Power System Reliability in New England

Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas

Analysis Group, Inc.

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Acknowledgments

This Report presents a review of winter electric resource needs in New England and compares the potential ways to meet those needs, considering both ratepayer cost and regional carbon emissions. This is an independent report by Analysis Group, Inc. (AGI) on behalf of the Massachusetts Office of the Attorney General (AGO), with funding from the Barr Foundation.

Throughout the project, AGI received input from the Office of the Attorney General, a Study Advisory Group comprising a wide spectrum of the region's electric and gas industry stakeholders (listed on the next page), and Dr. Jonathan Raab of Raab Associates (who facilitated the Advisory Group process). The authors wish to thank the Barr Foundation, the AGO, the Study Advisory Group, and Dr. Raab for their input on the analysis presented in this report. The authors also would like to recognize the significant contributions of Pavel Darling, Christopher Llop, Justin Metz, and Dana Niu of AGI for their assistance with this project.

The analytic method, views and observations described in this study, however, are solely those of the authors, and do not necessarily reflect the views and opinions of AGI, the Office of the Attorney General, Dr. Raab, or any members of the Study Advisory Group.

About AGI

AGI provides economic, financial, and business strategy consulting to leading law firms, corporations, and government agencies. The firm has more than 700 professionals, with offices in Boston, Chicago, Dallas, Denver, Los Angeles, Menlo Park, New York, San Francisco, Washington, D.C., Montreal, and Beijing.

AGI's energy and environment practice is distinguished by expertise in economics, finance, market analysis, regulatory issues, and public policy, as well as significant experience in environmental economics and energy infrastructure development. The practice has worked for a wide variety of clients including energy producers, suppliers and consumers; utilities; regulatory commissions and other public agencies; tribal governments; power system operators; foundations; financial institutions; and start-up companies, among others.

Study Advisory Group

The Attorney General's Office and AGI would like to thank the Advisory Group (listed below) for their invaluable feedback and input. The Advisory Group members served as a sounding board for the AGO and AGI throughout the modeling process. However, all of the modeling related decisions (including the modeling framework, assumptions, data choices, analysis, and conclusions) are the sole responsibility of the authors using their best professional judgment. Listing the Advisory Group members is not indicative of their concurrence or support for anything contained in this Report, and they may disagree with inputs, analysis, and observations set forth in it.

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TABLE OF CONTENTS

FIGURES AND TABLES

I. EXECUTIVE SUMMARY

Context

The New England region currently relies on natural gas to produce 44 percent of its net electricity needs and its total generating capacity, a figure that could exceed 50 percent by 2024.[1] Our region's dependence on natural gas for electricity generation raises concerns about the reliability of electricity supplies during winter peak conditions, when the region's interstate pipeline system is largely committed for heating needs. It also raises concerns about costs. In years when there are frequent constraints with high utilization on interstate pipelines, prices within the region for spot purchases of natural gas often spike, leading to cost increases for electricity consumers. As generation from new, efficient natural gas plants drives down the output from legacy coal, oil, nuclear, and older natural gas generating facilities, the region may in the future become even more reliant on natural gas fired generation to meet peak electric demand. Increased reliance on natural gas and gas-fired generators that operate without firm natural gas transportation capacity has led to concerns about whether, on the coldest winter days, the region will have enough generating resources to maintain system reliability. As a result, some have suggested that additional gas pipeline capacity is needed in the region for power system reliability and price benefits.

At the same time, this transition away from legacy coal, oil and older natural gas units and towards new, efficient natural gas plants has driven down the greenhouse gas (GHG) emission intensity of the system and lowered total GHG emissions, consistent with regional policies. As discussed further in this Report, however, this trend is not sufficient to meet the region's long-run climate objectives.

Study Purpose

The Massachusetts Attorney General's Office retained Analysis Group, Inc. (AGI) to conduct an independent assessment of the region's power system out to 2030 to determine the following:

1. *Could the region experience power system "deficiencies" – periods during peak winter demand when the electric system may not be able to meet peak electric demand?*
2. *If any such deficiencies are identified, what is the full suite of practical options for maintaining power system reliability – particularly during winter months – including but not limited to electric ratepayer funding for natural gas infrastructure?*

Then, considering the practical options identified for maintaining power system reliability:

3. *What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?*
4. *To what extent do various options help achieve or impede New England states' obligations and goals with respect to GHG emission reductions?*
5. *What other factors not captured in the quantitative analysis are relevant for consideration?*

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[1] ISO-NE, Resource Mix. Available: http://isone.org/about/what-we-do/key-stats/resource-mix.

This Report systematically reviews these questions to gain an understanding of whether the current system can maintain reliability and what the economic costs and benefits (to electric ratepayers) and GHG emission implications would be of either staying the course or pursuing a new path to meet the region's energy needs.

The purpose of this Report is to provide New England's policymakers and stakeholders with an independent and transparent assessment of the potential benefits and drawbacks associated with the various approaches to addressing the region's dependence on natural gas for electricity generation. We recognize that this is but one of many studies related to the region's dependence on natural gas, and that all studies require forecasting and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to consider carefully the purpose, analytic method, and outcomes of all such analyses.

Study Method

Our analysis is focused on the New England region, reviewing system conditions through 2030. We forecast the need for gas-fired generation to meet the region's electrical load requirements in each year and compare that to a forecast of available natural gas supply, after subtracting out firm demand for gas by local gas distribution companies. Combined, we use these forecasts to estimate any potential "deficiencies" – or periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity. We model a "base case," which reflects severe winter conditions, the capability of non-gas fired generation, and market incentives that increase the availability of generation to help meet peak electric demands. We also model "stressed system" scenarios that assess the impact of varying increases (over our base case assumptions) in dependence on natural gas for electricity generation that may arise due to changes in the electric generation resource mix.

We then identify several "solution sets" that represent different approaches to meeting any identified reliability needs going forward, including market-driven ("status quo") solutions, natural gas pipeline expansion, and energy efficiency/renewable energy investments. We compare the solution sets from the perspective of electric ratepayers, reviewing both the up-front costs to implement the solutions and the potential benefits of the solutions due to their impact on wholesale energy market prices. We also compare the solutions with respect to their impact on states' abilities to meet GHG reduction obligations and targets.

