to firm up their natural gas fuel supply. Generators do not receive compensation for investments in costly firm fuel supplies that could ensure they are able to dispatch electricity during periods of capacity constraints when it is needed the most[17].

Finally, multiple natural gas infrastructure projects have been proposed to connect growing Marcellus Shale natural gas production to markets in the Northeast US, Southeast US, and Canada. At the time this report was commissioned, only one proposal (Spectra's AIM project) had been made to build incremental capacity directly from Marcellus Shale production into New England. More recently, Tennessee Gas Pipeline proposed two expansion projects that could bring up to 1.2 Bcf/d of incremental Marcellus supplies to New England markets as early as 2016[18]. The construction of interstate natural gas pipeline capacity requires FERC regulatory approval that is highly contingent on the demonstration of market need. Such "need" is typically evidenced by long-term (10+ year) firm contract customer commitments. As LDC demand growth in New England generally lags growth experienced by the electric sector, without proper incentives in place to encourage power generators to purchase firm natural gas transportation capacity, it will become increasingly difficult for proposed pipeline projects to gain the requisite firm capacity commitments for regulatory approval[19].

While the Findings and Recommendations contained herein reflect our review of each of the aforementioned thirty-five papers and presentations, Black & Veatch focused its detailed review on four papers that provided the most detailed exploration and assessment of New England's natural gas infrastructure adequacy and related incentives:

- The "ISO-NE Gas Study": Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs, prepared for ISO New England by ICF, June 2012.
- The "Spectra Study": New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corp by Concentric Energy Advisors, May 2012.
- "ISO-NE July Whitepaper": Addressing Gas Dependence. ISO-NE. July 2012.
- "ISO-NE October Whitepaper": FCM Performance Incentives. ISO-NE October 2012.

Only the ISO-NE Gas Study attempts to quantify New England's natural gas infrastructure deficit. While the other three studies provide thoughtful and detailed analysis on related issues, they largely treat infrastructure inadequacy as a given. The Spectra Study estimates potential cost savings of incremental pipeline capacity from the Mid-Atlantic region to New England. The two ISO–NE papers provide an overview of natural gas fuel supply concerns to the electric industry and possible strategies that ISO-NE could employ to alleviate them.

Table 3 summarizes our review of each of the four studies we focused on and highlights their main gaps.

Table 3: Overview of Major Studies

	ISO-NE Gas Study	Spectra Study	ISO-NE White Papers
Scope	Assess the adequacy of natural gas pipeline capacity to serve core and electric sector demand in New England. "Deficiency" defined as a lack of adequate interruptible natural gas transportation capacity available to New England power generators.	Estimates benefit of incremental natural gas pipeline capacity from the Mid-Atlantic to New England	Discusses reliability issues that could arise from growing demand from natural gas-fired generation capacity and proposes several solutions.
Conclusions	1,500 to 2,300 MW equivalent capacity deficiency of interruptible natural gas transportation capacity available to New England Power Generators through 2020	Estimated benefit to New England of $420 to $630 million as a result of 300 MMcf/d of incremental natural gas delivery capacity	Propose several electric market incentives to mitigate reliability risk: • Allow hourly and intra-day offers to reflect the real-time cost of power generation • Better align natural gas and electric nominating schedules • Re-design the Forward Capacity Market
Analysis Gaps	• Does not consider impact of greater North American market on New England • Does not consider intricacies of New England natural gas and power infrastructure • Does not explore potential duration and probability of supply deficiency	• Incremental infrastructure may not restore historical price relationships as assumed in study • Deterministic analysis does not consider uncertainties related to evolving market conditions • Does not explore potential duration and probability of supply deficiency	• Do not explore costs, benefits, or market responses of proposed solutions

APPROACH

To develop an opinion on the conclusions reached the materials reviewed, Black & Veatch considered the following evaluation criteria:

- **Scope**: What issues are covered by the study scope and to what extent does the study address those issues?
- **Methodology**: What approach was utilized by the study to examine the issue at hand?
- **Assumptions**: What key assumptions were made in the study regarding electric market developments as well as natural gas infrastructure and the demands placed on it?
- **Uncertainties**: Did the study address uncertainties that could arise during the study period?
- **Analytical Tools**: What software and analytical tools were utilized?

DISCUSSION OF STUDIES

The ISO-NE Gas Study

Scope

The report assesses the adequacy of the region's natural gas pipeline infrastructure through a review of the projected growth in contracted natural gas firm transportation capacity needs of LDCs as well as projected electric demand growth in New England[20].

Within the context of the study, a natural gas supply "deficiency is defined as a lack of adequate interruptible natural gas pipeline capacity to meet the demand of New England power generators, assuming that firm transportation capacity held by LDCs is utilized at 100% of contracted volumes.

Based on this definition, the study concludes that New England's power generators should expect an interruptible pipeline capacity deficiency equivalent to 1,800 MW to 2,600 MW through 2020. This conclusion is based on an assumed gas demand forecast that is reflective of ISO-NE's 2011 Regional System Plan reference case (90/10) [21] electric demand. The deficiency is expected to occur under an LDC winter design day[22] assumption. No deficiency is expected for the peak summer day.

