



New England Energy Market Outlook

Demand for Natural Gas Capacity and Impact of the Northeast Energy Direct Project

Prepared for

Kinder Morgan, Inc.

Prepared by

ICF International
9300 Lee Highway
Fairfax, VA 22031

1331 Lamar St., Suite 660
Houston, TX 77010



COPYRIGHT © 2015 ICF Resources, LLC All rights reserved.

Warranties and Representations. ICF endeavors to provide information and projections consistent with standard practices in a professional manner. ICF MAKES NO WARRANTIES, HOWEVER, EXPRESS OR IMPLIED (INCLUDING WITHOUT LIMITATION ANY WARRANTIES OR MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), AS TO THIS MATERIAL. Specifically but without limitation, ICF makes no warranty or guarantee regarding the accuracy of any forecasts, estimates, or analyses, or that such work products will be accepted by any legal or regulatory body.

Waivers. Those viewing this Material hereby waive any claim at any time, whether now or in the future, against ICF, its officers, directors, employees or agents arising out of or in connection with this Material. In no event whatsoever shall ICF, its officers, directors, employees, or agents be liable to those viewing this Material.

Table of Contents

- Executive Summary 5**
 - Outlook for New England Gas Market Growth..... 6
 - New England Gas Supply/Demand Balance 6
 - NED Electric Market Benefits 8
 - Reliability, Operational, and Environmental Benefits of Additional Pipeline Capacity 9
- Introduction 13**
 - Study Background 13
 - Project Description 16
 - ICF New England Study Scope 17
 - Analytical Approach 17
- Base Case Market Fundamentals 20**
 - Residential/Commercial Demand 20
 - Industrial Demand 21
 - Gas Demand for the Electric Sector 21
 - Projected Supply Sources into New England 24
- New England Natural Gas Demand and Supply Balance 27**
 - Normal Weather 27
 - Design Weather 28
- Illustrative NED Impact on Winter 2013/14 30**
- Cost Savings - Normal Weather 33**
 - Natural Gas Price Impact – Monthly Average..... 33
 - Wholesale Power Price Impact – Monthly Average 34
 - Cost Savings from Average Price Reductions 34
 - Benefits from Reduced Daily Gas Price Volatility 34
 - Net Estimated Electric Cost Savings 35
- Other Benefits of Incremental New England Natural Gas Pipeline Capacity 37**
 - Enhanced Operational Reliability..... 37

Operational Flexibility 39
Support for Renewable Energy..... 40
Environmental Benefits..... 41

Executive Summary



ICF International (“ICF”) was engaged by Kinder Morgan Inc. (“KM”) to analyze the New England natural gas and power markets and the need for new natural gas supplies and capacity to serve the region. As part of this study, ICF was also asked to analyze potential energy market, reliability and other benefits that may arise from the construction of their proposed Northeast Energy Direct (“NED”) pipeline project to serve the New England region. As described in more detail in this report, the NED market project would originate at interconnects with interstate pipelines near Wright, New York and terminate at interstate pipeline interconnections near Dracut, Massachusetts.

In this study, ICF projects natural gas demand and supply in New England through 2035 and assesses the demand/supply capacity balance on a daily basis for discrete years. Emphasis is placed on understanding the demand for capacity during the winter season, when natural gas is in high demand as a fuel for heating and power generation. Sensitivity analyses consider the implications for capacity under both normal and “design” weather conditions.¹ The design weather condition is analyzed because it is a utility planning standard that recognizes the essential nature of services and the consequences of disruptions under extreme weather conditions — since a few hours of electricity disruption could result in loss of life and economic loss worth hundreds of millions of dollars, it is important to know what the system can tolerate.

NED’s benefits to the New England electric market are estimated for the 10-year period after the project is placed into service. Findings and conclusions integrate base case analysis produced using ICF’s proprietary market models and market data.

ICF’s analysis of energy demand/supply trends supports a finding that New England faces the risk of persistent and growing natural gas supply constraints, absent new sources of capacity. Given the current structure of the regional energy markets, such risks could disproportionately affect electricity markets, raising economic and potential service reliability concerns for consumers across the region. This report provides quantitative assessments of the timing and magnitude of the impending gas supply constraints, and the potential benefits associated with the development of new pipeline capacity that NED offers. NED’s contribution to reduced and more stable gas prices is derived from providing incremental transportation access to economic natural gas supply sources.

Key observations and conclusions are summarized below.

¹ “Design” weather represents a utility standard for defining extreme conditions; typically the coldest temperatures on record over a specified period of years. Utility practice varies from looking at the most recent 30 years to as long as temperature records have been kept.

Outlook for New England Gas Market Growth

New England Local Distribution Companies (LDCs) project that residential and commercial gas demand will increase by 8% over the next 3 years, and continue at a moderate pace thereafter

As a result of state initiatives to expand natural gas use in both the residential and commercial sectors, New England LDCs project their firm load requirements to grow by over 8% between 2015 and 2018. Through 2035, ICF projects that residential and commercial demand will grow at an average rate of 1.3% per year, with corresponding increases in winter peak day and seasonal demand.

New England power sector gas demand will grow as gas-fired power generation capacity replaces retired coal and nuclear capacity

Cumulative retirements of nuclear, coal and older oil/gas units in New England are expected to reach 3,480 MW by 2019. In the future, the New England electricity market will be increasingly served by a combination of natural gas, renewable and energy efficiency sources. ICF Base Case projections assume that all states will achieve their stated Renewable Portfolio Standards (“RPS”) targets on schedule.² Growth in electric load will be partially offset by energy efficiency gains, reducing projected growth in net energy load to 0.8% per year through 2035. Notwithstanding these increases in renewables and energy efficiency, ICF projects that the region will require approximately 1,750 MW of new gas-fired generating capacity by 2019, further increasing power sector gas demand.

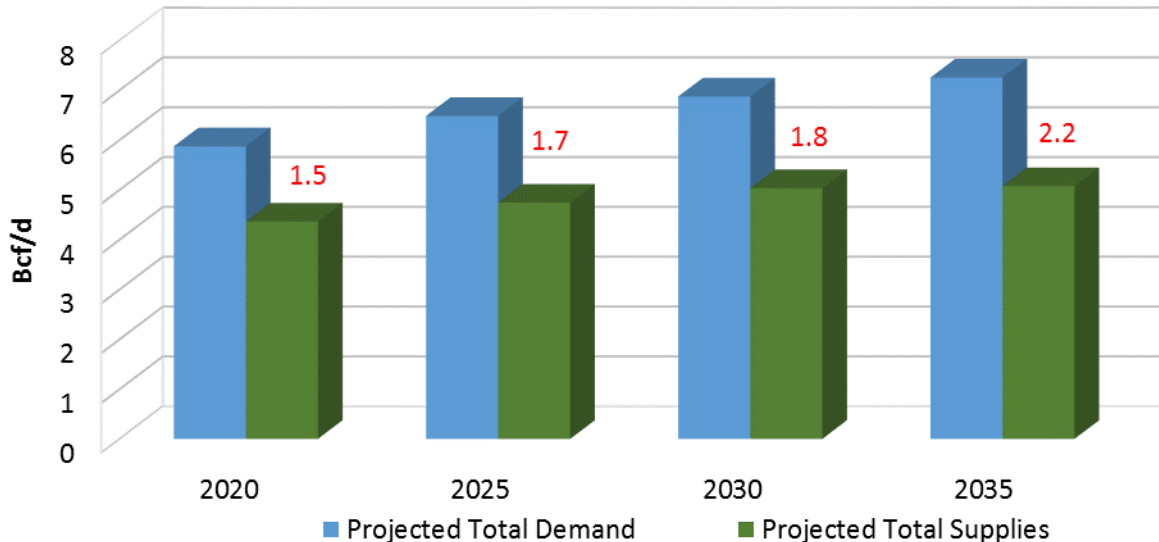
New England Gas Supply/Demand Balance

ICF’s analysis indicates that as New England peak-day gas demand requirements grow, the region’s gas supply deficit will increase, absent additional gas capacity

While several gas pipeline expansion projects are expected to be in-service by the end of 2017, they alone are not sufficient to meet the projected growth in New England’s peak day gas demand. Additionally, Canadian gas imports are projected to continue to decline. Together, the growth in demand and attrition of current gas supplies contribute to a continuously widening supply deficit on peak winter days. Under normal winter weather conditions, the peak day deficit is projected to be 1.5 billion cubic feet per day (Bcf/d) by 2020, and widens to 2.2 Bcf/d by 2035 (Figure 1). If peak day winter temperatures are much lower than normal (close to a “design day” in gas industry parlance), ICF projects that unmet peak day demand could reach 1.7 Bcf/d by 2020, and 3.2 Bcf/d by 2035.

² The implications for generating sources under the recently announced and revised Clean Power Plan are still being assessed.

Figure 1: New England Normal Weather Peak Day Demand and Supply Balance



Source: ICF, note that red numbers indicate the size of the supply deficit.

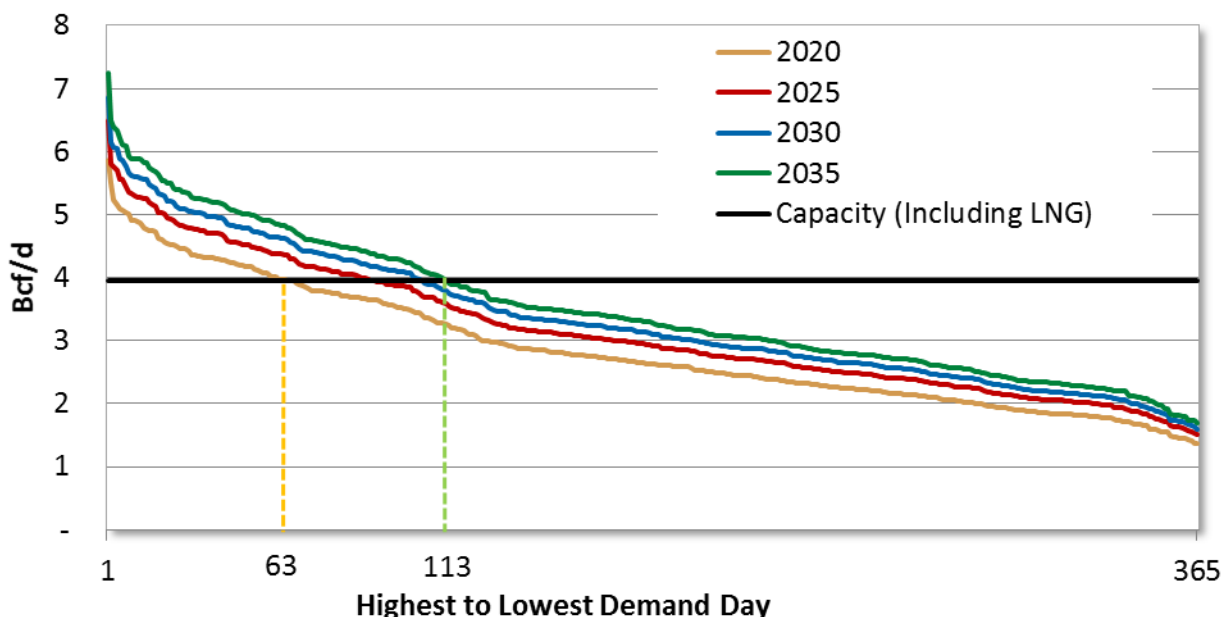
Increased natural gas consumption for electric generation will contribute to increases in the frequency and magnitude of daily natural gas capacity deficits over the course of a winter season

Absent new gas capacity into the New England market, ICF projects that by 2020, the number of days on which normal weather demand exceeds capacity could extend to 63 (Figure 2). On these days, the aggregate unmet power sector gas demand totals approximately 89 Bcf, reducing gas-fired generation by almost 12 million MWh, and thereby increasing electricity prices. By 2035, the projected duration of capacity deficits lengthens to an estimated 113 days, nearly 80% of the winter season.³ Unmet demand in the power sector grows to 210 Bcf, equivalent to 27 million MWh of lost gas-fired generation.

Under design weather conditions, ICF projects that by 2020 the duration of capacity deficits approaches 78 days (more than half the winter season days), and totals 110 Bcf. By 2035, the duration of the deficit under design weather conditions increases to 122 days, and totals 226 Bcf.

³ While primarily a winter problem, by 2030 gas supply deficits could also occur on peak summer days due to increases in power sector gas demand.

Figure 2: New England Normal Weather Load Duration Curves, 2020 - 2035



Source: ICF

The implication of these findings is that under both normal and design conditions, New England is projected to experience continued and growing gaps between available gas demand and supply capacity. These deficits will grow in daily frequency and impact the availability of gas supplies for power generation.

NED Electric Market Benefits

NED capacity could have reduced New England wholesale electric costs by approximately \$3.7 billion had it been in service during the 2013/14 winter

The 2013/14 “Polar Vortex” winter resulted in both record high and exceptionally volatile gas prices, which had a direct impact on wholesale power prices. ICF analyzed historical gas pipeline load factors and natural gas prices to estimate the potential reductions in New England wholesale power prices that might have been realized had the NED market project been in service. Based on reduced load factors and power prices, ICF estimates total potential savings of \$3.7 billion dollars had NED been in service during the winter of 2013/14.

In a normal weather year, NED could save New England electric consumers \$2.1 billion to \$2.8 billion per year

ICF estimates that, on average, NED could save New England electric consumers \$2.1 billion to \$2.8 billion per year over its first ten years of operation (2019 – 2028). For context, ISO-NE reported that “the total value of the region’s wholesale electricity markets, including electric energy, capacity, and ancillary services markets, rose...to about \$9.9 billion in 2014 ... [and electric] energy comprised \$8.4 billion of the total.”⁴ The potential cost savings stem from the highly correlated nature of natural gas prices and

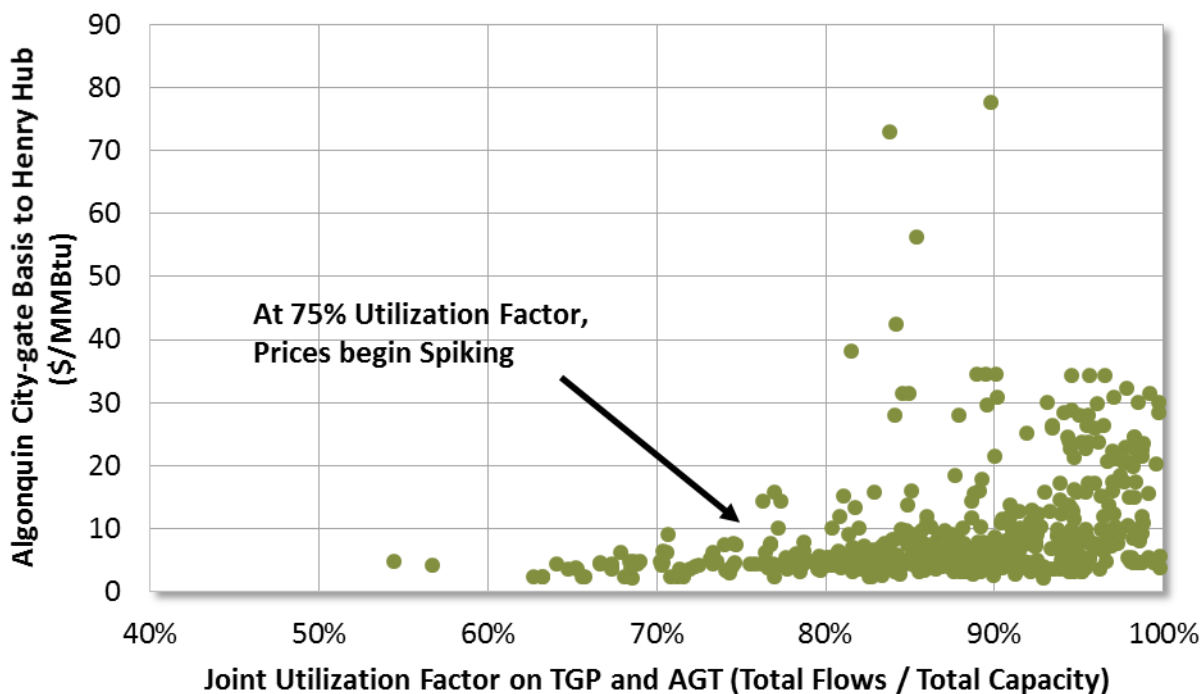
⁴ ISO-NE Press Release on 2014 Annual Markets Report, at http://www.iso-ne.com/static-assets/documents/2015/05/amr14_release_05202015_final.pdf

wholesale power prices in New England, and the fact that lower gas prices resulting from NED capacity can also reduce wholesale power prices. These savings would ultimately extend to all New England electric consumers, including those in the states not directly receiving natural gas from the NED project.