Additionally, we review two "infrastructure scenarios" that involve the development of natural gas or transmission infrastructure projects that are either larger and/or brought into service earlier than needed to meet power system reliability. These scenarios capture a wider range of impacts above and beyond just electric reliability needs.

We carry out our analysis from a conservative reliability planning perspective – namely, with every judgment and assumption we err on the side of overstating the need for electricity generation, and understating the level of resources available to meet that need.

Key Findings

Under the base case analysis, power system reliability can and will be maintained over time, with or without additional new interstate natural gas pipeline capacity.

New England's existing market structure, including recent changes to address reliability during challenging system conditions at the time of winter peak demand, will provide the resources and operational practices needed to maintain power system reliability. The region will continue to rely on natural gas as the dominant fuel of choice, but we find that under existing market conditions there is no electric sector reliability deficiency through 2030. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods.

Under the stressed system sensitivities we modeled, power system reliability deficiencies emerge by the winter of 2024/2025.

We also modeled the impact of an increase (over our base case assumptions) in dependence on natural gas for electricity generation. We assume approximately 1,200 megawatts (MW) of additional non-gas fired capacity retirements (beyond our base-case assumptions) are replaced with gas-only resources, and further assume that approximately 20 percent of existing oil-fired resources in the region do not have oil at the time of winter peak demand (this represents approximately 1,800 MW of generation). Under this stressed system scenario, an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to approximately 2,400 MW in 2029/30. From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d). There are 26 hours of deficiency spread out over 9 total days, with only 2 days and 4 hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

To meet this stressed system deficiency need, we considered five "solution sets" that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region's states and stakeholders. The impact of each solution set depends on how it affects price setting in wholesale power markets and also the required costs to implement each solution set. Each solution set also affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies.

Dual-fuel and/or Firm Liquefied Natural Gas (LNG) Solution Sets

Absent any action by states, electricity markets would likely meet any deficiency need through the addition of dual-fuel capability at existing facilities, and/or by contracting for LNG.

New England has significant potential new dual-fuel capability at existing gas-only resources, and underutilized LNG storage and vaporization capacity that could be relied on by gas-fired generators. Absent any action by states to promote alternative solutions, reliability will most likely be maintained through a combination of these resources. This pathway may continue to experience periods of elevated winter prices, but will also require the least cost investment from ratepayers. Specifically, these two "market outcome" solution sets reviewed – involving the conversion of gas-only generation to dual-fuel capability, or the specific contracting on a multi-year basis of storage and delivery as needed of LNG by or for electricity generators – involve minimal up-front investment by consumers. Instead, these solutions would increase costs to the owners of generating assets to meet capacity and energy market obligations, and associated implementation costs would partly or fully flow through to ratepayers over time through existing wholesale market mechanisms.

Market-based solutions fail to offer outcomes consistent with the climate change programs and goals of the New England states.

These market outcome solution sets offer trajectories of GHG emissions that exceed the region's potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region's climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

Additional Natural Gas Pipeline Capacity Solution Set

The construction of additional natural gas pipeline capacity could address the identified stressed system deficiency, provided such capacity was fully reserved for delivery to electricity generators under coincident winter peak conditions for heating and electricity generation.

Long-term investment in firm interstate pipeline capacity would enable sufficient gas-fired electricity generation to meet winter peak needs under the stressed system scenario. Specifically, the reservation of approximately 0.3 Bcf/d or more by 2024, with an incremental 0.12 Bcf/d for a cumulative total of 0.42 Bcf/d or more by 2029 would be sufficient, provided the capacity is guaranteed for delivery to electricity generators at the time of winter peak, and could not be diverted (e.g., to meet unexpectedly high heating needs of natural gas local distribution company (LDC) customers).

Investment in new interstate pipeline capacity generates significant wholesale electricity price benefits but would require up-front and long-term ratepayer commitments.

Increasing natural gas transportation capacity in New England would lower wholesale electricity costs by lowering natural gas prices at times when the interstate pipeline system would otherwise face greater constraints, and thus higher natural gas price basis differentials. The annual average price suppression benefit is likely large enough to exceed the annualized cost to implement the solution set. However, this solution set places up-front costs and risk on ratepayers through significant long-term commitments to pay for the associated infrastructure.

The pipeline solution fails to offer outcomes consistent with the climate change programs and goals of the New England states.

The pipeline solution set offers a trajectory of GHG emissions that exceeds the region's potential GHG reduction objectives. This level of excess potentially represents a failure to meet the region's climate goals and could increase GHG emission-reduction compliance costs for electric ratepayers over time.

Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE) Solution Sets

Increased investment in various combinations of EE, DR, and RE resources could address the identified stressed system deficiency, provided actions were taken to increase such investments beyond existing programs and their current trajectories.

There are many options to meet any identified deficiency need through expanded investment in EE, DR, and RE (through distant low-GHG resources transmitted across existing or new transmission capacity). We modeled three solution set combinations: 1) EE and DR sufficient to meet the need; 2) EE with imports of distant low-GHG energy using existing transmission lines, and 3) EE with imports of distant low-GHG energy using new transmission lines. The cost of low GHG imports reflects the fact that the capacity and energy must be guaranteed to be available at the time of, and for the duration of, winter peak conditions in order to address the region's reliability needs.

Investment in EE/DR represents the best solution from the perspective of ratepayer costs.

Sustained investment over time in EE and DR, above and beyond investment currently committed and expected due to existing state policies, has the greatest potential net consumer benefit. Further, this solution set represents a lower-risk pathway for ratepayers, since it involves flexible annual investments that can be altered over time in response to changing expectations around natural gas supply and demand, EE/DR technology development and resource cost, power system demand growth, and the addition and attrition of electric generating resources. That is, this effort also offers the potential to meet long term climate goals beyond 2030 with lower up-front capital investments. However, increased EE installations would require sustained commitment and action by New England states over the next decade.

Increased EE combined with new transmission and/or commitments to purchase firm capacity from distant low-carbon resources generates significant potential electricity price benefits but also involves significant ratepayer up-front investment obligations.