Methodology

The study utilizes a transparent process to determine the level of New England's natural gas infrastructure deficiency as defined by the study. First, total firm natural gas capacity available to the New England market is calculated, including firm capacity on interstate pipelines, LNG peak shaving capacity, and firm LNG import capacity. LDC firm demand needs, as reflected through growing design day demand, are then subtracted from firm capacity sources to determine the interruptible natural gas capacity available to power generators. This estimated available interruptible capacity is compared with the projected natural gas demand from the electric sector to quantify the level of surplus or deficit. As stated in the study, this approach does not necessarily identify that New England natural gas pipelines are physically under-designed and incapable of meeting firm transportation obligations. This is because the capacity deficit is estimated based on LDCs' design day requirement, which only occurs once over the course of several decades. The actual LDC load could be lower, reducing the "deficit" to electric generators.

Key Assumptions

The study assumes all gas supply sources serve the New England market as a homogenous whole; the specific location of pipeline capacity, upstream supply sources, and distribution of demand are not considered when assessing infrastructure adequacy. Supply adequacy was evaluated under a LDCs' winter design day. The natural gas needs from the electric sector were obtained from ISO–NE's 2011 planning scenarios.

The study assumes that a single pipeline expansion will offer incremental natural gas pipeline delivery capacity into New England. AGT's proposed AIM project totaling 350 MMcf/d of incremental capacity serving the New England market is assumed to be in service by 2017. Northeast Gateway and Neptune, the two LNG import facilities serving the New England market without firm supply agreements are excluded from the study's estimate of total firm natural gas supply capacity available to serve New England.

Uncertainties

The ISO-NE Gas Study utilizes scenarios to consider the uncertainties related to natural gas and electric markets going forward. Three demand scenarios are utilized to represent higher natural gas demand from the electric sector that exceeds what is assumed in the base case. The supply deficiency under design winter day conditions for these high demand scenarios ranges from an equivalent of 1,500 MW to 5,700 MW. With the exception of several years under the maximum gas demand scenario, adequate interruptible transportation capacity is available to power generators in all demand scenarios during peak summer day conditions.

The study also analyzes a contingency scenario, which is not available to the public, that considers the possible effect of gas supply disruptions.

Analytical Tools

The study does not explicitly utilize analytical tools to assess gas supply adequacy. Production simulations produced using ISO-NE's Inter-Regional Electric Market Model ("IREMM") are, however utilized within the study to project natural gas demand from the electric sector under several scenarios.

Black & Veatch Commentary

The study's approach is appropriate when considered in the context of its scope. However, as acknowledged in the study, the scope of its analysis was limited. This limited scope prevents the study from providing a more comprehensive picture of the natural gas supply/infrastructure adequacy for the electric sector in New England. Some gaps are as follows:

- The study assumes all pipeline capacity serving New England is capable of serving the demand of the region irrespective of the geographic location of pipeline capacity and demand. The study therefore does not consider the locational intricacies of New

England's natural gas and electric transmission infrastructure or the relative location of power generation units in the region. Although the study attempts to quantify New England's natural gas pipeline infrastructure inadequacy on an aggregate level, this lack of geographic specificity could distort the magnitude of the infrastructure inadequacy estimated by the study.

- As a simplifying assumption, the study treats gas production serving New England as an aggregate supply source that can fill the contracted capacity available to the region. Such an approach does not consider the outlook for various supply sources to fill the pipeline capacity serving New England going forward; if supplies from a basin are expected to experience significant declines, then incremental capacity into the region served by that basin will do little to alleviate reliability concerns. For example, the future of Canadian production serving New England is a major issue that must be considered when exploring potential investments in incremental infrastructure. Eastern Canadian production is expected to decline while robust production growth from the Marcellus Shale is expected to continue. In addition, if robust natural gas demand growth is expected upstream of New England, the supplies filling incremental capacity into New England could be consumed before they reach New England or alternatively, New England customers would have to compete with upstream demand in order to attract gas supplies. These supply dynamics suggest that the TGP and the AGT pipelines could be more constrained than the Maritimes and Iroquois pipelines. Consideration of incremental infrastructure must include the long-term supply dynamics of production basins serving the region and integrated demand dynamics.
- The conclusions are limited to only two daily conditions: a winter design day and a summer peak day. These conditions are static and do not provide any insights into the likely duration of infrastructure inadequacy. For example, the incremental infrastructure needed to serve several consecutive days of expected infrastructure inadequacy is likely far different from that required to alleviate a single day of inadequacy. In addition, the expectation of brief but sudden supply inadequacy for several hours in a given day necessitates an infrastructure solution that allows for the rapid deployment of incremental capacity on an intraday basis. Understanding the duration and probability of occurrence for these constraints is crucial to any cost benefit analysis of potential infrastructure solutions.

The Spectra Study

Scope

This study sets out to estimate the potential benefits that could be achieved with incremental natural gas infrastructure in the New England market. These benefits are estimated as the potential cost savings that could be achieved by a reduction in New England[23] natural gas and electric prices for the year 2011 through the construction of incremental natural gas pipeline capacity from the Mid-Atlantic to New England. The study estimates direct cost savings of $223 to $293 million to the electric sector from a natural gas pipeline offering 300 MMcf/d of capacity to New England from the Mid-Atlantic.

