Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs

FINAL REPORT
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Public Version

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Table of Contents

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LIST OF EXHIBITS

Acknowledgements

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[1] IREMM is the acronym for the Inter-Regional Electric Market Model (IREMM). More information can be found at: www.iremm.com.

Errors and Omissions Statement

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Executive Summary

In recent years, the wholesale power market in New England has seen an increase in the construction of gas-fired generation, aimed primarily at serving intermediate and peaking requirements, but also in some instances base load as well. With these additional demands for natural gas for electric generation added to the requirements to reliably serve New England's native local gas distribution company (LDC) firm demands, there is a growing concern about the adequacy of the regional natural gas infrastructure to serve electric generation demand under the traditional approach taken by most generators, whereby they choose to rely on interruptible pipeline transportation services. Gas supply adequacy been a concern for generators during the winter, when firm gas demand peaks and pipeline capacity is fully contracted to serve LDC loads, but it is also is becoming a concern in other times of the year, when pipeline capacity may be reduced due to maintenance. This report provides the results of a study conducted by ICF International (ICF) under the direction of ISO New England, Inc. (ISO-NE) aimed at assessing the adequacy of the natural gas pipeline infrastructure in New England to serve the combined needs of the core natural gas market and the regional generation fleet.

While LDCs contract for firm pipeline capacity and arrange for other supplies (such as LNG imports and peak shaving facilities) to meet the projected peak day demands of their firm gas customers, most electric generators rely on interruptible pipeline capacity for their fuel supplies. This analysis assumes that on a peak demand day, all the firmly contracted pipeline capacity is used to meet firm LDC loads, and also assumes that electric generators must rely on whatever supply capabilities remain.[2] ***Therefore, in the context of this report, a gas supply "deficiency" suggests that the firm shippers are at or near their full contract limits and there is insufficient interruptible pipeline capacity remaining to meet the overall needs of the electric generators. A potential deficit of supplies available to electric generators does not mean that the pipelines serving New England are under-designed or otherwise incapable of meeting their contractual firm shipper obligations; rather it raises a number of questions about how to address potential supply shortages for electric generators.***

The analysis focuses on the winter and summer peak fuel requirements through 2020, and consisted of five steps:

1) Estimate New England's natural gas supply capabilities (pipeline capacities, LNG import capacities, and peak-shaving facility capabilities.)
2) Estimate New England LDCs' firm gas requirements for a peak winter day and peak summer day.
3) By subtracting (2) from (1), estimate remaining gas supply capabilities to serve electric generation.
4) Project overall power sector gas demands.
5) By subtracting (4) from (3), estimate the difference between the demand projection and the remaining gas supply capabilities.

This analysis was repeated under four alternative generation forecasts for ISO-NE:

1) **Nominal Gas Demand Forecast**, based on a 50/50 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 50%.

[2] In reality, any spare pipeline capacity during the winter or summer peak load periods could be sought by regional gas LDCs, gas-fired generators, portfolio managers, gas marketers, etc.

2) **Reference Gas Demand Forecast**, based on a 90/10 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. While it is not identical to the gas sector concept of a design day, the 90/10 forecast is closer to the conditions assumed for the gas market on a peak day.
3) **Higher Gas Demand Forecast**, based on the Reference Gas Demand Forecast, where there is a large nuclear or coal-fired power plant outage, combined with high regional natural gas prices.
4) **Maximum Gas Demand Forecast**, based on the Reference Gas Demand Forecast, but where there is a large nuclear or coal-fired power plant outage with low regional natural gas prices.

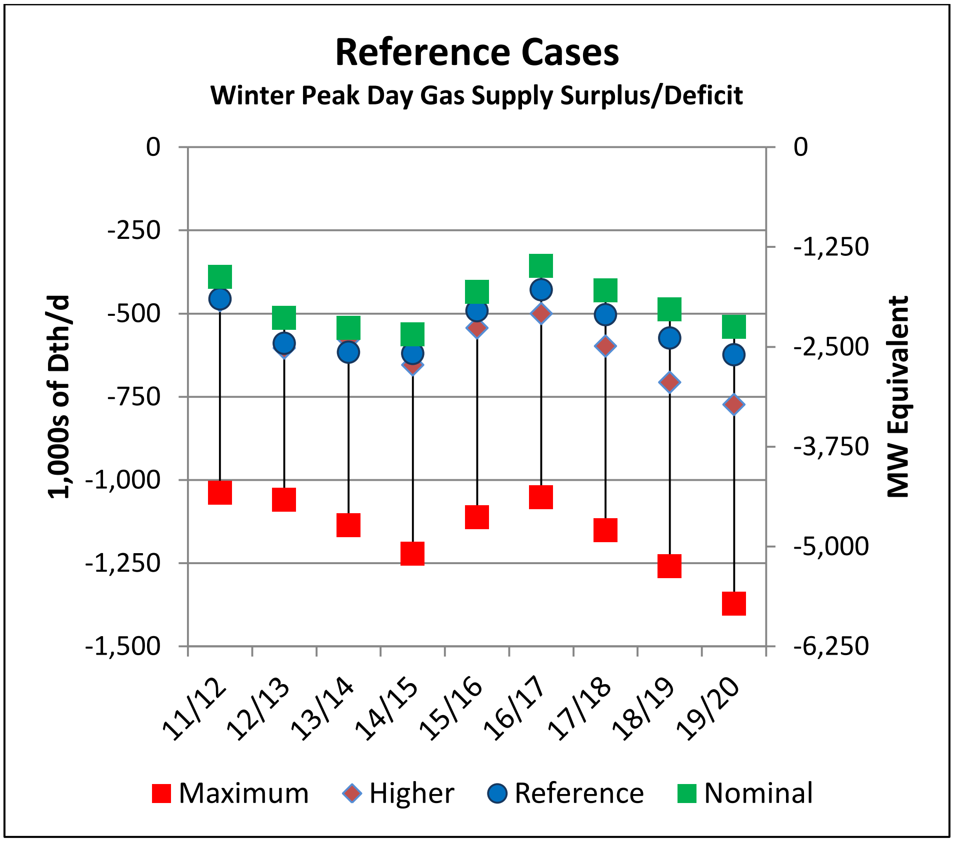
The forecasts of electric generation and power sector gas consumption were provided by ISO-NE, and are based on assumptions from ISO-NE's *2011 Regional System Plan (RSP11).*

The analysis considers these four forecasts under two scenarios: a "Reference Case Scenario," in which none of the existing generating capacity is repowered, and a "Repowering Case Scenario," in which a number of older facilities that primarily rely on coal and fuel oil are repowered as efficient (low heat rate) natural gas-fired generation, thus potentially increasing the consumption of natural gas. In addition, further analysis was conducted for "Contingency Case Scenarios," in which some gas infrastructure is assumed to be unavailable on peak days. It was expected that gas demands under all the Repowering cases would substantially increase above their counterpart Reference case values. However, the higher efficiencies of these repowered units/stations resulted in these repowered units/stations being dispatched first and thus produce equivalent amounts of power at lower levels of fuel consumption. The Contingency cases led, as expected, to greater deficiencies in gas supply capability, reducing further the amount of gas available to power generators. The Contingency scenarios are not included in the public version of this report.

Each of the scenarios was examined under peak winter day, or "design day" conditions for the LDC firm gas loads, as well as on peak summer days, when firm demands are lower. The projections for design day firms loads were derived from data either provided directly by the LDCs or from filings with the various state public utility commissions. When projecting design day loads, the LDCs look at temperature variance over a much longer period of time than is used for electric system planning. While the exact conditions used for design day planning vary among the region's individual LDCs, the design day criterion is generally the coldest day in the past 30 to 50 years. As a result, the LDCs design day standard is much more stringent than one-in-ten year ("90/10") standard ISO-NE uses for its resource adequacy planning.

In each of the scenarios and cases examining gas supply and demand under winter design day conditions, there is not enough gas supply capability remaining to meet the anticipated power sector gas demand after LDC firm demands are fully met. Exhibit ES-1 summarizes the results of the analysis for the four Reference Case Scenarios for winter design days through 2020. The slight inflection in the graph in 2015/16 is a result of ICF's estimated expansions within the gas system into New England.

Exhibit ES-1. Electric Sector Surplus/Deficit Availability to Meet Winter Peak Power Demand - Reference Case Results



The following observations can be made from this analysis.

- New England's gas delivery system is already in very tight balance on a winter design day, even before any future gas demand growth is factored in.

- Through 2020, the estimated winter design day deficit in the Reference Gas Demand Forecast is generally between -500,000 and -600,000 dekatherms (Dth) per day (Dth/d)[3] in most years; this is the equivalent of -2,100 MW to -2,500 MW of generating capacity unavailable. In the highest gas demand case (Maximum Gas Demand Forecast) the deficit ranges between -1,000,000 Dth/d (-4,200 MW) to -1,400,000 Dth/d (-5,800 MW) by 2020.

- On winter design days, supplies available to electric generators are usually below the imputed fuel "reserve margin" (the amount of gas pipeline capacity that would be needed to supply "operating reserve" units on the power system), indicating that there is not enough supply for generators with interruptible pipeline service.

[3] For this report, 1 Bcf is equal to 1,000,000 MMBtu or 1,000,000 Dekatherm or 1,000 MMcf and 1 Mcf is equal to 1 MMBTU or 1 Dekatherm.

- The regional LDCs contract for pipeline capacity and other supplies to meet the projected firm demand by their customer on a peak winter day. The results of this analysis suggests that regional gas supply capability is inadequate to satisfy both the LDCs firm load and the projected gas demand from electric generators on a winter design day over the next decade, barring incremental expansion of the gas delivery system beyond the expansions assumed in this study. While the probability that a gas-sector "design day" will occur is lower than the probability that a 90/10 electric load will occur, this is still a significant potential for supply shortages for gas generators with non-firm supplies over the next ten years.

- Firm demand from LDC gas customers is much lower in the summer, so summer peak day gas supplies remaining for electricity generation are, for the most part, not constrained. In the Reference Gas Demand Forecast, gas supply surpluses range from about 300,000 to just over 600,000 dekatherms per day (1,250 MW to 2,500 MW). The availability of gas supplies to electric generators is well above the fuel reserve margin, which indicates that gas supplies are adequate. However, in the Maximum Gas Demand Forecast, which assumes a large coal or nuclear plant off-line and strong gas demand due to low prices of gas, shortages of gas supply capability remaining for electric generators may occur before 2017, given our assumed pipeline expansions.

- The additional capacity that exists in the gas transmission pipeline system during non-winter periods is the capacity that is subsequently used by New England's gas-fired generators to convert gas into electricity. As this capacity diminishes over time, due to LDC load growth, it equally diminishes the amount of interruptible pipeline capacity, thus directly impacting the amount of gas-fired generation able to operate under non-firm gas transportation agreements.

ISO-NE intends to follow up on this analysis with additional, more detailed studies of the interactions between the natural gas system infrastructure and the power system.

1. Introduction

1.1 Purpose of the Report

This report provides the results of a study conducted by ICF International (ICF) under the direction of ISO New England, Inc. (ISO-NE) aimed at assessing the adequacy of the natural gas pipeline infrastructure in New England to serve the combined needs of the core natural gas market and the regional electric generation fleet.[4] In recent years, the wholesale power market in New England has seen an increase in the construction of new gas-fired generation, aimed primarily at serving both intermediate and peaking requirements, but also in some instances, base load as well. At the same time, the gas-fired generating fleet has been running at higher load factors with the decline in natural gas prices. This trend is expected to continue. With these additional demands for natural gas for electric generation added to the requirements to reliably serve New England's native local gas distribution company (LDC) firm demands, there is a growing concern about the adequacy of the regional natural gas infrastructure to serve electric generation demand. With this in mind, this study has had the following goals:

- Quantify the amount of natural gas delivery capability available for New England, including pipeline capacity, LNG import capability, and regional peaking capabilities.
- Assess the level of peak gas demands from all of New England's local gas distribution utilities (i.e. gas LDCs) and other firm customers.
- Estimate the remaining natural gas supply delivery capability that could be available for the power sector, after satisfying the peak gas demands of all firm customers of the regional gas utilities.
- Calculate the gas demands from the regional power sector for both a Reference and Repowering scenario.
- Determine the gas supply surplus or deficit by comparing the projected power sector demands against the remaining gas supply capability for both the Reference and Repowering scenarios.
- Estimate the gas supply surplus/deficit values for various gas sector contingency cases.

ISO-NE commissioned this report to provide a high level analysis of the potential future gas demands on the regional pipeline network as it is currently designed and as it can be expected to be expanded. The analysis looked at both winter peak day conditions and summer peak day conditions for both the electric grid and the regional pipeline network. The study focuses on New England, the pipelines serving this region and the imported liquefied natural gas (LNG) supplies capable of serving various New England gas markets. The analysis accounts for the requirements of gas LDCs within the six New England states and other firm industrial gas loads. This analysis should help to illuminate whether the future natural gas network can meet these firm system requirements of the gas LDCs and have remaining capacity sufficient to meet the needs of the gas-fired generators without firm pipeline capacity contracts.[5]

[4] The regional electric generation fleet consists of approximately ~18,000 MW (winter ratings) of gas-only or dual fueled power plants, serving base-load, intermediate and peaking power needs. The majority of this fleet procures its fuel supplies on a non-firm basis, and primarily operates through the regional (transportation) capacity release markets.

[5] For estimating total peak day gas requirements in New England, both ICF and ISO-NE assumed that all regional gas systems and the regional electric power system would peak on the same coincidental peak day.

1.2 Analytic Approach

The analysis focuses on the winter and summer peak fuel requirements in the future: the "short-term" timeframe (2011 to 2015) and the "near-term" timeframe (2015 to 2020).

There are five basic steps to the analysis:

1. Assess New England's current and projected natural gas supply capabilities (pipeline capacities, LNG import capacities, and peak-shaving facility capabilities) – performed by ICF.
2. Assess New England LDCs' current and projected firm gas requirements for a peak winter day and peak summer day – performed by ICF.
3. Estimate remaining gas supply capabilities to serve electric generation; that is, the total regional supply capability less the LDCs' firm demand requirements – performed by ICF.
4. Formulate projections for overall power sector gas demands, based on a variety of load and dispatch forecasts, under both Reference and Repowering scenarios – performed by ISO-NE.
5. Calculate for each power sector gas demand projection, the difference between the demand projection and the remaining gas supply capabilities; that is, the surplus or deficit in remaining gas supply capabilities – performed by ICF.

For this study, ISO-NE developed four cases focusing on expectations of peak day power demands which were all based on ISO-NE generated forecasts of an economic dispatch of the New England generating fleet. For each case, ISO-NE identified the gas-fired[6] generation dispatch and, based on gas-fired unit heat rates, estimated the corresponding daily fuel (gas) requirements. The four cases include economic dispatch for a:

1. **Nominal Gas Demand Forecast**, based on a 50/50 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 50%.
2. **Reference Gas Demand Forecast**, based on a 90/10 electric demand forecast where the probability of electric load (and therefore gas demand) exceeding the forecast is 10%. While it is not identical to the gas sector concept of a design day, the 90/10 forecast is close to the conditions assumed for the gas market on a peak day.
3. **Higher Gas Demand Forecast**, based on the Reference Gas Demand Forecast, where there is a large nuclear or coal-fired power plant outage, combined with high regional natural gas prices.
4. **Maximum Gas Demand Forecast**, based on the Reference Gas Demand Forecast, but where there is a large nuclear or coal-fired power plant outage with low regional natural gas prices.

The electric demand forecast cases are based on assumptions within ISO-NE's *2011 Regional System Plan (RSP11)*. The higher and lower natural gas price cases, although primarily based upon the Energy Information Administration's (EIA) Annual Energy Outlook,[7] were modified in reference to fuel price parity relationships for the purpose of making natural gas either more or less attractive to fuel switching[8] within the electric power sector.

[6] Also includes dual fuel units burning natural gas as either a primary or secondary fuel.
[7] For more information on the EIA's Annual Energy Outlook for regional fuel prices, please visit their web site located at: http://www.eia.gov/forecasts/aeo/
[8] Fuel switching between natural gas and/or heavy or light fuel oil.

The study also considered the potential for repowering a number of New England coal and oil-fired facilities to natural gas units, adding incremental fuel requirements to that of the existing fleet of gas-fired generation and adding to the level of natural gas required on both summer and winter peak days. ISO-NE provided ICF with a schedule of regional power plants assumed to be converted to natural gas along with their incremental fuel requirements. These additional requirements, added to the Reference cases above, created four Repowering cases. All of the Repowering cases are in the post-2015 period.

The final element of the analysis is a contingency study which considers the effect of the temporary loss of various elements of natural gas infrastructure on both the Reference and Repowering cases. Due to the nature of this Critical Energy Infrastructure Information (CEII), the details of this contingency analysis are provided in Section 6 of the Confidential Report.

ICF's approach, as commissioned by ISO-NE, has been straight-forward. ICF first developed information on the capacities of all of the interstate gas pipelines serving the New England market using applicable pipeline data. This was checked against each pipeline's Index of Shippers (IOS) reviewed in the late summer of 2011, and also against pipeline capacities and flows reported by Lippman Consulting,[9] a consulting firm that consolidates data from pipelines' electronic bulletin boards (EBBs). IOS data were used to estimate total pipeline capacity by state and to break out where capacity entering New England was actually intended for states outside New England. ICF also collected data on LNG import capability from the one onshore and two offshore projects that serve New England. This created a view of the maximum capacity available to serve the New England market from external sources. ICF also incorporated some recently announced pipeline capacity expansions in the greater Northeast region, and in some cases, made assumptions about the levels of these expansion projects serving New England.

ICF then collected forecast peak day sendout data from regional gas LDCs, with assistance from the Northeast Gas Association (NGA).[10] These data were compared with EIA Form 176 data to check for reasonableness. ICF also collected information on each LDCs peak-shaving capability, to arrive at a net peak day requirement that must be met by the interstate pipeline network. Where companies did not have forecasts for the full study period, ICF trended the forecast based on each company's recent peak day trends. For estimating total peak day gas requirements in New England, ICF assumed that all regional gas systems would peak on the same coincidental peak day. ICF used publicly available data sources and market modeling tools to estimate gas demand from LDCs that provided no data and for estimating firm industrial requirements. However, 90% of the overall LDC demands have been obtained from either their public utility commissions or was provided by the LDCs themselves.

The analysis proceeded deterministically through spreadsheets that compared the total deliverability capacity of the pipeline network to the sum of the regional demands from all LDCs and firm customers, net of peak-shaving offsets, with the remaining amount deemed available for electric generation needs.[11]

[9] More information about Lippman Consulting can be found at: www.lippmanconsulting.com
[10] The Northeast Gas Association's web site is located at: www.northeastgas.org
[11] This remaining amount of pipeline capacity would actually be competitively available for gas LDCs, gas-fired power generators, fuel suppliers, portfolio managers and marketers.

1.3 Issues and Uncertainties

A high level study such as this has made necessary assumptions and simplifications in order to develop a broad view of regional gas system capacity within New England. This study should be looked upon as a first approximation of the capabilities of the regional gas system to meet expected gas requirements of the gas-fired electric generation sector.

Natural gas pipelines in the United States are contract carriers. Their construction and operations are made possible by the support of anchor shippers who sign long-term contracts to ensure the pipeline transportation capacity to meet their gas supply needs. These shippers are mostly gas LDCs. By the terms of the various pipeline tariffs, which the Federal Energy Regulatory Commission (FERC) regulates, firm shippers have first call on utilization of pipeline capacity. However, most power plant shippers in New England (and elsewhere) rely on pipeline interruptible transportation capacity; i.e., capacity which is available when the firm shippers are not using their full contract quantities. Gas demand has increased in New England, while pipeline capacity into the region has been essentially static[12] despite some additional infrastructure. This has led to several developments in the regional gas market: 1) higher load factor usage of pipelines, 2) a reduction in the availability of non-firm capacity, 3) an increase in the number of constraints at bottlenecks, and 4) a reduction in operational flexibility and performance of the pipeline system. These developments are more pronounced during winter peak seasons than in summer, but are evident year-round.

Therefore in this report, conclusions about deficient pipeline capacity to meet full electric generation demands simply mean that the firm shippers are at or near their full contract limits, and there is less interruptible pipeline capacity to meet the overall needs of the power generators. Deficiency does not mean that the pipelines serving New England are under-designed or otherwise incapable of meeting their contractual firm shipper obligations.

The regional gas system has also experienced several natural gas generators taking higher than scheduled amounts as opposed to the full daily demand cycle of an LDC, which has implications for gas pipeline flows and pressures. Short-notice gas-fired generators seek to use intraday natural gas. Such short-notice generators may have electric system obligations to the ISO to generate power with notice of less than one hour, but lack the gas entitlements necessary to turn gas supply on and off this quickly. Short-notice generators using unscheduled gas when the pipeline is experiencing high heating demand has been a recurring problem which could potentially threaten both gas and electric system reliability.

Another related issue is hourly usage. Natural gas pipelines are generally designed to provide hourly flows conforming to usage throughout the 24 hour gas day. In contrast, most gas-fired generators use their full day's nomination of gas over a shorter span of hours (e.g., twelve hours) to meet electricity market directives, and then may use no gas at all during the remaining hours. This consumption profile is not consistent with the operational design of most pipelines.

As many generators become more reliant on interruptible capacity in an already constrained system, it is extremely critical that all parties comply with pipeline operating rules so that system integrity is maintained. This must be done to ensure customers that do contract for firm capacity receive those services. In a series of instances over the last year, certain pipelines

[12] The amount of imported LNG back-feeding the system has declined due to world LNG market economics.

have indicated a growing and recurring problem where some generators have not complied with operational limits; for example, overtaking on the system when not authorized to do so, using gas that had not been scheduled, and/or lacking adequate capacity/supply to meet needs while at the same time using other shippers' gas at their plant(s), thereby eroding system (including LDC) pressures. This behavior can threaten the overall integrity of the natural gas system and may also impact gas-fired generators themselves. Many generators require relatively high pressures in order to run; when one generator takes gas in excess of their daily nomination, it could not only jeopardize its own ability to run but may also cause other generators downstream to trip offline unexpectedly. As a result of this type of behavior by shippers, some interstate pipelines have requested and obtained from the FERC enhanced tariff authority to protect the integrity of their systems and, at the same time have more vigilance to enforced existing tariff authorities and operational protocols to protect firm gas customers.

While all these issues have a significant impact on both the gas and electric systems, they are beyond the scope this study. When reading the study, it is important to keep in mind the simplifying assumptions that were made, including:

- The analysis does not distinguish between the different power plant loads on the various pipelines, such that expectations about electric generation may in fact affect some pipeline segments more than others. This analysis treats the entire New England gas infrastructure as a single entity.
- As an analysis focusing on single peak day requirements, there is a potential mismatch between the format of the electric day and gas day. We have not attempted to convert the electric day gas demands into gas day demands. Scheduling of natural gas through the nomination/confirmation process can have an impact on deliveries of gas to the power system.
- The modeling of the bulk electric power system makes certain simplifying assumptions:
  - The start-up time necessary or the minimum up/minimum down time requirements of electric generating units was ignored.
  - Only major transmission constraints within the New England electric system and only those within neighboring systems, which impact imports and exports to the New England system, are factored in.
  - Although the IREMM production simulation model dispatches its capacity resources to satisfy hourly electrical demands, it does so in a way that does not specifically account for satisfying electric system operating reserves. Hence, the introduction later in this report of a concept entitled *"fuel reserve margin."*
  - Does not automatically account for seasonal fuel price volatility.
- The analysis of the gas system does not take into account the dynamic operating characteristics of interconnected gas pipelines that may allow the gas system to respond more robustly to demands than indicated within this analysis.
- The analysis of the gas system does not include dynamic flow modeling that would be necessary to identify flow and pressure transients caused by demand surges and that can lead to operating problems on pipelines.
- Operating rules for pipelines, such as scheduling, nominations, confirmations, imbalance provisions, operational flow orders (OFOs), etc., do not figure in to this analysis, despite their real world importance to the operation of both the gas and electric systems.

