Massachusetts Low Gas Demand Analysis: Final Report

RFR-ENE-2015-012

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1. Executive Summary

New England's natural gas infrastructure has become increasingly stressed during peak winter periods as regional demand for natural gas has grown. This situation has led to gas supply and transmission deficits into the region for the gas-fired electric generators during those winter months. Insufficient natural gas capacity for the electric sector has contributed to high wholesale gas prices to generators and thus high electricity prices. Furthermore, as non-gas generators retire and gas generators replace them, the New England electric system is becoming more dependent on natural gas generators. Governor Patrick directed the Department of Energy Resources (DOER) to determine whether or not new natural gas pipeline infrastructure is needed in the Commonwealth.

DOER retained Synapse Energy Economics (Synapse) to utilize current forecasts of natural gas and electric power under a range of scenarios, taking into consideration environmental, reliability and cost answering two key questions:

- What is the current demand for and capacity to supply natural gas in Massachusetts?
- If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

Eight scenarios (listed in Table ES-1) were evaluated from an economic and reliability perspective and were then assessed for compliance with the Massachusetts Global Warming Solutions Act (GWSA) targets.[1]

Table ES-1. Scenario key

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case Reference NG Price No Canadian Transmission	Base Case Low NG Price No Canadian Transmission	Base Case High NG Price No Canadian Transmission	Base Case Reference NG Price 2,400-MW Canadian Transmission	Low Demand Case Reference NG Price No Canadian Transmission	Low Demand Case Low NG Price No Canadian Transmission	Low Demand Case High NG Price No Canadian Transmission	Low Demand Case Reference NG Price 2,400-MW Canadian Transmission

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

From 2015 through 2019, electric generators have insufficient supply of natural gas, which results in spiking natural gas prices. Scarcity-driven high natural gas prices will force economic curtailment of

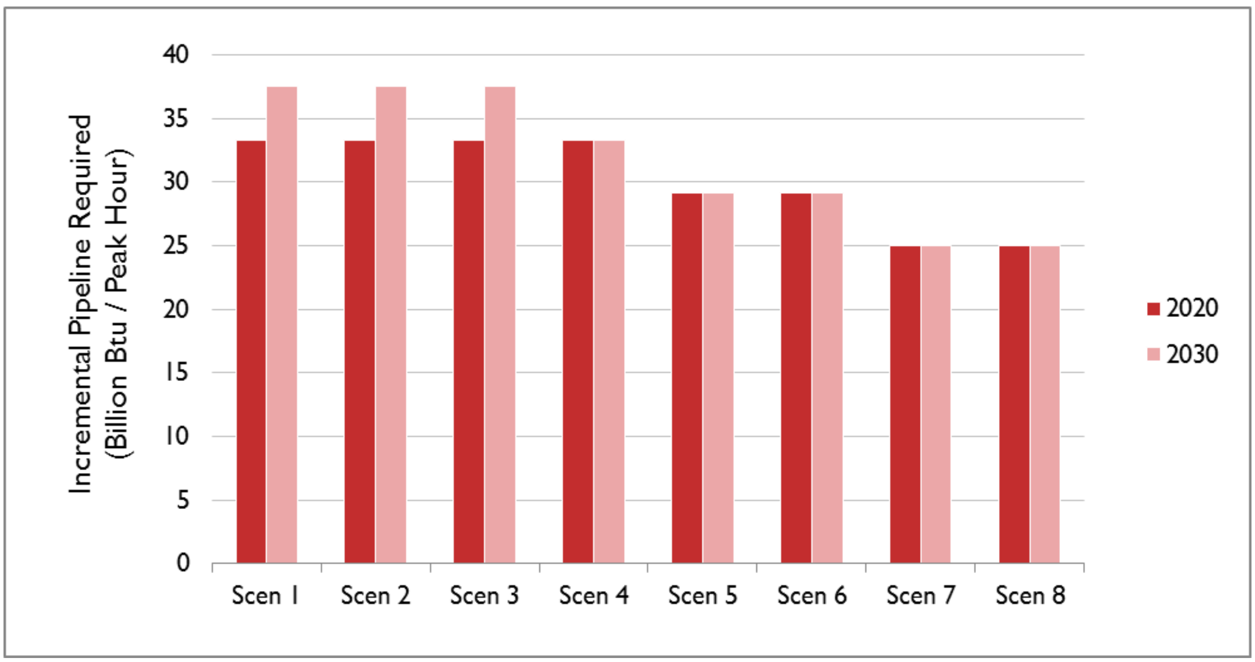
[1] Global Warming Solutions Act (GWSA), Chapter 298 of the Acts of 2008 as codified in M.G.L. Chapter 21N Climate Protection and Green Economy Act

natural gas-fired generators in favor of oil-fired units. The combination of increased oil utilization for electricity generation together with the use of emergency measures such as demand response and the ISO-NE Winter Reliability program (through January 2018) will allow electric demand to be met. From 2020 to 2030, existing and planned capacity plus incremental pipeline capacity balances system requirements.

Critical to this result is the assumption that winter peak hour gas shortages cannot be addressed using known measures (e.g. demand response or the addition of new natural gas pipeline) in years 2015 through 2019 and, as a result, gas prices are expected to reflect an out-of-balance market in those years. The electric sector responds to these high prices by shifting dispatch from gas to oil generation in the peak hour, reducing reliance on natural gas. In years 2020 through 2030, in contrast, winter peak hour gas shortages can be met using known measures (incremental pipeline) and, as a result, gas prices are expected to reflect an in-balance market in those years. The electric sector no longer has a price signal to shift dispatch away from gas generation in the peak hour, greatly increasing gas requirements and reducing reliance on oil in comparison to the previous period.

The amount of pipeline required differs based on scenario assumptions (see Figure ES-1). Year 2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 billion cubic feet (Bcf) per day to 0.8 Bcf per day).[2] Year 2030 pipeline additions range from 25 billion Btu per peak hour to 38 billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day).

Figure ES-1. Massachusetts gas capacity shortage during winter peak hour by scenario, 2020 and 2030



[2] Billion Btu can be converted to Bcf by multiplying billion Btu by 24 hours per day then dividing by 1,022 Btu per cubic foot.

Figure ES-2 compares Massachusetts natural gas capacity to the natural gas demand in the winter peak hour in three scenarios selected to highlight the progression of reducing gas shortages from a scenario with existing policies only, to the addition of technically and economically feasible alternative resources (i.e. renewable energy and energy efficiency measures), to the addition (inclusive of alternative measures) of new transmission from Canada:

- **Scenario 1: Base Case** is the base case with reference natural gas price and no incremental Canadian transmission,
- **Scenario 5: Low Demand** is the low energy demand case with reference natural gas price and no incremental Canadian transmission, and
- **Scenario 8: Low Demand + Incremental Canadian Transmission** is the low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission.

In all scenarios electric sector gas use increases between 2019 and 2020 as gas pipeline constraints are reduced, price spikes become less frequent, resulting in lower gas prices. Lower gas prices reduce economic curtailment of gas-fired units and increase gas use while reducing reliance on oil-fired units and oil use.

Figure ES-2. Comparison of Massachusetts gas capacity and demand for selected scenarios in winter peak hour

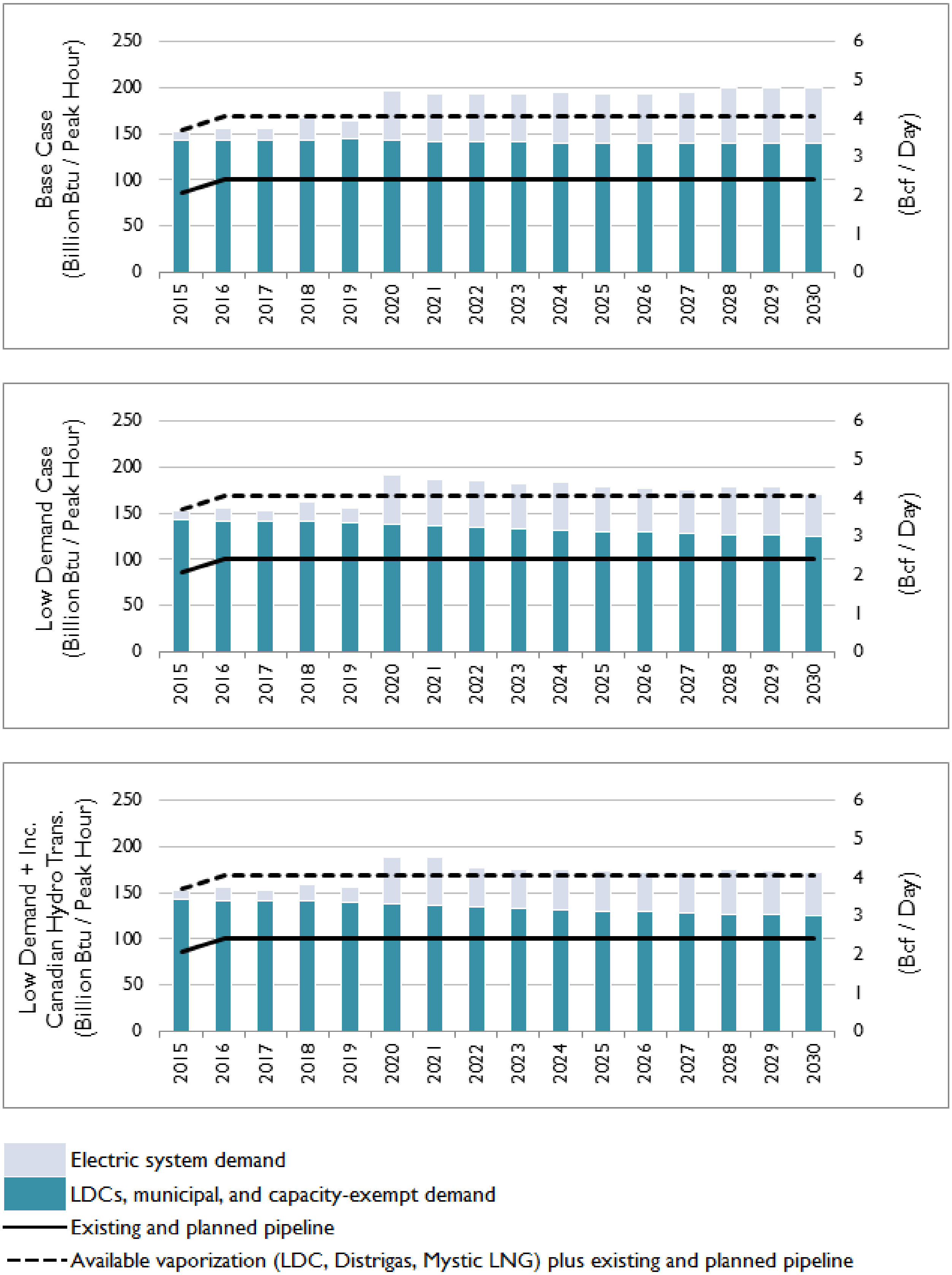
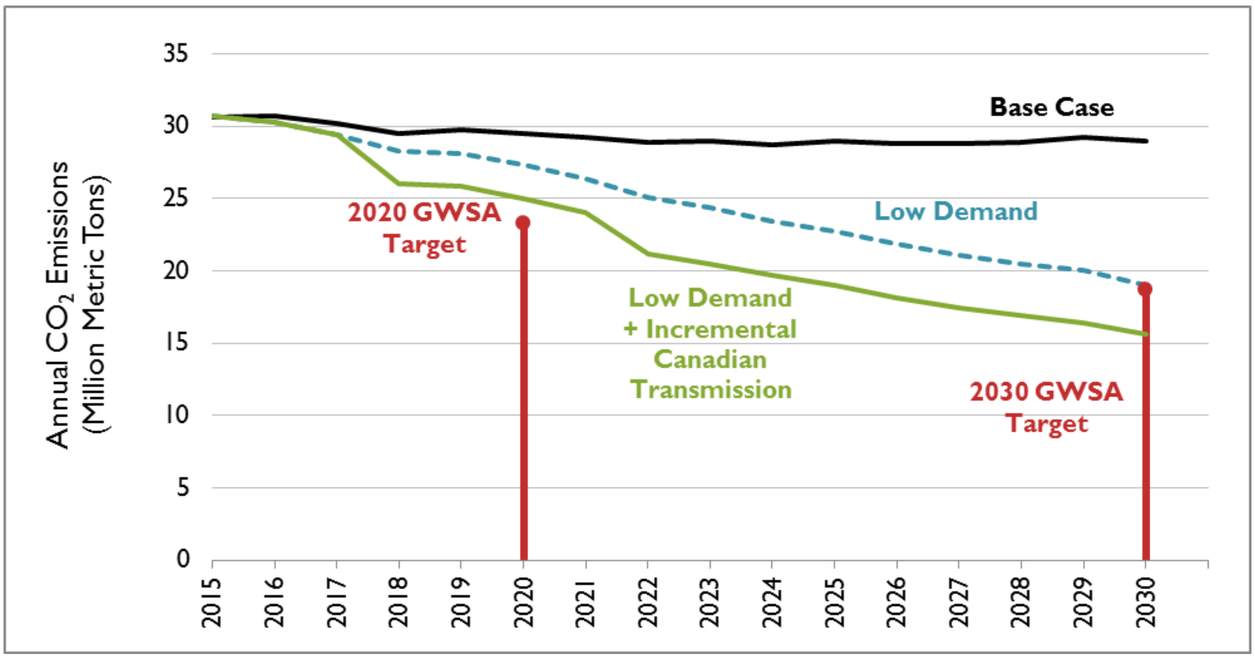


Figure ES-3 compares the projected emissions of Scenarios 1, 5 and 8 through 2030 with GWSA targets for the heating gas and electric sectors (refer to Section 4.3 for explanation of how targets are derived). The gas heating and electric sectors "2020 GWSA Target" depicted below would allow the GWSA 2020 emissions limit to be met, taking into account expected emissions from other sectors. While no scenario meets the GWSA targets for the heating gas and electric sectors in 2020, Scenario 8 (low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission), shown below, and Scenario 7 (low energy demand case with high natural gas price and no incremental Canadian transmission) meet the target in 2030. Scenario 5 (low energy demand with reference natural gas price and no incremental Canadian transmission) exceeds the 2030 GWSA target by 0.4 million metric tons or 1 percent of the 2030 statewide emission target.

The 2020 emission level for Scenario 8 shows an approximately 1.6 million metric ton CO_2 gap from the target (25.0 million metric ton CO_2 compared with the target of 23.3 million metric tons). The December 2013 *GWSA 5-Year Progress Report* also identified a potential shortfall in greenhouse gas reductions by 2020 for the buildings—including energy efficiency—and the electric generation sectors.

Figure ES-3. Massachusetts GWSA compliance in heating gas and electric sector for selected scenarios



The difference in each scenario's costs from that of Scenario 1 (base case with reference natural gas price and no incremental Canadian transmission) is shown for Scenario 5 (low demand case with reference natural gas price and no incremental Canadian transmission) and Scenario 8 (low demand case with reference natural gas price and 2,400-MW incremental Canadian transmission) in Figure ES-4. Scenario 5 costs exceed those of Scenario 1 by less than $100 million in each year through 2020 and less than $200 million each year thereafter. In Scenario 8, the addition of new Canadian transmission in 2018 reduces overall costs in comparison to the low demand case without new transmission (Scenario 5) in 2018 and 2019 because of the large reduction in electric system costs provided by new transmission in those years. Starting in 2020, the Scenario 8 costs exceed those of Scenario 5 as more alternative resources are introduced.

Figure ES-4. Massachusetts difference in cost between Scenario 1 (Base Case) and selected scenarios

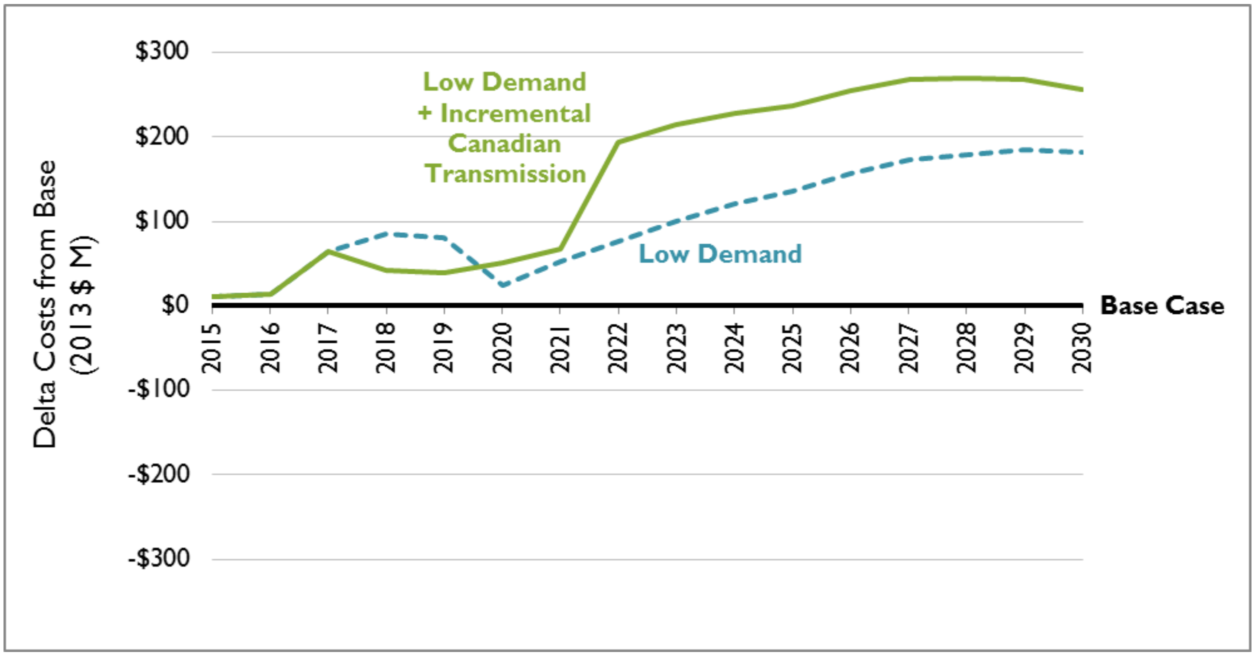


Table ES-2 reports the difference in each scenario's costs from that of Scenario 1 in net present value terms over the study period (2015 to 2030), along with the pipeline required by 2030. The addition of technically and economically feasible alternative measures (Scenario 5) adds $1,433 million in costs (i.e. capital, maintenance, fuel) to Scenario 1, while the addition of both these alternative measures and a 2,400-MW incremental Canadian transmission (Scenario 8) adds $2,157 million in costs to Scenario 1. Note that in the low natural gas price sensitivity, Massachusetts costs fall in comparison to scenarios run with the reference gas price. While Scenario 2 (base case, low gas price sensitivity, no incremental Canadian transmission) has $8.6 billion in cost savings compared to Scenario 1, Scenario 6 (low demand case, low gas price sensitivity, no incremental Canadian transmission) has $0.3 billion in added costs compared to Scenario 1. This difference in costs is due to the costs of implementing the low demand measures included in Scenario 6.

Table ES-2. Massachusetts difference in cost from Scenario 1 in net present value (million $), 2015 to 2030 compared to 2030 pipeline requirements

	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 5	Scen. 6	Scen. 7	Scen. 8
NPV ($ M)	$0	-$8,611	$5,384	$840	$1,433	$389	$15,112	$2,157
2030 Pipeline (Bcf/day)	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.6

This study's results are sensitive to numerous assumptions made in our analysis. These assumptions have been caveated throughout the following report and include important assumptions regarding multiple topics, laid out in detail in the following report. Any interpretations of this study's results should make full consideration of all specified caveats.

2. INTRODUCTION

2.1. Purpose

The Massachusetts Department of Energy Resources (DOER) retained Synapse Energy Economics (Synapse) to determine, given updated supply and demand information, whether or not new natural gas pipeline infrastructure is required in the Commonwealth taking into consideration environmental issues, reliability, and costs.[3] Key questions for consideration included:

- What is the current demand for and capacity to supply natural gas in Massachusetts?
- If all technologically and economically feasible alternative energy resources are utilized, is any additional natural gas infrastructure needed, and if so, how much?

Caveats to model scope

Caveats are included in each of the following sections to summarize issues not included in this modeling study. Any interpretations of this study's results should make full consideration of all specified caveats.

- The scope of this study was restricted to expected Massachusetts natural gas demand and capacity only. We did not examine gas constraints in the wider region, nor did we examine the effect of expected gas demand or capacity constraints outside of the Commonwealth.
- The scope of this study was restricted to scenarios in which Massachusetts natural gas capacity constraints were resolved. We did not construct a scenario based on the assumption that incremental pipeline would not be an option.
- The scope of this study was to investigate the need for a new pipeline. We assumed neither that new pipeline and corresponding natural gas usage were necessary, nor that new pipeline and corresponding natural gas were unnecessary.
- The study determines whether or not each scenario modeled is or is not compliant with Massachusetts Global Warming Solutions Act (GWSA) compliant. We did not assume that Massachusetts would be in compliance with GWSA.
- The study examines the sensitivity of model results to changes in the price of natural gas and the addition of 2,400 MW of incremental Canadian transmission. Potential sensitivities of interest not modeled include: the availability in the winter peak hour of existing coal, nuclear, or other potentially at-risk generation; the combined sensitivity to a low or high gas price and the addition of incremental Canadian transmission; and

[3] RFR-ENE-2015-012

incremental Canadian resources assumed to be dedicated transmission of hydroelectric generation or any other resource.

- The study examined the period of 2015 through 2030. Although new natural gas infrastructure is not available until 2020, we analyzed years 2015 through 2019 as these years have changes to the natural gas system including reduced natural gas demand as a result of energy efficiency measures, and changes to the electric system as a result of generating unit retirements, energy efficiency measures, and alternative measures. The inclusion of these years permits more thorough analysis of differences among the scenarios.

2.2. Intent

This report presents information intended to inform state energy decision-makers as they develop and implement policies and actions with regards to Massachusetts' energy infrastructure. The information in this report can also assist state energy officials in addressing ISO-New England (ISO-NE) market rule changes that can enable increasing levels of alternative resources and demand response.

2.3. Analysis

This study considers a range of solutions to address Massachusetts' short- and long-term needs, taking into account system reliability, economic costs, and greenhouse gas reductions. All scenarios are evaluated from an economic and reliability perspective and are then assessed for compliance with GWSA. Our analysis was conducted in four steps:

1) Development of a base case and sensitivity assumptions
2) Feasibility study of alternative resources in a low energy demand case
3) Scenario modeling of eight scenario and sensitivity combinations
4) Assessment of natural gas capacity to demand balance in a winter peak event

2.4. Stakeholder Process

DOER, with the facilitation leadership of Raab Associates, hosted a stakeholder input process to solicit varied points of view and ensure that the list of solutions and metrics for evaluation were informed by stakeholder input. This process included three public stakeholder meetings held on October 15, October 30 and December 18, 2014. Prior to each meeting, Synapse posted meeting materials to a website for stakeholder review.[4] DOER made public high level summaries and encouraged stakeholders to submit written comments and suggestions, which were considered at all stages of the study process.

[4] http://synapse-energy.com/project/massachusetts-low-demand-analysis

2.5. Report Outline

Section 3 provides an overview of the model methodology and model design for this analysis of the Massachusetts gas sector from 2015 to 2030. It first describes the base case and low demand case, with the sensitivities associated with each scenario. It outlines the key outputs of the model runs: 1) sufficiency of gas pipeline capacity under winter peak event conditions, and 2) annual costs and emissions. This section then gives an overview of the feasibility analysis for the low energy demand case that is modeled as the base case with the addition of the maximum amount of technologically and economically feasible alternative demand and supply-side resources.

Section 4 presents model results for all eight scenarios and sensitivity combinations. It displays the difference between natural gas capacity and natural gas demand during a winter peak event in each scenario and sensitivity for each modeled year. Each scenario's annual costs compared to the base case are reported. This section also depicts total emissions from the Massachusetts' natural gas heating and electric sectors in 2020 and 2030 for each scenario compared to 2020 and 2030 GWSA targets for the buildings and electric sectors.

Section 5 describes our observations regarding these modeling results. Some of these observations include the sensitivity of winter peak hour requirements to gas prices, the impact of incremental Canadian transmission, and impacts of alternative measures to reduce Massachusetts' gas demands.

Caveats are discussed in each section of the report to summarize issues not included in this modeling study. Any interpretations of this study's results should make full consideration of all specified caveats.

Six appendices present detailed modeling assumptions and results:

- Appendix A presents the feasibility analysis for the low energy demand case;
- Appendix B presents assumptions used in modeling the base case;
- Appendix C presents assumptions used in modeling the low energy demand case;
- Appendix D presents assumptions regarding the sensitivity analysis of changes in the price of natural gas;
- Appendix E presents assumptions regarding the sensitivity analysis of the addition of incremental electric transmission from Canada; and
- Appendix F presents detailed tables of the model results.

3. Model Overview

Synapse analyzed eight future scenario-and-sensitivity combinations of the Massachusetts gas sector from 2015 through 2030. We modeled two future scenarios:

1) A **base case** representing existing policies in place, and
2) A **low energy demand case** in which the maximum feasible amount of additional alternative resources are utilized.

In addition, we tested each of these scenarios for their sensitivity to changes in the price of natural gas and the addition of 2,400 MW of incremental Canadian transmission as follows:

- Base case
    - No incremental Canadian transmission
        - Reference natural gas prices (Scenario 1)
        - Low natural gas prices (Scenario 2)
        - High natural gas prices (Scenario 3)
    - 2,400-MW incremental Canadian transmission
        - Reference natural gas prices (Scenario 4)
- Low energy demand case
    - No incremental Canadian transmission
        - Reference natural gas prices (Scenario 5)
        - Low natural gas prices (Scenario 6)
        - High natural gas prices (Scenario 7)
    - 2,400-MW incremental Canadian transmission
        - Reference natural gas prices (Scenario 8)

From this model we established the difference between natural gas capacity and natural gas demand during a winter peak event in each scenario and sensitivity for each modeled year, 2015 through 2030, and investigate the availability of additional measures to relieve shortage conditions.

Our analysis provides the following key outputs:

- **Sufficiency of Massachusetts' gas pipeline capacity under winter peak event conditions:** We modeled Massachusetts gas supply and demand under conditions defined by a winter peak event (as described in Section 3.2), taking account of the impact on energy storage of a "cold snap" or series of winter peak days.

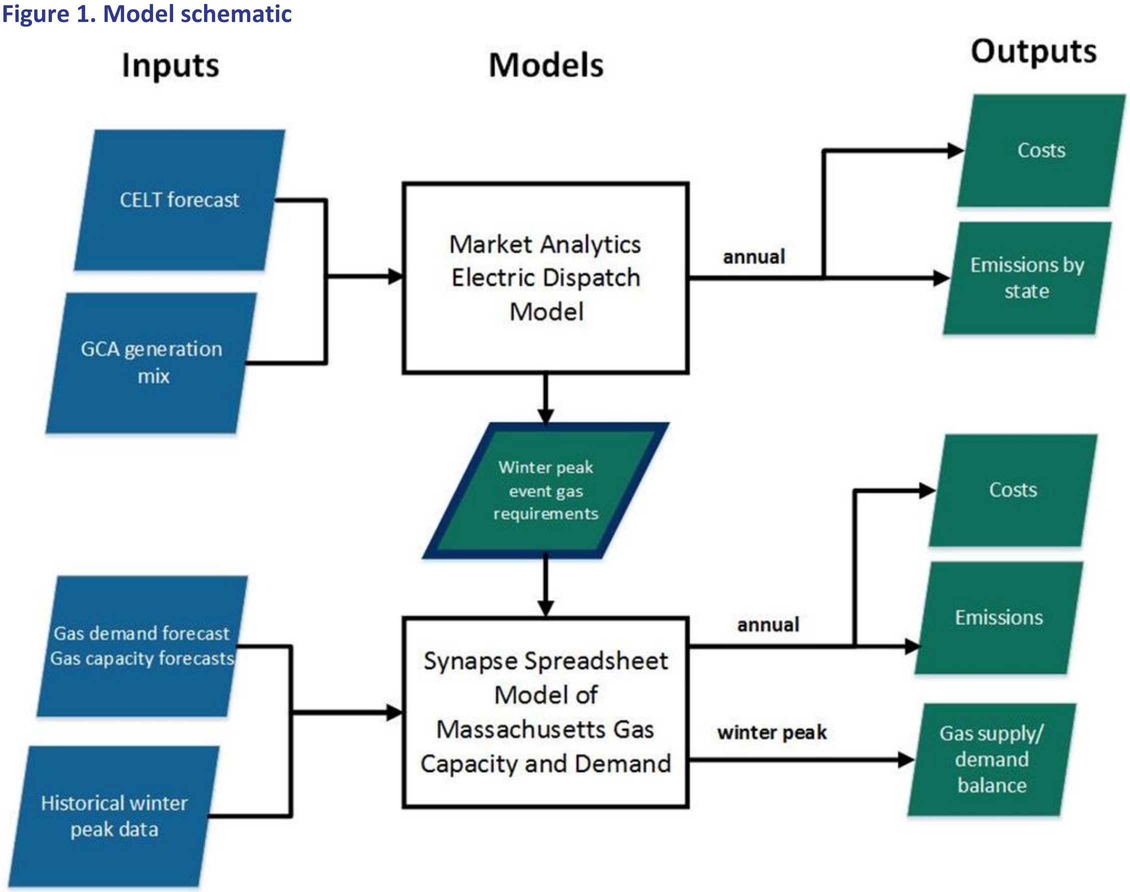
- **Annual costs and emissions:** We modeled fuel use, electric generation, variable and levelized capital energy costs, and greenhouse gas emissions on an annual basis. Annual costs and emissions were modeled based on expected (most likely) weather conditions, not extreme conditions. These expected weather conditions included the occurrence of winter high demand events. We then determined if additional pipeline capacity is needed to meet demand.

Reliability requirements were a basic criterion for all modeled scenarios.

3.1. Model Design

Model design for this analysis included Ventyx's Market Analytics electric dispatch model and a Synapse purpose-built spreadsheet model of Massachusetts gas capacity and demand (see Figure 1).

Figure 1. Model schematic



Note: "CELT" is the 2014 forecast of energy and load demand by ISO-New England and "GCA" is the Massachusetts Green Communities Act, per Synapse's 2014 analysis.

Electric-sector greenhouse gas emissions and cost modeling in Market Analytics

Synapse projected greenhouse gas emissions, electric system gas use, and wholesale energy prices using Ventyx's Market Analytics electric-sector simulation model of ISO-NE including its imports and exports. Market Analytics uses the PROSYM simulation engine to produce detailed results for hourly electricity prices and market operations based on a security-constrained chronological dispatch model. The PROSYM simulation engine optimizes unit commitment and dispatch options based on highly detailed information on generating units. This modeling includes detailed runs designed to estimate electric-sector gas requirements during the winter event peak hour. Although New England and regions exporting electricity to New England are modeled to portray economic dispatch of resources as accurately as possible, only generators located in Massachusetts' gas requirements, emissions and costs are considered in final model results.

A Synapse purpose-built model of Massachusetts natural gas capacity and demand

We developed a dynamic spreadsheet model of natural gas needs for an indicative winter peak event in Massachusetts, with annual analysis extending out to 2030. This model facilitates assessment of the balance of New England's gas capacity and demand under winter peak event conditions. Development of this model included Massachusetts-specific analysis of historical stress and shortage gas supply conditions, historical winter peak event conditions, and diversity and reliability of supply.

Gas requirements as defined in the model represent demand from residential, commercial, industrial, and electric-generation sectors in Massachusetts only:

- Local distribution companies (LDCs – local gas providers)
- Municipal light and gas companies (munis)
- Capacity exempt customers (customers that purchase gas supplies from third-party suppliers and are not required to take and pay for pipeline capacity that LDCs have under contract)
- Gas energy efficiency measures
- Gas reduction measures: Time varying rates, demand response, ISO-NE's Winter Reliability program, advanced building costs, renewable thermal policies, and in low energy demand case, various demand- and supply-side measures were included.
- Gas-fired electric generators located in Massachusetts.

Gas capacity as defined in the model represents existing and planned pipeline capacity, liquefied natural gas (LNG) storage and vaporization, and incremental pipeline capacity as needed to meet gas sector demand by scenario and year:

- Existing pipeline capacity: Algonquin Gas Transmission Company (AGT), Maritimes/Northeast Pipeline Company (M&NP); Tennessee Gas Pipeline Company (TGP)

- Planned pipeline capacity: Algonquin Incremental Market (AIM) pipeline capacity, which is an expansion of the AGT line, expected to be complete in 2017
- LDC's LNG storage and vaporization: National Grid (NGrid), Columbia, NSTAR, Liberty, Fitchburg Gas and Electric, Berkshire Gas, Holyoke, Middleboro
- Full GDF Suez LNG vaporization in Everett, MA with an allocation for Mystic electric generation plant
- Incremental pipeline capacity

The model assumes that the existing and planned pipeline and LNG vaporization capacity defined above (including the GDF Suez capacity and Canaport/M&NE Pipeline) is fully utilized to meet demand during the winter peak event and identifies if and when incremental capacity is needed. Incremental capacity is specified as pipeline capacity but it can also be supplied by additional LNG. The feasibility and cost of incremental LNG facilities are highly dependent on factors and conditions present at specific locations. Such an analysis was beyond the scope of this study. If additional LNG imports through the GDF Suez, Neptune, Excelerate or Canaport facilities are economical, the delivery of those supplies into the Massachusetts distribution system during the winter peak event would be limited by the capacity defined above. Similarly, new LNG facilities will require both additional storage and liquefaction capability to insure reliability comparable to that of a pipeline, which in most instances will drive its cost well above the cost of a new pipeline. However, we assume that market and economic factors will drive decisions as to the most feasible and cost-effective means for meeting natural gas demand.

In addition to modeling winter peak event conditions, Synapse's spreadsheet model estimates state and regional annual greenhouse gas emissions and costs related to Massachusetts' natural gas use. This gas-sector emissions and cost analysis includes expected displacement of other fossil fuels (coal and oil) where applicable. While gas forecasting is typically conducted in terms of a November-October year, our analysis was conducted in calendar years to facilitate comparisons with greenhouse gas emission reduction targets. To convert gas demand for November-October years into calendar years, we allocated split year demand into calendar year demand based on the ratio of each month's expected gas consumption using the updated monthly forecast data provided by NGrid.

3.2. Winter Peak Event

Massachusetts' gas demand is at its greatest during a very cold winter day. Our analysis of the sufficiency of Massachusetts natural gas capacity was conducted through the lens of a "winter peak event"—a series of particularly cold winter days under which high gas demands have the greatest potential to exceed gas capacity. For the purposes of this analysis, a winter peak event was defined as follows:

- Capacity and demand in the peak hour of an expected future "design day". Design days are used in gas LDCs' forecasts of future natural gas demand and are determined by calculating the effective degree days (a measure of expected heating demand) expected to occur under a specified probability (from once in 30 years to once in 50 years depending on the LDC).

- Gas requirements for electric generation were developed in Market Analytics to represent the coincident peak with LDCs' design day (the electric peak that coincides with the gas demand peak): for each year, the highest gas requirement for a January day from 6 to 7pm.[5]

- LDCs' five-year design day forecasts were applied to the January of the split year (e.g. 2015/16) and remain unadjusted from their most recent filing as provided to DOER.[6] For those years not provided by the companies, the average annual load growth rate for the given forecasted years was used to extrapolate the design day and annual forecasts out through 2019. From 2020 through 2030 design day and annual gas demand was projected using a 0.5-percent annual growth rate per DOER projections.[7]

- Sufficiency of natural gas capacity took into account the effects of a cold snap. Each Massachusetts LDC defines cold snaps differently using a series of the coldest days ranging from 10 to 24 days; the Commonwealth's two largest LDCs use ten and 14 days. For the purposes of this analysis, we will define a cold snap as a series of 12 cold weather days, with the design day occurring on the 12th day of the cold snap. In this model the length of the cold snap impacts the amount of LNG in storage facilities and the resulting rate of deliverable natural gas from storage.

Caveats to winter peak event

- This study examines the difference between Massachusetts' gas demand and capacity in an illustrative winter peak event hour. We did not analyze gas constraints in a specific historical or expected future hour.

3.3. Scenarios and Sensitivities

Synapse modeled a base and a low energy demand case of the following possible Massachusetts gas and electric systems (see Table 1). Both cases assume that there is no incremental transmission from Canada to New England and a reference natural gas price. In addition, we investigated model results' sensitivity to changes in the price of natural gas and to the addition of 2,400-MW in new transmission capacity from Canada to the New England hub.

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[5] Eastern Interconnection Planning Collaborative (EIPC) *Draft Gas-Electric Interface Study Target 2 Report*, p.64-65.

[6] We used the latest Department of Public Utilities filings for all LDCs except NGrid and Columbia, which provided DOER with updated design day forecasts.

[7] According to background papers to the CECP, DOER assumed a 0.5-percent annual growth rate for Massachusetts gas demand after 2020. See Exhibit EAS-13 to MA DPU 14-86.