Methodology

The study utilizes econometric analysis as a statistical means of understanding the historical relationship of natural gas prices between two market points. A statistical review of historical monthly natural gas prices in New England and the Mid-Atlantic[24] shows that New England prices exhibited an above-average (when compared to historical trends) price premium over Mid-Atlantic prices in 2011. The study assumes that this price premium was driven by inadequate natural gas pipeline capacity between the two regions. It further assumes that incremental pipeline infrastructure between the two regions will resolve the physical constraints and in turn restore the historical price relationship between the two regions by reducing New England prices while holding Mid-Atlantic prices constant at levels observed in 2011. The study further estimates additional cost savings for the New England market assuming that Mid-Atlantic prices were even lower than observed in 2011.

Key Assumptions

The study's natural gas demand growth assumptions are based on projections from publically available sources, such as LDC integrated resource plans as well as EIA and ISO–NE planning scenarios.

The study makes two implicit assumptions in estimating the cost savings to New England consumers. First, incremental pipeline capacity will restore the historical price relationship between the New England and the Mid-Atlantic market by reducing New England prices. Second, incremental infrastructure will allow expected lower priced Mid-Atlantic supply - resulting from Northeast shale gas production - to flow through to New England and therefore lower New England natural gas market price.

Uncertainties

The Spectra Study is deterministic and does not explicitly consider uncertainties related to the future natural gas and electric markets. The assumption that the pricing relationship between the Mid-Atlantic and New England will return to historical norms with the inclusion of incremental infrastructure between the two regions does not consider other fundamental market factors that could impact this price relationship. These unaccounted for factors include changes in natural gas production serving New England and demand growth dynamics in New England and the Mid-Atlantic.

Black Veatch Commentary

Black & Veatch agrees, as posited by the study, that incremental pipeline infrastructure alleviates market constraints. Certainly, incremental pipeline infrastructure between the Mid-Atlantic and New England will benefit the New England market, resulting in lower natural gas and electric prices. Black & Veatch also concurs that incremental natural gas infrastructure into New England will more than likely be constructed to receive natural gas from the Mid-Atlantic region due to the growth potential of Marcellus Shale production. However, gaps remain that prevent the study from fully addressing New England's natural gas infrastructure needs and potential benefits from incremental infrastructure. Those gaps are as follows:

- **Cost savings estimated through the exclusive use of statistical analysis of historical data may not be representative of the actual market response**. The assumption that incremental infrastructure will bring the pricing relationship between the Mid-Atlantic and New England back to historical norms does not consider key fundamental market factors that could impact this price relationship. These factors include natural gas production serving New England and demand growth in New England and the Mid-Atlantic. For example, it is likely that incremental infrastructure will result in a combination of higher Mid-Atlantic prices due to increased market outlets for Appalachian supplies and lower New England prices due to the alleviation of delivery capacity constraints. The market impact of incremental infrastructure and its associated benefits are best gauged through a forward-looking fundamental model that considers the future natural gas and electric market dynamics in New England as well as across North America.
- **Although the study analyzes the potential social benefits of incremental infrastructure, it does not consider the costs associated with this infrastructure or how those costs will be distributed among market participants.** As noted, full cost-benefit analysis of potential solutions is far more valuable than an assessment that only considers potential benefits. Without information about cost implications, it is reasonable to expect low levels of confidence about potential options and a dampened likelihood of consensus about which solutions may be most appropriate.

The ISO-NE White Papers

Scope

Two ISO-NE White Papers identify issues that could arise from the increasingly important role natural gas plays in the electric industry and outline potential solutions to alleviate these issues.

ISO-NE October Whitepaper

ISO-NE presents a detailed re-design of the electricity Forward Capacity Market ("FCM") to reward generators who provide energy during periods of electric capacity constraints. The new performance incentive design will, if adopted and operates as ISO-NE expects, result in payment transfers from under-performing to over-performing generation resources. If the changes function as ISO-NE suggests, they will provide strong incentives for each resource to perform as needed and encourage generators to invest in firming up fuel supply to produce energy, especially when electric capacity shortages occur.

ISO-NE has three concerns relative to the current FCM and natural gas markets.

- **Performance of resources**. Aging resources that ISO-NE relies upon for peaking, ramping, and reserves are beginning to demonstrate deficiencies in performance. Notable events during September 2, 2010 and January 14-24, 2011, in which pipelines curtailed natural gas deliveries to electric generators, clearly highlighted these deficiencies.
- **Natural gas adequacy**. Increased reliance on natural gas-fired resources is impacting the ability of the interstate pipelines to provide adequate capacity during periods of high utilization of gas for both generation and other natural gas needs.
- **Flexibility of resources**. The mix of supply resources, particularly non-dispatchable renewable generation (namely wind generation) may reduce ISO-NE's ability to dispatch resources in a flexible manner which, in turn, impacts reliability. As new natural gas-fired resources are added to replace the aging units cited and to meet the increased needs for balancing for non-dispatchable resources, increased demand for natural gas could exacerbate existing natural gas capacity constraints.

ISO-NE has proposed incentives that will provide four benefits.