While these issues were beyond the scope of this study, ISO-NE believes these are important topics for future analysis.

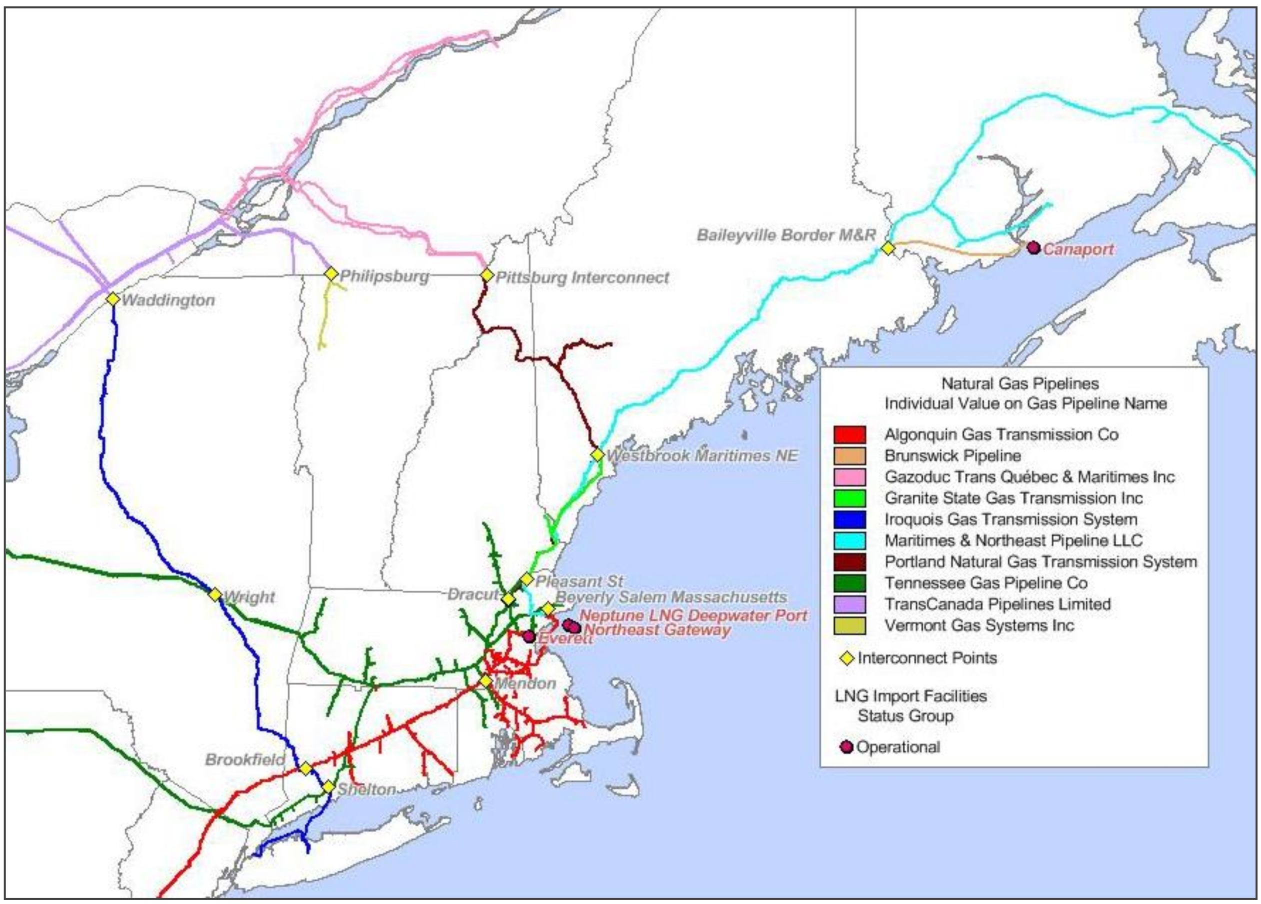
1.4 Organization of this Report

The next section of this report provides an overview of the natural gas infrastructure in New England. Section 3 provides an overview of New England's firm gas demand for gas utilities. Section 4 provides the Reference case results. Section 5 presents the Repowering case results and Section 6 addresses the Contingency cases. The Appendices contain the detailed background on the construction of the Reference and Repowering cases and ISO-NE's modeling assumptions that went into developing these cases.

2. Overview of New England's Gas Supply

In this section, ICF reviews the natural gas system's capability to serve gas demand in New England. New England's highest demand for natural gas is in winter and the gas supply system is designed to meet those winter peak design day demands. The gas supply system consists of four elements: 1) the interstate gas transmission pipelines that bring gas into the region; 2) liquefied natural gas (LNG) import facilities that feed the system from several import terminals; 3) the LNG/LPG peak shaving facilities, operated by the LDCs that help distribution them meet peak day sendout requirements; and 4) interruptible customers, who typically have the capability to switch to a liquid fuel source and subsequently make their gas available to firm customers. Unlike most regions of the country, New England has no native underground natural storage capacity within the region; the geology does not support it. All storage services are from outside the region, principally in Pennsylvania and New York. ICF also addresses the outlook for additional natural gas supply from recently proposed pipeline expansions. Exhibit 2-1 provides an overview of the natural gas pipelines serving New England.[13]

Exhibit 2-1. New England Natural Gas Supply Network



This map is a courtesy of Ventyx.

[13] The Vermont Gas pipeline is not included in this analysis since it is a small system, isolated from the general gas pipeline infrastructure available to the electric generation sector and the other LDCs in New England.

2.1 Natural Gas Transmission Pipelines Serving New England

Five interstate natural gas transmission pipelines supply natural gas to New England from outside the region. In addition, Granite State Gas Transmission (GSGT), an intraregional gas transmission pipeline provides high pressure gas transmission to several New England states.[14] GSGT receives all of its gas from other interstate pipelines supplying New England and is therefore not considered in the analysis of supply capability, since it only redelivers this gas within New England. ICF estimated the capacities of the five pipelines at the points of entry into the New England states using publicly available information from the natural gas pipeline web sites (electronic bulletin boards or EBBs), as well as additional current information from a vendor of pipeline flow data, Lippman Consulting. ICF also reviewed each pipeline's Index of Customers (i.e., shippers) to confirm the contracted capability to supply customers in the New England states. In considering pipeline capacity, ICF has focused on the pipelines' contracted Maximum Daily Quantity (MDQ), with one exception, since this is the authorized level of gas that can be delivered to customers on the systems.[15]

2.1.1 Algonquin Gas Transmission (AGT)

The AGT pipeline is one of the five major pipelines serving New England. It receives most of its gas supply from Texas Eastern Transmission (TETCo) in New Jersey and then delivers gas into Connecticut, Rhode Island, and Massachusetts. AGT has interconnections with Iroquois Gas Transmission System (IGTS) at Brookfield, Connecticut; with Tennessee Gas Pipeline (TGP) also at separate connections in Connecticut and Massachusetts, and with the Maritimes and Northeast Pipeline (M&N) at the north end of its system at Beverly, Massachusetts (via AGT's "HubLine" extension). Total contracted capacity into New England on the AGT system is about 1.09 Bcf per day (Bcf/d). The AGT also has interconnections with Distrigas of Massachusetts (DOMAC), the LNG import facility (located in Everett, Massachusetts) and the offshore LNG buoys of Excelerate and Neptune. Major shippers on AGT are LDCs, power plants, and marketers.

2.1.2 Iroquois Gas Transmission System (IGTS)

The IGTS receives up to 1.2 Bcf of gas per day at the border of New York and Quebec at Waddington, New York and delivers gas into New York State and New England. At Wright, New York, IGTS interconnects with and delivers gas into the Tennessee Gas Pipeline (TGP), which also takes gas into New England. IGTS also interconnects with TGP at Shelton, Connecticut and with AGT, receiving up to 300 MMcf/d at Brookfield, Connecticut, a bi-directional delivery/receipt point. IGTS transports approximately 700 MMcf/d from New York into Connecticut; of that, about 220 MMcf/d is generally reserved for customer utilization in Connecticut.

2.1.3 Maritimes & Northeast Pipeline (M&N)

[14] Granite State Gas Transmission (GSGT) is an interstate pipeline that is located in New England, and thus does not bring gas into the region but receives gas from other interstate pipelines: Tennessee Gas Pipeline (TGP) in Haverhill, MA, Portland Natural Gas Transmission System (PNGTS) in Newington, NH, and Maritimes and Northeast Pipeline (M&N) in Westbrook, ME. The pipeline runs from Maine to Massachusetts and delivers gas to utilities and customers in Maine and New Hampshire. Granite State is not evaluated for purposes of establishing gas supply availability because it does not bring in gas supplies from outside the region.

[15] The exception is the PNGTS, which is currently contractually undersubscribed.

The M&N pipeline is one of the newest pipelines serving New England, having entered into service in 2000. M&N originally carried natural gas from the Scotian Shelf from the offshore fields at Sable Island. The M&N pipeline enters New England from New Brunswick, Canada at Baileyville, Maine, and terminates at Dracut, Massachusetts, where it interconnects with TGP. M&N also interconnects with the AGT system via the “HubLine System” at Beverly, Massachusetts. M&N also interconnects with the Portland Natural Gas Transmission System (PNGTS) at Westbrook, Maine. The M&N and PNGTS systems then share a common pipe (Joint Facility System) into the Dracut hub, in Massachusetts. The M&N system has a capacity of approximately 833 MMcf/d into New England. Supply for M&N comes from Sable Island, some local New Brunswick production, and the new Canaport LNG terminal located in Saint John, New Brunswick. In 2012, the M&N pipeline will also begin receiving gas from Encana’s offshore Deep Panuke field. The major shippers on the M&N pipeline are North Atlantic gas producers and Repsol Energy North America, who leases the entire 1.0 Bcf/d of regasification capacity at the Canaport LNG facility, and whose affiliate owns a 75% interest in the Canaport LNG facility (the other 25% interest is owned by Irving Oil).

2.1.4 Tennessee Gas Pipeline (TGP)

TGP crosses into New England at two points. The northern main line (Line 200) enters Massachusetts from New York. The southern line (Line 300) enters Connecticut from New York, interconnects with the AGT and then interconnects with TGP’s main line in Agawam, Massachusetts. Historically TGP has brought gas from the Gulf Coast, Midwest and Canada into the New England market. TGP is a major supplier to the Boston market as well as New Hampshire, and western Massachusetts. The contracted capacity into New England is approximately 1.26 Bcf per day (2011). Though TGP’s overall market portfolio is large and diverse, major shippers on the pipeline are LDCs in Massachusetts, Connecticut and New Hampshire.

2.1.5 Portland Natural Gas Transmission System (PNGTS)

PNGTS receives gas at the New Hampshire/Quebec border at Pittsburg, New Hampshire, crosses into Maine, delivering gas to industrial customers, and ties into the M&N pipeline at Westbrook, Maine. From that point south to Dracut, the M&N and the PNGTS operate the Joint Facility System. PNGTS has a FERC certified capacity of about 168 MMcf/d. Shippers on the pipeline include LDCs, marketers, and industrials.

2.2 LNG Import Facilities

Distrigas of Massachusetts (DOMAC) is the oldest operating LNG import terminal in the United States (since 1971).[16] It is owned by GDF Suez Energy of North America. Located in Everett, Massachusetts in Boston Harbor, it has a storage capacity of approximately 3.4 Bcf and sendout capability of about 715 MMcf/d. Distrigas is a major source of gas supply to the Boston market. Distrigas also trucks LNG to satellite peak-shaving plants across New England. Distrigas is directly tied into Boston Gas (National Grid) and to the AGT and the TGP.

The Northeast Gateway LNG Deepwater Port is a buoy-based off-shore LNG facility owned by Excelerate Energy, located in Massachusetts Bay, about 13 miles northeast of Boston.[17] It is

[16] For more information, the web site is located at: http://www.domac.com/
[17] For more information, the web site is located at: http://www.excelerateenergy.com/northeast.html

capable of receiving up to 800 MMcf/d of ship-regasified LNG for delivery into the AGT's HubLine system.

GDF Suez Energy of North America also operates the Neptune LNG Deepwater Port off Gloucester, Massachusetts.[18] Like the Northeast Gateway Deepwater Port, it is a buoy-based receiving system, tied into the HubLine system. Neptune has a peak delivery capability of 750 MMcf/d and an average deliverability of 400 MMcf/d.

ICF has not included the capacities of the two offshore LNG facilities into that available to meet New England gas needs. Unlike DOMAC, neither of the offshore facilities has firm supply contracts or any LNG storage capability.

Although the Canaport LNG import terminal serves the New England market, its access to the market is exclusively through the M&N pipeline, so it is not considered separately in the assessment of New England's gas supply capabilities.[19]

2.3 Peak-Shaving Facilities

LNG peak-shaving facilities are relatively small facilities, mostly owned by LDCs around the region, used to supplement gas supply on peak winter days. A few of the LNG peak shaving facilities have liquefaction capability to make and store LNG from pipeline-sourced gas during the summer months, for regasification during winter peak demand periods.[20] Most of New England's peak-shaving facilities receive LNG delivered by tanker trucks from DOMAC which they store and re-gasify on peak winter days. There are about forty-five LNG peak-shaving plants across New England with a total deliverability of about 1.36 Bcf per day.[21] Because they have little storage capability, these facilities are used only on the very coldest of winter days and have limited capabilities beyond those peak days.

Another form of peak-shaving is propane air, where propane is mixed with air to inject into the distribution system to provide supplemental supply on peak winter days. We estimate that propane air can provide an additional 137 MMcf/d of peaking capability. Because of the differences in chemical composition of pipeline gas and propane, these facilities are used primarily only on the winter design day.

Peak-shaving facilities are only available to meet the peak day demands of their on-system distribution customers and are usually not available to supplement supply for off-distribution customers. Moreover, LDCs would not back down pipeline deliveries to operate their peak-shaving units; rather peak-shaving supplements pipeline supply.

2.4 Specific Pipeline Expansions for New England

Based on publicly announced plans (press releases, open season announcements, trade press articles, etc.), ICF has developed a list of forty potential pipeline expansions throughout the greater Northeast U.S. which may go into service by 2015 (Exhibit 2-2). ***It is important to note***

[18] For more information, the web site is located at: http://www.suezenergyna.com/ourcompanies/lngna-neptune.shtml
[19] The Canaport LNG terminal is located in Saint John, New Brunswick. For more information, the web site is located at: http://www.canaportlng.com/
[20] LDCs' total LNG storage capacity is 16 Bcf. LDCs' approximate vaporization capacity is 1.36 Bcf/d. Liquefaction is available at six LDC-owned facilities, with total liquefaction capability of 0.051 Bcf/d.
[21] Regional LNG peak-shaving facilities include 45 tanks in 30 communities in 5 states (CT, ME, MA, NH, RI).

that only one of these projects, the potential AGT AIM project, would add new capacity to New England. The AGT expansion proposes to add capacity by adding compression and pipeline looping and is intended to facilitate the delivery of Marcellus Shale gas into New England. No binding open season has been held and the project is still in preliminary stages. AIM's final capacity has not been announced, but ICF has estimated it will be between 200 MMcf/d and 500 MMcf/d. For this report, we have assumed 350 MMcf/d, with 200 MMcf/d available in 2015/16 and another 150 MMcf/d available by 2016/17.

The other Northeast expansion projects help to "debottleneck" upstream supplies, which may be positive for New England, but do not add new capacity into the region. These expansions are being proposed for a variety of uses. They include expansions on interstate pipelines to increase deliveries to markets as well as expansions to receive new gas supplies (primarily from the Marcellus Shale). Some expansions will provide hub, interconnection, and storage services. Many new gathering pipelines are proposed to connect Marcellus production to the interstate pipelines.

Exhibit 2-2. Proposed and Planned Greater Northeast U.S. Gas Pipeline Expansions

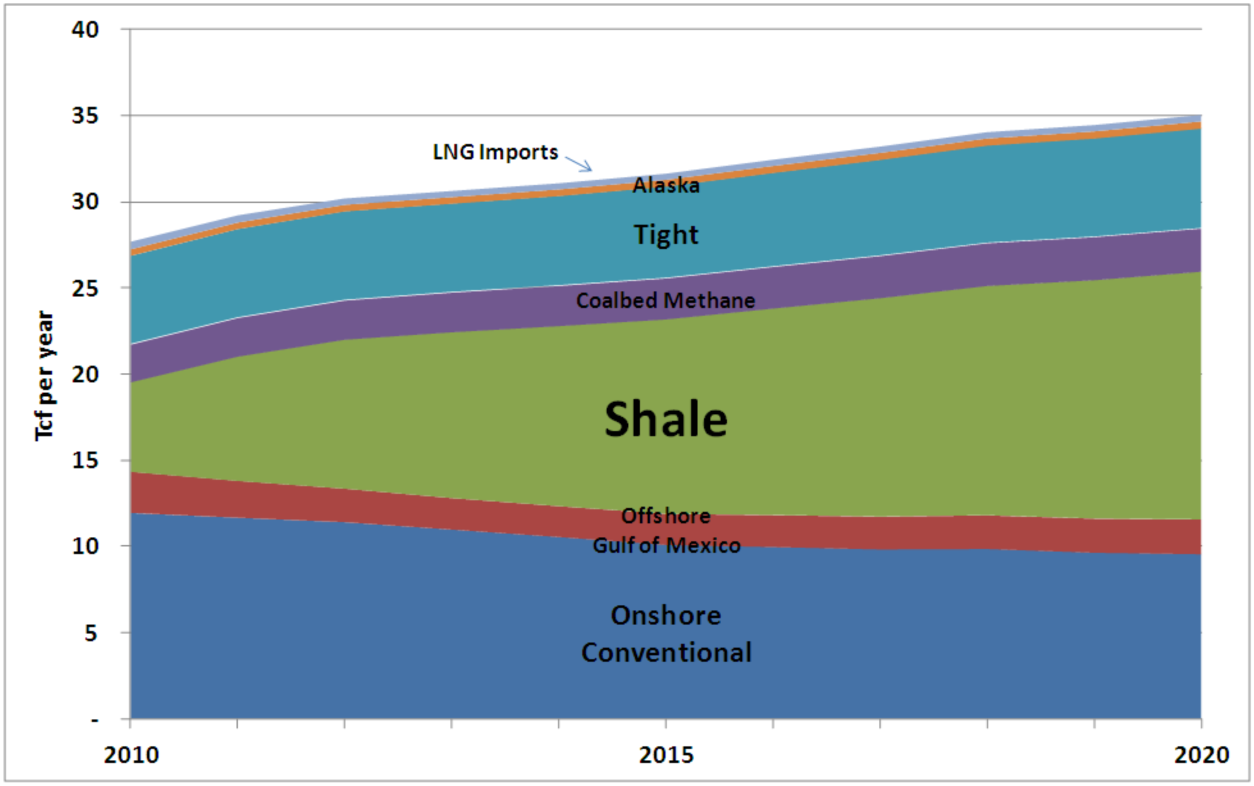
Rest of Northeast US Planned Expansions Pipeline - Expansion Name	Area	Capacity (MMcfd)	Planned In Service	Status
Algonquin - AIM Project	Algonquin compression	TBD	Nov-15	E
Dominion Transmission - Appalachia Gateway	West Virginia to Oakford PA	484	Sep-12	A
Dominion Transmission - Northeast Expansion	SW PA to Leidy	200	Sep-12	B
Dominion Transmission - Marcellus 404 Project	West Virginia	300	Nov-12	A
Dominion Transmission (For Tenn NSD Project) - Ellisburg-to-Craigs	Ellisburg PA to Craigs NY	150	Nov-12	B
Dominion Transmission - Tioga Area Expansion	Tioga, Potter, Clinton, and Greene Counties	270	Nov-13	D
Texas Eastern - TEAM 2012	Interconnects OH, WV, PA	200	Nov-12	A
Texas Eastern - TEAM 2014	OH, WV, PA Looping & Compression	1400	Nov-13	E
Spectra -TETCO - Algonquin - NJ-NY Expansion	Linden NJ to Staten Island NY and new connection to ConEd in Manhattan	800	Nov-13	C
National Fuel - Northern Access	Potter Co PA to Niagara	320	Nov-12	B
National Fuel - Line N 2012 Expansion	Along Western PA border	150	Nov-12	C
National Fuel/Empire - Central Tioga County or (TCE2)	Tioga PA Interconnect to TGP	260	Sep-13	E
National Fuel - West to East Phase 1 & 2	Overbeck PA to Leidy	425	Dec-13	E
Tennessee Gas Pipeline - Northeast Supply Diversification	Marcellus supply Z4 to Z5 and Z6	250	Nov-12	B
Tennessee Gas Pipeline - MPP Project	Z4 with backhaul to Z1-Z3	240	Nov-13	D
Tennessee Gas Pipeline - Northeast Upgrade Project	Line 300 to Interconnects with NJ Pipelines	636	Nov-13	C
NiSource & UGI - PennStar Pipeline	Leidy area to Corning NY	500	2013	E
Millennium Pipeline - Minisink Compression	Corning to Ramapo mainline	150	Nov-12	D
Millennium Pipeline - Neversink Compression Replacement	Corning to Ramapo mainline	525	2014	E
Williams Transcontinental - Bayonne Lateral	14" lateral and oil line conversion in NJ	250	Apr-12	F
Williams Transcontinental - Northeast Connector	St195 SE PA to Rockaway Deliv Lateral - National Grid NYC	100	2014	E
Williams Transcontinental - Northeast Supply Link	Northern NJ and Leidy Line looping and compression	250	Nov-13	D
Williams/Dominion - Keystone Connector	REX Clarington OH to Transco St195 SE PA	1000	2014	E
Williams - Atlantic Access	SW PA Marcellus to Transco St195	1800	Nov-14	E
Iroquois Gas Transmission - NYMarc	Sussex NJ to Pleasant Valley NY	500	Nov-14	E
Central New York Oil & Gas - Marc I Hub Line	Bradford PA (Tenn) to Lycoming Co PA (Transco)	550	Nov-12	A
EQT Midstream - Sunrise Project	WV and West PA	430	Jul-2012	A
Dominion Transmission - Marcellus Gathering Enhancement	West Virginia Gathering and Hasting Plant Exp.	50	Sep-2012	A
DTE Energy - Bluestone Gathering	Susquehanna PA to Broome NY (Millennium)	250	Jun-2012	A
National Fuel Gas Supply - Trout Run Gathering	Lycoming Co PA	466	Jun-2012	A
Boardwalk/Southwestern Energy - Marcellus Gathering	Susquehanna and Lackawanna PA to Tenn	275	Jul-2012	A
Crestwood Midstream/ Mountaineer Keystone - Tygart Valley Pipeline	NE WV Randolph Co to Columbia Gas Trans	200	Dec-2012	E
NiSource - Big Pine Gathering	SW PA, Butler, Indiana, Armstrong, and Westmoreland Counties	425	Dec-2012	E

A FERC Approved and Under Construction
B FERC Approved
C Filed with FERC, Favorable Environmental Impact Statement but waiting on FERC Approval
D Filed with FERC
E Potential Expansion either announced or had open season but not yet filed with FERC
F Bayonne Lateral is authorized to start service as of April 5th, 2012.