Table 1. Scenarios and sensitivities

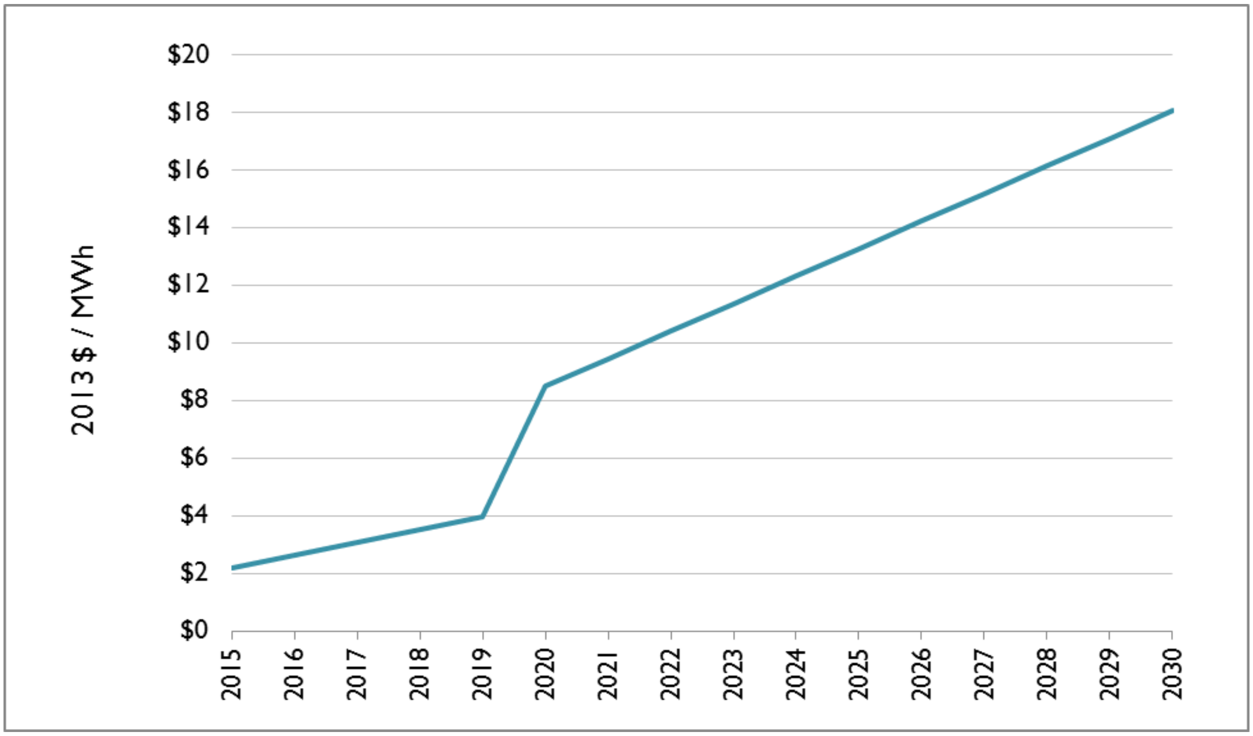
	No Incremental Canadian Transmission			2,400-MW Incremental
	Reference NG Price	**Low NG Price**	**High NG Price**	**Reference NG Price**
Base Case	*Base Case *Ref NG Price *No Canadian Transmission (Scenario 1)	*Base Case *Low NG Price *No Canadian Transmission (Scenario 2)	*Base Case *High NG Price *No Canadian Transmission (Scenario 3)	*Base Case *Ref NG Price *2,400-MW Canadian Transmission (Scenario 4)
Low Energy Demand Case	*Low Case *Ref NG Price *No Canadian Transmission (Scenario 5)	*Low Case *Low NG Price *No Canadian Transmission (Scenario 6)	*Low Case *High NG Price *No Canadian Transmission (Scenario 7)	*Low Case *Ref NG Price *2,400-MW Canadian Transmission (Scenario 8)

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

All scenarios and sensitivities include the carbon price forecast assumption used in the *Avoided Energy Supply Costs in New England: 2013 Report* (AESC 2013) for the electricity sector.[8] As depicted in Figure 2, RGGI prices extend to 2019; the Synapse "mid" CO_2 price forecast is used in AESC 2013 for 2020 and beyond.

[8] Hornby et al. 2013. Exhibit 4-1. Column 6 "Synapse" CO_2 emission allowance price.

Figure 2. AESC 2013 CO_2 price forecast



Base case

The base case is defined as the energy resource mix and forecasted energy demand expected under existing policy measures, using a reference natural gas price (see discussion under the "natural gas price sensitivity" subsection later in this section), and the assumption that there will be no incremental electric transmission from Canada in the 2015 to 2030 period.

Base case electric and gas loads were modeled using existing, well-recognized projections, including ISO-NE's latest CELT forecast for electric demand, the Massachusetts' LDCs' gas demand forecasts, and the most up-to-date gas demand information available regarding capacity exempt customers and municipal entities. Reductions to load from energy efficiency were modeled based on program administrators' data as filed with their respective Departments of Public Utilities.[9] These reductions were extended into the future using the following assumptions: (1) for states other than Massachusetts energy efficiency budgets remain constant over time in real terms; and (2) for Massachusetts energy efficiency remains constant as a 2.6-percent share of retail sales from 2015 through 2030.

The base case electric generation resource mix was modeled using the Market Analytics scenario designed by Synapse for DOER in early 2014 to provide an accurate presentation of Green Communities

[9] Program administrators are the entities that administer energy efficiency programs in the Commonwealth. Typically, program administrators are the same as utilities (e.g., NSTAR, National Grid), but also include non-utility entities such as the Cape Light Compact.

Act (GCA) policies as well as the Renewable Portfolio Standards—by class—of the six New England states. Synapse's GCA analysis for DOER was developed using the NERC 9.5 dataset, based on the Ventyx Fall 2012 Reference Case. We verified and updated these data with the most current information on gas prices, loads, retirements, and additions. This case assumes all existing policies—including the ISO-NE Winter Reliability program with its current sunset date, advanced building codes, renewable thermal technologies, and the recent DPU Order 14-04 on time-varying rates—and forecasted LNG and propane usage. We modeled distributed resources using ISO-NE's PV Energy Forecast Update, held constant after 2020. Detailed modeling assumptions for the base case are presented in Appendix B.

Caveats to base case

- The base case for this study includes only existing policies and <u>does not consider or account for currently developing policies or new legislations</u>.
- This study bases its base case projections of electric demand on ISO-NE's CELT 2014 forecast, with the exceptions of adjustments made to ISO-NE's energy efficiency projections (we base these instead on program administrator's latest three-year plans). Any inaccuracies in this forecast—including its accounting of new housing starts—have the potential to affect model results.
- This study bases its base case projections of distributed generation installation on ISO-NE's PV Energy Forecast Update by state, held constant after 2020 (see Appendix B). Any inaccuracies in this forecast have the potential to affect model results.
- This study assumes that gas heating demand is inelastic—that is, gas heating demand does not fluctuate with changes in the gas prices. While actual consumer fuel use is widely regarded to be largely insensitive to fuel prices in the short run, heating demand has the potential to exhibit more sensitivity to gas prices in the long run as customers change heating technologies. While this study does not model long-run sensitivity to increasing gas prices per se, it does include Massachusetts' existing policy for large-scale conversion to renewable thermal heating technologies per the DOER-commissioned CARTS study.[10]
- This study did not consider MA H.4164 expansion of gas distribution and the effect of this expansion on gas demand.[11] Inclusion of gas distribution expansion has the potential to change model results, to the extent that this expansion is not already

[10] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[11] MA H.4164 establishes a uniform classification standard for natural gas leaks. It also requires natural gas companies to repair serious leaks immediately, produce a plan for removing all leak-prone infrastructure, and provide a summary of their progress and a summary of work to be completed every five years.

accounted for in the LDC's heating gas demand forecasts through 2019 and the DOER-based growth rate for heating gas demand thereafter.[12]

- The modeling analysis presented in this study includes the coal unit retirement assumptions indicated in Table 2. Different assumptions have the potential to impact on model results.

Table 2. Modeled coal retirements

Unit Name	State	Retirement date
Bridgeport Harbor 3	CT	6/1/2017
Salem Harbor 3	MA	6/1/2014
Mount Tom	MA	10/1/2014
Brayton Point 1	MA	6/1/2017
Brayton Point 2	MA	6/1/2017
Brayton Point 3	MA	6/1/2017
Mead 1 (103 MW)	ME	none
Schiller 4	NH	1/1/2020
Schiller 6	NH	1/1/2020
Merrimack ST1 (114 MW)	NH	none
Merrimack ST2 (345 MW)	NH	none
S A Carlson 5	NY	1/1/2016

Low energy demand case

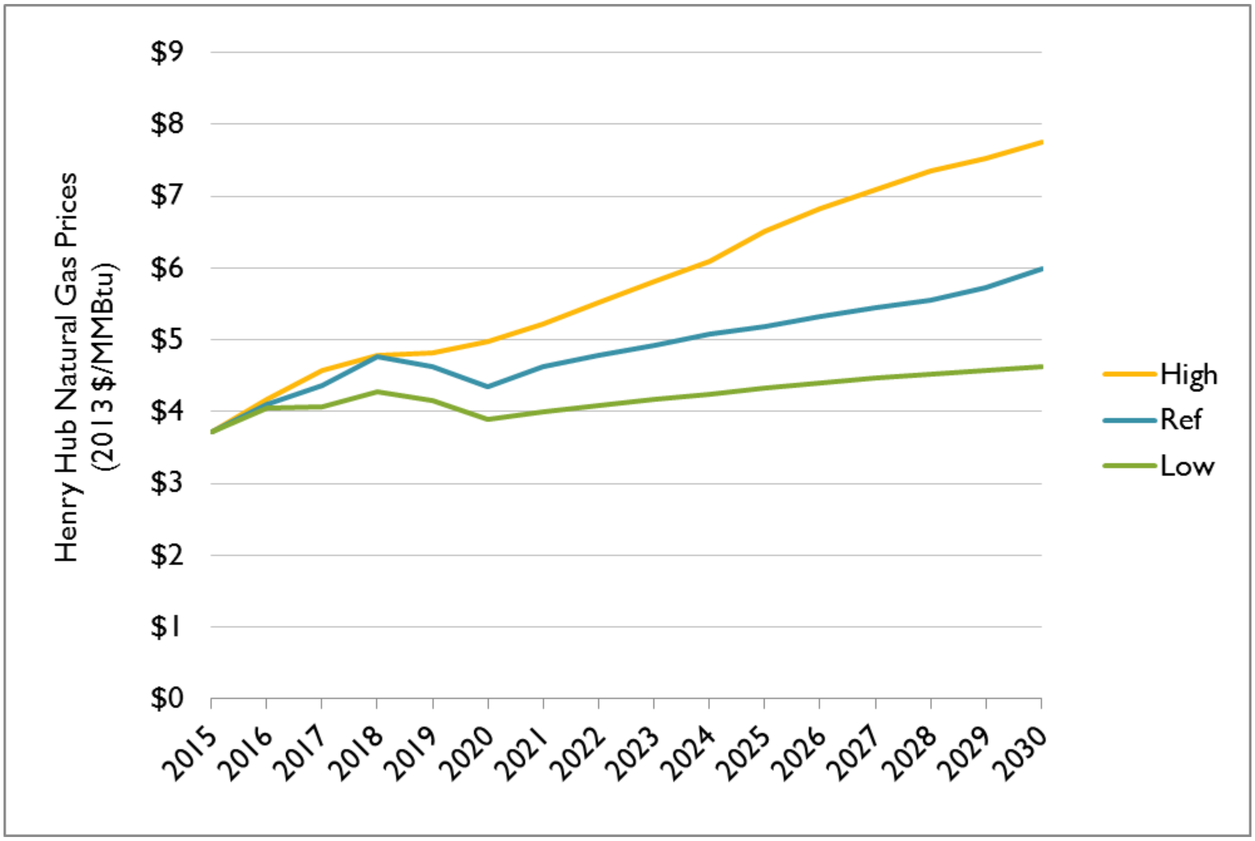
The low energy demand case was designed by making adjustments to the base case. In the low energy demand case, all alternative resources were utilized to the greatest extent that is determined to be feasible (the methodology for this feasibility assessment is described in Section 3.4). In this scenario, changes to public policy were assumed for Massachusetts only and not for the neighboring states. Detailed modeling assumptions for the low energy demand case are presented in Appendix C.

Natural gas price sensitivity

We investigated the sensitivity of modeling results to both increases and decreases in the expected price of natural gas. Figure 3 depicts the reference, low and high Henry Hub natural gas price forecasts for use in this analysis.

[12] According to background papers to the CECP, DOER assumed a 0.5-percent annual growth rate for Massachusetts gas demand after 2020. See Exhibit EAS-13 to MA DPU 14-86.

Figure 3. Reference Henry Hub natural gas prices



For the electric sector monthly average Henry Hub price forecasts were then adjusted for projections of the basis differential between Henry Hub and the Massachusetts (Algonquin) city gates designed to reflect the higher basis when gas demand approaches or exceeds capacity. We assume—based on preliminary modeling results—that the Massachusetts (and upstream) gas sector will remain out of balance from 2015 to 2019, but will be in balance from 2020 through 2030. Detailed assumptions used in the natural gas price sensitivity analysis are presented in Appendix D.

Caveats to natural gas price assumptions

- This study explores the sensitivity of model results to the range in natural gas prices described above. Still higher or lower natural gas prices have the potential to change model results.
- This study does not specifically examine the impact of natural gas exports on the potential range of gas prices. The low and high gas prices used in sensitivities were the "Low and High Oil and Gas Resource Cases" from the U.S. Department of Energy (DOE) and EIA's *2014 Annual Energy Outlook* and were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes the uncertainty of gas availability from shale reserves and developed these alternate resource cases to address it.
- This study does not include a risk premium associated with natural gas price volatility.

- This study does not incorporate the dramatic decline in world crude oil prices or the decline in Henry Hub natural gas commodity prices that occurred during the course this analysis. While these changes will have an impact on the energy market economics in Massachusetts, and the annual cost estimates presented in this study, the DOE/EIA latest Short Term Energy Outlook (December 2014) shows that retail gas prices in the Northeast continue to have a significant price advantage over retail heating oil prices.[13] Furthermore, prices that occur during the winter peak event are driven more from the capacity constraints and pipeline basis differential prices than the cost of the commodity.

Incremental Canadian transmission sensitivity

We investigated the sensitivity of modeling results to the addition of 2,400 MW of new, incremental transmission of system power from Canada to the New England hub: one 1,200 MW line by 2018 and a second by 2022. Note that this transmission is assumed to be heavily weighted to be composed of hydroelectric-based generation, but includes power from other Canadian generators. Table 3 summarizes our basic assumptions for this sensitivity. We assume the capacity factor on these incremental lines will be 75 percent on average on a winter peak day and 71 percent in a winter peak hour. Our research underlying regarding Canadian transmission is presented in Appendix E. Note that Massachusetts is assumed to receive all power from these lines—as it would were the Commonwealth to purchase renewable or clean energy certificates associated with the generation or enter into long-term contracts with the generators—and therefore both pays the full costs of constructing the lines and claims the full emissions reductions associated with generation imported on the lines.

[13] U.S. Energy Information Administration, *Short-Term Energy Outlook, December 2014*, Table WF01, Average Consumer Prices and Expenditures for Heating Fuels During the Winter.

Table 3. Incremental Canadian transmission assumptions

Canadian Transmission HVDC 1	Annual Capacity Factor	Total Potential Capacity	Annual Net Levelized Cost	Annual Net Levelized Cost	Annual Energy Production	Peak Hour Gas Savings
	%	MW	$/MWh	$/MMBtu NG	MMBtu NG	MMBtu NG
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	67%	1,200	$100	$839	59,161,536	6,840
2021-2030	n/a	0	n/a	n/a	n/a	n/a
Canadian Transmission HVDC 2	**Annual Capacity Factor**	**Total Potential Capacity**	**Annual Net Levelized Cost**	**Annual Net Levelized Cost**	**Annual Energy Production**	**Peak Hour Gas Savings**
	%	MMBtu / yr	$/MMBtu	$/MMBtu NG	MMBtu NG	MMBtu NG
2015	n/a	0	n/a	n/a	n/a	n/a
2016-2020	n/a	0	n/a	n/a	n/a	n/a
2021-2030	50%	1,200	$147	$1,231	44,150,400	6,840

Caveats to incremental Canadian transmission assumptions

- Both existing and incremental Canadian transmission is modeled as system power from Québec –that is, generation and its associated emissions are assumed to be an average or mix of Québécois resources, and not dedicated transmission of hydroelectric or any other resource. Average Québécois electric generation is treated as having zero greenhouse gas emissions in this study when in fact the emission rate associated with Québec imports is estimated to be 0.002 metric tons per MWh.[14] Incorporating the actual emissions associated with these imports in our study would have no appreciable impact on total emissions or GWSA compliance.

- While based on the most recent data for costs and in-service dates of proposed transmission lines, in this study, Canadian transmission lines are generic and do not represent any specific project. The costs and in-service dates of actual transmission lines would be expected to vary from the generic lines represented here. Changes to costs or in-service dates of these lines would be expected to impact model results.

3.4. Feasibility Analysis for Low Energy Demand Scenario

The low energy demand case is modeled as the base case with the addition of the maximum amount of alternative demand- and supply-side resources determined to be feasible. We performed feasibility analyses for alternative resources for 2015, 2020 and 2030. All alternative resources assessed to be both

[14] National Inventory Report 1990-2011, Part III. Environment Canada. 2013. p.71. Available at http://unfccc.int/files/national_reports/annex_i_ghg_inventories/national_inventories_submissions/application/zip/can-2013-nir-15apr.zip

technically feasible and practically achievable in Massachusetts for each year, but ignoring cost, were included in the economic feasibility analysis. For each such resource, the ratio of annual net costs to annual energy in MMBtu (annual-$/annual-MMBtu) was compared to a threshold for economic feasibility.

The estimated annual cost of a generic, scalable natural gas pipeline is used as the threshold for economic feasibility in this report. Using pipeline construction costs from the AIM project we assume a 95-percent utilization (chosen to represent the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline) on 80 percent of winter days.[15] This study assumes that incremental pipeline capacity consists of non-specific generic projects that can be added in increments of 100,000 MMBtu per day and are in addition to the existing and planned capacity defined above. Based on this calculation, the economic threshold for including additional alternative resources in the model is $4/MMBtu.

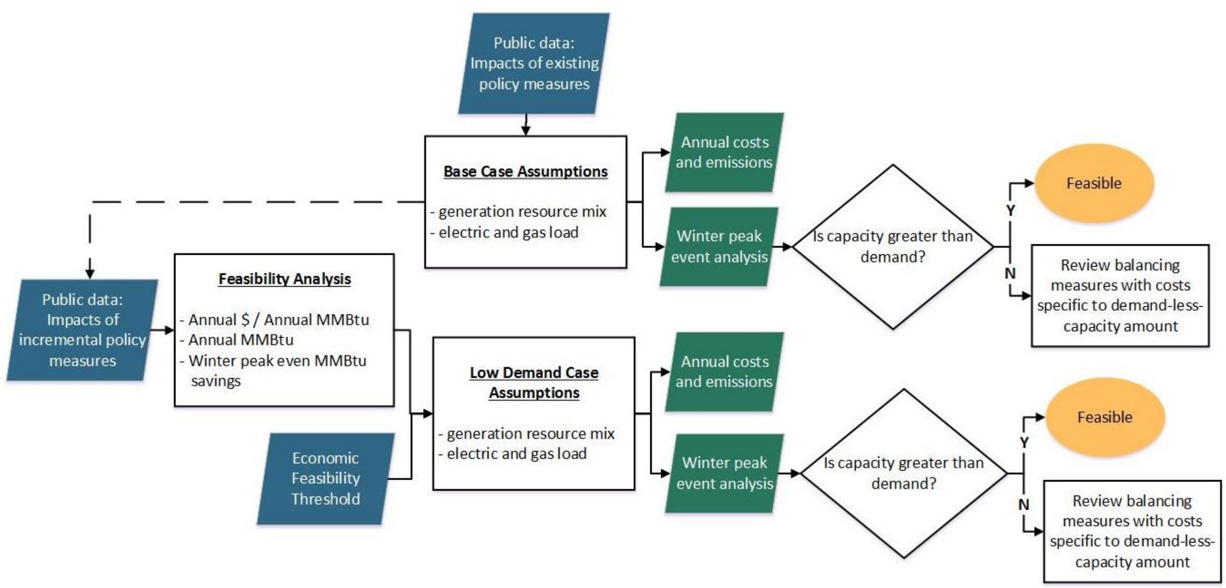
Resources were assessed as either less or more expensive than the selected threshold:

- If Annual-$/annual-MMBtu are less costly than the economic feasibility threshold, then resources are included in the determination of the electric generation resource mix and electric and gas loads in the low energy demand case.

- If Annual-$/annual-MMBtu are more costly than the economic feasibility threshold, then resources are not included in the low energy demand case.

Figure 4 provides a schematic of the role of feasibility analysis in this modeling project.

Figure 4. Feasibility analysis schematic



[15] Algonquin Gas Transmission, AIM Project, FERC CP 14-96, February 2014

Measures included in the feasibility analysis meet two basic criteria:

1. These measures are incremental (i.e., over and above) the amounts of the same technologies associated with the same policy measures included in the base case.

2. These measures are associated with expected annual MMBtu savings in the analysis year; that is, they are technically and practically feasible.

For the purpose of the feasibility analysis, reduced natural gas consumption from displaced electric generators is calculated using an 8.4 MMBtu/MWh heat rate. This is the average annual natural gas marginal heat rate used by ISO-NE in 2013.[16] Detailed assumptions and results of the feasibility analysis are presented in Appendix A.

Table 4 reports the alternative measures included in the low energy demand case at the reference gas price along with the total annual savings potential for this group of measures.[17] Note that savings are incremental from the base case and incremental from the previous year. Measures that do not have annual MMBtu savings are included in the "balancing" phase of modeling (described in Section 3.5)—battery storage, pumped storage, demand response, and the ISO-NE Winter Reliability program—and not in the feasibility study.

[16] 2013 Assessment of the ISO-NE Electricity Markets. Potomac Economics. June 2014. p.44.

[17] Synapse conducted two rounds of analysis of this group of measures; the first round analyzed gas use, emissions, and cost impacts of a subset of these measures. After correcting for a calculation error in the supply curves, Synapse extrapolated the impact of the first round of measures to the entire group. Results for 2015 were unchanged. Very minor corrections were needed for 2020 in all gas price sensitivities, while 2030 saw a larger impact from these additional measures in each gas price sensitivity. The final results shown throughout this report reflect these changes.

Table 4. Alternative measures included in low energy demand case at reference gas price

		Total Annual Savings Potential (trillion Btu)
2015	Anaerobic digestion, landfill gas, converted hydro[18], small CHP	0.2
2020	Appliance standards, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, low-income electric energy efficiency, small CHP, residential gas energy efficiency, commercial and industrial gas energy efficiency, low-income gas energy efficiency, Class 1 biomass power	30.9
2030	Residential gas energy efficiency, appliance standards, commercial and industrial gas energy efficiency, low-income gas energy efficiency, residential electric energy efficiency, commercial and industrial electric energy efficiency, anaerobic digestion, large CHP, landfill gas, converted hydro, small CHP, low-income electric energy efficiency, commercial PV, residential PV, Class 1 biomass power, utility-scale PV, small wind, Class 5 large wind, Class 4 large wind, Class 2 biomass power	129.9

Feasibility supply curve results are dependent on the choice of natural gas price sensitivity: alternative resources avoided different costs based on the assumed gas price. Overall, the results of the supply curve analysis were not very sensitive to low gas prices: the same set of resources clear the economic threshold in 2015 as in the reference gas price case. In 2020, one fewer resource clears with the low gas price, representing less than 1 trillion Btu of the total 31 trillion Btu cleared savings in the reference case. Sensitivity to the low gas price is greater in 2030, with two resources totaling 8 trillion Btu not clearing the economic threshold as a result of lower gas prices, compared to total cleared savings of 130 trillion Btu. The model exhibits somewhat higher sensitivity to a change to higher gas prices. In 2015, the higher gas price results in a new 2 billion Btu resource clearing the economic threshold, compared to total cleared savings of 235 billion Btu. In 2020, two additional resources clear the economic threshold, representing 9 trillion Btu cleared savings of the total 31 trillion Btu cleared savings in the reference case. In 2030, two new resources clear the economic threshold, raising the total amount of cleared savings from 130 trillion Btu to 264 trillion Btu. Detailed feasibility analysis results for the natural gas price sensitivities are presented in Appendix A.

Caveats to feasibility analysis assumptions and methodology

- In this study, only resources jointly deemed technically feasible and practically achievable in Massachusetts for each year, given our best understanding of the pace of policy change and resource implementation (but ignoring cost), were assessed for

[18] The inclusion of converted hydro addresses energy potential only and does not take into account the other environmental considerations which may be raised by the Commonwealth's environmental agencies, such as the Department of Fish and Game.

economic feasibility and potential inclusion in the low demand case. Technological advancements and new information regarding the expected pace of policy change and resource implementation would have the potential to result in the inclusion of different resources in the feasibility analysis, different alternative measures included in the low demand case and different model results for this case.

- In this study, resources are deemed “economically feasible” if they are less expensive than a threshold estimated as the per MMBtu cost of a generic, scalable natural gas pipeline. The choice of this threshold determines what alternative resources are or are not included in the low demand case. A different threshold for inclusion in the low demand case would result in the inclusion of different alternative measures, and different model results for the low demand case.

- This study only includes alternative measures that could potentially result from changes to Massachusetts policy, and not alternative measures brought about by policy changes in other New England states.

- The avoided costs attributed to alternative measures in this study are derived from the AESC 2013 (see Appendix A). Since the publication of AESC 2013 there have been changes to projected fuel prices, public policy, and the market structure in ISO-NE, all of which are expected to be included in modeling for the AESC 2015 that is currently in progress. Avoided costs modeled in AESC 2015 may be different—higher or lower—than those modeled in AESC 2013.

- Benefits to alternative measures not included in the low demand case include:

    - The avoided carbon cost of GWSA compliance (which was included only for energy efficiency measures in this study consistent with DPU 14-86)

    - Non-energy benefits including improved health, or reduced health costs, and new jobs related to alternative measures

- Costs to alternative measures not included in this study have the potential, if considered, to result in fewer resources deemed economic and included in the low demand case, changing the results of that case. Potential costs not included in the assessment of these measures include non-energy costs such as negative environmental impacts from alternative resource siting.

- The examination of possible alternative resources to be included in this feasibility analysis was not—and could not possibly be—comprehensive. Alternatives resources that were either not deemed to be reasonably available during the time frame of this study or of limited potential capability were not included in the supply curves for economic feasibility assessment. Resources not considered in the analysis include:

    - Solar panels installed on every sunny rooftop, and on every piece of land, where the installation is technically feasible

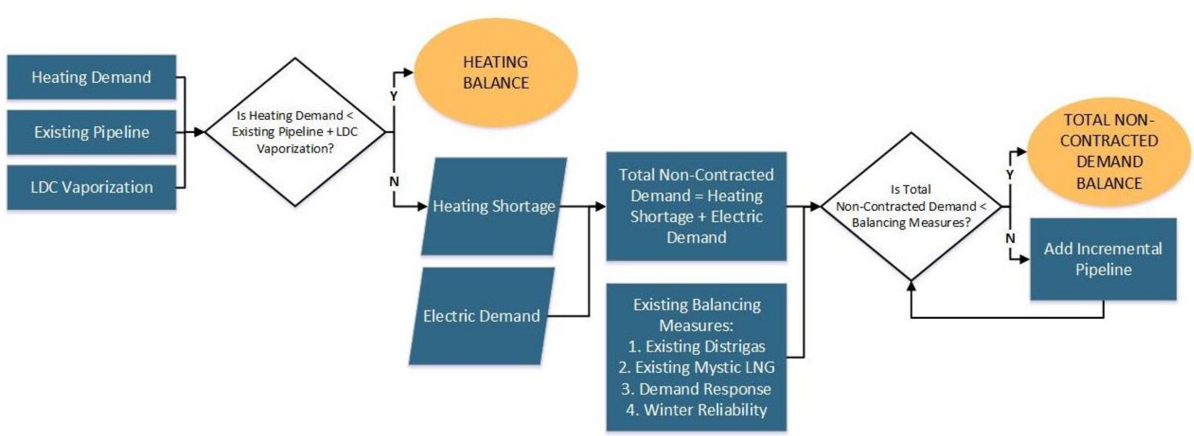
    - Unrestricted deployment of neighborhood-shared and community-shared solar

- Solar energy with no net-metering cap or restriction and without any type of restriction imposed by utility companies
- Co-location of solar panels with food production or other land uses
- Technological improvement in the lighting efficiency
- A public education campaign in Massachusetts similar to Connecticut's "Wait 'til 8" program
- Solar energy backed by batteries as a separate alternative resource
- Rate reforms such as peak time rebates and demand charges
- Transmission for wind firmed by hydro
- Smart appliances
- All new affordable-housing units built as zero-net-energy or net positive energy residences
- Net zero carbon zoning codes
- Voluntary trends towards green building
- Conversion to electric vehicles

3.5. Relationship between Capacity and Demand

The Synapse Massachusetts gas-sector model designed for this analysis examines the relationship between the Commonwealth's natural gas demand and natural gas capacity in the winter peak hour. This assessment of balance is accomplished as depicted in Figure 5:

Figure 5. Winter peak hour gas capacity and demand balancing schematic



First, in each scenario and year, heating demand (LDC, muni and capacity exempt gas demand less gas energy efficiency, reductions from advanced building codes and renewable thermal technologies, and (in the low demand case) other gas reduction demand measures) is compared with existing and planned (AIM project) pipeline capacity and existing vaporization capacity from LDC-owned storage.[19]

- If heating demand is less than existing and planned pipeline capacity plus LDC-owned storage, then the gas heating sector is in balance.
- If heating demand is greater than existing and planned pipeline capacity plus LDC-owned storage, then it is combined with electric demand as "non-contracted demand" in the next step.

Next, non-contracted demand (the sum of shortages in gas heating and gas required for gas-fired electric generation) is compared to balancing available from existing measures: Distrigas, Mystic LNG, and Demand Response (in all years), and the ISO-NE Winter Reliability Program (through 2018).

- If non-contracted demand is less than existing balancing measures, then the gas heating and electric sector is in balance. Existing balancing measures are:
    - "Distrigas" is existing LNG vaporization capacity less what is dedicated to Mystic directly available to the natural gas distribution system in Massachusetts.
    - "Mystic LNG" is existing LNG vaporization capacity directly available to the Mystic generating facility.
    - Electric demand response (available 2015 to 2019) is added at a minimum increment of 0.76 MMBtu of gas savings.
    - ISO-NE's Winter Reliability program (available 2015 to January 2018) is added at a minimum increment of 1.0 MMBtu of gas savings.
    - Incremental pipeline (available 2020 through 2030) is added at a minimum increment of 4.2 MMBtu per hour of gas.
- If non-contracted demand is greater than existing balancing measures, the incremental pipeline is added until a balance is achieved.

The balance criteria of gas demand no greater than 95-percent of gas capacity reflects the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline. The impact of gas constraint on natural gas prices is thought to begin when gas demand rises above 80-percent of gas capacity. Gas prices associated with out-of-balance conditions are assumed in 2015 through 2019 in our model.

[19] LDC-owned storage is existing LNG storage used to provide vaporization during the peak hour throughout the 12-day cold snap. Propane storage is not available in this model as a balancing measure; existing propane storage facilities are sufficient for a 3-day cold snap.

Caveats to capacity and demand balance assessment methodology

- This study assumes that no additional LNG storage facilities will be sited in Massachusetts during the study period. This is based on expected challenges related to permitting, siting, financing and potential public opposition.
- This study assumes additions of a generic natural gas pipeline, available in 4.2 peak hour MMBtu increments and based on the per MMBtu costs of the AIM pipeline (see Appendix B). Although pipeline increments are added based on the requirement in the peak hour, incremental pipeline is assumed to be in use throughout the year. As a result, we have levelized the cost of these pipeline increments over an entire year. If a pipeline increment were only in use for a portion of the year, the implied levelized cost would be different.
- This study does not consider environmental impacts of pipeline siting and construction, nor does it consider the environmental impacts of natural gas extraction, such as those related to fracking.
- This study does not consider pipeline investments potential displacement of alternative resources, thereby slowing their growth.
- This study analyzes Massachusetts capacity during a winter peak event hour assuming that if demand exists, market forces will make it economic to utilize existing capacity. We do not examine the ability of specific supply basins to produce natural gas, or the impact on supply to Massachusetts of demand in other regions.
- Gas capacity constraints shown in this analysis may be higher than what is shown in the Forecast and Supply Plans filed by the Massachusetts LDCs due to the inclusion of capacity-exempt customer demand. LDCs, by regulation, do not acquire gas supply resources to serve capacity-exempt customers. Those customers, however, are firm gas customers that place demands on the system. In MA-DPU 14-111, the Massachusetts LDCs petitioned the DPU to allow them to acquire resources to serve up to 30 percent of the capacity-exempt load. In that petition, the LDCs estimated that the total capacity exempt load on a design day is approximately 294,200 Dth. The total capacity-exempt load is included in our analysis.
- Our analysis assumes LNG availability from Distrigas for import in the peak hour. If natural gas from this source is not available in the peak hour, the ability for the natural gas system to be in balance will be reduced.
- For this analysis, we have assumed the full vaporization capacity of the Distrigas LNG facility and the full capacity of the Maritimes & Northeast Pipeline are available in the peak hour. In order for markets to fully utilize this capacity, there must be sufficient supply supporting those facilities. The Distrigas LNG terminal relies on imported LNG. LNG markets are influenced by world supply and demand dynamics, which most recently have made it difficult for imported LNG to compete in U.S. markets. These dynamics have caused significant disruptions in deliveries to the Distrigas LNG facility in Everett, MA over the past few years. Similarly, for the Maritimes & Northeast Pipeline, one of its primary supply sources is the Canaport LNG facility in St. John, New Brunswick, Canada. That facility also relies exclusively on imported LNG, making its supply subject

to the same market dynamics as the Distrigas LNG. Sable Island production, another major supply source for the Maritimes & Northeast Pipeline, is down to about 100 million cubic feet per day and there is speculation that production will soon cease.[20] The other major supply source for Maritimes & Northeast Pipeline is Encana's Deep Panuke project in Nova Scotia. That project has recently reached full production of 300 million cubic feet per day. However, according to Encana, the output is expected to drop to below 200 million cubic feet per day in the fourth year and below 100 million cubic feet per day by the eighth year.[21]

[20] EIA. "Production lookback 2013". January 2014. Available at http://www.eia.gov/naturalgas/review/production/2013/.

[21] Arugs Media. "Deep Panuke startup could mitigate gas price spikes". August 2013. Available at http://www.argusmedia.com/pages/NewsBody.aspx?id=860753&menu=yes

4. Model Results

This section presents model results for Massachusetts natural gas capacity and demand. Table 5 provides a key to the scenarios.

Table 5. Scenario key

Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6	Scenario 7	Scenario 8
Base Case Reference NG Price No Canadian Transmission	Base Case Low NG Price No Canadian Transmission	Base Case High NG Price No Canadian Transmission	Base Case Reference NG Price 2,400-MW Canadian Transmission	Low Demand Case Reference NG Price No Canadian Transmission	Low Demand Case Low NG Price No Canadian Transmission	Low Demand Case High NG Price No Canadian Transmission	Low Demand Case Reference NG Price 2,400-MW Canadian Transmission

Note: "Canadian transmission" refers to incremental transmission of system power from Québec. This transmission includes electricity both from hydroelectric and other generators.

4.1. Peak Hour Gas Shortages

Figure 6 displays the amount of winter peak hour supply—including existing pipeline, planned AIM pipeline, plus available LNG vaporization—needed to meet demand in Massachusetts during a winter peak event in three scenarios selected to highlight the progression of reducing gas shortages from a scenario with existing policies only, to the addition of technically and economically feasible alternative resources, to the addition (inclusive of alternative measures) of new transmission from Canada:

- **Scenario 1: Base Case** is the base case with reference natural gas price and no incremental Canadian transmission,
- **Scenario 5: Low Demand** is the low energy demand case with reference natural gas price and no incremental Canadian transmission, and
- **Scenario 8: Low Demand + Incremental Canadian Transmission** is the low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission.

The dark blue area represents the demand from LDCs, municipal entities, and capacity-exempt demand in each year, which changes each year as a result of load growth and energy efficiency. Stacked on top in light blue is the peak hour natural gas demand from the Massachusetts electric system, which varies year-to-year as a result of the electric system reacting to changes in available resources and natural gas prices.

In all scenarios, winter peak hour gas requirements are heavily weighted towards LDC and muni demand. During the peak hour in 2015, on average across the scenarios, electric-system gas requirements were just 9 percent of total Massachusetts natural gas demand. As electric system gas consumption rises beginning in 2020 as natural gas price spikes decline, this value rises to 27 percent in 2020 and to 28 percent in 2030.

The solid line in Figure 6 represents existing and planned pipeline capacity and a dotted line represents this pipeline capacity plus the additional LNG vaporization from both existing LDC storage and Distrigas LNG. Any year in which the stacked blue columns exceed the dotted line is a year in which incremental pipeline is required to balance the system. Scenario 5 (low demand, reference gas price, no incremental Canadian transmission) and Scenario 8 (low demand, reference gas price, 2,400-MW incremental Canadian transmission) both require less incremental pipeline than Scenario 1 (base case, reference gas price, no incremental Canadian transmission) in every year.