- Promote operation-related investment to ensure resources are available when needed to maintain reliability
- Increase resource responsiveness and flexibility through shortened start times and/or increased ramp rates
- Improve cost effectiveness by rewarding suppliers that implement improvements to enhance system performance and availability
- Promote efficient resource evolution that will improve flexibility and efficiency of future generation mix

ISO-NE June Whitepaper

The ISO-NE June White Paper proposes changes to bidding rules that allow generators to make hourly and intra-day offers to reflect their real-time costs of generation. These changes are designed to provide financial incentives to generators to produce energy in real-time.

Currently, there is a mismatch of timing between natural gas supply and generation dispatch that does not allow generators the opportunity to secure firm gas after they know whether they have been selected to dispatch in the next day's energy market. ISO-NE proposes to alter the timing of the day-ahead market so that generating schedules are published earlier to help gas-fired generators to purchase and nominate for flow the appropriate amount of gas for its generation use.

Methodology

The ISO-NE White Papers do not assess or quantify the adequacy of natural gas pipeline infrastructure serving New England. Instead, they review concerns related to the increasing gas dependency of the New England generation fleet and propose revisions to bidding rules and Forward Capacity Market ("FCM") design to mitigate anticipated reliability issues.

Key Assumptions

The white papers do not make specific supply, demand and infrastructure assumptions because they do not independently estimate natural gas infrastructure or supply capacity inadequacies. Rather, they make broad assumptions related to the interdependency of natural gas and electric markets, assuming New England's dependence on natural gas will continue as a result of increasing reliance on natural gas as a power fuel.

Black & Veatch Commentary

Black & Veatch believes that the ISO-NE White Papers accurately depict the issues arising from New England's increasing reliability on natural gas. Furthermore, the solutions proposed in these white papers could serve to mitigate these issues[25]. However, the scope of the ISO-NE White Papers does not include detailed analysis to address the following key issues, which in our view are important to the consideration of potential solutions:

- Analysis that illustrates the potential magnitude, location and duration of the constraints
- Assessment of the expected magnitude of the over-performance premium
- Evaluation of the costs and benefits of different options to firm up fuel supplies

5.0 Conclusions and Recommendations

Black & Veatch believes that the natural gas infrastructure serving New England will become increasingly stressed as regional demand for natural gas grows. ***The increasing prominence of natural gas as a power fuel in the New England generation fleet raises electric reliability concerns.*** Given that New England relies almost exclusively on natural gas supplies and storage from outside the region, natural gas infrastructure constraints could develop at key locations across the region. However, as previously stated, studies conducted to date do not fully define the extent or explore the ramifications of potential inadequacies.

The inability of gas-fired generators to meet dispatch obligations for lack of fuel could place the reliability of electric service at risk. This is especially true during periods in which the region is tight on generation capacity and faces localized congestion. Accordingly, a full understanding of the extent of natural gas infrastructure inadequacy and a comprehensive assessment of possible solutions is important. For example, more detailed information on the timing and magnitude of any natural gas deficiency would inform consideration of appropriate strategies to relieve inadequacies. The following graphic illustrates the integrated framework that Black & Veatch utilizes when assessing natural gas infrastructure adequacy for the electric sector.

There is no study to date that has approached the issue in a comprehensive manner that considers each of the elements outlined above. The studies reviewed for this report consider some of these elements, but due, in part, to the limited topics covered in their scopes, none concurrently incorporate each element into a single study.

Black & Veatch believes that concerns over New England's infrastructure adequacy could be strengthened in several key areas:

Definition of Adequacy for Natural Gas Infrastructure

No study or other benchmark specifically articulates what level of natural gas infrastructure could be considered "adequate" to alleviate the electric reliability challenges facing New England. A benchmark specific to the region is needed to identify the level of infrastructure required to achieve an acceptable balance of costs, benefits, and systemic reliability risk.

What constitutes gas supply adequacy for power generators (and a regional grid in the aggregate) is typically a location-specific determination affected by numerous factors including load characteristics, geography, power infrastructure and fuel alternatives. For this reason, having "adequate natural gas supplies" does not necessarily require that the natural gas infrastructure meets the last unit of peak natural gas demand. There can be a variety of alternatives available to optimize the investments in gas and power reliability as the system moves closer to meeting 100% of peak natural gas demand.