2.5 Expectation for Overall North American Gas Supply Development

New England receives all its natural gas supplies from outside the region, either via pipeline or LNG imports. The major development in North American gas supply is the productivity of shale, which is driving much of the pipeline expansions in the Northeast. With the addition of the shale and other unconventional resources, the U.S. and Canada still have over 260 Trillion cubic feet (Tcf) of proven gas reserves and over 3,900 Tcf of gas resources remaining to be developed.[22] Total U.S. and Canadian natural gas production is projected to grow from about 28 Tcf in 2010 to about 35 Tcf by 2020, an average annual growth rate of 2.2% per year (Exhibit 2-3).

Exhibit 2-3. U.S. and Canadian Gas Supplies



Unconventional natural gas production (from shale, coal-bed methane, and deep-tight formations) is projected to increase by about 17 Tcf, or by over 100%, while conventional domestic gas production is projected to decline by about 3 Tcf or by 23%. In short, unconventional gas production will become the dominant gas supply source in ICF's projection, and many of the currently conventional supplies will become the marginal sources of natural gas supply in the near future.

Much of the growth in unconventional natural gas production occurs in shale gas plays spread throughout North America. The major shale plays in the U.S. are located in the Mid-continent, including the Barnett, Woodford, Fayetteville, and Haynesville shales; the Eagle Ford in south

[22] This estimate is based on ICF's assessment of the amount of natural gas that can be economically recovered within the U.S. and Canada, given current exploration and production (E&P) technologies. We have relied on a variety of sources for this estimate, including the U.S. Geological Survey (U.S.G.S), estimates from the Minerals Management Service (MMS), estimates from the U.S. Department of Energy (U.S. DOE), and our own independent analysis of the resource base.

Texas; and the Marcellus in Appalachia. The Rocky Mountain producing region, which contains large amounts of producing conventional and deep/tight gas, also has shale plays that have not yet become major gas producers. There also are shale plays in Canada, most notably the Montney and Horn River Shales in British Columbia, and the Utica Shale in Eastern Canada. Due in large part to the abundance of shale gas supply, ICF has dropped any development of Alaskan gas from its forecast.

As regional natural gas supplies and demand continue to evolve and shift over time, there will be significant changes in interregional pipeline flows and potential implications for the U.S. Northeast and New England. In particular, the growth of production from the Marcellus Shale – which spans West Virginia, Pennsylvania, and New York – will begin to replace traditional gas supplies that have traditionally served the region emanating from the Gulf Coast, the Midwest, and Western Canada. At the same time, there is a general decline of gas exports from Western Canada to the United States, primarily due to declining production, but also from increased demand within Alberta itself, that will translate into less gas flowing from Western Canada into the Northeast. Most of the recently announced pipeline expansions in the Northeast have been made to attach new Marcellus production into the Northeastern gas grid.

Other sources of natural gas for New England could be LNG and additional production from the Canadian Maritimes provinces. However, given the current pricing of natural gas in North America compared to LNG within Europe and other parts of the world, it is not expected that it will be economic for substantial additional supplies of LNG to flow into the region. ICF expects that future LNG deliveries will be opportunistic, to capture high prices when shippers can or to meet firm delivery obligations. Production from the Sable Offshore Energy Project (SOEP) appears to have leveled off and begun to decline.[23] EnCana's Deep Panuke field is expected to come on line sometime in mid/late 2012.[24] There are no other plans announced for further development within that area of the Scotian Shelf. While there is ongoing exploration in the shale formations within the Maritimes, there appears to be no major expansions of production planned and the future of Eastern Canada's offshore fields is likely to decline. However, given the robust development of shale gas supplies in North America (and particularly in the Marcellus Shale), it is reasonable to assume that New England's in-bound pipelines will be well supplied over the next ten years.

2.6 Summary of New England Gas Supply and Capacity, with Caveats Regarding Gas Supply

ICF's estimation of the overall gas supply capability into New England is based on a summation of the interstate pipeline contract capacities into the region, the firm LNG import capability at DOMAC, and local peak shaving capability. This deterministic assessment provides a snapshot of the peak winter day deliverability. The estimate for the peak summer day deliverability does not include the local peak shaving capacity, since these facilities are owned by the gas LDCs in the region and typically do not operate in the summer months.[25] Exhibit 2-4 presents our estimate over the forecast period, including anticipated pipeline capacity expansions, as identified above.

[23] For more information, the web site is located at: http://www.soep.com/cgi-bin/getpage?pageid=0/0/1
[24] For more information, the web site is located at: http://www.encana.com/operations/canada/deeppanuke/
[25] Local peak-shaving capability is devoted to serving the economics and reliability of the regional gas LDCs and is almost never used to support merchant power production.

Exhibit 2-4. Summary of Natural Gas Supply and Capacity for New England

Supply Capability by Source, Base on Rated Capacity (1000 Dekatherms per Day)

Total Projected Pipeline Capacity	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**
Forward Haul Pipeline Capacity									
Algonquin Gas Transmission (AGT).	1,087	1,087	1,087	1,087	1,287	1,437	1,437	1,437	1,437
Iroquois Gas Transmission System (IGTS).	220	220	220	220	220	220	220	220	220
Tennessee Gas Pipeline (TGP).	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261
Portland Natural Gas Transmission System (PNGTS).	168	168	168	168	168	168	168	168	168
Pipeline Capacity Partly Dependent on LNG Supplies									
Maritimes & Northeast Pipeline (M&N).	833	833	833	833	833	833	833	833	833
Subtotal	**3,570**	**3,570**	**3,570**	**3,570**	**3,770**	**3,920**	**3,920**	**3,920**	**3,920**
Peak Shaving Capacity									
LNG Peakshaving	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319	1,319
Propane-Air	137	137	137	137	137	137	137	137	137
Subtotal	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**	**1,456**
Direct LNG Import Capability									
Everett Distrigas Facility	715	715	715	715	715	715	715	715	715
Northeast Gateway	600	600	600	600	600	600	600	600	600
Neptune	750	750	750	750	750	750	750	750	750
Subtotal	**2,065**	**2,065**	**2,065**	**2,065**	**2,065**	**2,065**	**2,065**	**2,065**	**2,065**
Total Assumed Supply Capability Available on a Winter Design Day	**5,741**	**5,741**	**5,741**	**5,741**	**5,941**	**6,091**	**6,091**	**6,091**	**6,091**
Total Assumed Supply Capability Available on a Summer Peak Day	**4,285**	**4,285**	**4,285**	**4,285**	**4,485**	**4,635**	**4,635**	**4,635**	**4,635**

Note: Total Assumed Supply Capability Available on a Winter Design Day excludes Northern Gateway and Neptune. Total Assumed Supply Capability Available on a Summer Peak Day also excludes these LNG facilities as well as all Peak Shaving Capacity.

There are a number of assumptions and caveats to note about this forecast of gas supply capability for New England:

- Assumed Winter capability includes peak-shaving facilities but excludes LNG from Northeast Gateway and Neptune, as these facilities have no firm supplies.
- Assumed Summer capability excludes peak-shaving (which is typically only used in the winter) and also excludes LNG from Northeast Gateway and Neptune, as these facilities have no firm supplies.
- The analysis includes up to 350 MMcf/d of future pipeline expansion projects into New England on AGT with its AIM Project. While not certain, the assumption that these projects will be completed is reasonable, based on currently available information.
- Maritimes & Northeast Pipeline capacity is constrained by supply which is uncertain in the case of Sable Island offshore production and dependent on Canaport imports of LNG. We have assumed the combination would fill the pipeline at least through 2020. We also have assumed gas prices in New England will support Distrigas imports at the level shown.
- Additional gas supplies are possible over short periods of time due to line pack, but are not considered within this analysis, since this assessment does not address locational and/or intraday issues.
- All gas sector, peak-shaving facilities are assumed to be fully available at 100% of their rated capacity and that LDCs can fully utilize their peak-shaving facilities on a winter

design day for their own system needs. LDC peak-shaving facilities do not support merchant power production.

- Intra-regional constraints have been investigated, but are assumed non-binding on pipeline capacities into New England. The pipelines serving New England can satisfy all firm contracts in the region. In particular, the analysis also assumes that the system operates under FERC tariff rules and that upstream shippers do not “over-pull” gas off the pipeline system in excess of their scheduled deliveries which would result in less supply delivery capability for downstream markets in New England. Intra-regional constraints may be more relevant in considering how back-flows from LNG facilities and the operations of peak-shaving facilities affect the overall availability of gas supply. The analysis treats these as fully additive, which they may not be.

3. Overview of New England's Firm Gas Demand from Gas Utilities

In this section, ICF reviews the assessment of New England LDC's firm demand requirements. It begins with an overview of the region's gas utilities. Next, discussion focuses on the methodology used to project firm LDC demands, including the data sources used, and then projections are provided for firm demand annually, for peak winter days, and for peak summer days.

3.1 Introduction to Gas Utilities in New England

The majority of firmly contracted pipeline capacity in New England is held by LDCs to serve their customers. As shown in Exhibit 3-1, there are twenty-three LDCs currently operating in New England, serving approximately 2.5 million natural gas customers.

Exhibit 3-1. Local Distribution Companies in New England

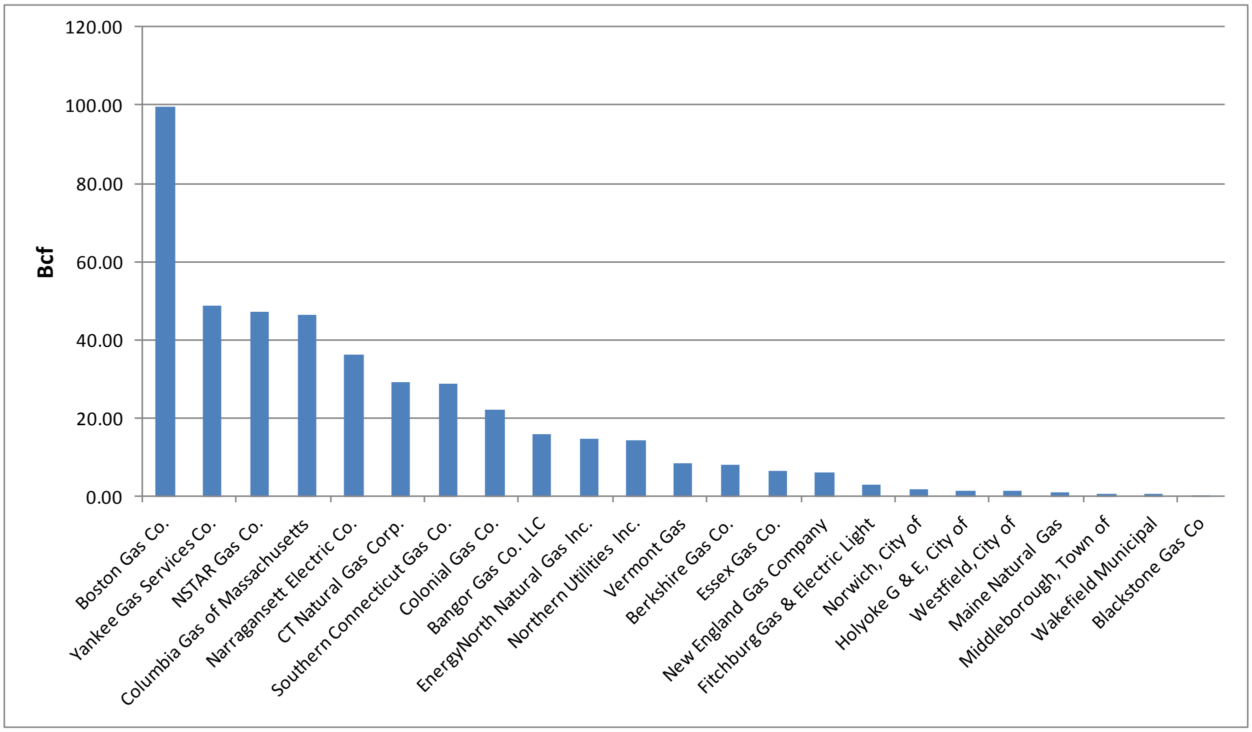
Company Name	States Served	Notes
1. Bangor Gas Co. LLC	ME	
2. Berkshire Gas Co.	MA	Division of United Illuminating
3. Blackstone Gas Co	MA	
4. Boston Gas Co.	MA	Division of National Grid
5. Colonial Gas Co.	MA	Division of National Grid
6. Columbia Gas of Massachusetts	MA	Division of NiSource
7. CT Natural Gas Corp.	CT	Division of United Illuminating
8. EnergyNorth Natural Gas Inc.	NH	Division of National Grid
9. Essex Gas Co.	MA	Division of National Grid
10. Fitchburg Gas & Electric Light	MA	Division of Unitil
11. Holyoke G & E, City of	MA	
12. Maine Natural Gas	ME	
13. Middleborough, Town of	MA	
14. Narragansett Electric Co.	RI	Division of National Grid
15. New England Gas Company	MA	Division of Southern Union
16. Northern Utilities Inc.	ME and NH	Division of Unitil
17. Norwich, City of	CT	
18. NSTAR Gas Co.	MA	
19. Southern Connecticut Gas Co.	CT	
20. Vermont Gas[26]	VT	Supplied via TCPL
21. Wakefield Municipal	MA	
22. Westfield, City of	MA	
23. Yankee Gas Services Co.	CT	Division of NU

Most of the gas consumption is concentrated in a few large-city utilities, as shown in Exhibit 3-2, which ranks regional LDCs by the size of their firm customer loads (primarily residential and commercial but may include industrial and electric generation). The largest LDC in New England is Boston Gas, a division of National Grid. The largest five LDCs account for about

[26] Vermont Gas is not included in this analysis since it is a small system, isolated from the general gas pipeline infrastructure available to the electric generation sector and the other LDCs in New England.

63% of the regional firm load and the top ten LDC account for about 88%. Some smaller utilities have large electric generation loads on their systems. These include NStar, Southern Connecticut Natural Gas, and Maine Natural Gas, which if counted, would move them up within the rankings. In particular, Southern Connecticut Natural Gas would be the second largest LDC if electric generation load were considered.

Exhibit 3-2. Distribution of LDCs by Size of Firm Loads, 2009 (Bcf)



Source: EIA Form 176.

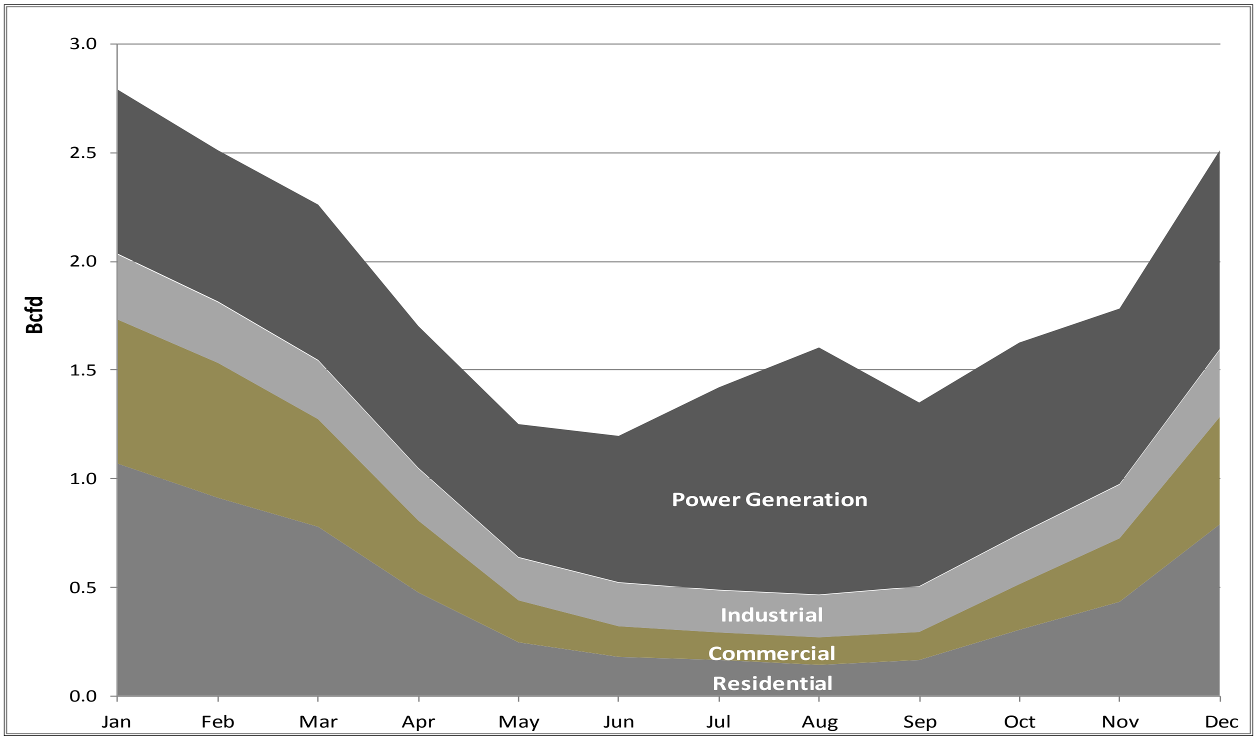
Exhibit 3-3 sums historic sendout by all New England LDCs to each customer class, as reported by the LDCs to the Energy Information Administration (EIA). In 2009, the New England LDCs in aggregate delivered a total of approximately 525 Bcf of gas to all classes of customers. About 66% of all deliveries (~346 Bcf) were to residential and commercial customers.

Exhibit 3-3. Total Annual Gas Deliveries by New England LDCs (Bcf)

Customer Class	2005	2006	2007	2008	2009	*Share of Total*
Residential	194	170	188	205	206	*39%*
Commercial	121	111	126	139	140	*26%*
Industrial	81	79	97	97	96	*18%*
Electric Power	99	97	81	69	82	*17%*
Total Deliveries	**495**	**457**	**492**	**510**	**524**	*100%*
Source: EIA Form-176						

While over 90% of the LDCs' customers are residential and commercial consumers, LDCs also provide gas service to industrial facilities and power plants. All deliveries to residential and commercial customers are provided as firm service, whereas the deliveries to industrial and power sector customers are a mix of firm and interruptible service. The monthly distribution of gas demand in New England is presented in Exhibit 3-4, which shows total demand and not just demand behind LDC city gates. This shows that the residential and commercial sectors are highly seasonal, with most of their demand coming in the winter months. The seasonality of power sector is somewhat counter to the residential and commercial sector. Electric power gas consumption has two peaks: a summer peak for the air conditioning load and a lesser winter peak associated with heating and lighting. By comparison, industrial consumption is fairly flat, with somewhat greater industrial gas use in the summer than in the winter. Two interesting observations to make from this graphic are that: 1) the peak month for electric generation (July) is almost as large as peak month for residential demand (January), and 2) the annual gas consumption for the electric generation sector is greater than that of the residential and commercial sectors combined.

Exhibit 3-4. New England Monthly Gas Consumption by Sector 2009



Source: Energy Information Administration, most recent complete year data.

3.2 Peak Day Firm Gas Demand from the Gas Utilities

Unlike the electric power industry, the natural gas distribution sector does not use the concept of "reserve margin" for setting the capacity needed to meet demand. LDCs plan their systems based on demand requirements on the "design day," typically the coldest winter day observed in the past 30 years (or some other metric). This report uses the design day concept as being the same as the peak day for firm gas demand.[27] Firm demand, moreover, refers to demand from the LDC's residential and commercial customers, plus any other firm transportation services the LDC provides to industrial or power customers within their service territory (typically referred to as industrial and power customers located "behind-the-citygate"), plus a small amount of gas the LDC consumes for its own operations. The LDCs also have interruptible service customers, whose gas deliveries may be curtailed during very cold weather or other events (i.e. force majeure) so that the LDCs can reliably serve all of their firm customer requirements. By definition, these interruptible loads are not included within the LDC projections for firm design day demands. LDC planners develop design day forecasts based on projected customer growth and usage patterns and trends.

The supply assets LDCs use to serve their firm customers consist of firm gas supply commodity contracts, firm (underground) storage contracts, firm gas transportation contracts on the interstate pipelines, and peak-shaving facilities. LDCs hold firm gas supply contracts with producers or gas marketers and include both domestic U.S. gas supply and imported gas supply, either from Canada or as LNG. In total, the gas supply assets of a LDC are sized to meet the LDC's projected firm demand on the design day as well as satisfying overall gas consumption throughout the winter period.

All of the interstate pipelines bringing gas into New England have been sized to meet the aggregate LDC firm requirements, net of peak-shaving capacity, as well as that of other firm shippers, who have committed to firm contracts in accordance with FERC-approved tariffs. Because the entire system is designed to meet peak day requirements, most New England LDCs operate at a low annual load factor, where the annual winter peak day is several times the summer base-load demand and considerably higher than the average day flows over the interstate pipelines.

The additional capacity that exists in the gas transmission pipeline system during non-winter periods is the capacity that is subsequently used by New England's gas-fired generators to convert gas into electricity. As this capacity diminishes over time, due to LDC load growth, it equally diminishes the amount of interruptible pipeline capacity, thus directly impacting the amount of gas-fired generation able to operate under non-firm gas transportation agreements.

3.2.1 Methodology

For this portion of the study, ICF first estimated the current winter peak or design day requirements of all New England LDCs. Next, ICF *projected* the aggregate winter and summer peak day requirements for all New England LDCs, primarily by assembling existing forecasts made by the LDCs themselves.

At the start of this study, ISO-NE contacted the Northeast Gas Association (NGA) to request their assistance in collecting data from the New England LDCs on their firm demand.[28] The NGA is a regional trade association, which includes LDCs as well as transmission companies, liquefied natural gas importers, and associate member companies throughout the northeast

[27] Strictly speaking, the peak day in any one year is not likely to be the design day, but close. Peak days are highly dependent on weather, customer growth and behavior, and other conditions that vary year to year. Design day is more a theoretical reasonable extreme which must be planned for since the system cannot be allowed to lose pressure. There are no "black-outs" on gas LDC systems.

[28] For more information on the Northeast Gas Association, please visit their web site located at: www.northeastgas.org.

U.S. Through the NGA, ISO-NE requested data from the LDCs on their current and projected winter design day and summer peak day firm gas loads. In additional to the data provided directly by the LDCs, ICF also collected forecast data from various planning documents filed by those LDCs with their corresponding state public utility commissions (PUCs).

In total, ICF was able to assemble gas demand projections for eighteen of the twenty-three regional gas LDCs, based either on information provided directly from the LDCs themselves or PUC filings. The data for these eighteen LDCs represents 95% of the total firm gas demand from New England's LDCs. Most of the LDCs gas demand forecasts extended only through the winter of 2014/15. After 2014/15, ICF assumed their demand growth continued at pre-2014 growth rates. Where demand projections were not available for existing LDCs, ICF estimated the annual, winter design day, and summer peak day demands based on historic demand data as reported on EIA Form 176.[29]

In addition to the existing LDCs in New England, one new LDC serving consumers in Maine (Kennebec Valley Gas Company) is proposed to begin operations in the next few years. Currently, there are no load forecasts available for Kennebec Valley Gas Company, so the winter design day projection is based on the maximum capacity the system's main distribution line.