Figure 6. Massachusetts peak hour demand and existing supply for Scenario 1, Scenario 5, and Scenario 8

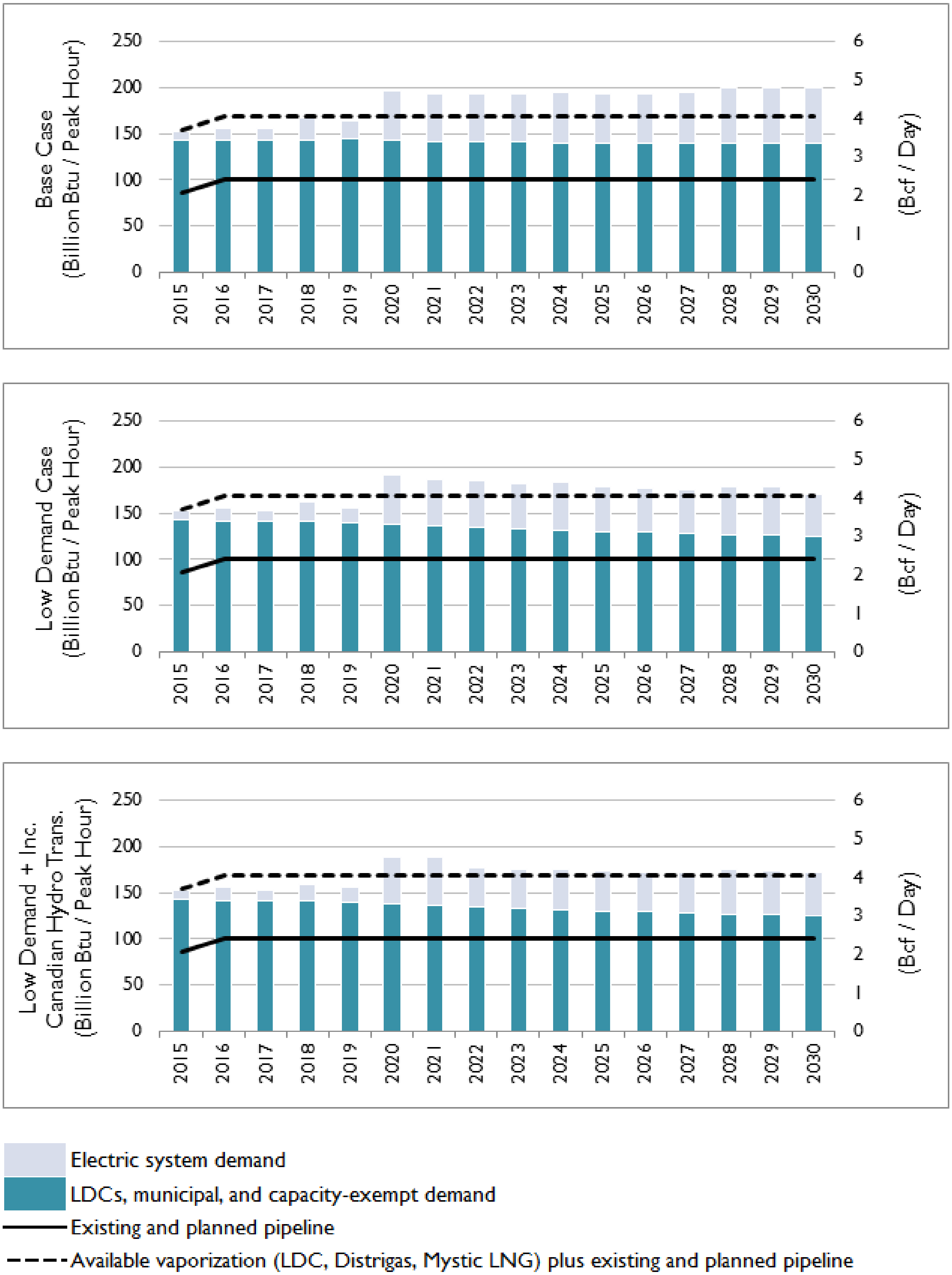
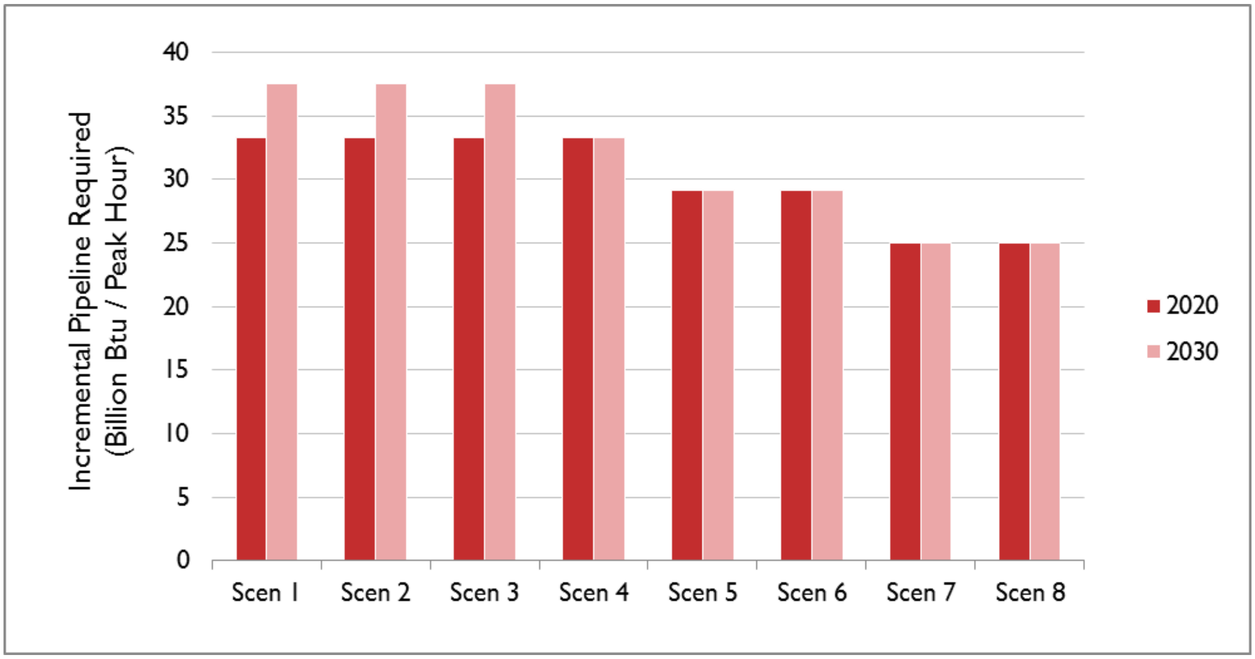


Figure 7 reports gas capacity shortage and incremental pipeline required in a winter peak event in all eight scenarios for 2020 and 2030 (in both years additional pipeline is reported as incremental to existing and planned pipeline). Scenario 8 (low demand, reference gas price, 2,400 MW of incremental Canadian transmission) has the smallest requirements. 2020 pipeline additions range from 25 billion Btu per peak hour to 33 billion Btu per peak hour (0.6 billion cubic feet (Bcf) per day to 0.8 Bcf per day).[22] 2030 pipeline additions range from 25 billion Btu per peak hour to 38 billion Btu per peak hour (0.6 Bcf to 0.9 Bcf per day.

Figure 7. Massachusetts gas capacity shortage in the winter peak hour in 2020 and 2030



From 2015 through 2019, electric generators have insufficient supply of natural gas, which results in spiking natural gas prices. Scarcity-driven high natural gas prices will force economic curtailment of natural gas-fired generators in favor of oil-fired units. The combination of increased oil utilization for electricity generation together with the use of emergency measures such as demand response and the ISO-NE Winter Reliability program (through January 2018) will allow electric demand to be met. From 2020 to 2030, existing and planned capacity plus incremental pipeline capacity balances system requirements.

Critical to this result is the assumption that winter peak hour gas shortages cannot be met using known measures (e.g. demand response or the addition of new natural gas pipeline) in years 2015 through 2019 and, as a result, gas prices are expected to reflect an out-of-balance market in those years. The electric sector responds to these high prices by shifting dispatch from gas to oil generation in the peak hour, reducing reliance on natural gas. In years 2020 through 2030, in contrast, winter peak hour gas

[22] Billion Btu can be converted to Bcf by multiplying billion Btu by 24 hours per day then dividing by 1,022 Btu per cubic foot.

shortages can be met using known measures (incremental pipeline) and, as a result, gas prices are expected to reflect an in-balance market in those years. The electric sector no longer has a price signal to shift dispatch away from gas generation in the peak hour, greatly increasing gas requirements in comparison to the previous period.

4.2. Annual Natural Gas Demand

Figure 8, Figure 9, and Figure 10 display Massachusetts' annual natural gas consumed for each scenario in 2015, 2020, and 2030, respectively. In 2015, annual natural gas consumption is largely constant across all scenarios, ranging from 417 to 427 trillion Btu per year (408 to 418 Bcf per year). In 2020, annual natural gas consumption increases for Scenario 2 as a result of the low natural gas price modeled, while it decreases in the low demand scenarios (Scenario 5 through 8) as a result of reduced natural gas demand from alternative measures and, in Scenario 8, the addition of incremental Canadian transmission. As a result, the range of annual natural gas consumption in 2020 is 439 to 523 trillion Btu per year (430 to 512 Bcf per year). This trend continues in 2030 as low demand measures and incremental Canadian transmission play a greater role in avoiding natural gas demand in selected scenarios. The range of annual natural gas consumption in 2030 is 360 to 520 trillion Btu per year (352 to 509 Bcf per year).

Figure 8. Massachusetts annual gas demand in 2015

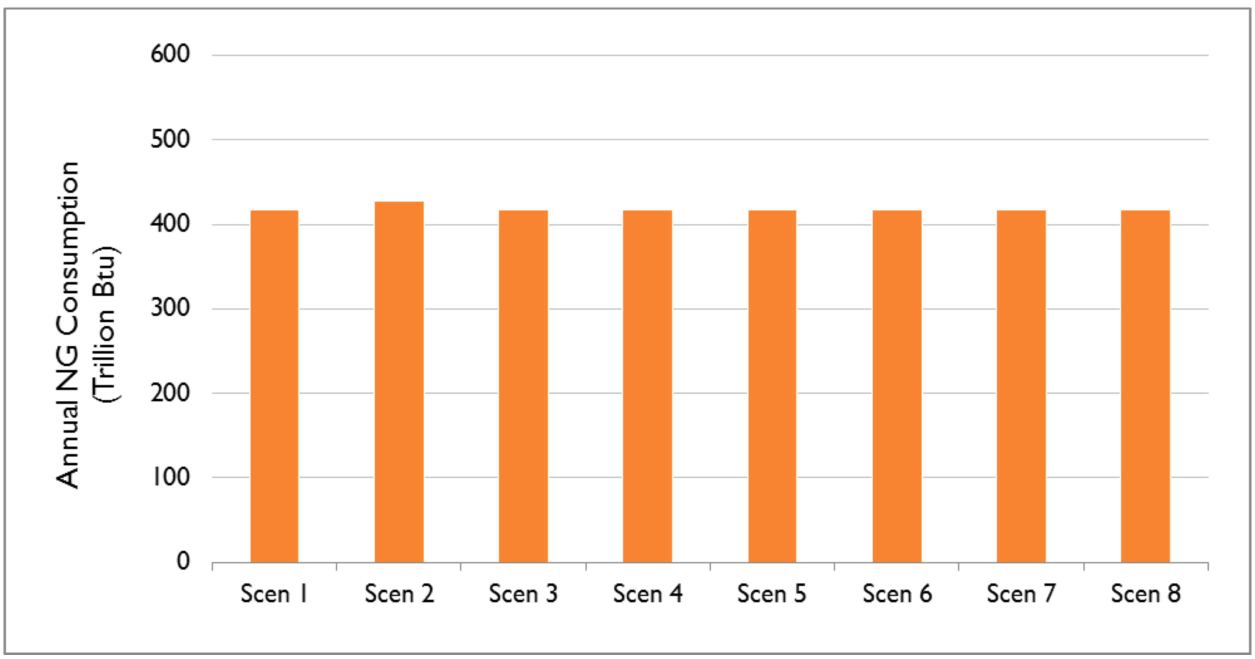


Figure 9. Massachusetts annual gas demand in 2020

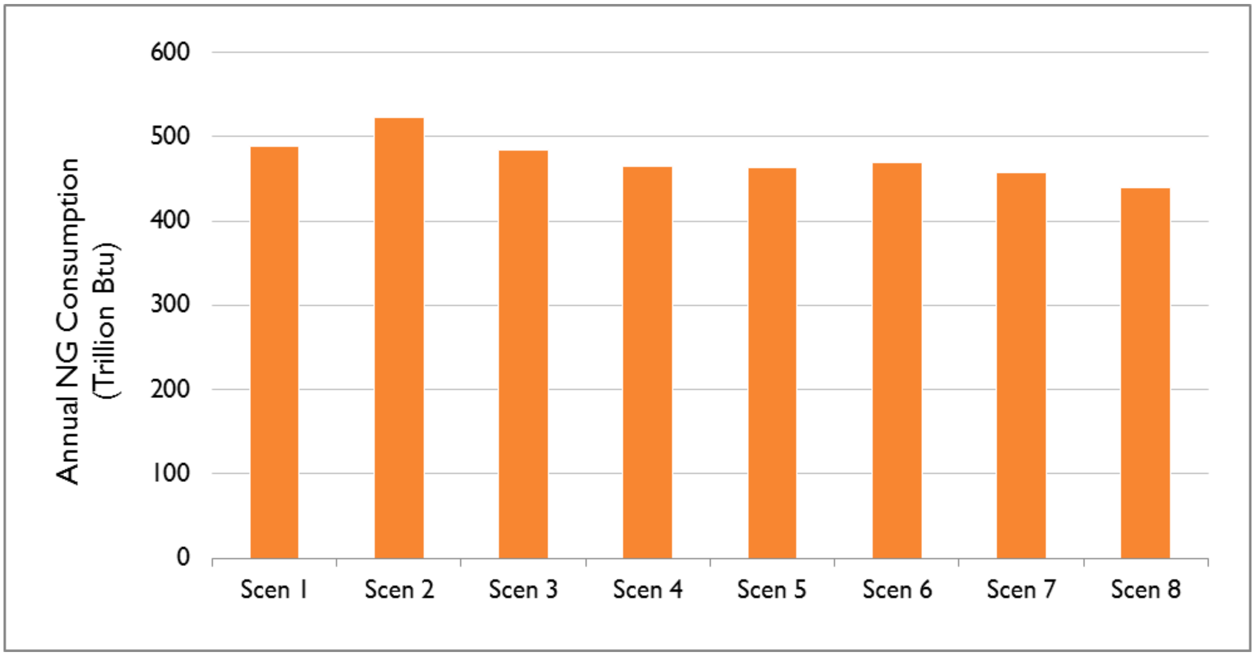
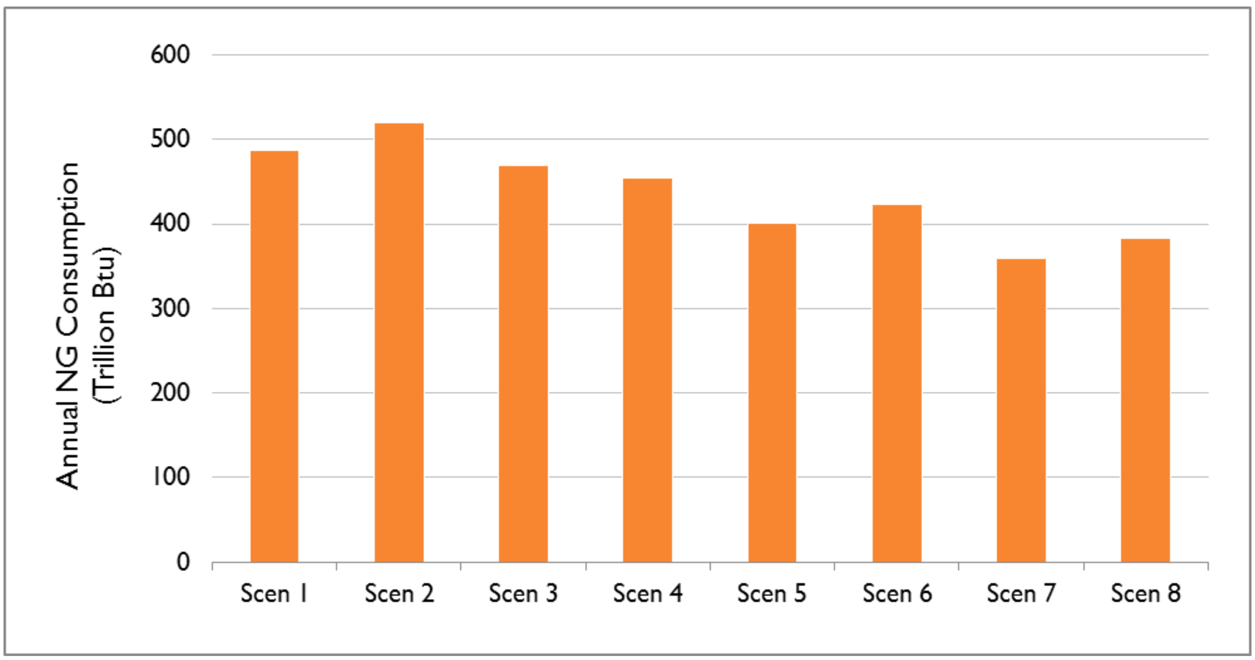


Figure 10. Massachusetts annual gas demand in 2030

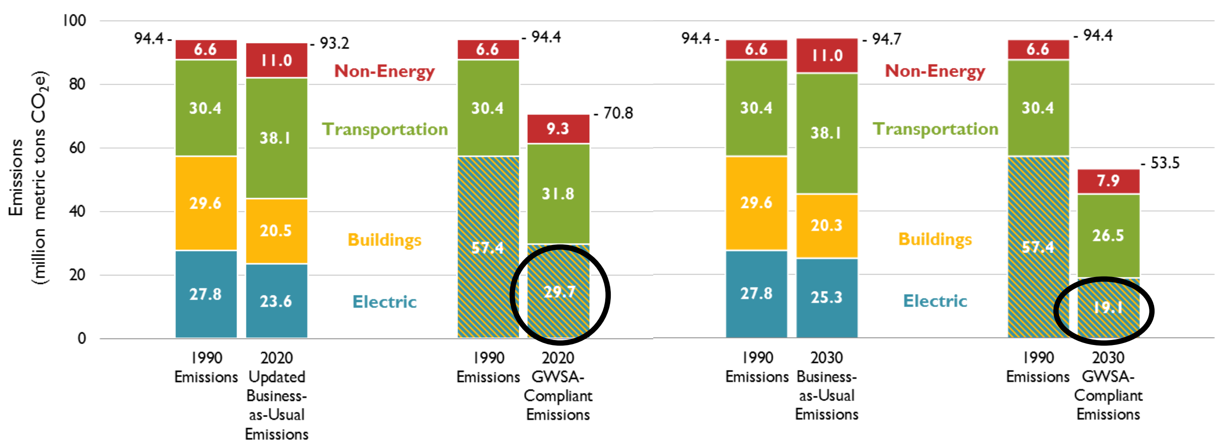


4.3. Annual CO_2 Emissions

Compliance with the Massachusetts 2008 climate law—the GWSA—is not a criterion for scenarios and sensitivities; rather, the Massachusetts emissions associated with each scenario and sensitivity are an output of the model. Massachusetts emissions are estimated according to the methodology set out in the *2008-2010 Massachusetts Greenhouse Gas Emissions Inventory* and include emissions associated with Massachusetts generation, out-of-state renewable energy certificate (REC) purchases, Canadian system power imports for which the Commonwealth has a particular claim, and emissions from residual sales as a share of imports from both out of state and out of region (see Appendix B for a more complete description).[23]

In MA-DPU Docket 14-86, the electric and buildings sectors in a GWSA compliant scenario have a combined emission allocation of 29.7 million metric tons in 2020 and 19.1 million metric tons of CO_2-e in 2030 (see Figures 2 and 5 of Corrected Amended Direct Testimony of Elizabeth A. Stanton, December 4, 2014, reproduced as Figure 11 here).[24] Note that 2030 emission targets are not specified by GWSA; per MA-DPU Docket 14-86 we have linearly interpolated the 2030 target based on the 2020 and 2050 targets. The allocation shown in Figure 11 is based on the assumption that emissions in the transportation and non-energy sectors will follow the December 2010 *Massachusetts Clean Energy and Climate Plan for 2020* (CECP).

Figure 11. Massachusetts 2020 and 2030 GWSA compliant emissions



Of this allocation we expect that, following the CECP, direct use of oil will emit 6.4 million metric tons of CO_2-e in 2020 and 0.4 million metric tons in 2030.[25] As a result, GWSA compliance cannot be achieved if combined emissions from the electric sector and direct use of gas exceed 23.3 million metric tons in 2020 or 18.7 million metric tons in 2030 (see Table 6).

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[23] Note that imports from Canada include generation both from hydro resources and non-hydro resources.

[24] In MA DPU 14-86 the Massachusetts Departments of Energy Resources and Environmental Protection jointly petitioned MA-DPU to "commence an appropriate proceeding to determine whether the existing method of calculating the compliance costs associated with GHG emissions should be replaced by the marginal abatement cost curve methodology."(Joint Petition, May 26, 2014)

[25] This estimate of 2020 and 2030 oil heating emissions is based on information presented in MA-DPU 14-86 Exhibit EAS-8 and is calculated as oil heating business-as-usual emissions in those years less CECP emission reductions for oil heating in those years.

Table 6. Emissions available under GWSA target

	2020	2030
GWSA Target (% reduction below 1990 statewide levels)	25%	43%
GWSA Target (million metric tons CO_2-e)	70.8	53.5
CECP Non-Energy Sector Emissions (million metric tons CO_2-e)	9.3	7.9
CECP Transportation Sector Emissions (million metric tons CO_2-e)	31.8	26.5
CECP Building and Electric Sector Target (million metric tons CO_2-e)	29.7	19.1
CECP Building Sector Oil Emissions (million metric tons CO_2-e)	6.4	0.4
Emissions Available under GWSA Gas Heating and Electric Target	23.3	18.7

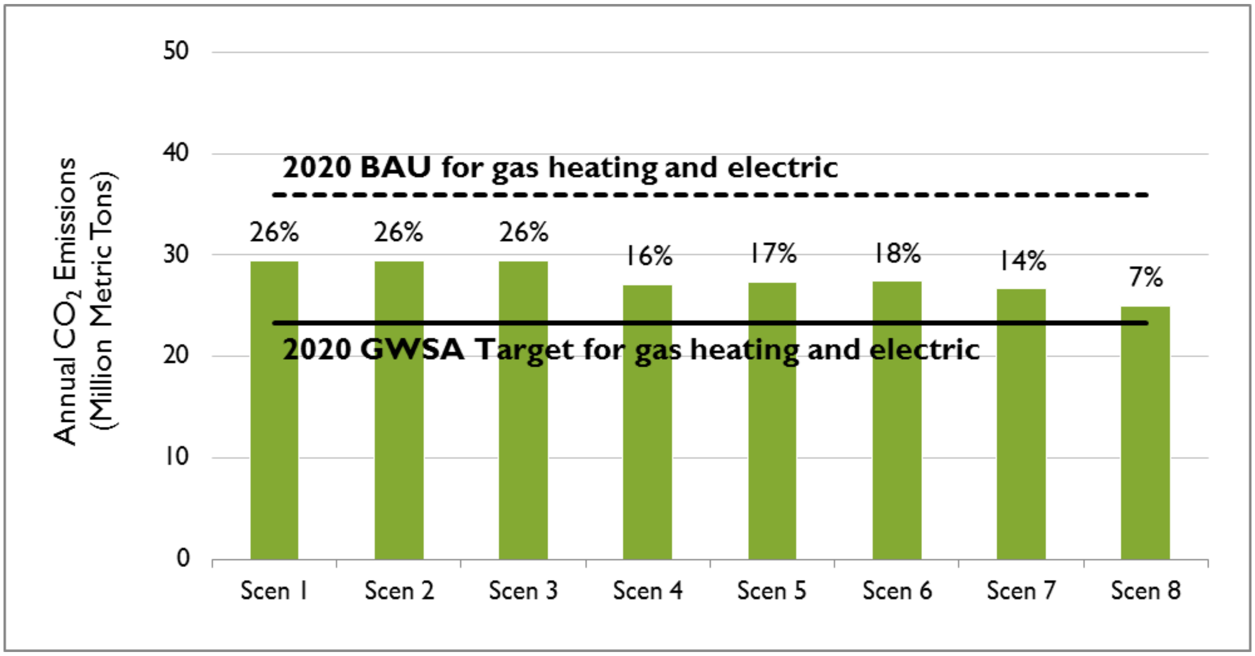
The "emissions available under GWSA gas heating and electric target" shown in the last row of Table 6 is a target for emission levels from natural gas heating and electricity generation that would allow the GWSA 2020 limit to be met, taking into account expected emissions from other sectors. Calculation of the target takes into account greenhouse gas emission reductions that could be achieved through successful implementation of a suite of policies identified in the CECP to reduce demand and emissions from the transport, non-energy and non-natural gas thermal sectors.[26] The economy-wide 2020 greenhouse gas emissions limit of 70.8 million metric tons CO_2-e, based on a 25 percent reduction from 1990 levels, will be achieved from a combination of strategies including reductions to building, electricity, transportation, land use and non-energy emissions.

Total emissions from Massachusetts' natural gas heating and electric sectors in 2020 and 2030 are presented in Figure 12 and Figure 13. Each figure is overlaid with two horizontal lines: one showing business-as-usual (BAU) emissions, and the other showing that year's GWSA target for the natural gas heating and electric sectors assuming that the non-energy, transportation and oil heating sectors will meet their CECP targets. Percentages refer to the degree to which each scenario under- or over-complies with the target.[27] While no scenario achieves GWSA compliance in the heating gas and electric sectors in 2020, Scenario 8 (low energy demand case with reference natural gas price and 2,400-MW incremental Canadian transmission), shown below, and Scenario 7 (low energy demand case with high natural gas price and no incremental Canadian transmission) meet compliance in 2030. Scenario 5 (low energy demand with reference natural gas price and no incremental Canadian transmission) exceeds 2030 GWSA compliance by 0.4 million metric tons or 1 percent of the 2030 statewide emission target.

[26] The CECP will be updated in 2015 as required by the GWSA, and every five years thereafter. This may result in revisions to the share of greenhouse gas reductions expected from, or allocated to, the buildings, electric, transportation and non-energy sectors in order to meet GWSA limits.

[27] The GWSA target for the natural gas and electric sectors assumes emissions in the transportation and non-energy sectors and direct use of oil as described in Appendix B.

Figure 12. Annual Massachusetts gas and electric sector emissions in 2020



Note: Percentages displayed in the above chart indicate the degree to which each scenario is above the 2020 GWSA target for the gas and electric sectors. For example, the emissions in Scenario 1 are 26 percent higher than the 2020 GWSA target for the gas and electric sectors.

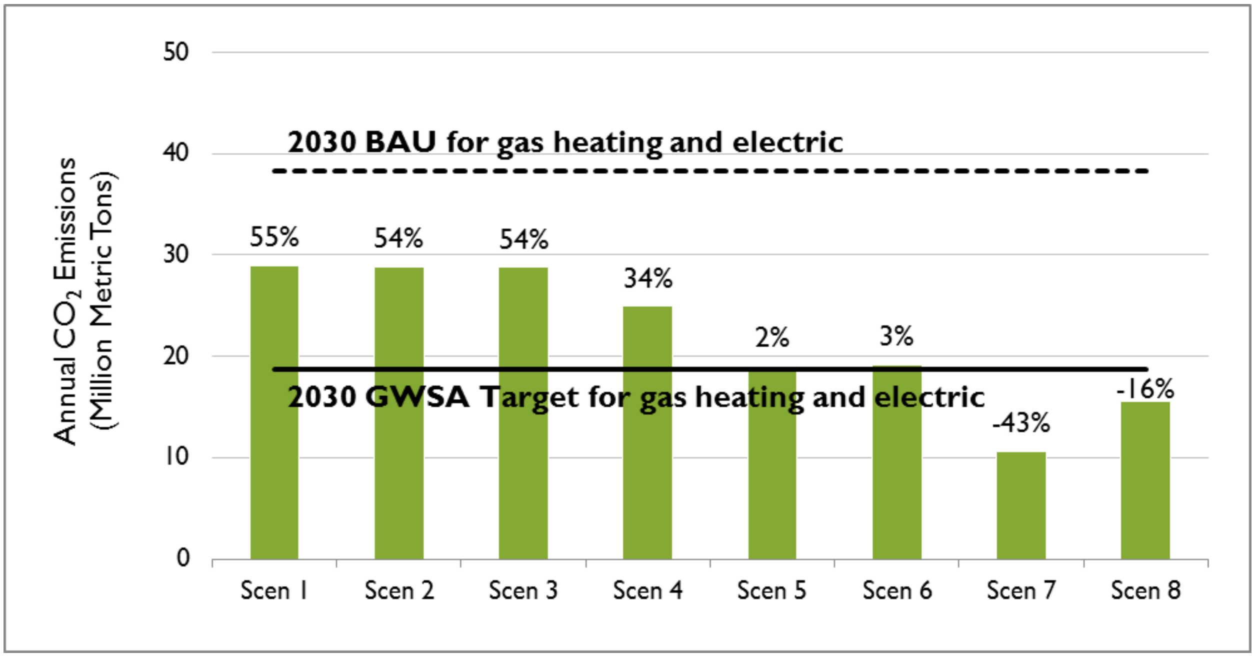
The emission level for Scenario 8 is the closest to compliance with the 2020 GWSA target (for heating and electric sectors), showing a 7-percent gap, equivalent to 1.6 million metric tons CO_2-e. The December 2013 *GWSA 5-Year Progress Report* also identified a potential shortfall in greenhouse gas reductions by 2020 for the buildings—including energy efficiency—and the electric generation sectors.

The "2020 GWSA Target for gas heating and electric" (23.3 million metric tons CO_2) is a target that would allow the GWSA 2020 emissions limit to be met, taking into account expected emissions from other sectors. The GWSA limit for state-wide greenhouse gas emissions in 2020 of 71 million metric tons CO_2 (a 25-percent reduction from 1990 baseline greenhouse gas emission levels) will require a combination of strategies including building, electricity, transportation, land use and non-energy emissions.

The emission estimates for Scenarios 1 through 8 in Figure 12 assume implementation of current Massachusetts policies. Scenarios 4 through 8 also include additional strategies determined to be economically and technically feasible by 2020 per the criteria set by the study, but do not reflect implementation of all policies considered in the CECP. Scenarios 4 and 8 include 2,400-MW of incremental Canadian transmission, 1,200-MW in 2018 and another 1,200-MW in 2022.

If additional renewable energy measures with costs higher than economic threshold (modeled in this study as the cost of incremental natural gas pipeline) were implemented for 2020 and 2030, this would serve to reduce and potentially close the gap between emission estimates from the modeled scenarios and the GWSA targets for the natural gas heating and electric sectors.

Figure 13. Annual Massachusetts gas and electric sector emissions in 2030



Note: Percentages displayed in the above chart indicate the degree to which each scenario is above the 2030 GWSA target for the gas and electric sectors. For example, the emissions in Scenario 1 are 55 percent higher than the 2030 GWSA target for the gas and electric sectors.

This approach assumes no change between 2020 and 2030 in the share of total reductions from the transportation and non-energy sectors. Transportation-related emissions are expected to rise under the CECP's business-as-usual assumptions. Policy impacts are expected to reduce emissions below business-as-usual levels. Incremental Canadian transmission is included for Scenario 4 and Scenario 8. Increased use of renewable energy in 2030—available at a higher cost than economic threshold used for this study—would reduce the emissions gap between modeled scenarios and GWSA targets.

Caveats to GWSA target assumptions

- Estimation of methane emissions from upstream leaks and other sources of emissions in the natural gas system—as well as all other life-cycle emission impacts of Massachusetts heating and electric sectors—was not in the scope of this study. Estimation of these impacts has the potential to increase greenhouse gas emissions in all scenarios. Synapse recommends that if life-cycle emission analysis is included in future scenarios it be included for all heating fuel and electric generation and alternative resources, and not for a subset of these resources.

- Estimation of emissions from leaks in the Massachusetts natural gas distribution system as well as potential emission reductions available from repairs to these leaks were not included in this study. An ICF study of Massachusetts gas leaks commissioned by MA-DPU was not released in time for use in this study. Synapse recommends that this information be considered in future studies. MA H.4164 establishes a uniform classification standard for natural gas leaks. It also requires natural gas companies to repair serious leaks immediately, produce a plan for removing all leak-prone infrastructure, and provide a summary of their progress and a summary of work to be completed every five years. The law further provides for the DPU to implement cost recovery mechanisms for LDC's to recover in a timely manner the costs of accelerated main replacement programs with intent of improving distribution system integrity, and reducing leaks and emissions. Leaks associated with interstate pipelines located in Massachusetts are minimal such that virtually all of methane emissions in Massachusetts are from distribution system pipe.

- This study does not analyze the impact that investments in pipeline infrastructure have on increasing the Commonwealth's long-term commitment to reliance on natural gas and the potential impact of this reliance on GWSA compliance.
- A Clean Energy and Climate Plan for 2030 has not yet been developed. The 2030 GWSA target is based on straight line extrapolation towards the 2050 limit and similar allocation of relative reductions from each sector as was assigned for 2020 in CECP.

4.4. Annual Costs

Figure 14 and Figure 15 depicts each scenario's annual costs as compared to costs in Scenario 1 (base case, reference gas price, no incremental Canadian transmission), respectively. Costs captured in this analysis are the costs that differ between the base case and other scenarios: the cost of gas delivery to LDCs and municipal entities, the system costs of Massachusetts's electric sector (estimated as product of Massachusetts sales and the wholesale price of energy as determined in Market Analytics), capital costs of new natural gas combine cycle plants needed to meet electric load, electric and gas energy efficiency, implementation of time-varying rates, avoided price spikes, and, in the low demand case, costs associated with gas and electric alternative resources.[28]

[28] Note that the costs associated with avoided price spikes are identical in all scenarios.

Figure 14. Annual costs for 2015-2030 as compared to Scenario 1, base case scenarios

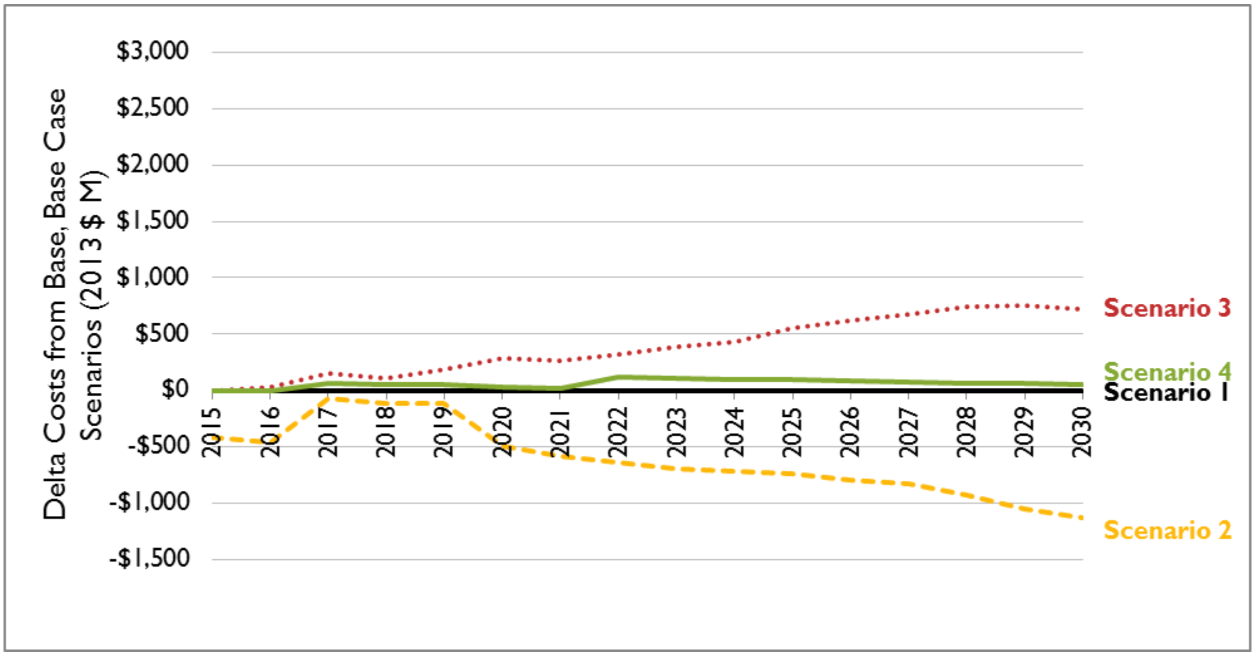


Figure 15. Annual costs for 2015-2030 as compared to Scenario 1, low demand case scenarios

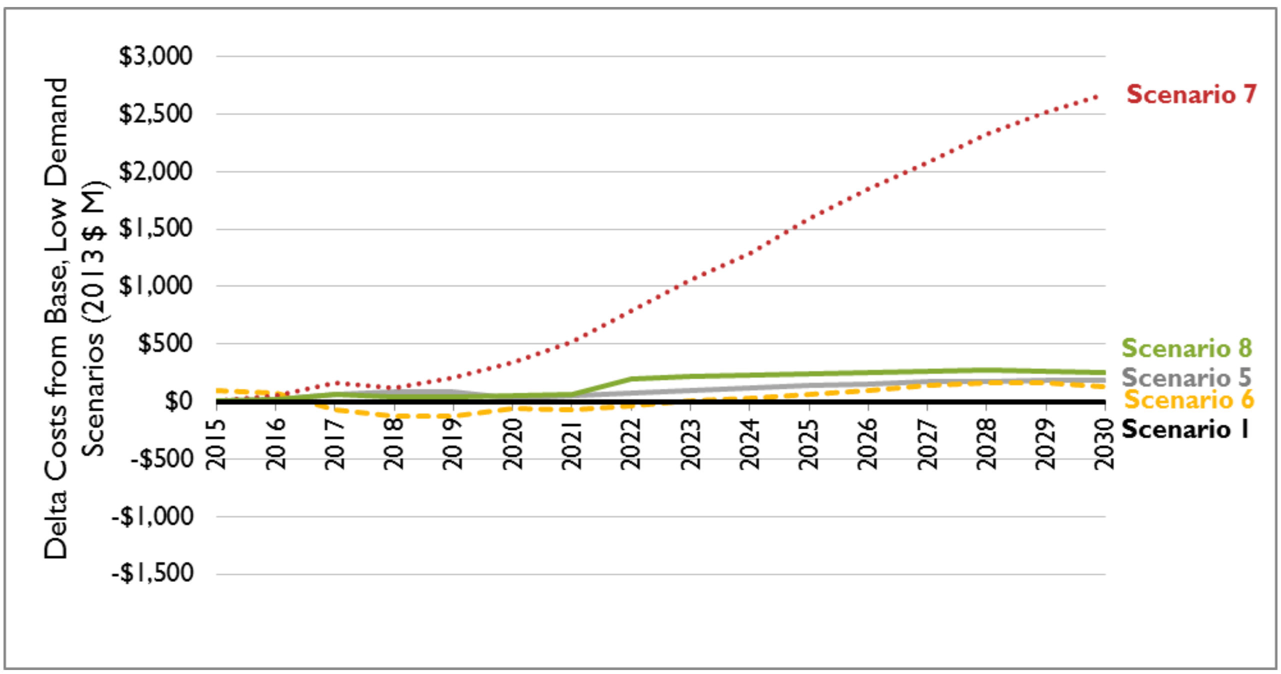


Table 7 reports the difference in each scenario's costs from that of Scenario 1 in net present value terms over the study period (2015 to 2030), compared to 2030 pipeline requirements. The addition of technically and economically feasible alternative measures (Scenario 5) adds $1,433 million in costs to Scenario 1, while the addition of both these alternative measures and a 2,400-MW incremental Canadian transmission (Scenario 8) adds $2,157 million in costs to Scenario 1. Note that in the low natural gas price sensitivity, Massachusetts costs fall in comparison to scenarios run with the reference gas price. While Scenario 2 (base case, low gas price sensitivity, no incremental Canadian transmission) has $8.6 billion in cost savings compared to Scenario 1, Scenario 6 (low demand case, low gas price sensitivity, no incremental Canadian transmission) has $0.3 billion in added costs compared to Scenario 1. This difference in costs is due to the costs of implementing the low demand measures included in Scenario 6.

Table 7. Net present value of difference in cost from Scenario 1 (in millions of 2013 dollars), 2015-2030 compared to 2030 pipeline requirements

	Scen. 1	Scen. 2	Scen. 3	Scen. 4	Scen. 5	Scen. 6	Scen. 7	Scen. 8
NPV ($ M)	$0	-$8,611	$5,384	$840	$1,433	$389	$15,112	$2,157
2030 Pipeline (Bcf/day)	0.9	0.9	0.9	0.8	0.7	0.7	0.6	0.6

Note: Assumes a 1.36 percent real discount rate per AESC 2013, Appendix B

5. OBSERVATIONS

In this section we lay out our observations from these results.

Price sensitivity of winter peak hour requirements to gas prices

Massachusetts' winter peak hour gas requirements are relatively insensitive to the range of gas prices explored in this analysis. Energy services are relatively inelastic (price insensitive)—particularly in the short run—and are modeled here as such. Changes to the gas price have a limited impact on dispatch in the electric sector in the peak hour, but the dominance of gas in the dispatchable resource mix is, already well established in 2015, only increasing over time. In contrast, annual gas requirements in the electric sector—and, therefore, electric-sector greenhouse gas emissions—do exhibit some sensitivity to gas prices in the range explored. Annual scenario costs, however, are very sensitive to gas prices.