An EE solution set that includes the transmission of low-carbon and/or renewable resources to New England markets instead of DR could generate substantial wholesale electricity price savings, to the extent that imports displace higher-priced marginal generating resources. However, in order to represent a solution to meet reliability deficiency needs, such imports would need to be backed by firm capacity commitments, including delivery at the time of winter peak. The cost of such a capacity commitment, if combined with the cost of transmission investments, could exceed the electricity price suppression benefits associated with this solution. While imports of low-carbon resources that are not backed by firm commitments may be more economic and help the region meet climate goals, they do not represent a solution to any winter reliability need.

EE combined with firm imports of distant low-carbon resources on new or existing transmission lines provides the greatest benefits from the standpoint of GHG emissions.

Meeting winter system reliability deficiency needs through EE and firm imports of low carbon resources would achieve significant reductions in the emissions of GHG associated with electricity generation in the New England region relative to the status quo outcome. It would also provide increased flexibility to meet longer-term climate policy targets.

Infrastructure Scenarios

"Infrastructure scenarios" – involving major pipeline or transmission investments sooner and/or larger than needed to address reliability needs – amplify the impacts of similar solution sets.

In addition to reviewing solution sets designed to address the reliability need, we reviewed major infrastructure investments in natural gas transportation capacity that is larger and sooner than needed and transmission capacity that comes into operation sooner than needed. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets sized and timed to address stressed system deficiencies.

Summary of Observations

Based on our analysis, we find that power system reliability will be maintained with or without electric ratepayer investment in new natural gas pipeline capacity. This outcome is consistent with the current and expected future conditions facing our region. New England has maintained reliability through cold winter conditions over the past few years, and going forward, the regional grid operator forecasts declining peak demand for electricity during winter months.[2] Further, recent changes to wholesale markets provide strong financial signals for resource developers and operators of existing assets to ensure unit reliability during periods of winter scarcity. In short, the combination of declining demand and the success of new market initiatives will likely accomplish intended results: power system reliability will be maintained going forward, including at the time of winter peak demand. However, the region may want to consider pathways that provide additional certainty of meeting identified deficiencies that may exist under a "stressed system" perspective.

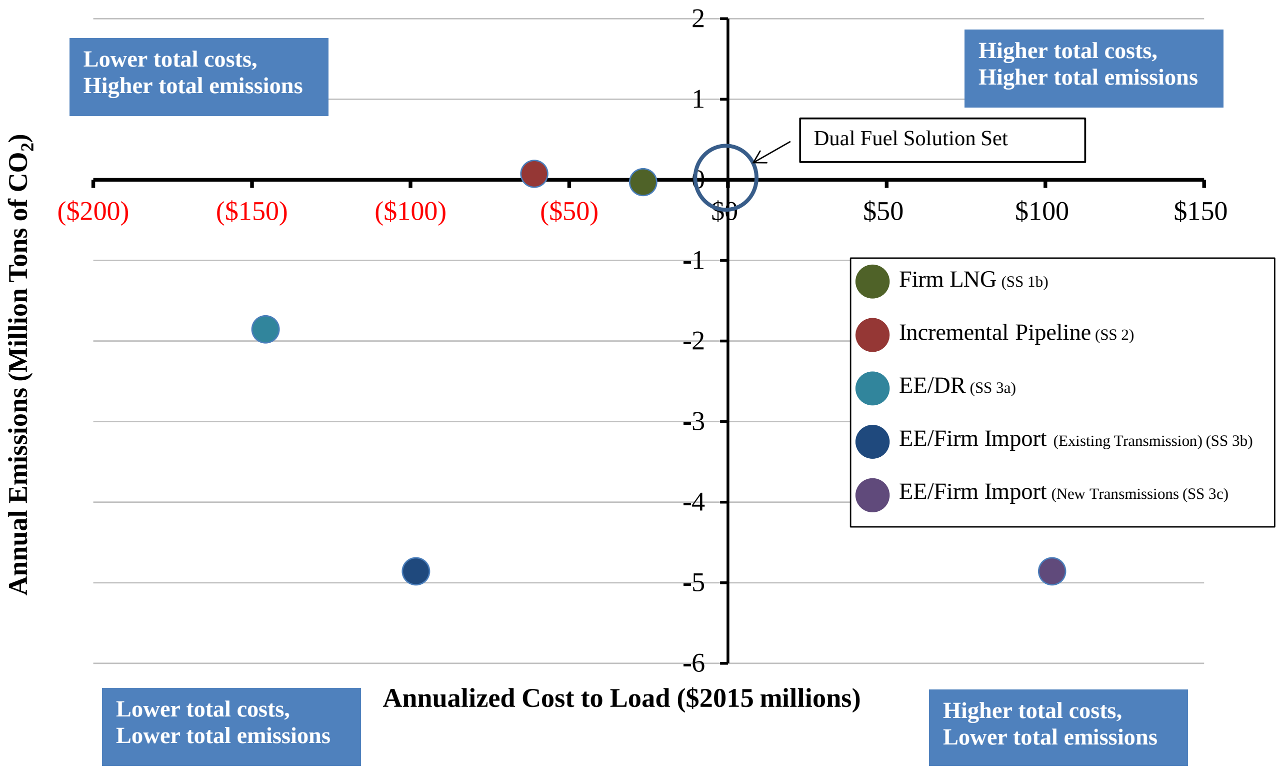
Importantly, the different solution sets that meet the stressed system deficiency vary in fundamental ways from both ratepayer cost and climate policy perspectives. Certain options offer long-term price reducing benefits, but require major up-front investments by ratepayers; others require more measured investments, but also provide fewer price reductions for consumers. Thus there may be additional value that should be attributed to the "incremental" approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

This option value may also be important given the region's GHG goals and commitments. With little to replace in the way of higher-emitting resources, solution sets that continue our growing dependence on natural gas for electricity generation do not appear sustainable relative to our region's and our Nation's evolving GHG emission reduction requirements and goals. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so could require more significant investments at a later date.

[2] ISO-NE Capacity, Energy, Load and Transmission (CELT) Report, System Planning, May 1, 2015.