New England wholesale gas and electric prices rise and become more volatile at pipeline capacity load factors well below 100% utilization

During the 2013-2014 winter, daily utilization factors on major inbound pipelines — Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) — averaged 90% and frequently exceeded 95%. ICF analysis illustrates how traded spot gas prices in New England – and wholesale power prices by extension – can spike and be more volatile when pipeline utilization factor rises above approximately 75% (Figure 3). It is not necessary for the region to experience actual gas capacity deficits for higher costs to materialize.

Figure 3: AGT and TGP Utilization Factor vs. Algonquin City-gates Winter Basis (2011/12 - 2013/14)



Source: Point logic, Ventyx

Reliability, Operational, and Environmental Benefits of Additional Pipeline Capacity

NED increases New England’s electric infrastructure reliability

It is evident from ICF analysis that new pipeline capacity, as proposed in the NED market project, would enhance the availability of gas service that is essential to supplying a growing New England market. And by providing capacity for growth, NED would also mitigate increasingly tight capacity conditions for most

power generators in New England.⁵ As such, for new and existing gas shippers alike, NED would also provide valuable reliability against service interruptions.

The NED-TGP integration would support service continuity for roughly 50%, or 9,049 MW, of New England’s current power supplies, shown in Table 1. Based on average dispatch heat-rates, TGP services support some of the most efficient electric generators in New England.

Table 1: TGP Served Power Generation in New England

	Operating Capacity (MW)	% of New England Total	Average Generation (GWh)	% of New England Total	Average Gas Burn (Bcf/d)	% of New England Total
Direct Deliveries	4,894	27%	17,080	32%	0.34	32%
Indirect Deliveries via Supplying LDCs	827	5%	1,601	3%	0.04	4%
Indirect Deliveries via Supplying AGT	3,328	18%	9,142	17%	0.18	17%
Total TGP	9,049	50%	27,823	52%	0.57	52%

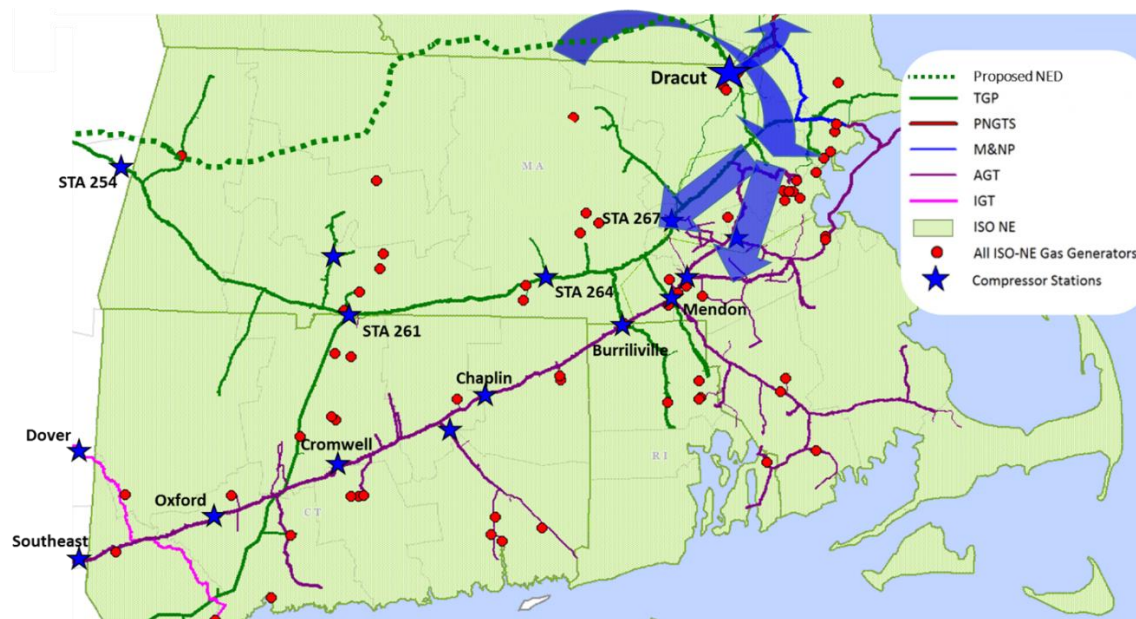
* For the purposes of this table, Milford & Ocean States I & II are included as TGP Direct Deliveries.

* Numbers in the table may not add up exactly to the total because of rounding.

Source: SNL and ICF

With modifications to receiving pipelines, NED could similarly enhance service reliability for shippers on the AGT, Portland Natural Gas (PNGTS) and Maritimes and Northeast (M&NP) pipelines. As illustrated in the map below (Figure 4), through deliveries at pipeline interconnections near Dracut, Massachusetts, NED is potentially able to “back feed” additional gas supplies to all existing pipelines in New England, creating a new path to reach all gas customers.

Figure 4 - New England Gas-Fired Generation and Natural Gas Infrastructure



Source: Ventyx

⁵ Power generators who receive gas deliveries through constrained laterals may require additional pipeline investments to utilize capacity made available by the construction of NED.

The NED-TGP configuration is particularly integral to New England electric reliability because it is capable of delivering high pressure gas east of the Mass. Hub and north of Boston to an area where a dense concentration of power generation facilities operate. Gas deliveries to power generators in this region on existing interstate gas pipelines are downstream of, and dependent upon, nearly twenty TGP and AGT compressor stations. If confronted by outages or other potential supply disruptions on existing AGT and TGP facilities, NED would provide pipeline operators an alternative path for delivering gas supplies to the region, potentially mitigating costly and disruptive power interruptions.

As noted above, the value of pipeline capacity reliability for a region increases materially as gas use for power generation grows. Without adequate gas capacity, New England's electric system could face costly load shedding measures. NED can help New England avert or lessen this type of costly electric load shedding.

NED increases the existing gas and electric infrastructure's operational flexibility

Gas-fired electric generators require large volumes of high-pressure gas to operate. However, their demand for gas can vary with electric markets and load conditions throughout the day, creating rapid ramps up and down in gas loads. Pipeline operators typically will work with their shippers to accommodate such intra-day "swings," but their flexibility to do so is contingent upon having capacity adequate to meet firm demand.⁶ If they do not have sufficient capacity above and beyond firm demand, their flexibility to meet power generator demand fluctuations is limited.

Furthermore, absent new pipeline capacity additions, intra-day swing flexibility will inevitably erode as large power generation loads are added (a process that has been happening rapidly in New England over the past decade). These restrictions on intra-day load swings apply to both power and non-power gas shippers. The remedy for lost operational flexibility is either to curb demand or to purchase additional firm pipeline capacity that meets peak-hour needs within a day. Both solutions come with additional costs. NED could restore and enhance the system's operational flexibility to support power generators' intra-day swings, and thereby mitigate these added costs.

NED provides essential support for renewable generation

New England states have embraced aggressive renewable energy programs, including both wind and solar resource development. These renewable resources are "intermittent" generators, which means their power production can fluctuate dramatically and rapidly between peak capacity and zero. As the renewable market share grows in New England, these swings have greater effects on the regional electric grid, and thereby place greater demands on the system to accommodate the variation.

Gas-fired generation is a highly complementary resource to buffer the intermittent production of renewable energy. Unlike other types of power generation that are more rigid in their dispatch

⁶ As is explained in the report, gas LDCs typically purchase "firm" service, which guarantees gas delivery. Power generators typically buy their supply from leftover capacity. This gas comes at a lower cost than firm supplies, but is "interruptible," meaning that it is only available if there is capacity left over after firm customers are supplied. "Shippers" comprise all entities that contract with a pipeline for capacity and transportation of natural gas and own it while it is being transported by the pipeline.

capabilities, gas turbines are engineered to ramp up and down in tandem with renewable generation variability. Assuming these turbines can be supplied with gas on a comparable schedule, gas generation therefore provides an ideal complement to renewable energy. In that regard, the pipeline system's operational flexibility — which would be enhanced by NED — is a key source of capacity that can enable gas turbines to manage intermittent renewable power, and support the rise of renewable generation in New England.

NED provides environmental benefits by reducing power sector air emissions

Over the past ten years, New England's power sector has dramatically reduced NO_x, SO₂, and CO₂ emissions by shifting from oil- and coal-fired generation to natural gas. Introducing new natural gas transportation capacity into New England would further reduce the region's reliance on oil- and coal-fired generation and provide additional incremental reductions in emissions.

ICF estimates that by 2020, absent new pipeline capacity, New England generators would encounter the equivalent of approximately 12 million MWh of gas supply deficits to meet power demands. Using fuel oil instead of gas to bridge such a deficit would emit an additional 5 thousand tons of NO_x, 67 thousand tons of SO₂, and 5.6 million tons of CO₂ into the atmosphere than gas-fired generation. These additional emissions would sharply reverse the previous decade's reductions, and represent respective increases of 23%, 372% and 14% of total NO_x, SO₂, and CO₂ over 2013 emission levels.

Introduction

Study Background

For the past 15 years, New England has been steadily increasing its reliance on natural gas-fired electricity generation. At present, approximately 50% of New England’s power comes from gas-fired generation, compared to roughly 15%⁷ in 2000. The projected retirements of regional nuclear and coal-fired power plants will result in the construction of new gas-fired generation and continue this trend.

The growth in gas-fired generation raises important questions about the reliability of gas supplies to meet that demand. Central to the issue is New England’s reliance on interruptible gas supplies for much of its power generation fuel supply. Unlike LDCs, which contract for firm pipeline and storage services to ensure gas supplies (especially on the coldest days), most gas-fired generators in New England rely on non-firm (or “interruptible”) pipeline capacity for their fuel supplies. This practice worked in the past because power sector gas demand was concentrated in the summer months, when interruptible pipeline capacity is widely available. However, gas-fired power plants now provide a high percentage of total electric generation throughout the year, including the winter months when LDC demands are high and interruptible capacity is scarce. As more nuclear and coal plants retire and at least some portion of their capacity is replaced by more gas-fired generation, year-round power sector gas demand will continue to increase, and it will be increasingly difficult to meet power sector gas demand on peak winter days.

In a recent article for IEEE Power & Energy Magazine on conditions during the winter of 2013/14, ISO-NE stated that “subordinate contracts for gas transport were generally not available to power providers.”⁸ ISO-NE was able to avoid potential brownouts and blackouts during the winter of 2013/14 through the implementation of a number of measures, most notably its “Winter Reliability Program”.⁹ However, one of the consequences of constraints on gas supplies has been extremely high and volatile natural gas prices during the winter months. This increases the cost of fuel for electric generators, which results in higher electricity costs for New England consumers. As shown in Figure 5, all six New England states rank among the top ten U.S. states with the highest residential electricity rates, averaging 45% higher than the U.S. average.¹⁰

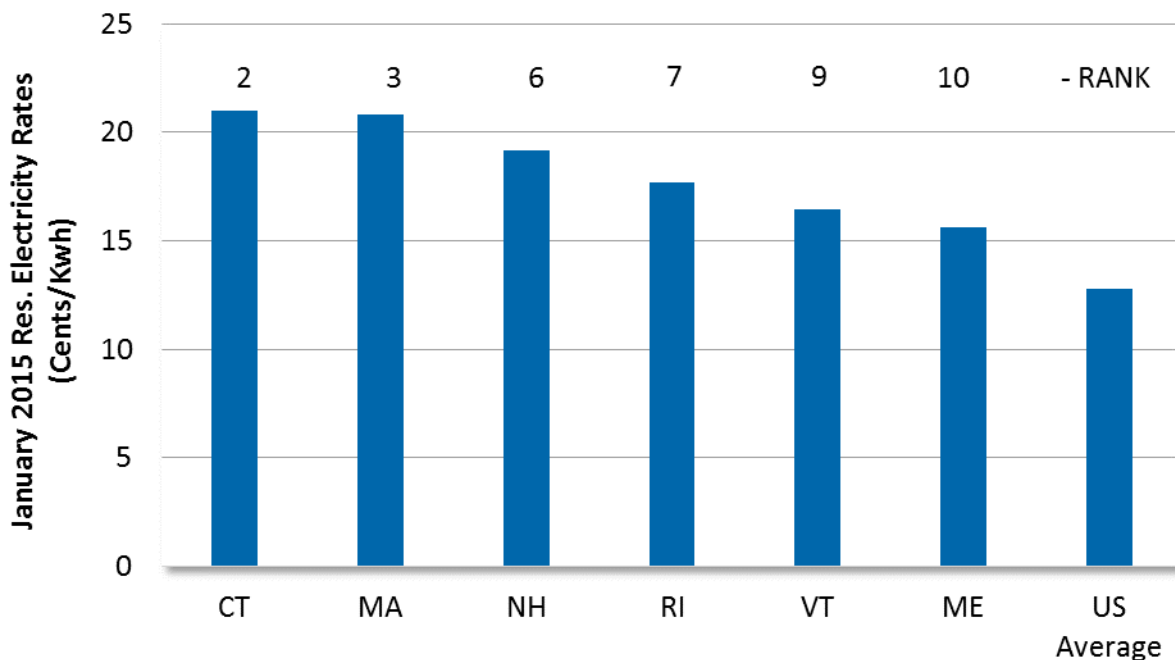
⁷ http://www.iso-ne.com/static-assets/documents/2015/03/icf_ison_e_van_welie.pdf slide 7.

⁸ Babula, M. & Petak, K. (2014). The Cold Truth, Managing Gas-Electric Integration: The ISO New England Experience. IEEE Power & Energy Magazine, November/December 2014, pp 20-28.

⁹ A collaboration between ISO New England and regional stakeholders, this project focused on developing a short-term, interim solution to filling a projected “reliability gap” of megawatt-hours (MWh) of energy that would be needed in the event of colder-than-normal weather during winter 2013/2014. The solutions included a demand side response program, an oil inventory service, incentives for dual fuel units, and market monitoring changes.