Impact of incremental Canadian transmission

Incremental Canadian transmission at the level explored in this analysis—2,400-MW—reduces Massachusetts' winter peak hour gas requirements in 2030. It also reduces annual gas requirements and electric-sector greenhouse gas emissions while increasing overall costs.

Similarity in gas requirements across scenarios

Annual gas requirements across scenarios vary -10 to 7 percent per year from Scenario 1 (base case, reference gas price, no incremental Canadian transmission) in 2020 and -26 to 7 percent in 2030.

Impact of alternative measures

At the reference natural gas price, alternative measures reduce Massachusetts' gas requirements by 18 percent in 2030. The majority, or roughly 13 percentage points of this reduction, occurs in the electric sector. Capturing additional costs avoided by alternatives—such as costs of compliance with state environmental laws—has the potential to shift the economic feasibility assessments that determine this result. Also, additional program incentives or policies not currently in place as well as a different economic threshold could also impact the economic feasibility and resulting inclusion of additional alternative measures.

APPENDIX A: FEASIBILITY ANALYSIS

Alternative resources were assessed for feasibility. Resources that are determined to have annual MMBtu savings in 2015, 2020, or 2030 were included in that year's supply curve. Resources with annual-$/annual-MMBtu costs lower than an annual-$/annual-MMBtu cost economic threshold were modeled in the low energy demand case.

Avoided Costs

In this feasibility analysis all measures are assessed in terms of their total annual costs in the study year net of their avoided costs in that same year. As a proxy for analysis of avoided costs taking into consideration the load shape and year of implementation for each resource, we use the AESC 2013 avoided energy, capacity, transmission, distribution, and environmental compliance costs for each study year.[29] Avoided capacity, transmission and distribution costs are adjusted in relation to each resource's ISO-NE capacity credit. For energy efficiency resources only, AESC 2013 base case avoided environmental compliance costs are adjusted to include the costs of compliance with the GWSA, as described in the current MA-DPU Docket 14-86.[30] For all resources other than energy efficiency, avoided environmental compliance costs follow the AESC 2013 base case adjusted as appropriate to each resource (see Table 8).

[29] We assume that avoided energy costs are roughly proportional to gas prices (see AESC 2013 8-2 to 8-3 in support of this assumption). Using this assumption, we have updated the AESC 2013 avoided costs to reflect the natural gas prices used in this analysis using this assumption.

[30] MA-DPU 14-86, Amended Direct Testimony of Tim Woolf, September 11, 2014, Figure 4 represents these costs in levelized form.

Table 8. Avoided cost assumptions

		Electric Resources			Gas Resources	
		Energy Efficiency	*Non-EE, Distributed*	*Non-EE, Utility-Scale*	*Energy Efficiency*	*Non-EE, Distributed*
Avoided Energy	$/MWh	AESC 2013 Electric	AESC 2013 Electric	AESC 2013 Electric, Adj. for line losses	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Avoided Environmental Compliance	$/MWh	DPU 14-86	AESC 2013 Electric	AESC 2013 Electric	DPU 14-86	None
Avoided Capacity	$/kW	AESC 2013 Electric	None	None	None	None
Avoided Transmission and Distribution	$/kW	AESC 2013 Electric	AESC 2013 Electric	None	AESC 2013 Natural Gas	AESC 2013 Natural Gas
Non-Energy Benefits	$/MWh	DPU 14-86	None	None	DPU 14-86	None
Capacity Revenue	$/kW	None	AESC 2013 Electric	AESC 2013 Electric	None	None

Many of the resources explored in the feasibility analysis have an impact on removing gas capacity constraints and, therefore, some impact on avoiding costs associated with constraint-elevated gas prices. However, in keeping with our assumption that a balance between gas capacity and demand is achieved in all scenarios, we do not capture this avoided cost here (although we do in modeling scenario costs, as described below). Similarly, alternatives resources may avoid some share of the cost of a new natural gas pipeline—and pipelines may avoid the cost of new alternative resources. We do not attempt to capture these costs in this feasibility analysis. Rather, we use the cost of a generic, scalable natural gas pipeline as the economic threshold determining which of the alternative resources in the feasibility analysis are included in the low demand case.

Resource Assessments

Synapse assessed 28 resources as potential alternative measures for inclusion in the low energy demand case. Detailed tables showing assumption by year and resources are presented below in this Appendix. Note that the costs described here use the reference natural gas price. Supply curves for all three natural gas prices are presented below.

Wind

For on-shore wind installations 10 kilowatts (kW) or less, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 16 percent. Annual levelized costs fall from $760 per megawatt-hour (MWh) in 2015 to $592/MWh in 2030.[31] (Net of avoided costs these values are $655/MWh and $457/MWh, respectively.) These assumptions are based personal communications with wind developers.[32]

For on-shore wind installation greater than 10 kW up to 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 1 MW by 2015, 100 MW from 2016 to 2020, and 300 MW from 2021 to 2030 with an annual capacity factor of 25 percent. Annual levelized costs fall from $218/MWh in 2015 to $156/MWh in 2030. (Net of avoided costs these values are $123/MWh and $32/MWh, respectively.) These assumptions are based on personal communications with wind developers.[33]

For Class 5 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 200 MW from 2016 to 2020, and 480 MW from 2021 to 2030 with annual capacity factors of 41 to 42 percent. Annual levelized costs fall from $113/MWh in 2020 to $111/MWh in 2030. (Net of avoided costs these values are $38/MWh and $8/MWh, respectively.) These assumptions are based on National Renewable Energy Laboratory (NREL) supply curves for New England wind regions.

For Class 4 on-shore wind installation greater than 100 kW, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 0 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factor of 40 percent. Annual levelized costs are $118/MWh in 2030. (Levelized costs net of avoided costs are $14/MWh in 2030.) These assumptions are based on NREL supply curves for New England wind regions.

For off-shore wind installation, incremental to wind in the base case, we assume a total potential capacity addition of 0 MW by 2015, 800 MW from 2016 to 2020, and 4,000 MW from 2021 to 2030 with annual capacity factors of 44 to 45 percent. Annual levelized costs fall from $207/MWh in 2020 to $162/MWh in 2030. (Net of avoided costs these values are $133/MWh and $59/MWh, respectively.) These assumptions are based on NREL supply curves for New England wind regions.

In addition, we added costs to all large on-shore wind incremental to the base case, to represent the levelized cost of new transmission necessary to deliver incremental wind from Maine south to the major New England load centers. We assume a real, levelized cost of new transmission of $35 per MWh, based

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[31] All dollar values in the memo are report in real (inflation-adjusted) 2013 dollars

[32] Personal Communications with Katrina Prutzman, Urban Green Energy. October 2014.

[33] Personal Communications with Trevor Atkinson, Northern Power. October 2014.

on a cost of $2.15 billion for 1,200 MW of capacity recovered over 30 years. This cost assumption is from work Synapse recently performed for DOER.[34]

Solar

For residential photovoltaic (PV) installations, incremental to PV in the base case, we assume a total potential capacity addition of200 kW by 2015, 5 MW from 2016 to 2020, and 200 MW from 2021 to 2030 with an annual capacity factor of 13 percent. Annual levelized costs fall from $211/MWh in 2015 to $163/MWh in 2030. (Net of avoided costs these values are $100/MWh and $19/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER;[35] 2030 assumptions are Synapse estimates.

For commercial PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 1.6 MW by 2015, 50 MW from 2016 to 2020, and 800 MW from 2021 to 2030 with an annual capacity factor of 14 percent. Annual levelized costs fall from $184/MWh in 2015 to $149/MWh in 2030. (Net of avoided costs these values are $75/MWh and $9/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

For utility-scale PV installations, incremental to PV in the base case, we assume a total potential capacity addition of 0 MW by 2015, 16 MW from 2016 to 2020, and 160 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $162/MWh in 2020 to $118/MWh in 2030. (Net of avoided costs these values are $76/MWh and $3/MWh, respectively.) These cost and capacity factor assumptions for 2015 and 2020 are based on work done in 2013 for DOER; 2030 assumptions are Synapse estimates.

Non-Powered Hydro Conversion

For hydro installations at dam sites that are not currently producing electricity, we assume a total potential capacity addition of 500 kW by 2015, 61 MW from 2016 to 2020, and 56 MW from 2021 to 2030 with an annual capacity factor of 38 percent. Annual levelized costs are constant over the study period at $63/MWh. (Net of avoided costs these values are -$35/MWh, -$37/MWh, and -$67/MWh, respectively.) These assumptions are based on an Ohio Case study of converting a dam site to generate electricity and the EIA's *Annual Energy Outlook* capital and operating costs forecast.[36]

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[34] Hornby, Rick, et al., *Memorandum: Incremental Benefits and Costs of Large-Scale Hydroelectric Energy Imports*, prepared by Synapse Energy Economics for the Massachusetts Department of Energy Resources, November 1, 2013.

[35] http://www.mass.gov/eea/docs/doer/rps-aps/doer-post-400-task-1.pdf

[36] http://www.hydro.org/tech-and-policy/developing-hydro/powering-existing-dams/
http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf

Landfill Gas

For landfill gas installations, incremental to landfill gas in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 78 percent. Annual levelized costs are constant over the study period at $38/MWh. (Net of avoided costs these values fall from -$47/MWh in 2015 to -$75/MWh in 2030.) These assumptions are based on the 2012 U.S. Environmental Protection Agency's *Landfill Gas Energy* study.[37]

Anaerobic Digestion

For anaerobic digestion installations, incremental to anaerobic digestion in the base case, we assume a total potential capacity addition of 300 kW by 2015, 20 MW from 2016 to 2020, and 6 MW from 2021 to 2030 with an annual capacity factor of 90 percent. Annual levelized costs are constant over the study period at $47/MWh. (Net of avoided costs these values fall from -$54/MWh in 2015 to -$83/MWh in 2030.) These assumptions are based on a 2003 Wisconsin case study presented in the *Focus on Energy Anaerobic Digester Methane to Energy* statewide assessment.[38]

Biomass

For biomass Class 1 installations (with fuel costs of $3/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 20 MW from 2016 to 2020, and 20 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $110/MWh. (Net of avoided costs these values fall from $27/MWh in 2020 to -$2/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and Office of Energy Efficiency and Renewable Energy (EERE).[39]

For biomass Class 2 installations (with fuel costs of $4/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 40 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $128/MWh. (Net of avoided costs these values fall from $44/MWh in 2020 to $15/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

For biomass Class 3 installations (with fuel costs of $10/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 40 MW from 2016 to 2020, and 60 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $214/MWh. (Net of avoided costs these values fall from $130/MWh in 2020 to $102/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

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[37] http://epa.gov/statelocalclimate/documents/pdf/landfill_methane_utilization.pdf

[38] http://www.mrec.org/pubs/anaerobic_report.pdf

[39] http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf; http://bv.com/docs/reports-studies/nrel-cost-report.pdf; http://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf

For biomass Class 4 installations (with fuel costs of $13/MMBtu), incremental to biomass in the base case, we assume a total potential capacity addition of 0 MW by 2015, 50 MW from 2016 to 2020, and 70 MW from 2021 to 2030 with an annual capacity factor of 80 percent. Annual levelized costs are constant over the study period at $259/MWh. (Net of avoided costs these values fall from $175/MWh in 2020 to $146/MWh in 2030.) These assumptions are based on analyses by EIA, Black & Veatch, and EERE.

CHP

For small combined heat and power (CHP) installations (estimated as 500 kW reciprocating engines), incremental to CHP in the base case, we assume a total potential capacity addition of 5 MW by 2015, 35 MW from 2016 to 2020, and 65 MW from 2021 to 2030 with an annual capacity factor of 50 percent. Annual levelized costs rise from $135/MWh in 2015 to $153/MWh in 2030. (Net of avoided costs these values are -$12/MWh and -$34/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.[40]

For large combined heat and power (CHP) installations (estimated as 12.5 MW combustion turbines), incremental to CHP in the base case, we assume a total potential capacity addition of 0 MW by 2015, 25 MW from 2016 to 2020, and 50 MW from 2021 to 2030 with an annual capacity factor of67 percent. Annual levelized costs rise from $77/MWh in 2020 to $84/MWh in 2030. (Net of avoided costs these values are -$46/MWh and -$78/MWh, respectively.) These assumptions are based on ICF's 2013 *The Opportunity for CHP in the U.S.* report.

Electric Energy Efficiency

For residential electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 28 MW from 2016 to 2020, and 64 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $9/MWh. (Net of avoided costs these values are -$108/MWh in 2020 and -$128/MWh in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For commercial and industrial electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 113 MW from 2016 to 2020, and 380 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs are constant over the study period at $31/MWh. (Net of avoided costs these values are -$86/MWh in 2020 and -$107/MWh in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For low-income electric energy efficiency installations, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 MW by 2015, 3 MW from 2016 to 2020, and 7 MW from

[40] http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Documents/The%20Opportunity%20for%20CHP%20in%20the%20United%20States%20-%20Final%20Report.pdf

2021 to 2030 with an annual capacity factor of %55 percent. Annual levelized costs are constant over the study period at $104/MWh. (Net of avoided costs these values are -$13/MWh and -$33/MWh, respectively.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Efficiency costs are modeled from program administrators' three-year plan data and are assumed to be the same on a $/MWh basis as the costs used for the base case. If efficiency costs were, instead, assumed to increase for additional increments of efficiency, even the efficiency sector with the highest costs—low-income gas measures—would require a cost escalation of more than 80 percent to exceed the economic threshold.

Federal Appliance Standard

For federal appliance standards, incremental to federal standards in the base case, we assume a total potential capacity addition of 0 MW by 2015, 216 MW from 2016 to 2020, and 619 MW from 2021 to 2030 with an annual capacity factor of 55 percent. Annual levelized costs rise from -$205/MWh in 2020 to -$205/MWh in 2030. (Net of avoided costs these values are -$390/MWh and -$343/MWh, respectively.) These savings and cost assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Heat Pumps

For air source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 6,307 annual MMBtu by 2015, 75,686 annual MMBtu from 2016 to 2020, and 1,127,727 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $18/MMBtu in 2015 to $26/MMBtu in 2030. (Net of avoided costs these values are $17/MMBtu and $25/MMBtu, respectively.) These savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[41] Cost assumptions are based on a 2010 NREL webinar, *Residential Geothermal Heat Pump Retrofits*.[42]

For ground source heat pump installation, incremental to heat pumps in the base case, we assume a total potential capacity addition of 1,577 annual MMBtu by 2015, 18,922 annual MMBtu from 2016 to 2020, and 281,932 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $16/MMBtu in 2015 to $22/MMBtu in 2030. (Net of avoided costs these values are $15/MMBtu and $20/MMBtu, respectively.) These savings and cost assumptions are based on DOER's assessment of the gas savings

[41] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[42] http://energy.gov/eere/wipo/downloads/doe-webinar-residential-geothermal-heat-pump-retrofits-presentation

available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[43]

Solar Hot Water

For solar hot water installation, incremental to solar hot water in the base case, we assume a total potential capacity addition of 1573 annual MMBtu by 2015, 18,896 annual MMBtu from 2016 to 2020, and 281,607 annual MMBtu from 2021 to 2030. Annual levelized costs rise from $53/MMBtu in 2015 to $86/MMBtu in 2030. (Net of avoided costs these values are $9/MMBtu and $32/MMBtu, respectively.) These savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[44] Cost assumptions are based on communications with solar hot water vendors.

Thermal Biomass

For thermal biomass installation, incremental to thermal biomass in the base case, we assume a total potential capacity addition of 6291 annual MMBtu by 2015, 75,586 annual MMBtu from 2016 to 2020, and 1,126,428 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at $16/MMBtu. (Net of avoided costs these values are $9/MMBtu in 2015 and $7/MMBtu in 2020.) Cost and savings assumptions are based on DOER's assessment of the gas savings available from the measures described in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors.[45]

Gas Energy Efficiency

For residential gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 3,758,369 annual MMBtu from 2016 to 2020, and 5,290,473 MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at -$72/MMBtu. (Net of avoided costs these values are -$78/MMBtu in 2015 and -$79/MMbtu in 20230.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For commercial and industrial gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 4,121,834 annual MMBtu from 2016 to 2020, and 9,748,498 annual MMBtu from 2021 to 2030. Annual levelized costs are

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43 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

44 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

45 http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

constant over the study period at -$17/MMBtu. (Net of avoided costs these values are -$23/MMBtu in 2020 and -$25/MMBtu in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

For low-income gas energy efficiency installation, incremental to efficiency in the base case, we assume a total potential capacity addition of 0 annual MMBtu by 2015, 584,036 annual MMBtu from 2016 to 2020, and 1,818,671 annual MMBtu from 2021 to 2030. Annual levelized costs are constant over the study period at -$9/MMBtu. (Net of avoided costs these values are -$15/MMBtu in 2020 and -$17/MMBtu in 2030.) These assumptions are based on the Massachusetts Clean Energy and Climate Plan as modeled in DPU 14-86.

Efficiency costs are modeled from program administrators' three-year plan data and are assumed to be the same on a $/MWh basis as the costs used for the base case. If efficiency costs were, instead, assumed to increase for additional increments of efficiency, even the efficiency sector with the highest costs—low-income gas measures—would require a cost escalation of more than 80 percent to exceed the economic threshold.

Feasibility Analysis Results

The feasibility analysis methodology employed in this report compares measures' annual-$/annual-MMBtu to thresholds for economic feasibility in annual-$/annual –MMBtu. Supply curves for 2015, 2020 and 2030 using the reference natural gas price are displayed in Figure 16, Figure 17 and Figure 18, and Table 9, Table 10, and Table 11. Measures with negative annual net levelized costs (i.e., net benefits) are shown in blue while measures with positive annual net levelized costs are shown in red. Due to large differences in the scale of resource availability, the supply curve for 2015 is presented in billion Btu and the supply curves for 2020 and 2030 are presented in trillion Btu. Table 12, Table 13, and Table 14 summarize the cost and savings for each measure available for each scenario in the Reference natural gas price case, while Table 21, Table 22, and Table 23 provide additional detail on costs and savings. Note that savings for each scenario remain the same across different natural gas prices, but net costs may change as a result of different avoided costs.

Supply curves for 2015, 2020 and 2030 using the low natural gas price are displayed in Table 15, Table 16, and Table 17. Supply curves for 2015, 2020 and 2030 using the high natural gas price are displayed in Table 18, Table 19, and Table 20.

Figure 16. Reference natural gas price supply curve for 2015 (billion Btu)

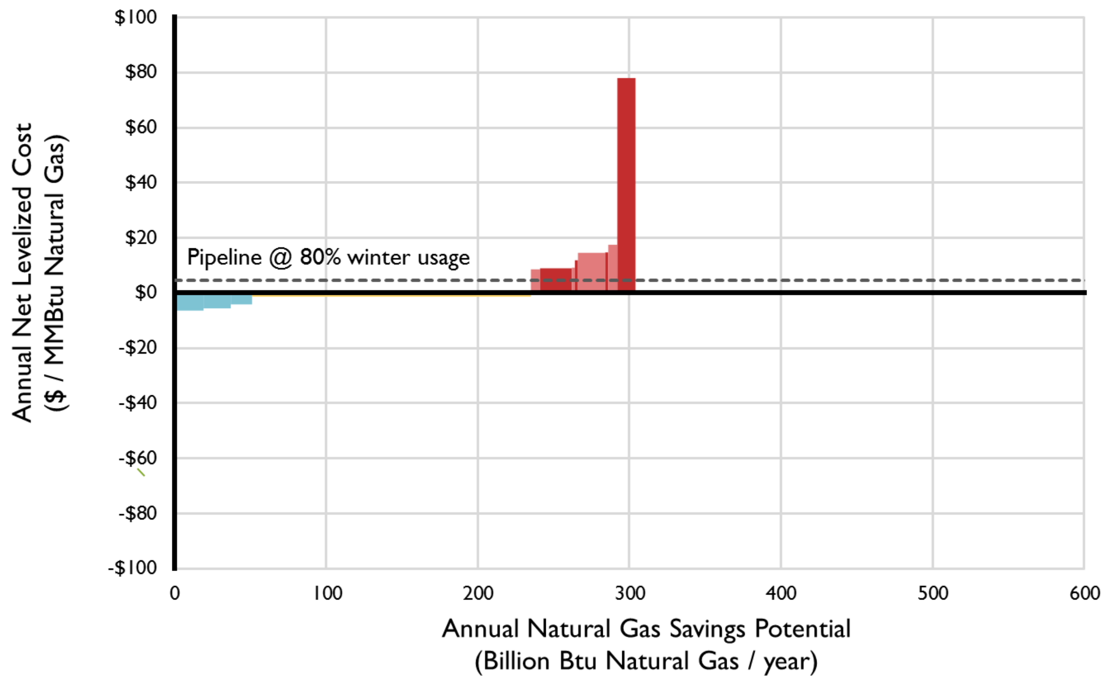

Table 9. Reference natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$6	20
2	Landfill Gas	-$6	17
3	Converted Hydro	-$4	14
4	Small CHP	-$1	184
Pipeline @ 80% winter usage		$4	-
5	Biomass Thermal	$9	6
6	Commercial PV	$9	21
7	Solar Hot Water	$9	2
8	Residential PV	$12	2
9	Wind (<100 kW)	$15	18
10	GS Heat Pump	$15	2
11	AS Heat Pump	$17	6
12	Wind (<10 kW)	$78	12

Figure 17. Reference natural gas price supply curve for 2020 (trillion Btu; note unit change from previous figures)

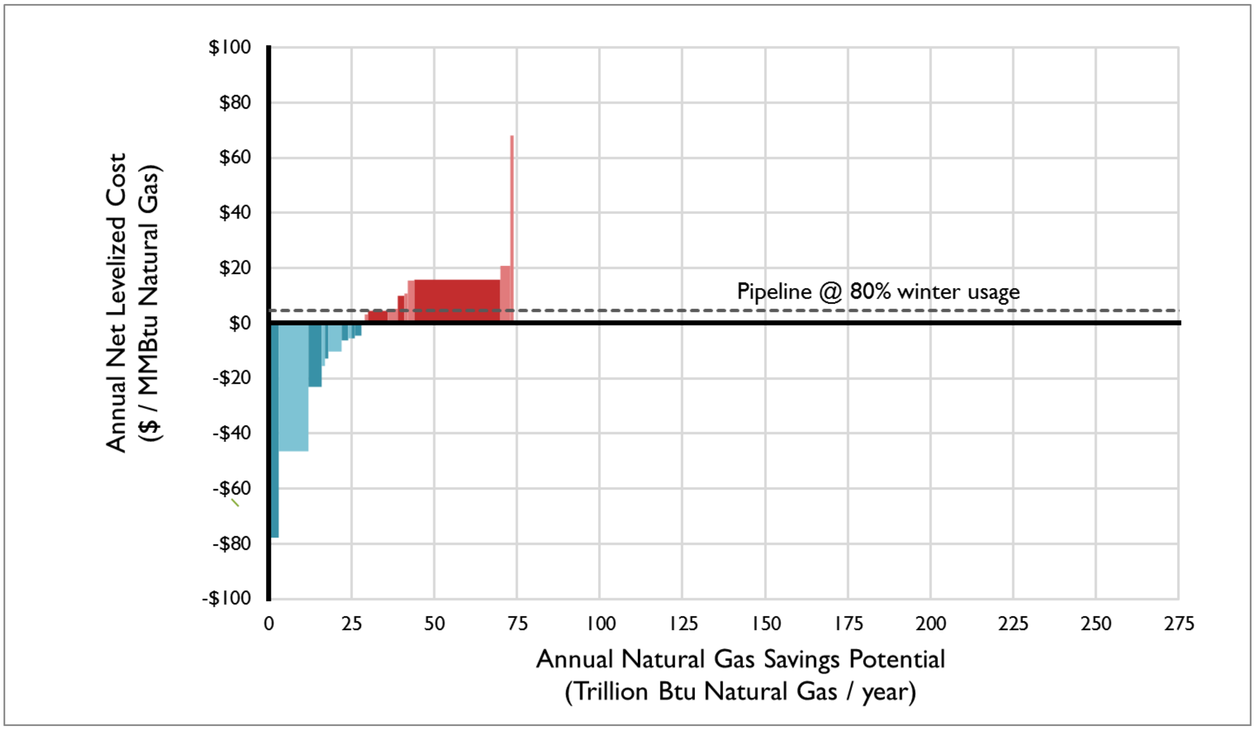

Table 10. Reference natural gas price supply curve for 2020 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$78	4
2	Appliance Standards	-$46	9
3	CI Gas EE	-$23	4
4	LI Gas EE	-$15	1
5	Res. Electric EE	-$13	1
6	CI Electric EE	-$10	5
7	Anaerobic Digestion	-$6	1
8	Landfill Gas	-$5	1
9	Large CHP	-$5	1
10	Converted Hydro	-$4	2
11	LI Electric EE	-$2	0.1
12	Small CHP	$0.4	1
13	Biomass Power C1	$3	1
Pipeline @ 80% winter usage		$4	-
14	Large Wind C5	$5	6
15	Biomass Power C2	$5	2
16	Utility-Scale PV	$9	0.2
17	Biomass Thermal	$9	0.1
18	Wind (<100 kW)	$10	2
19	Commercial PV	$11	1
20	Residential PV	$13	0.05
21	Biomass Power C3	$16	2
22	Offshore Wind	$16	26
23	GS Heat Pump	$16	0.02
24	AS Heat Pump	$20	0.1
25	Biomass Power C4	$21	3
26	Solar Hot Water	$24	0.02
27	Wind (<10 kW)	$68	1

Figure 18. Reference natural gas price supply curve for 2030 (trillion Btu)

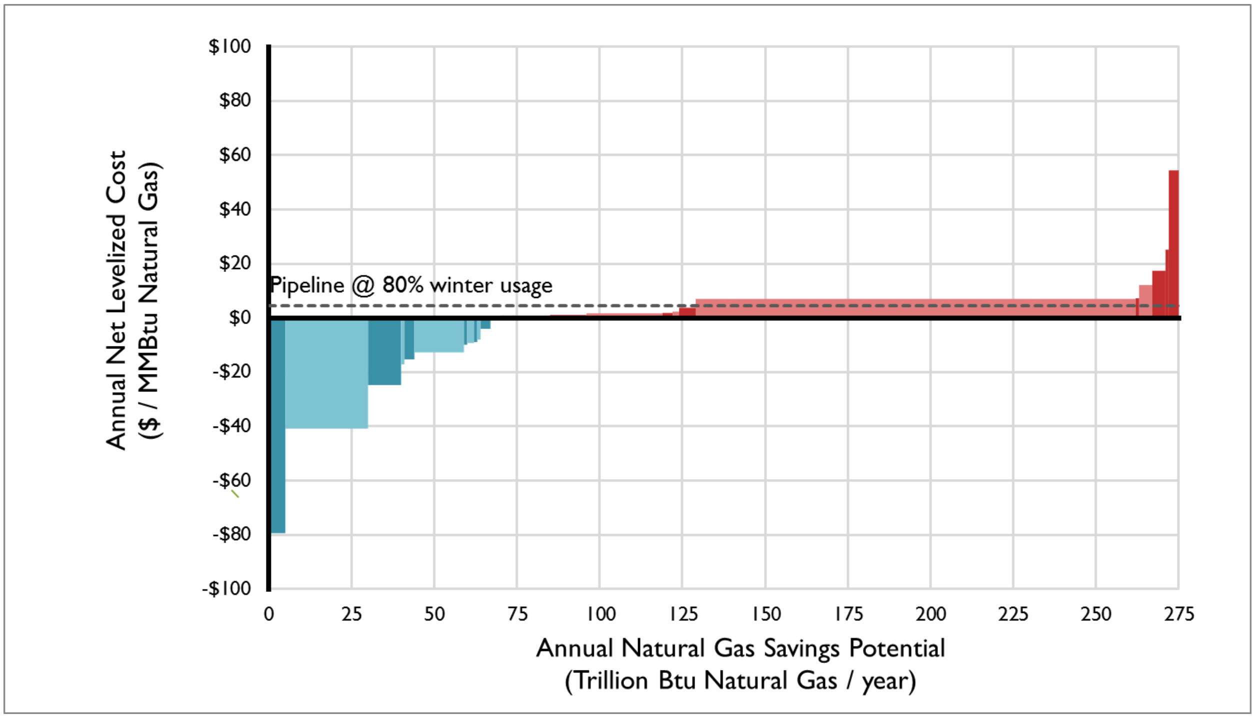

Table 11. Reference natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$41	25
3	CI Gas EE	-$25	10
4	LI Gas EE	-$17	2
5	Res. Electric EE	-$15	3
6	CI Electric EE	-$13	15
7	Anaerobic Digestion	-$10	0.4
8	Large CHP	-$9	2
9	Landfill Gas	-$9	0.3
10	Converted Hydro	-$8	2
11	Small CHP	-$4	2
12	LI Electric EE	-$4	0.3
13	Biomass Power C1	-$0.2	1
14	Utility-Scale PV	$0	2
15	Large Wind C5	$1	15
16	Commercial PV	$1	11
17	Large Wind C4	$2	24
18	Biomass Power C2	$2	2
19	Residential PV	$2	2
20	Wind (<100 kW)	$4	6
Pipeline @ 80% winter usage		$4	-
21	Offshore Wind	$7	132
22	Biomass Thermal	$7	1
23	Biomass Power C3	$12	4
24	Biomass Power C4	$17	4
25	GS Heat Pump	$20	0.3
26	AS Heat Pump	$25	1
27	Solar Hot Water	$32	0.3
28	Wind (<10 kW)	$54	2

Table 12. Reference gas price resource assessment summary for 2015

Electricity Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
Wind (<10 kW)	16%	1	$655	$78	11,773	3
Wind (<100 kW)	25%	1	$123	$15	18,396	3
Large Wind C5	no incremental capacity available by 2015					
Large Wind C4	no incremental capacity available by 2015					
Offshore Wind	no incremental capacity available by 2015					
Utility-Scale PV	no incremental capacity available by 2015					
Commercial PV	14%	2	$75	$9	21,192	0
Residential PV	13%	0	$100	$12	2,391	0
Large CHP	no incremental capacity available by 2015					
Small CHP	50%	5	-$12	-$1	183,960	19
Landfill Gas	78%	0	-$47	-$6	17,325	2
Anaerobic Digestion	90%	0	-$54	-$6	19,868	2
Biomass Power C1	no incremental capacity available by 2015					
Biomass Power C2	no incremental capacity available by 2015					
Biomass Power C3	no incremental capacity available by 2015					
Biomass Power C4	no incremental capacity available by 2015					
Converted Hydro	38%	1	-$35	-$4	14,000	4
Res. Electric EE	55%	0	-$117	-$14	0	0
LI Electric EE	55%	0	-$22	-$3	0	0
CI Electric EE	55%	0	-$96	-$11	0	0
Appliance Standards	no incremental capacity available by 2015					

Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump	0%	0	$0	$17	6,307	9
GS Heat Pump	0%	0	$0	$15	1,577	2
Solar Hot Water	0%	0	$0	$9	1,573	0
Biomass Thermal	0%	0	$0	$9	6,291	10
Res. Gas EE	0%	0	$0	-$78	0	0
LI Gas EE	0%	0	$0	-$15	0	0
CI Gas EE	0%	0	$0	-$23	0	0

Table 13. Reference gas price resource assessment summary for 2020

Electricity Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
Wind (<10 kW)	16%	100	$572	$68	1,177,344	266
Wind (<100 kW)	25%	100	$84	$10	1,839,600	266
Large Wind C5	41%	200	$38	$5	6,033,888	532
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)					
Offshore Wind	44%	800	$133	$16	25,901,568	2,128
Utility-Scale PV	15%	16	$76	$9	216,337	0
Commercial PV	14%	50	$91	$11	662,256	0
Residential PV	13%	5	$106	$13	47,830	0
Large CHP	67%	25	-$46	-$5	1,232,532	59
Small CHP	50%	35	$3	$0	1,287,720	136
Landfill Gas	78%	20	-$46	-$5	1,155,000	144
Anaerobic Digestion	90%	20	-$52	-$6	1,324,512	144
Biomass Power C1	80%	20	$27	$3	1,177,344	144
Biomass Power C2	80%	40	$44	$5	2,354,688	289
Biomass Power C3	80%	40	$130	$16	2,354,688	289
Biomass Power C4	80%	50	$175	$21	2,943,360	361
Converted Hydro	38%	61	-$37	-$4	1,708,000	440
Res. Electric EE	55%	28	-$108	-$13	1,147,100	118
LI Electric EE	55%	3	-$13	-$2	138,528	14
CI Electric EE	55%	113	-$86	-$10	4,577,386	473
Appliance Standards	55%	216	-$390	-$46	8,736,000	902
Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor %	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump	0%	0	$0	$20	75,686	104
GS Heat Pump	0%	0	$0	$16	18,922	26
Solar Hot Water	0%	0	$0	$24	18,896	0
Biomass Thermal	0%	0	$0	$9	75,586	125
Res. Gas EE	0%	0	$0	-$78	3,758,369	236
LI Gas EE	0%	0	$0	-$15	584,036	37
CI Gas EE	0%	0	$0	-$23	4,121,834	259

Table 14. Reference gas price resource assessment summary for 2030

Electricity Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
Wind (<10 kW)	16%	200	$457	$54	2,354,688	532
Wind (<100 kW)	25%	300	$32	$4	5,518,800	798
Large Wind C5	42%	480	$8	$1	14,834,534	1,277
Large Wind C4	40%	800	$14	$2	23,546,880	2,128
Offshore Wind	45%	4,000	$59	$7	132,451,200	10,640
Utility-Scale PV	15%	160	$3	$0	2,163,370	0
Commercial PV	14%	800	$9	$1	10,596,096	0
Residential PV	13%	200	$19	$2	2,391,480	0
Large CHP	67%	50	-$78	-$9	2,465,064	118
Small CHP	50%	65	-$34	-$4	2,391,480	252
Landfill Gas	78%	6	-$75	-$9	346,500	43
Anaerobic Digestion	90%	6	-$83	-$10	397,354	43
Biomass Power C1	80%	20	-$2	$0	1,177,344	144
Biomass Power C2	80%	40	$15	$2	2,354,688	289
Biomass Power C3	80%	60	$102	$12	3,532,032	433
Biomass Power C4	80%	70	$146	$17	4,120,704	505
Converted Hydro	38%	56	-$67	-$8	1,568,000	404
Res. Electric EE	55%	64	-$128	-$15	2,604,729	269
LI Electric EE	55%	7	-$33	-$4	301,858	31
CI Electric EE	55%	380	-$107	-$13	15,382,106	1,589
Appliance Standards	55%	619	-$343	-$41	25,048,800	2,587

Direct Gas Reduction Technologies						
Technology	Annual Capacity Factor *%*	Total Potential Capacity *MW*	Annual Net Levelized Cost *$/MWh*	Annual Net Levelized Cost *$/MMBtu NG*	Annual Energy Production *MMBtu NG*	Peak Hour Gas Savings *MMBtu NG*
AS Heat Pump	0%	0	$0	$25	1,127,727	1,549
GS Heat Pump	0%	0	$0	$20	281,932	387
Solar Hot Water	0%	0	$0	$32	281,607	4
Biomass Thermal	0%	0	$0	$7	1,126,428	1,869
Res. Gas EE	0%	0	$0	-$79	5,290,473	332
LI Gas EE	0%	0	$0	-$17	1,818,671	114
CI Gas EE	0%	0	$0	-$25	9,748,498	612

Table 15. Low natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$5	20
2	Landfill Gas	-$5	17
3	Converted Hydro	-$3	14
4	Small CHP	$0.02	184
Pipeline @ 80% winter usage		$4	-
5	Biomass Thermal	$9	6
6	Commercial PV	$10	21
7	Residential PV	$13	2
8	GS Heat Pump	$15	2
9	Wind (<100 kW)	$16	18
10	Solar Hot Water	$17	2
11	AS Heat Pump	$18	6
12	Wind (<10 kW)	$79	12

Table 16. Low natural gas price supply curve for 2020 (trillion Btu; note unit change from previous table)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	Res. Gas EE	-$77	4
2	Appliance Standards	-$45	9
3	CI Gas EE	-$22	4
4	LI Gas EE	-$14	1
5	Res. Electric EE	-$11	1
6	CI Electric EE	-$8	5
7	Anaerobic Digestion	-$5	1
8	Landfill Gas	-$4	1
9	Large CHP	-$4	1
10	Converted Hydro	-$3	2
11	LI Electric EE	$0.3	0.1
12	Small CHP	$2	1
Pipeline @ 80% winter usage		$4	-
13	Biomass Power C1	$4	1
14	Large Wind C5	$6	6
15	Biomass Power C2	$7	2
16	Utility-Scale PV	$10	0.2
17	Biomass Thermal	$11	0.1
18	Wind (<100 kW)	$11	2
19	Commercial PV	$12	1
20	Residential PV	$14	0.05
21	Biomass Power C3	$17	2
22	GS Heat Pump	$17	0.02
23	Offshore Wind	$17	26
24	AS Heat Pump	$20	0.1
25	Biomass Power C4	$22	3
26	Solar Hot Water	$39	0.02
27	Wind (<10 kW)	$70	1

Table 17. Low natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$38	25
3	CI Gas EE	-$23	10
4	LI Gas EE	-$15	2
5	Res. Electric EE	-$12	3
6	CI Electric EE	-$10	15
7	Anaerobic Digestion	-$7	0.4
8	Landfill Gas	-$7	0.3
9	Large CHP	-$6	2
10	Converted Hydro	-$6	2
11	LI Electric EE	-$1	0.3
12	Small CHP	-$0.1	2
13	Biomass Power C1	$2	1
14	Utility-Scale PV	$3	2
15	Large Wind C5	$3	15
16	Commercial PV	$4	11
17	Large Wind C4	$4	24
18	Biomass Power C2	$4	2
Pipeline @ 80% winter usage		$4	-
19	Residential PV	$5	2
20	Wind (<100 kW)	$6	6
21	Offshore Wind	$9	132
22	Biomass Thermal	$10	1
23	Biomass Power C3	$14	4
24	Biomass Power C4	$20	4
25	GS Heat Pump	$21	0.3
26	AS Heat Pump	$26	1
27	Wind (<10 kW)	$57	2
28	Solar Hot Water	$68	0.3

Table 18. High natural gas price supply curve for 2015 (billion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (billion Btu)*
1	Anaerobic Digestion	-$8	20
2	Landfill Gas	-$7	17
3	Converted Hydro	-$5	14
4	Small CHP	-$3	184
5	Solar Hot Water	$1	2
Pipeline @ 80% winter usage		$4	-
6	Biomass Thermal	$7	6
7	Commercial PV	$8	21
8	Residential PV	$10	2
9	Wind (<100 kW)	$13	18
10	GS Heat Pump	$15	2
11	AS Heat Pump	$17	6
12	Wind (<10 kW)	$77	12