LDCs typically do not project summer peak day demands since it has little impact on capacity planning. However, four LDCs did provided ICF with summer peak day data. For the rest, ICF estimated their summer peak day requirements as the average of the daily sendout to all customers for the months of July and August.

3.2.2 Firm Industrial and Power Load Behind-the-City Gate

To estimate how much of the gas sendout by LDCs is provided to industrial and power generators on an interruptible basis, ICF used EIA data to estimate a line item entitled "Regional Industrial Demand" at approximately 286,900 Dth/d. While data collected by EIA (EIA Form 176) provides the total industrial and electric generation gas deliveries by LDCs, it does not indicate how much of that total amount is firm and how much is interruptible. ICF subsequently examined the pattern of historic LDC deliveries to industrial and power consumers, and based on how much they varied in consumption, ICF estimated the firm portion as approximately 200,000 Dth/d.

[29] For more information on the filing requirements for EIA Form 176, please visit their web site located at: http://www.eia.gov/survey/

3.3 Summary of Firm Demand Forecasts and Caveats

The aggregate projection for LDC firm demand (annual, winter peak day, and summer peak day) is shown below in Exhibit 3-5.

Exhibit 3-5. Forecast of LDC Firm Gas Demand

Gas Year	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	***CAGR 2011-2020***
Annual Consumption, Bcf/year	421	425	429	434	439	444	450	456	462	468	1.2%
Winter	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**	**2019/20**	
Winter Peak Day, Bcf/d	4.252	4.306	4.360	4.414	4.472	4.541	4.612	4.685	4.760	4.839	1.4%
Summer	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	
Summer Peak Day, Bcf/d	0.605	0.611	0.615	0.621	0.627	0.635	0.642	0.651	0.659	0.668	1.1%

CAGR = Cumulative Average Growth Rate. For this table, 1 Bcf is equal to 1,000,000 MMBtu or 1,000,000 Dth.

Growth rates for annual, winter peak day and summer peak day are generally similar. Overall consumption grows at approximately 1.2% per year over the forecast period, whereas peak requirements grow slightly higher at approximately 1.4%. Winter peak gas demand is projected to grow at a slightly faster rate because of increased gas use for space heating, which is highest in winter. Likewise, summer peak day demand grows at a slightly slower rate (1.1% per year) for the same reason.

4. Reference Case Results

This section of the report presents ISO-NE's forecasts of winter peak and summer peak electric power natural gas demand under alternative case assumptions. ICF then compares these estimates of power (gas) demand to the requirements of firm customers on the winter peak and summer peak days and subsequently calculates the (deficit) or surplus (+) in gas supply capability to meet these combined loads. The Reference Case scenarios are described below.

4.1 Brief Summary of Reference Case Scenarios

Using its internal production simulation program, the Inter-Regional Electric Market Model (IREMM), [30] ISO-NE developed the natural gas demands for the Reference Case Scenarios, which were then reviewed and benchmarked, and subsequently incorporated into the capacity analysis spreadsheet developed by ICF. The Reference Case Scenarios are summarized in Exhibit 4-1.

Exhibit 4-1. Reference Case Scenarios

Nominal Gas Demand Forecast	Nominal gas demand from reference case (50/50) electric demand case. (this case yields the lowest levels of gas demand over time)
Reference Gas Demand Forecast	Reference gas demand from extreme case (90/10) electrical demand case. (this case aligns itself with the "design day" concept within the gas sector)
Higher Gas Demand Forecast	Starts with the above Reference Gas Demand Forecast with additional gas demand to cover a disruption to non-gas-fired capacity. Also assumes regionally high natural gas prices.
Maximum Gas Demand Forecast	Starts with the above Reference Gas Demand Forecast with additional gas demand to cover a disruption to non-gas-fired capacity. Also assumes regionally low natural gas prices. (this case yields the highest levels of gas demand over time)

Note: The reference case (50/50) peak electrical loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2 ºF, and the winter peak load is expected to occur at 7.0 ºF. The extreme case (90/10) peak loads have a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2 ºF, and the winter peak is expected to occur at a temperature of 1.6 ºF. (Source: ISO-NE, *2011 Regional System Plan*)

The development of these production simulation cases for the Reference Assessment were based on the ISO-NE assumptions that the electrical supply and demand-side capacity for the short-term (2011 – 2015) would be the same as that that procured within the ISO's Forward Capacity Market's (FCM) - Forward Capacity Auctions (FCA), specifically, FCA#2 through FCA#5.[31] Exhibit 4-2 shows the aggregate supply and demand-side capacity (Capacity Supply

[30] For more information on the IREMM, the web site is located at: http://www.iremm.com/

[31] FCA#2 procured forward capacity for the June 1, 2011 to May 31, 2012 capability period. FCA#3 procured forward capacity for the June 1, 2012 to May 31, 2013 capability period. FCA#4 procured forward capacity for the June 1, 2013 to May 31, 2014 capability period. FCA#5 procured forward capacity for the June 1, 2014 to May 31, 2015 capability period.

Obligations (CSOs)) procured within the respective Forward Capacity Auction in the short-term timeframe (2011-2014).

Exhibit 4-2. ISO-NE Short-Term Capacity Procurement (MW)

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
CSOs FCA #2 37,678	CSOs FCA #3 37,026	CSOs FCA #3 37,246	CSOs FCA #4 37,589	CSOs FCA #4 37,800	CSOs FCA #5 37,040	CSOs FCA #5 37,276

For the near-term assumption (2015-2020), ISO-NE then held the overall supply and demand-side capacity assumptions constant by continuing the use of that same capacity procured under FCA#5.[32] Exhibit 4-3 identifies the aggregate supply and demand-side capacity in the near-term timeframe.

Exhibit 4-3. ISO-NE Near-Term Capacity Procurement (MW)

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040

4.2 Gas Use in Electric Generation for the Reference Case Scenarios

4.2.1 Characteristics of the New England Power Market – Seasonality, Generating Fleet, Growth Outlook[33]

ISO-NE's Regional System Plan 2011 (RSP11) forecast for the annual use of electric energy is slightly higher than the 2010 forecast, but the peak demand forecasts are somewhat similar. The forecast is highly dependent on the economic forecast, which reflects: (1) the recent recession ending in 2009 followed by weak economic growth in 2010, and (2) a projected rebound in 2013 followed by sustained load growth.

The RSP11 electrical forecasts incorporate the expected effects of Federal Energy Efficiency (EE) standards for appliances and commercial equipment that will go into effect in 2013 and reflect the historical energy-efficiency savings excluding the historical savings of Demand Resources (DR) that participate in the Forward Capacity Market (i.e., reductions in past loads resulting from energy-efficiency measures). These forecasts consider Demand Resources that cleared in the Forward Capacity Market (FCM) to be sources of supply and not demand-side measures for reducing the demand forecast. These forecasts of the energy savings attributable to Federal appliance standards and FCM passive resources are 1.6% and 4.7%, respectively. These represent a total energy savings of 6.3% of the gross consumption of electric energy projected for 2020.

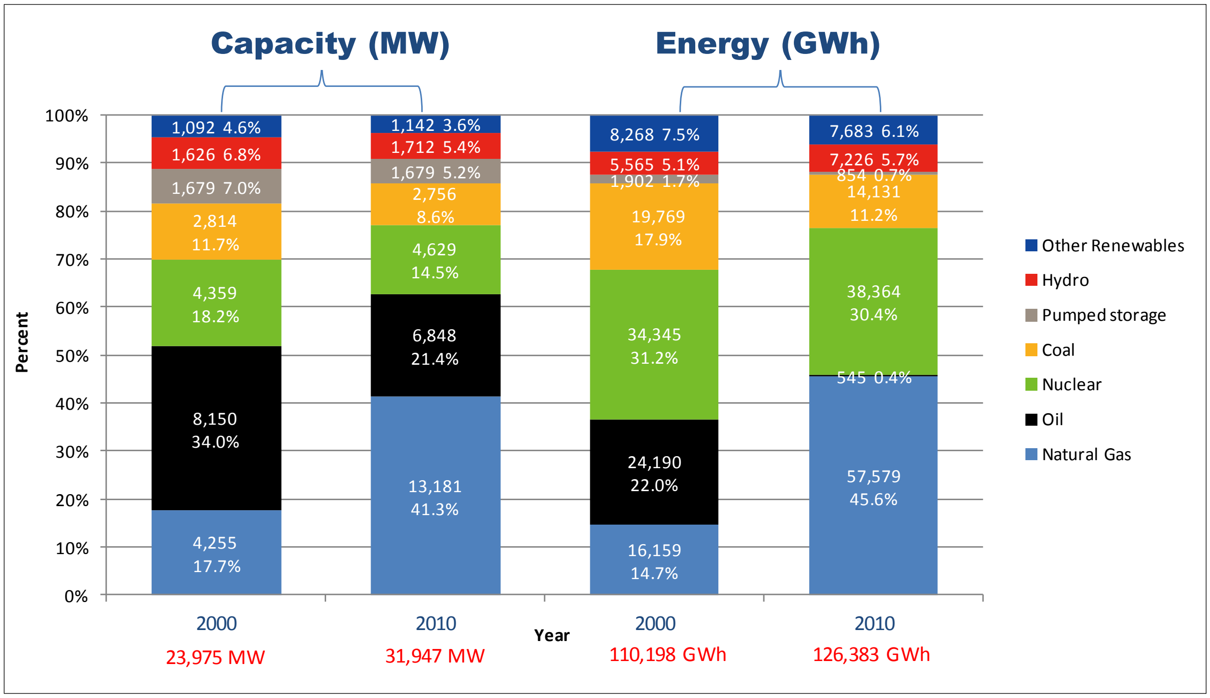
[32] FCA#5 is the Forward Capacity Market (FCM) Auction procuring regional capacity for the June 1, 2014 to May 31, 2015 capability period.
[33] This section is based on ISO-NE 2011 Regional System Plan (RSP11), Sections 1.1.1.1 and 1.1.5.1.

The reference case (50/50) summer peak forecast is 27,550 megawatts (MW) for 2011, which grows to 31,215 MW by 2020. The extreme case (90/10) summer peak forecast is 29,695 MW for 2011 and grows to 33,700 MW by 2020.[34] The actual demand has been near or above the 50/50 forecast nine times during the last nineteen years as a result of regional weather conditions and has been near or has exceeded the 90/10 forecast five times during the same period. ISO-NE forecasts the 10-year (2011 – 2020) compound annual growth rate (CAGR) to be 1.4% per year for the summer peak load, 0.5% per year for the winter peak load, and 1.1% per year for the annual use of electric energy. The annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load) remains fairly stable and declines slightly from 56.1% in 2011 to 54.5% in 2020.

While New England remains heavily dependent on natural gas as a primary fuel for generating electric energy, improvements to the region's natural gas infrastructure and coordination between the gas and electric system operators have mitigated some concerns about fuel diversity and system reliability. However, the region's dependency on natural gas is expected to increase with time. As shown in Exhibit 4-4, in 2000, 17.7% of the region's capacity was natural gas-fired generation, which produced 14.7% of the region's electric energy, whereas in 2010, natural gas plants represented 41.3% of the region's capacity and provided about 45.6% of the system's electrical energy. In sharp contrast to the growth in gas-fired capacity is the corresponding decrease in oil-fired energy production. At 34.0% of the region's capacity in 2000, oil units produced 22.0% of the region's electric energy, but in 2010, at 21.4% of the overall capacity, oil units only produced 0.4% of the region's electric energy. Almost 90% of the summer (rated) capacity of these oil units (MW) is over 20 years old.

[34] The CELT forecast within RSP11 is considered the "gross" electrical forecast. The amount of passive Demand Resources (DR) has not been netted out of these projections. Therefore, forecast electrical peaks that will have to be met by regional supply would have the passive DR subtracted out; 774 MW in 2011 and 1,148 MW in 2020. The resulting 50/50 reference case summer peak loads would be would be 26,776 MW (2011) and 30,067 MW (2020) and the resulting 90/10 extreme case summer peak loads would be 28,921 MW (2011) and 32,552 MW (2020).

Exhibit 4-4. Comparison of the 2000 and 2010 Capacity and Electric Energy Production in New England



Many of the older coal, oil, and nuclear units could likely be replaced (i.e. repowered) by natural gas-fired generating units, which could be built in these same locations, requiring relatively little additional transmission system infrastructure.

Although the addition of renewable resources would provide some diversity of the fuel supply, the increased regulation and reserve requirements needed to reliably integrate these new variable resources into the system could place new stresses on the natural gas system that would need to flexibly provide fuel to quick-start, gas-fired generators on very short notice. Exacerbating the problem is that many existing units lack the physical ability to provide flexible operation and economical or effective dual fuel capability (in terms of the amount of time it takes to switch over from gas to oil, ramping rates, or the availability and sustainability of secondary fuel inventory). All these issues have been identified as part of ISO-NE's Strategic Planning Initiative (SPI).

Recent and planned improvements to the regional and interregional natural gas infrastructure have helped and will work to expand and diversify natural gas supply sources to meet New England's increasing demand for natural gas. Also, the implementation of new ISO-NE Operating Procedures (OPs) and improved communications between electric power and natural gas system operators have decreased some operational risks and worked to improve the reliability and diversity of natural gas supply and transportation. However, more work still needs to be done.

4.2.2 Methodology for Projection Gas Use in New England's Electric Generation

Using the IREMM, ISO-NE performed seventy-two production simulations to determine both the nominal, reference, higher, and maximum limits on the overall gas demands from the power sector, to approximate the seasonal peak day fuel requirements (consumption) of all regional gas-fired and dual fueled power generators serving both short-term and near-term winter and summer peak electrical demands.

In order to gauge both the short-term and near-term fuel requirements of New England's power sector, ISO-NE performed numerous production simulation dispatches, which are categorized below:[35]

1) The Nominal Gas Demand Forecasts were developed using the Reference Case (50/50) seasonal electric demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands.
2) The Reference Gas Demand Forecast were developed using the Extreme Case (90/10) seasonal electric demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands. After consideration, the project team concluded that using the Extreme Case (90/10) electrical demand cases provided better correlation to the gas LDCs "design day" winter weather concept.
3) The Higher Gas Demand Forecast were developed using the Extreme Case (90/10) seasonal electrical demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands using natural gas prices that were increased from their reference projections, along with the simulated outage of a large, non-gas-fired, power station.
4) The Maximum Gas Demand Forecasts were developed using the Extreme Case (90/10) seasonal electrical demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands using natural gas prices that were decreased from their reference projections, along with the simulated outage of a large, non-gas-fired, power station.

ISO-NE then performed and internal review of the results and findings of these IREMM production simulations in order to determine their accuracy and correctness. Upon completion of this process, ISO-NE then supplied the results of these production simulations to ICF Resources for incorporation into their capacity analysis spreadsheet. The results included the power sector's overall natural gas requirements for both individual regional pipelines (including LNG), and aggregate fuel requirements for the total system. As noted earlier, over seventy-two production simulations were developed to *"bandwidth"* the analysis. The results of ISO-NE's seventy-two production simulations (in aggregate fuel consumption in MMBtu/d format) are provided below for both the summer and winter peak demand periods for the Reference Assessment.

4.2.3 Projected Gas Use in Electric Generation

Exhibit 4-5 presents ISO-NE's forecast of gas demand for electric generation in New England for the Reference Assessment. The exhibit shows the following cases, as previously described in Exhibit 4-1:

[35] Seventy-two production simulations were run in total = The sum of the 1) Nominal Gas Demand Cases (18) = Winter and Summer production runs for nine years (2011-2020), 2) Reference Gas Demand Cases (18) = Winter and Summer productions runs for nine years, 3) Higher Gas Demand Cases (18) = Winter and Summer production runs for nine years, and 4) Maximum Gas Demand Cases (18) = Winter and Summer production runs for nine years.

- Nominal Gas Demand Forecast
- Reference Gas Demand Forecast
- Higher Gas Demand Forecast
- Maximum Gas Demand Forecast

In the Nominal Gas Demand Forecasts, the power sector's winter peak day demand is about 1.5 million Dth/d in 2011/12 and relatively flat over the forecast period. Summer peak day gas demand is about 2.4 million Dth/d in 2012, increasing to 2.8 million Dth/d in 2020.

In the Reference Gas Demand Forecasts, the power sector's winter peak day gas demand is 1.6 million Dth/d in 2011/12 and 1.6 million Dth/d in 2019/20. Summer peak day gas demand is 2.7 million Dth/d in 2012 and 3.0 million Dth/d in 2020.

Under the Higher Gas Demand Forecasts, the power sector's winter peak day gas demand is not much different at 1.6 million Dth/d in 2011/12 and 1.7 million Dth/d in 2019/20. Summer peak day gas demand is 2.9 million Dth/d in 2012, increasing to 3.1 million Dth/d in 2020.

Under the Maximum Gas Demand Forecasts, the power sector gas demands are the highest at 2.2 million Dth/d on the peak winter day in 2011/12 and 2.3 million Dth/d in 2019/20. Summer peak day gas demand is 3.3 million Dth/d in 2012 and 3.5 million Dth/d in 2020.

Exhibit 4-5. Reference Assessment – Power Sector Gas Demands (1,000 Dth/d)

Nominal Gas Demand Forecast			
Winter 2011/12	1,536.2	Summer 2012	2,419.8
Winter 2012/13	1,605.3	Summer 2013	2,503.4
Winter 2013/14	1,582.6	Summer 2014	2,507.6
Winter 2014/15	1,543.7	Summer 2015	2,532.9
Winter 2015/16	1,546.3	Summer 2016	2,587.8
Winter 2016/17	1,547.7	Summer 2017	2,646.4
Winter 2017/18	1,548.9	Summer 2018	2,709.8
Winter 2018/19	1,531.0	Summer 2019	2,757.7
Winter 2019/20	1,504.4	Summer 2020	2,794.2

Reference Gas Demand Forecast			
Winter 2011/12	1,603.0	Summer 2012	2,748.3
Winter 2012/13	1,682.4	Summer 2013	2,862.1
Winter 2013/14	1,655.4	Summer 2014	2,832.5
Winter 2014/15	1,600.9	Summer 2015	2,867.0
Winter 2015/16	1,603.5	Summer 2016	2,907.7
Winter 2016/17	1,619.8	Summer 2017	2,944.8
Winter 2017/18	1,621.8	Summer 2018	2,973.4
Winter 2018/19	1,616.4	Summer 2019	2,994.1
Winter 2019/20	1,588.2	Summer 2020	3,016.8

Higher Gas Demand Forecast			
Winter 2011/12	1,608.4	Summer 2012	2,892.4
Winter 2012/13	1,696.8	Summer 2013	2,947.7
Winter 2013/14	1,616.6	Summer 2014	2,947.7
Winter 2014/15	1,635.5	Summer 2015	2,986.9
Winter 2015/16	1,655.2	Summer 2016	3,017.0
Winter 2016/17	1,691.5	Summer 2017	3,052.3
Winter 2017/18	1,716.3	Summer 2018	3,079.4
Winter 2018/19	1,749.6	Summer 2019	3,104.8
Winter 2019/20	1,738.0	Summer 2020	3,127.7

Maximum Gas Demand Forecast			
Winter 2011/12	2,184.9	Summer 2012	3,303.3
Winter 2012/13	2,152.5	Summer 2013	3,376.3
Winter 2013/14	2,174.7	Summer 2014	3,393.9
Winter 2014/15	2,202.2	Summer 2015	3,423.1
Winter 2015/16	2,224.6	Summer 2016	3,444.3
Winter 2016/17	2,243.0	Summer 2017	3,471.5
Winter 2017/18	2,270.3	Summer 2018	3,487.2
Winter 2018/19	2,301.7	Summer 2019	3,501.5
Winter 2019/20	2,336.2	Summer 2020	3,515.1

4.3 Comparing Projected Supply and Gas Use to Determine System Surpluses/Deficits in the Reference Assessment

ICF took the forecast power system gas demands shown in Exhibit 4-5, compared these with natural gas system capabilities net of firm loads on the gas system, and developed estimates of the surplus (+) or (deficiency) available for power sector consumption.[36] Below we present the results under both winter and summer peak day conditions.

4.3.1 Winter Design Day

Exhibits 4-6 through 4-9 present the winter surplus or deficit that would occur under different assumptions about gas utilization within the power sector. We first take the total gas pipeline and supply capability and subtract from it the firm gas demands from the gas utilities. Then, adjustments are made for the firm industrial demands that are served directly by pipelines, and the adjustments are made to account for firm power and industrial demands served by LDCs. The resulting estimate is the amount of gas grid capability which remains for serving the electric power sector.

To arrive at the net surplus or deficit in fuel supply, we subtract the (various) estimates of power sector fuel requirements from Exhibit 4-5[37] as well as a value for *"Fuel Reserve Margin."* The Fuel Reserve Margin concept, imputed by ISO-NE, represents the amount of additional gas required to be continuously delivered (over a 24 hour period) from the triggering of operating reserves in order to replenish the hypothetical loss of a generic 1,200 MW class nuclear unit within the regional fleet.[38] This fuel reserve margin may be viewed as a lower limit for the required surplus/deficit value, to keep the power system in an equilibrium state as Control Room Operators prepare for the next potential contingency on the electric system. Under the Nominal Gas Demand Forecasts shown in Exhibit 4-6, there is a gas deficiency in all nine forecast years.

[36] In reality, any spare regional pipeline capacity would actually be competitively available for gas LDCs, gas-fired power generators, fuel suppliers, portfolio managers and marketers.
[37] For the four cases entitled: 1) Nominal Gas Demands, 2) Reference Gas Demands, 3) Higher Gas Demands, and 4) Maximum Gas Demands.
[38] This is approximately equivalent to the largest generating facility on the New England system, or possibly the Largest First Contingency (N-1) in NERC terminology.

Exhibit 4-6. Winter Gas System Supply Capability under the Nominal Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,536	1,605	1,583	1,544	1,546	1,548	1,549	1,531	1,504
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(389)**	**(512)**	**(543)**	**(562)**	**(434)**	**(356)**	**(430)**	**(487)**	**(539)**
MW Equivalent (Surplus or Deficiency)	*(1,619)*	*(2,132)*	*(2,262)*	*(2,342)*	*(1,807)*	*(1,482)*	*(1,791)*	*(2,031)*	*(2,247)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-7 presents the results for the Reference Gas Demand Forecasts, which is more representative of a peak winter day occurrence in the gas sector. This case shows supply deficiencies in all nine years, and these deficiencies are greater than those within the Nominal Gas Demand Forecasts.

Exhibit 4-7. Winter Gas System Supply Capability under the Reference Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,603	1,682	1,655	1,601	1,603	1,620	1,622	1,616	1,588
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(455)**	**(589)**	**(616)**	**(619)**	**(491)**	**(428)**	**(503)**	**(573)**	**(623)**
MW Equivalent (Surplus or Deficiency)	*(1,897)*	*(2,453)*	*(2,565)*	*(2,580)*	*(2,046)*	*(1,782)*	*(2,095)*	*(2,387)*	*(2,597)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-8 presents the Higher Gas Demand Forecasts, in which there is additional regional gas demand due to the (temporary/hypothetical) loss of capacity by non-gas-fired power station with a higher regional gas price. Under this case, gas supply deficiencies again occur in all nine years, similar to the Reference Gas Demand Forecasts, however, these deficiencies are somewhat greater.