¹⁰ The other states are Hawaii (1), Alaska (4), New York (5) and California (8).

Figure 5: Residential Electricity Rates Ranking by State (Highest to Lowest)



Source: EIA

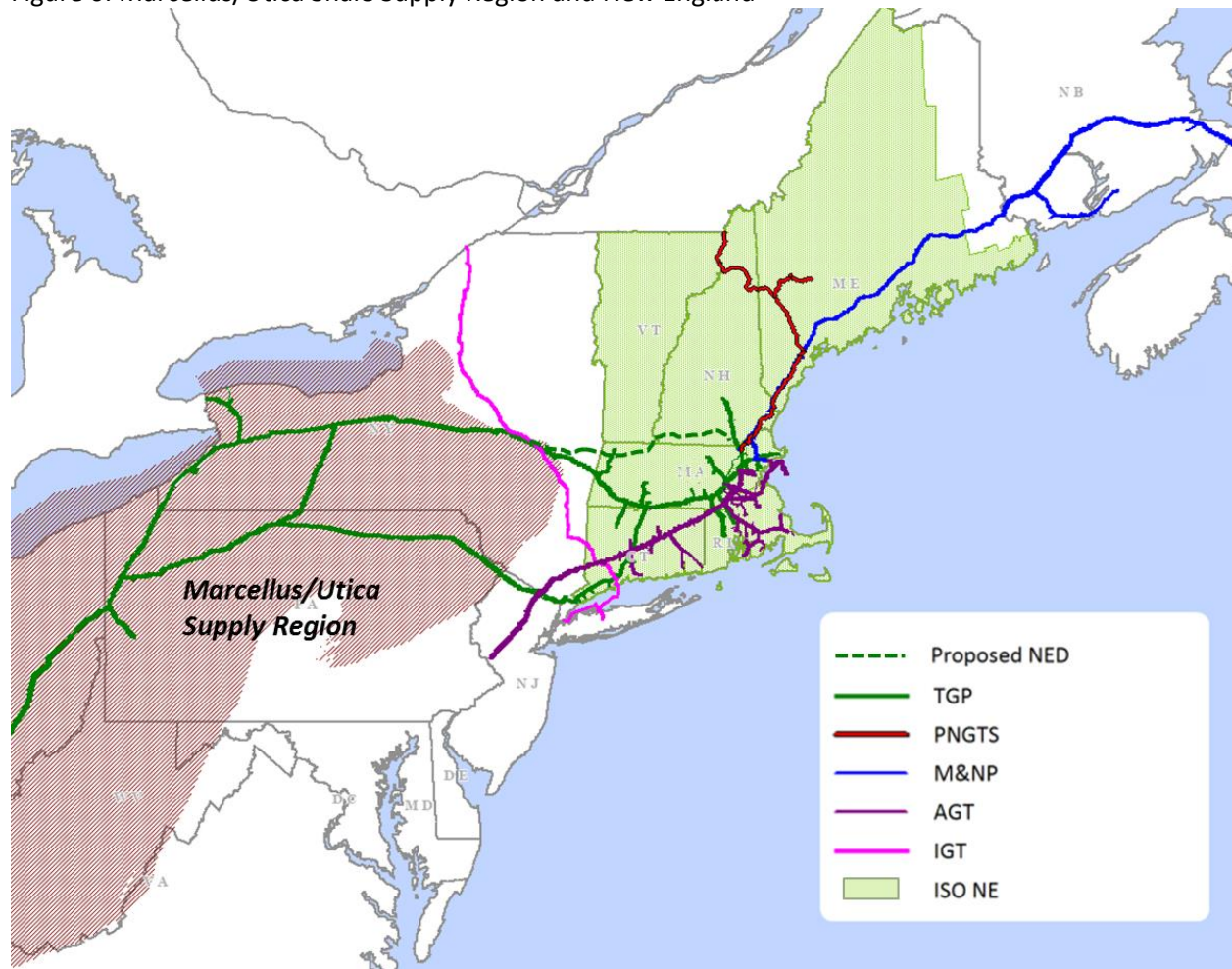
In 2013, the governors of all six New England states issued a joint statement on natural gas and electric system interdependency, and the need for regional cooperation on energy infrastructure issues.¹¹ In 2015, the governors again released a joint statement, acknowledging that “New England continues to face significant energy system challenges with serious economic consequences for the region’s consumers. These challenges require cost-effective solutions to reduce consumer energy costs, strengthen grid reliability and enhance regional economic competitiveness”.¹²

New England’s natural gas supply deficit occurs against the back drop of a production boom from the Marcellus and Utica shales in the nearby Appalachian Basin in Pennsylvania, West Virginia, and Ohio (Figure 6). ICF expects that the Appalachian Basin will become the biggest natural gas supply basin in North America, with production from the Marcellus/Utica region projected to more than double, reaching 42 Bcf/d by 2035 (Figure 7).

¹¹ http://nescoe.com/uploads/New_England_Governors_Statement-Energy_12-5-13_final.pdf

¹² http://www.nescoe.com/uploads/6_State_Joint_Statement_FINAL_4-22-15_12-3.36pm_w-sealsf.pdf

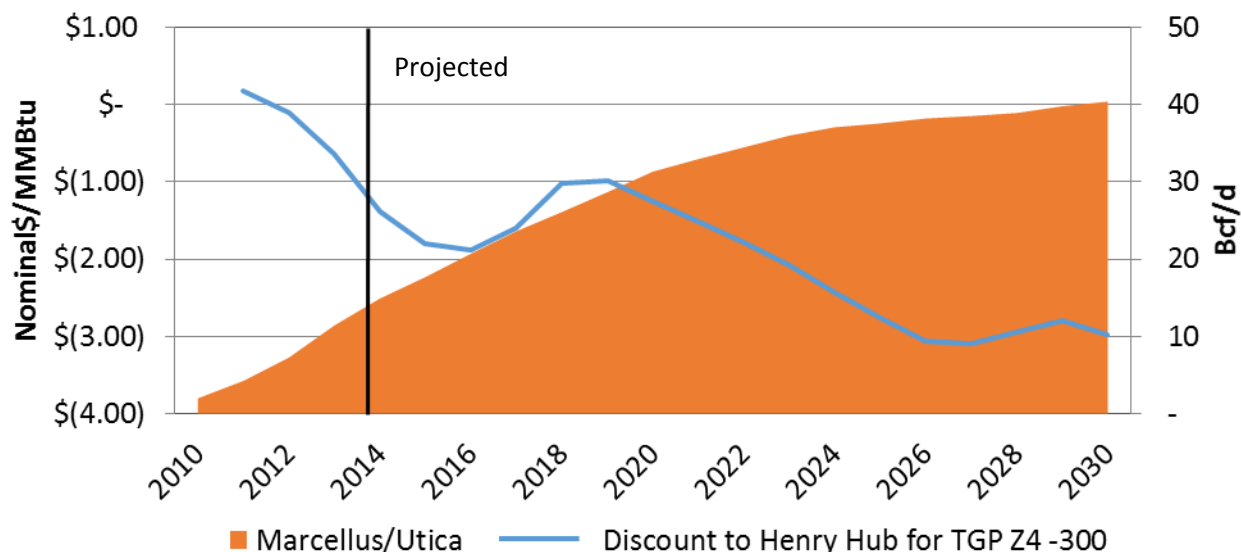
Figure 6: Marcellus/Utica Shale Supply Region and New England



Source: ICF, Ventyx

The dramatic increase in low-cost Appalachian Basin gas production has materially altered the relationship of gas prices there to other trading points across the North American market. As shown on the right axis of Figure 7, the price of natural gas in the Appalachian Basin (represented by the Tennessee Zone 4, 300 Line pricing point in Northeast Pennsylvania) is expected to be traded at significant discount relative to the North American benchmark Henry Hub (Louisiana) price.

Figure 7: Historical and Projected Marcellus/Utica Production and TGP Z4-Line 300 to Henry Hub Basis¹³



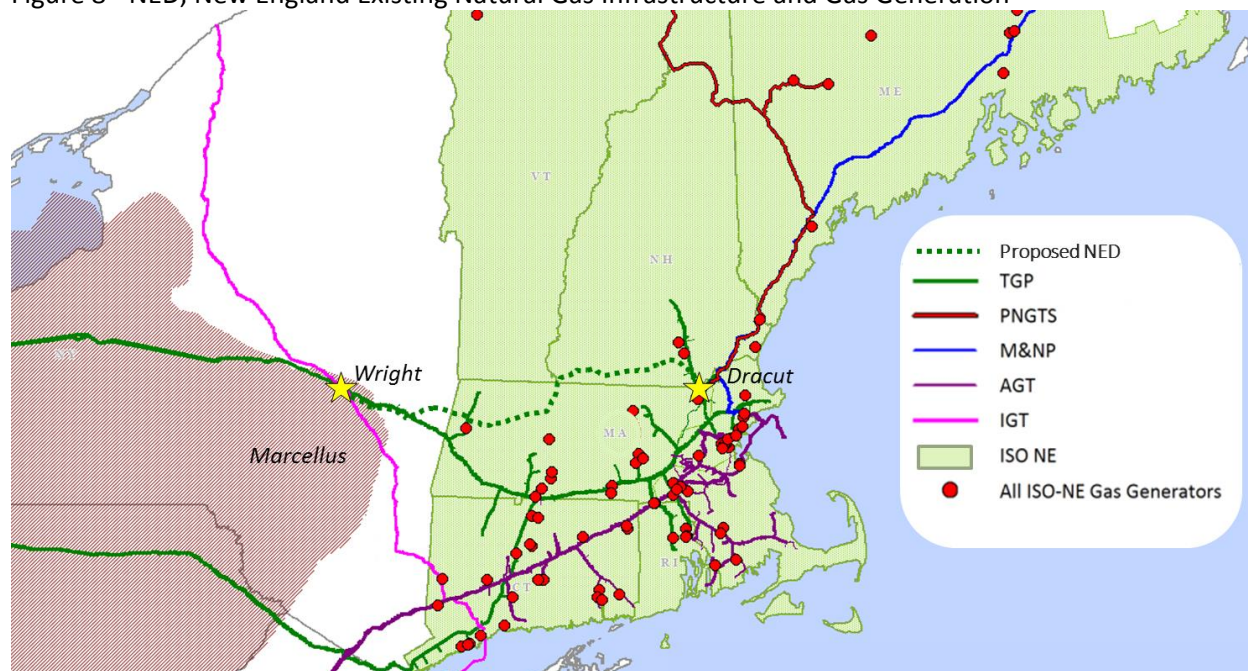
Source: ICF, SNL

Project Description

Kinder Morgan’s NED market project would provide 1.3 billion cubic feet per day (Bcf/d) of new pipeline capacity from Wright, New York to Dracut, (Figure 8). It would be operated by TGP, a KM subsidiary, and provide a new path for Marcellus shale and other gas production sources into New England. According to KM, over 90% of NED’s mainline path will follow existing energy rights of way (“ROW”). NED would receive gas supplies at Wright through interconnections with multiple interstate gas pipelines, transport gas to customers along its route through Massachusetts and New Hampshire, and also deliver gas to TGP and other pipelines at its terminus at Dracut for redelivery throughout the region. The proposed in-service date is November 2018.

¹³ Basis presented here is TGP Z4- Line 300 price minus Henry Hub price.

Figure 8 - NED, New England Existing Natural Gas Infrastructure and Gas Generation



Source: Ventyx, ICF and TGP

ICF New England Study Scope

ICF’s analysis of New England’s needs for gas capacity and potential impacts from the NED pipeline includes:

- Summary of TGP’s current role in serving existing New England gas-fired generation
- Comparisons of the New England’s projected gas demand and likely gas supply
- Estimate of the need for additional natural gas supplies to New England through 2035
- Estimate of the potential cost savings that NED may generate for New England’s wholesale electric market
- Assessments of NED’s reliability, operational and environmental benefits to New England

Analytical Approach

ICF’s analyses and findings draw from years of experience consulting on North American natural gas and electric markets, as well as the proprietary software tools and databases developed for that purpose. For this analysis, ICF utilized a suite of analytical tools, including its Gas Market Modeling (GMM[®]) and Integrated Planning Model (IPM[®]).

Demand/Supply Balance Analysis

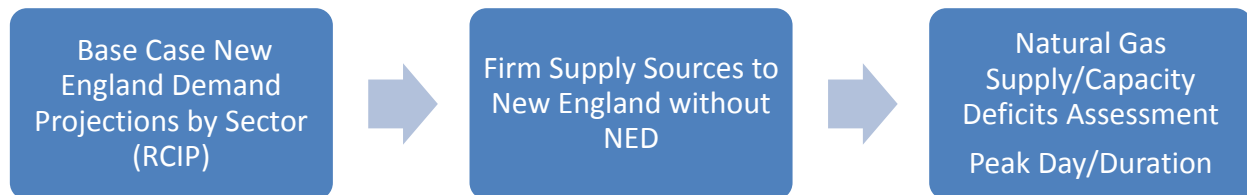
As a starting point for this analysis, ICF used its Q3 2015 (July) Base Case for the North American gas market, including specific regional projections for New England natural gas demand, supplies, and prices. ICF updates its projections for North American energy markets (including power, natural gas and other fuels) each month, based on its internal assessment of demand growth, supply costs, and infrastructure changes.

Short-term residential and commercial demand for natural gas is projected using the portfolio plans filed by major New England LDCs. Long-term projections are based upon the historical relationship between residential and commercial natural gas consumption to population and economic growth.

Future growth in gas demand from the power sector is estimated using ICF's IPM® model, which considers New England's electric gross annual and peak load growth, energy efficiency, renewable policies and nuclear strategy. ICF models the impact of environmental policies, such as MATS, CSAPR and a Federal cap-and-trade program on CO₂ starting in 2020.¹⁴ Power sector demand is projected with reasonable natural gas supply availability to dispatch the region's generation portfolio.

The projected demand growth is then compared to natural gas supplies available to serve the region to understand New England's supply and demand balance. ICF estimated the region's natural gas capacity deficit on the peak day and duration of the deficits over a year under both normal weather and design weather conditions. This process is illustrated below in Figure 9.

Figure 9: Assessing the Deficit - Process



Source: ICF

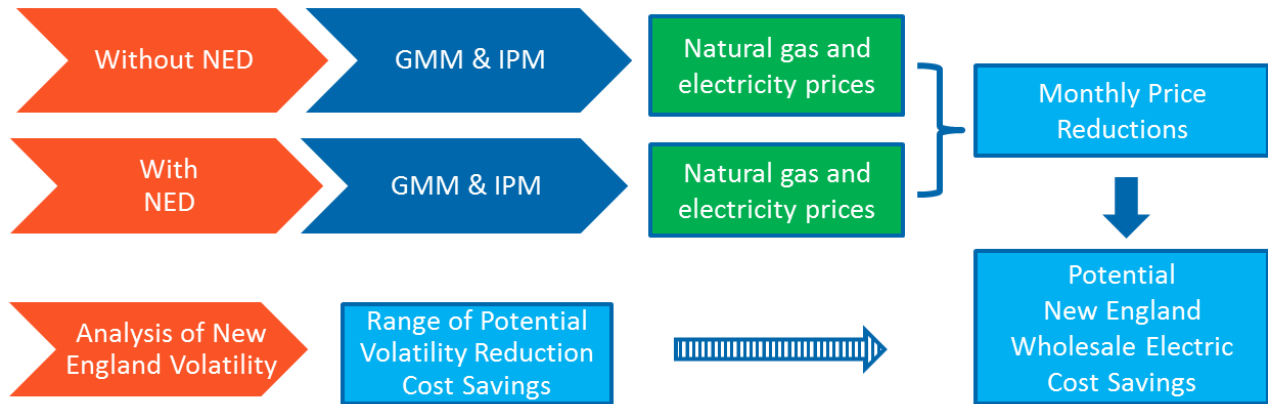
Wholesale Electric Cost Savings

ICF estimates NED's impacts on New England's electric market by assessing the reduction of wholesale electricity costs – measured as the wholesale energy price multiplied by total energy load in New England. The cost savings are estimated from two perspectives. For the first perspective, ICF examines the reduction of the region's average monthly natural gas and electric prices caused by the additional pipeline capacity from NED. ICF estimates this impact by running the GMM and IPM models under normal weather conditions with and without NED, and compares the difference of natural gas and electricity prices between the two scenarios. The price reduction is used to calculate the market impact and potential reduction to New England's wholesale electric costs.