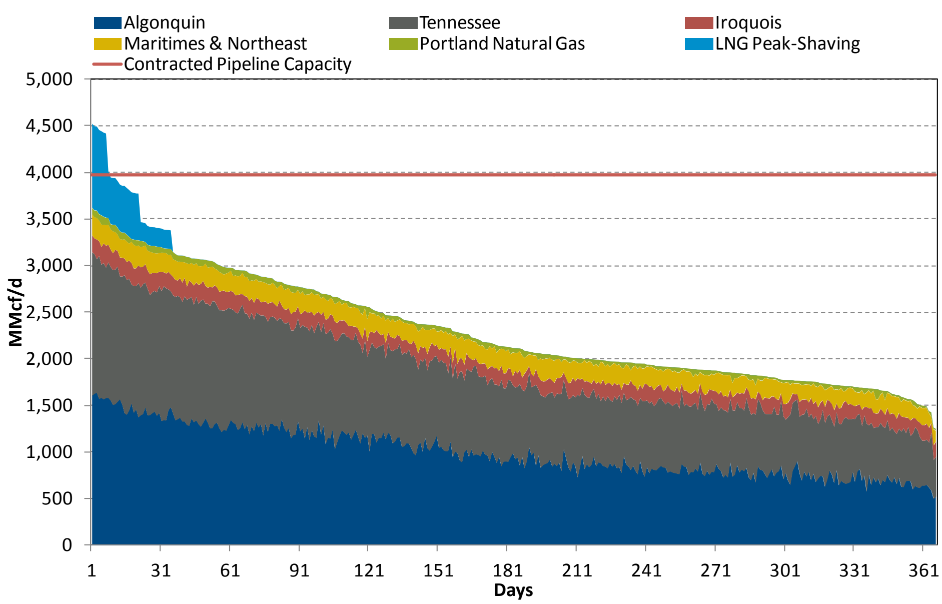
Defining adequacy and the trade-off between costs, reliability and economic benefits should also recognize the individual risk tolerances of industry participants. A one-size-fits-all set of rigid benchmarks will be difficult, if not impractical, to construct given the multitude of variables involved. For this reason, it is advisable for regions and individual market participants to have prominent roles in the determination of appropriate adequacy measures.

Dynamic Natural Gas Demand Projections

A static projection of future demand on a single average, peak, or design day, as examined in the ISO-NE Gas Study is not sufficient to assess the adequacy of natural gas infrastructure. ***No study has examined the seasonality, daily and hourly fluctuations of demand in an effort to identify the nature and duration of potential infrastructure constraints***. Figure 8, which catalogues natural gas deliveries to New England over the past 12-months, indicates that aggregate deliveries to the region are more often than not less than the total delivery capacity into the region.

If demand growth in the future causes total gas demand to exceed pipeline capacity, the duration of this capacity shortage will be a key factor in determining appropriate size, type, and placement of incremental infrastructure. If the constraints are transient in nature, firm fuel solutions for peak periods, such as peak shaving facilities, or peak electric solutions, such as demand side management, may be more cost effective than the construction of pipeline capacity that must be paid for 365 days of the year.

Figure 8: Natural Gas Pipeline Deliveries to New England

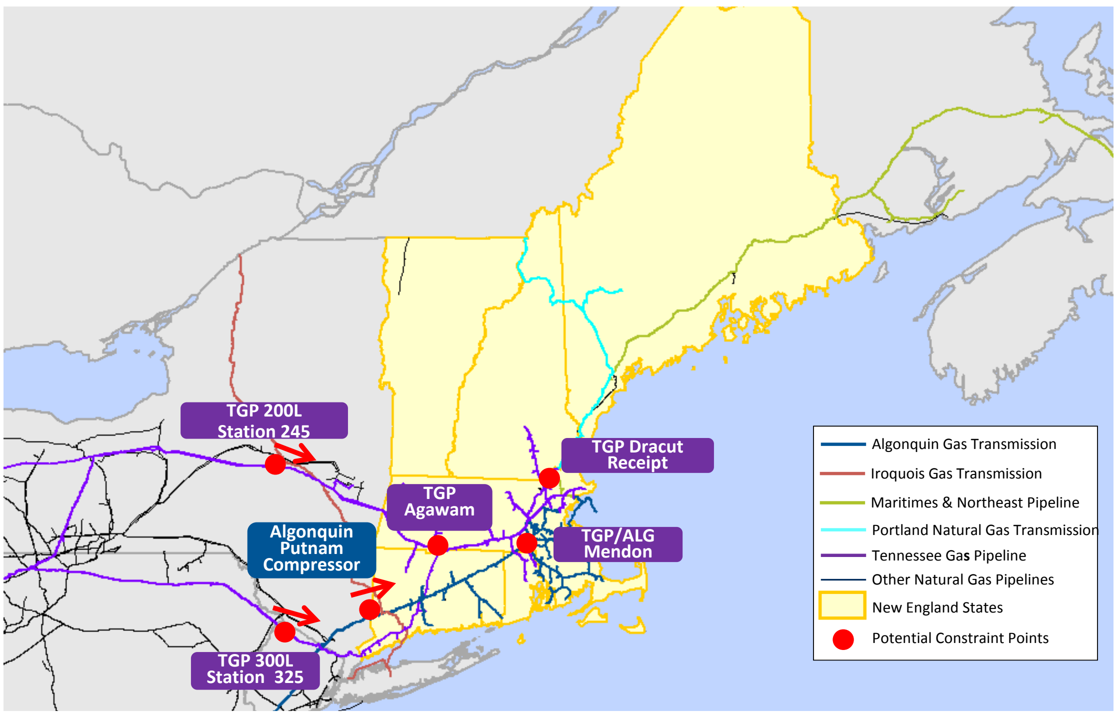


Source: *Black & Veatch Analysis, Pipeline Electronic Bulletin Board Data, LCI Energy Insight*

Identification of Localized Constraints

No study to date has considered the intra-regional constraints and unique characteristics of New England's natural gas and electric infrastructure. Constraints develop in specific locations due to the complex nature of New England's natural gas infrastructure. For example, at the TGP Agawam junction where TGP's 200 and 300 lines meet, total eastbound capacity on the pipeline is reduced from over 2 Bcf/d to just over 1 Bcf/d and begins to reduce in capacity as it reaches the greater Boston market. More detailed studies should, at a minimum, address the differences between western and eastern New England gas markets.