Exhibit 4-8. Winter Gas System Supply Capability under the Higher Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,608	1,697	1,617	1,635	1,655	1,692	1,716	1,750	1,738
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(461)**	**(603)**	**(577)**	**(654)**	**(543)**	**(500)**	**(597)**	**(706)**	**(773)**
MW Equivalent (Surplus or Deficiency)	*(1,920)*	*(2,513)*	*(2,403)*	*(2,724)*	*(2,261)*	*(2,081)*	*(2,489)*	*(2,942)*	*(3,221)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-9 shows the results for the Maximum Gas Demand Forecasts, which combines the (temporary/hypothetical) loss of a non-gas-fired power station with a lower regional gas price to create conditions for maximum gas utilization within the power sector. Relative to all three previous cases, this case creates a more substantial deficiency in gas system supply for the power sector, with deficiencies again in all nine of the forecast years.

Exhibit 4-9. Winter Gas System Supply Capability under the Maximum Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,185	2,153	2,175	2,202	2,225	2,243	2,270	2,302	2,336
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(1,037)**	**(1,059)**	**(1,135)**	**(1,221)**	**(1,112)**	**(1,051)**	**(1,151)**	**(1,258)**	**(1,371)**
MW Equivalent (Surplus or Deficiency)	*(4,322)*	*(4,412)*	*(4,729)*	*(5,086)*	*(4,634)*	*(4,379)*	*(4,797)*	*(5,243)*	*(5,713)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

4.3.2 Summer Peak Day

The following Exhibits (4-10 through 4-13) present the same type of assessments for summer peak conditions. Note that natural gas system's total capacity (first line) is less than the winter capacity, since LNG peak-shaving and propane-air capability is not included in the total. These peak-shaving facilities are for winter operation by regional LDCs and would never be used to supplement power sector gas demands. In addition, these peak-shaving facilities generally would not be fully available in summer, since this is when peak-shaving plants replenish their LNG/LPG supplies. LDCs' firm demand is much smaller in summer; therefore almost all four of the summer Reference Assessment Forecasts show surplus capabilities for all the forecast years. As the assumptions about power system gas demand increase, from the Nominal to the Maximum Gas Demand Forecasts, the size of the surplus declines, as should be expected.

Exhibit 4-10. Summer Gas System Supply Capability under the Nominal Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,420	2,503	2,508	2,533	2,588	2,646	2,710	2,758	2,794
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**967**	**879**	**870**	**839**	**977**	**1,061**	**990**	**934**	**889**
MW Equivalent (Surplus or Deficiency)	*4,031*	*3,664*	*3,625*	*3,496*	*4,070*	*4,420*	*4,123*	*3,890*	*3,703*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-11. Summer Gas System Supply Capability under the Reference Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,748	2,862	2,833	2,867	2,908	2,945	2,973	2,994	3,017
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**639**	**521**	**545**	**505**	**657**	**762**	**726**	**697**	**666**
MW Equivalent (Surplus or Deficiency)	*2,662*	*2,169*	*2,271*	*2,104*	*2,738*	*3,176*	*3,025*	*2,905*	*2,775*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-12. Summer Gas System Supply Capability under the Higher Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,892	2,948	2,948	2,987	3,017	3,052	3,079	3,105	3,128
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**495**	**435**	**430**	**385**	**548**	**655**	**620**	**587**	**555**
MW Equivalent (Surplus or Deficiency)	*2,061*	*1,813*	*1,791*	*1,604*	*2,282*	*2,729*	*2,584*	*2,444*	*2,313*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 4-13. Summer Gas System Supply Capability under the Maximum Gas Demand Forecasts (1,000 Dth/d)

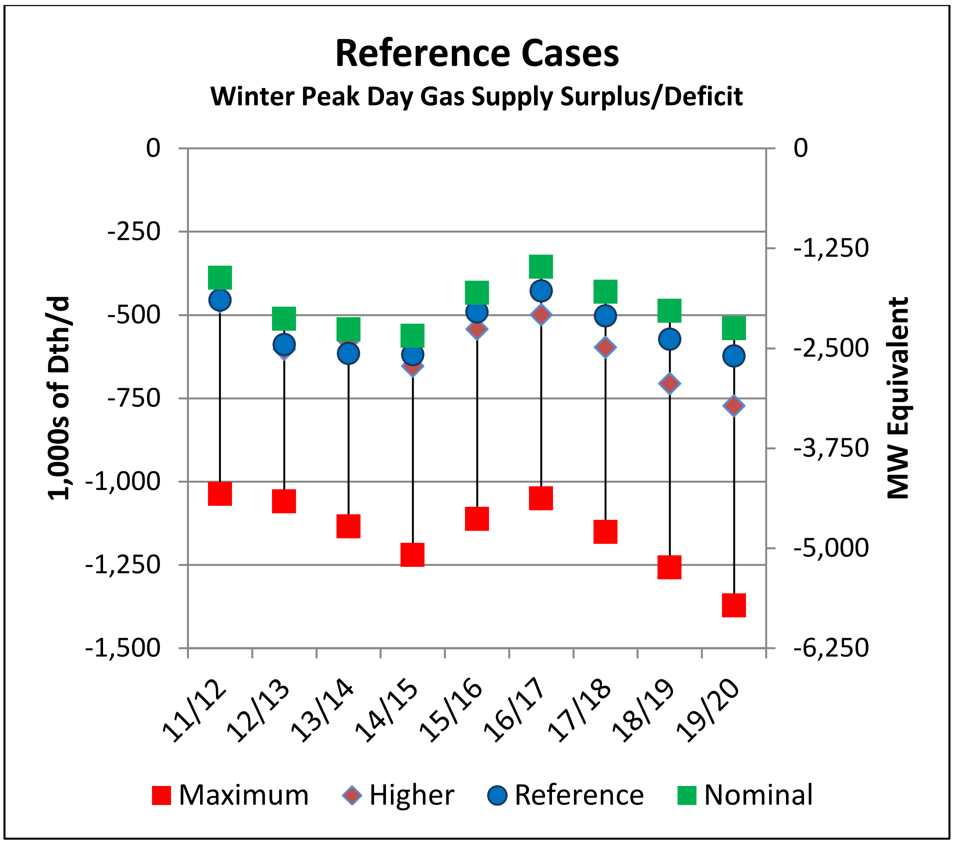
	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	3,303	3,376	3,394	3,423	3,444	3,471	3,487	3,502	3,515
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**84**	**7**	**(16)**	**(51)**	**120**	**236**	**212**	**190**	**168**
MW Equivalent (Surplus or Deficiency)	*350*	*27*	*(68)*	*(213)*	*502*	*982*	*884*	*791*	*699*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh

4.4 Summary of Reference Case Results, with Key Findings

Exhibit 4-14 summarizes the results of the winter cases; and Exhibit 4-15 summarizes the results of the summer cases. Of the cases examined, the **Reference Gas Demand Forecasts** case (summer and winter) represents the most likely alignment between gas system and power system requirements. In winter (Exhibit 4-14), although the regional LDCs utilize their peak shaving facilities to serve gas loads, for most of the study years, the Reference Gas Demand Forecasts would need more fuel supplies than those that are projected to be available on the regional gas system. The inflection in the graphs showing surplus in 2014/15 are a result of ICF's estimated expansions within the gas system into New England as described in Section 2.

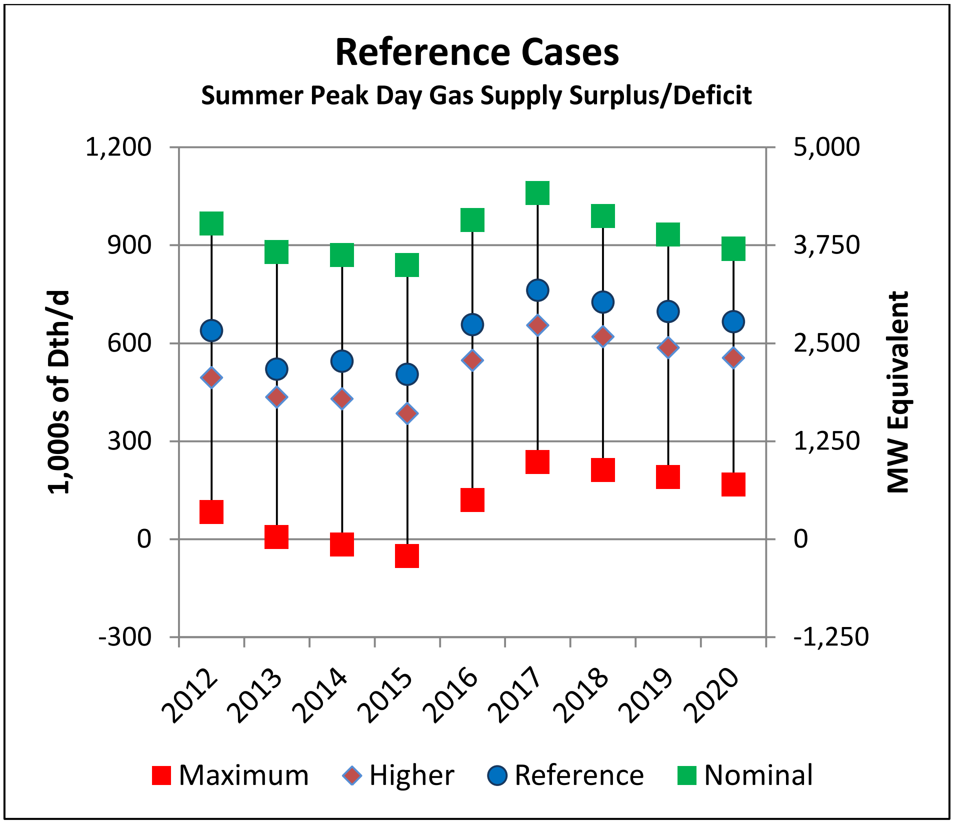
Exhibit 4-14. Electric Sector Surplus/Deficit Availability to Meet Winter Peak Power Demand - Reference Case Results



The **Higher Gas Demand Forecasts** reflect loss of non-fossil generation and therefore additional competition for gas supplies on a peak day. This case has only slightly greater gas system deficiency than the Reference Gas Demand Forecasts case, presumably because there is substantial oil-fired generation to manage the shortfall in capacity, even at very high gas prices relative to oil.

In summer (Exhibit 4-15), under the Reference Gas Demand Forecasts, regional gas system capability is adequate over the forecast period (again, the inflection in 2015 is due to expansions of pipeline capacity into New England). Indeed, in summer, the electric system appears capable of managing the loss of other generation resources and still be able to rely on natural gas to supply replacement generation. This is shown by the **Higher Gas Demand Forecasts**. Under Higher Gas Demand Forecasts, regional natural gas prices would likely be higher as generators bid for gas to meet power demands, but at prices more competitive with oil than in the winter. Most of the time, there would be sufficient gas pipeline capacity to meet the additional demand.

Exhibit 4-15. Electric Sector Surplus/Deficit Availability to Meet Summer Peak Power Demand - Reference Case Results



ICF has the following observations about these cases:

- New England's gas delivery system is already in very tight balance on a winter design day, even before any future gas demand growth is assumed.
- Through 2020, the estimated winter design day deficit in the Reference Gas Demand Forecast is generally between -425,000 and -625,000 dekatherms per day (-1,775 MW to -2,600 MW) in most years. In the highest gas demand case (Maximum Gas Demand Forecast) the deficit ranges between -1,000,000 dekatherms per day (-4,175 MW) to almost 1,375,000 dekatherms per day or about 5,725 MW by 2020.
- The winter design day is usually below the imputed fuel "reserve margin." (This is the amount of gas/pipeline capacity that would be needed to supply operating reserve units on the power system.)

- This result suggests that regional gas supply capability is inadequate to satisfy regional electric sector gas demands on a winter design day over the next decade, barring incremental expansion of the gas delivery system beyond those expansions assumed herein.

- Summer peak day gas supply is generally not constrained with Reference Gas Demand Forecast surpluses range from about 500,000 to over 750,000 dekatherms per day (2,075 MW to 3,125 MW). The summer peak day balance is well above the fuel reserve margin. However, this conclusion will not necessarily remain true with gas sector maintenance, outages or contingencies being considered. In the Maximum Gas Demand Forecast, with a large coal or nuclear plant off-line and strong gas demand due to low prices of gas, minor shortages of gas supply capability can occur before 2016, prior to our assumed pipeline expansions.

5. Repowering Case Results

5.1 Background on Repowering Case

ISO-NE developed the Repowering Assessment to estimate the fuel implications of repowering on power sector natural gas demands. The Repowering cases assume the same electric load forecasts as the Reference cases, but replace *"At-Risk"* coal and oil-fired units with new, gas-fired technologies, thereby creating additional on-peak power sector gas demands.

The development of the Repowering Assessment was based on the same supply and demand-side capacity assumptions used within the Reference Assessment for both the short and near-term (2011 – 2020), with the hypothetical exception that several *"At-Risk*" regional power stations would subsequently be repowered within the study timeframe. The units and/or stations that were subject to this potential repowering are those that are currently subject to the ongoing environmental policies of the U.S. Environmental Protection Agency (EPA), and as such, would face pending compliance with several new air emissions and water management policies. As a preface to these repowering assumptions, these potential retirements are exemplified at the nation-wide level within the 2010 NERC Assessment entitled *"2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations.*"[39] The significant findings from the 2010 NERC Special Reliability Scenario Assessment includes the ramifications of potential retirements of existing facilities due to compliance with four U.S. EPA rulemaking policies, which include:

- Clean Water Act – Section 316(b) - Cooling Water and Wastewater
- Clean Air Act – Utility Air Toxics Rule
- Clean Air Act – Cross State Air Pollution Rule (CSAPR)[40]
- Resource Conservation & Recovery Act - Coal Combustion Residuals (CCR)

Under the umbrella of ISO-NE's Strategic Planning Initiative and to specifically support this gas study scope of work, ISO-NE has develop a similar list of *"At-Risk"* regional power plants/stations that could potentially retire due to the economics related to compliance with pending environmental regulations. This ISO-NE "*At-Risk List"* identifies the potential retirements of existing coal and oil-fired facilities within New England. Within the Repowering Assessment, ISO-NE takes these potential retirements one step further by assuming that the units/stations within this *At-Risk List"* are subsequently repowered to equivalent capacity, natural gas-fired power plants/stations. Then ISO-NE performed new production simulations under this Repowering Assessment, to gauge the incremental gas demands from the electric system with these potentially repowered gas-fired facilities included. Thus the Repowering Assessment tries to identify the potential upper limit of future gas demand from the electric power sector, under the overarching assumption that the majority of the new capacity within New England's fleet will come from the retirement of *"At-Risk"* units/stations and subsequent repowering of these sites with new, gas-fired technologies. Exhibit 5-1 presents ISO-NE's repowering results. (Colors in the table are keyed to the notes below the table.)

[39] This report can be located at the NERC web site at: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

[40] Generators in New England are not subject to the Cross State Air Pollution Rule (CSAPR). Little regional impact is expected from proposed Coal Combustion Residuals Rule (CCR), regardless of which waste handling option the U.S. EPA adopts under this rule since there are no remaining coal surface impoundments within New England subject to this rulemaking.

Exhibit 5-1. ISO-NE "At-Risk List" of Generating Units Targeted for Repowering

EXHIBIT 5-1 HAS BEEN REDACTED TO COMPLY WITH ISO-NE INFORMATION POLICY

5.2 Brief Summary of Repowering Case Scenarios

Repowering cases used the same assumptions as the Reference cases, except that existing and future electric market conditions combined with pending U.S. EPA Air and Water Regulations, put approximately 7,250 MW of regional coal and oil-fired facilities *"At-Risk"* to potential retirement. The key Repowering case assumptions were the following:

- All *"At-Risk*" units/stations are repowered to "equivalent capacity" gas-fired technologies at the compliance date of the applicable U.S. EPA regulation.
- Repowered units/stations are connected to the nearest gas supply source.
- Repowered technologies were taken from the GE Electric generation web site.[41]
- Existing capacity within the 16 MW – 35 MW range was repowered with a G.E. LM2500+ gas turbine with an associated heat rate of 9,287 Btu/kWh.
- Existing capacity within the 35 MW – 65 MW range was repowered with a G.E. LM6000 gas turbine with an associated heat rate of 8,364 Btu/kWh.
- Existing capacity within the 65 MW - 120 MW range was repowered with a G.E. LMS100 gas turbine with an associated heat rate of 7,695 Btu/kWh. Existing capacity within the 120 MW – 400 MW range were repowered with multiple G.E. LMS100 units.
- Existing capacity within the 400 MW – 650 MW range was repowered with a G.E. FlexEfficiency-50 combine-cycle station with a heat rate of 5,900 Btu/kWh.[42]

In this section, ICF considers four repowering case scenarios, winter and summer, as described in Exhibit 5-2.

[41] For more information on these new power technologies, please visit the G.E. Electric Generation web site located at: http://www.ge-energy.com/products_and_services/industries/power_generation.jsp

[42] The Repower cases assume at-risk units are replaced with gas-fired units operating at the heat rates listed above. The need for additional flexibility to follow load changes and swings in renewable generation may result in the selection of replacement capacity with higher heat rates and/or higher heat rates due to load following.

Exhibit 5-2. Repowering Case Scenarios

Nominal Gas Demand Forecast (Repower)	Nominal gas demand from reference case (50/50) electric demand case. (this case yields the lowest levels of gas demand over time)
Reference Gas Demand Forecast (Repower)	Reference gas demand from extreme case (90/10) electrical demand case. (this case aligns itself with the "design day" concept within the gas sector)
Higher Gas Demand Forecast (Repower)	Starts with the above Reference Gas Demand Forecast with additional gas demand to cover a disruption to non-gas-fired capacity. Also assumes regionally high natural gas prices.
Maximum Gas Demand Forecast (Repower)	Starts with the above Reference Gas Demand Forecast with additional gas demand to cover a disruption to non-gas-fired capacity. Also assumes regionally low natural gas prices. (this case yields the highest levels of gas demand over time).

Note: The reference case (50/50) peak electrical loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2 ºF, and the winter peak load is expected to occur at 7.0 ºF. The extreme case (90/10) peak loads have a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2 ºF, and the winter peak is expected to occur at a temperature of 1.6 ºF. (Source: ISO-NE, *2011 Regional System Plan*)

The repowering gas demand cases are presented below in Exhibit 5-3.

Exhibit 5-3. Repower Assessment - Power Sector Gas Demands (1,000 Dth/d)

Nominal Gas Demand Forecast			
Winter 2011/12	1,536.2	Summer 2012	2,419.7
Winter 2012/13	1,605.4	Summer 2013	2,503.4
Winter 2013/14	1,606.4	Summer 2014	2,672.4
Winter 2014/15	1,621.4	Summer 2015	2,716.2
Winter 2015/16	1,635.2	Summer 2016	2,778.5
Winter 2016/17	1,662.4	Summer 2017	2,832.2
Winter 2017/18	1,675.4	Summer 2018	2,900.4
Winter 2018/19	1,602.7	Summer 2019	2,792.5
Winter 2019/20	1,615.3	Summer 2020	2,828.1

Reference Gas Demand Forecast			
Winter 2011/12	1,603.0	Summer 2012	2,748.1
Winter 2012/13	1,682.6	Summer 2013	2,862.1
Winter 2013/14	1,692.4	Summer 2014	3,024.9
Winter 2014/15	1,699.2	Summer 2015	3,066.4
Winter 2015/16	1,716.1	Summer 2016	3,113.0
Winter 2016/17	1,752.5	Summer 2017	3,154.4
Winter 2017/18	1,760.1	Summer 2018	3,181.0
Winter 2018/19	1,697.0	Summer 2019	3,181.6
Winter 2019/20	1,712.4	Summer 2020	3,217.7

Higher Gas Demand Forecast			
Winter 2011/12	1,608.4	Summer 2012	2,892.0
Winter 2012/13	1,696.8	Summer 2013	2,947.7
Winter 2013/14	1,743.5	Summer 2014	3,160.8
Winter 2014/15	1,760.0	Summer 2015	3,200.0
Winter 2015/16	1,780.0	Summer 2016	3,231.3
Winter 2016/17	1,837.2	Summer 2017	3,266.9
Winter 2017/18	1,862.9	Summer 2018	3,294.6
Winter 2018/19	1,800.8	Summer 2019	3,302.8
Winter 2019/20	1,782.3	Summer 2020	3,342.7

Maximum Gas Demand Forecast			
Winter 2011/12	2,184.8	Summer 2012	3,302.9
Winter 2012/13	2,152.3	Summer 2013	3,376.2
Winter 2013/14	2,129.0	Summer 2014	3,496.4
Winter 2014/15	2,150.2	Summer 2015	3,531.8
Winter 2015/16	2,172.0	Summer 2016	3,558.4
Winter 2016/17	2,182.7	Summer 2017	3,591.4
Winter 2017/18	2,209.0	Summer 2018	3,615.5
Winter 2018/19	2,041.0	Summer 2019	3,598.4
Winter 2019/20	2,061.6	Summer 2020	3,628.3

For this presentation, 1,000,000 Dth = 1 Bcf.

5.3 Comparing Projected Supply and Gas Use to Determine System Surpluses/Deficits in the Repowering Assessment

In this section, the results of the natural gas supply analysis for ISO-NE's Repowering cases are presented in four tables.

5.3.1 Winter Design Day

The four Exhibits below (Exhibits 5-4 through Exhibit 5-7) present the gas supply surplus/deficit calculations for the Repowering cases for peak winter days.

Exhibit 5-4 shows the results of the analysis for the Repowering Nominal Gas Demand Forecasts. All of the forecast years indicate a gas supply deficiency.

Exhibit 5-4. Winter Gas System Supply Capability under the Repowering Nominal Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,536	1,605	1,606	1,621	1,635	1,662	1,675	1,603	1,615
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(389)**	**(512)**	**(567)**	**(640)**	**(523)**	**(470)**	**(556)**	**(559)**	**(650)**
MW Equivalent (Surplus or Deficiency)	*(1,619)*	*(2,132)*	*(2,361)*	*(2,666)*	*(2,178)*	*(1,960)*	*(2,318)*	*(2,330)*	*(2,710)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-5 shows the results of the analysis for the Repowering Reference Gas Demand Forecasts. All of the forecast years indicate a gas supply deficiency, increasing from a low of 455,000 Dth/d this year to almost 750,000 Dth/d in 2019/20.

Exhibit 5-5. Winter Gas System Supply Capability under the Repowering Reference Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,603	1,683	1,692	1,699	1,716	1,753	1,760	1,697	1,712
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(455)**	**(589)**	**(653)**	**(717)**	**(604)**	**(560)**	**(641)**	**(654)**	**(747)**
MW Equivalent (Surplus or Deficiency)	*(1,897)*	*(2,454)*	*(2,719)*	*(2,990)*	*(2,515)*	*(2,335)*	*(2,671)*	*(2,723)*	*(3,114)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-6 presents the Repowering Higher Gas Demand Forecasts, showing supply deficiencies in all nine years of the forecast, increasing to over 700,000 Dth/d by 2013/14 and rising to over 800,000 Dth/d by the end of the period.

Exhibit 5-6. Winter Gas System Supply Capability under the Repowering Higher Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	1,608	1,697	1,744	1,760	1,780	1,837	1,863	1,801	1,782
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(461)**	**(603)**	**(704)**	**(778)**	**(668)**	**(645)**	**(744)**	**(757)**	**(817)**
MW Equivalent (Surplus or Deficiency)	*(1,920)*	*(2,513)*	*(2,932)*	*(3,243)*	*(2,781)*	*(2,688)*	*(3,099)*	*(3,156)*	*(3,405)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-7 presents the Repowering Maximum Gas Demand Forecasts. As expected, it shows the largest deficiencies of all the forecast years, with the gas supply deficiencies in all nine forecast years averaging about 1,000,000 Dth/d (approximately 4,200 MW).