Table 19. High natural gas price supply curve for 2020 (trillion Btu; note unit change from previous table)

		Annual Net Levelized Cost ($/MMBtu)	Annual Savings Potential (trillion Btu)
1	Res. Gas EE	-$80	4
2	Appliance Standards	-$50	9
3	CI Gas EE	-$25	4
4	LI Gas EE	-$17	1
5	Res. Electric EE	-$16	1
6	CI Electric EE	-$14	5
7	Anaerobic Digestion	-$9	1
8	Large CHP	-$9	1
9	Landfill Gas	-$8	1
10	Converted Hydro	-$7	2
11	LI Electric EE	-$5	0.1
12	Small CHP	-$3	1
13	Biomass Power C1	$1	1
14	Large Wind C5	$2	6
15	Biomass Power C2	$3	2
Pipeline @ 80% winter usage		$4	-
16	Utility-Scale PV	$7	0.2
17	Wind (<100 kW)	$7	2
18	Biomass Thermal	$7	0.1
19	Commercial PV	$8	1
20	Residential PV	$10	0.05
21	Biomass Power C3	$13	2
22	Offshore Wind	$13	26
23	Solar Hot Water	$13	0
24	GS Heat Pump	$16	0.02
25	Biomass Power C4	$18	3
26	AS Heat Pump	$20	0.1
27	Wind (<10 kW)	$65	1

Table 20. High natural gas price supply curve for 2030 (trillion Btu)

		Annual Net Levelized Cost ($/MMBtu)	*Annual Savings Potential (trillion Btu)*
1	Res. Gas EE	-$79	5
2	Appliance Standards	-$49	25
3	CI Gas EE	-$28	10
4	Res. Electric EE	-$24	3
5	CI Electric EE	-$21	15
6	LI Gas EE	-$20	2
7	Large CHP	-$18	2
8	Anaerobic Digestion	-$17	0.4
9	Landfill Gas	-$16	0.3
10	Converted Hydro	-$15	2
11	Small CHP	-$13	2
12	LI Electric EE	-$13	0.3
13	Biomass Power C1	-$7	1
14	Utility-Scale PV	-$6	2
15	Commercial PV	-$6	11
16	Large Wind C5	-$6	15
17	Large Wind C4	-$5	24
18	Residential PV	-$5	2
19	Biomass Power C2	-$5	2
20	Wind (<100 kW)	-$3	6
21	Offshore Wind	$0.4	132
22	Biomass Thermal	$4	1
Pipeline @ 80% winter usage		$4	-
23	Biomass Power C3	$5	4
24	Biomass Power C4	$11	4
25	GS Heat Pump	$20	0.3
26	AS Heat Pump	$26	1.1
27	Solar Hot Water	$31	0.3
28	Wind (<10 kW)	$47	2

Table 21. Reference gas price resource assessment for 2015

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	*%*	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MMBtu NG*	*%*	*MMBtu NG*
Wind (<10 kW)	16%	1.0	1,402	11,773	$11,500	20	9.0%	$25	$0	$0	$760	$79		$26	$655	$78	35%	3
Wind (<100 kW)	25%	1.0	2,190	18,396	$5,000	20	9.0%	$25	$0	$0	$218	$79		$16	$123	$15	35%	3
Large Wind C5	no incremental capacity available by 2015																	
Large Wind C4	no incremental capacity available by 2015																	
Offshore Wind	no incremental capacity available by 2015																	
Utility-Scale PV	no incremental capacity available by 2015																	
Commercial PV	14%	1.6	2,523	21,192	$2,593	25	8.0%	$25	$0	$0	$184	$79		$30	$75	$9	0%	0
Residential PV	13%	0.2	285	2,391	$2,842	25	7.6%	$25	$0	$0	$211	$79		$33	$100	$12	0%	0
Large CHP	no incremental capacity available by 2015																	
Small CHP	50%	5	21,900	183,960	$2,181	10	15.4%	$0	$11	$11	$135	$107		$39	-$12	-$1	95%	19
Landfill Gas	78%	0.3	2,063	17,325	$1,421	20	9.0%	$132	$0	$0	$38	$73		$12	-$47	-$6	95%	2
Anaerobic Digestion	90%	0.3	2,365	19,868	$4,102	20	9.0%	$0	$0	$0	$47	$79		$22	-$54	-$6	95%	2
Biomass Power C1	no incremental capacity available by 2015																	
Biomass Power C2	no incremental capacity available by 2015																	
Biomass Power C3	no incremental capacity available by 2015																	
Biomass Power C4	no incremental capacity available by 2015																	
Converted Hydro	38%	0.5	1,667	14,000	$2,083	30	9.3%	$14	$0	$0	$63	$73		$24	-$35	-$4	95%	4
Res. Electric EE	55%	0	0	0							$9	$89	$37		-$117	-$14	55%	0
LI Electric EE	55%	0	0	0							$104	$89	$37		-$22	-$3	55%	0
CI Electric EE	55%	0	0	0							$31	$89	$37		-$96	-$11	55%	0
Appliance Standards	no incremental capacity available by 2015																	
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	*$/MMBtu*	*Yrs*	*%*	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*		*$/MMBtu NG*	*%*	*MMBtu NG*
AS Heat Pump				6,307	$281,898	15	11%	$2,000	$0	$50	$18	$7				$17	95%	9
GS Heat Pump				1,577	$324,979	15	11%	$2,000	$0	$50	$16	$7				$15	95%	2
Solar Hot Water				1,573	$53	15	11%	$0	$0	$3,250	$53	$7				$9	17%	0
Biomass Thermal				6,291	$367,964	15	11%	$879	$0	$4.63	$16	$7				$9	95%	10
Res. Gas EE				0							-$72	$6				-$78	55%	0
LI Gas EE				0							-$9	$6				-$15	55%	0
CI Gas EE				0							-$17	$6				-$23	55%	0

Table 22. Reference gas price resource assessment for 2020

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	MW	MWh	MMBtu NG	$/kW	Yrs	%	$/kW-yr	$/MWh	$/MMBtu	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MMBtu NG	%	MMBtu NG
Wind (<10 kW)	16%	100	140,160	1,177,344	$9,200	20	9.0%	$115	$0	$0	$676	$74		$29	$572	$68.12	35%	266
Wind (<100 kW)	25%	100	219,000	1,839,600	$4,000	20	9.0%	$25	$0	$0	$177	$74		$19	$84	$10	35%	266
Large Wind C5	41%	200	718,320	6,033,888	$2,359	20	9.7%	$50	$0	$0	$113	$69		$6	$38	$5	35%	532
Large Wind C4	Assuming wind projects built in 2020 are constructed in best wind locations (i.e., C5)																	
Offshore Wind	44%	800	3,083,520	25,901,568	$5,600	20	12.2%	$115	$0	$0	$207	$69		$6	$133	$16	35%	2,128
Utility-Scale PV	15%	16.00	25,754	216,337	$2,233	25	8.7%	$16	$0	$0	$162	$69		$18	$76	$9	0%	0
Commercial PV	14%	50	78,840	662,256	$2,842	25	8.0%	$24	$0	$0	$199	$74		$34	$91	$11	0%	0
Residential PV	13%	5	5,694	47,830	$2,943	25	7.6%	$24	$0	$0	$217	$74		$37	$106	$13	0%	0
Large CHP	67%	25	146,730	1,232,532	$1,750	20	9.7%	$0	$5	$7	$77	$90		$33	-$46	-$5	95%	59
Small CHP	50%	35	153,300	1,287,720	$2,457	10	15.4%	$0	$11	$12	$148	$101		$44	$3	$0	95%	136
Landfill Gas	78%	20	137,500	1,155,000	$1,421	20	9.0%	$132	$0	$0	$38	$69		$15	-$46	-$5	95%	144
Anaerobic Digestion	90%	20	157,680	1,324,512	$4,102	20	9.0%	$0	$0	$0	$47	$74		$25	-$52	-$6	95%	144
Biomass Power C1	80%	20	140,160	1,177,344	$4,175	30	8.0%	$105	$11	$3	$110	$69		$15	$27	$3	95%	144
Biomass Power C2	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$4	$128	$69		$15	$44	$5	95%	289
Biomass Power C3	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$10	$214	$69		$15	$130	$16	95%	289
Biomass Power C4	80%	50	350,400	2,943,360	$4,175	30	8.0%	$105	$11	$13	$259	$69		$15	$175	$21	95%	361
Converted Hydro	38%	61	203,333	1,708,000	$2,083	30	9.3%	$14	$0	$0	$63	$69		$31	-$37	-$4	95%	440
Res. Electric EE	55%	28	136,560	1,147,100							$9	$74	$42		-$108	-$13	55%	118
LI Electric EE	55%	3	16,491	138,528							$104	$74	$42		-$13	-$2	55%	14
CI Electric EE	55%	113	544,927	4,577,386							$31	$74	$42		-$86	-$10	55%	473
Appliance Standards	55%	216	1,040,000	8,736,000							-$273	$74	$42		-$390	-$46	55%	902
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	$/MMBtu	Yrs	%	$/MMBtu-yr	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu		$/MMBtu NG	%	MMBtu NG
AS Heat Pump				75,686	$281,898	15	11%	$2,000	$0	$59	$20	$6				$20	95%	104
GS Heat Pump				18,922	$324,979	15	11%	$2,000	$0	$59	$18	$6				$16	95%	26
Solar Hot Water				18,896	$62	15	11%	$0	$0	$3,824	$62	$6				$24	17%	0
Biomass Thermal				75,586	$367,964	15	11%	$879	$0	$4.80	$16	$6				$9	95%	125
Res. Gas EE				3,758,369							-$72	$6				-$78	55%	236
LI Gas EE				584,036							-$9	$6				-$15	55%	37
CI Gas EE				4,121,834							-$17	$6				-$23	55%	259

Table 23. Reference gas price resource assessment for 2030

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
Electricity Technologies																		
Technology	Annual Capacity Factor	Total Potential Capacity	Annual Energy Production	Annual Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy	Annual Net Levelized Cost	Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
	%	*MW*	*MWh*	*MMBtu NG*	*$/kW*	*Yrs*	%	*$/kW-yr*	*$/MWh*	*$/MMBtu*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MWh*	*$/MMBtu NG*	%	*MMBtu NG*
Wind (<10 kW)	16%	200	280,320	2,354,688	$8,050	20	9.0%	$102	$0	$0	$592	$105		$30	$457	$54	35%	532
Wind (<100 kW)	25%	300	657,000	5,518,800	$3,500	20	9.0%	$25	$0	$0	$156	$105		$19	$32	$4	35%	798
Large Wind C5	42%	480	1,766,016	14,834,534	$2,359	20	9.7%	$50	$0	$0	$111	$97		$6	$8	$1	35%	1,277
Large Wind C4	40%	800	2,803,200	23,546,880	$2,460	20	9.7%	$50	$0	$0	$118	$97		$7	$14	$2	35%	2,128
Offshore Wind	45%	4,000	15,768,000	132,451,200	$4,760	20	11%	$102	$0	$0	$162	$97		$6	$59	$7	35%	10,640
Utility-Scale PV	15%	160	257,544	2,163,370	$1,600	25	8.7%	$14	$0	$0	$118	$97		$18	$3	$0	0%	0
Commercial PV	14%	800	1,261,440	10,596,096	$2,075	25	8.0%	$22	$0	$0	$149	$105		$35	$9	$1	0%	0
Residential PV	13%	200	284,700	2,391,480	$2,150	25	7.6%	$22	$0	$0	$163	$105		$39	$19	$2	0%	0
Large CHP	67%	50	293,460	2,465,064	$1,750	20	9.7%	$0	$5	$8	$84	$127		$34	-$78	-$9	95%	118
Small CHP	50%	65	284,700	2,391,480	$2,457	10	15.4%	$0	$11	$13	$153	$142		$46	-$34	-$4	95%	252
Landfill Gas	78%	6	41,250	346,500	$1,421	20	9.0%	$132	$0	$0	$38	$97		$16	-$75	-$9	95%	43
Anaerobic Digestion	90%	6	47,304	397,354	$4,102	20	9.0%	$0	$0	$0	$47	$105		$26	-$83	-$10	95%	43
Biomass Power C1	80%	20	140,160	1,177,344	$4,175	30	8.0%	$105	$11	$3	$110	$97		$15	-$2	$0	95%	144
Biomass Power C2	80%	40	280,320	2,354,688	$4,175	30	8.0%	$105	$11	$4	$128	$97		$15	$15	$2	95%	289
Biomass Power C3	80%	60	420,480	3,532,032	$4,175	30	8.0%	$105	$11	$10	$214	$97		$15	$102	$12	95%	433
Biomass Power C4	80%	70	490,560	4,120,704	$4,175	30	8.0%	$105	$11	$13	$259	$97		$15	$146	$17	95%	505
Converted Hydro	38%	56	186,667	1,568,000	$2,083	30	9.3%	$14	$0	$0	$63	$97		$32	-$67	-$8	95%	404
Res. Electric EE	55%	64	310,087	2,604,729							$9	$94	$44		-$128	-$15	55%	269
LI Electric EE	55%	7	35,936	301,858							$104	$94	$44		-$33	-$4	55%	31
CI Electric EE	55%	380	1,831,203	15,382,106							$31	$94	$44		-$107	-$13	55%	1,589
Appliance Standards	55%	619	2,982,000	25,048,800							-$205	$94	$44		-$343	-$41	55%	2,587
Direct Gas Reduction Technologies																		
Technology				Potential Energy Production	Installed Cost	Lifetime	Real Levelization Rate	Annual Fixed O&M	Annual Variable O&M	Annual Levelized Fuel Cost	Annual Levelized Cost	Avoided Energy Cost	Avoided Capacity Cost	Capacity Payment Proxy		Annual Net Levelized Cost	Winter Load Carrying Capcity	Peak Hour Gas Savings
				MMBtu NG	*$/MMBtu*	*Yrs*	%	*$/MMBtu-yr*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*	*$/MMBtu*		*$/MMBtu NG*	%	*MMBtu NG*
AS Heat Pump				1,127,727	$281,898	15	11%	$2,000	$0	$82	$26	$9				$25	95%	1,549
GS Heat Pump				281,932	$324,979	15	11%	$2,000	$0	$82	$22	$9				$20	95%	387
Solar Hot Water				281,607	$86	15	11%	$0	$0	$5,353	$86	$9				$32	17%	4
Biomass Thermal				1,126,428	$367,964	15	11%	$879	$0	$5.16	$16	$9				$7	95%	1,869
Res. Gas EE				5,290,473							-$72	$8				-$79	55%	332
LI Gas EE				1,818,671							-$9	$8				-$17	55%	114
CI Gas EE				9,748,498							-$17	$8				-$25	55%	612

APPENDIX B: BASE CASE ASSUMPTIONS

Overview: The base case energy resource mix and demand model expected conditions under existing policy measures.

Gas prices: Reference natural gas prices are monthly NYMXEX prices escalated annually in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Reference Case (Tab 13, line 44). Monthly average Henry Hub price forecasts were then adjusted for projections in the basis differential between Henry Hub and the Massachusetts city gates designed to reflect the higher basis when gas demand is highest. Based on preliminary modeling results, we assume that the Massachusetts (and upstream) gas sector will remain out of balance from 2015 through 2019, but will be in balance from 2020 through 2030. In 2015 through 2019, we use a winter basis estimate as the daily November to March difference between Henry Hub and Algonquin City Gate daily prices in 2013/2014. For the summer months in 2015 through 2019, and for all months in the remaining years, we assume one constant basis differential for every day, calculated as the average difference between Henry Hub and Algonquin City Gate daily prices in the April through October of 2014. See Figure 3 and Figure 19.

Canadian transmission: There is no transmission from Canada incremental to what exists today. We used Ventyx's default assumptions to depict existing transmission from Canada, and use these assumptions in each of the model runs.

Carbon prices: The electric-sector carbon allowance price in the electricity sector is the *Avoided Energy Supply Costs in New England: 2013 Report* (AESC 2013) carbon price forecast[46] (see Figure 2); GWSA compliance is not a criterion for scenarios and sensitivities; rather, the Massachusetts emissions associated with each scenario and sensitivity are an output of the model.

Greenhouse gas emissions: Electric-sector emissions are calculated in the Market Analytics model. Massachusetts' share of these emissions is estimated using a methodology based on the *2008-2010 Massachusetts Greenhouse Gas Emissions Inventory*: all emissions from the Commonwealth's electric generator; emissions associated with Massachusetts purchase of out-of-state RECs and its claim on low-emission imports; a share of the residual New England electric emissions based on Massachusetts' requirements above its own generation, out-of-state REC purchases and claim on low-emission imports; and a share of the emissions from Quebec and the Maritimes based on New England's requirements above its own generation, out-of-state REC purchases and claim on low-emission imports.

Gas sector emissions (other than electric) are calculated as MMBtus of annual demand multiplied by a weighted average emissions rate for residential, commercial, industrial, and transportation sectors per

[46] Hornby et al. 2013. Exhibit 4-1. Column 6 "Synapse" CO_2 emission allowance price.

AEO 2014.[47] In each year, the weighted average emissions rate for all non-electric system natural gas demand is about 0.053 metric tons per MMBtu, or about 116 lbs per MMBtu.

GWSA compliance: GWSA compliance for years 2020 and 2030 was determined using data from the MA-DPU 14-86 docket by assuming that emissions from sectors other than gas or electric would (1) would be the same under all scenario-and-sensitivity assumptions, and (2) would approximate levels anticipated given the policy measures described in Massachusetts *Clean Energy and Climate Plan for 2020*.[48] Scenarios in which Massachusetts emits more than 23.3 million metric tons of CO_2 in 2020 in gas and electric sectors or more than 18.7 million metric tons in these sectors in 2030 do not achieve GWSA compliance (see Table 6). The 2030 GWSA reduction target below 1990 statewide levels of 43 percent was estimated following the method used in DPU 14-86: A linear trend was drawn between the Commonwealth's 2020 and 2050 emission reduction targets.

Energy efficiency: Reductions to load from energy efficiency were modeled based on program administrator's data as filed with the Department of Public Utilities, extended into the future using the following assumptions: (1) for states other than Massachusetts energy efficiency budgets remain constant over time in real terms; and (2) for Massachusetts energy efficiency remains constant as a share of load from 2015 through 2030. For Massachusetts electric efficiency: annual savings are 2.5 percent of program administrators' transmission-and-distribution-adjusted load in each year. For Massachusetts gas efficiency: annual savings are 1.1 percent of annual retail sales. Data on energy efficiency savings at winter peak were derived from the program administrators three-year reports. Costs are reported in Appendix A.

Time varying rates: Based on DPU's June 2014 Order 14-04 on time-varying rates we assume annual savings of 0.3 percent (2-percent annual savings assuming an 82-percent of customers on basic service out of the 37-percent residential share of load and a 50-percent opt in rate).[49] We assume winter peak savings 2.0 percent on the winter peak hour (13-percent average winter peak savings among four test groups modeled by Navigant assuming an 82-percent of customers on basic service out of the 37-percent residential share of load and a 50-percent opt in rate). Costs were estimated as a cost of $100 smart thermostat rebates paid in once in 2015 and again in 2025 (assuming a 10-year measure life).

Advanced Building Codes: Based on the assumptions in the Massachusetts Clean Energy and Climate Plan for 2020 ("CECP"), we assumed savings of 1.5 million metric tons of CO_2 reductions to be available from the Advanced Building Code policy currently in place in Massachusetts in 2020 and 2030.[50] Of

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[47] AEO 2014, Table 2.1 and Table 18.1. Available at http://www.eia.gov/forecasts/aeo/

[48] MA-DPU 14-86, Amended Direct Testimony of Elizabeth A. Stanton, September 11, 2014, Exhibits EAS-8 and EAS-13. CECP building sector oil emissions were calculated as the "Updated" business-as-usual buildings sector oil emission less anticipated oil energy efficiency and other CECP program savings.

[49] MA-DPU 14-04-B, "Anticipated Policy Framework for Time Varying Rates", June 12, 2014, http://www.mass.gov/eea/docs/dpu/orders/d-p-u-14-04-b-order-6-12-14.pdf. See also, Navigant (2014) *NSTAR Smart Grid Pilot: Final Technical Report*. Prepared for the U.S. DOE on behalf of NSTAR Gas and Electric Corporation.

[50] Massachusetts Office of Energy and Environmental Affairs. "Massachusetts Clean Energy and Climate Plan for 2020". 2010.

these reductions, we assume 0.9 million metric tons of reductions come from avoided natural gas consumption in both 2020 and 2030, using the ratio of natural gas to oil consumption in the business-as-usual case for each year as modeled in DPU 14-86. Using the average emission rate of residential natural gas consumption (0.053 metric tons per MMBtu), these emission reductions were then translated into MMBtu reductions. Given that this is an existing policy, costs are assumed to be zero.

Renewable thermal technologies: Based on the assumptions in Navigant's 2013 *Incremental Cost Study Phase Two Final Report*, the *Commonwealth Accelerated Renewable Thermal Strategy* and information from vendors, we assumed reduced CO_2 emissions of 1.2 million metric tons in 2020 and 5.8 million metric tons as a result of existing renewable thermal policy.[51] Per DOER, we assume 15 percent of the emission reductions from this existing policy take place in the form of reduced residential natural gas consumption (85 percent of CO_2 reductions apply to oil use). Using the average emission rate of residential natural gas consumption (0.053 metric tons per MMBtu), these emission reductions were then translated into MMBtu reductions. Given that this is an existing policy, costs are assumed to be zero. The renewable thermal reductions listed in the above supply curves (air- and ground-source heat pumps, solar hot water, and biomass thermal) are assumed to be incremental to the CARTS study, per DOER.

Demand response: Electric demand response is available as a balancing agent (discussed below) but not otherwise included in modeling.

Winter Reliability program: The ISO-NE Winter Reliability program is available as a balancing agent (discussed below) but not otherwise included in modeling.

Distributed generation: We modeled distributed resources using ISO-NE's PV Energy Forecast Update by state, held constant after 2020.[52] Total New England annual distributed generation is 1,695 GWh. Costs are reported in Appendix A.

Retirements: We modeled the retirements from current capacity shown in Table 24.

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[51] http://www.neep.org/sites/default/files/products/NEEP%20ICS2%20FINAL%20REPORT%202013Feb11-Website.pdf; http://www.mass.gov/eea/docs/doer/renewables/thermal/carts-report.pdf

[52] ISO-NE, "PV Energy Forecast Update: Distributed Generation Forecast Working Group" presentation, December 15, 2014, Holyoke, MA. Slide 8.

Table 24. Unit retirements

Unit Name	Region	Fuel type	Retirement
Framingham 1	Boston	FO#2 NPCC	1/1/2020
Framingham 2	Boston	FO#2 NPCC	1/1/2019
Framingham 3	Boston	FO#2 NPCC	1/1/2019
Mystic 7	Boston	NG	1/1/2021
Mystic J1	Boston	FO#2 NPCC	1/1/2019
Salem Harbor 3	Boston	Coal	6/1/2014
Salem Harbor 4	Boston	FO#6 NPCC	6/1/2014
Waters River 1	Boston	NG	1/1/2021
West Medway 1	Boston	FO#2 NPCC	1/1/2020
West Medway 2	Boston	FO#2 NPCC	1/1/2020
Middletown 2	CT NE Centr	NG	1/1/2022
Middletown 3	CT NE Centr	NG	1/1/2022
Middletown 4	CT NE Centr	NG	1/1/2017
Montville 5	CT NE Centr	FO#6 NPCC	1/1/2020
Montville 6	CT NE Centr	FO#6 NPCC	1/1/2017
Norwich (North Main) 5	CT NE Centr	FO#2 NPCC	1/1/2022
Norwalk Harbor 1	CT Norwalk	FO#6 NPCC	6/1/2017
Norwalk Harbor 10	CT Norwalk	FO#2 NPCC	6/1/2017
Norwalk Harbor 2	CT Norwalk	FO#6 NPCC	6/1/2017
Bridgeport Harbor 2	CTSW	FO#6 NPCC	6/1/2017
Bridgeport Harbor 3	CTSW	Coal	6/1/2017
New Haven Harbor 1	CTSW	FO#6 NPCC	1/1/2021
Borden 1	Maritimes	FO#2 NPCC	1/1/2021
Borden 2	Maritimes	FO#2 NPCC	1/1/2023
Burnside 1	Maritimes	FO#2 NPCC	1/1/2026
Burnside 2	Maritimes	FO#2 NPCC	1/1/2026
Burnside 3	Maritimes	FO#2 NPCC	1/1/2026
Burnside 4	Maritimes	FO#2 NPCC	1/1/2026
Caribou ST CS1	Maritimes	FO#6 NPCC	1/1/2013
Caribou ST CS2	Maritimes	FO#6 NPCC	1/1/2015
Charlottetown 10	Maritimes	FO#6 NPCC	1/1/2028
Charlottetown 7	Maritimes	FO#6 NPCC	1/1/2015
Charlottetown 8	Maritimes	FO#6 NPCC	1/1/2020
Charlottetown 9	Maritimes	FO#6 NPCC	1/1/2023
Courtenay Bay 2	Maritimes	FO#6 NPCC	1/1/2025
Tusket 1	Maritimes	FO#2 NPCC	1/1/2021
Victoria Junction 1	Maritimes	FO#2 NPCC	1/1/2025
Victoria Junction 2	Maritimes	FO#2 NPCC	1/1/2025
Cherry Street 12	NEMA	FO#2 NPCC	1/1/2022
Lost Nation GT 1	NH	FO#2 NPCC	1/1/2019
Schiller 4	NH	Coal	1/1/2020
Schiller 6	NH	Coal	1/1/2020
Arthur Kill 1	NY	NG	1/1/2020
Astoria GT 1	NY	NG	1/1/2017
Astoria GT 11	NY	FO#2 NPCC	5/1/2014
Astoria GT 12	NY	FO#2 NPCC	5/1/2014
Astoria GT 13	NY	FO#2 NPCC	5/1/2014
Astoria GT 2-1	NY	NG	5/1/2016
Astoria GT 2-2	NY	NG	5/1/2016
Astoria GT 2-3	NY	NG	5/1/2016
Astoria GT 2-4	NY	NG	5/1/2016
Astoria GT 3-1	NY	NG	5/1/2016
Astoria GT 3-2	NY	NG	5/1/2016
Astoria GT 3-3	NY	NG	5/1/2016
Astoria GT 3-4	NY	NG	5/1/2016
Astoria GT 4-1	NY	NG	5/1/2016
Astoria GT 4-2	NY	NG	5/1/2016
Astoria GT 4-3	NY	NG	5/1/2016
Astoria GT 4-4	NY	NG	5/1/2016
Astoria GT 5	NY	NG	5/1/2014
Astoria GT 7	NY	NG	5/1/2014
Astoria GT 8	NY	NG	5/1/2014
Astoria ST2	NY	NG	7/30/2015
Barrett G1	NY	NG	1/1/2020
Barrett G1	NY	NG	1/1/2020
Barrett G10	NY	NG	1/1/2021
Barrett G11	NY	NG	1/1/2021
Barrett G12	NY	NG	1/1/2021
Barrett G2	NY	NG	1/1/2020
Barrett G3	NY	NG	1/1/2020
Barrett G4	NY	NG	1/1/2020
Barrett G5	NY	NG	1/1/2020
Barrett G6	NY	NG	1/1/2020
Barrett G7	NY	NG	1/1/2020
Barrett G8	NY	NG	1/1/2020
Barrett G9	NY	NG	1/1/2021
Charles P Keller 12	NY	NG	1/1/2017
Charles P Keller 13	NY	NG	1/1/2024
Danskammer 2	NY	NG	1/1/2014
East Hampton 1	NY	FO#2 NPCC	1/1/2020
East River 6	NY	NG	1/1/2026
East River 7	NY	NG	1/1/2015
Freeport 1 4	NY	FO#2 NPCC	1/1/2014
Freeport 2 3	NY	FO#2 NPCC	1/1/2023
Glenwood GT1	NY	FO#2 NPCC	1/1/2017
Glenwood GT2	NY	FO#2 NPCC	1/1/2022
Glenwood GT3	NY	FO#2 NPCC	1/1/2022
Gowanus 1-1	NY	FO#2 NPCC	1/1/2022
Gowanus 1-2	NY	FO#2 NPCC	1/1/2022
Gowanus 1-3	NY	FO#2 NPCC	1/1/2022
Gowanus 1-4	NY	FO#2 NPCC	1/1/2022
Gowanus 1-5	NY	FO#2 NPCC	1/1/2022
Gowanus 1-6	NY	FO#2 NPCC	1/1/2022
Gowanus 1-7	NY	FO#2 NPCC	1/1/2022
Gowanus 1-8	NY	FO#2 NPCC	1/1/2022
Gowanus 2-1	NY	NG	1/1/2021
Gowanus 2-2	NY	NG	1/1/2021
Gowanus 2-3	NY	NG	1/1/2022
Gowanus 2-4	NY	NG	1/1/2022
Gowanus 2-5	NY	NG	1/1/2022
Gowanus 2-6	NY	NG	1/1/2022
Gowanus 2-7	NY	NG	1/1/2022
Gowanus 2-8	NY	NG	1/1/2022
Gowanus 3-1	NY	FO#2 NPCC	1/1/2021

Table 13. Unit retirements (continued)

Unit Name	Region	Fuel type	Retirement	Unit Name	Region	Fuel type	Retirement
Gowanus 3-2	NY	FO#2 NPCC	1/1/2021	Ravenswood G10	NY	NG	1/1/2019
Gowanus 3-3	NY	FO#2 NPCC	1/1/2021	Ravenswood G11	NY	NG	1/1/2019
Gowanus 3-4	NY	FO#2 NPCC	1/1/2021	Ravenswood G21	NY	NG	1/1/2019
Gowanus 3-5	NY	FO#2 NPCC	1/1/2021	Ravenswood G22	NY	NG	1/1/2019
Gowanus 3-6	NY	FO#2 NPCC	1/1/2021	Ravenswood G23	NY	NG	1/1/2019
Gowanus 3-7	NY	FO#2 NPCC	1/1/2021	Ravenswood G24	NY	NG	1/1/2019
Gowanus 3-8	NY	FO#2 NPCC	1/1/2021	Ravenswood G31	NY	NG	1/1/2019
Gowanus 4-1	NY	FO#2 NPCC	1/1/2021	Ravenswood G32	NY	NG	1/1/2019
Gowanus 4-2	NY	FO#2 NPCC	1/1/2021	Ravenswood G33	NY	NG	1/1/2019
Gowanus 4-3	NY	FO#2 NPCC	1/1/2021	Ravenswood G4	NY	NG	1/1/2019
Gowanus 4-4	NY	FO#2 NPCC	1/1/2021	Ravenswood G5	NY	NG	1/1/2019
Gowanus 4-5	NY	FO#2 NPCC	1/1/2021	Ravenswood G6	NY	NG	1/1/2019
Gowanus 4-6	NY	FO#2 NPCC	1/1/2021	Ravenswood G7	NY	NG	1/1/2019
Gowanus 4-7	NY	FO#2 NPCC	1/1/2021	Ravenswood G9	NY	NG	1/1/2019
Gowanus 4-8	NY	FO#2 NPCC	1/1/2021	Rochester 9 2	NY	NG	1/1/2019
Hillburn GT 1	NY	NG	1/1/2022	S A Carlson 5	NY	Coal	1/1/2016
Holtsville 1	NY	FO#2 NPCC	1/1/2024	Shoemaker GT 1	NY	NG	1/1/2022
Holtsville 10	NY	FO#2 NPCC	1/1/2025	Shoreham GT 1	NY	FO#2 NPCC	1/1/2021
Holtsville 2	NY	FO#2 NPCC	1/1/2024	Shoreham GT 2	NY	FO#2 NPCC	1/1/2016
Holtsville 3	NY	FO#2 NPCC	1/1/2024	Southhold 1	NY	FO#2 NPCC	1/1/2014
Holtsville 4	NY	FO#2 NPCC	1/1/2024	West Babylon GT 4	NY	FO#2 NPCC	1/1/2021
Holtsville 5	NY	FO#2 NPCC	1/1/2024	West Coxsackie 1	NY	NG	1/1/2019
Holtsville 6	NY	FO#2 NPCC	1/1/2025	Cadillac GT 1	Quebec	FO#2 NPCC	1/1/2027
Holtsville 7	NY	FO#2 NPCC	1/1/2025	Cadillac GT 2	Quebec	FO#2 NPCC	1/1/2026
Holtsville 8	NY	FO#2 NPCC	1/1/2025	Cadillac GT 3	Quebec	FO#2 NPCC	1/1/2027
Holtsville 9	NY	FO#2 NPCC	1/1/2025	La Citiere GT 1	Quebec	FO#2 NPCC	1/1/2030
Hudson Ave 4	NY	FO#2 NPCC	1/1/2020	La Citiere GT 3	Quebec	FO#2 NPCC	1/1/2030
Hudson Ave GT3	NY	FO#2 NPCC	1/1/2020	La Citiere GT 4	Quebec	FO#2 NPCC	1/1/2029
Hudson Ave GT5	NY	FO#2 NPCC	1/1/2020	Brayton Point 1	MA	Coal	6/1/2017
Indian Point 2 GT1	NY	FO#2 NPCC	1/1/2019	Brayton Point 2	MA	Coal	6/1/2017
Indian Point GT 2	NY	FO#2 NPCC	1/1/2021	Brayton Point 3	MA	Coal	6/1/2017
Indian Point GT 3	NY	FO#2 NPCC	1/1/2020	Brayton Point 4	MA	FO#6 NPCC	6/1/2017
L Street Jet 1	NY	FO#2 NPCC	1/1/2016	West Medway 3	MA	FO#2 NPCC	1/1/2020
Narrows Gen 1	NY	NG	1/1/2022	Canal 1	SEMA	FO#6 NPCC	1/1/2020
Narrows Gen 2	NY	NG	1/1/2022	Canal 2	SEMA	FO#6 NPCC	1/1/2020
Narrows Gen 21	NY	NG	1/1/2022	Cleary 8	SEMA	FO#6 NPCC	1/1/2022
Narrows Gen 22	NY	NG	1/1/2022	Somerset (MA) 2	SEMA	FO#2 NPCC	1/1/2021
Narrows Gen 23	NY	NG	1/1/2022	Cape GT 4	SME	FO#2 NPCC	1/1/2020
Narrows Gen 24	NY	NG	1/1/2022	Cape GT 5	SME	FO#2 NPCC	1/1/2020
Narrows Gen 25	NY	NG	1/1/2022	Wyman-Yarmouth 1	SME	FO#6 NPCC	1/1/2017
Narrows Gen 26	NY	NG	1/1/2022	Wyman-Yarmouth 2	SME	FO#6 NPCC	1/1/2017
Narrows Gen 27	NY	NG	1/1/2022	Wyman-Yarmouth 3	SME	FO#6 NPCC	1/1/2020
Narrows Gen 3	NY	NG	1/1/2022	Wyman-Yarmouth 4	SME	FO#6 NPCC	1/1/2022
Narrows Gen 4	NY	NG	1/1/2022	Ascutney GT 1	VT	FO#2 NPCC	1/1/2013
Narrows Gen 5	NY	NG	1/1/2022	Burlington NPCC 1	VT	FO#2 NPCC	1/1/2021
Narrows Gen 6	NY	NG	1/1/2022	Gorge (Colchester) 1	VT	FO#2 NPCC	1/1/2015
Narrows Gen 7	NY	NG	1/1/2022	Cabot 6	WCMA	NG	1/1/2015
Narrows Gen 8	NY	NG	1/1/2022	Cabot 8	WCMA	NG	1/1/2013
Northport GT1	NY	FO#2 NPCC	1/1/2017	Cabot 9	WCMA	NG	1/1/2013
Port Jefferson GT1	NY	FO#2 NPCC	1/1/2016	Mount Tom	WCMA	Coal	10/1/2014
Ravenswood 143	NY	NG	1/1/2025	West Springfield 3	WCMA	FO#6 NPCC	1/1/2022
Ravenswood G1	NY	NG	1/1/2017				

Additions: In addition to any generic natural-gas combined cycle units added to achieve reliability requirements, our electric-sector model includes the following new units and upgrades:

- Footprint Power Combined Cycle unit as of June 1, 2017 at 674 MW; located in ISO-NE Boston at the Salem Harbor site.
- Cape Wind as of January 1, 2016 at 136 MW, capacity increases on January 1, 2017 to 365 MW; located in ISO-NE SEMA.
- Northfield Mountain pumped storage capacity increases to 1,119.2 MW in 2015.

Capital costs: Capital costs of avoiding new NGCC construction are calculated using values from AEO 2014.[53] Capital costs associated with alternative, low-demand resources are discussed but not reported Appendix A.

Benefit of eliminating constraint-elevated prices: The benefit of eliminating elevated prices and price spikes related to natural gas capacity constrains is estimated as the product of base case gas demand in each month of each year modeled and the difference between two average natural gas price bases for that month: (1) the 2015 price basis; and (2) the actual model year basis.

Electric sales data: Electric sales, before demand-side measures, were taken from ISO-NE's CELT 2014.

Electric capacity data: The base case electric generation resource mix was modeled using the Market Analytics scenario designed by Synapse for DOER in early 2014 to provide an accurate presentation of Green Communities Act (GCA) policies as well as the Renewable Portfolio Standards—by class—of the six New England states. Synapse's GCA analysis for DOER was developed using the NERC 9.5 dataset, based on the Ventyx Fall 2012 Reference Case. We verified and updated these data with the most current information on gas prices, loads, retirements, and additions. Note that if load becomes too small or transmission constraints are reached, wind generation will back down or curtail.

Existing electric transmission from Canada: We used the Market Analytics default assumptions for the existing lines.

Gas LDC demand data: Base case gas demand, before demand-side measures, was modeled using the Massachusetts' LDCs' gas demand forecasts and the most up-to-date information available regarding capacity exempt customers.

- Planning year load includes company use, commercial and industrial customers, and heating and non-heating load of residential customers. It also accounts for energy efficiency adjustments, unbilled sales and losses, and adjustments for capacity exempt customers. Capacity exempt adjustments represent commercial and industrial capacity exempt and capacity exempt unaccounted for gas.

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[53] Electricity Market Module. AEO 2014. Available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf

- Design year planning load was calculated using the design year daily effective degree days for each of five LDCs. All of the items included in planning year load calculations are included in the design year. NGrid provided updated planning year data that replaced their most recent filing.

- The reconstituted design year reflects the load projected by the LDCs in the design year but is then adjusted for all the energy efficiency expected by the LDCs' forecast (including capacity exempt) to generate an expected load prior to energy efficiency.