As Figure ES1 (below) shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. Both the pipeline solution set and the firm LNG solution sets can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy supply and new transmission capacity. In general, however, imports without a firm capacity commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

Figure ES1: Annualized Cost and Emission Impacts, By Solution Set ($2015 mil)



Infrastructure scenarios that are larger and/or installed sooner than needed to meet the deficiency amplify the impacts of similar solution sets, but do not change the relative ranking of each option. These infrastructure scenarios demonstrate cost, risk, electricity price, and GHG emission impacts that are similar in nature but larger in size than the pipeline and transmission solution sets.

II. INTRODUCTION AND PURPOSE

A. Emerging Challenges to Winter Power Supply

New England generating capacity additions and operations are governed by the administration of competitive wholesale markets for capacity, energy, and ancillary services. Recent changes to those markets are expected to provide incentives to ensure that generation capacity is available to meet system needs every hour of the year. Nevertheless, the wholesale market construct has two features that have been the focus of significant analysis and policy deliberation in recent years: (1) resource attrition (i.e., from nuclear, coal, and oil-fired capacity) and addition of gas-fired capacity are increasing the region's reliance on power plants using natural gas as the primary fuel, and (2) to date, most natural gas power plant owners have not found it in their financial interest to purchase much firm natural gas transportation capacity for power plant operations. In light of these two features of wholesale market operations, there is concern that under some scenarios the region could have insufficient generating and demand resource capacity available to meet electric system needs, and/or that system constraints lead to high prices, particularly under cold winter conditions with periods of high natural gas demand from all sectors (especially for home heating demand).

Over the past couple years, a number of states in New England have taken steps to evaluate whether *electric* utilities should be allowed to collect in rates costs associated with the forward procurement of new interstate *natural gas* pipeline capacity on a firm basis.[3] In order to take this step, regulators should be convinced that this type of market intervention is needed to address potential power system reliability risks, and represents a prudent investment for the life of the asset. Beyond reliability, states may also consider whether such an investment would lower overall costs for electricity ratepayers, or otherwise be in the public interest.

Reviewing our dependence on natural gas is warranted for several reasons. Local resources for the supply of electricity are limited in New England, particularly at the time of winter peak demand. The only significant indigenous fuels for electricity generation in the region – biomass, hydro, wind, and sunlight – are restricted by resource availability and/or output variability. The contribution of local and renewable resources to annual energy requirements is significant, has substantial potential for expansion, and continues to grow. However, reliability concerns are tied more to the certainty of resource availability at the time of the winter system peak, or under unpredictable stressed system conditions, than to the magnitude of annual energy production. For example, there are only limited opportunities to increase hydro resources within New England, and at the time of winter peak solar capacity is generally not available and wind resource output is an unpredictable function of weather. As a result, the reliable

[3] This includes Massachusetts, Maine, Connecticut, and New Hampshire. Relevant studies include MA (D.P.U. Docket 15-37), ME (Maine Energy Cost Reduction Act, 35-A M.R.S. §1904-(2)), CT (Public Act No 15-107), and NH (NH PUC Docket IR 15-124). In addition, the New England States Committee on Electricity (NESCOE) also reviewed the issue in a series of reports in 2012 and 2013. See B&V (2013).

operation of the electric system in New England under system peak conditions remains heavily dependent on the timely delivery and/or storage of fuels from outside the region for nuclear and fossil-fuel (coal, oil, and natural gas) power plants.

Several of the more "traditional" resource options have their own set of challenges, with implications for the overall level of reliability of fuel supply and electricity generation. The two resource types with the most reliable fuel storage for long-run operations – nuclear and coal-fired generation – face economic and regulatory hurdles to continued operations and have experienced substantial retirements in recent years. Specifically, persistent low energy market prices, and the increased variable costs or need for incremental capital investment associated with emerging safety and emission control requirements, are putting pressure on continued participation by these resources in regional electricity markets.[4] Further, there are major economic and regulatory impediments to the siting new nuclear or coal-fired resources in the region; in fact, no one has filed for review of new nuclear or coal resources under ISO-NE's interconnection review procedures.[5]

The remaining resources – generating capacity fueled by oil, natural gas, or both (dual-fuel) – require fuel imported from outside New England, and are subject to limitations on the ability to store such fuel for long-run operations. Continuous oil-fired operation at many units is constrained by both limited on-site tank capacity (with the need for potentially frequent replenishment of fuel) and in some cases annual operating limits based on applicable air regulations. Similarly, natural gas-fired capacity is dependent on contemporaneous fuel delivery on an as-needed basis through the region's interstate pipeline system.[6]

The continuous increase in natural gas capacity and its share of regional generation is creating dependence within New England on natural gas for electricity generation throughout all hours of the year. From 2000 to 2014, the region's reliance on natural gas for energy generation increased from 15 to 44 percent, largely replacing coal- and oil-fired generation.[7] Over the same time period, the region added approximately 12,000 MW of gas-fired generating capacity, with all other resource types combined adding just over 2,000 MW.[8] Further, there is little reason to believe this trend will diminish anytime soon. Natural gas dominates the ISO-NE interconnection queue for baseload or cycling resources, representing over 7,000 MW and approximately 62 percent of all interconnection queue resources. Most

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[4] Recent wholesale electricity market rule changes (discussed below) are designed to significantly improve the economics of existing capacity resources. Nevertheless, in October 2015, Pilgrim announced its intent to retire by 2019 (and possibly as early as 2017), due in part to the need for new capital investments in response to NRC regulations.

[5] See, for example, the ISO-NE Interconnection Request Queue, available: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

[6] Some of the region's gas-fired capacity is connected to the distribution networks of the natural gas local distribution companies.

[7] ISO New England, *2015 Regional Energy Outlook*, (hereafter "2015 REO"), page 15.

[8] 2015 REO, page 18.

of the remainder – nearly 3,700 MW (36 percent) – are wind resources whose capacity value is set at a fraction of nameplate capacity.[9]

ISO-NE has conducted significant due diligence over the past five years on the potential impact of our dependence on natural gas on power system reliability. In response, ISO-NE and the region have enacted a comprehensive suite of electricity market reforms to address the issue, affecting virtually every market (energy, capacity, reserves/ancillary services),[10] creating better alignment between the timing of transactions in the natural gas and electricity markets, and establishing clear and frequent lines of communication between power system and pipeline operators, particularly during times of high demand. These changes should fundamentally alter the economics and reliability of power system operations under severe winter conditions, providing the necessary financial signals for enhanced availability and the reliable operation of existing resources, as well as longer-term investment in new resources to enhance the resilience of power system operations during winter peak conditions.