Exhibit 5-7. Winter Gas System Supply Capability under the Repowering Maximum Gas Demand Forecasts (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total Gas Pipeline and Supply Capability	5,741	5,741	5,741	5,741	5,941	6,091	6,091	6,091	6,091
(Minus) Firm Demand by LDCs (Note 1)	4,306	4,360	4,414	4,472	4,541	4,612	4,685	4,760	4,839
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	1,348	1,294	1,240	1,182	1,313	1,392	1,319	1,243	1,165
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,185	2,152	2,129	2,150	2,172	2,183	2,209	2,041	2,062
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**(1,037)**	**(1,059)**	**(1,089)**	**(1,169)**	**(1,059)**	**(991)**	**(1,090)**	**(998)**	**(1,097)**
MW Equivalent (Surplus or Deficiency)	*(4,321)*	*(4,411)*	*(4,538)*	*(4,869)*	*(4,414)*	*(4,128)*	*(4,541)*	*(4,157)*	*(4,569)*

1. Represents the design day value for the winter beginning November of the prior year through March of the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

5.3.2 Summer Peak Day

The following Exhibits (Exhibit 5-8 through Exhibit 5-11) present the same repowering analysis under summer peak day conditions. In all of the cases but one, the Maximum Gas Demand Forecast, there is excess gas supply capability to meet the summer demands from regional power generators. In all of the cases, supply capability is reduced prior to the AGT expansion in 2016. In the Maximum Forecast (Exhibit 5-11) there is inadequate capacity in 2014 and 2015, and very limited spare capacity thereafter.

Exhibit 5-8. Summer Gas System Supply Capability under the Repowering Nominal Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,420	2,503	2,672	2,716	2,778	2,832	2,900	2,793	2,828
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**967**	**879**	**705**	**656**	**786**	**875**	**799**	**899**	**855**
MW Equivalent (Surplus or Deficiency)	*4,031*	*3,664*	*2,938*	*2,732*	*3,276*	*3,646*	*3,329*	*3,745*	*3,562*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-9. Summer Gas System Supply Capability under the Repowering Reference Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,748	2,862	3,025	3,066	3,113	3,154	3,181	3,182	3,218
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**639**	**521**	**353**	**305**	**452**	**553**	**518**	**510**	**465**
MW Equivalent (Surplus or Deficiency)	*2,663*	*2,169*	*1,470*	*1,273*	*1,882*	*2,303*	*2,160*	*2,124*	*1,938*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-10. Summer Gas System Supply Capability under the Repowering Higher Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	2,892	2,948	3,161	3,200	3,231	3,267	3,295	3,303	3,343
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**495**	**435**	**217**	**172**	**333**	**440**	**405**	**389**	**340**
MW Equivalent (Surplus or Deficiency)	*2,063*	*1,813*	*903*	*716*	*1,389*	*1,834*	*1,687*	*1,619*	*1,417*

1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

Exhibit 5-11. Summer Gas System Supply Capability under the Repowering Maximum Gas Demand Forecasts (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Total Gas Pipeline and Supply Capability	4,285	4,285	4,285	4,285	4,485	4,635	4,635	4,635	4,635
(Minus) Firm Demand by LDCs (Note 1)	611	615	620	626	633	641	649	657	665
(Minus) Regional Industrial Demands (Note 2)	287	287	287	287	287	287	287	287	287
(Plus) Firm Power and Industrial Demands Served Behind LDC Citygates (Note 3)	200	200	200	200	200	200	200	200	200
(Equals) Gas Grid Capability to Serve Power sector Demands Surplus or (Deficiency)	3,587	3,583	3,578	3,572	3,765	3,907	3,899	3,891	3,883
(Minus) Power sector Demand (from ISO-NE Scenarios)	3,303	3,376	3,496	3,532	3,558	3,591	3,616	3,598	3,628
(Minus) Fuel Reserve Margin	200	200	200	200	200	200	200	200	200
(Equals) Remaining Gas Grid Capability: Surplus or (Deficiency)	**84**	**7**	**(119)**	**(160)**	**6**	**116**	**84**	**93**	**55**
MW Equivalent (Surplus or Deficiency)	*351*	*27*	*(495)*	*(666)*	*26*	*483*	*350*	*387*	*227*

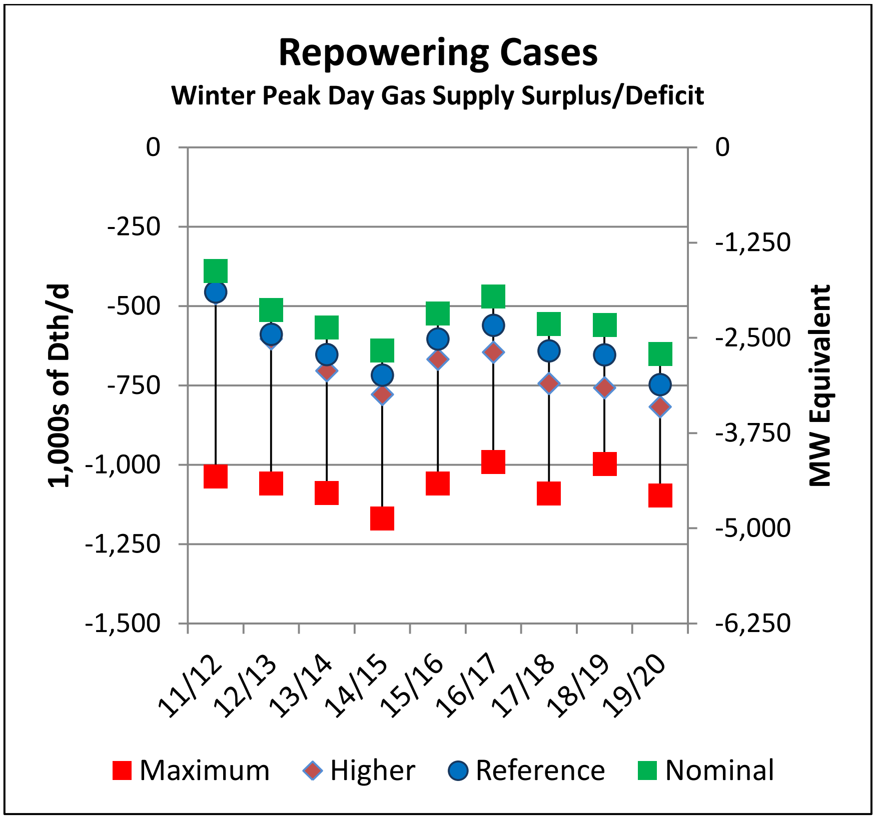
1. Represents the projected summer peak day value for the forecast year.
2. Projected industrial load remains constant at the annual 2009 value reported by EIA divided by 365.
3. This calculation nets out the estimated firm power and industrial load served directly by gas utilities.
4. The MW equivalent of the gas grid surplus/deficit is based on an assumed marginal heat rate of 10,000 Btu/kWh.

5.4 Summary of Repowering Case Results, with Key Findings

The power sectors gas demands for the Repowering cases are summarized in Exhibit 5-12 and Exhibit 5-13. As should be expected, the Repowering cases show greater gas system deficiencies for meeting power gas demand than the Reference cases.

As shown in Exhibits 5-12, the winter **Repowering Reference Gas Demand Forecast** is deficient in all years. The Repowering case reflects a likely outcome when both the gas and electric systems are at their winter peaks. In the later years of the forecast, the gas supply deficit becomes more substantial. (Again, the slight inflection in 2015/16 reflects additional gas pipeline capacity coming on line.)

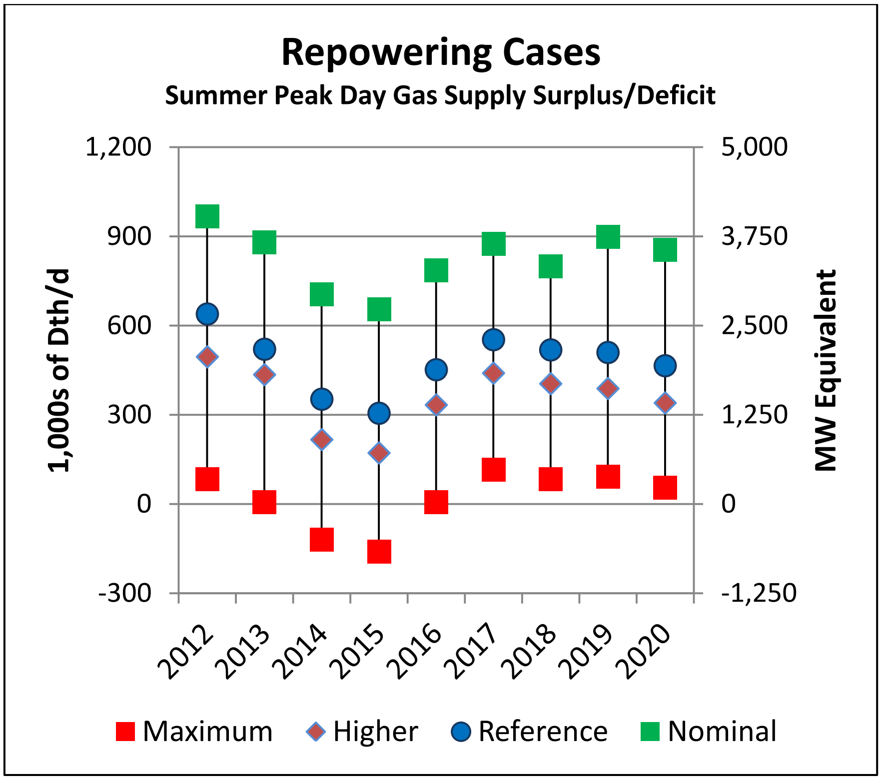
Exhibit 5-12. Electric Sector Surplus/Deficit Availability to Meet Winter Peak Power Demand - Repowering Case Results



Turning to the summer peak, almost all the Repowering cases still show some gas supply surplus through the forecast. The difference being the impact of the loss of base load, coal-fired units drives more gas demand for electric generation and lowers the surplus by approximately the equivalent of the loss of base-load, coal-fired capacity.

A comparison of the summer peak day gas supply results is shown in Exhibit 5-13. One case worth noting is the **Maximum Gas Demand Forecasts**, which assumes some non-fossil generation outages and low regional natural gas prices leading to high gas consumption. Under this case, the gas system surplus is under 100,000 Dth/d initially and becomes a deficit in 2014 and 2015, recovering only when AGT expands. Still the surplus thereafter is negligible and suggests a very tight gas supply situation even in summer. Under this situation, it is likely that gas prices would increase and cause a change in the overall economic dispatch, thereby reducing power sector gas demand. It also could indicate a potential arbitrage opportunity for additional LNG imports through the Northeast Gateway and Neptune projects, if LNG shipments are were available.

Exhibit 5-13. Electric Sector Surplus/Deficit Availability to Meet Summer Peak Power Demand - Repowering Case Results



5.5 Implications of Repowering Case Results

The assumption for *"At-Risk"* unit repowering further increases gas demands within the power sector beyond those within the Reference cases, thereby increasing the potential gas supply deficits. Below, ICF has compared the Reference and Higher Gas Demand cases with and without repowering. In both cases, unit repowering, which begins post-2015, further increases the winter deficits as shown below in Exhibit 5-14. Repowering also reduces the surplus in summer gas supplies by approximately 215,000 Dth/d (~900 MW) (Exhibit 5-15).

Exhibit 5-14. Impact of Repowering on Surplus/Deficit: Winter (1,000 Dth/d)

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Reference Gas Demand	(455)	(589)	(616)	(619)	(491)	(428)	(503)	(573)	(623)
Repowering vs Reference Gas Demand	(455)	(589)	(653)	(717)	(604)	(560)	(641)	(654)	(747)
Repowering Impacts	0	0	(37)	(98)	(113)	(133)	(138)	(81)	(124)
Higher Gas Demand	(461)	(603)	(577)	(654)	(543)	(500)	(597)	(706)	(773)
Repowering vs Higher Gas Demand	(461)	(603)	(704)	(778)	(668)	(645)	(744)	(757)	(817)
Repowering Impacts	0	0	(127)	(125)	(125)	(146)	(147)	(51)	(44)

Exhibit 5-15. Impact of Repowering on Surplus/Deficit: Summer (1,000 Dth/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Gas Demand	639	521	545	505	657	762	726	697	666
Repowering vs Reference Gas Demand	639	521	353	305	452	553	518	510	465
Repowering Impacts	0	0	(192)	(199)	(205)	(210)	(208)	(187)	(201)
Higher Gas Demand	495	435	430	385	548	655	620	587	555
Repowering vs Higher Gas Demand	495	435	217	172	333	440	405	389	340
Repowering Impacts	0	0	(213)	(213)	(214)	(215)	(215)	(198)	(215)

ICF has the following observations about the Repowering cases.

- The Repowering cases generally increase gas demands over their counterpart Reference and Higher gas demand cases, increasing deficits and/or reducing surpluses by between 37,000 Dth/d (~150 MW) and 215,000 Dth/d (~900 MW).
- This result suggests that the regional gas delivery system will be increasing tight on a winter peak day under the Repowering scenarios, and in need of additional gas supply capability beyond the projected capability.
- While the regional gas system is mostly able to accommodate the additional gas demands created within the Repowering cases, in the summer, surplus gas supply capability is reduced.
- Although the initial thought would be that gas demands under all the Repowering cases would be substantially increased above their counterpart Reference case values, the higher efficiencies (i.e. lower heat rates) of these repowered units/stations would be lead to these repowered units/stations being dispatched first (due to their lower “marginal” cost/bids) and thus would produce equivalent amounts of energy at lower fuel consumption rates.

6. Contingency Assessments

ISO-NE provided ICF with a set of hypothetical gas sector contingency cases to be incorporated into the analysis. These contingency cases examined the impact on gas system's surplus or deficits when either one element (N-1) or two elements (N-1-1) of the regional gas system are not available on the peak winter or peak summer days. The analysis consisted of re-estimating the surplus or deficiency after removing the (supply or transportation) capacity of a selected source of natural gas. The following contingency events were examined:

Removal of:

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Regional firm gas demand was held unchanged from the projected amounts, as applied within both the Reference and Repowering cases. In reality, some firm gas demand, particularly industrial gas demand, may be shed during such *"force majeure"* disruptions. Also, the analysis did not consider the geographic effects of disruptions where, for example, only the generating plants connected to a pipeline presumed to be unavailable within the contingency case would be affected. Also, there was no consideration of pipeline system flexibility to reconfigure flows when a single pipeline or facility was deemed unavailable.

6.1 Overview of Contingency Assessments, Considered Contingencies

As with each of the gas demand forecasts presented in Sections 4 and 5, ICF evaluated the contingency cases over the forecast period. The contingencies, i.e., loss of gas supply or transmission, were applied to all of the Reference Assessment forecasts (i.e. without Repowering). To bracket the potential outcomes, Exhibit 6-1 shows the outcomes under the Nominal Gas Demand Forecast within the Reference Assessment and Exhibit 6-3 shows the contingency outcome under the Maximum Gas Demand Forecast within the Reference Assessment. The Exhibits present a summary of the impacts of the contingency cases. To reduce the number of tables, we have provided a summary showing the average impact over the nine-year forecast, the minimum capacity available with the contingency outage (i.e., the most dire impact) and the maximum capacity available (i.e. the less dire impact).

**Exhibit 6-1. Contingency Surplus/Deficiency Analysis
2012-2020 Nominal Forecast (1,000 Dth/d)**

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Exhibit 6-2. Contingency Surplus/Deficiency Analysis
2012-2020 Maximum Forecast (1,000 Dth/d)

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6.2 Summary of Contingency Results

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7. Next Steps

In this section we discuss some next steps that may be considered for further analysis.

The major conclusion of this report is that natural gas pipeline capacity will be insufficient to satisfy gas needs at New England's power plants during the next ten years. This is based on the high level analysis put forward in this report. The analysis did not look at localized constraints that may evolve over time within New England, nor did it investigate mismatches between gas supply and demand that could result because of inconsistencies in gas and power markets. More specifically, intra-day balancing of gas supply with load has not investigated. Further analysis could focus at a more granular geographic level within New England and/or on intra-day balancing issues to further assess the adequacy of natural gas pipeline capacity.

Putting intraregional and intra-day balancing issues aside for a moment, the study results seem to suggest that the next area of focus should be on measures that could be undertaken to alleviate concerns about inadequate electric sector gas supply. Several options are obvious but each raises a number of questions and concerns. The options include:

- Expand the regional natural gas system – who would pay for this expansion? Would power generators be willing to shoulder the cost of firm capacity expansion? Can ISO-NE develop market mechanisms that permits recovery of costs associated with the gas system expansion?

- Invest in storage/LNG to "back-feed" the regional natural gas system – who would make this investment and how would the costs be recovered?

- Require gas-fired generators to have liquid back-up fuel – this also involves substantial costs and may run into air quality issues. How would these costs or permitting be addressed?

- Reconsider repowering – is there a way for the oil-fired stations to meet environmental requirements without converting to natural gas?

- Aggressively promote Demand Side Management (DSM) – would this have much of an effect on the gas capacity shortfall issue, given that DSM is already promoted across the region?

- Increase electric transmission capacity from outside the region – is there sufficient generating capacity in other regions to offset shortages from the lack of sufficient gas in New England to meet electric generation requirements? What reliability issues do these increases raise?

- Improve electric and gas coordination through alignment of the electric and gas days.

- Next steps should investigate the duration and impacts of operating through another "cold-snap" incident.

Each of these options involves costs and trade-offs that should be evaluated under a common analytical framework. The next steps outlined below suggest a research program to evaluate these questions. ICF can develop a scoping document to undertake this evaluation.

1. Estimate Social Cost of Less Available Gas Supply. As a first step in any analysis, there should be an assessment of the social costs of not meeting power demand. This would involve several steps.

- Prepare a very focused and specific analysis of the natural gas network and the potential electric sector gas shortfalls. This analysis would be more pipeline specific and would consider the loads on segments of the pipelines. It would aim at developing a more nuanced understanding of the gas supply/capacity shortfalls. The objective would be to develop a more detailed estimate of when and where shortages would occur and which power plants would be affected.

- Examine the effects of "bad behavior" on regional gas pipeline operations and estimate the costs. Bad behavior refers to situations where generators may fail to nominate or schedule gas under the pipeline rules but who will take gas in any event leading to loss of downstream pressure and causing strains on the gas system.

- These analyses should consider localized congestion and intra-day issues.

- Using standard social cost criteria employed in the electric generation industry, estimate the social cost of gas supply disruptions when this leads to loss of generating performance. This analysis would be grounded in the gas system analysis of the previous steps.

The objective of this analysis could be to quantify the social costs of disruptions to gas supply. The probabilities of different disruption scenarios could be determined to calculate an expected social cost for inadequate gas supply.

2. Identify and Evaluate Options to Address the Shortfalls Projected in this Study. This study looked at system adequacy on a single design day, but concerns have been expressed as to how often this situation could occur and how long the electric sector supply shortages would last. The options to consider include those listed above: contracting for new pipeline capacity, additional storage or LNG, adding fuel switching capability, not repowering, additional imports of power, and DSM. To properly evaluate the options requires considering the potential duration of a supply shortfall and the cost of each option. The goal of the analysis would be to find the most cost effective combination of options to ensure electric system reliability not just on a single peak day but throughout sustained periods of high electricity and gas demand.

3. Evaluate Market Mechanisms for Reconciling Options. This work would investigate the relative effectiveness and costs associated with different market mechanisms that have been employed elsewhere or could be implemented to promote solutions to the gas supply issue.

4. Identify Shortcomings in Communications and Alignment of Scheduling Protocols Between the Gas and Electric Systems and Suggest Possible Improvements. It is widely recognized that the existing gas and electric system infrastructure is not optimized because difference in the scheduling protocols for gas and electric system operations (i.e., the difference between gas

day and electric day scheduling). A better alignment of scheduling between the two systems and enhanced communications between gas and electric system operators would greatly improve the efficiency of the existing systems.

Appendix A – Power Sector Gas Demands

This appendix was prepared by the staff of ISO-NE.

A.1 Methodology

As stated within the original Scope of Work (in Appendix C), the development of the power sector natural gas demands were performed by ISO New England Inc. (ISO-NE). Using its internal production simulation program, the Inter-Regional Electric Market Model (IREMM), ISO-NE developed the natural gas demands for both the Reference and Repowering Assessments, which were then reviewed and benchmarked, and subsequently incorporated into the capacity analysis spreadsheet developed by ICF Resources. Appendix A identifies the major assumptions used within the production simulations for both the Reference and Repowering Assessments.

The development of the production simulation cases for the Reference Assessment were based on the assumptions that the supply and demand-side capacity for the short-term (2011–2015) would be the same as that that procured within the ISO's Forward Capacity Market's (FCM) - Forward Capacity Auctions (FCAs), specifically, FCA#2 through FCA#5.[43] Table A1 identified the aggregate supply and demand-side capacity (Capacity Supply Obligations (CSOs)) procured within the respective FCA. For the near-term assumption (2015-2020), ISO-NE then held the overall supply and demand-side capacity assumptions constant by continuing the use of that same capacity procured under FCA#5.[44] Table A2 identifies the aggregate supply and demand-side capacity in the near-term timeframe.

Table A1 – Short-Term Capacity Procurement (MW)

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
CSOs FCA #2 37,678	CSOs FCA #3 37,026	CSOs FCA #3 37,246	CSOs FCA #4 37,589	CSOs FCA #4 37,800	CSOs FCA #5 37,040	CSOs FCA #5 37,276

Table A2 – Near-Term Capacity Procurement (MW)

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040

[43] FCA#2 procured forward capacity for the June 1, 2011 to May 31, 2012 capability period. FCA#3 procured forward capacity for the June 1, 2012 to May 31, 2013 capability period. FCA#4 procured forward capacity for the June 1, 2013 to May 31, 2014 capability period. FCA#5 procured forward capacity for the June 1, 2014 to May 31, 2015 capability period.

[44] FCA#5 is the Forward Capacity Market (FCM) Auction procuring regional capacity for the June 1, 2014 to May 31, 2015 capability period.

The development of the Repowering Assessment was based on the same supply and demand-side capacity assumptions used within the Reference Assessment for both the short and near-term (2011–2020), with the hypothetical exception that several regional power stations would subsequently be repowered within the timeframe. The units and/or stations that were subject to this potential repowering are those that are currently subject to the ongoing environmental policies of the U.S. Environmental Protection Agency (EPA), and as such, would face pending compliance with several new air emissions and water management policies. As a preface to these repowering assumptions, these potential retirements are exemplified at the nation-wide level within the 2010 NERC Assessment entitled *"2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations."*[45] The significant findings from the 2010 NERC Special Reliability Scenario Assessment includes the ramifications of potential retirements of existing facilities due to compliance with four U.S. EPA rulemaking policies, which include:

1. Clean Water Act – Section 316(b) - Cooling Water and Wastewater
2. Clean Air Act – Utility Air Toxics Rule
3. Clean Air Act - Cross State Air Pollution Rule (CSAPR)
4. Resource Conservation & Recovery Act - Coal Combustion Residue (CCR)

Under the umbrella of ISO-NE's Strategic Planning Initiative and to specifically support this gas study scope of work, ISO-NE has develop a similar list of *"At-Risk"* regional power plants/stations that could potentially retire due to the economics related to compliance with pending environmental regulations. This ISO-NE "*At-Risk List"* identifies the potential retirements of existing coal and oil-fired facilities within New England. Within the Repowering Assessment, ISO-NE takes these potential retirements one step further by assuming that the units/stations within this *At-Risk List"* are subsequently repowered to "equivalent capacity," natural gas-fired power plants/stations. Then the ISO performed new production simulations under this Repowering Assessment, to gauge the incremental gas demands of these potentially repowered gas-fired facilities within New England. Thus the Repowering Assessment identifies the potential upper limit of future gas demand from the electric power sector, under the assumption that the majority of the new capacity within the fleet will come from the retirement of *"At-Risk"* units/stations and the subsequent repowering of these sites with new, gas-fired technologies.