- LDC's five-year design day forecasts were applied to the January of the split year and remain unadjusted from their most recent filing as provided to DOER.[54] For those years not provided by the companies, the average annual load growth rate for the given forecasted years was used to extrapolate the design day and annual forecasts out through 2019. From 2020 through 2030 design day and annual gas demand was projected at a 0.5-percent annual growth rate per EIA projections using the AEO 2013 Demand Technology Case average annual natural gas consumption growth rate for New England.

- Design day planning load was calculated by using the design day effective degree days level.[55] Design day planning load includes the same items as design year and for three of the LDCs (Berkshires, NStar, and Liberty) the most recent LDC filing was used. Columbia and NGrid's design day loads were replaced with updated values provided through the stakeholder process. The design day value includes the LDCs' expected energy efficiency and is not "reconstituted."

Munis natural gas demand data: Demand for munis is modeled as a proxy based on the natural gas capacity under contract to these utilities in 2015.[56] This proxy demand is then forecasted to increase in each year using the same average growth rate as used by LDCs. Munis natural gas demand is roughly 2 percent of LDC natural gas demand in each year.

Gas capacity data: We model existing natural gas capacity from:

- Existing pipelines: Algonquin Gas Transmission Company (AGT), Maritimes/Northeast Pipeline Company (M&NP); Tennessee Gas Pipeline Company (TGP)

- Planned pipeline capacity: Algonquin Incremental Market (AIM) pipeline capacity, which is an expansion of the AGT line, expected to be complete in 2017

- LDC's LNG storage and vaporization: National Grid, Columbia, NSTAR, Liberty, Fitchburg Gas and Electric, Berkshire Gas, Holyoke, Middleboro

[54] We used the latest Department of Public Utilities filings for all LDCs except NGrid and Columbia, which provided DOER with updated design day forecasts.

[55] Berkshire Gas Company. 2014. Long Range Forecast and Supply Plan. Prepared for the Massachusetts Department of Public Utilities.

[56] Tennessee Gas Pipeline informational postings, http://pipeline2.kindermorgan.com/Capacity/OpAvailPoint.aspx?code=TGP

- Full GDF Suez LNG vaporization at Everett, MA with an allocation for Mystic electric generation plant
- Existing propane: NGrid; Columbia; Fitchburg Gas and Electric; and Berkshire Gas

Where LDC demand forecasts do not extend to 2019 we extrapolated each LDC's demand based on its trend during the forecast period. LDC demand growth after 2019 is projected to be 0.5 percent per year, based on the assumptions developed for the CECP. Muni and capacity exempt demand growth is assumed to keep pace with LDC demand.

Winter peak: In the electric sector, in addition to our annual modeling, we reran January for each year in the analysis for the purpose of modeling the gas requirements in the winter peak hour. We modeled each January as a period of cold weather—defined as the CELT 2014 5-percent confidence interval or high case—assuming that all modeled regions (New England, New York, Quebec, and the Maritimes) all experience a relative cold snap. Winter peak energy efficiency and time-varying rate savings were also assumed. Peak hour data were as then extracted as the highest peak 6pm hour among days from January 13 through 31—in this way assuring that the peak hour falls in a period of at least 12 contiguous "cold snap" days.

In the gas sector, gas requirements were represented as each LDC's demand day requirements (including natural gas consumers commonly referred to as "capacity-exempt customers"), adjusted to an hourly requirement based on an assumption that 5.6 percent of daily peak demand falls during the peak hour.[57] We evaluated the effects of an extended cold snap by modeling design day load over a 12-day period, then applying the impacts extended use of stored natural gas natural storage on the available storage capacity. Our research determined that existing LNG storage facilities have sufficient capacity for 13 days using existing vaporizers. Propane storage is not available in this model as a balancing measure; existing propane storage facilities are sufficient for a 3-day cold snap. Gas capacity was adjusted to an hourly requirement assuming that 1/24 of daily capacity is available during the peak hour.

Constraint criteria: The balance criteria of gas demand no greater than 95-percent of gas capacity reflects the level of pipeline utilization at which operational flow orders are typically declared and shippers are held to strict tolerances on their takes from the pipeline. The impact of gas constraint on natural gas prices is thought to begin when gas demand rises above 80-percent of gas capacity. Gas prices associated with out-of-balance conditions are assumed in 2015 through 2019 in our model.

Balancing measures: We determined the least-cost set of measures that would eliminate constraints and balancing the Massachusetts gas sector. Balancing measures are shown in Table 25 and Table 26.

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[57] Eastern Interconnection Planning Collaborative Draft Gas-Electric Interface Study Target 2 Report, p.64-65

Table 25. Balancing measures available in base case

	Increment	Total winter peak hour availability	Total annual availability	Winter peak hour availability	Annual availability	Hours of availability at winter peak per year	Annual cost	Per MMBtu cost	Number of minimum increments available
2015 Balancing Measures		*MMBtu*	*MMBtu*	*MMBtu*	*MMBtu*	*hours*	*$*	*$/MMBtu Annual*	
Pipeline (long- and short-haul)	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Winter Reliability Program	Minimum	29,434	29,434	1	150	150	$450	$3.00	29,434
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Battery Storage	Minimum	289	52,560	289	52,560	182	$20,051,425	$381	1
2020 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	1,444	52,560	289	10,512	182	$19,153,973	$364	5
2030 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	190	5,040	0.76	20	24	$1,326	$66	250
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	8,664	52,560	289	1,752	182	$15,509,561	$295	30

Table 26. Balancing measures available in low demand case

	Increment	Total winter peak hour availability	Total annual availability	Winter peak hour availability	Annual availability	Hours of availability at winter peak per year	Annual cost	Per MMBtu cost	Number of minimum increments available
2015 Balancing Measures		*MMBtu*	*MMBtu*	*MMBtu*	*MMBtu*	*hours*	*$*	*$/MMBtu Annual*	
Pipeline (long- and short-haul)	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Winter Reliability Program	Minimum	29,434	29,434	1	150	150	$450	$3.00	29,434
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Battery Storage	Minimum	289	52,560	289	52,560	182	$20,051,425	$381	1
2020 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	1,444	52,560	289	10,512	182	$19,153,973	$364	5
2030 Balancing Measures									
Pipeline (long- and short-haul)	Minimum	undetermined	undetermined	4,167	36,500,000	n/a	$51,100,000	$1.40	undetermined
Winter Reliability Program	Minimum	0	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response	Minimum	760	20,160	0.76	20	24	$1,326	$66	1000
Pumped Storage	Minimum	4,043	367,920	2,022	183,960	182	$94,466,330	$257	2
Battery Storage	Minimum	8,664	52,560	289	1,752	182	$15,509,561	$295	30

- Pipeline capacity (long- and short-haul[58]), incremental to existing and planned natural gas pipeline capacity in both the base and low demand cases, is assumed to be available in 100,000 MMBtu/day increments with a minimum increment of 100,000 MMBtu and a maximum increment of 500,000 MMBtu/day beginning in 2019. There are no economies of scale for differences in the size of these increments. The existing and planned pipeline capacity (included in modeling, not as a balancing measure) for 2020 includes the 342,000 MMBtu/day of capacity associated with the AIM project which is scheduled to be online by November 1, 2016. The cost assumptions associated with the incremental pipeline expansions are derived from the cost data submitted by Algonquin in its filing with the Federal Energy Regulatory Commission.[59]

- ISO-NE Winter Reliability program is an inventory buy-back program for oil, LNG and a very small portion of demand response that will be in effect for the next four winters: 2014/15, 2015/16, 2016/17 and 2017/18. In the both the base case and low demand case, the Winter Reliability program is not available as a balancing measure after 2018. In years it is available, Winter Reliability is always applied as a balancing measure directly after demand response, in order to simulate how ISO-NE develops its forecast for required inventory for the program. This program is then allowed to function as a balancer for up to 29,434 MMBtu per peak hour in 2015 (in both the base case and low demand case).

- Demand response in the electric sector is available for two 4-hour periods in each of three months: December, January and February. For Massachusetts, 25 MW of demand response is estimated to be available in the base case during each of these periods at a monthly cost of $1/kW-month, and an hourly cost of $500/MW. 100 MW is estimated to be available in the low demand case at the same cost per MW.

- Pumped storage, incremental to existing pumped hydro installations in both the base and low demand cases, is assumed to be available as follows: 0 MW by 2015, 560 MW from 2016 to 2020, and an additional 560 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs are constant over the study period at $257/MWh. These assumptions are based on a DOE and Electric Power Research Institute (EPRI) 2013 *Electricity Storage Handbook*. 60 The minimum facility size is assumption to 280 MW and we are not aware of evidence of economies of scale for larger installations. This balancing measure is more expensive than incremental pipeline and, therefore, is not used in any scenario or year.

- Battery storage is assumed to be available as follows in both the base and low demand cases: 40 MW by 2015, an additional 200 MW from 2016 to 2020, and an additional 1200 MW from 2021 to 2030 with an annual capacity factor of 15 percent. Annual levelized costs fall from $381/MWh in 2015 to $295/MWh in 2030. These assumptions are based on DOE/EPRI's 2013 *Electricity Storage Handbook*. The minimum facility size is

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[58] Long haul pipeline capacity transports gas from the Gulf Coast and Western Canada, Short haul capacity transports gas from storage fields and Marcellus Shale regions

[59] Algonquin Gas Transmission, AIM expansion, FERC CP-14-96.

[60] Table B-12. http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

assumption to 40 MW and we are not aware of evidence of economies of scale for larger installations. This balancing measure is more expensive than incremental pipeline and, therefore, is not used in any scenario or year.

- In addition, we examined the utility of LNG imports in balancing scenarios and found that, while this capacity could be purchased for approximately $9.85 per MMBtu (the basis to European winter purchases of LNG) its reliability suffers from the problem of a time lag between identifying the need for the resources (and the price conditions to make it profitable) and the ability of ships to make delivery at the Massachusetts port.

APPENDIX C: LOW ENERGY DEMAND CASE ASSUMPTIONS

Overview: Low energy demand case energy is modeled as the base case with the addition of the maximum feasible amount of additional alternative resources.

Gas prices: As in base case.

Canadian transmission: As in base case.

Carbon prices: As in base case.

Greenhouse gas emissions: As in base case.

GWSA compliance: As in base case.

Energy efficiency: For Massachusetts electric efficiency: annual savings rise to 2.9 percent of program administrators' transmission-and-distribution-adjusted load by 2020; the annual share of savings remains constant through 2030. For Massachusetts gas efficiency: annual savings rise to 1.9 percent of annual retail sales by 2020; the annual share of savings remains constant through 2030. Energy efficiency savings at winter peak as in base case. Costs are reported in Appendix A.

Time varying rates: As in base case.

Advanced Building Codes: As in base case.

Renewable thermal technologies: As in base case.

Winter Reliability program: As in base case.

Distributed generation: Incremental to distributed generation in the base case, the alternative resources in Table 27 were added.

Table 27. Alternative resources added to low demand case at reference natural gas price

2015		2020		2030	
	Annual Savings Potential (billion Btu)		*Annual Savings Potential (trillion Btu)*		*Annual Savings Potential (trillion Btu)*
Anaerobic Digestion	20	Res. Gas EE	4	Res. Gas EE	5
Landfill Gas	17	Appliance Standards	9	Appliance Standards	25
Converted Hydro	14	CI Gas EE	4	CI Gas EE	10
Small CHP	184	LI Gas EE	1	LI Gas EE	2
		Res. Electric EE	1	Res. Electric EE	3
		CI Electric EE	5	CI Electric EE	15
		Anaerobic Digestion	1	Anaerobic Digestion	0.4
		Landfill Gas	1	Large CHP	2
		Large CHP	1	Landfill Gas	0.3
		Converted Hydro	2	Converted Hydro	2
		LI Electric EE	0.1	Small CHP	2
		Small CHP	1	LI Electric EE	0.3
		Biomass Power C1	1	Biomass Power C1	1
				Utility-Scale PV	2
				Large Wind C5	15
				Commercial PV	11
				Large Wind C4	24
				Biomass Power C2	2
				Residential PV	2
				Wind (<100 kW)	6

Retirements: As in base case.

Additions: As in base case plus alternative resources below the economic threshold in the feasibility analysis.

Capital costs: As in base case.

Benefit of eliminating constraint-elevated prices: As in base case.

Electric sales data: As in base case.

Electric capacity data: As in base case, adjusted to included alternative resources below the economic threshold in the feasibility analysis.

Existing electric transmission from Canada: As in base case.

Gas LDC demand data: As in base case, adjusted to included alternative resources below the economic threshold in the feasibility analysis.

Gas Muni demand data: As in base case.

Gas capacity data: As in base case.

Winter peak: As in base case.

Constraint criteria: As in base case.

Balancing measures: We determined the least-cost set of measures that would eliminate constraints and balancing the Massachusetts gas sector. Balancing measures are described above in Appendix B.

APPENDIX D: NATURAL GAS PRICE SENSITIVITY ASSUMPTIONS

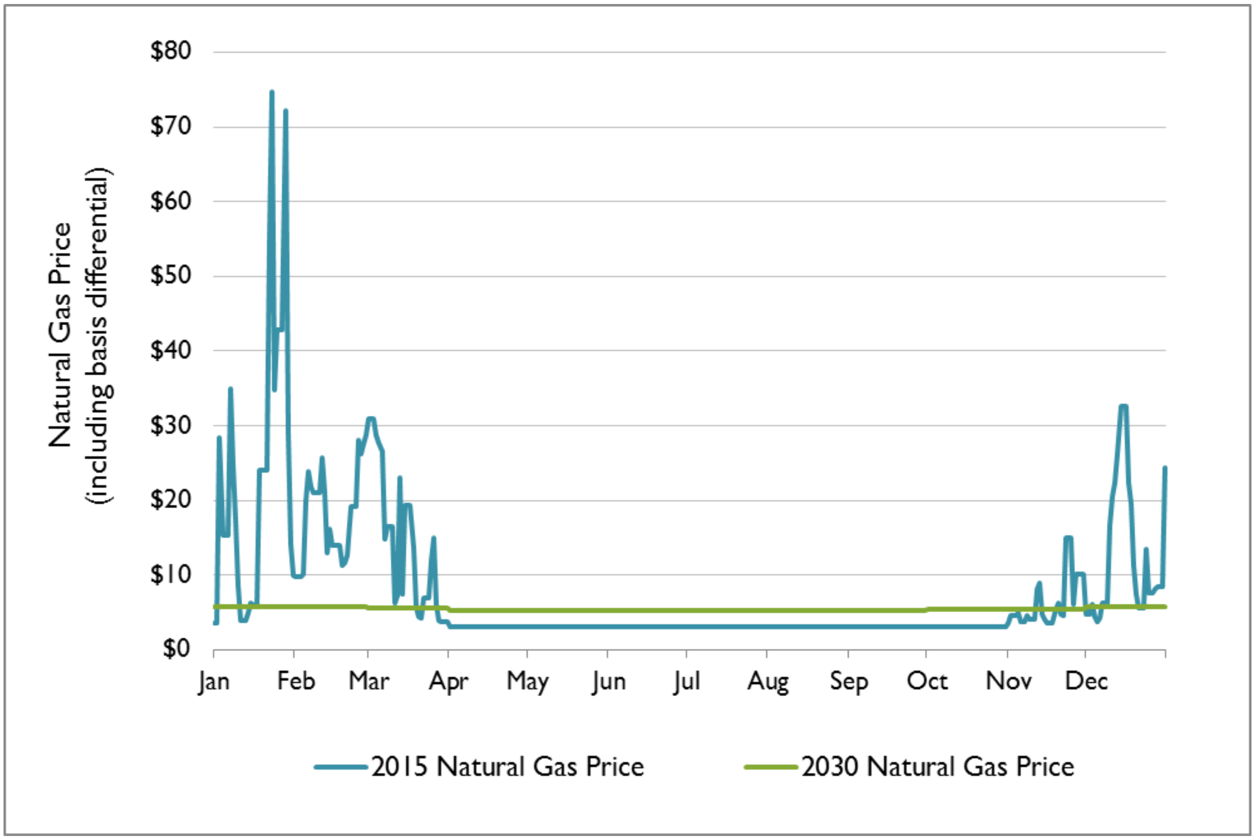
Natural gas price projections are Henry Hub prices developed from three sources: the October 2014 Short Term Energy Outlook (STEO) and the April 2014 Annual Energy Outlook (AEO) both issued by the DOE/ EIA; and the New York Mercantile Exchange (NYMEX) futures gas prices as of October 14, 2014.

In all three price sensitivities the historical monthly prices from January 2012 through October 2014 are from the STEO Figure 14. Also, in all three price sensitivities the monthly price projections from November 2014 through December 2015 are from the October 14, 2014 NYMEX close. The three price sensitivities vary beginning in January 2016. For the reference gas price, the monthly NYMXEX prices are escalated annually in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Reference Case (Tab 13, line 44). For the high gas price, the monthly NYMEX prices are escalated in proportion to the annual percentage changes in the Henry Hub prices from the 2014 AEO Low Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, Low Oil and Gas Resource Case Table, line 57). For the low gas price, the Henry Hub prices from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57) were adjusted in 2019 and 2020 to align better with the prices from the reference price forecast. Without this adjustment, the low price case was higher than the reference case in those two years. The monthly NYMEX prices are then escalated in proportion to the annual percentage changes in the adjusted Henry Hub price trajectory from the 2014 AEO High Oil and Gas Resource Case (Total Energy Supply, Disposition, and Price Summary, High Oil and Gas Resource Table, line 57).

The Low and High Oil and Gas Resource Cases from the 2014 AEO were chosen to represent a range in future gas supplies available from shale reserves. DOE/EIA explicitly recognizes this uncertainty and developed these alternate resource cases to address it.

In 2015 through 2019, we use a winter basis estimate as the November to March difference between Henry Hub and Algonquin City Gate daily prices in 2013/2014. For the summer months in 2015 through 2019, and for all months in the remaining years we assume one constant basis differential for every day, calculated as the average difference between Henry Hub and Algonquin City Gate daily prices in the April through October of 2014. Figure 19 displays the daily reference gas price adjusted for the basis differential for 2015 and 2030.

Figure 19. Daily reference gas price adjusted for basis differential, 2015 and 2030



APPENDIX E: CANADIAN TRANSMISSION SENSITIVITY ASSUMPTIONS

This appendix provides information on Hydro Quebec (HQ) export strategies, data on existing power flows from Canada into New England, and recommendations for modeling assumptions. Table 28 summarizes modeling assumptions related to incremental transmission from Canada.

Table 28. Incremental Canadian transmission assumptions

Imports into New England	Generic HVDC 1	Generic HVDC 2
Model Cases	Canadian transmission only	Canadian transmission only
Nominal/Max	1200	1200
Summer Max	1200	1200
Winter Design Day Peak Hour (6 PM)	1200	1200
Winter Peak Day CF	0.75	0.75
Winter Peak Hour CF	0.71	0.71
Year Available	2018	2022
Comments/Source	Generic baseloaded import	Generic intermediate-loaded import
Flow Patterns	Historic Ph II pattern	Historic Ph II pattern
Ave Ann CF	0.67	0.50
Cost of Line ($2013)	$1.5 billion	$2.2 billion

Documentation of HQ Export Intentions

Synapse relied in part upon Hydro Quebec's (HQ) 2009-2013 Strategic Energy Plan, and HQ's 2012 Annual Report to document "Major Sources of Incremental Hydroelectric Energy" in our memo to the MA DOER, November 1, 2013[61]. Since that time, HQ has released a new annual report, but they have not yet posted any new Strategic Plan documents. HQ's 2013 Annual Report notes the following:

> Hydro-Québec Production is continuing talks regarding participation in projects to build transmission lines between Québec and certain states in the U.S. Northeast. These interconnections would enable us to increase our exports to those markets. (p. 12)

[61] Synapse Energy Economics, "Incremental Benefits and Costs of Large-Scale Hydroelectric Energy Imports", Prepared for the Massachusetts Department of Energy Resources, November 1, 2013. See, e.g., pages 8-9.

The information in the Annual Report (2013) does not clarify exactly how much capacity and/or annual energy HQ might be capable of providing to New England, for any given year or for any given price point. The 2009-2013 Strategic Plan clearly indicates that HQ plan to "Step Up Exports" but with Ontario, New York, New Brunswick, and New England all having access to HQ for energy, it's not certain what that means for New England. From the Strategic Plan:

> Objective 2: Step up exports.
>
> …
>
> As a result of recent and ongoing hydroelectric development projects, Hydro-Quebec Production expects to have the generating capacity needed to ensure export growth. By 2013, we will have nearly 24 TWh at our disposal. This margin of flexibility will enable us to increase the volume of our exports. (p. 25)

And

> Strategy 2 – Step up exports to New England and New York.
>
> …
>
> Hydro-Quebec Production is currently negotiating agreements to supply electricity, via this transmission line [Northern Pass], to these two U.S. distributors and other New England distributors, starting in the middle of the next decade.
>
> Other discussions are under way with State of New York authorities, including the New York Power Authority (NYPA) and the New York Independent System Operator (NYISO), with a view to increasing electricity sales to that market. The State of New York is considering a number of means, including imports of Québec hydropower, to reach its renewable energy goals and GHG emission reduction targets. (p. 27)

And

> We also plan to upgrade the New York interconnection (Chateauguay substation). With import and export capability, this interconnection plays a major role in energy interchanges between Quebec and the United States. We will coordinate the work with the U.S. operators to reduce impacts on service. We are considering other projects to ensure long-term operability and are keeping up our efforts to maintain or increase the exploitable capacity of all our interconnection facilities. We will increase our participation on technical committees with the operators of neighboring power grids and continue to make representations on joint operating rules and reliability standards for interconnected transmission systems. (p. 42)

HQ is on track to complete up to 3,000 MW of new wind energy integration (since ~2008) by 2015.[62] HQ is also continuing its development of hydroelectric resources.[63] HQ continues with an energy efficiency

[62] See e.g. http://www.hydroquebec.com/publications/en/others/pdf/depliant_eolienne_distribution.pdf.

[63] See Strategic Plan 2009-2013, Objective 1: Increase hydroelectric generating capacity, page 19.

program[64]. HQ is in the process of continuing to reinforce and upgrade its transmission network in southern Quebec, and other areas of the Province. For example, transmission reinforcement around Montreal is anticipated over the next five years:

> BOUT-DE-L'ÎLE 735-KV SECTION
>
> Hydro-Québec TransÉnergie (TransÉnergie) is adding a new 735-kV section at Bout-de-l'Île substation (located at east end of Montréal Island). This was originally a 315/120-kV station. The Boucherville – Duvernay line (line 7009), which passes by Bout-de-l'Île, will be looped into the new station. A new -300/+300-Mvar SVC will be integrated into the 735-kV section in 2013.
>
> The project also includes the addition of two 735/315-kV 1,650-MVA transformers in 2014. This new 735-kV source will allow redistribution of load around the Greater Montréal area and absorb load growth in eastern Montréal. This project will enable future major modifications to the Montréal area regional subsystem. Many of the present 120-kV distribution stations will be rebuilt into 315-kV stations and the Montréal regional network will be converted to 315-kV. The addition of a second -300/+300-Mvar SVC at Bout-de-l'Île in 2014 is also projected. [65]

Based on publicly available HQ information, it appears that there are no particular institutional impediments to increasing export levels to New England over the next decade. This is because 1) HQ continues to state that it plans to "step up exports", and 2) its investment in hydro and wind generation, demand side resources, and transmission reinforcement indicates ongoing activity that will allow for increased exports; and 3) it acknowledges activity to allow for exports associated with specific transmission projects to New England and New York.[66]

Existing Canadian Interconnections: Size, Flows, Capacity Factors, and Recommendations for Modeling

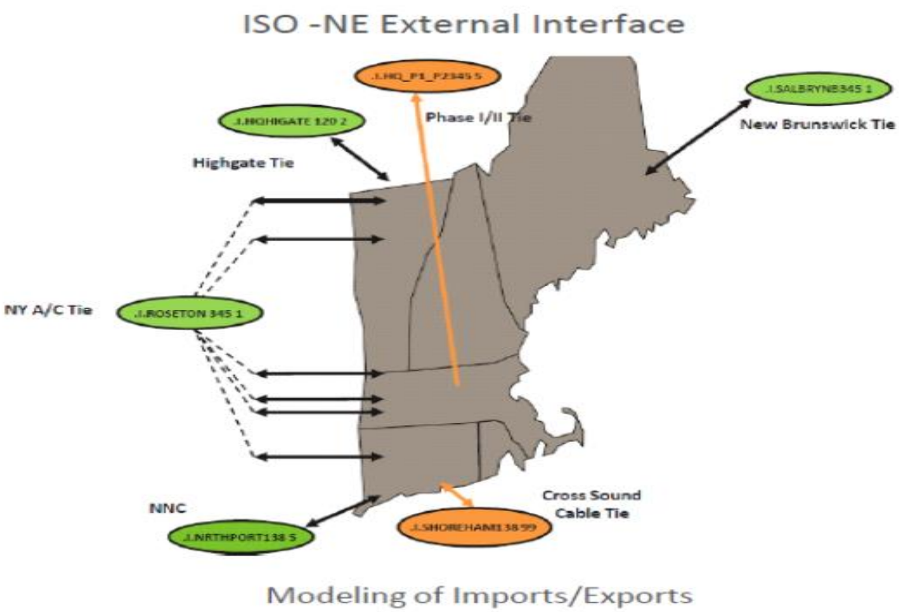
The figure below shows how ISO NE represents transfers to New England from importing points.

64 See Strategic Plan 2009-2013, Objective 2: Step up energy efficiency efforts, page 50.

65 NERC 2013 Long-Term Reliability Assessment, December 2013. NPCC-Quebec section. Page 122. See also the full section, pages 117-122. See also 2013 Annual Report, e.g., pages 15-19.

66 Strategic Plan, p27, p42. Website, http://www.hydroquebec.com/hertel-new-york/en/project/. 2013 Annual Report, page 12.

Figure 20. ISO NE representation for imports



Source: ISO NE

Table 29 shows hourly utilization/capacity factors for the HQ Phase 2 path for 19 of the highest load days during the 2013-2014 winter season. These 19 days include the 9 days that contain the top 24 hours of winter season load, and generally reflect the days that could represent cold snap periods. While on a few of these very-high-load days, the peak load hours (hour ending 18-19, or the 6PM to 7PM time frame) see a utilization of 99 percent or greater, on average the utilization for these 2 critical hours is 83.9-85.5 percent.

Table 29. Summary of hourly capacity factor / utilization of Phase 2 during high load days in the Winter of 2013-2014

Capacity Factor / Hourly Utilization, Phase 2 Line - 19 High Load Days During December - February, 2013-2014

Note: 100% CF on a 1400 MW basis is equal to 70% CF on a 2000 MW basis.

Average of CF @ 1400	Column Label																		
Row Label	**12/17/2013**	**1/2/2014**	**1/3/2014**	**1/7/2014**	**1/8/2014**	**1/9/2014**	**1/21/2014**	**1/22/2014**	**1/23/2014**	**1/24/2014**	**1/25/2014**	**1/26/2014**	**1/27/2014**	**1/28/2014**	**1/29/2014**	**2/10/2014**	**2/11/2014**	**2/12/2014**	**2/13/2014**	**Grand Total**
1	99.7%	98.0%	78.9%	99.9%	99.5%	92.6%	100.0%	99.7%	99.7%	99.4%	100.0%	88.9%	89.1%	96.1%	100.0%	99.9%	89.1%	100.0%	89.0%	95.8%
2	99.7%	100.0%	78.4%	99.9%	99.5%	92.6%	100.0%	99.7%	98.2%	99.9%	100.0%	88.9%	89.0%	96.2%	100.1%	99.9%	89.1%	100.0%	89.1%	95.8%
3	99.7%	100.0%	78.3%	99.9%	93.4%	92.6%	92.5%	99.7%	99.7%	99.9%	100.0%	89.0%	89.0%	96.2%	100.0%	100.0%	89.1%	100.0%	89.1%	95.2%
4	99.7%	99.9%	78.4%	99.9%	89.9%	92.6%	78.0%	99.7%	99.7%	99.9%	100.0%	89.1%	92.6%	96.2%	100.0%	100.0%	89.1%	100.1%	89.1%	94.4%
5	98.3%	99.9%	81.9%	99.9%	82.0%	92.6%	46.4%	97.1%	99.7%	99.9%	100.0%	89.1%	92.6%	96.1%	100.1%	100.0%	89.1%	100.0%	89.0%	92.3%
6	99.1%	99.9%	68.9%	99.9%	81.9%	92.7%	46.4%	99.0%	99.7%	98.1%	93.1%	89.1%	92.6%	96.2%	100.0%	99.9%	89.1%	100.0%	89.1%	91.3%
7	69.1%	96.3%	81.3%	99.9%	78.4%	92.6%	78.0%	68.4%	97.2%	82.5%	88.9%	89.1%	97.0%	96.1%	100.0%	100.0%	89.1%	98.3%	89.1%	89.0%
8	89.3%	98.5%	79.1%	100.0%	81.9%	92.6%	91.9%	55.1%	97.2%	81.8%	89.0%	89.1%	99.9%	98.6%	100.0%	99.9%	89.1%	59.1%	92.5%	88.7%
9	99.5%	94.9%	84.4%	99.9%	94.8%	92.6%	98.9%	65.6%	97.2%	80.5%	89.0%	89.1%	99.9%	87.1%	100.0%	99.9%	99.7%	77.9%	92.6%	91.8%
10	94.7%	94.9%	83.8%	100.0%	95.3%	92.7%	99.0%	79.5%	97.2%	99.6%	89.0%	89.0%	94.9%	99.5%	100.1%	90.8%	96.8%	92.3%	92.5%	93.8%
11	92.6%	94.9%	52.3%	98.6%	92.6%	92.6%	99.0%	87.1%	86.1%	100.1%	89.0%	89.1%	95.9%	100.0%	100.0%	89.1%	90.7%	92.9%	90.5%	91.2%
12	92.6%	94.3%	93.1%	92.2%	92.7%	92.6%	99.1%	83.4%	85.7%	100.0%	89.1%	89.1%	96.4%	100.0%	100.1%	89.1%	89.1%	92.9%	89.8%	92.7%
13	99.6%	70.8%	99.7%	92.3%	92.6%	92.6%	99.1%	89.1%	96.8%	100.0%	88.9%	89.1%	90.1%	100.1%	100.2%	89.1%	89.1%	99.9%	89.8%	93.1%
14	99.6%	94.2%	96.2%	92.3%	92.7%	92.6%	99.1%	99.1%	97.2%	100.0%	89.0%	89.1%	89.5%	100.0%	100.2%	89.1%	89.1%	90.6%	89.8%	94.2%
15	99.6%	92.9%	92.9%	92.3%	92.6%	92.6%	99.1%	99.7%	97.2%	100.0%	88.9%	89.1%	83.1%	100.0%	100.2%	89.1%	89.1%	89.7%	89.8%	93.6%
16	99.6%	51.9%	89.4%	92.3%	92.6%	92.6%	98.5%	99.7%	96.8%	100.1%	88.9%	89.1%	89.6%	100.0%	100.1%	89.1%	89.1%	89.7%	86.9%	91.4%
17	99.5%	50.3%	89.3%	92.3%	92.6%	90.7%	67.5%	89.8%	71.6%	99.6%	88.9%	88.6%	79.9%	92.9%	100.1%	89.1%	89.1%	89.8%	86.9%	86.8%
18	99.6%	47.0%	85.7%	92.3%	85.5%	92.6%	57.8%	73.2%	46.5%	81.9%	88.9%	69.7%	83.0%	92.8%	100.1%	89.1%	89.1%	89.6%	83.6%	81.5%
19	99.5%	55.8%	92.6%	99.4%	88.9%	92.6%	71.5%	53.4%	38.9%	86.6%	88.9%	88.6%	83.1%	99.9%	100.0%	89.1%	89.1%	92.8%	83.5%	83.9%
20	99.5%	57.6%	90.6%	99.5%	92.6%	92.6%	56.6%	66.8%	40.1%	99.6%	88.9%	89.1%	89.6%	100.0%	100.0%	89.1%	89.1%	92.9%	89.6%	85.5%
21	99.5%	74.3%	87.4%	92.8%	92.7%	92.6%	65.1%	81.3%	43.7%	100.0%	88.9%	89.1%	89.8%	100.1%	100.0%	89.1%	91.9%	94.4%	89.6%	87.5%
22	99.4%	92.3%	92.6%	99.4%	92.6%	92.6%	77.7%	99.5%	43.8%	100.0%	88.9%	89.0%	96.6%	100.0%	100.0%	89.1%	84.9%	92.9%	89.6%	90.6%
23	99.4%	92.7%	99.6%	99.5%	92.6%	92.5%	87.9%	90.8%	55.3%	100.0%	88.9%	89.1%	92.9%	100.1%	92.3%	89.1%	99.4%	90.6%	89.6%	91.7%
24	99.4%	92.7%	99.8%	96.5%	92.7%	92.5%	96.3%	99.6%	85.0%	100.1%	88.9%	89.1%	92.8%	100.0%	89.1%	89.1%	100.1%	89.1%	89.7%	93.8%
Grand Total	**97.0%**	**85.2%**	**85.6%**	**97.1%**	**90.9%**	**92.5%**	**83.6%**	**86.5%**	**82.1%**	**96.2%**	**91.4%**	**88.2%**	**91.2%**	**97.7%**	**99.3%**	**93.3%**	**90.8%**	**92.3%**	**89.2%**	**91.1%**

Table 30. Summary of hourly capacity factor / utilization of New Brunswick Tie during high load days in the Winter of 2013-2014

NB Capacity Factor
800

Hour End	12/17/2013	1/2/2014	1/3/2014	1/7/2014	1/8/2014	1/9/2014	1/21/2014	1/22/2014	1/23/2014	1/24/2014	1/25/2014	1/26/2014	1/27/2014	1/28/2014	1/29/2014	2/10/2014	2/11/2014	2/12/2014	2/13/2014	Ave all Days
1	80%	56%	19%	85%	73%	97%	98%	91%	67%	73%	83%	96%	97%	97%	96%	81%	100%	91%	80%	82%
2	79%	51%	25%	78%	77%	97%	97%	83%	64%	63%	82%	98%	89%	97%	98%	98%	87%	87%	76%	80%
3	81%	45%	33%	74%	78%	96%	96%	78%	71%	66%	75%	97%	88%	97%	97%	96%	83%	89%	91%	81%
4	82%	36%	31%	79%	73%	94%	82%	68%	69%	67%	72%	97%	84%	97%	97%	97%	85%	87%	92%	79%
5	81%	23%	23%	71%	45%	95%	75%	60%	61%	75%	68%	97%	82%	97%	97%	93%	95%	87%	84%	74%
6	20%	10%	8%	86%	44%	75%	58%	63%	58%	67%	69%	96%	85%	80%	91%	84%	97%	90%	74%	66%
7	7%	7%	-11%	87%	48%	51%	68%	45%	39%	52%	68%	96%	56%	64%	55%	71%	80%	49%	79%	53%
8	-20%	1%	-21%	90%	82%	40%	79%	44%	49%	33%	69%	97%	58%	69%	47%	74%	77%	41%	81%	52%
9	14%	4%	-11%	87%	81%	33%	76%	40%	50%	42%	71%	97%	73%	90%	46%	85%	81%	57%	81%	58%
10	36%	-3%	18%	96%	95%	36%	97%	79%	28%	80%	79%	84%	94%	97%	85%	95%	98%	94%	97%	73%
11	51%	-12%	-5%	97%	95%	33%	98%	48%	27%	77%	81%	85%	97%	99%	89%	97%	98%	97%	98%	71%
12	57%	-23%	-22%	89%	93%	34%	98%	80%	26%	79%	89%	85%	95%	98%	88%	99%	97%	99%	83%	71%
13	46%	-23%	-11%	95%	93%	51%	100%	80%	55%	85%	93%	96%	98%	100%	88%	99%	99%	92%	99%	75%
14	36%	-9%	-15%	97%	93%	43%	99%	79%	61%	80%	95%	97%	96%	99%	92%	100%	99%	95%	99%	75%
15	45%	14%	-12%	96%	91%	42%	97%	76%	58%	79%	95%	96%	96%	98%	89%	96%	99%	94%	98%	76%
16	24%	11%	-11%	92%	92%	40%	95%	75%	55%	56%	97%	97%	96%	97%	84%	97%	97%	94%	97%	73%
17	11%	16%	10%	93%	93%	46%	62%	56%	46%	34%	96%	86%	95%	75%	69%	95%	70%	90%	80%	64%
18	3%	24%	22%	77%	94%	52%	60%	60%	44%	38%	98%	69%	84%	78%	82%	96%	74%	97%	100%	66%
19	8%	-16%	10%	78%	93%	61%	66%	58%	48%	68%	98%	70%	84%	88%	91%	92%	71%	95%	92%	66%
20	19%	-21%	24%	83%	92%	61%	69%	57%	35%	76%	97%	82%	96%	92%	83%	94%	71%	99%	77%	68%
21	32%	-20%	41%	92%	79%	57%	71%	55%	36%	77%	98%	89%	95%	78%	84%	97%	71%	98%	79%	69%
22	51%	-20%	45%	88%	86%	54%	76%	59%	47%	86%	98%	96%	98%	97%	85%	99%	75%	86%	99%	74%
23	60%	-2%	38%	97%	87%	55%	75%	94%	76%	88%	98%	85%	97%	98%	84%	99%	97%	98%	99%	80%
24	29%	39%	49%	83%	91%	52%	84%	85%	58%	80%	97%	83%	91%	80%	85%	100%	85%	56%	99%	75%
Ave all hrs	39%	8%	11%	87%	82%	58%	82%	67%	51%	68%	86%	90%	88%	90%	83%	93%	87%	86%	89%	71%

Table 31. Summary of hourly capacity factor / utilization of Highgate Tie during high load days in the Winter of 2013-2014

Highgate
225
CF

hr	12/17/2013	1/2/2014	1/3/2014	1/7/2014	1/8/2014	1/9/2014	1/21/2014	1/22/2014	1/23/2014	1/24/2014	1/25/2014	1/26/2014	1/27/2014	1/28/2014	1/29/2014	2/10/2014	2/11/2014	2/12/2014	2/13/2014	Grand Total
1	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	95.6%	97.8%	97.8%	97.8%	97.8%	97.3%	98.2%	93.3%	93.3%	97.8%	96.5%
2	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	98.2%	97.8%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.6%
3	97.8%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	98.2%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.7%
4	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	98.2%	93.3%	93.3%	97.8%	96.7%
5	97.3%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	95.6%	96.9%	97.8%	97.8%	97.8%	97.8%	97.8%	97.3%	98.2%	93.3%	93.3%	97.8%	96.4%
6	97.3%	97.8%	88.9%	93.3%	93.3%	93.3%	85.3%	10.7%	94.7%	95.1%	97.8%	97.8%	97.8%	97.8%	96.0%	98.2%	93.3%	93.3%	98.2%	90.5%
7	86.7%	97.8%	95.6%	93.3%	93.3%	93.3%	11.1%	17.3%	10.7%	4.0%	97.8%	97.8%	97.8%	97.8%	96.9%	97.3%	93.3%	93.3%	98.2%	77.5%
8	86.7%	97.8%	3.6%	93.3%	93.3%	93.3%	11.1%	81.3%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	96.9%	93.3%	93.3%	97.3%	75.7%
9	97.3%	97.8%	8.9%	93.3%	97.8%	93.3%	96.0%	11.1%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	96.4%	96.9%	77.8%
10	97.8%	97.8%	10.7%	93.3%	97.8%	93.3%	97.3%	8.9%	8.9%	0.0%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	97.3%	98.2%	78.0%
11	97.8%	97.8%	84.9%	93.3%	97.8%	93.3%	97.8%	8.9%	8.9%	2.2%	97.8%	97.8%	97.8%	94.2%	97.8%	93.3%	93.3%	97.8%	97.8%	81.6%
12	97.8%	97.3%	97.3%	93.3%	97.8%	93.3%	97.8%	10.7%	66.7%	95.6%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	90.5%
13	98.2%	86.7%	97.8%	93.3%	97.8%	93.3%	97.8%	95.6%	95.6%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.1%
14	98.2%	97.3%	97.8%	93.3%	97.8%	93.3%	97.8%	97.8%	94.7%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.7%
15	98.2%	97.3%	97.8%	93.3%	97.8%	93.3%	97.8%	97.8%	93.8%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	98.2%	96.7%
16	98.2%	86.7%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	4.9%	97.3%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	91.2%
17	98.2%	86.2%	95.6%	93.3%	93.3%	93.3%	96.4%	96.0%	9.8%	93.8%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	90.9%
18	98.2%	86.2%	2.2%	93.3%	93.3%	93.3%	4.0%	11.1%	8.4%	2.7%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	97.3%	97.8%	71.8%
19	98.2%	86.2%	0.9%	93.3%	93.3%	93.3%	0.0%	8.9%	0.0%	2.2%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	71.0%
20	98.2%	86.2%	11.1%	93.3%	93.3%	93.3%	1.3%	8.9%	0.0%	95.6%	97.8%	98.2%	97.8%	97.8%	97.8%	93.3%	93.3%	98.2%	97.8%	76.5%
21	98.2%	97.3%	96.0%	93.3%	93.3%	93.3%	94.2%	8.9%	0.0%	97.8%	97.8%	97.8%	97.3%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	86.5%
22	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	10.7%	0.0%	97.3%	97.8%	97.8%	98.2%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	86.9%
23	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	95.6%	0.0%	96.9%	97.8%	97.8%	98.2%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	91.3%
24	98.2%	97.8%	97.8%	93.3%	93.3%	93.3%	97.8%	97.8%	10.7%	97.8%	97.8%	97.8%	97.8%	97.8%	97.8%	93.3%	93.3%	97.8%	97.8%	92.0%
ave all hours	97.0%	94.9%	73.7%	93.3%	94.6%	93.3%	77.7%	56.8%	42.2%	69.1%	97.8%	97.9%	97.8%	97.6%	97.6%	95.2%	93.3%	96.4%	97.8%	87.6%

Crucially, the CF percentage listed is based on a winter benchmark limit of 1400 MW for the HQ Phase 2 line. As seen, on these cold days, usage rarely exceeds 1,400 MW (a few intervals show usage at as high as 100.2 percent during midday hours, but never more than 1400 MW during the critical hours). If using a different benchmark for capacity factor, or utilization – such as the maximum nominal rating of the path, 2000 MW—a capacity factor of 70 percent would represent a flow of 1,400 MW.