ISO-NE has expressed confidence that the suite of market changes it has promoted will provide the necessary financial incentives for reliable operations at all times of the year on a fuel neutral basis.[11] Yet ISO-NE has also promoted the potential benefits of new natural gas transportation infrastructure to address reliability and energy pricing needs.[12] And while most of the New England states are committed to letting competition in the electricity sector determine the path of infrastructure development and electricity pricing, the states are now actively considering (through legislation and/or regulatory action) options to pursue pipeline infrastructure contracts paid by electricity customers to address winter electric system reliability and cost challenges, and to have electric distribution companies procure large quantities of distant low-carbon resources through long-term contracts in part to help address GHG reduction goals.[13]

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[9] Due to the variable nature of wind generation and the operational performance incentives inherent to New England's capacity market (discussed further below), wind resource capacity value is discounted for reliability planning purposes, and many wind resource owners may choose not to take on capacity supply obligations.

[10] Changes include progressively stronger incentives in the capacity market for reliable operations during periods of peak system needs; more flexibility in the timing and structure of energy market offers to allow for a diverse set of approaches to fuel supply and pricing; changes to amounts procured and pricing in reserve markets providing for substantial additional revenues to generators during times of scarcity; enhanced auditing of generating resource operational capability on all fuels; greater coordination between electric and natural gas system operators; and clarification of the responsibilities of generators that have capacity supply obligations. In combination, these changes represent a fundamentally different and more lucrative structure for ensuring the reliable operation of generating units – including the acquisition of necessary fuel on a timely basis – during winter peak conditions and other times of scarcity.

[11] Testimony of Matthew White on behalf of the ISO, submitted ISO New England Inc. and New England Power Pool, Filings of Performance Incentives and Market Rule Changes; Docket No. ER14-1050-000, filed January 17, 2014.

[12] The Recorder: ISO New England calls for increased gas capacity. Richie Davis, Recorder Staff. January 21, 2015. Published in print: Thursday, January 22, 2015.

[13] See FN 1. In addition, see Appendix 4.

To some extent, the states' efforts reflect the difficult balance between relying on competitive market forces to guide reliable and efficient power system outcomes, but recognizing the paramount importance of preventing power (and natural gas) system reliability failures, and meeting broad-based climate risk mitigation objectives. On one hand, the proper design of the region's wholesale markets for capacity, energy and ancillary services – particularly with recent changes – should allow the market to identify the most efficient, lowest-cost path to maintaining power system reliability in all hours of the year, resulting from competition among a variety of fuel and resource options including pipeline gas, liquefied natural gas, oil and dual-fuel capability, grid-connected and distributed renewables, and demand-side measures. On the other hand, the consequences of missing the reliability and climate objectives are high, and potentially unacceptable from a public policy perspective: if markets cannot or do not provide proper and timely financial incentives, the potential economic, health and public safety impacts of having insufficient resources and infrastructure to meet peak demand can be severe.[14]

B. Purpose of the Study

The Massachusetts Attorney General's Office (AGO) hired AGI to conduct an independent region-wide assessment of potential regional power system reliability needs and solutions and to analyze potential future resource outcomes comparing cost and GHG emission impacts. Specifically, we review:

- Could the region experience power system "deficiencies" – periods during peak winter demand when the electric system may not be able to meet peak electric demand?
- If any such deficiencies are identified, what are the full suite of practical options for maintaining power system reliability – particularly during winter months, including but not limited to electric ratepayer funding for natural gas infrastructure?
- What would be the relative costs to electric ratepayers associated with these options – both to implement the options and as a result of how they affect wholesale electric prices?
- To what extent do various options help achieve or impede New England states' obligations and goals with respect to GHG emission reductions?
- What other factors not captured in the quantitative analysis are relevant for consideration?

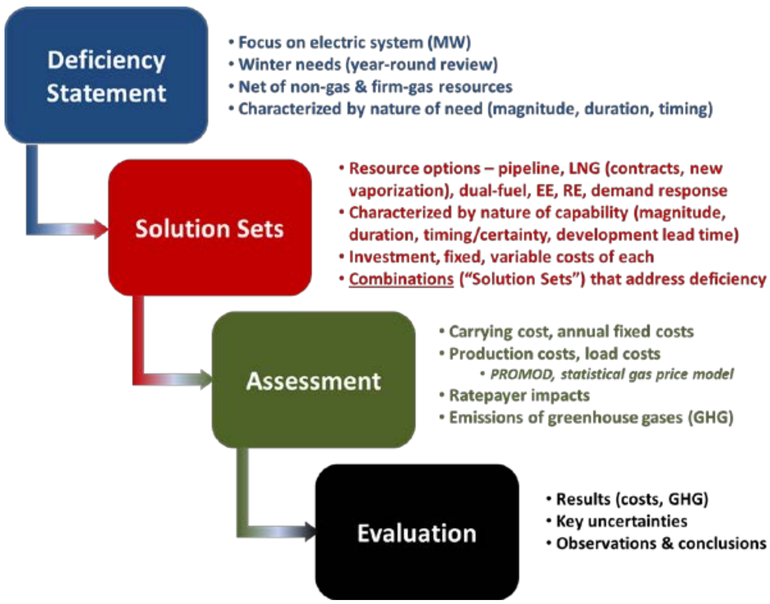
The purpose of our review is to provide information and data to help New England's policymakers and stakeholders consider the potential benefits and drawbacks of various approaches to addressing our region's dependence on natural gas for electricity generation. We recognize that this is one of many studies related to the region's dependence on natural gas, and that all studies require forecasting

[14] ISO-NE and stakeholders in effect recognize this balance in the implementation of the temporary "Winter Programs." During the interim period while the financial signals of recent and pending market rule changes begin to take effect and grow, ISO-NE has proposed and the region has implemented significant out-of-market actions to secure fuel for reliable system operations, to ensure power system reliability until the full effect of the new market structures is in place.

and judgment on highly variable and uncertain future market conditions. It is incumbent on policy makers and stakeholders to carefully consider the purpose, analytic method, and outcomes of the various analyses. Our analysis is designed to provide data and analysis to support the region's consideration of these issues.