In the second perspective, ICF examines NED's potential impact on natural gas price volatility by reducing the region's natural gas price spikes, which will result in subsequent reduction in the electric price spikes and provide additional cost savings. This impact is estimated as a potential range using parameters derived from historical data analysis, assuming that the incremental NED capacity could facilitate a shift in New England's natural gas market environment – either from high to medium or from medium to low volatility regimes. This analytical process is summarized below in Figure 10.

¹⁴ The EPA Clean Power Plant (CPP) was not finalized until August 3, 2015, so it is not included in ICF's July 2015 Base Case.

Figure 10: Cost Savings Analysis Methodology



Source: ICF

For the purpose of this analysis, ICF further assumes that reductions or increases in wholesale electric costs would ultimately flow through to all New England electric consumers.

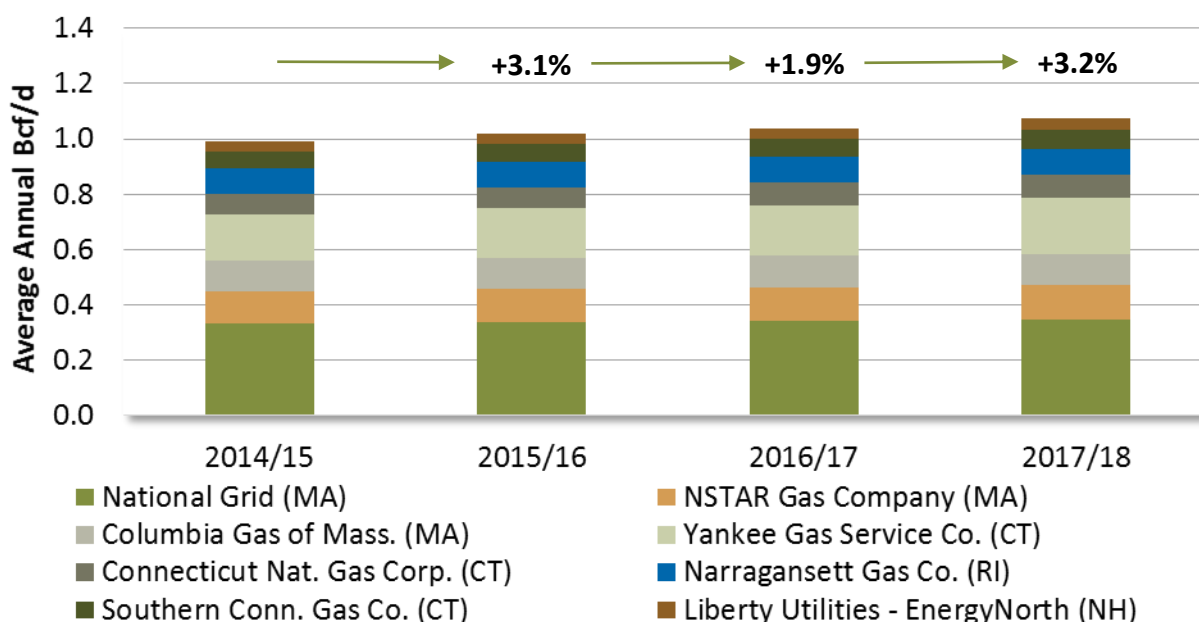
Base Case Market Fundamentals

Residential/Commercial Demand

In its Base Case, ICF projects New England residential and commercial natural gas demand to grow at a compound annual growth rate (CAGR) of 1.31%, between 2016 and 2035. ICF bases its near-term growth projection on the Integrated Resource Planning (IRP) filings by the 8 largest local distribution companies (LDCs) in New England, by volume of gas delivered.¹⁵

Figure 11 below shows the projected annual firm load projections by these major New England LDCs under normal weather conditions. Design year load projections are approximately 10% higher than normal weather; in other words, a design year projection of 1.1 Bcf/d in 2014/2015 would match 1 Bcf/d for normal weather projections.

Figure 11: Normal Weather Annual LDC Demand Projections (Bcf/d)

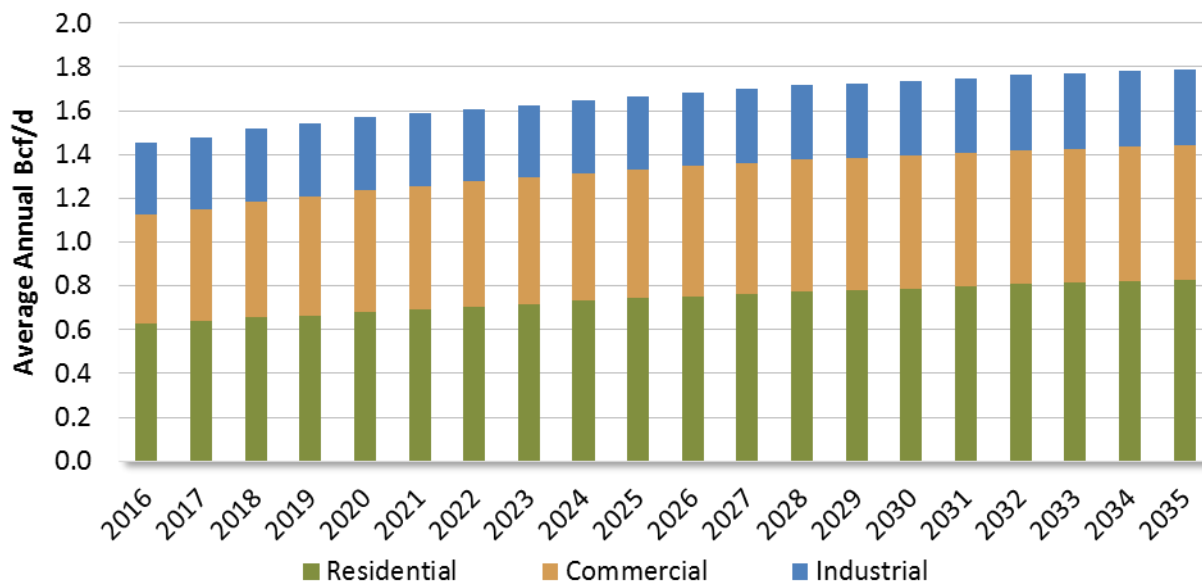


Source: LDC Integrated Resource Plan filings, aggregated by ICF

Through 2018, ICF assumes New England residential and commercial demand will grow at the rates shown in Figure 11, based on the LDCs IRP filings. Post-2018, the ICF Base Case assumes normal weather and projects residential, commercial, and industrial gas demand growth based on a combination of factors, including projected population growth, projected economic growth, the rate of new gas customers additions, and changes in per-household gas consumption. Figure 12 below illustrates ICF’s Residential, Commercial, and Industrial demand growth through 2035 in the ICF Base Case.

¹⁵ Collectively, these top eight LDCs account for nearly 90% of New England’s Residential and Commercial gas consumption; the top eight LDCs include National Grid (MA), Connecticut Nat. Gas Corp (CT), Southern Conn. Gas Co. (CT), Columbia Gas of Mass. (MA), NSTAR Gas Company (MA), Yankee Gas Service Co. (CT), Narragansett Gas Co. (RI), and Liberty Utilities – Energy North (NH).

Figure 12: New England Natural Gas Demand by Sector, Normal Weather, Average Annual Bcf/d



Source: ICF

Industrial Demand

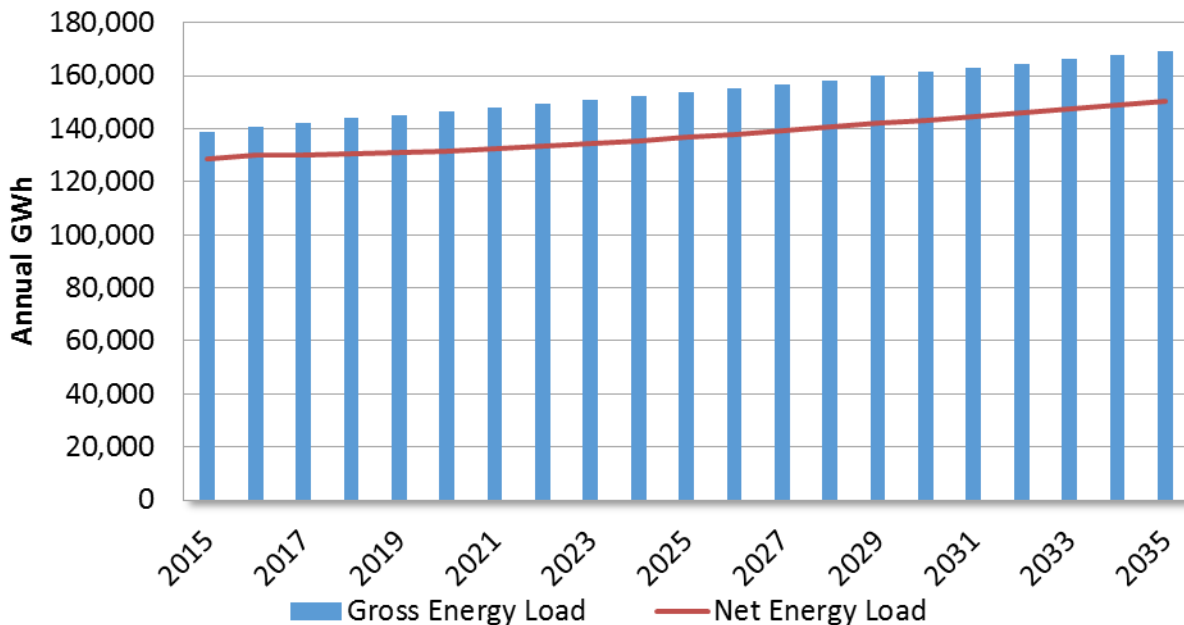
The industrial sector accounts for a relatively small share of New England’s total gas demand, and ICF projects very little growth in this sector. As shown in Figure 12 above, annual average industrial demand is projected to be nearly flat at approximately 0.33 Bcf/d throughout the projection.

Gas Demand for the Electric Sector

Electric Load Growth

ICF projects that New England’s gross electric load grows at 1% per year between 2016 and 2035. However, growth in energy efficiency and passive demand side management offsets some of the increase, such that net energy for load grows at an average of 0.8% through 2035 (Figure 13). ICF’s projections for energy efficiency resources (EE) are estimated based on the levels of cleared Passive Demand Resources (DR) during the 2013-2018 time frame, and are assumed to be available 60% of the time.

Figure 13: Gross and Net Energy Electric Load Forecast for New England



Source: ICF, ISO-NE

Capacity Retirements and Builds

In this analysis, ICF assumes that approximately 3,480 MW of coal, oil/gas and nuclear generation capacity in ISO-NE is retired by 2018 as shown in Table 2; this includes almost 1,000 MW of capacity already retired by the end of 2014.

Table 2: ISO – New England Firm Retirements

Plant Name	Owner	Capacity Type	State	Year	MW
Salem Harbor 3	Dominion	Coal	MA	2014	150
MEAD	New Page Corp.	Coal	ME	2014	15
Somerset Jet 2	Asset Recovery Group	Oil	MA	2014	18
VT Yankee Nuclear Power Station	Entergy	Nuclear	VT	2014	604
Mt. Tom	GDF Suez	Coal	MA	2014	144
Salem Harbor 4	Dominion	Oil/Gas	MA	2015	437
Kendall Steam	GenOn	Gas	MA	2016	25
Lowell Cogeneration Plant	Alliance Energy NY	Gas	MA	Retired	28
Bridgeport Harbor 2	PSEG	Oil	CT	2017	182
Brayton Point 1-4 and Peaking	Dynegy	Coal/OG	MA	2017	1535
Norwalk Harbor 1-3	Norwalk Power LLC	OG	CT	2017	342
Total					3480

Source: ICF

Based on announced capacity additions, ICF assumes 1,750 MW of firm natural gas generation capacity (capacity that cleared the forward capacity auctions) will be added in ISO – NE by 2019 (Table 3). In

addition to these firm capacity additions, ICF projects that an additional 218 MW of natural gas peaking generation capacity will clear the upcoming auction (2019/2020 capacity period).

Table 3: ISO – New England’s Firm Capacity Additions by 2019

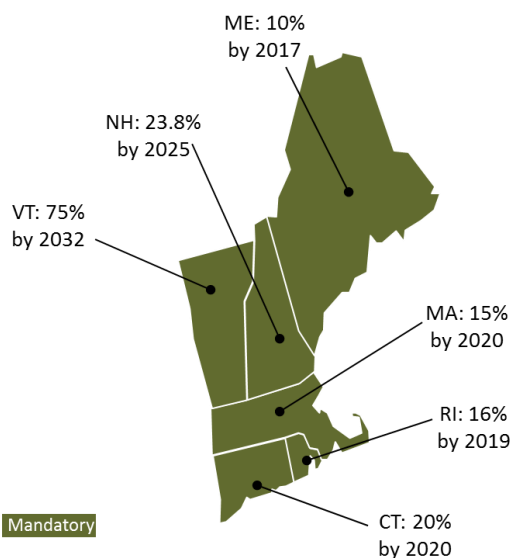
Fuel	2015	2016	2017	2018	Total
Biomass	0	0	7	0	7
Solar	0	4	1	16	21
Wind	64	7	6	0	77
Water	1	48	0	0	50
Landfill Gas	0	0	1	1	2
Oil/Gas	0	39	0	0	39
Natural Gas	10	7	690	1043	1750
Total	76	105	704	1060	1945

Source: ICF

Renewables

ICF assumes that all New England states’ Renewable Portfolio Standards (“RPS”) are met according to currently proposed timelines. Each state’s respective RPS goals can be seen below in Figure 14.