During other hours of the winter, flows reaching as high as 1,749 MW were seen on the HQ Phase 2 path. A number of days see many hours with flows exceeding 1,600 MW.

As shown in Table 30, the New Brunswick line should use a 67 percent capacity factor (on a base of 800 MW, or 536 MW), for the maximum flow during peak hours 6-7 PM. For peak days, a capacity factor/utilization value of 71 percent, or 568 MW should be used. The patterns can reflect the "total" column seen in Table 2 of this report.

Based on the same idea, and as seen in Table 31, the Highgate line should use a 75 percent capacity factor (on a base of 225 MW, or 168 MW), for the maximum flow during peak hours 6-7 PM. For peak days, a capacity factor/utilization value of 88 percent, or 198 MW should be used. The patterns can reflect the "total" column seen in Table 3 of this report.

As is documented in the following tables (Table 32 through Table 41), existing patterns of energy transfer over the HQ Phase II interconnection, Highgate, and the path from New Brunswick illustrate that even in the absence of winter capacity contracts for the full aggregate capacity of the interconnections, HQ imports large amounts of energy to New England during winter periods. We surmise this is due primarily to the economics of importing Canadian energy during high-priced winter periods.

Table 32. Recommendations for modeling existing paths

Imports into New England	HQ Phase II (DC)	New Brunswick (AC)	Highgate (DC)
Nominal/Max	2,000/1,400	1,000/800	225/198
Winter Design Day Max	1,400/1,190	568	198
Ave Ann Capacity Factors (from Nominal Max)	67 percent	40 percent	80 percent
Flow Patterns	Per recent history (2013/14). See monthly CF by peak/off-peak periods	Per recent history (2013/14). See monthly CF by peak/off-peak periods	Per recent history (2013/14). See monthly CF by peak/off-peak periods
Source/Comment	Historical data	Historical data / note increase in 2013/14 with Pt. Lepreau back online	Historical data

The following three tables show the utilization of the Phase II line based on data from 2011-present.

Table 33. HQ Phase II average monthly flows into New England by peak and off-peak periods (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	-1,270	-1,237	-1,405	-1,326	-1,308
	Feb	-1,297	-1,164	-1,331	-1,304	-1,273
	Mar	-799	-1,290	-1,416	-1,344	-1,220
	Apr	-909	-1,231	-1,191	-1,241	-1,141
	May	-945	-1,015	-1,321	-1,039	-1,078
	Jun	-982	-1,164	-1,434	-1,000	-1,150
	Jul	-1,128	-1,417	-1,264	-1,096	-1,226
	Aug	-858	-1,228	-1,493	-1,282	-1,220
	Sep	-436	-1,029	-961	-1,152	-898
	Oct	-764	-1,406	-1,473		-1,202
	Nov	-657	-1,016	-1,428		-1,039
	Dec	-1,261	-1,399	-1,403		-1,355
	Off-peak Avg	-945	-1,218	-1,345	-1,198	-1,175
Peak	*Jan*	-1,371	-1,399	-1,392	-1,347	-1,377
	Feb	-1,377	-1,422	-1,337	-1,330	-1,367
	Mar	-1,333	-1,498	-1,396	-1,393	-1,404
	Apr	-1,451	-1,485	-1,470	-1,488	-1,474
	May	-1,549	-1,270	-1,476	-1,552	-1,460
	Jun	-1,495	-1,456	-1,532	-1,366	-1,462
	Jul	-1,456	-1,637	-1,354	-1,427	-1,467
	Aug	-1,348	-1,537	-1,543	-1,508	-1,483
	Sep	-813	-1,260	-1,114	-1,373	-1,138
	Oct	-1,446	-1,503	-1,531		-1,495
	Nov	-1,279	-1,294	-1,505		-1,357
	Dec	-1,459	-1,451	-1,428		-1,446
	Peak Avg	-1,364	-1,435	-1,424	-1,421	-1,410
Annual Avg		**-1,144**	**-1,321**	**-1,383**	**-1,304**	**-1,287**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse. Note: Peak periods are defined as weekdays, from hour-ending 8AM to hour-ending 11PM.

Table 33 shows that average monthly peak period flows during the winter are generally more than 1,300 MW even in the absence of any firm capacity commitments by HQ. The patterns show relatively high average utilization of the path.

Table 34. Maximum HQ Phase II import levels, 2011-2014 (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-1,505	-1,662	-1,696	-1,632	-1,696
	Feb	-1,604	-1,584	-1,606	-1,647	-1,647
	Mar	-1,554	-1,652	-1,651	-1,599	-1,652
	Apr	-1,585	-1,746	-1,636	-1,619	-1,746
	May	-1,646	-1,723	-1,719	-1,670	-1,723
	Jun	-1,646	-1,737	-1,816	-1,575	-1,816
	Jul	-1,641	-1,801	-1,789	-1,622	-1,801
	Aug	-1,641	-1,745	-1,705	-1,725	-1,745
	Sep	-1,609	-1,723	-1,689	-1,731	-1,731
	Oct	-1,610	-1,853	-1,742		-1,853
	Nov	-1,629	-1,706	-2,516		-2,516
	Dec	-1,647	-1,631	-1,789		-1,789
	Off-peak Max	-1,647	-1,853	-2,516	-1,731	-2,516
Peak	*Jan*	-1,599	-1,749	-1,691	-1,648	-1,749
	Feb	-1,589	-1,701	-1,609	-1,651	-1,701
	Mar	-1,580	-1,717	-1,812	-1,626	-1,812
	Apr	-1,601	-1,746	-1,638	-1,753	-1,753
	May	-1,688	-1,736	-1,753	-1,762	-1,762
	Jun	-1,657	-1,733	-1,794	-1,677	-1,794
	Jul	-1,650	-1,842	-1,795	-1,696	-1,842
	Aug	-1,640	-1,835	-1,700	-1,738	-1,835
	Sep	-1,611	-1,796	-1,669	-1,758	-1,796
	Oct	-1,670	-1,820	-1,832		-1,832
	Nov	-1,662	-1,789	-1,716		-1,789
	Dec	-1,781	-1,613	-1,748		-1,781
	Peak Max	-1,781	-1,842	-1,832	-1,762	-1,842
Annual Max		**-1,781**	**-1,853**	**-2,516**	**-1,762**	**-2,516**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse

Table 34 shows that winter (December-February) period peak exports to New England have reached at least 1,781 MW (December 2011), and often reach levels that exceed 1,600 MW. Summer peak period maximums are greater than 1,800 MW.

Table 35. HQ Phase II average annual capacity factor and monthly patterns (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Total	2013 Capacity Factor	
							1,800 MW	*2,000 MW*
Off-peak	*Jan*	-518,228	-484,784	-528,188	-498,561	-2,029,761	83%	75%
	Feb	-456,555	-419,097	-468,643	-458,917	-1,803,212	81%	73%
	Mar	-300,602	-505,669	-577,756	-548,381	-1,932,408	91%	82%
	Apr	-349,021	-472,553	-438,207	-456,594	-1,716,375	72%	65%
	May	-370,378	-381,537	-496,738	-407,095	-1,655,748	78%	71%
	Jun	-361,193	-447,019	-573,719	-383,978	-1,765,909	95%	85%
	Jul	-460,115	-555,599	-475,306	-412,158	-1,903,178	75%	68%
	Aug	-322,589	-461,889	-585,235	-522,954	-1,892,667	92%	83%
	Sep	-160,429	-411,642	-368,944	-423,821	-1,364,836	61%	55%
	Oct	-311,590	-528,506	-553,758		-1,393,854	87%	79%
	Nov	-241,640	-373,903	-548,381		-1,163,924	91%	82%
	Dec	-494,397	-570,828	-549,972		-1,615,197	87%	78%
	Off-peak Total	-4,346,737	-5,613,026	-6,164,847	-4,112,459	-20,237,069		
Peak	*Jan*	-460,571	-492,501	-512,283	-495,529	-1,960,884	73%	65%
	Feb	-440,792	-477,634	-427,786	-425,755	-1,771,967	68%	61%
	Mar	-490,717	-527,202	-469,111	-467,890	-1,954,920	66%	60%
	Apr	-487,473	-498,927	-517,586	-523,693	-2,027,679	75%	67%
	May	-545,304	-467,396	-543,192	-546,131	-2,102,023	77%	69%
	Jun	-526,297	-489,094	-490,282	-458,953	-1,964,626	71%	64%
	Jul	-489,315	-576,230	-498,161	-525,005	-2,088,711	71%	64%
	Aug	-495,895	-565,449	-543,282	-506,760	-2,111,386	77%	69%
	Sep	-286,128	-403,348	-374,345	-483,349	-1,547,170	54%	49%
	Oct	-485,988	-553,160	-563,540		-1,602,688	80%	72%
	Nov	-450,134	-455,319	-505,708		-1,411,161	73%	66%
	Dec	-513,656	-487,483	-502,764		-1,503,903	71%	64%
	Peak Total	-5,672,270	-5,993,743	-5,948,040	-4,433,065	-22,047,118		
Annual Total		**-10,019,007**	**-11,606,769**	**-12,112,887**	**-8,545,524**	**-42,284,187**		
1,800 MW Avg CF		64%	74%	77%	72%	72%		
2,000 MW Avg CF		57%	66%	69%	65%	64%		

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse.

Table 36. Highgate average annual flows (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	-215	-187	-214	-211	-207
	Feb	-205	-175	-213	-216	-202
	Mar	-141	-159	-218	-206	-182
	Apr	-151	-216	-194	-120	-170
	May	-170	-129	-183	-97	-144
	Jun	-130	-159	-180	-120	-148
	Jul	-165	-183	-205	-96	-162
	Aug	-122	-158	-206	-154	-160
	Sep	-121	-126	-208	-168	-156
	Oct	-134	-20	-176		-111
	Nov	-72	-91	-215		-127
	Dec	-145	-187	-212		-182
	Off-peak Avg	-148	-150	-202	-154	-164
Peak	*Jan*	-218	-218	-219	-196	-213
	Feb	-220	-215	-217	-217	-217
	Mar	-217	-219	-220	-215	-218
	Apr	-220	-218	-215	-216	-217
	May	-199	-187	-188	-177	-188
	Jun	-179	-206	-219	-217	-205
	Jul	-212	-205	-215	-217	-212
	Aug	-209	-209	-217	-217	-213
	Sep	-207	-214	-218	-212	-213
	Oct	-169	-47	-194		-136
	Nov	-209	-99	-217		-174
	Dec	-216	-219	-218		-218
	Peak Avg	-206	-187	-213	-209	-203
Annual Avg		**-176**	**-167**	**-207**	**-180**	**-183**

Source: ISO NE SMD Interchange Data, 2011-2014. Tabulation by Synapse.

Table 37. Highgate maximum flows (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-222	-221	-221	-221	-222
	Feb	-222	-220	-221	-222	-222
	Mar	-222	-221	-221	-222	-222
	Apr	-222	-221	-222	-221	-222
	May	-223	-220	-222	-220	-223
	Jun	-212	-221	-222	-218	-222
	Jul	-219	-221	-222	-219	-222
	Aug	-218	-221	-222	-217	-222
	Sep	-221	-221	-222	-217	-222
	Oct	-210	-219	-222		-222
	Nov	-218	-222	-418		-418
	Dec	-221	-221	-222		-222
	Off-peak Max	-223	-222	-418	-222	-418
Peak	*Jan*	-221	-221	-221	-221	-221
	Feb	-222	-221	-221	-221	-222
	Mar	-222	-222	-222	-222	-222
	Apr	-222	-221	-222	-222	-222
	May	-222	-221	-222	-220	-222
	Jun	-220	-220	-222	-218	-222
	Jul	-219	-221	-222	-218	-222
	Aug	-210	-221	-222	-218	-222
	Sep	-219	-220	-222	-218	-222
	Oct	-219	-219	-222		-222
	Nov	-220	-226	-222		-226
	Dec	-221	-221	-222		-222
	Peak Max	-222	-226	-222	-222	-226
Annual Max		**-223**	**-226**	**-418**	**-222**	**-418**

Table 38. Highgate average annual capacity factor and monthly capacity factor patterns (negative indicates import to New England from Quebec)

		2011	2012	2013	2014	2011-2014 Total	2013 CF *225 MW*
Off-peak	*Jan*	-87,742	-73,118	-80,335	-79,512	-320,707	101%
	Feb	-72,097	-62,974	-75,013	-75,965	-286,049	104%
	Mar	-53,091	-62,346	-88,913	-84,098	-288,448	112%
	Apr	-57,796	-82,906	-71,456	-44,079	-256,237	95%
	May	-66,492	-48,665	-68,698	-37,873	-221,728	87%
	Jun	-47,849	-61,063	-72,172	-46,186	-227,270	95%
	Jul	-67,278	-71,765	-76,928	-36,096	-252,067	97%
	Aug	-45,957	-59,576	-80,746	-62,638	-248,917	102%
	Sep	-44,635	-50,356	-80,053	-61,880	-236,924	106%
	Oct	-54,594	-7,428	-66,336		-128,358	84%
	Nov	-26,615	-33,415	-82,371		-142,401	109%
	Dec	-56,744	-76,490	-83,230		-216,464	105%
	Off-peak Total	-680,890	-690,102	-926,251	-528,327	-2,825,570	
Peak	*Jan*	-73,368	-76,672	-80,596	-72,306	-302,942	91%
	Feb	-70,302	-72,350	-69,524	-69,345	-281,521	88%
	Mar	-79,806	-77,239	-73,939	-72,128	-303,112	84%
	Apr	-73,806	-73,263	-75,742	-76,139	-298,950	88%
	May	-70,151	-68,744	-69,075	-62,302	-270,272	78%
	Jun	-63,041	-69,048	-69,976	-73,072	-275,137	81%
	Jul	-71,158	-72,042	-79,156	-79,825	-302,181	90%
	Aug	-77,046	-76,914	-76,515	-72,848	-303,323	87%
	Sep	-72,895	-68,405	-73,348	-74,556	-289,204	85%
	Oct	-56,889	-17,218	-71,405		-145,512	81%
	Nov	-73,708	-34,762	-72,789		-181,259	84%
	Dec	-76,177	-73,731	-76,624		-226,532	87%
	Peak Total	-858,347	-780,388	-888,689	-652,521	-3,179,945	
Annual Total		**-845,758**	**-1,539,237**	**-1,470,490**	**-1,814,940**	**-1,180,848**	
1,000 MW Avg CF		10%	78%	75%	92%	80%	

Table 39. New Brunswick average flows (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Avg
Off-peak	*Jan*	38	47	-164	-604	-164
	Feb	143	181	-408	-667	-186
	Mar	40	-37	-241	-509	-193
	Apr	-97	-253	-208	-300	-214
	May	-177	-173	-320	-111	-194
	Jun	-220	-132	-532	-191	-272
	Jul	-247	-127	-576	-400	-333
	Aug	-169	-115	-642	-371	-328
	Sep	-236	-136	-581	-309	-315
	Oct	-119	-208	-365		-228
	Nov	-29	-204	-367		-202
	Dec	-16	-121	-526		-220
	Off-peak Avg	-92	-107	-412	-382	-239
Peak	*Jan*	159	113	-118	-564	-111
	Feb	226	313	-439	-676	-139
	Mar	-22	-29	-276	-510	-203
	Apr	-127	-295	-173	-311	-227
	May	-153	-118	-487	-92	-214
	Jun	-304	-69	-531	-165	-265
	Jul	-270	-10	-677	-423	-350
	Aug	-260	-18	-673	-422	-338
	Sep	-301	49	-628	-320	-305
	Oct	-96	-186	-414		-236
	Nov	-4	-126	-349		-157
	Dec	-28	-33	-479		-183
	Peak Avg	-102	-36	-436	-386	-230
Annual Avg		**-97**	**-73**	**-424**	**-384**	**-235**

Table 40. New Brunswick maximum flows (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Max
Off-peak	*Jan*	-386	-242	-589	-808	-808
	Feb	-404	-147	-818	-802	-818
	Mar	-438	-832	-792	-801	-832
	Apr	-497	-590	-433	-648	-648
	May	-439	-600	-675	-581	-675
	Jun	-632	-512	-791	-508	-791
	Jul	-639	-600	-810	-687	-810
	Aug	-586	-424	-810	-649	-810
	Sep	-615	-369	-817	-757	-817
	Oct	-326	-449	-746		-746
	Nov	-339	-438	-738		-738
	Dec	-293	-491	-806		-806
	Off-peak Max	-639	-832	-818	-808	-832
Peak	*Jan*	-314	-270	-751	-800	-800
	Feb	-286	-81	-816	-803	-816
	Mar	-438	-803	-797	-797	-803
	Apr	-540	-665	-476	-656	-665
	May	-484	-557	-814	-649	-814
	Jun	-572	-461	-792	-505	-792
	Jul	-603	-363	-804	-676	-804
	Aug	-645	-349	-803	-675	-803
	Sep	-761	-292	-803	-728	-803
	Oct	-408	-419	-774		-774
	Nov	-374	-509	-802		-802
	Dec	-325	-474	-806		-806
	Peak Max	-761	-803	-816	-803	-816
Annual Max		**-761**	**-832**	**-818**	**-808**	**-832**

Table 41. New Brunswick average annual capacity factor and monthly patterns (negative indicates import to New England from New Brunswick)

		2011	2012	2013	2014	2011-2014 Total	2013/14 CF *1,000 MW*
Off-peak	*Jan*	15,664	18,463	-61,656	-227,137	-254,666	65%
	Feb	50,420	65,154	-143,501	-234,812	-262,739	73%
	Mar	15,128	-14,428	-98,212	-207,516	-305,028	59%
	Apr	-37,268	-97,018	-76,630	-110,556	-321,472	33%
	May	-69,352	-65,020	-120,457	-43,701	-298,530	12%
	Jun	-81,050	-50,590	-212,937	-73,395	-417,972	22%
	Jul	-100,961	-49,728	-216,497	-150,221	-517,407	43%
	Aug	-63,441	-43,325	-251,677	-151,371	-509,814	43%
	Sep	-86,764	-54,570	-222,986	-113,734	-478,054	34%
	Oct	-48,680	-78,368	-137,250		-264,298	39%
	Nov	-10,720	-74,947	-140,848		-226,515	42%
	Dec	-6,266	-49,279	-206,310		-261,855	59%
	Off-peak Total	-423,290	-493,656	-1,888,961	-1,312,443	-4,118,350	
Peak	*Jan*	53,399	39,628	-43,518	-207,549	-158,040	53%
	Feb	72,160	105,044	-140,638	-216,171	-179,605	61%
	Mar	-8,237	-10,201	-92,818	-171,496	-282,752	44%
	Apr	-42,532	-99,003	-60,803	-109,547	-311,885	29%
	May	-53,943	-43,496	-179,102	-32,261	-308,802	8%
	Jun	-107,011	-23,261	-169,792	-55,539	-355,603	14%
	Jul	-90,848	-3,372	-248,955	-155,745	-498,920	40%
	Aug	-95,778	-6,701	-236,822	-141,932	-481,233	36%
	Sep	-106,069	15,611	-211,070	-112,745	-414,273	29%
	Oct	-32,221	-68,300	-152,221		-252,742	39%
	Nov	-1,465	-44,479	-117,427		-163,371	31%
	Dec	-9,923	-11,158	-168,727		-189,808	43%
	Peak Total	-422,468	-149,688	-1,821,893	-1,202,985	-3,597,034	
Annual Total		**-845,758**	**-643,344**	**-3,710,854**	**-2,515,428**	**-7,715,384**	
1,000 MW Avg CF		10%	7%	42%	38%	23%	

Additional figures and data below illustrate the patterns of Canadian flow to New England during the cold snap week in early January, 2014, along with power prices and system load on January 7, 2014.

Figure 21. Canadian imports to New England, week of January 2, 2014 (negative numbers represent imports to New England from Canada)

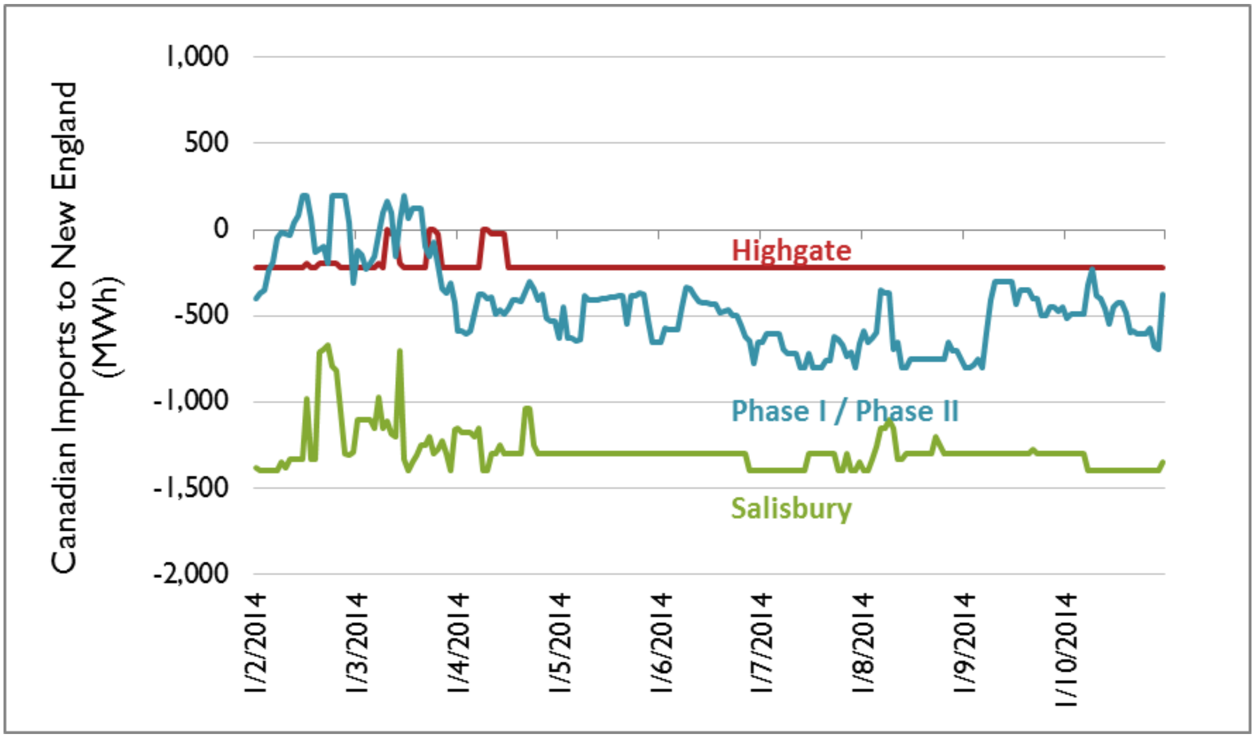


Figure 22. Canadian imports to New England, week of January 2, 2014 (negative numbers represent imports to New England from Canada)

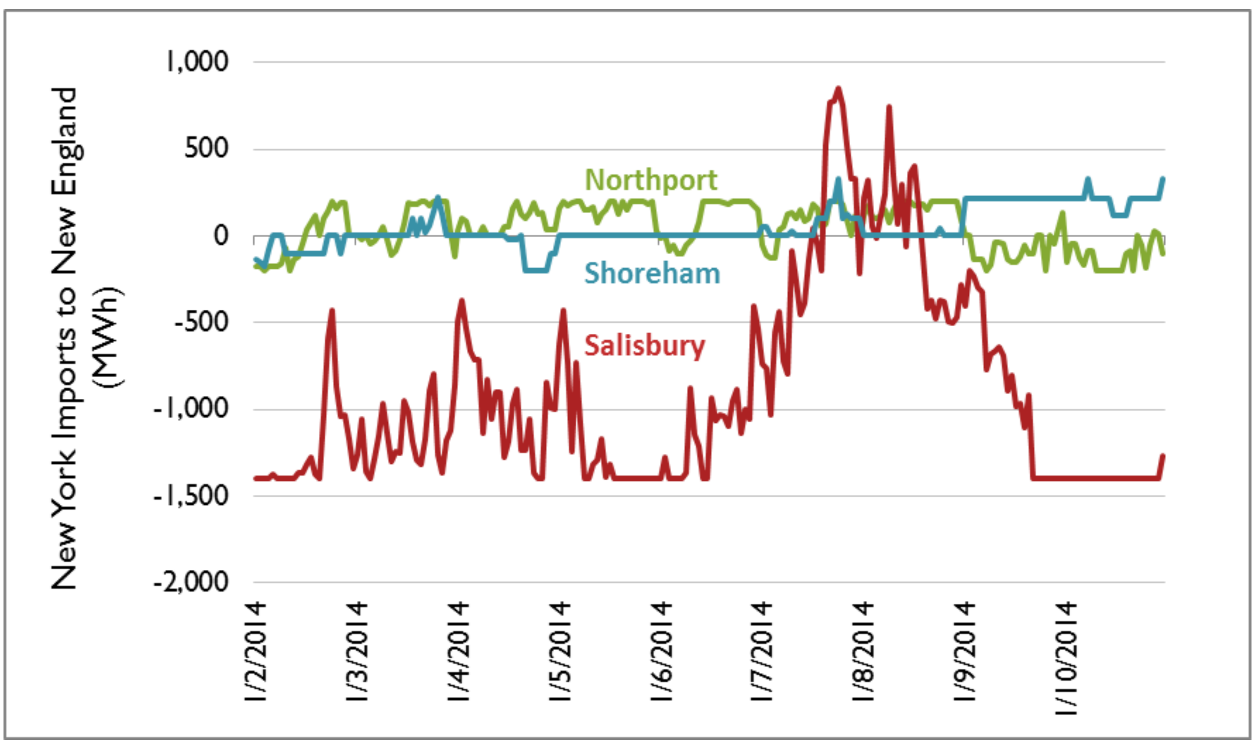


Figure 23. ISO-NE system load, January 7, 2014

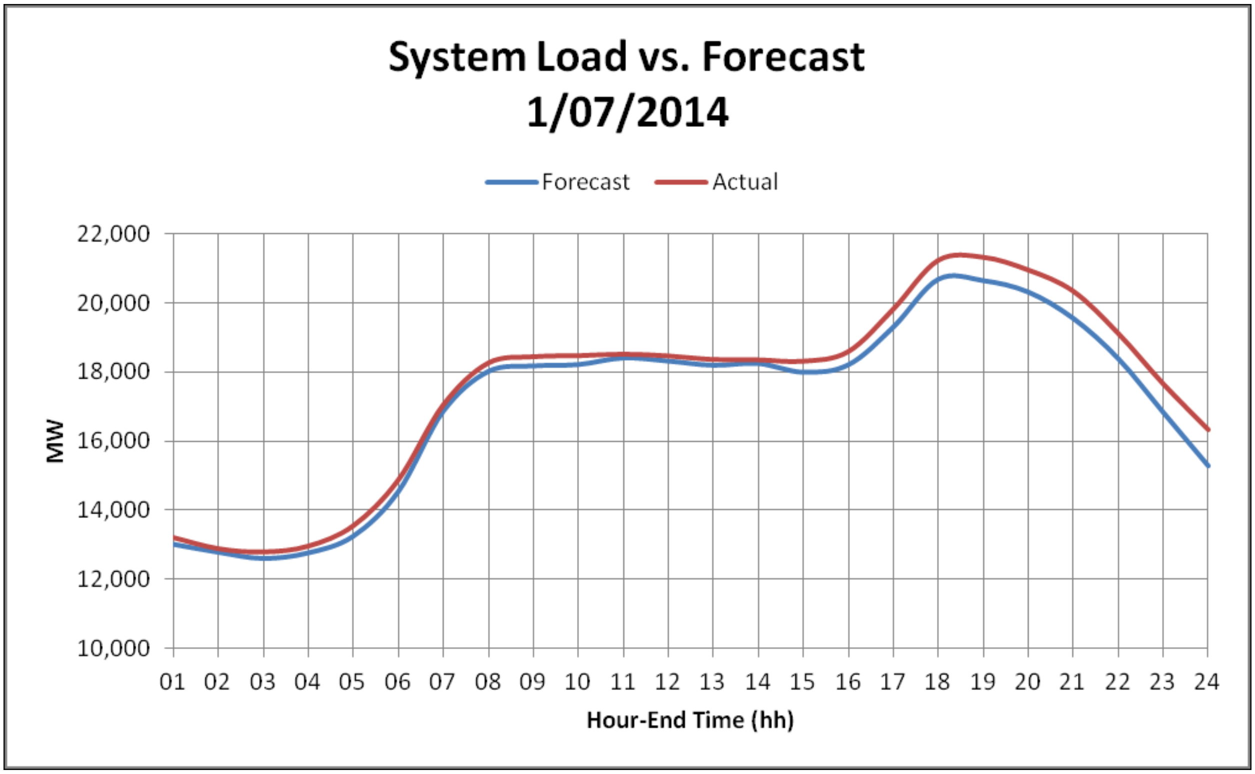


Figure 24. HQ Interface prices, cold snap period, January 2014

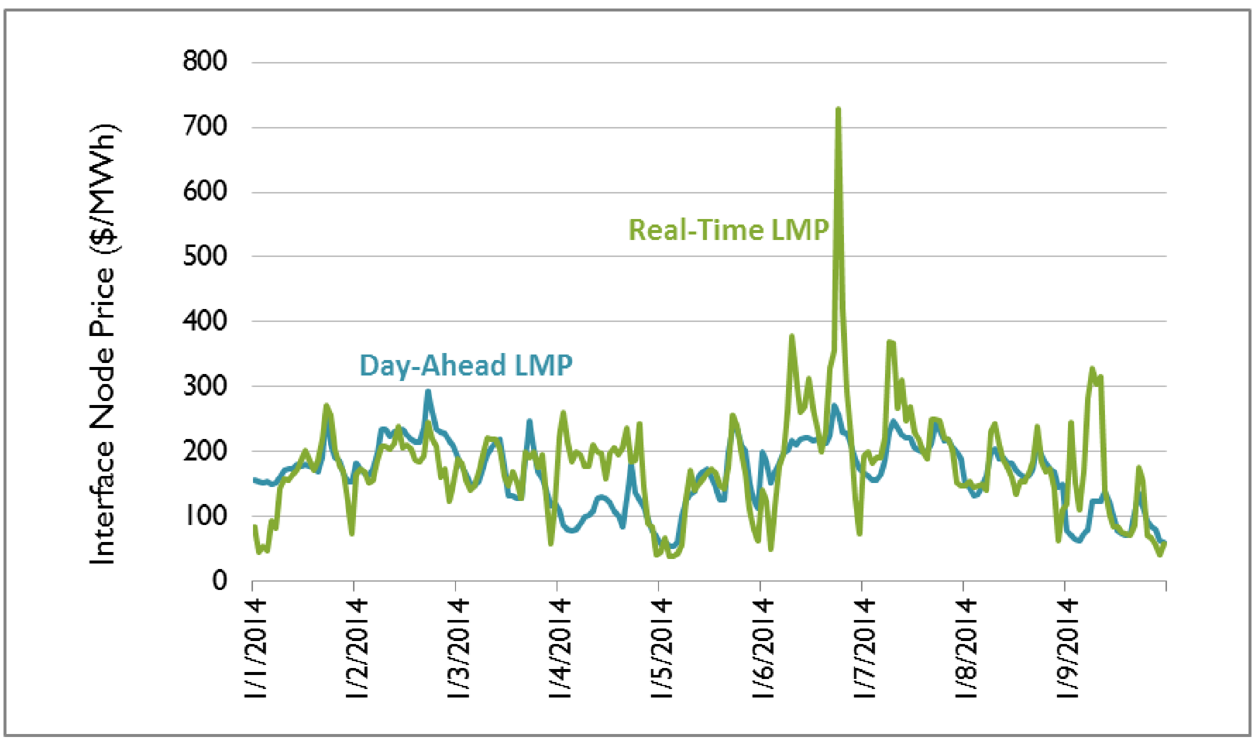


Table 42. Modeling recommendations on new transmission to New England

Imports into New England	Generic HVDC 1	Generic HVDC 2	HQ Phase II Expand to Max Rating
Model Cases	Canadian transmission only	Canadian transmission only	Canadian transmission only
Nominal/Max	1,100	1,100	200
Summer Max	1,100	1,100	200
Winter Peak Day MW	1,100	1,100	200
Year Available	2018	2022	2020
Comments/Source	Generic “baseloaded” import	Generic intermediate import	Increase – for extreme peak periods only – after New York upstate upgrades complete
Flow Patterns	TBD	TBD	TBD
Avg Ann CF	.67	.5	Available only on extreme peak days

Table 42 lists the two recommended new Canadian transmission sources for the incremental Canadian transmission sensitivity run, totaling 2,200 MW, plus an assumption that the Phase II facility will be able to operate at its maximum rating by 2020. Synapse assumes one new line will be available by 2018, and a second by 2022, in our sensitivity for new Canadian transmission.

1) The two generic lines represent any of a number of possible Canadian generation source points, through Maine, New Hampshire, Vermont, or possibly even Connecticut paths. They are based on the same information available to Synapse in November 2013. See data in Table 43, taken from the November 1, 2013 Memo to MA DOER.

2) The incremental Phase II capacity is based in part on the observations in ISO NE’s “2013 Draft Economic Study” which looked at the production cost and emissions impacts of various configurations that would increase the Phase II limits up to the maximum 2,000 MW equipment ratings. Also, we note that ongoing proceedings in New York State indicate that by 2020, there is likely to be substantial upgrade of the major west-to-east constrained paths in upstate New York that contribute to the loss-of-source contingency event limitations on Phase II.

3) We note that the total of the Phase II and the generic new lines results in a total incremental Canadian transmission capacity to New England of 2,400 MW on peak days when New England pricing allows increased flows, in the Canadian transmission sensitivity.

Table 43. From Table A-1, Synapse 11/1/13 Memo, Expanded potential transmission paths, new projects

Route / Path	VT Route / overland + submarine	ME Route 1 / overland	ME Route 2 / overland + submarine	NH Route / Northern Pass	CHPE II / submarine
Proxy	Clean energy express	Northeast Energy Link	Green Line	Northern Pass	
Capacity (MW)	1,000	1,100	1,000	1,200	1,000
Estimated Capital Costs (2013 $ B)	$1.50	$2.20	$2.50	$1.40	$2.00
Cost Normalized to 1200 MW (2013 $ B)	$1.80	$2.40	$3.00	$1.40	
Injection	Canada-VT border	Orrington	Orrington / ME Yankee	NH-VT border	CT via submarine path from QC
Terminus	VT - 345 kV Southern	MA - Tewksbury	MA - Boston	NH - 345 kV Deerfield	
Project Developer Estimated In-Service date	2019	2016	NA	2016	
Synapse modeling In-Service date	2018	2020	2022	2015	
Project Type	New	New	New	New	New
Energy Sources					

Other source material:

4) CRA report for Northern Pass assumes full 1,200 MW import on winter peak day (http://northernpass.us/assets/permits-and-approvals/FERC_TSA_Filing_CharlesRiverAssoc_analysis.pdf, page 33)

5) Northern Pass amended application to US DOE 1200 MW baseload power, Page 1, Page 73[67]

6) TDI Clean Power Express, application to US DOE for presidential permit, 1,000 MW. No statement on baseload, or CF.