C. Overview of Analytic Method

As noted above, this study's primary purpose is to provide a consistent cost and emission comparison of feasible options for maintaining reliable electric supply through 2030, in consideration of potential constraints on natural gas delivery for electric generation.[15] We focus on options to maintain system reliability in the face of increasing dependence on natural gas for electricity generation – including but not limited to electric company pipeline capacity contracts – and conduct a comparative evaluation of the options from reliability, ratepayer costs and risks, and GHG emission perspectives.



The analysis comprises four basic components, described further in the sections that follow. First, we identify the timing, magnitude, and nature of deficiencies that would exist on the electric system absent new resource development beyond what will otherwise occur in response to ISO-NE Forward Capacity Auctions to maintain resource adequacy. For the deficiency review we analyze and model electric and natural gas system conditions in New England through the year 2030, taking into consideration electric system load and all available resources, with attention to the amount of natural gas transportation likely to be available for electricity generation (particularly during winter months). Second, we identify a discrete number of solution sets that represents various feasible combinations of infrastructure and/or resource options in amounts that (1) are sufficient to address any identified deficiency, and (2) can result from the operation of market outcomes or otherwise be implemented through legislative or regulatory action.[16] Next, we conduct an assessment of the solutions sets including financial/ratepayer analysis, production cost modeling, and a review of GHG

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[15] We assume and expect power supply reliability is maintained, even if it is uncertain at this time which resources will emerge to maintain reliability over the forecast horizon. Thus while we use the term "deficiency," we do not mean to suggest or indicate an expectation that the electric system will experience a power supply reliability problem over the forecast horizon.

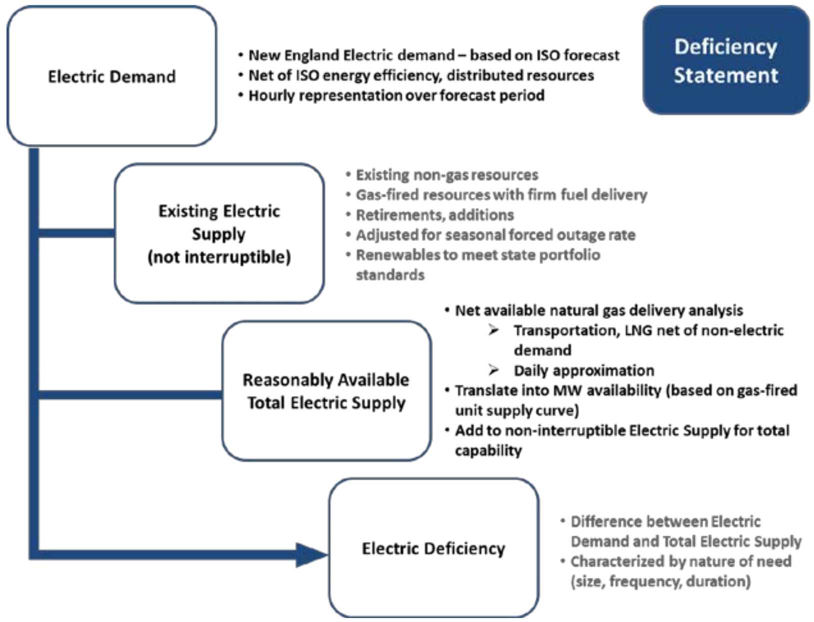
[16] We discuss our screening criteria for "practical" solution sets in Section V.

emission impacts. Finally, we evaluate the results in a comparative analysis of solution sets, identify key uncertainties, and provide observations on the results.

III. POWER SUPPLY DEFICIENCY ANALYSIS

A. Power Supply Deficiency Analysis

To identify the timing and size of solution sets to be evaluated in this report, we first identify a potential deficiency to be met through future resource or infrastructure development. In this context, the term deficiency is not meant to indicate an actual reliability shortfall; instead, it is an estimate for modeling purposes of periods when the electric system may not be able to meet peak electric demand given constraints in natural gas transportation capacity, and thus requiring some combination of additional actions.



In evaluating potential power system deficiencies, we are careful not to construct the analysis in a way that predetermines the conclusion. Specifically, our analysis does not "assume in" a gas supply deficiency by dispatching the electric system *assuming sufficient gas transportation is available in all hours*. This recognizes that whether or not additional interstate pipeline capacity is built (and if so, how much) is not yet known, and that absent additional pipeline capacity there are other ways electric load would be met in constrained hours. Similarly, we do not "assume away" a deficiency by anticipating potential future non-pipeline resource commitments (e.g., firm LNG storage and delivery) or policies (aggressive new renewable, load-shifting, or load-reducing measures or policies). All such potential outcomes are instead configured and evaluated as solution sets to allow for consistent comparison of cost and GHG emission impacts. Thus we adhere in our deficiency analysis to a straight-forward continuation of current market, infrastructure, and regulatory conditions. Under this outlook, the region will continue to rely on natural gas as the dominant fuel of choice, and we include more than 19.5 GW of natural gas fired capacity in 2020 in our base case, representing 52 percent of total system capacity. This total includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.[17] This total also assumes the retirement of the Pilgrim Nuclear facility in 2019.[18]

Our development of the deficiency statement involves four basic steps: (1) identifying hourly demand for electricity through the modeling horizon; (2) establishing the contribution of non gas-fired supply resources that may be relied upon during cold winter conditions; (3) estimating the quantity of natural gas pipeline capacity that may be assumed to be available for electricity generation on a daily basis across the year, reflecting forecasted LDC pipeline use, and translating this into MW of available generating capacity; and (4) combining these estimates to develop a daily and hourly representation of the total megawatt deficiency of the electric system over the modeling horizon – that is, the amount of electric load that would need to be met through changed operations on the current system, or development of new infrastructure or resources.