Figure 14: New England State RPS Standards



Source: ICF, States’ RPS

Environmental Regulations

For this analysis, ICF assumes that federal maximum achievable control technology (MACT) standards, consistent with those set by the Environmental Protection Agency (EPA) in its final mercury and air toxics standards (MATS) released on December 21, 2011, will be in effect throughout the projection. ICF also assumes that the EPA will not have an alternative to the current Clean Air Interstate Rule (CAIR) regulations, and that the current CAIR remains in place through 2017. In 2018, ICF-assumed standards tighten to the Cross State Air Pollution Rule (CSAPR) Phase II requirements. Furthermore, ICF considers a

national CO₂ cap and trade program starting in 2020. On the regional level, the analysis assumes that the existing CO₂ market for Northeastern and Mid-Atlantic states¹⁶ under the Regional Greenhouse Gas Initiative (“RGGI”) program remains in place¹⁷ and is gradually integrated into the federal program.¹⁸

Projected Supply Sources into New England

New England’s primary source of natural gas supply is now Marcellus/Utica production, which is then transported to New England’s LDCs principally via TGP and AGT. During peak winter months New England also relies on both peak shaving facilities operated by LDCs as well as intermittent LNG imports via LNG import terminals. Canadian production from Nova Scotia and transported on M&NP has dwindled in recent years and no longer serves as a primary source of natural gas supplies to New England during peak winter months.

LNG Imports

New England has one onshore LNG import facility, Distrigas’s Everett LNG terminal. Between 2010 and 2014, total volumes delivered out of Everett declined by 81%. In response to cold weather and higher prices, volumes rebounded slightly in January 2015, but the 2014/15 peak winter sendout was still less than half of the 2011 volumes. ICF projects annual average and peak winter sendout from Everett to be similar to 2015 levels, declining slightly after new pipeline capacity (AIM, TGP CT, and Atlantic Bridge) is added.

New England also has two offshore LNG import terminals: Neptune and Northeast Gateway. Neptune has not received shipments since 2010, and in 2013 suspended its deep-water port license. Northeast Gateway received two shipments in January 2015, its first since 2010. ICF projects that neither Neptune nor Northeast Gateway are likely to provide gas supplies to New England in the future.

Canadian Supplies via M&NP

M&NP has nominal capacity to deliver up to 0.8 Bcf/d into New England. M&NP was originally designed to bring production from Sable Island Offshore Energy Project (SOEP) to markets in the Maritimes Provinces and New England. M&NP also receives production from the Deep Panuke offshore field and a small onshore field (McCully).

Weaker-than-expected production from SOEP left M&NP underutilized. In 2008, Repsol commissioned Canaport LNG in New Brunswick, which has provided additional supplies for M&NP. In 2013, Repsol sold its LNG supply contracts and ship charters to Shell, leaving Canaport with only a small fixed supply contract.

¹⁶ States participating in the RGGI program include MD, CT, DE, ME, MA, NH, RI, VT, and NY.

¹⁷ The RGGI CO₂ program is assumed to be subsumed by National CO₂ program by 2026. Inflation used beyond 2013 is 2.1% annually. Therefore the values presented here beyond 2025 are actually national CO₂ numbers.

¹⁸ As mentioned earlier in this report, ICF’s Q3 2015 Base Case pre-dates the EPA CPP rule issued on August 3, 2015, so CPP is not included in this analysis.

Even as Eastern Canadian production and LNG imports have declined¹⁹, gas demand in the Maritimes provinces has been increasing. While relatively small, at about 0.2 Bcf/d, demand in the Maritimes provinces uses supplies that could otherwise be exported to New England. Flows on the M&NP system have already reversed on occasion, with gas flowing north into New Brunswick. Even if Canaport continues to import at or slightly above recent levels, the Maritime Provinces are likely to be net gas importers by 2020. As such, M&NP is unlikely to provide gas supplies during the winter peak starting in 2020.

Other Pipelines into New England

TGP, AGT, PNGTS, and IGT have existing firm contracts into New England that total about 3.1 Bcf/d. Three planned pipeline expansions (AGT AIM and Atlantic Bridge, and TGP Connecticut) will provide about 0.6 Bcf/d of additional gas supplies into New England on peak winter days. Based on sendout over the past two winters, Everett is expected to provide no more than 0.25 Bcf/d during peak winter periods. M&NP is still expected to provide some winter supplies in the next few years, but then drop to zero due to decreasing supplies and increasing demand in the Maritime Provinces. This leaves New England with winter gas supplies of about 4 Bcf/d by 2020, as shown in Table 4.

Table 4: Assumed Winter Pipeline and LNG Supplies to New England (Bcf/d)¹

	Supply Path	2020 - 2035
Expected Supplies from Existing Pipelines and LNG Imports	TGP	1.41
	AGT	1.35
	IGT ²	0.21
	PNGTS ³	0.17
	M&NP	0
	Everett LNG	0.25
Supplies from Pipeline Expansions	AIM	0.34
	TGP - Connecticut Expansion	0.07
	Atlantic Bridge	0.15
	Total Pipeline and LNG Supplies	3.95

Source: ICF

1. Unless noted, the table reflects operational capacity. Historical data shows that physical flows occasionally exceed operational capacity under certain conditions.
2. IGT capacity is estimated using firm contracts with receipt points outside of New England and delivery points to end customers in New England according to second quarter 2015 IGT Index of Customers.
3. PNGTS operational receipt capacity at Pittsburg.

Peak Shaving Resources

LDCs in New England operate about 60 peak shaving storage facilities, with a total storage capacity of 16.3 Bcf and a maximum daily sendout of 1.4 Bcf/d. The peak shaving facilities are used by the LDCs to maintain system reliability and help meet firm customer demand on peak winter demand days. It is unlikely that the LDCs would utilize the 100% of the peak sendout capability on any day due to operational constraints

¹⁹ On Jun 25, 2015, CBC News reported that ExxonMobil Decommissioning manager Friederich Krispin said that “the work [decommissioning SOEP] will begin as early as 2017 when the company hires a rig to plug and abandon wells.”

and the desire to conserve peak shaving supplies for later in the season. ICF assumes a peak day sendout of 1.1 Bcf/d, or 80% of maximum daily sendout capability. LDCs need their peak shaving capacity to ensure reliable service for their firm demand customers, so they will not use it to meet spikes in non-firm power sector gas demand.

New England Natural Gas Demand and Supply Balance

In order to determine if New England has sufficient natural gas infrastructure to serve the region’s growing demand, ICF has compared projected daily gas demand and firm gas supplies for selected years.

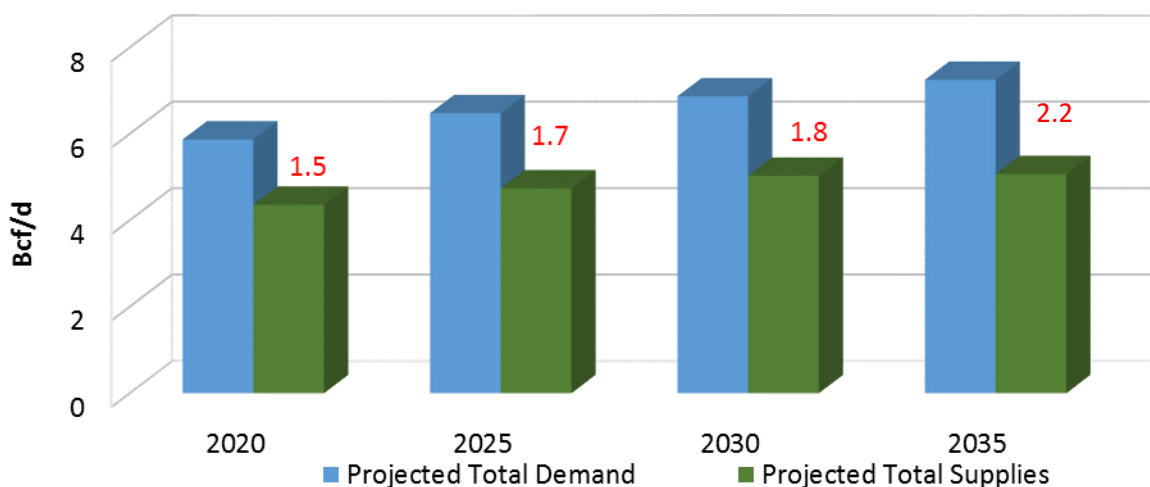
Demand and supply balance analysis typically considers both “peak-day” — which is the day in a given year with the highest demand — and annual consumption projections under both “normal” and “design” conditions, where “normal” weather reflects long-term (20- to 30-year) averages and “design” weather takes into account the coldest weather recorded over a designated time frame.²⁰ The ICF demand/supply analysis includes all four scenarios derived from combining these consumption and weather conditions, with the objective of understanding potential gas supply or capacity deficits/surpluses for the highest demand day, as well as their potential duration over a year. These findings provide valuable insights into the optimal portfolio solutions for the region.

Capacity deficits are estimated as the difference between the Base Case projected demand and total gas supplies.²¹ The estimated capacity deficits do not include potential needs for gas to support the intermittent renewable generation. Duration of capacity deficits is the number of days during the specific year when total demand exceeds total supplies.

Normal Weather

Figure 15 shows that under normal weather conditions, New England’s peak day capacity deficit will reach 1.5 Bcf/d in 2020, 1.7 Bcf/d in 2025, 1.8 Bcf/d in 2030, and 2.2 Bcf/d in 2035.

Figure 15 : Projected New England Capacity Deficits - Normal Weather Peak Day



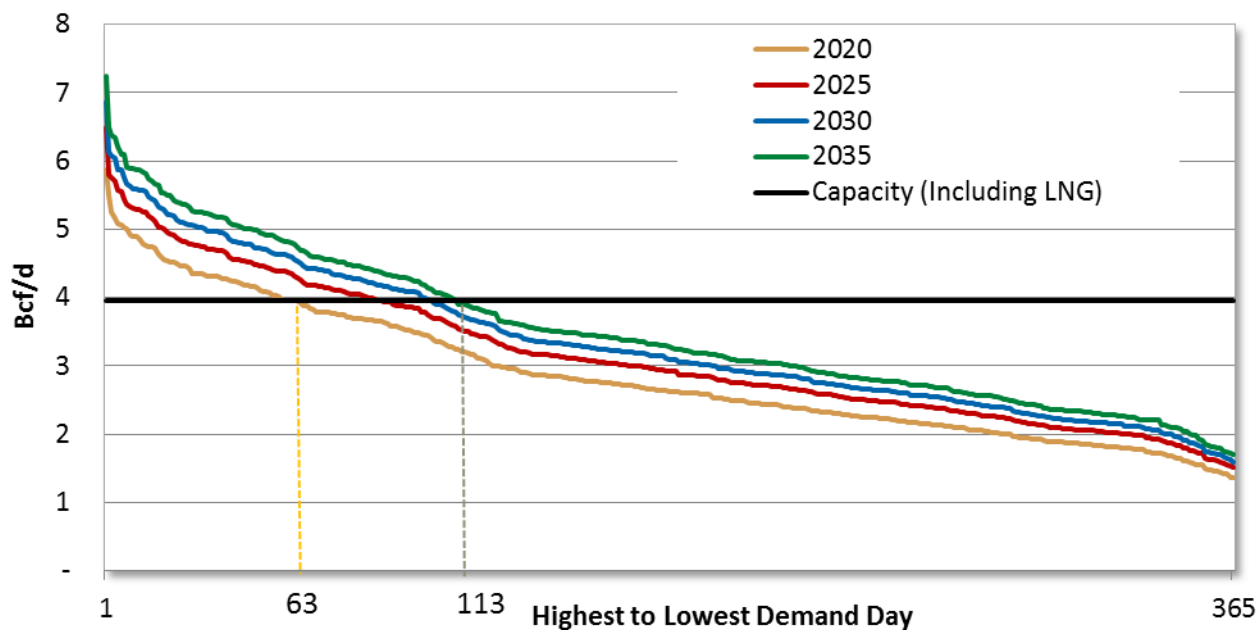
Source: ICF, note that red numbers indicate the size of the supply deficit.

²⁰ For gas utilities, design weather standards vary and may extend back 30 to 50 years or as long as temperatures have been recorded.

²¹ Peak shaving facilities are assumed to contribute to peak day supply capability on those days when LDC demands exceed the region’s firm pipeline capacity. However, since they are operated by the LDC, the peak shaving facilities are not available to meet power sector demand.

Figure 16 provides a standard way of visualizing gas capacity deficits, by plotting gas demand in the region from the highest to the lowest demand day throughout a given year. This produces a curve which can be compared against available supply capacity to show how many days the region is in deficit. Figure 16 shows that for each of the successive five-year intervals depicted from 2020 to 2035, these daily load curves continually shift upward as demand grows over time. With supply capacity serving the region remaining the same from 2020 forward, the number of days that daily load exceeds supply capacity increases from 63 days in 2020 to 113 days in 2035. On these days, the aggregate unmet power sector gas demand totals approximately 89 Bcf, reducing gas-fired generation by almost 12 million MWh, and potentially creating spikes in both gas and electricity prices. By 2035, the projected duration of capacity deficits lengthens to an estimated 113 days, or nearly 80% of the winter season.²² Unmet demand in the power sector grows to 210 Bcf, equivalent to lost gas-fired generation of 27 million MWh.

Figure 16: New England Daily Gas Load 2020-2035 (Normal Weather)



Source: ICF

Design Weather

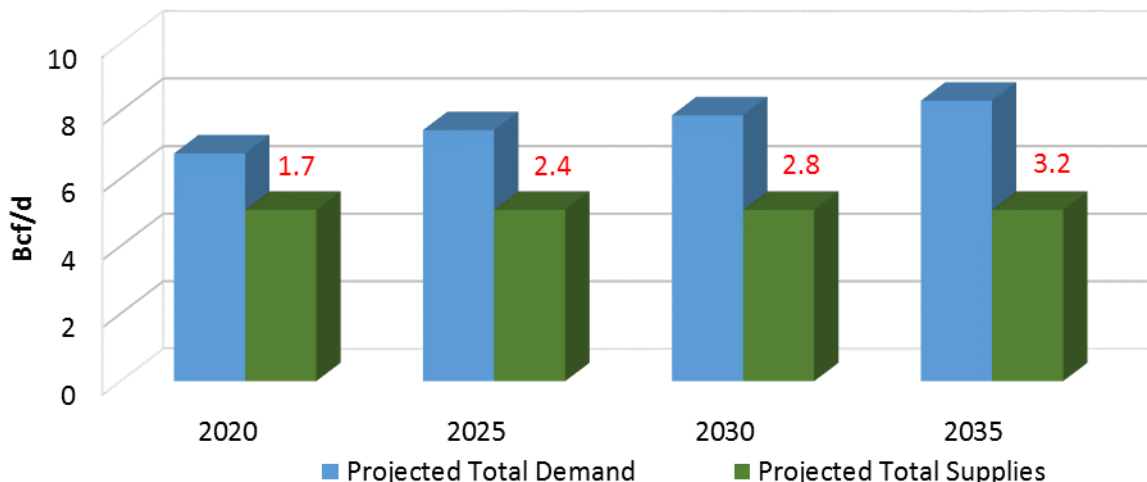
Based on projections made by the eight largest LDCs in New England, ICF projects that under design weather conditions, annual LDC demand will be 10% higher than normal weather demand. Based on design day and normal weather peak day temperature assumptions, ICF estimates that design day residential and commercial demand (which makes up the majority of LDC load) is approximately 20% higher than that on a normal weather peak day.

Figure 17 shows that, assuming that the design day LDC load is 20% higher than on a normal year average peak day and power demand remains the same as a normal year average peak day, New England design

²²After 2030, capacity constraints occur on a couple of days in peak summer months as well.

day demand will increase from 6.7 Bcf/d in 2020 to 8.3 Bcf/d in 2035. The potential unmet demand is approximately 1.7 Bcf/d in 2020, increasing to 3.2 Bcf/d in 2035.