[45] This report can be located at the NERC web site at: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

Figure A1 – ISO-NE "At-Risk List" of Generating Units Targeted for Repowering

FIGURE A1 HAS BEEN REDACTED TO COMPLY WITH ISO-NE INFORMATION POLICY

It should also be noted that within this repowering process, the *"At-Risk*" units/stations were theoretically repowered with new, equivalent capacity, single-cycle (unit level) or combined cycle (station level) power plants that reflect *"state-of-the-art"* gas-fired technologies with improved heat-rates for fuel to electricity conversions.[46] The ISO-NE "*At-Risk List,"* which has been classified ISO-NE Confidential, is shown in Figure A1 (above).

[46] These new generation technologies were chosen from the G.E. Electric generation web site, located at: http://www.ge-energy.com/products_and_services/industries/power_generation.jsp

A.2 Power Sector Gas Demands

Introduction

As stated within the original Scope of Work, the development of the power sector natural gas demands was performed by ISO New England Inc. Seventy-two production simulations were run to determine both the economic, upper and lower limit on the overall power sector natural gas demands. ISO-NE used its own, internal production simulation model, IREMM, to approximate the seasonal peak day fuel requirements (consumption) of all regional gas-fired and dual-fueled power generators serving both short-term and near-term winter and summer peak electrical demands.

In order to gauge both the short-term and near-term fuel requirements of New England's power sector, ISO-NE performed several production simulation dispatches, which are categorized below;

1. An Economic Dispatch under both Reference (50/50) and Extreme (90/10) electrical demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands.
2. An Upper Dispatch Limit under both Reference (50/50) and Extreme (90/10) electrical demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands using natural gas prices that were decreased from their reference projections, along with the simulated outage of a large nuclear station.
3. A Lower Limit Dispatch under both Reference (50/50) and Extreme (90/10) electrical demand forecasts. The simulation of the New England power system was economically committed and dispatched to serve regional electrical demands using natural gas prices that were increased from their reference projections, along with the simulated outage of a large nuclear station.

ISO-NE then performed and internal review of the results and findings of these production simulations in order to determine their accuracy and correctness. Upon completion of this process, ISO-NE then supplied the seasonal results of these production simulations to ICF for incorporation into their capacity analysis spreadsheet. The results included the power sector's overall natural gas requirements for both individual regional pipelines (including LNG), and aggregate fuel requirements for the total system. As noted earlier, over seventy-two production simulations were developed to *"bandwidth"* the project. The results of ISO-NE's production simulations (in aggregate fuel consumption in MMBtu/d format) are provided below for both the summer and winter peak demand periods for both the Reference and Repowering Assessments.

A.2.2 Reference Assessment Power Sector Gas Demands

A.2.2.1 Reference Assessment – Nominal Gas Demand Forecasts

Table A3 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Reference Assessment - Nominal Gas Demand Forecasts.

This assessment is representative of *"normal winter weather conditions"* on both the electric and natural gas systems, with respect to peak electrical loads resulting from normal winter weather. However, these *"normal winter weather conditions"* may not be indicative of *"Design-Day"* operations within the natural gas sector.

Table A3 - Reference Assessment – Nominal Gas Demand Forecasts

Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,536.2	**Summer 2012**	2,419.8
Winter 2012/13	1,605.3	**Summer 2013**	2,503.4
Winter 2013/14	1,582.6	**Summer 2014**	2,507.6
Winter 2014/15	1,543.7	**Summer 2015**	2,532.9
Winter 2015/16	1,546.3	**Summer 2016**	2,587.8
Winter 2016/17	1,547.7	**Summer 2017**	2,646.4
Winter 2017/18	1,548.9	**Summer 2018**	2,709.8
Winter 2018/19	1,531.0	**Summer 2019**	2,757.7
Winter 2019/20	1,504.4	**Summer 2020**	2,794.2

A.2.2.2 Reference Assessment – Reference Gas Demand Forecasts

Table A4 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Reference Assessment – Reference Gas Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector.[47]

Table A4 - Reference Assessment – Reference Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Summer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,603.0	**Summer 2012**	2,748.3
Winter 2012/13	1,682.4	**Summer 2013**	2,862.1
Winter 2013/14	1,655.4	**Summer 2014**	2,832.5
Winter 2014/15	1,600.9	**Summer 2015**	2,867.0
Winter 2015/16	1,603.5	**Summer 2016**	2,907.7
Winter 2016/17	1,619.8	**Summer 2017**	2,944.8
Winter 2017/18	1,621.8	**Summer 2018**	2,973.4
Winter 2018/19	1,616.4	**Summer 2019**	2,994.1
Winter 2019/20	1,588.2	**Summer 2020**	3,016.8

[47] This would include the use of regional peak-shaving LNG facilities to ensure gas sector LDC reliability.

A.2.2.3 Reference Assessment - Higher Gas Demand Forecasts

Table A5 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Reference Assessment - Higher Gas Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector.[48] This assessment also reflects a regionally high natural gas price,[49] with respect to the reference fuel price forecast, combined with the implications of needing additional regional, natural gas-fired capacity online to replenish the temporary (hypothetical) loss of a 1,200 MW nuclear unit within the generation fleet.

Table A5 – Reference Assessment - Higher Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Summer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,608.4	**Summer 2012**	2,892.4
Winter 2012/13	1,696.8	**Summer 2013**	2,947.7
Winter 2013/14	1,616.6	**Summer 2014**	2,947.7
Winter 2014/15	1,635.5	**Summer 2015**	2,986.9
Winter 2015/16	1,655.2	**Summer 2016**	3,017.0
Winter 2016/17	1,691.5	**Summer 2017**	3,052.3
Winter 2017/18	1,716.3	**Summer 2018**	3,079.4
Winter 2018/19	1,749.6	**Summer 2019**	3,104.8
Winter 2019/20	1,738.0	**Summer 2020**	3,127.7

[48] This would include the use of regional peak-shaving LNG facilities to ensure gas sector LDC reliability.
[49] High natural gas prices are supposed to be reflective of volatility within the region gas markets due to extreme weather, transportation basis "blow-outs", and constrained availability and deliverability of spot-market gas.

A.2.2.4 Reference Assessment - Maximum Gas Demand Forecasts

Table A6 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Reference Assessment - Maximum Gas Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector. This assessment also reflects a regionally low natural gas price, with respect to the reference fuel price forecast, combined with the implications of needing additional regional, natural gas-fired capacity online to replenish the temporary (hypothetical) loss of a 1,200 MW nuclear unit within the generation fleet.

Table A6 – Reference Assessment - Maximum Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Sumer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	2,184.9	**Summer 2012**	3,303.3
Winter 2012/13	2,152.5	**Summer 2013**	3,376.3
Winter 2013/14	2,174.7	**Summer 2014**	3,393.9
Winter 2014/15	2,202.2	**Summer 2015**	3,423.1
Winter 2015/16	2,224.6	**Summer 2016**	3,444.3
Winter 2016/17	2,243.0	**Summer 2017**	3,471.5
Winter 2017/18	2,270.3	**Summer 2018**	3,487.2
Winter 2018/19	2,301.7	**Summer 2019**	3,501.5
Winter 2019/20	2,336.2	**Summer 2020**	3,515.1

A.2.3 Repowering Assessment Power Sector Gas Demands

A.2.3.1 Repowering Assessment - Nominal Gas Demand Forecasts

Table A7 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Repowering Assessment - Nominal Gas Demand Forecasts.

In addition to identifying the incremental gas demands from the Reference Assessment, for the fleet of *"At-Risk"* units/stations that were hypothetically *"repowered,"* this assessment is also representative of *"normal winter weather conditions"* on both the electric and natural gas systems, with respect to peak electrical loads resulting from normal winter weather. However, these *"normal winter weather conditions"* may not be indicative of *"Design-Day"* operations within the natural gas sector.

Table A7 - Repowering Assessment - Nominal Gas Demand Forecasts

Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,536.2	Summer 2012	2,419.7
Winter 2012/13	1,605.4	Summer 2013	2,503.4
Winter 2013/14	1,606.4	Summer 2014	2,672.4
Winter 2014/15	1,621.4	Summer 2015	2,716.2
Winter 2015/16	1,635.2	Summer 2016	2,778.5
Winter 2016/17	1,662.4	Summer 2017	2,832.2
Winter 2017/18	1,675.4	Summer 2018	2,900.4
Winter 2018/19	1,602.7	Summer 2019	2,792.5
Winter 2019/20	1,615.3	Summer 2020	2,828.1

A.2.3.2 Repowering Assessment - Reference Gas Demand Forecasts

Table A8 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Repowering Assessment - Reference Gas Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector.

Table A8 – Repowering Assessment - Reference Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Summer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,603.0	**Summer 2012**	2,748.1
Winter 2012/13	1,682.6	**Summer 2013**	2,862.1
Winter 2013/14	1,692.4	**Summer 2014**	3,024.9
Winter 2014/15	1,699.2	**Summer 2015**	3,066.4
Winter 2015/16	1,716.1	**Summer 2016**	3,113.0
Winter 2016/17	1,752.5	**Summer 2017**	3,154.4
Winter 2017/18	1,760.1	**Summer 2018**	3,181.0
Winter 2018/19	1,697.0	**Summer 2019**	3,181.6
Winter 2019/20	1,712.4	**Summer 2020**	3,217.7

A.2.3.3 Repowering Assessment - Higher Gas Demand Forecasts

Table A9 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Repowering Assessment - Higher Gas Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector. This assessment also reflects a regionally high natural gas price, with respect to the reference fuel price forecast, combined with the implications of needing additional regional, natural gas-fired capacity online to replenish the temporary (hypothetical) loss of a 1,200 MW nuclear unit within the generation fleet.

Table A9 – Repowering Assessment - Higher Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Summer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	1,608.4	Summer 2012	2,892.0
Winter 2012/13	1,696.8	Summer 2013	2,947.7
Winter 2013/14	1,743.5	Summer 2014	3,160.8
Winter 2014/15	1,760.0	Summer 2015	3,200.0
Winter 2015/16	1,780.0	Summer 2016	3,231.3
Winter 2016/17	1,837.2	Summer 2017	3,266.9
Winter 2017/18	1,862.9	Summer 2018	3,294.6
Winter 2018/19	1,800.8	Summer 2019	3,302.8
Winter 2019/20	1,782.3	Summer 2020	3,342.7

A.2.3.4 Repowering Assessment - Maximum Gas Demand Forecast

Table A10 reflects the aggregate fuel consumption (in MMBtu/d format) by all gas-fired and dual fuel generators within the region, under the Repowering Assessment - Maximum Demand Forecasts.

This assessment is representative of peak conditions on both the electric and natural gas systems, with respect to peak electrical loads resulting from extremely cold and windy winter weather. These extreme winter weather conditions also reflect indicative *"Design-Day"* operations within the natural gas sector. This assessment also reflects a regionally low natural gas price, with respect to the reference fuel price forecast, combined with the implications of needing additional regional, natural gas-fired capacity online to replenish the temporary (hypothetical) loss of a 1,200 MW nuclear unit within the generation fleet.

Table A10 – Repowering Assessment - Maximum Gas Demand Forecasts

Winter Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)	Sumer Peak Demand Period	Total Power Sector Gas Demand (MMBtu/d)
Winter 2011/12	2,184.8	Summer 2012	3,302.9
Winter 2012/13	2,152.3	Summer 2013	3,376.2
Winter 2013/14	2,129.0	Summer 2014	3,496.4
Winter 2014/15	2,150.2	Summer 2015	3,531.8
Winter 2015/16	2,172.0	Summer 2016	3,558.4
Winter 2016/17	2,182.7	Summer 2017	3,591.4
Winter 2017/18	2,209.0	Summer 2018	3,615.5
Winter 2018/19	2,041.0	Summer 2019	3,598.4
Winter 2019/20	2,061.6	Summer 2020	3,628.3

A.3 Additional Assumptions, Caveats, and Observations

A.3.1 Accounting for Operating Reserves

Although the IREMM production simulation model dispatches its available capacity resources to satisfy hourly electrical demands, it does so in a way that does not specifically account for electric system operating reserves (both spinning and non-spinning reserves).[50] Therefore ISO-NE imputes that to satisfy the modeling and the potential invocation and delivery of operating reserves, and the fuel required to deliver and sustain such reserves in the event that they were called upon to replenish the occurrence of a first contingency (N-1) event on New England's bulk electric system, ISO-NE will assume that a *"fuel reserve margin"* of 200,000 MMBtu/d is needed above and beyond the specific power sector fuel requirements developed from the IREMM production simulation modeling. This 200,000 MMBtu/d *"fuel reserve margin"* was developed using the assumption that this was the daily amount of fuel needed to continuously deliver approximately 1,200 MW of gas-fired reserves to the power system at an approximate heat rate of ~7,000 Btu/KWh.

This *"fuel reserve margin"* serves as a placeholder to represent the amount of additional fuel required to be delivered (over a 24 hour period) from the subsequent invocation of operating reserves in order to replenish the resultant energy loss from sustaining a first contingency event (i.e. the hypothetical loss of a 1,200 MW class nuclear unit within the regional generation fleet). Implementation of this assumption would then restore the post-contingency state of the power system to an equilibrium state, as the Control Room Operators re-dispatched the power system to prepare for the next potential (second) contingency (N-1-1) on the system.

In relation to implementing this *"fuel reserve margin"* concept into the gas study analysis, the *"fuel reserve margin"* was held constant at 200,000 MMBtu/d for all cases within this gas study project.

A.3.2 Power Sector Caveats

In developing the production simulations for the ISO-NE gas study, ISO-NE should note the following caveats with respect to the limitations of the overall modeling process. These are due to variations in input assumption sets and the resultant disclaimers on ISO-NE's development of power sector gas demands:

1. Overall power sector natural gas demands reflect peak (winter/summer) daily gas consumption for the twenty-four hour Electric Day, which begins and ends at midnight, and is referred to in hour ending format (i.e., HE01 to HE 24).

[50] In New England, a typical daily operating reserve requirement may be 2,000 MW, which represents 100% first largest contingency (~1,200 MW and deliverable within 10 minutes) and 50% of the second largest contingency (~800 MW and deliverable within 30 minutes). In addition, at least 50% of the first contingency coverage must be in the form of spinning reserves (~600 MW) and the remaining first contingency coverage (~600 MW) may be offline be must be deliverable within 10 minutes. The second contingency coverage (30 minute reserves) can also be a combination of both spinning and non-spinning reserves, with the spinning portion being that which may be online and available for delivery after satisfying the first contingency (10 minute reserve) requirement, which is typically based on the reserve unit(s) response rates (in MW per minute times 30 minutes), and any additional offline capacity that is available for delivery within the 30 minute timeframe.

2. Since only daily gas demands were assessed, the ability to observe and critique the seasonal peak hour of delivery within both the electric and gas sectors is not provided. However, this may be one of the possible *"Next-Steps"* within the sequence of the Strategic Planning Initiative.

3. Since the Gas Day in New England is from 10:00 AM to 10:00 AM and because the power sector gas demands were developed in Electric Day format, the misalignment between the Electric and Gas Days should be noted. It must also be noted that the power sector gas demands were not converted into an equivalent Gas Day gas demands, and thus the scheduling of natural gas through the pipeline nomination/confirmation process may impact the actual fuel deliveries required by the power sector.

4. The IREMM production simulations resulted in the generation of approximately seventy-two seasonal results.

5. The IREMM production simulations produced aggregate power sector natural gas demands (by pipeline) for New England. These simulations also produced fuel demands from the Mystic 8 & 9 power block (located in Everett, MA), which reflects direct vaporization of LNG from the Distrigas Terminal. These gas demands were subsequently included within the overall gas demands for the power sector.

6. The IREMM production simulation modeling:
    a. Does not reflect the start-up time necessary or the minimum up/minimum down time requirements of older fossil-steam units.
    b. Only reflects major transmission constraints within the New England system and only those within neighboring systems, which impact imports and exports to the New England system.
    c. Although IREMM dispatches its capacity resources to satisfy hourly electrical demands, it does not do so in a way that would specifically account for electric system operating reserves.
    d. Does not automatically account for seasonal fuel price volatility.

Appendix B – Assumptions for Developing Power Sector Gas Demands

B.1. Demand Forecast:

All the power sector demand forecasts were obtained from the ISO-NE Report entitled *"Forecast Report of Capacity, Energy, Load and Transmission (CELT)"* dated April 2011.[51]

Table B1. Demand Forecasts, Short-Term and Near-Term

2011 CELT - Short-Term Forecast: Reference 50/50 Peak Electrical Demand Forecast (MW)

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
22,255	28,095	22,365	28,525	22,510	28,970	22,630

2011 CELT - Short-Term Forecast: Extreme 90/10 Peak Electrical Demand Forecast (MW)

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
22,935	30,290	23,050	30,765	23,190	31,250	23,310

2001 CELT - Near-Term Forecast: Reference 50/50 Peak Electrical Demand Forecast (MW)

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
29,380	22,750	29,775	22,875	30,155	23,000	30,525	23,120	30,875	23,240	31,215

2011 CELT - Near-Term Forecast: Extreme 90/10 Peak Electrical Demand Forecast (MW)

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
31,705	23,435	32,135	23,555	32,555	23,680	32,955	23,800	33,335	23,925	33,700

B.2 Supply-Side Assumptions

Supply and Demand-Side Resources

The development of the production simulation cases were based on the assumptions that the supply and demand-side capacity for the short-term (2011–2015) would be the same as that that procured within the ISO's Forward Capacity Auctions, specifically, FCA#2 through FCA#5.[52] For the near-term assumption (2015-2020), ISO-NE then held the overall supply and demand-side capacity assumptions constant by continuing the use of that same capacity procured under FCA#5.[53]

[51] The CELT Report is located at: http://www.iso-ne.com/trans/celt/report/index.html

[52] FCA#2 procured forward capacity for the June 1, 2011 to May 31, 2012 capability period. FCA#3 procured forward capacity for the June 1, 2012 to May 31, 2013 capability period. FCA#4 procured forward capacity for the June 1, 2013 to May 31, 2014 capability period. FCA#5 procured forward capacity for the June 1, 2014 to May 31, 2015 capability period.

[53] FCA#5 is the Forward Capacity Market (FCM) Auction procuring regional capacity for the June 1, 2014 to May 31, 2015 capability period.

Table B2. Capacity Supply Obligation

Short-Term Forecast: Capacity Supply Obligations (MW)

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
CSOs FCA #2 37,678	CSOs FCA #3 37,026	CSOs FCA #3 37,246	CSOs FCA #4 37,589	CSOs FCA #4 37,800	CSOs FCA #5 37,040	CSOs FCA #5 37,276

Near-Term Forecast: Capacity Supply Obligations (MW)

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040	CSOs FCA #5 37,276	CSOs FCA #5 37,040

Capacity Additions

The development of the production simulation cases were based on the assumptions that the capacity additions for the short-term (2011–2015) would be the same as that that procured within the ISO's Forward Capacity Auctions, specifically, FCA#2 through FCA#5. For the near-term assumption (2015-2020), ISO-NE then held the overall capacity addition assumptions constant by continuing the use of that same capacity procured under FCA#5.

Table B3. Capacity Addition Forecast

Short-Term Forecast: Capacity Addition Assumptions

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
CSOs FCA #2	CSOs FCA #3	CSOs FCA #3	CSOs FCA #4	CSOs FCA #4	CSOs FCA #5	CSOs FCA #5

Near-Term Forecast: Capacity Addition Assumptions

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5

Capacity Attrition

Salem Harbor Units 1 & 2 are assumed to be retired by the Winter 2011/12 and Salem Harbor Units 3 & 4 are assumed to be retired by the Summer of 2015.

Imports and Exports

The development of the production simulation cases were based on the assumptions that the capacity purchases and sales for the short-term (2011–2015) would be the same as that that procured within the ISO's Forward Capacity Auctions, specifically, FCA#2 through FCA#5. For the near-term assumption (2015-2020), ISO-NE then held the overall capacity purchases and sales assumptions constant by continuing the use of that same capacity procured under FCA#5.

Table B4. Imports & Exports Forecast

Short-Term Forecast: Imports & Exports

Winter 2011/12	Summer 2012	Winter 2012/13	Summer 2013	Winter 2013/14	Summer 2014	Winter 2014/15
CSOs FCA #2	CSOs FCA #3	CSOs FCA #3	CSOs FCA #4	CSOs FCA #4	CSOs FCA #5	CSOs FCA #5

Near-Term Forecast: Imports & Exports

Summer 2015	Winter 2015/16	Summer 2016	Winter 2016/17	Summer 2017	Winter 2017/18	Summer 2018	Winter 2018/19	Summer 2019	Winter 2019/20	Summer 2020
CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5	CSOs FCA #5

Generating Resource Availability

For both the winter and summer peak demand periods, the generating resource availability is assumed to be equivalent to the 5-year rolling average availability factor.

B.3. Demand-Side Assumptions

Demand Response

Please note the amounts of demand response have already been included within the Capacity Supply Obligation values as noted in Table B2 and Table B3 above.

Demand Resource Availability

For both the winter and summer peak demand periods, the demand resource availability is assumed to be 100% during both the winter and summer peak demand day.

Appendix C – Original Scope of Work Document

Scope-of-Work

This Document Contains Both ISO-NE Confidential and Critical Energy Infrastructure Information
Not for Public Dissemination

RFP # 11-24

Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs

ISO New England Inc.
System Planning
May 20, 2011
Rev 3

Scope-of-Work

This Document Contains Both ISO-NE Confidential and Critical Energy Infrastructure Information

Not for Public Dissemination

Table of Contents

Contents

Scope-of-Work

This Document Contains Both ISO-NE Confidential and Critical Energy Infrastructure Information
Not for Public Dissemination

1 Objectives

ISO New England Inc. (ISO-NE) has determined that the objectives of this Scope of Work can be categorized into three, inter-related natural gas assessments. At an overview level, these three assessments include a Reference Assessment, a Repowering Assessment, and a Contingency Assessment which in detail include:

1) With respect to satisfying regional fuel requirements, determine whether New England's gas-fired, electric fleet is seasonally deficient or surplus, within both the *Short-Term*[54] and *Near-Term*[55] timeframes, based on the existing regional gas sector infrastructure and any probable gas sector enhancements that are projected to be placed in service only within the *Short-Term* timeframe. This is referred to as the Reference Assessment.