Our deficiency calculation is focused on winter peak conditions from a reliability planning perspective. Consequently, the deficiency statement assumes a demand forecast based on extremely cold weather year conditions (e.g., the temperature profile of 2004, one of the coldest years in the past two decades) and coincident high electric load (e.g., the Capacity, Energy, Loads, and Transmission (CELT) 90/10 load forecast, net of existing energy efficiency and photovoltaic (PV) resources).[19] More detail on the steps in our deficiency calculation are summarized in Appendix 1. Below, we describe in more detail two key elements of the deficiency analysis – our derivation of the quantity of natural gas that will be available for electricity generation (in consideration of natural gas LDC demand forecasts and supply plans), and our estimate of the need for natural gas-fired generation on the electric system once all other electric resource options have been considered.

1. Availability of Natural Gas for Electricity Generation

To estimate the total quantity of natural gas available to the electric generation sector, we compare an estimate of forecasted LDC demand for natural gas from interstate pipelines to total available pipeline capacity.[20] First, we assume that the total existing interstate natural gas pipeline capacity is equal

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[17] This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

[18] In October 2015, the owners of the Pilgrim Nuclear facility filed a non-price retirement request with ISO-NE.

[19] The 90/10 forecast is based on an expectation that system loads will exceed the forecast only 10 percent of the time. In contrast, the 50/50 load, which is used for resource adequacy planning and in the net Installed Capacity Requirement (ICR), would be expected to be exceeded 50 percent of the time.

[20] We recognize that there are other potential sources of natural gas for electricity generation in addition to interstate pipeline gas, such as supplies sourced from regional LNG facilities. Since these would require forward contracts to procure and ensure LNG is available for electricity generation at the time of winter peak, we do not assume LNG as a resource in the deficiency statement but, rather, assess it as potential solution set.

to 3.95 Bcf/day, based on Energy Information Administration (EIA) State to State capacity data.[21] This includes capacity for Algonquin, Iroquois, Tennessee, Portland Natural Gas, and Maritimes & Northeast Pipelines. We include an additional 0.414 Bcf/day of new capacity in the third quarter of 2016 for the Spectra Algonquin Incremental Market (AIM) Project and the Kinder Morgan Connecticut Expansion Project.[22] Therefore, starting in the 2016/2017 winter, the total capacity of interstate natural gas pipelines is 4.36 Bcf/day.

Next, we develop a forecast of LDC demand for natural gas from interstate pipelines based on the historical relationship between interstate pipeline deliveries to both LDCs and other end-users with historical weather conditions. To do so, we use daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using data provided by SNL Financial.[23] We also use the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.[24]

Using this historical data, we then develop the statistical relationship between demand and temperature for the three-year winter periods 2012/13, 2013/14, and 2014/15, as shown in Figure 1. We forecast future gas demand assuming a growth rate for LDC and end-user demand from interstate pipelines of 1.4 percent.[25] We recognized that peak day demands of the LDCs are not fully met through pipeline deliveries, and any peak day demand above this growth rate is met through other resources, such as increased LNG vaporization from regional LNG facilities (e.g. Distrigas) and LNG peak shaving supplies. We assume that these supplies are unavailable to the electric generation sector. Therefore, our

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[21] We note that this assumption is consistent with the 3.7 Bcf/d used in ICF/ISO-NE (2014) and the 3.9 Bcf/d used in B&V/NESCOE (2013). See ICF International. "Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs: Phase II" Prepared for ISO New England, November 20, 2014. Additional detail on our review of LDC supply and demand, and how both may change over the modeling horizon, is presented in Appendix 1.

[22] These projects have received or are pending final FERC authorization. In contrast, we exclude projects that have initiated the FERC pre-filing process or may have precedent agreements with shippers. This includes both the Spectra Atlantic Bridge project, the Spectra Access Northeast project, and the Kinder Morgan Northeast Energy Direct project.

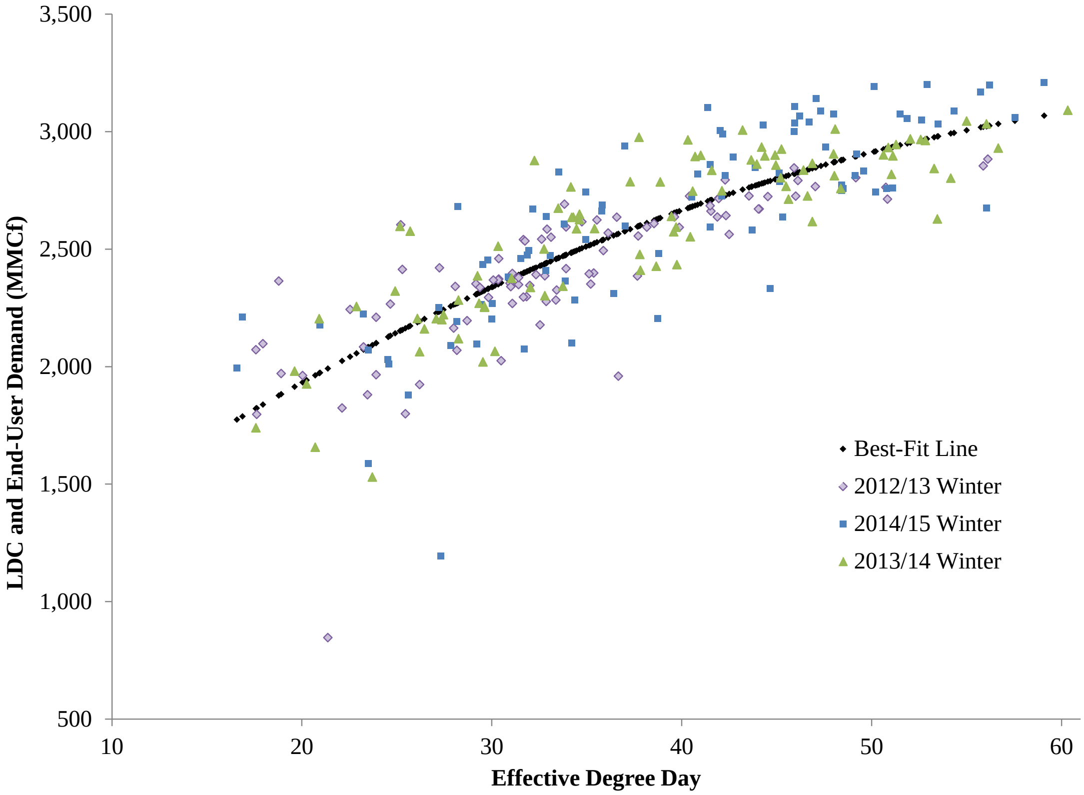
[23] SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