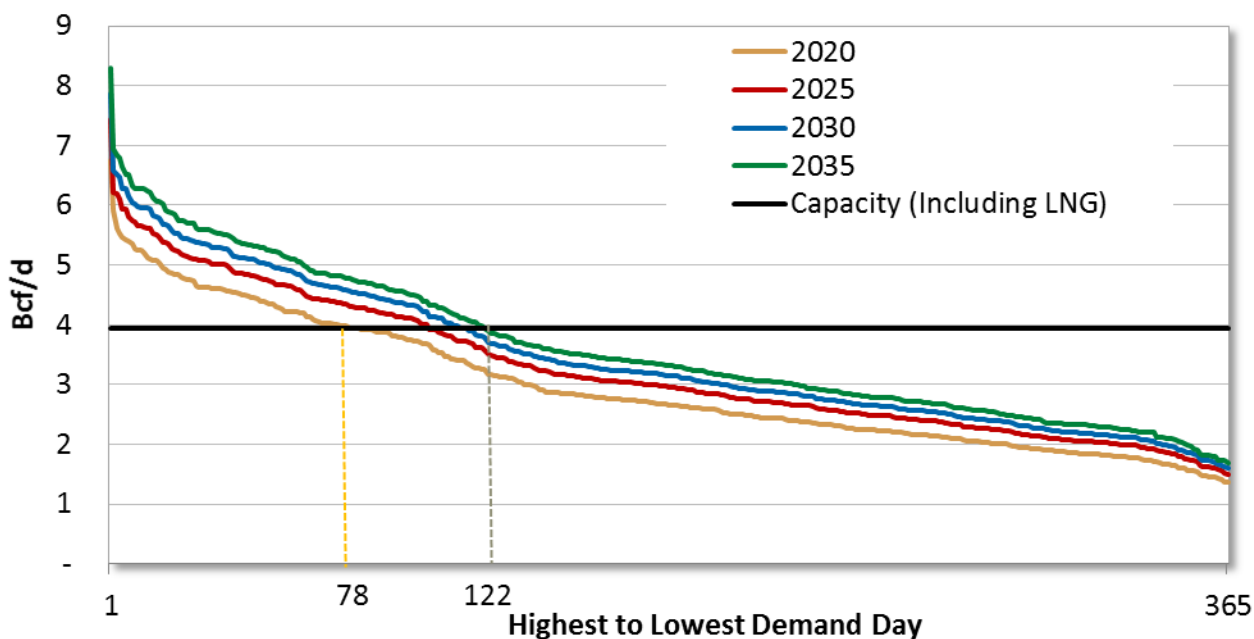
Figure 17: Projected New England Capacity Deficits – Design Day



Source: ICF, note that red numbers indicate the size of the supply deficit

Figure 18 shows that by 2020, projected demand is greater than projected supply on 78 days under design year conditions. Over those 78 days, the unmet demand from the power sector is 110 Bcf, reducing gas-fired generation by 14 million MWh. By 2035, the number of days of unmet demand increases to 122. Over those 122 days, the unmet demand in the power sector is 226 Bcf, reducing gas-fired generation by over 29 million MWh.

Figure 18: New England Daily Gas Load 2020-2035 (Design Year)

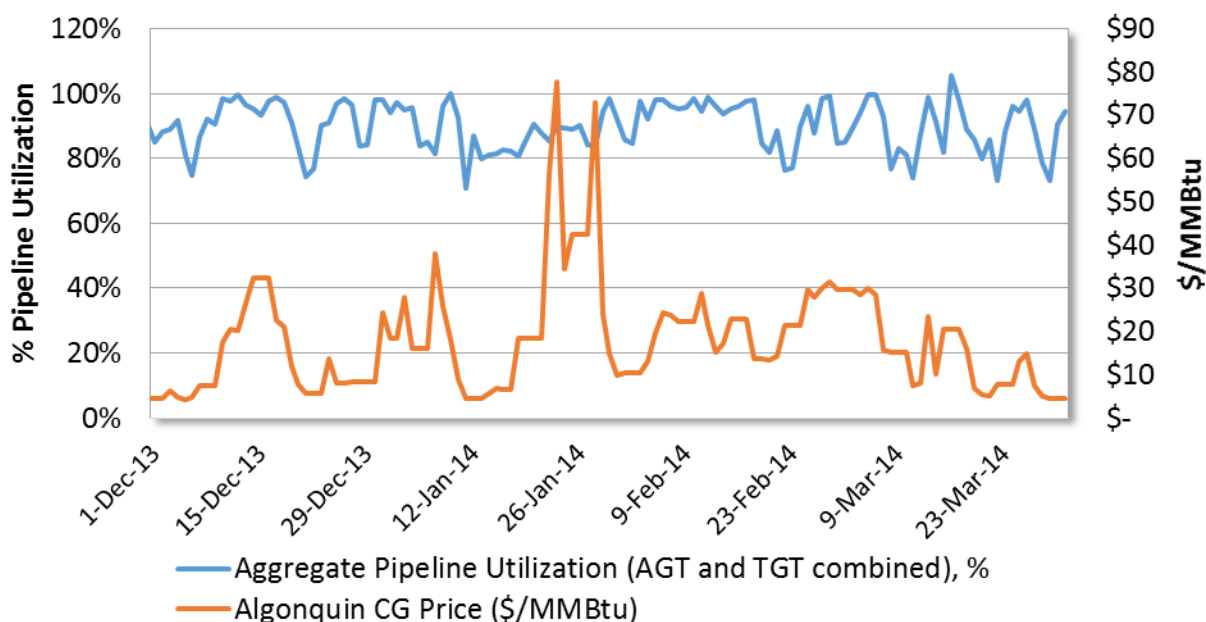


Source: ICF

Illustrative NED Impact on Winter 2013/14

To illustrate the potential impact NED could have on New England’s power market, ICF analyzed New England’s natural gas and power market during the historic “polar vortex” winter of 2013/14. ICF reviewed the combined daily load factors on key pipelines serving New England (TGP and AGT), daily gas prices at Algonquin city-gates, daily real time average prices and daily load for ISO-NE and identified days with natural gas price spikes for the period using a threshold of approximately \$10.00/MMBtu or price rising more than 100% in a day. The vast majority of these spikes occurred between December 2013 and March 2014. As shown in Figure 19, daily load factors on AGT and TGP averaged 90% for this period, and load factors on price spike days frequently exceeded 95%.

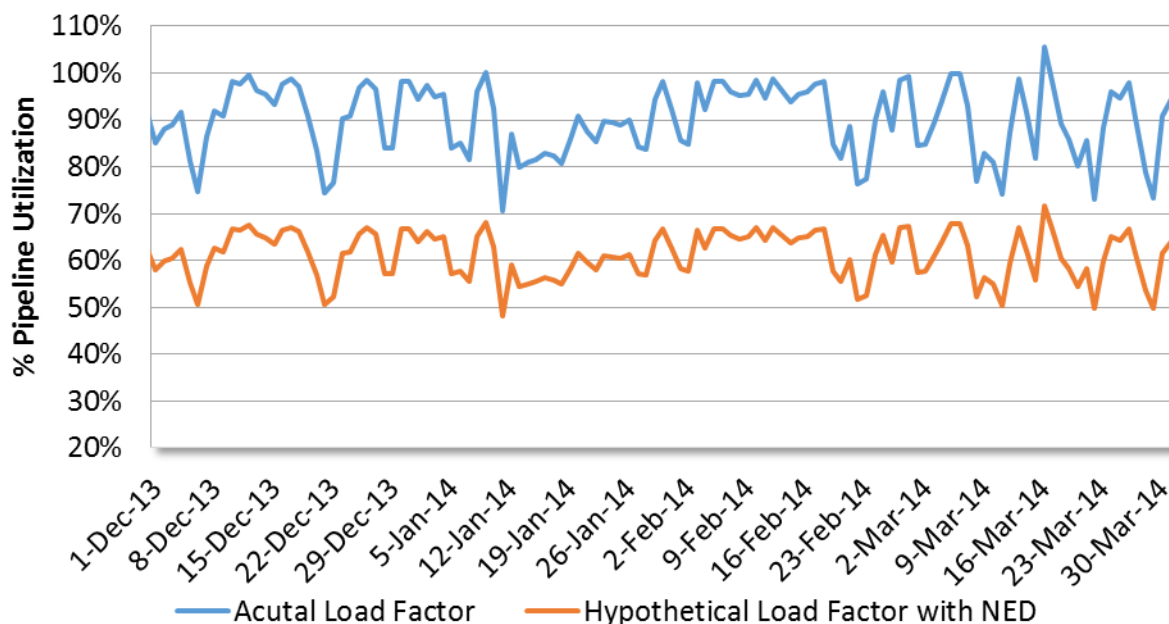
Figure 19: TGP / AGT Pipeline Utilization versus New England Natural Gas Prices, Winter 2013-2014



Sources: Ventyx (gas prices), PointLogic Energy (pipeline capacity and flows)

ICF then recalculated the load factor on the days with price spikes incorporating the 1.3 Bcf/d NED capacity. This hypothetical load factor is much lower than the actual, as shown in Figure 20.

Figure 20: Actual Pipeline Load Factors and Hypothetical Reduced Load Factors with NED



Source: ICF

Based on analysis of historical data, as shown in the Executive Summary (Figure 3), New England gas price spikes and associated electric price spikes are far less likely to occur when pipeline load factors are at or below 75%.²³

To calculate the estimated impact that NED could have had on peak power prices, ICF assumed that on the day of the price spikes, if the load factor were reduced below 75%, power prices would revert to the level experienced on the day prior to the spike. Based on this analysis, additional pipeline capacity equivalent to the proposed NED market project would have eliminated gas and electric price spikes on 86 days during the 2013/14 winter, reducing wholesale electricity expenditure in New England by \$3.7 billion. Table 5 shows the cost savings of the top 10 days.

Table 5: Power Costs ISO-NE Peak Days, Actual and Hypothetical (Winter 2013-2014)

	Actual TGP/AGT Flows (MMcf/d)	Actual Load Factor (%)	Gas Price (\$/MMBtu)	Actual Electric Price (\$/MWh)	Average Hourly Load (MWh)	Hypothetical Load Factor (%)	Hypothetical Electric Price (\$/MWh)	Daily Cost Savings (Million \$)
1/28/2014	2,313	84%	\$ 73.00	\$ 333.65	16,944	57%	\$ 45.68	\$ 117.10
1/23/2014	2,479	90%	\$ 77.60	\$ 318.90	17,599	61%	\$ 45.68	\$ 115.40
1/24/2014	2,470	89%	\$ 34.50	\$ 280.85	17,409	61%	\$ 45.68	\$ 98.25
3/3/2014	2,473	90%	\$ 29.62	\$ 284.29	16,193	61%	\$ 48.53	\$ 91.62
3/4/2014	2,599	94%	\$ 28.50	\$ 280.08	16,357	64%	\$ 48.53	\$ 90.90
1/22/2014	2,357	85%	\$ 56.25	\$ 258.61	17,655	58%	\$ 45.68	\$ 90.22

²³ Historical data analysis indicates that New England prices tend to spike up when pipeline load factors exceed 75% of existing infrastructure capacity, which is consistent with findings of the NESCOE Gas-Electric Study Phase II. http://www.nescoe.com/uploads/Phase_II_Report_FINAL_04-16-2013.pdf

New England Energy Market Outlook – Demand for Gas Capacity and Impact of the NED Project

1/25/2014	2,456	89%	\$ 42.50	\$ 281.18	15,813	60%	\$ 45.68	\$ 89.37
1/7/2014	2,251	82%	\$ 38.09	\$ 256.23	17,251	55%	\$ 46.43	\$ 86.86
1/8/2014	2,650	96%	\$ 25.91	\$ 235.82	17,656	65%	\$ 46.43	\$ 80.25
1/26/2014	2,487	90%	\$ 42.50	\$ 259.34	15,565	61%	\$ 45.68	\$ 79.81

Source: ICF

The estimated cost savings were extraordinary for winter 2013/14, because the polar vortex conditions impacted a very large US geographic area (including the Northeast, Southeast, and Mid-west simultaneously) that drove up the demand for natural gas throughout the natural gas transportation systems.

Cost Savings - Normal Weather

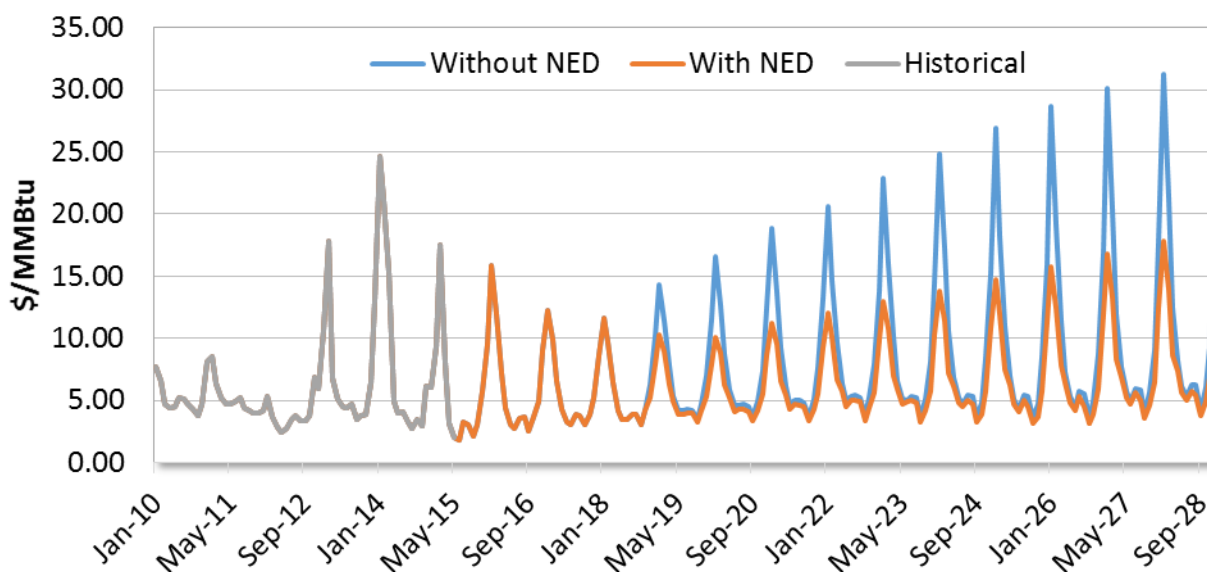
ICF estimated the energy market impact of NED by running GMM and IPM models under normal weather conditions with and without the project, and then compared the difference for natural gas prices and wholesale power prices. The wholesale power price reduction was then used to calculate the market impact and potential cost savings to New England electric consumers. In addition, the project’s impact on natural gas price volatility and the resulting further reduction to electric price spikes were then estimated separately utilizing a statistical approach.

Natural Gas Price Impact – Monthly Average

Figure 21 shows that without NED, under normal weather conditions, ICF projects that peak winter month gas prices in New England will initially decline from the levels seen in the past two winters. Incremental capacity expansions (such as AIM, Tennessee’s Connecticut Expansion, and Spectra’s Atlantic Bridge) will temporarily contain the peak winter price for three years before demand growth and Eastern Canada supply declines outpace the expanded capacity. Peak winter prices then will steadily increase over time and exceed, in 2024, the levels experienced in the Polar Vortex winter of 2013/14 and surpass a monthly average of \$30/MMBtu by 2028.