Figure 9: Illustrative Pipeline Constraint Points in New England



Source: *Black & Veatch Analysis, Energy Velocity, Pipeline Electronic Bulletin Board Data*

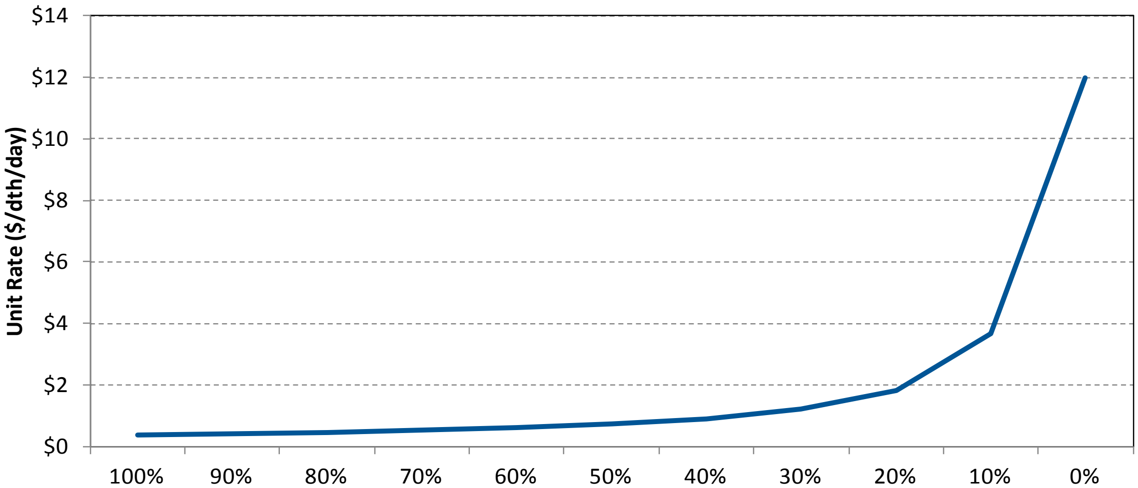
No study to date has examined the distribution of electric and natural gas demand across New England. The specific location of electric and natural gas infrastructure as well as load centers is critical to understanding the adequacy of the natural gas infrastructure to meet the needs of the region. For example, the implications of curtailments to natural gas-fired generators in the Northern Massachusetts/Boston area could be more severe than curtailments at less capacity-constrained areas.

Modeling these localized electric and natural gas supply and demand dynamic is essential to evaluating system adequacy and the value of incremental investments.

Costs and Benefits of Incremental Infrastructure

No study reviewed examined the costs of constructing incremental infrastructure. An infrastructure solution might yield benefits, but its implementation will not be supported by market participants if it levies unreasonable costs on those participants. In addition to total investment costs, the projected utilization of incremental infrastructure must be considered, given that the construction cost likely will be distributed across each unit of gas utilized under a tolling mechanism. As illustrated in Figure 10, if a pipeline expansion is built to alleviate capacity inadequacy projected to occur only several days of each year, a low share of its design capacity will be utilized and result in major increases of its effective unit rate. In such a case, other incremental infrastructure that is better suited to serving more sporadic capacity needs, such as peak-shaving capacity, should be employed.

Figure 10: Illustrative Effective Unit Cost of Gas Transportation Across Utilization Levels



Source: *Black & Veatch Analysis*

No study has quantified the benefits of additional infrastructure in a way that accounts for the uncertainties attributable to market fundamentals

Estimating the benefits of incremental infrastructure exclusively through statistical analysis of historical data, as done in the Spectra study, may not fully capture uncertainties associated with market dynamics. Fundamental modeling for the natural gas and electric markets, however, would enhance any quantification of the benefits offered by incremental infrastructure investments.

In sum, given that New England is located at the terminus of the natural gas supply infrastructure, relies on supplies from outside the region, and contains no underground storage capacity to provide supply flexibility, Black & Veatch expects the natural gas infrastructure serving the region will become increasingly stressed as regional demand for natural gas grows and that policymakers would find substantial value in filling the information gaps identified here. Most notably, we believe more granular assessments of the adequacy of natural gas infrastructure, potential solutions, and their costs and benefits will aid policymakers in their decisions going forward.

Appendix A – Materials Reviewed

Recent Studies, Presentations and Data Points In Connection with New England Natural Gas Supply and Implications on the Reliable Operation of the Electric Power System

1. *New England Cost Savings Associated with New Natural Gas Supply and Infrastructure*. Concentric Energy Advisors. May 2012.

2. *New Jersey Natural Gas Market Analysis*. Concentric Energy Advisors. March 2011

3. *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Power Generation Needs*. ICF International, LLC. June 2012.

4. *Transco Line Northeast and Mid-Atlantic Projects*, Williams Partners LP, 7th Annual Platts Development & Expansion.

5. *Natural Gas Whitepaper*. ISO-NE. 2012.