2) This Section is classified as *"ISO-NE Confidential" and Requires a Confidentiality Agreement:"* With respect to satisfying regional fuel requirements, determine whether New England's gas-fired, electric fleet is seasonally deficient or surplus, only within the *Near-Term* timeframe, based on increased fuel requirements from the potential repowering of marginal oil, coal and nuclear facilities to equivalent capacity natural gas facilities. This is referred to as the Repowering Assessment. The results and findings of this Repowering Assessment shall be classified as *ISO-NE Confidential,* and as such, the unit specific details shall be excluded from the Final Public Domain Report.

3) This Section is classified as "*Critical Energy Infrastructure Information (CEII):*"
A Contingency Assessment will be developed to gauge the potential impacts on both *Short-Term* and *Near-Term* regional gas supply or transportation capacity resulting from hypothetical contingencies occurring within the regional gas sector. These hypothetical contingencies were developed to identify the resultant capacity/supply impacts from an N-1 and N-2 contingency scenario(s) possibly occurring within the regional gas sector. The results and findings of this Contingency Assessment shall be classified as *Critical Energy Infrastructure Information*, and as such, shall be excluded from the Final Public Domain Report.

2 Consultant's Option

It is assumed that this assessment should be deterministic in nature and should not require the development of hydraulic pipeline modeling, using either steady-state or transient analysis. In order to satisfy the three Objectives, the Consultant can follow the proposed methodology as identified herein, or the Consultant may propose a different methodology that will subsequently accomplish the same three Objectives while ensuring the same level of accuracy of results. If the Consultant proposes a new methodology that is dissimilar to the one proposed within this Scope of Work, they must present that new methodology to ISO-NE for review and obtain ISO-NE approval, prior to any work being performed.

[54] *Short-Term* timeframe includes the winter of 2011/2012 through the winter of 2014/15 (i.e. FCM Window).
[55] *Near-Term* timeframe includes the summer of 2015 through the summer of 2020 (i.e. Long-Lead Time Window).

3 Objective of the Reference and Repowering Assessments

To assess the total amount of natural gas pipeline transportation capacity available to serve the regional gas-fired electric generation sector during two specific time frames; the *Short-Term* (i.e. winter of 2011/2012 through winter 2014/15) and the *Near-Term* (i.e. summer 2015 through summer 2020).

4 Proposed Methodology for the Reference and Repowering Assessments

These assessments could be performed by aggregating the total amount of existing natural gas pipeline transportation capacity into the New England region, while accounting for other in-region supply or demand-side sources,[56] and then subtracting out the aggregate amount of capacity required to serve all firm design-day[57] LDC demands (i.e. the core gas market), while accounting for all other firm demands, including those of large, non-interruptible commercial or industrial loads or those of firm contracted power generators. Sensitivity to regional LDC gas demands from temperatures that differ from winter peak design-day demands should also be considered.

Any remaining amount of regional pipeline capacity not required to serve the aggregate regional demand of all firm customers could then be assumed to be available to serve the demands of regional gas-fired electric generation. This amount of (surplus) pipeline capacity, if any, could then be converted into a fuel quantity, to gauge the amount (and location) of gas-fired electric generation that could utilize this surplus pipeline capacity to serve winter and summer peak electrical demands.

5 Reference Assessment: Assess New England's Gas Pipeline Capacity to Satisfy Both Short-Term and Near-Term Electric Generation Needs

5.1 Timeframe

Perform this Reference Assessment for both the *Short-Term* (winter of 2011/2012 through winter 2014/15) and the *Near-Term* (summer 2015 through summer 2020) timeframes.

5.2 Scope of Work

5.2.1 This Item (5.2.1) will be performed by ISO New England Inc.

[56] These in-region natural gas supply and demand-side sources include: the combined supply-side effects from vaporization from regional satellite, peak shaving LNG and LPG facilities as well as the effects from demand-side measures such as contractually-interruptible gas sector demands and/or other measureable and verifiable gas sector demand-side reductions.

[57] Quantify the impacts of temperature on natural gas availability for New England's electric power sector. While the natural gas capacity analysis is based on "winter peak design-day" conditions, actual regional temperatures may be higher or lower and the sensitivity of these values would provide valuable information about the remaining supply of natural gas for electric generation during those time periods.

Note: Within this portion of the Reference Assessment, ISO-NE will identify all the supply & demand-side electrical assumptions within both the *Short-Term* and *Near-Term* timeframes.

To determine both the economic and upper limit on the overall electric sector natural gas demands, ISO-NE will use its own production simulation models to approximate the seasonal peak day fuel requirements (consumption) of all regional gas-fired[58] power generators serving both *Short-Term* and *Near-Term* winter and summer (seasonal) peak electrical demands and operating reserves. ISO-NE will perform two separate dispatches; 1) An *Economic Dispatch:* the New England power system will be economically committed and dispatched to serve regional demands and operating reserves in order to gauge the *Economic Dispatch Limit* on both *Short-Term* and *Near-Term* fuel requirements, and 2) An *Upper Dispatch Limit*: All regional gas-fired generation will be committed and dispatched to their seasonal claimed, full-load capability in order to gauge the *Upper Dispatch Limit* on both *Short-Term* and *Near-Term* fuel requirements. ISO-NE will then supply the seasonal results of these production simulations for the *Economic Dispatch Limit* and *Upper Dispatch Limit* to support this assessment. The results will include:

a. Unit specific peak day fuel requirements.
b. Aggregate fuel requirements by ISO-NE load zones and total system.
c. Aggregate fuel requirements by regional pipeline / LDC.
d. Sensitivities to winter and summer peak design-day fuel requirements for both 50/50 and 90/10 electrical demands will also be considered.

Note: The remaining items within this section, Items 5.2.2 through 5.2.5, will be performed by the Consultant.

5.2.2 Assess the total amount of natural gas pipeline (firm) capacity into New England. Identify all regional pipeline capacity by contract owner (i.e. gas LDC, Fuel Manager, Portfolio Manager, Power Generator, Industrial or Commercial Customer, Gas Supplier, LNG Supplier, etc). Summarize the pipeline capacity into the region for the following interstate natural gas pipelines:[59]

a. Algonquin Gas Transmission (AGT).
b. Granite State Gas Transmission (GSGT) Pipeline[60]
c. Iroquois Gas Transmission System (IGTS).
d. Maritimes & Northeast Pipeline (M&N).
e. Tennessee Gas Pipeline (TGP).

[58] Gas-fired facilities include both single-fuel, gas-only power stations as well as those with dual fuel capability, burning either oil, gas, or some combination of both.

[59] Within the Reference and Repowering Assessments, assume that there is ample natural gas supplies beyond New England's border to ensure that all regional pipeline capacity can be packed full of supply to ensure delivery of volumes at certified-firm pipeline capacity. Within the Contingency Assessment, assume the same assumptions (as above) while taking into account the resultant impacts from the specific gas sector contingency being analyzed.

[60] Although the Granite State Gas Transmission (GSGT) Pipeline is classified as an interstate pipeline, it does not cross the New England border. GSGT pipeline relies on gas receipts from both the Tennessee Gas Pipeline (TGP) and the Joint Facility System of the Portland Natural Gas Transmission System (PNGTS) and the Maritimes & Northeast (M&N) Pipeline.

f. Portland Natural Gas Transmission System (PNGTS).
g. Any intrastate pipeline capacity that may contribute to regional interstate capacity (with respect to being able to serve existing (or newly repowered) electric generation demands).[7]

5.2.2.1 Identify and incorporate the following into the overall gas pipeline capacity calculation (5.2.2 above):

i. Existing regional pipeline constraints that could limit the deliverability of gas supply into and throughout New England.
ii. Existing regional pipeline interconnections that could increase the delivery of gas supply into and throughout New England.
iii. Assess the capacity benefits/detriments from regional intrastate interconnections.

5.2.2.2 Identify and incorporate the following into the overall gas pipeline capacity calculation (5.2.2 above):

i. For the *Short-Term* timeframe, incorporate all probable pipeline(s) and/or pipeline project(s) or other gas sector physical enhancements, which would result in increased regional pipeline capacity. This portion of the assessment should employ "E*ngineering Judgment*" to identify and incorporate only the "*probable winning projects*" from the overall list of proposed gas sector project(s) that may be competing for the same or similar market share (i.e. parallel projects).
ii. For the *Near-Term* timeframe, do not include any probable/proposed pipeline(s) and/or pipeline project(s) or other regional gas sector enhancements. Roll the resultant infrastructure assumptions from 5.2.2.2.i above into this timeframe.

5.2.3 Assess the contributions from regional gas sector supply and demand-side resources. Incorporate the direct and potential benefits to regional gas sector pipeline capacity (5.2.2 above) from:

a. Impacts of regional LDC satellite LNG & LPG storage facilities.[61]
b. Distrigas LNG (Serving LDCs, TGP, AGT and Mystic Station).
c. Canaport LNG (Serving the M&N Pipeline, via the Brunswick Pipeline)
d. Potential contributions from Northeast Gateway (via Hubline).
e. Potential contributions from Neptune LNG (via Hubline).

[61] As referenced within the Northeast Gas Association's 2010 Statistical Guide, there are approximately 45 LNG and/or LPG tanks in five (5) New England states, with a total storage capacity ~ 16.2 Bcf and a corresponding vaporization capacity ~ 1.36 Bcf/d.

f. Potential contributions from demand-side effects, including contractually-interruptible gas sector demands and/or other measureable/verifiable demand-side reductions.

5.2.4 Using both *Short-Term* and *Near-Term* forecasts from the regional gas LDCs,[62] determine the winter and summer peak (design-day) gas demands of all regional gas LDCs.[63] A list of the regional gas LDCs is provided in Appendix 1. Aggregate the total coincident winter peak design-day gas demands from all New England gas LDCs and all other firm demands. Aggregate the total coincident summer peak gas demands from all New England gas LDCs and all other firm demands. Provide sensitivities to winter and summer peak design-day natural gas demands for New England's gas LDCs and other firm demands.

5.2.4.1 Aggregate the total coincident winter and aggregate the total coincident summer peak gas demands from all the New England gas-fired power generators with firm natural gas transportation contracts.

5.2.4.2 Aggregate the total coincident winter and aggregate the total coincident summer peak gas demands from all other major non-interruptible demand sources, which may include, but is not to limited to; 1) large commercial demands, 2) large industrial demands, 3) pipeline/LDC fuel and losses, and 4) other firm demands.

5.2.4.3 Aggregate the total coincident winter and aggregate the total coincident summer peak gas demands from all in-region demands identified in Items 1.2.4 through 1.2.4.2 (above).

5.2.5 Subtract New England's aggregate coincident winter and aggregate coincident summer peak gas demand, identified in Item 5.2.4.3, from the aggregate seasonal transportation capacity, identified in Items 5.2.2 & 5.2.3. The remaining (seasonal surplus) pipeline capacity, if any, may assumed to be allocated to other non-firm demands, including regional gas-fired power generators. Identify excess pipeline capacity by season, and if possible, by pipeline and region/location.

5.2.5.1 Identify any surplus or deficiency in aggregate regional capacity to serve aggregate firm regional demands.

[62] *Short-Term* gas LDC forecasts should be obtained from their respective state DPUCs. *Near-Term* gas LDC forecasts may require an extrapolation from the (DPUC approved) *Short-Term* forecasts.

[63] The regional gas LDC demands should only include the peak design-day gas demands from core natural gas markets (i.e. residential, commercial and industrial customers only) and should not include any demands from gas-fired electric generation located behind the LDC citygate(s).

5.2.5.2 If it is determined (from item 5.2.5.1 above) that there is excess or surplus regional capacity to serve regional demand, use "generic" heat rate information as a representative for portions of New England's gas-fired generation fleet (base load versus peaking capacity), to estimate the amount of winter and summer peak day gas-fired capacity available for peak day operation.

6 Repowering Assessment: Assess New England's Gas Pipeline Capacity to Satisfy Only Near-Term Electric generation Needs Using a Revised Set of Electric Sector Resource Assumptions

6.1 Classified ISO-NE Confidential

This entire Repowering Assessment shall be classified as *ISO-NE Confidential* (Requiring a Confidentiality Agreement), and as such, the unit specific results and finding shall be excluded from the Final Public Domain Report.

6.2 Timeframe

For only the *Near-Term* (i.e. summer 2015 through summer 2020) timeframe, perform this Repowering Assessment.

6.3 Introduction

This Repowering Assessment was developed to gauge the potential for incremental *Near-Term* regional gas demands resulting from the potential retirements and repowering (with natural gas) of those regional (nuclear, coal and oil-fired) power plants faced with complying with pending federal and/or state environmental air and water policies. These incremental natural gas demands from the newly repowered gas-fired facilities would then be added to that of the existing fleet of units in order to gauge the potential Maximum Upper Limit on *Near-Term* fuel requirements for New England's electric power sector.

These reliability concerns, stemming from the economics of environmental compliance, are exemplified at the nation-wide level within the 2010 NERC Assessment entitled *"2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations."*[64] The significant findings from the *2010 NERC Special Reliability Scenario Assessment* includes the ramifications of potential retirements of existing facilities due to compliance with four U.S. Environmental Protection Agency (EPA) rulemaking policies, which include:

[64] The 2010 NERC Special Reliability Scenario Assessment Report is located at: http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

1. Clean Water Act – Section 316(b) - Cooling Water and Wastewater
2. Clean Air Act – Utility Air Toxics Rule
3. Clean Air Act - Clean Air Transport Rule (CATR)
4. Resource Conservation & Recovery Act - Coal Combustion Residue (CCR)

Under the process of its Strategic Planning Initiative, ISO-NE has develop a similar list of *"At-Risk"* regional power plants/stations that could potentially retire due to the economics related to compliance with pending environmental regulations. This *"ISO-NE At-Risk List"* identifies the potential retirements of existing (nuclear, coal and oil-fired) facilities within New England. Within this Repowering Assessment, this *"ISO-NE At-Risk List"* is to be used to identify all of the marginal nuclear, coal and oil-fired facilities in order to gauge their potential conversion to equivalent capacity, repowered natural gas-fired power plants. These new repowered, gas-fired facilities will subsequently add incremental gas demands to those of the existing fleet of gas-fired facilities within New England. The *"ISO-NE At-Risk List,"* which has been classified ISO-NE Confidential, is contained in Appendix 2 of this Scope of Work.

6.4 Scope of Work

Note: All the items within this section, Items 2.4 through 2.4.6, will be performed by the Consultant.

6.4.1 Using the results and findings from the aforementioned Reference Assessment (Items 5.0 – 5.2.5.2), the Consultant shall update ISO-NE's electric sector resource assumptions to include the units identified as retiring within the *ISO-NE At-Risk List* and then those same units/stations being subsequently repowered:

6.4.1.1 Conversion of all marginal oil-fired power plants to equivalent capacity, repowered natural gas-fired power plants. Identify the seasonal capacity (MW) amount(s) of these marginal oil-fired power plants and their proximity to a regional natural gas supply source.

6.4.1.2 Conversion of all marginal coal-fired power plants to equivalent capacity, repowered natural gas-fired power plants. Identify the seasonal capacity (MW) amount(s) of these marginal coal-fired power plants and their proximity to a regional natural gas supply source.

6.4.1.3 Conversion of all marginal nuclear power plants to equivalent capacity, repowered natural gas-fired power plants. Identify the seasonal capacity (MW) amount(s) of these marginal nuclear power plants and their proximity to a regional natural gas supply source. [65]

[65] Marginal oil-fired, coal-fired, and nuclear power plants are envisioned to be those power stations where the economics of complying with pending (air and water) environmental mandates are projected to be uneconomic over the projected life cycle of the facility. These power stations are thought to be ideal candidates for gas-fired repowering since "minimal" switchyard and transmission work should be required to accommodate an equivalent capacity conversion.

6.4.2 For Items 6.4.1.1 through 6.4.1.3 above, identify the seasonal capacity (MW) amount(s) of this repowered gas-fired capacity, along with its assumed technology type and corresponding seasonal peak day fuel requirements.

6.4.3 Add the incremental fuel requirements from the newly repowered marginal oil-fired power plants to that of the existing fleet of gas-fired units within New England and perform the Reference Assessment (Items 5.0 – 5.2.5.2) again, for only the *Near-Term* timeframe.

6.4.4 Add the incremental fuel requirements from the newly repowered marginal coal-fired power plants to that of the existing fleet of gas-fired units within New England and perform the Reference Assessment (Items 5.0 – 5.2.5.2) again, for only the *Near-Term* timeframe.

6.4.5 Add the incremental fuel requirements from the newly repowered nuclear power plants to that of the existing fleet of gas-fired units within New England and perform the Reference Assessment (Items 5.0 – 5.2.5.2) again, for only the *Near-Term* timeframe.

6.4.6 Add the incremental fuel requirements from all of the newly repowered oil, coal, and nuclear power plants (Items 6.4.3, 6.4.4 and 6.4.5 above) to that of the existing fleet of gas-fired units within New England and perform the Reference Assessment (Items 5.0 – 5.2.5.2) again, for only the *Near-Term* timeframe.

7 Contingency Assessment: Assess New England's Gas Pipeline Capacity to Satisfy Both *Short-Term* and *Near-Term* Electric Generation Needs Under Hypothetical Gas Sector Contingencies

7.1 Classified Critical Energy Infrastructure Information (CEII):

This entire Contingency Assessment shall be classified as CEII, and as such, the results and finding shall be excluded from the Final Public Domain Report.

7.2 Timeframe

Perform this Contingency Assessment for both the *Short-Term* (winter of 2011/2012 through winter 2014/15) and the *Near-Term* (summer 2015 through summer 2020) timeframes.

7.3 Introduction

This Contingency Assessment will be developed to gauge the potential impacts on both *Short-Term* and *Near-Term* regional gas demands resulting from hypothetical contingencies occurring within the regional gas sector. These hypothetical contingencies have been developed to identify the resultant pipeline capacity/supply impacts from a hypothetical N-1 and N-2 contingency scenario possibly occurring within the regional gas sector.

7.4 Scope of Work

Note: All the items within this section, Items 3.1 through 3.4.2, will be performed by the Consultant.

7.4.1 Using the results and findings from the aforementioned Reference Assessment (Items 5.0 – 5.2.5.2) and Repowering Assessment (Items 6.3 – 6.3.6), the Consultant shall then update the regional gas sector assumptions to include the hypothetical regional gas sector contingencies as identified below:

7.4.1.1 ***REDACTED DUE TO CEII INFORMATION***

7.4.1.2 ***REDACTED DUE TO CEII INFORMATION***

7.4.1.3 ***REDACTED DUE TO CEII INFORMATION***

7.4.2 Determine the capacity/supply impacts resulting from each of these gas sector contingencies as identified above (7.4.1.1 through 7.4.1.3) from the aggregate seasonal transportation capacity (Section 1.0, Item 1.2.5) and perform the Reference Assessment (Items 5.0 – 5.2.5.2) and Repowering Assessment (Items 6.4 – 6.4.6) again.

8 Consultant's Deliverables

8.1 Draft Report and Presentation to ISO-NE

No later than September 1, 2011, the Consultant shall deliver a *Draft Report* and *Draft Supplementary Presentation* to ISO-NE for preliminary review and comment. ISO-NE shall review and comment on the Consultant's *Draft Report* and *Draft Supplementary Presentation*. In addition, ISO-NE and the Consultant will work together to identify those sections of the *Draft Report* and *Draft Supplementary Presentation* that are deemed classified as either *ISO-NE Confidential* or *Critical Energy Infrastructure Information*. ISO-NE shall review and return all comments to the Consultant by September 15, 2011. The Consultant shall make best efforts to incorporate all of ISO-NE's comments and suggestions, or provide an explanation of why the specific ISO-NE comments were not incorporated.

8.2 Final Report and Presentation to ISO-NE

No later than September 30, 2011, the Consultant shall deliver the following to ISO-NE:

8.2.1 A *Final Confidential Report* and *Final Confidential Supplementary Presentation*.

8.2.2 A *Final Public Domain Report* and *Final Public Domain Supplementary Presentation*, in which both have been "redacted" from the *Final Confidential Report* and *Final Confidential Supplementary Presentation* to eliminate all *ISO-NE Confidential* and *Critical Energy Infrastructure Information*.

8.3 Presentation of Results and Findings to ISO-NE Senior Staff

At a time that is mutually agreeable to both ISO-NE Senior Staff and the Consultant, the Consultant shall deliver a presentation to ISO-NE Senior Staff on the results and findings of this Assessment.

8.4 Presentation of Results and Findings to ISO-NE Board of Directors

At a time that is mutually agreeable to both ISO-NE's Board of Directors (SPARC) and the Consultant, the Consultant shall deliver a presentation to ISO-NE's Board of Directors on the results and findings of this Assessment.

8.5 Presentation of Results and Findings to Regional Stakeholders

At a time that is mutually agreeable to both the Planning Advisory Committee (PAC) and the Consultant, the Consultant shall deliver a presentation to the PAC on the results and findings of this Assessment.

8.6 Additional Consultant Support Time

In addition to satisfying all the Deliverable requirements, the Consultant shall provide both administrative and technical support on all aspects of this Assessment to ISO-NE for up to an additional 25 staff hours after this Assessment has been completed.

9 Revision History

Rev 0 – Initial Release – May 13, 2011

Rev 1 – Revised to re-classify the Granite State Gas Transmission (GSGTS) Pipeline from an intrastate pipeline to an interstate pipeline, with footnote clarifications. (Section 1.2.2.b) – May 16, 2011.

Rev 2 – Revised to add as Appendix 2, the ISO-NE Repowering Assessment (Section 2.0) "ISO-NE At-Risk List" of potential retirements of regional power stations. – May 17, 2011.

Rev 3 – Revised to add Granite State Gas Transmission Pipeline to Section 3 – Contingency Assessment and clarify in-region Contingencies – May 20, 2011.

10 Appendix 1 – List of New England Gas LDCs

Note that this list may not include all of New England's natural gas local distribution companies

a. Bangor Gas Company
b. Bath Electric, Gas & Water System
c. The Berkshire Gas Company
d. Blackstone Gas Company
e. Columbia Gas of Massachusetts
f. Connecticut Natural Gas Corporation
g. Holyoke Gas & Electric
h. Maine Natural Gas
i. Middleboro Gas & Electric
j. National Grid
k. New England Gas Company
l. New Hampshire Gas Company
m. Norwich Public Utilities
n. NSTAR Gas
o. The Southern Connecticut Gas Company
p. Unitil (Fitchburg Gas and Electric & Northern Utilities, Inc.)
q. Vermont Gas Systems
r. Wakefield Municipal Gas & Light
s. Westfield Gas & Electric
t. Yankee Gas Services Company
u. Other New England natural gas LDCs not mentioned above.

11 Appendix 2 – Repowering Assessment's *"ISO-NE At-Risk List"*

Classified ISO-NE Confidential

Within Section 2.0 (Repowering Assessment) of this Scope of Work, the *"ISO-NE At-Risk List"* is to be used to identify all of the regional, marginal facilities in order to gauge their potential conversion to equivalent capacity, repowered natural gas-fired power plants. These new repowered, gas-fired facilities will subsequently add incremental gas demands to those of the existing fleet of gas-fired facilities within New England.

This Repowering Assessment's *"ISO-NE At-Risk List"* shall be classified as *ISO-NE Confidential* (Requiring a Confidentiality Agreement), and as such, shall be omitted from dissemination within the public domain. In addition, the specific units within the *"ISO-NE At-Risk List"* and the unit specific results and finding of the Repowering Assessment shall be excluded from the Final Public Domain Report.

ISO-NE "AT-RISK" LIST HAS BEEN REDACTED
TO COMPLY WITH ISO-NE INFORMATION POLICY

{ End of Scope of Work }