In this projection, NED significantly lowers peak winter gas prices. Even though prices continue to rise as the market responds to demand growth and supply declines, peak winter monthly prices are projected to be substantially lower than levels reached in the 2013/14 winter. On average, NED reduces New England’s natural gas prices by \$2.4/MMBtu over the 10-year period between 2019 and 2028. During the peak winter months of December, January and February, NED could reduce prices by as much as \$8.7/MMBtu.

Figure 21: New England Natural Gas Price Forecast – Monthly Average

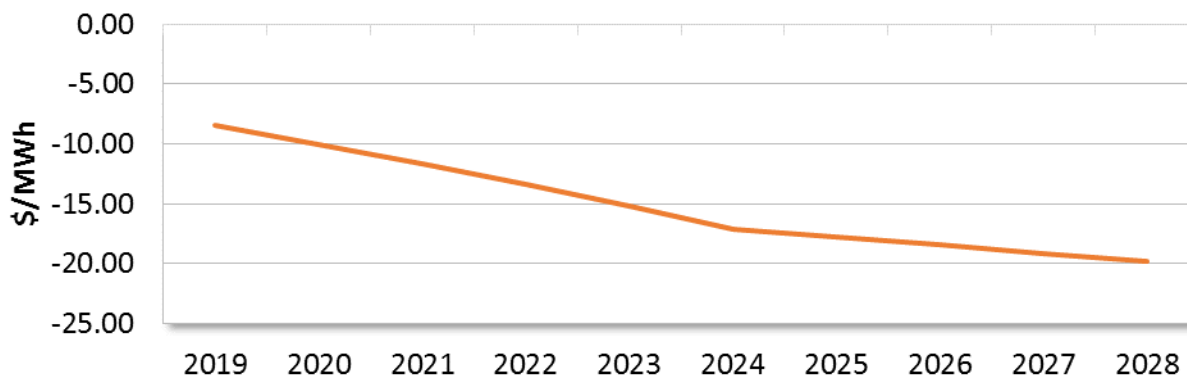


Source: ICF, SNL

Wholesale Power Price Impact – Monthly Average

New England’s wholesale power prices are closely related to natural gas prices due to the region’s dependence upon gas-fired power generation capacity. By reducing spot prices in New England, the NED market project would have a direct impact on New England’s wholesale power prices. As shown in Figure 22, NED reduces the New England annual average wholesale power price by \$9/MWh to \$20/MWh between 2019 and 2028.

Figure 22: New England Annual Average Wholesale Power Price Reductions with NED – Monthly Average



Source: ICF

Cost Savings from Average Price Reductions

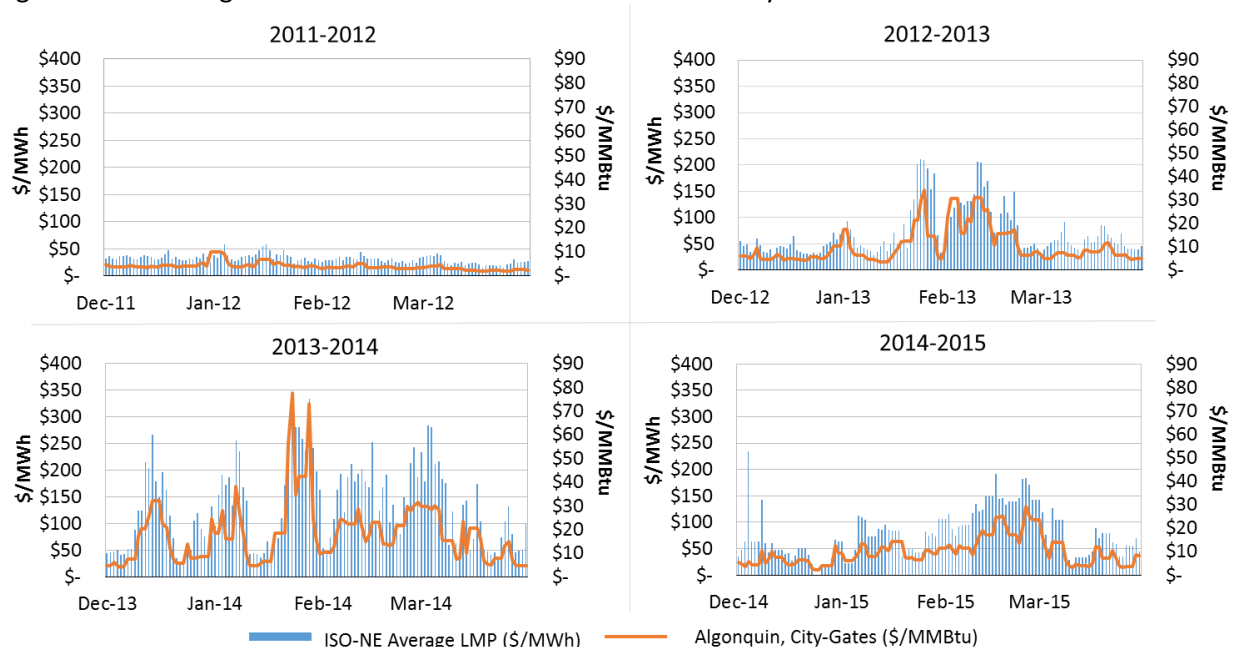
The analysis results presented above show that NED could reduce New England’s wholesale electricity prices by lowering the regional natural gas price and the fuel costs for gas-fired power generation. In this analysis, ICF assumes that wholesale power price reduction provided by infrastructure solutions reduces the wholesale costs across New England. Annual wholesale power cost savings are calculated as the reduction in New England’s wholesale energy prices multiplied by ISO-NE annual net energy load. ICF estimated that NED could potentially generate annual cost savings of \$2.1 billion on average for the 10-year period between 2019 and 2028.

Benefits from Reduced Daily Gas Price Volatility

In addition to the monthly average price reduction that ICF estimated using the GMM and IPM models, the gas supply capacity created by a project like NED could produce additional cost savings through reductions in daily natural gas and power price volatility. New England’s gas and wholesale power prices both exhibit asymmetric patterns – daily prices can spike up to extremely high levels, but only decline modestly. Therefore, reduction in the frequency and magnitude of natural gas and electricity price spikes could potentially result in price reductions beyond the monthly average levels discussed above. ICF estimated the potential impact of volatility only for the peak winter months of December through March.

Price volatility is determined by complex market drivers, the analysis of which is beyond the scope of this report. For this study, ICF assumed certain ranges of reduction of frequency and magnitude of extraordinary price spikes as a proxy to measure the impact of volatility reductions. Figure 23 presents daily Algonquin City Gate gas prices and ISO-NE daily average real-time locational marginal prices (RTLMPs—prices for electricity at different locations in the grid) for the past four winters.

Figure 23 - New England Historical Gas and Electric Price Volatility



Source: ICF, SNL, ISO-NE

The range of NED’s potential volatility reduction impacts is estimated assuming two volatility reduction levels:

- Low Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a moderate volatility market, similar to what was experienced in the 2011/2012 or 2014/2015 winter;
- High Volatility Reduction Assumption - Frequency and size of price spikes are reduced by approximately half from a high volatility market, similar to what was experienced in the 2013/14 winter.

These assumptions generate a range of additional cost savings of \$0.3 billion to \$0.8 billion dollars a year on average for the 10-year period of 2019 through 2028.

Net Estimated Electric Cost Savings

ICF estimated that by reducing monthly average natural gas and electricity prices, NED could potentially generate \$2.1 billion a year in wholesale electricity cost savings. These wholesale electric cost savings would ultimately flow through to all New England electric consumers.

NED could also reduce the daily price volatility in natural gas and power prices, which could contribute an additional \$0.3 to \$0.8 billion dollars a year in cost savings.

Overall, NED could generate, on average, \$2.1 billion to \$2.8²⁴ billion a year in total cost savings to New England electric consumers, assuming zero volatility and high volatility reduction impacts respectively.

The annual carrying costs that need to be borne by electric consumers for pipeline infrastructure are estimated using a pipeline Cost of Service proxy. Cost of service reflects the annual costs that a pipeline needs to recover from all shippers who reserve capacity on the pipeline. Major variables in the cost of service calculation include O&M costs, depreciation and taxes, and the returns on the capital investments in constructing the pipeline. ICF estimated that the annual carrying costs of NED transportation capacity for the power sector would be \$400 million.²⁵ Therefore, NED could generate an average annual net electric cost savings of \$1.7 billion to \$2.4 billion to New England electric consumers.

²⁴ Estimates for savings from average price reductions (\$2.1) and volatility savings (up to \$0.8 billion) are rounded to the nearest \$0.1 billion; the round sum of the two is \$2.8 billion.

²⁵ ICF estimates the first year's cost of service based on \$2.0 billion total capital costs to be borne by New England's electric sector for the construction of NED.

Other Benefits of Incremental New England Natural Gas Pipeline Capacity

ICF analysis in the preceding report sections focuses on potential capacity deficits and the resulting natural gas and electricity price implications that could emerge as regional natural gas demand grows. This section summarizes other potential benefits associated with additional pipeline capacity.

Enhanced Operational Reliability

It is evident from ICF analysis that new pipeline capacity as proposed in the NED market project would enhance the availability of gas service that is essential to supplying a growing New England market. And by providing capacity for growth, NED would also mitigate increasingly tight capacity conditions for most gas-fired power generators in New England. As such, for new and existing gas shippers alike, NED would also provide valuable reliability against service interruptions.

Natural gas pipelines in New England and elsewhere have a demonstrated history of high reliability: operational outages that impair services to firm customers are exceptionally rare. Nonetheless, the expanded role of natural gas as a primary energy source for heating and as a fuel for electricity materially increases the potential costs of service disruptions that might occur for any reason. NED is uniquely effective in this regard because its interconnection with TGP at Dracut, Massachusetts and integration with the TGP system would allow it to provide supplies for end users across both the eastern and western parts of New England.

The NED-TGP integration would support service continuity for roughly 50% of New England's current power supplies. ICF analysis indicates that TGP currently serves 9,049 MW of New England gas-fired generation capacity.²⁶ As shown in Table 6, during 2012-2014, TGP transported an average of 0.57 Bcf/d of natural gas to New England power generators, equivalent to 52% of the total natural gas consumed by those generators.²⁷ Based on average dispatch heat-rates, TGP services support some of the most efficient electric generators in New England.

Table 6 - TGP Served Power Generation in New England

	Operating Capacity (MW)	% of New England Total	Average Generation (GWh)	% of New England Total	Average Gas Burn (Bcf/d)	% of New England Total
Direct Deliveries	4,894	27%	17,080	32%	0.34	32%
Indirect Deliveries via Supplying LDCs	827	5%	1,601	3%	0.04	4%
Indirect Deliveries via Supplying AGT	3,328	18%	9,142	17%	0.18	17%
Total TGP	9,049	50%	27,823	52%	0.57	52%

* For the purposes of this table, Milford & Ocean States I & II are included as TGP Direct Deliveries.

* Numbers in the table may not add up exactly to the total because of rounding.

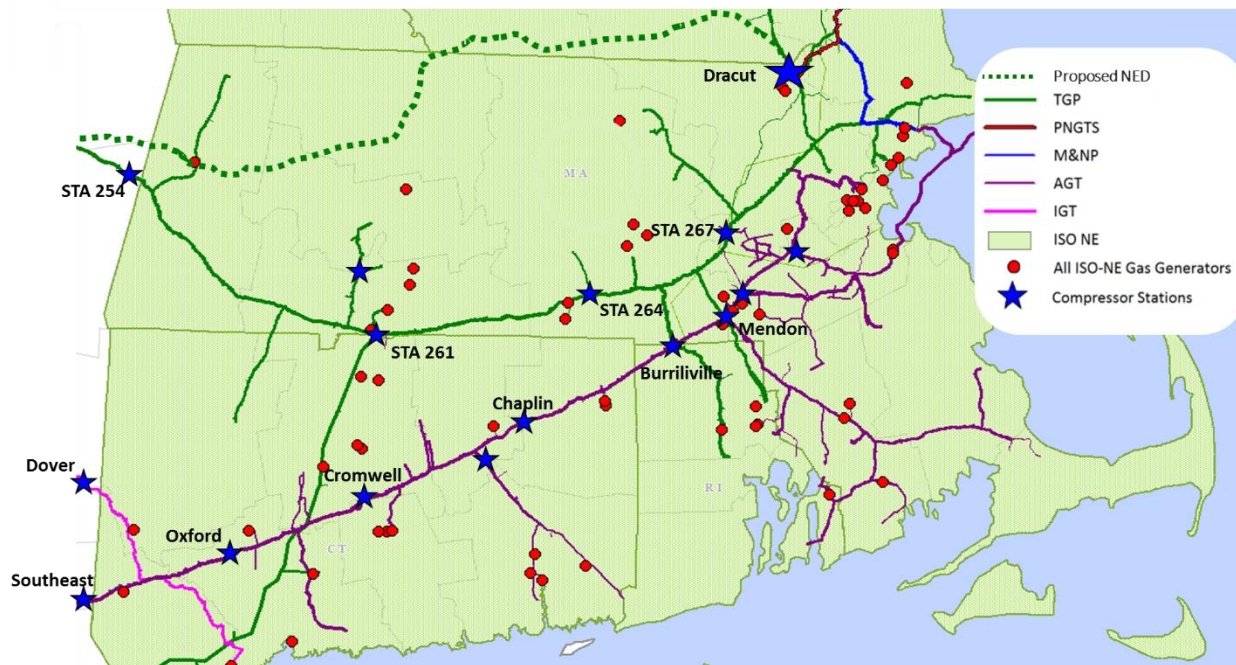
Source: SNL and ICF

²⁶ TGP transportation services deliver gas to power generators both directly through physical interconnections or exchanges and indirectly through deliveries to other regional pipelines and LDCs.

²⁷ Generation capacity and gas consumed for generation represent different but related measures of the role of natural gas in the generation of electric power.

With modifications, NED service could similarly enhance service reliability for shippers on the AGT, PNGTS, and M&NP pipelines. As illustrated in the Figure 24 map below, through deliveries at Dracut, MA, NED is potentially able to “back feed” additional gas supplies to all existing pipelines in New England, creating a new path to all gas customers.

Figure 24 - New England Gas-Fired Generation and Natural Gas Infrastructure



Source: Ventyx

The NED-TGP configuration is particularly integral to New England electric reliability because it is capable of delivering high pressure gas east of the Mass. Hub and north of Boston to the area where a dense concentration of power generation facilities operate. Gas deliveries to power generators in this region on existing interstate gas pipelines are downstream of, and dependent upon, nearly twenty TGP and AGT compressor stations. If confronted by outages or other potential supply disruptions on AGT and TGP, NED would provide pipeline operators an alternative path for delivering gas supplies to the region, potentially mitigating costly and disruptive power interruptions.