6. *Coordinating Natural Gas & Electricity in New England*. Vamsi Chadalavada. June 2012.

7. *A Natural Gas Generator's Perspective*. James Ginnetti. June 2012.

8. *Natural Gas and Electric Generation --- Issues and Opportunities*, Bill Yardly, Group Vice-President, Spectra Energy. June 2012.

May 2012 NECPUC Symposium:

9. *Coordinating Natural Gas & Electricity in New England*. Peter T. Brandien - Vice President, System Operations, ISO-New England. May 2012 NECPUC Symposium.

10. *Gas-Electric Market Coordination. Tom Kaslow - Director, Market Design & Policy, IPR-GDF*
    SUEZ North America, Inc. May 2012 NECPUC Symposium.

11. *Natural Gas - A National Treasure.* Steve Mueller - President & CEO, Southwestern Energy Company. May 2012 NECPUC Symposium.

12. *Integrating Natural Gas and Renewable Generating Resources: Natural Gas Pipeline Perspective*. Donald Santa - President & CEO, Interstate Natural Gas Association of America. May 2012 NECPUC Symposium.

13. *Integrating Variable Resources and Natural Gas.* Russ Young - Market Development Manager, GE Power & Water. May 2012 NECPUC Symposium.

14. *System Planning: Reliably Integrating and Managing Systems*. Steve Rourke - Vice President, System Planning, ISO-New England. May 2012 NECPUC Symposium.

15. *A New Englander's Perspective: Shale Gas-Quantities, Price and What's to be Done*. Richard L. Levitan, President, Levitan & Associates. May 2012 NECPUC Symposium.

16. *Natural Gas: Smarter Power Today.* Matt Most - Vice President, Environmental Policy, Encana. May 2012 NECPUC Symposium.

May 2012 NECPUC Symposium

17. *The North American and Northeastern US Natural Gas Markets*. Bob Fleck, Vice President/Americas Gas and Power Consulting, Wood Mackenzie. May 2012 NECPUC Symposium. *Northeast Gas Association 2012 Regional Market Trends Forum:*

18. *Pipeline Overview*. Cynthia Armstrong, PNGTS. Northeast Gas Association 2012 Regional Market Trends Forum.

19. *Project Updates*. Stan Brownell, Millennium Pipeline. Northeast Gas Association 2012 Regional Market Trends Forum.

20. *Project Updates*. Mike Dirrane, Spectra Energy, "Project Updates", Northeast Gas Association 2012 Regional Market Trends Forum

21. *Gas/Electric Issues*. Mike Hachey, TransCanada Power. Northeast Gas Association 2012 Regional Market Trends Forum.

22. *Project Updates*. Jessica Miller, Tennessee Gas Pipeline. Northeast Gas Association 2012 Regional Market Trends Forum.

23. *Shale Gas Development and Environmental Protection*. Scott Perry, Pennsylvania Department of Environmental Protection. Northeast Gas Association 2012 Regional Market Trends Forum.

24. *Northeast Supply Dynamics*. Jennifer Robinson, BENTEK Energy. Northeast Gas Association 2012 Regional Market Trends Forum.

25. *Project Updates*. Jeffrey Schauger, National Fuel Gas Supply / Empire Pipeline. Northeast Gas Association 2012 Regional Market Trends Forum

26. *Project Updates*. Todd White, Iroquois Gas Transmission. Northeast Gas Association 2012 Regional Market Trends Forum.

Additional Sources

27. *Embedded Natural Gas-Fired Electric Power Generation Infrastructure Analysis: An Analysis of Daily Pipeline Capacity Availability*. Gregory L. Peters. Prepared for the Midwest Independent Transmission System Operator, May 2012.

28. *2011 Long Term Reliability Assessment.* North America Electric Reliability Corporation. November 2011.

29. *Morgan Stanley Marcellus/Utica Mini-Conference*. Frank Billings, Williams Partners L.P. September 18, 2012

30. *Barclays Capital Investment Grade Energy and Pipeline Conference*. Don Chappel, Williams Partners L.P. March 7, 2012

31. *2012 Gas/Electric Focus Group Iroquois Pipeline.* John Esposito. October 30, 2012.

32. *The Impacts of Eastern Gas Supply on New England Power Generation.* Vince Morrissette. October 30, 2012.

33. *Tennessee Gas Pipeline Co, LLC Gas/Electric Group.* Laura Heckman. October 30, 2012.

34. *Staff Report on Gas-Electric Coordination Technical Conferences (Docket No. AD12-12-000).* Federal Energy Regulatory Commission. November 15, 2012.

35. *2012-13 Energy Market Assessment, Item No. A-3.* Federal Energy Regulatory Commission . November 15, 2012.

Endnotes

[1] In fact, a general consensus coming away from a series of August 2012 Federal Energy Regulatory Commission ("FERC") technical conferences on gas reliability was that New England is likely facing more pressing concerns concerning gas supply reliability than any other regional grid. Major interstate pipeline operators have already reported frequent issues with system constraints due to higher demand from the electric sector.