[67] United States of America before the Department of Energy Office of Electricity Delivery and Energy Reliability Northern Pass Transmission LLC Docket No. PP-371 Amended Application July 1, 2013

Also, we note that a new line from Canada of roughly 1,100 MW will result in a range of energy transfer up to as much as 8.4 TWh into New England. However, the total transfer could be only roughly half that amount if the line is operated in more of an "intermediate" than a "baseload" mode. Two lines will lead to an increase in imports of potentially twice those amounts. Table 44 documents the increases in Canadian exports that would be required to accommodate operation of these lines at the utilization levels listed in the table.

Table 44. Estimate of total annual energy from imports from new sources, given (TWh)

		Avg Annual Capacity Factor		
		50%	**67%**	**80%**
Line Capacity (MW)	**1,000**	4.4	5.9	7.0
	1,100	4.8	6.5	7.7
	1,200	5.3	7.0	8.4

APPENDIX F: DETAILED PRELIMINARY MODEL RESULTS

See the next eight pages for detailed model results for each scenario.

Scenario 1: Base Case - Reference Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	20	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	54	19	12			33	5	92%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	52	19	12			33	8	87%
2023	171	-16	-15	100	37	-4	103%	4	53	19	12			33	8	88%
2024	172	-16	-16	100	37	-3	102%	3	55	19	12			33	6	90%
2025	173	-17	-16	100	37	-3	102%	3	53	19	12			33	8	87%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	56	19	12			33	6	90%
2028	175	-18	-19	100	37	-2	101%	2	60	19	12			38	7	90%
2029	176	-18	-20	100	37	-2	101%	2	60	19	12			38	7	90%
2030	177	-18	-21	100	37	-2	101%	2	61	19	12			38	6	92%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	181	0	417
2016	267	-17	-14	185	0	421
2017	270	-20	-15	200	0	435
2018	274	-22	-17	199	0	434
2019	278	-24	-19	205	0	440
2020	279	-26	-21	256	0	489
2021	280	-27	-22	247	0	478
2022	282	-28	-23	233	0	463
2023	283	-29	-25	236	0	465
2024	284	-30	-26	248	0	477
2025	286	-31	-27	254	0	482
2026	287	-31	-29	255	0	482
2027	289	-32	-30	254	0	480
2028	290	-32	-32	270	0	496
2029	291	-32	-33	274	0	500
2030	293	-32	-34	261	0	487

Million Metric Tons CO_2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	"Total" Costs: Gas EE	"Total" Costs: Electric EE PA	"Total" Costs: TVR	"Total" Costs: Avoided Price Spikes	"Total" Costs: Incremental Pipeline	"Total" Costs: MA Electric System	"Total" Costs: Demand Response	"Total" Costs: Winter Reliability	"Total" Costs: Total	"Delta" Costs: Gas Reduction Measures	"Delta" Costs: Low Demand Resources Capital	"Delta" Costs: Other Resouces Capital	"Delta" Costs: Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	
2016	$971	$158	$577	$0	$0	$0	$2,300	$0	$0	$4,007	$0	$0		$0	
2017	$1,024	$181	$641	$0	$0	$0	$2,239	$0	$0	$4,086	$0	$0		$0	
2018	$1,117	$199	$695	$0	$0	$0	$2,290	$0	$0	$4,301	$0	$0		$0	
2019	$1,085	$215	$737	$0	$0	$0	$2,272	$0	$0	$4,309	$0	$0		$0	
2020	$1,013	$232	$775	$0	-$3,479	$40	$2,089	$0	$0	$670	$0	$0		$0	
2021	$1,069	$244	$811	$0	-$3,430	$40	$2,127	$0	$0	$860	$0	$0		$0	
2022	$1,098	$253	$844	$0	-$3,321	$40	$2,204	$0	$0	$1,118	$0	$0		$0	
2023	$1,125	$257	$874	$0	-$3,327	$40	$2,287	$0	$0	$1,257	$0	$0		$0	
2024	$1,162	$263	$901	$0	-$3,481	$40	$2,334	$0	$0	$1,219	$0	$0		$0	
2025	$1,180	$269	$923	$97	-$3,440	$40	$2,403	$0	$0	$1,471	$0	$0		$0	
2026	$1,205	$274	$943	$0	-$3,460	$40	$2,484	$0	$0	$1,485	$0	$0		$0	
2027	$1,231	$277	$961	$0	-$3,477	$40	$2,546	$0	$0	$1,578	$0	$0		$0	
2028	$1,258	$281	$973	$0	-$3,579	$45	$2,653	$0	$0	$1,630	$0	$0		$0	
2029	$1,293	$283	$984	$0	-$3,597	$45	$2,773	$0	$0	$1,780	$0	$0		$0	
2030	$1,350	$284	$997	$0	-$3,575	$45	$2,855	$0	$0	$1,956	$0	$0		$0	

Scenario 2: Base Case - Low Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand			Heating Balancing		Heating Delta		Non-Contracted Demand		Non-Contracted Balancing					Non-Contracted Delta	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*Existing Pipeline Capacity*	*Existing LDC Vaporization*	*Supply less Demand*	*Demand as a % of Supply*	*Heating Demand Shortage*	*MA Electric System*	*Existing Distrigas Vaporization*	*Mystic LNG Injection*	*Demand Response*	*Winter Reliability*	*Incremental Pipeline*	*Supply less Demand*	*Demand as a % of Supply*
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	20	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	54	19	12			33	5	92%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	7	89%
2022	170	-15	-14	100	37	-4	103%	4	52	19	12			33	8	87%
2023	171	-16	-15	100	37	-4	103%	4	54	19	12			33	7	89%
2024	172	-16	-16	100	37	-3	102%	3	55	19	12			38	10	85%
2025	173	-17	-16	100	37	-3	102%	3	54	19	12			38	12	83%
2026	174	-17	-17	100	37	-2	102%	2	54	19	12			38	12	82%
2027	174	-17	-18	100	37	-2	102%	2	56	19	12			38	10	85%
2028	175	-18	-19	100	37	-2	101%	2	60	19	12			38	7	90%
2029	176	-18	-20	100	37	-2	101%	2	61	19	12			38	6	91%
2030	177	-18	-21	100	37	-2	101%	2	61	19	12			38	6	92%

Annual

Trillion NG Btu per Year	Heating Demand			Non-Contracted		Total
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric System*	*Winter Reliability*	
2015	262	-15	-12	192	0	427
2016	267	-17	-14	195	0	431
2017	270	-20	-15	200	0	435
2018	274	-22	-17	199	0	434
2019	278	-24	-19	205	0	440
2020	279	-26	-21	291	0	523
2021	280	-27	-22	303	0	534
2022	282	-28	-23	300	0	530
2023	283	-29	-25	299	0	528
2024	284	-30	-26	295	0	524
2025	286	-31	-27	297	0	524
2026	287	-31	-29	299	0	526
2027	289	-32	-30	296	0	523
2028	290	-32	-32	296	0	522
2029	291	-32	-33	297	0	523
2030	293	-32	-34	294	0	520

Million Metric Tons CO_2 per Year	Heating Demand			Non-Contracted		Total	GWSA Emissions	
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Gas Reduction Measures*	*MA Electric Inventory*	*Winter Reliability*		*Maximum allowable for complicance*	*Compliant?*
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs										"Delta" Costs				Delta Costs from Base
	LDCs, Munis, Capacity Exempt	*Gas EE*	*Electric EE PA*	*TVR*	*Avoided Price Spikes*	*Incremental Pipeline*	*MA Electric System*	*Demand Response*	*Winter Reliability*	*Total*	*Gas Reduction Measures*	*Low Demand Resources Capital*	*Other Resouces Capital*	*Total*	
2015	$873	$138	$507	$97	$0	$0	$1,770	$0	$12	$3,397	$0	$0		$0	-$411
2016	$957	$158	$577	$0	$0	$0	$1,850	$0	$0	$3,542	$0	$0		$0	-$464
2017	$952	$181	$641	$0	$0	$0	$2,239	$0	$0	$4,014	$0	$0		$0	-$72
2018	$1,002	$199	$695	$0	$0	$0	$2,290	$0	$0	$4,186	$0	$0		$0	-$115
2019	$974	$215	$737	$0	$0	$0	$2,272	$0	$0	$4,198	$0	$0		$0	-$111
2020	$909	$232	$775	$0	-$3,479	$40	$1,694	$0	$0	$171	$0	$0		$0	-$499
2021	$922	$244	$811	$0	-$3,430	$40	$1,696	$0	$0	$281	$0	$0		$0	-$578
2022	$937	$253	$844	$0	-$3,321	$40	$1,720	$0	$0	$473	$0	$0		$0	-$645
2023	$953	$257	$874	$0	-$3,327	$40	$1,767	$0	$0	$565	$0	$0		$0	-$692
2024	$972	$263	$901	$0	-$3,481	$45	$1,798	$0	$0	$497	$0	$0		$0	-$722
2025	$982	$269	$923	$97	-$3,440	$45	$1,852	$0	$0	$728	$0	$0		$0	-$743
2026	$995	$274	$943	$0	-$3,460	$45	$1,897	$0	$0	$693	$0	$0		$0	-$791
2027	$1,009	$277	$961	$0	-$3,477	$45	$1,931	$0	$0	$746	$0	$0		$0	-$832
2028	$1,025	$281	$973	$0	-$3,579	$45	$1,961	$0	$0	$706	$0	$0		$0	-$925
2029	$1,033	$283	$984	$0	-$3,597	$45	$1,976	$0	$0	$724	$0	$0		$0	-$1,055
2030	$1,045	$284	$997	$0	-$3,575	$45	$2,033	$0	$0	$829	$0	$0		$0	-$1,127

Scenario 3: Base Case - High Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	23	19	12				2	95%
2019	168	-13	-11	100	37	-7	105%	7	19	19	12				5	85%
2020	169	-14	-12	100	37	-6	104%	6	52	19	12			33	7	90%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	51	19	12			33	9	85%
2023	171	-16	-15	100	37	-4	103%	4	52	19	12			33	9	86%
2024	172	-16	-16	100	37	-3	102%	3	54	19	12			33	7	89%
2025	173	-17	-16	100	37	-3	102%	3	53	19	12			33	8	87%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	52	19	12			33	10	84%
2028	175	-18	-19	100	37	-2	101%	2	56	19	12			33	6	90%
2029	176	-18	-20	100	37	-2	101%	2	60	19	12			38	7	90%
2030	177	-18	-21	100	37	-2	101%	2	57	19	12			38	10	86%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-17	-14	187	0	423
2017	270	-20	-15	195	0	430
2018	274	-22	-17	196	0	431
2019	278	-24	-19	201	0	436
2020	279	-26	-21	251	0	484
2021	280	-27	-22	242	0	473
2022	282	-28	-23	227	0	457
2023	283	-29	-25	229	0	458
2024	284	-30	-26	241	0	469
2025	286	-31	-27	244	0	471
2026	287	-31	-29	241	0	468
2027	289	-32	-30	238	0	465
2028	290	-32	-32	256	0	482
2029	291	-32	-33	258	0	484
2030	293	-32	-34	244	0	470

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	17	0	29	-	-
2019	15	-1	-1	17	0	30	-	-
2020	15	-1	-1	17	0	29	23	No
2021	15	-1	-1	17	0	29	-	-
2022	15	-1	-1	17	0	29	-	-
2023	15	-2	-1	17	0	29	-	-
2024	15	-2	-1	17	0	29	-	-
2025	15	-2	-1	17	0	29	-	-
2026	15	-2	-2	17	0	29	-	-
2027	15	-2	-2	17	0	29	-	-
2028	15	-2	-2	17	0	29	-	-
2029	15	-2	-2	17	0	29	-	-
2030	16	-2	-2	17	0	29	19	No

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	Gas EE	Electric EE PA	TVR	Avoided Price Spikes	Incremental Pipeline	MA Electric System	Demand Response	Winter Reliability	Total	"Delta" Costs: Gas Reduction Measures	Low Demand Resources Capital	Other Resouces Capital	Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	$0
2016	$985	$158	$577	$0	$0	$0	$2,312	$0	$0	$4,033	$0	$0		$0	$26
2017	$1,072	$181	$641	$0	$0	$0	$2,338	$0	$0	$4,233	$0	$0		$0	$147
2018	$1,120	$199	$695	$0	$0	$0	$2,389	$0	$0	$4,403	$0	$0		$0	$102
2019	$1,133	$215	$737	$0	$0	$0	$2,407	$0	$0	$4,492	$0	$0		$0	$183
2020	$1,159	$232	$775	$0	-$3,479	$40	$2,231	$0	$0	$958	$0	$0		$0	$289
2021	$1,206	$244	$811	$0	-$3,430	$40	$2,249	$0	$0	$1,119	$0	$0		$0	$259
2022	$1,268	$253	$844	$0	-$3,321	$40	$2,354	$0	$0	$1,439	$0	$0		$0	$321
2023	$1,330	$257	$874	$0	-$3,327	$40	$2,466	$0	$0	$1,640	$0	$0		$0	$383
2024	$1,397	$263	$901	$0	-$3,481	$40	$2,528	$0	$0	$1,647	$0	$0		$0	$428
2025	$1,478	$269	$923	$97	-$3,440	$40	$2,653	$0	$0	$2,019	$0	$0		$0	$548
2026	$1,546	$274	$943	$0	-$3,460	$40	$2,766	$0	$0	$2,108	$0	$0		$0	$624
2027	$1,605	$277	$961	$0	-$3,477	$40	$2,847	$0	$0	$2,253	$0	$0		$0	$675
2028	$1,665	$281	$973	$0	-$3,579	$40	$2,988	$0	$0	$2,368	$0	$0		$0	$738
2029	$1,697	$283	$984	$0	-$3,597	$45	$3,118	$0	$0	$2,530	$0	$0		$0	$750
2030	$1,750	$284	$997	$0	-$3,575	$45	$3,180	$0	$0	$2,680	$0	$0		$0	$724

Scenario 4: Base Case - Reference Gas Price - Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.1	4		2	95%
2016	160	-9	-8	100	37	-6	104%	6	14	19	12				11	63%
2017	162	-11	-9	100	37	-6	104%	6	12	19	12				13	59%
2018	165	-12	-10	100	37	-6	105%	6	21	19	12				4	87%
2019	168	-13	-11	100	37	-7	105%	7	16	19	12				8	74%
2020	169	-14	-12	100	37	-6	104%	6	53	19	12			33	6	91%
2021	169	-15	-13	100	37	-5	104%	5	52	19	12			33	8	88%
2022	170	-15	-14	100	37	-4	103%	4	51	19	12			33	10	85%
2023	171	-16	-15	100	37	-4	103%	4	46	19	12			33	15	76%
2024	172	-16	-16	100	37	-3	102%	3	51	19	12			33	10	85%
2025	173	-17	-16	100	37	-3	102%	3	51	19	12			33	11	83%
2026	174	-17	-17	100	37	-2	102%	2	53	19	12			33	9	86%
2027	174	-17	-18	100	37	-2	102%	2	48	19	12			33	14	78%
2028	175	-18	-19	100	37	-2	101%	2	52	19	12			33	10	84%
2029	176	-18	-20	100	37	-2	101%	2	54	19	12			33	9	87%
2030	177	-18	-21	100	37	-2	101%	2	52	19	12			33	11	84%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	181	0	417
2016	267	-17	-14	185	0	421
2017	270	-20	-15	197	0	432
2018	274	-22	-17	177	0	412
2019	278	-24	-19	185	0	420
2020	279	-26	-21	232	0	465
2021	280	-27	-22	222	0	454
2022	282	-28	-23	192	0	421
2023	283	-29	-25	196	0	425
2024	284	-30	-26	213	0	441
2025	286	-31	-27	217	0	444
2026	287	-31	-29	217	0	444
2027	289	-32	-30	217	0	443
2028	290	-32	-32	233	0	459
2029	291	-32	-33	237	0	463
2030	293	-32	-34	228	0	454

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	31	-	-
2017	14	-1	-1	18	0	30	-	-
2018	14	-1	-1	15	0	27	-	-
2019	15	-1	-1	15	0	27	-	-
2020	15	-1	-1	15	0	27	23	No
2021	15	-1	-1	15	0	27	-	-
2022	15	-1	-1	13	0	25	-	-
2023	15	-2	-1	13	0	25	-	-
2024	15	-2	-1	13	0	25	-	-
2025	15	-2	-1	13	0	25	-	-
2026	15	-2	-2	13	0	25	-	-
2027	15	-2	-2	13	0	25	-	-
2028	15	-2	-2	13	0	25	-	-
2029	15	-2	-2	13	0	25	-	-
2030	16	-2	-2	13	0	25	19	No

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	"Total" Costs: Gas EE	"Total" Costs: Electric EE PA	"Total" Costs: TVR	"Total" Costs: Avoided Price Spikes	"Total" Costs: Incremental Pipeline	"Total" Costs: MA Electric System	"Total" Costs: Demand Response	"Total" Costs: Winter Reliability	"Total" Costs: Total	"Delta" Costs: Gas Reduction Measures	"Delta" Costs: Low Demand Resources Capital	"Delta" Costs: Other Resouces Capital	"Delta" Costs: Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,181	$0	$12	$3,808	$0	$0		$0	$0
2016	$971	$158	$577	$0	$0	$0	$2,300	$0	$0	$4,007	$0	$0		$0	$0
2017	$1,024	$181	$641	$0	$0	$0	$2,298	$0	$0	$4,145	$0	$0		$0	$59
2018	$1,117	$199	$695	$0	$0	$0	$2,210	$0	$0	$4,221	$0	$0	$129	$129	$49
2019	$1,085	$215	$737	$0	$0	$0	$2,192	$0	$0	$4,229	$0	$0	$129	$129	$49
2020	$1,013	$232	$775	$0	-$3,479	$40	$1,989	$0	$0	$570	$0	$0	$129	$129	$29
2021	$1,069	$244	$811	$0	-$3,430	$40	$2,014	$0	$0	$747	$0	$0	$129	$129	$16
2022	$1,098	$253	$844	$0	-$3,321	$40	$2,000	$0	$0	$914	$0	$0	$318	$318	$114
2023	$1,125	$257	$874	$0	-$3,327	$40	$2,076	$0	$0	$1,046	$0	$0	$318	$318	$107
2024	$1,162	$263	$901	$0	-$3,481	$40	$2,116	$0	$0	$1,001	$0	$0	$318	$318	$99
2025	$1,180	$269	$923	$97	-$3,440	$40	$2,177	$0	$0	$1,245	$0	$0	$318	$318	$92
2026	$1,205	$274	$943	$0	-$3,460	$40	$2,250	$0	$0	$1,251	$0	$0	$318	$318	$84
2027	$1,231	$277	$961	$0	-$3,477	$40	$2,307	$0	$0	$1,339	$0	$0	$318	$318	$78
2028	$1,258	$281	$973	$0	-$3,579	$40	$2,404	$0	$0	$1,377	$0	$0	$318	$318	$64
2029	$1,293	$283	$984	$0	-$3,597	$40	$2,520	$0	$0	$1,522	$0	$0	$318	$318	$60
2030	$1,350	$284	$997	$0	-$3,575	$40	$2,589	$0	$0	$1,685	$0	$0	$318	$318	$47

Scenario 5: Low Demand Case - Reference Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	23	19	12				5	84%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	53	19	12			29	6	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			29	9	85%
2022	170	-22	-14	100	37	2	98%	0	50	19	12			29	10	83%
2023	171	-23	-15	100	37	4	97%	0	49	19	12			29	12	81%
2024	172	-25	-16	100	37	5	96%	0	51	19	12			29	9	84%
2025	173	-26	-16	100	37	6	95%	0	48	19	12			29	12	80%
2026	174	-27	-17	100	37	8	94%	0	48	19	12			29	12	79%
2027	174	-28	-18	100	37	9	94%	0	48	19	12			29	12	79%
2028	175	-29	-19	100	37	10	93%	0	51	19	12			29	9	85%
2029	176	-30	-20	100	37	11	92%	0	53	19	12			29	7	88%
2030	177	-31	-21	100	37	12	91%	0	46	19	12			29	14	76%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	193	0	424
2018	274	-27	-17	189	0	419
2019	278	-30	-19	193	0	421
2020	279	-34	-21	240	0	464
2021	280	-37	-22	224	0	445
2022	282	-40	-23	205	0	423
2023	283	-43	-25	202	0	418
2024	284	-45	-26	212	0	425
2025	286	-48	-27	211	0	421
2026	287	-50	-29	208	0	416
2027	289	-52	-30	203	0	409
2028	290	-54	-32	214	0	418
2029	291	-56	-33	213	0	416
2030	293	-58	-34	200	0	401

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	16	0	27	23	No
2021	15	-2	-1	15	0	26	-	-
2022	15	-2	-1	14	0	25	-	-
2023	15	-2	-1	13	0	24	-	-
2024	15	-2	-1	12	0	23	-	-
2025	15	-3	-1	12	0	23	-	-
2026	15	-3	-2	11	0	22	-	-
2027	15	-3	-2	10	0	21	-	-
2028	15	-3	-2	10	0	20	-	-
2029	15	-3	-2	9	0	20	-	-
2030	16	-3	-2	8	0	19	19	No

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	"Total" Costs: Gas EE	"Total" Costs: Electric EE PA	"Total" Costs: TVR	"Total" Costs: Avoided Price Spikes	"Total" Costs: Incremental Pipeline	"Total" Costs: MA Electric System	"Total" Costs: Demand Response	"Total" Costs: Winter Reliability	"Total" Costs: Total	"Delta" Costs: Gas Reduction Measures	"Delta" Costs: Low Demand Resources Capital	"Delta" Costs: Other Resouces Capital	"Delta" Costs: Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$2		$2	$11
2016	$962	$179	$580	$0	$0	$0	$2,281	$0	$0	$4,001	$0	$19		$19	$14
2017	$1,009	$214	$651	$0	$0	$0	$2,246	$0	$0	$4,120	$0	$30		$30	$64
2018	$1,092	$246	$714	$0	$0	$0	$2,292	$0	$0	$4,344	$0	$41		$41	$85
2019	$1,054	$277	$770	$0	$0	$0	$2,238	$0	$0	$4,338	$0	$52		$52	$80
2020	$976	$308	$821	$0	-$3,479	$35	$1,970	$0	$0	$631	$0	$63		$63	$24
2021	$1,022	$335	$869	$0	-$3,430	$35	$1,938	$0	$0	$768	$0	$143		$143	$52
2022	$1,041	$359	$915	$0	-$3,321	$35	$1,942	$0	$0	$971	$0	$224		$224	$76
2023	$1,059	$376	$957	$0	-$3,327	$35	$1,953	$0	$0	$1,053	$0	$303		$303	$100
2024	$1,085	$396	$996	$0	-$3,481	$35	$1,926	$0	$0	$957	$0	$382		$382	$120
2025	$1,092	$416	$1,031	$97	-$3,440	$35	$1,915	$0	$0	$1,147	$0	$461		$461	$136
2026	$1,106	$435	$1,064	$0	-$3,460	$35	$1,922	$0	$0	$1,102	$0	$539		$539	$156
2027	$1,121	$454	$1,096	$0	-$3,477	$35	$1,907	$0	$0	$1,135	$0	$616		$616	$173
2028	$1,136	$472	$1,121	$0	-$3,579	$35	$1,931	$0	$0	$1,115	$0	$693		$693	$178
2029	$1,158	$489	$1,146	$0	-$3,597	$35	$1,965	$0	$0	$1,194	$0	$770		$770	$185
2030	$1,199	$506	$1,172	$0	-$3,575	$35	$1,955	$0	$0	$1,292	$0	$846		$846	$182

Scenario 6: Low Demand Case - Low Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	23	19	12				5	84%
2019	168	-17	-11	100	37	-3	102%	3	18	19	12				10	68%
2020	169	-19	-12	100	37	-1	101%	1	53	19	12			29	6	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			29	9	85%
2022	170	-22	-14	100	37	2	98%	0	50	19	12			29	10	84%
2023	171	-23	-15	100	37	4	97%	0	50	19	12			29	11	82%
2024	172	-25	-16	100	37	5	96%	0	51	19	12			29	9	85%
2025	173	-26	-16	100	37	6	95%	0	51	19	12			29	10	84%
2026	174	-27	-17	100	37	8	94%	0	50	19	12			29	10	83%
2027	174	-28	-18	100	37	9	94%	0	48	19	12			29	12	80%
2028	175	-29	-19	100	37	10	93%	0	50	19	12			29	10	83%
2029	176	-30	-20	100	37	11	92%	0	53	19	12			29	7	88%
2030	177	-31	-21	100	37	12	91%	0	49	19	12			29	11	81%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-19	-14	186	0	420
2017	270	-23	-15	196	0	427
2018	274	-27	-17	192	0	422
2019	278	-30	-19	196	0	424
2020	279	-34	-21	245	0	470
2021	280	-37	-22	232	0	453
2022	282	-40	-23	212	0	430
2023	283	-43	-25	209	0	425
2024	284	-45	-26	216	0	429
2025	286	-48	-27	213	0	424
2026	287	-50	-29	208	0	416
2027	289	-52	-30	201	0	407
2028	290	-54	-32	209	0	413
2029	291	-56	-33	208	0	411
2030	293	-58	-34	193	0	394

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	16	0	27	23	No
2021	15	-2	-1	15	0	26	-	-
2022	15	-2	-1	14	0	25	-	-
2023	15	-2	-1	13	0	24	-	-
2024	15	-2	-1	12	0	23	-	-
2025	15	-3	-1	12	0	23	-	-
2026	15	-3	-2	11	0	22	-	-
2027	15	-3	-2	10	0	21	-	-
2028	15	-3	-2	10	0	21	-	-
2029	15	-3	-2	9	0	20	-	-
2030	16	-3	-2	9	0	19	19	No

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	Gas EE	Electric EE PA	TVR	Avoided Price Spikes	Incremental Pipeline	MA Electric System	Demand Response	Winter Reliability	Total	"Delta" Costs: Gas Reduction Measures	Low Demand Resources Capital	Other Resouces Capital	Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,279	$1	$11	$3,905	$0	$2		$2	$99
2016	$948	$179	$580	$0	$0	$0	$2,356	$0	$0	$4,062	$0	$17		$17	$73
2017	$938	$214	$651	$0	$0	$0	$2,187	$0	$0	$3,990	$0	$26		$26	-$70
2018	$980	$246	$714	$0	$0	$0	$2,203	$0	$0	$4,143	$0	$35		$35	-$123
2019	$946	$277	$770	$0	$0	$0	$2,151	$0	$0	$4,143	$0	$44		$44	-$123
2020	$876	$308	$821	$0	-$3,479	$35	$1,998	$0	$0	$559	$0	$53		$53	-$58
2021	$881	$335	$869	$0	-$3,430	$35	$1,985	$0	$0	$675	$0	$115		$115	-$70
2022	$888	$359	$915	$0	-$3,321	$35	$2,030	$0	$0	$906	$0	$177		$177	-$34
2023	$897	$376	$957	$0	-$3,327	$35	$2,083	$0	$0	$1,022	$0	$240		$240	$4
2024	$907	$396	$996	$0	-$3,481	$35	$2,097	$0	$0	$951	$0	$302		$302	$34
2025	$909	$416	$1,031	$97	-$3,440	$35	$2,123	$0	$0	$1,172	$0	$365		$365	$65
2026	$914	$435	$1,064	$0	-$3,460	$35	$2,171	$0	$0	$1,159	$0	$427		$427	$102
2027	$919	$454	$1,096	$0	-$3,477	$35	$2,200	$0	$0	$1,225	$0	$490		$490	$137
2028	$926	$472	$1,121	$0	-$3,579	$35	$2,267	$0	$0	$1,241	$0	$552		$552	$163
2029	$925	$489	$1,146	$0	-$3,597	$35	$2,327	$0	$0	$1,325	$0	$614		$614	$159
2030	$928	$506	$1,172	$0	-$3,575	$35	$2,344	$0	$0	$1,409	$0	$677		$677	$130

Scenario 7: Low Demand Case - High Gas Price - No Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	25	19	12				3	92%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	52	19	12			25	3	94%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			25	6	90%
2022	170	-22	-14	100	37	3	98%	0	49	19	12			25	7	87%
2023	171	-23	-15	100	37	4	97%	0	44	19	12			25	12	79%
2024	172	-25	-16	100	37	6	96%	0	44	19	12			25	12	78%
2025	173	-26	-17	100	37	7	95%	0	41	19	12			25	16	72%
2026	174	-27	-18	100	37	9	94%	0	43	19	12			25	13	77%
2027	174	-28	-19	100	37	10	93%	0	39	19	12			25	17	69%
2028	175	-29	-20	100	37	11	92%	0	41	19	12			25	15	73%
2029	176	-30	-22	100	37	13	91%	0	45	19	12			25	11	80%
2030	177	-31	-23	100	37	14	90%	0	39	19	12			25	18	69%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	189	0	421
2018	274	-27	-17	187	0	417
2019	278	-30	-19	189	0	417
2020	279	-34	-21	232	0	457
2021	280	-37	-22	211	0	432
2022	282	-40	-24	190	0	408
2023	283	-43	-25	185	0	401
2024	284	-45	-27	190	0	402
2025	286	-48	-28	181	0	391
2026	287	-50	-30	177	0	384
2027	289	-52	-31	166	0	371
2028	290	-54	-33	178	0	381
2029	291	-56	-34	171	0	372
2030	293	-58	-36	160	0	359

Million Metric Tons CO_2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	16	0	28	-	-
2019	15	-2	-1	16	0	28	-	-
2020	15	-2	-1	15	0	27	23	No
2021	15	-2	-1	13	0	25	-	-
2022	15	-2	-1	11	0	23	-	-
2023	15	-2	-1	10	0	21	-	-
2024	15	-2	-1	8	0	19	-	-
2025	15	-3	-1	7	0	18	-	-
2026	15	-3	-2	5	0	16	-	-
2027	15	-3	-2	4	0	15	-	-
2028	15	-3	-2	3	0	14	-	-
2029	15	-3	-2	2	0	12	-	-
2030	16	-3	-2	0	0	11	19	Yes

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	Gas EE	Electric EE PA	TVR	Avoided Price Spikes	Incremental Pipeline	MA Electric System	Demand Response	Winter Reliability	Total	"Delta" Costs: Gas Reduction Measures	Low Demand Resources Capital	Other Resouces Capital	Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$3		$3	$12
2016	$976	$179	$580	$0	$0	$0	$2,288	$0	$0	$4,023	$0	$35		$35	$51
2017	$1,056	$214	$651	$0	$0	$0	$2,272	$0	$0	$4,192	$0	$62		$62	$168
2018	$1,096	$246	$714	$0	$0	$0	$2,279	$0	$0	$4,335	$0	$88		$88	$123
2019	$1,101	$277	$770	$0	$0	$0	$2,251	$0	$0	$4,398	$0	$115		$115	$204
2020	$1,117	$308	$821	$0	-$3,479	$30	$2,072	$0	$0	$869	$0	$142		$142	$341
2021	$1,152	$335	$869	$0	-$3,430	$30	$1,959	$0	$0	$915	$2	$464		$466	$521
2022	$1,201	$359	$915	$0	-$3,321	$30	$1,937	$0	$0	$1,121	$2	$785		$787	$790
2023	$1,249	$376	$957	$0	-$3,327	$30	$1,916	$0	$0	$1,202	$2	$1,105		$1,108	$1,053
2024	$1,300	$396	$996	$0	-$3,481	$30	$1,843	$0	$0	$1,084	$2	$1,425		$1,427	$1,292
2025	$1,364	$416	$1,031	$97	-$3,440	$30	$1,818	$0	$0	$1,316	$2	$1,744		$1,746	$1,591
2026	$1,413	$435	$1,064	$0	-$3,460	$30	$1,788	$0	$0	$1,270	$3	$2,062		$2,065	$1,850
2027	$1,454	$454	$1,096	$0	-$3,477	$30	$1,724	$0	$0	$1,280	$3	$2,379		$2,382	$2,084
2028	$1,495	$472	$1,121	$0	-$3,579	$30	$1,717	$0	$0	$1,256	$3	$2,696		$2,699	$2,324
2029	$1,510	$489	$1,146	$0	-$3,597	$30	$1,702	$0	$0	$1,279	$3	$3,012		$3,015	$2,514
2030	$1,543	$506	$1,172	$0	-$3,575	$30	$1,619	$0	$0	$1,294	$3	$3,327		$3,330	$2,668

Scenario 8: Low Demand Case - Reference Gas Price - Hydro

This scenario requires a pipeline.

Peak Hour

Billion NG Btu per Hour	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Heating Balancing: Existing Pipeline Capacity	Heating Balancing: Existing LDC Vaporization	Heating Delta: Supply less Demand	Heating Delta: Demand as a % of Supply	Non-Contracted Demand: Heating Demand Shortage	Non-Contracted Demand: MA Electric System	Non-Contracted Balancing: Existing Distrigas Vaporization	Non-Contracted Balancing: Mystic LNG Injection	Non-Contracted Balancing: Demand Response	Non-Contracted Balancing: Winter Reliability	Non-Contracted Balancing: Incremental Pipeline	Non-Contracted Delta: Supply less Demand	Non-Contracted Delta: Demand as a % of Supply
2015	157	-8	-7	86	37	-19	116%	19	14	19	12	0.6	4		2	95%
2016	160	-10	-8	100	37	-4	103%	4	14	19	12				13	59%
2017	162	-13	-9	100	37	-4	103%	4	12	19	12				15	52%
2018	165	-15	-10	100	37	-4	103%	4	19	19	12				8	73%
2019	168	-17	-11	100	37	-3	102%	3	16	19	12				12	62%
2020	169	-19	-12	100	37	-1	101%	1	50	19	12			25	5	90%
2021	169	-20	-13	100	37	1	99%	0	51	19	12			25	5	92%
2022	170	-22	-14	100	37	2	98%	0	43	19	12			25	13	76%
2023	171	-23	-15	100	37	4	97%	0	42	19	12			25	14	75%
2024	172	-25	-16	100	37	5	96%	0	44	19	12			25	12	78%
2025	173	-26	-16	100	37	6	95%	0	44	19	12			25	12	78%
2026	174	-27	-17	100	37	8	94%	0	44	19	12			25	13	78%
2027	174	-28	-18	100	37	9	94%	0	45	19	12			25	11	80%
2028	175	-29	-19	100	37	10	93%	0	49	19	12			25	7	87%
2029	176	-30	-20	100	37	11	92%	0	48	19	12			25	8	85%
2030	177	-31	-21	100	37	12	91%	0	46	19	12			25	10	83%

Annual

Trillion NG Btu per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric System	Non-Contracted: Winter Reliability	Total
2015	262	-15	-12	182	0	417
2016	267	-19	-14	184	0	418
2017	270	-23	-15	193	0	424
2018	274	-27	-17	171	0	401
2019	278	-30	-19	174	0	403
2020	279	-34	-21	215	0	439
2021	280	-37	-22	203	0	424
2022	282	-40	-23	170	0	388
2023	283	-43	-25	169	0	384
2024	284	-45	-26	185	0	398
2025	286	-48	-27	181	0	392
2026	287	-50	-29	182	0	390
2027	289	-52	-30	176	0	382
2028	290	-54	-32	192	0	396
2029	291	-56	-33	190	0	393
2030	293	-58	-34	182	0	383

Million Metric Tons CO2 per Year	Heating Demand: LDCs, Munis, Capacity Exempt	Heating Demand: Gas EE	Heating Demand: Gas Reduction Measures	Non-Contracted: MA Electric Inventory	Non-Contracted: Winter Reliability	Total	GWSA Emissions: Maximum allowable for complicance	GWSA Emissions: Compliant?
2015	14	-1	-1	18	0	31	-	-
2016	14	-1	-1	18	0	30	-	-
2017	14	-1	-1	17	0	29	-	-
2018	14	-1	-1	14	0	26	-	-
2019	15	-2	-1	14	0	26	-	-
2020	15	-2	-1	13	0	25	23	No
2021	15	-2	-1	12	0	24	-	-
2022	15	-2	-1	10	0	21	-	-
2023	15	-2	-1	9	0	20	-	-
2024	15	-2	-1	8	0	20	-	-
2025	15	-3	-1	8	0	19	-	-
2026	15	-3	-2	7	0	18	-	-
2027	15	-3	-2	7	0	17	-	-
2028	15	-3	-2	6	0	17	-	-
2029	15	-3	-2	6	0	16	-	-
2030	16	-3	-2	5	0	16	19	Yes

2013 $ M per Year	"Total" Costs: LDCs, Munis, Capacity Exempt	Gas EE	Electric EE PA	TVR	Avoided Price Spikes	Incremental Pipeline	MA Electric System	Demand Response	Winter Reliability	Total	"Delta" Costs: Gas Reduction Measures	Low Demand Resources Capital	Other Resouces Capital	Total	Delta Costs from Base
2015	$873	$138	$507	$97	$0	$0	$2,191	$1	$11	$3,817	$0	$2		$2	$11
2016	$962	$179	$580	$0	$0	$0	$2,281	$0	$0	$4,001	$0	$19		$19	$14
2017	$1,009	$214	$651	$0	$0	$0	$2,246	$0	$0	$4,120	$0	$30		$30	$64
2018	$1,092	$246	$714	$0	$0	$0	$2,120	$0	$0	$4,173	$0	$41	$129	$170	$42
2019	$1,054	$277	$770	$0	$0	$0	$2,068	$0	$0	$4,168	$0	$52	$129	$181	$39
2020	$976	$308	$821	$0	-$3,479	$30	$1,873	$0	$0	$529	$0	$63	$129	$192	$51
2021	$1,022	$335	$869	$0	-$3,430	$30	$1,829	$0	$0	$654	$0	$143	$129	$272	$67
2022	$1,041	$359	$915	$0	-$3,321	$30	$1,747	$0	$0	$770	$0	$224	$318	$541	$194
2023	$1,059	$376	$957	$0	-$3,327	$30	$1,756	$0	$0	$851	$0	$303	$318	$621	$215
2024	$1,085	$396	$996	$0	-$3,481	$30	$1,721	$0	$0	$748	$0	$382	$318	$700	$228
2025	$1,092	$416	$1,031	$97	-$3,440	$30	$1,703	$0	$0	$930	$0	$461	$318	$779	$237
2026	$1,106	$435	$1,064	$0	-$3,460	$30	$1,707	$0	$0	$882	$0	$539	$318	$857	$254
2027	$1,121	$454	$1,096	$0	-$3,477	$30	$1,689	$0	$0	$912	$0	$616	$318	$934	$268
2028	$1,136	$472	$1,121	$0	-$3,579	$30	$1,709	$0	$0	$888	$0	$693	$318	$1,011	$269
2029	$1,158	$489	$1,146	$0	-$3,597	$30	$1,736	$0	$0	$961	$0	$770	$318	$1,088	$268
2030	$1,199	$506	$1,172	$0	-$3,575	$30	$1,717	$0	$0	$1,049	$0	$846	$318	$1,164	$256