As noted above, the value of pipeline capacity reliability for a region increases materially as gas use for power generation grows. Without adequate gas capacity, New England’s electric system could face costly load shedding measures. Studies regarding the estimated costs of power service outages are limited, but a 2013 filing with state regulators by Potomac Electric Power (PEPCO), a PJM electric utility that serves Maryland and Washington D.C., provides one benchmark. In that filing, summarized in Table 7, PEPCO estimated that an eight-hour outage for a quarter of its customers could cost approximately \$988 million. NED can help New England avert this type of costly electric load shedding.

Table 7: Estimated Costs of Outages by PEPCO in 2013 Maryland State Filing

Customer Class	Total Cost per Customer for an 8 hour Outage (\$)	One Quarter of Total Customers	Estimated Costs for an 8 Hour Outage affecting a quarter of Total Customers (\$)
Residential	11	58,774	623,004
Small Commercial and Industrial	5,195	65,453	340,027,569
Large Commercial and Industrial	69,284	9,350	647,833,633
TOTAL		133,557	\$988,484,206

Source: PEPCO

It is also relevant that additional gas pipeline capacity in New England can help insulate consumers against disruptions in power generation capacity. Gas demand forecasts for power generators assume the availability of other types of generation facilities (nuclear, renewables). Many of these power plants will, because of lower variable costs, dispatch before natural gas plants. When there are unscheduled outages in other types of capacity, gas-fired plants, because of their quick start capabilities, are often forced into operation and will require natural gas service.

Operational Flexibility

Gas-fired electric generators require large volumes of high-pressure gas to operate. However, their demand for gas can vary with electric markets and load conditions throughout the day, and require rapid ramps up and down. Pipeline operators typically will work with their shippers to accommodate such intra-day “swings,” but their flexibility to do so is contingent upon having capacity adequate to meet firm demand. If they do not have sufficient capacity above and beyond firm demand, their flexibility to meet power generator demand fluctuations is limited.

When firm gas demand ramps up (often at the same time as interruptible power demand for gas rises) pipelines begin restricting the flexibility they grant to all shippers. As conditions become more severe, pipelines can issue additional restrictions in the form of operational flow orders (OFOs) to maintain the quality of services. As noted in a report published by the North American Electric Reliability Corporation (NERC): “The sudden demand swings from generators may cause pipeline pressure drops that could reduce the quality of service to all pipeline customers.”²⁸ A report by ISO-NE identified an incident in which a “pipeline reported serious problems with gas pressure with the potential to interrupt gas flow to certain generators due to gas-fired generators over-drawing their gas nominations. An additional 800 MW of gas-fired generation was at risk over the peak load hour due to questionable gas supplies.”²⁹

Absent new pipeline capacity additions, intra-day swing flexibility will inevitably erode as large power generation loads are added (a process that has been happening rapidly in New England over the past decade). These restrictions on intra-day load swings apply to both power and non-power gas shippers.

²⁸ Special Reliability Assessment: Accommodating an Increasing Dependence on Natural Gas for Electric Power. North American Electric Reliability Corporation, May 2013.

²⁹ http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf, page 6.

The remedy for lost operational flexibility is either to curb demand or to purchase additional firm pipeline capacity that meets peak-hour needs within a day. Both solutions come with additional costs.

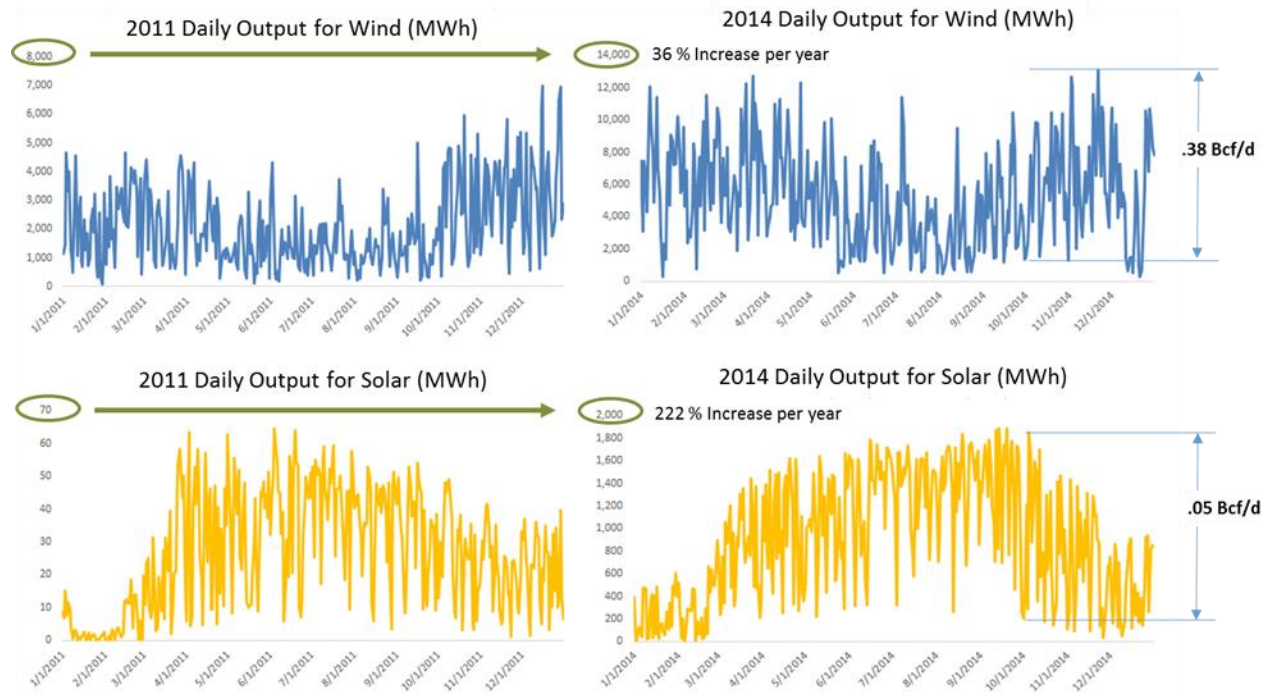
By providing high pressure deliveries to its terminus at Dracut, NED could provide greater support to its direct-connect customers and help downstream interconnecting pipelines maintain system pressures, potentially without requiring extensive investments in incremental compression or line upgrades.³⁰ The economic benefits of maintaining regional operating flexibility can be very difficult to quantify, but the incremental pressure provided by NED could enhance the flexibility of natural gas pipelines throughout the region.

Support for Renewable Energy

New England states have embraced aggressive renewable energy programs, including both wind and solar facility development. These renewable resources are “intermittent” generators, which means their power production can fluctuate dramatically and rapidly between peak capacity and zero. As the renewable market share grows in New England, these swings have greater effects on the regional electric grid, and thereby place greater demands on the system to accommodate the variation.

The graphs in clearly depict how generation output from renewable wind and solar resources fluctuates both throughout the day and from one day to the next. By comparing the y-axis of each graph, they also show how the power production swings have grown in just three years from 2011 to 2014.

Figure 25 – New England Wind and Solar Output



Source: ISO-NE

³⁰ KM indicates that the estimated delivery pressure at Dracut is between 1,440 and 1,460 (psi).

Gas-fired generation is a highly complementary resource to buffer the intermittent production of renewable energy. Unlike other types of power generation that are more rigid in their dispatch capabilities, gas turbines are engineered to ramp up and down in tandem with renewable generation variability. Assuming these turbines can be supplied with gas on a comparable schedule, gas generation therefore provides an ideal complement to renewable energy. In that regard, the pipeline system's operational flexibility — which would be enabled by NED — discussed above is a key source of capacity that can enable gas turbines to manage intermittent renewable power, and support the rise of renewable generation in New England. In some instances, operators may find it contractually necessary to supplement renewable energy with pipeline firm transportation contracts, but the norm will be to rely on operational flexibility.

The graphs in Figure 25 above, confirm estimations of the pipeline capacity required to support New England renewable energy in 2014. Using simplifying assumptions, the data suggest that intermittent load swings of wind and solar resources could require an estimated daily pipeline capacity of .38 Bcf/d and .05 Bcf/d respectively, a total of .43 Bcf/d.³¹ On peak winter or summer days when pipeline capacity utilization is high, such swings would exert a material pull on the region's gas infrastructure, with resulting supply/demand pressures and cost impacts.

Environmental Benefits

Natural gas burns cleaner in power generation than other fossil fuels historically used in New England. The development of new pipeline transportation capacity in New England is essential to supporting the conversion of fuel oil- and coal-fired generation to natural gas, and achieving mandated reductions in NO_x, SO₂, and CO₂ emissions.³²

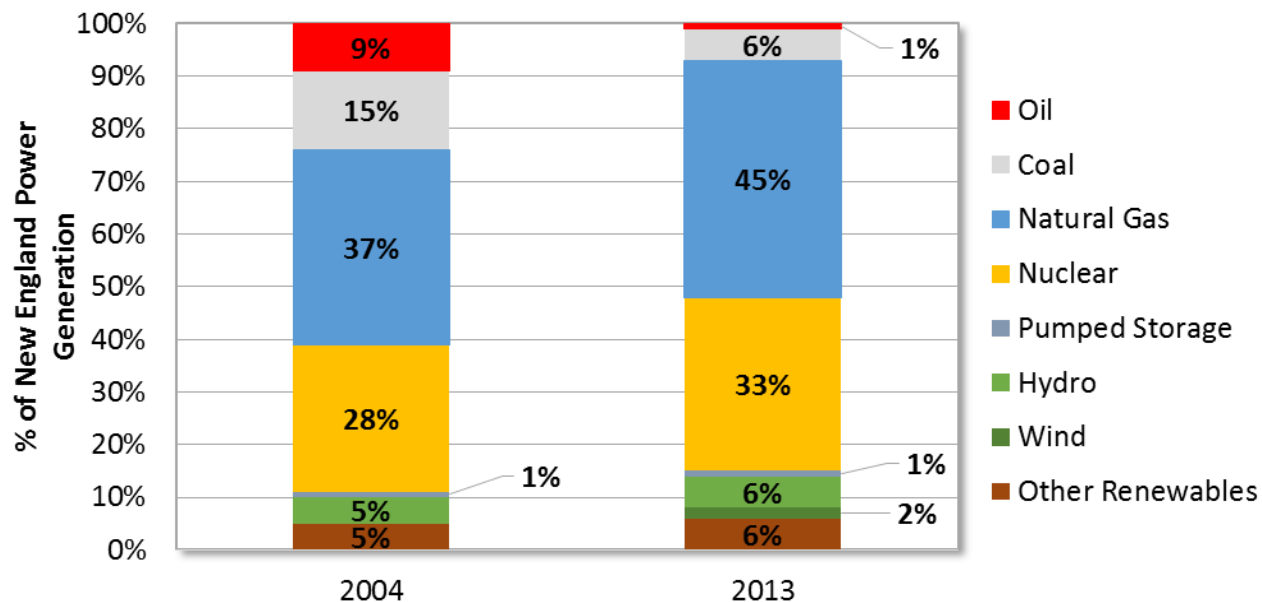
Figure 26 - on the next page, summarizes the role that natural gas and nuclear energy have played in reducing power generated from burning coal and oil. Between 2004 and 2013, coal and oil generation declined from 25% of total generation to less than 7%.³³

³¹ Key assumptions include the hourly duration of renewable energy production on a given intermittent resource day, and the effective heat rates of a modern gas turbine producing an equivalent amount of energy.

³² NO_x is Nitrogen Oxides; SO₂ is Sulfur Dioxide, CO₂ is Carbon Dioxide; all Greenhouse Gases.

³³ http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf, Figure 1-1.

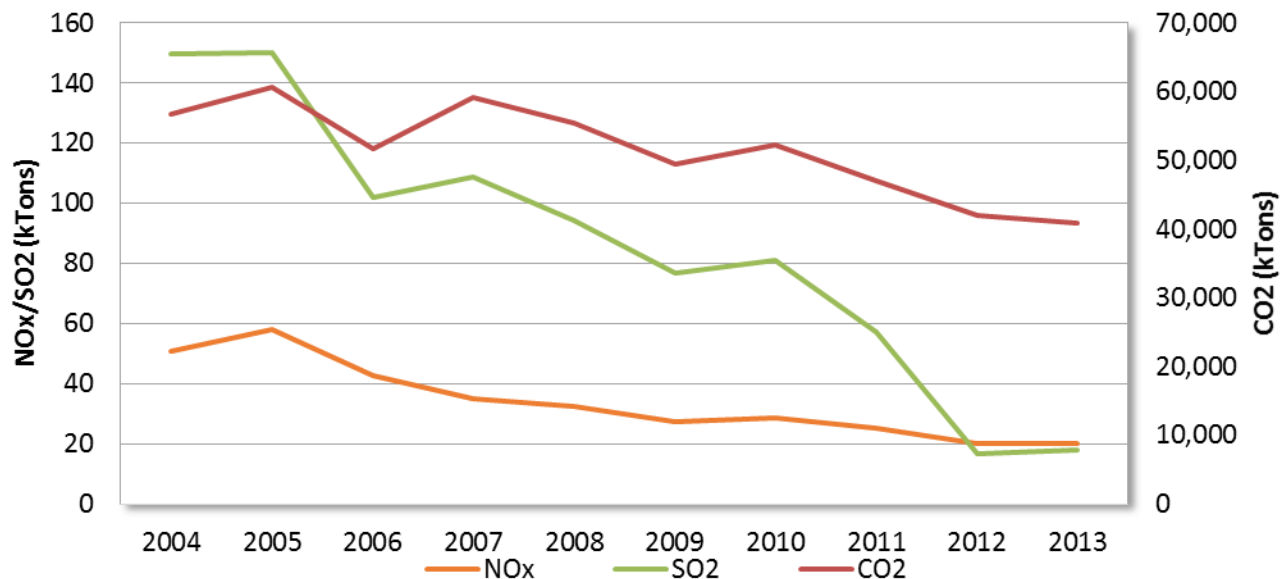
Figure 26 - New England Generation Mix 2004 vs. 2013



Source: ISO-NE

The migration from oil- and coal-fired generation led to sharply reduced emissions from New England power generators. The graph below illustrates the corresponding decreases in NO_x (60%), SO₂ (88%), and CO₂ (28%) emissions from 2004 through 2013 (Figure 27).³⁴

Figure 27 - New England Power Sector Emissions, 2004-2013



Source: ISO-NE

³⁴ http://www.iso-ne.com/static-assets/documents/2014/12/2013_emissions_report_final.pdf, Appendix Table 4.

Electric demand growth will require increased fuel supply. Natural gas, delivered through incremental pipeline capacity, is one primary source. Increased fuel oil/distillate use — supported by plant switching and storage tank investments and delivered by trucks, rail, barges and pipelines — is another.

The economic comparison of increased fuel oil versus natural gas in power generation could be uncertain, hinging on key assumptions regarding plant load factors, logistics, permitting and emissions costs.

The environmental consequence of increasing fuel oil use are clearer. ICF estimates that by 2020, absent new pipeline capacity, New England generators could encounter the equivalent of approximately 12 million MWh of gas supply deficits. Using fuel oil instead of gas to bridge such a deficit would emit an additional 5 thousand tons of NO_x, 67 thousand tons of SO₂, and 5.6 million tons of CO₂ into the atmosphere compared to gas-fired generation. These additional emissions would sharply reverse the previous decade's reductions, and represent respective increases of 23%, 372% and 14% of total NO_x, SO₂, and CO₂ over 2013 emission levels.



Passion. **Expertise.** **Results.**

icfi.com