[2] For example, see: *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*. Prepared by ICF International. Submitted to ISO New England Inc. June 15, 2012; New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corp by Concentric Energy Advisors, May 2012; Addressing Gas Dependence. ISO-NE. July 2012; FCM Performance Incentives. ISO-NE. October 2012**;** *Coordinating Natural Gas & Electricity in New England*. Vamsi Chadalavada. June 2012; *A Natural Gas Generator's Perspective*. James Ginnetti. June 2012; *Coordinating Natural Gas & Electricity in New England*. Peter T. Brandien. May2012 NEPCUC Symposium; *Integrating Natural Gas and Renewable Generating Resources: Natural Gas Pipeline Perspective*. Donald Santa. May 2012 NECPUC Symposium; *System Planning: Reliably Integrating and Managing Systems*. Steve Rourke. May 2012 NECPUC Symposium; *The North American and Northeastern US Natural Gas Markets.* Bob Fleck. May 2012 NECPUC Symposium. *Northeast Gas Association 2012 Regional Market Trends Forum; Northeast Supply Dynamics*. Jennifer Robinson. Northeast Gas Association 2012 Regional Market Trends Forum.

[3] For example, see: *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*. Prepared by ICF International. Submitted to ISO New England Inc. June 15, 2012; New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corp by Concentric Energy Advisors, May 2012; Addressing Gas Dependence. ISO-NE. July 2012; FCM Performance Incentives. ISO-NE. October 2012**;** *Coordinating Natural Gas & Electricity in New England*. Peter T. Brandien. May2012 NEPCUC Symposium; *Integrating Natural Gas and Renewable Generating Resources: Natural Gas Pipeline Perspective*. Donald Santa. May 2012 NECPUC Symposium; *Gas-Electric Market Coordination.* Tom Kaslow. May 2012 NECPUC Symposium.

[4] For example, see: *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*. Prepared by ICF International. Submitted to ISO New England Inc. June 15, 2012; New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corp by Concentric Energy Advisors, May 2012; Addressing Gas Dependence. ISO-NE. July 2012; FCM Performance Incentives. ISO-NE. October 2012**;** *Coordinating Natural Gas & Electricity in New England*. Peter T. Brandien. May2012 NEPCUC Symposium; *Integrating Natural Gas and Renewable Generating Resources: Natural Gas Pipeline Perspective*. Donald Santa. May 2012 NECPUC Symposium; *Gas-Electric Market Coordination.* Tom Kaslow. May 2012 NECPUC Symposium; *Gas/Electric Issues.* Mike Hachey. Northeast Gas Association 2012 Regional Market Trends Forum.

[5] Based on a December 3, 2012 Northeast Gas Association presentation, Tennessee Gas Pipeline is proposing two projects: (1) the Northeast Expansion Bullet Line and (2) 200L Looping, with potential incremental capacity of up to 1.2 Bcf/d to deliver Marcellus shale supplies to the New England market. The expected in-service date for these projects ranges from 2016 through 2018.

[6] Proposed projects are mentioned in a number of the studies reviewed and described in detail by a number of natural gas pipelines participating in the May 2012 NECPUC Symposium: Portland Natural Gas Transmission System, Millennium Pipeline, Spectra Energy, Tennessee Gas Pipeline, National Fuel Gas Supply/Empire Pipeline, Iroquois Gas Transmission

[7] *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*. Prepared by ICF International. Submitted to ISO New England Inc. June 15, 2012.

[8] See Docket No. AD12-12-000

[9] New England Cost Savings Associated with New Natural Gas Supply and Infrastructure, prepared for Spectra Energy Corp by Concentric Energy Advisors, May 2012.

[10] ISO-NE 2012 Regional System Plan, page 119.

[11] See Docket No. AD12-12-000

[12] *Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs*. Prepared by ICF International for ISO New England Inc. June 15, 2012.

[13] The effective level of dual-fired capacity that can be dispatched using oil to serve load could be restricted by air emissions permits.

[14] Natural Gas- A National Treasure. 65th Annual NEPCUC Symposium

[15] See endnote 2

[16] See endnote 3

[17] See endnote 4

[18] Northeast Gas Association Pre-Winter Briefing 2012/2013. Dodson Skipworth. December 3, 2012.

[19] See endnote 5

[20] This report defined New England as the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

[21] The demand for natural gas from the electric sector in this report is from ISO-NE's 2011 Regional System Plan. The extreme case (90-10) peak electric load has a 10% chance of underestimating actual load due to weather conditions. The summer peak load is expected to

occur at a weighted New England-wide temperature of 94.2^0 F and the winter peak load is expected to occur at 1.6^0 F. This case represents
the electric market condition that aligns with the "design day" concept used within the natural gas industry.

[22] A winter design day for a LDC's planning purpose reflects its needs for gas for the coldest winter day observed in the past 30 years. (Some LDC also uses a 20-year coldest day criterion).

[23] This study defined New England as the states of Massachusetts, Connecticut, and Rhode Island.

[24] The study reviewed historical monthly natural gas prices at Algonquin City Gate, used to represent New England natural gas prices and Texas Eastern M-3, used to represent Mid-Atlantic natural gas prices.

[25] This reflects Black & Veatch's independent assessment with regard to the proposed changes in operation rules and market re-designs. The actual impacts of these proposals will be contingent upon the response of market participants and implementation.