[24] See ISO-NE, Zonal Information, available: http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[25] Our estimate is consistent with the long term growth rate used by other recent studies (ICF (2015); Synapse/DOER (2015)). While certain LDCs currently are forecasting higher growth rates, these forecasts typically include demand from end-use customers (as returning capacity exempt customers), which we already separately account for in our estimates. Using a higher LDC growth rate based on current LDC assumptions could double-count end-user demand. On the supply side we exclude incremental supply resources proposed to meet higher growth rate expectations. We assume that any supply additions approved through an LDC resource planning process would be reserved to meet LDC demand above and beyond the quantity forecasted here and unavailable to the electric generation sector. In Appendix 1 we provide a sensitivity that tests both assumptions.

estimate represents a forecast of LDC firm demand for natural gas only from the existing interstate pipeline system.

Figure 1: Historical Relationship of Weather and Gas Demand, 2012-2015

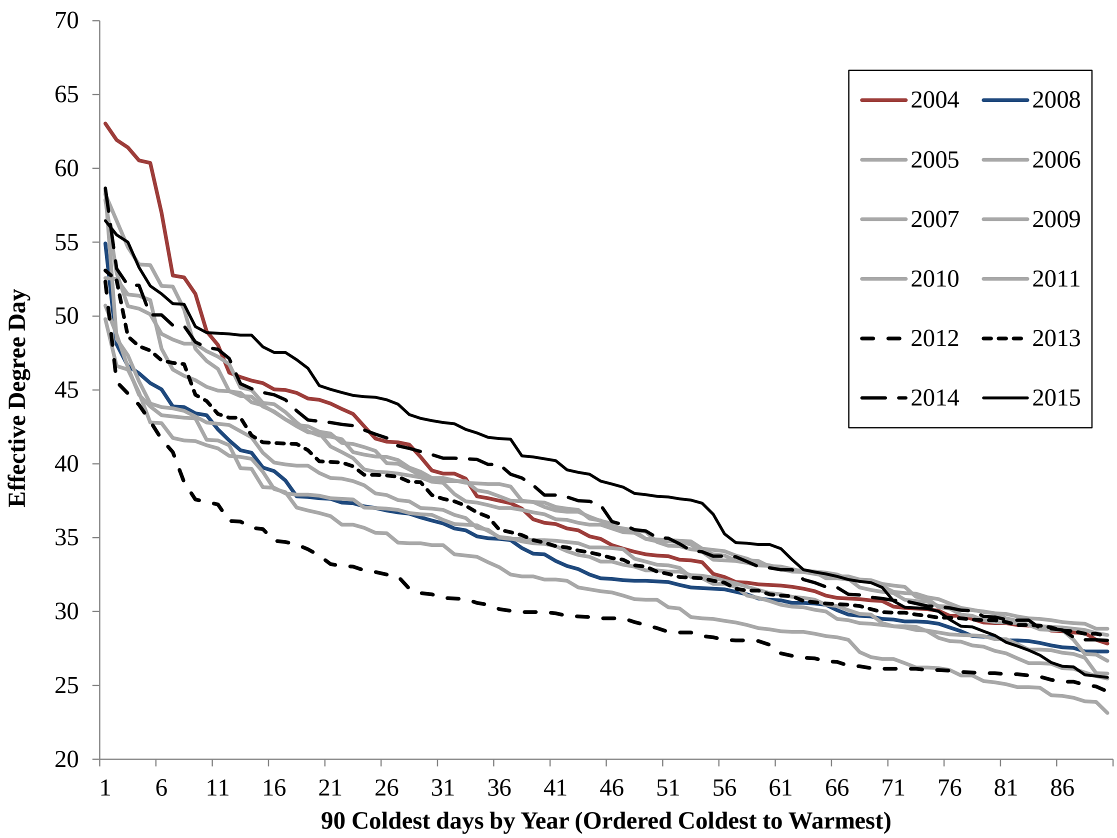


Notes:
[1] Total deliveries are the sum of LDC and End-User demand.
[2] Winter includes December, January, and February.
[3] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

Using the historical relationship between weather and gas demand Figure 1, we develop natural gas demand forecasts based on both the 2008 weather year (a median winter) and the 2004 weather year (representing a cold weather year, including the coldest day of the past 10 years). As shown in Figure 2, the 2004 year (shown in red) represents far colder winter peak conditions than either of the recent winters in 2012/13 or 2013/14, when New England experienced "Polar Vortex" conditions in late January 2014. This also includes the 2015 year, which experienced a period of sustained cold greater than any previous year.

By combining our estimates for total natural gas pipeline capacity and the daily forecast of natural gas LDC and end-user pipeline demand developed above, we estimate the total hourly pipeline natural gas available to the electric generation sector. Finally, we assume that our daily natural gas availability is fully ratable; that is, the pipeline gas available to electricity generation in each hour is one twenty-fourth of our daily estimate.

Figure 2: Historical Weather Years, 2004-2015



Note:
[1] Weighted average temperature for the ISO-NE control area.
[2] Effective degree day is defined as 65 degrees Fahrenheit – Temperature.

2. Electric Sector Natural Gas Demand

Base Case Deficiency Evaluation

In the second step, we estimate the total quantity of natural gas fired capacity that is needed to meet electric load in every hour, assuming that non-gas fired resources are operable at the time of winter peak conditions (though quantities available are fully reduced by historical seasonal equivalent forced outage rates). We compare this quantity of capacity to the total capacity of gas-fired generation resources that could be dispatched, given the estimated quantity of pipeline natural gas available to the electric generation sector. As a general rule, we use assumptions and data consistent with the ISO-NE planning process.

This estimate requires forecasts for electric sector load and available electric sector generation resources. In order to focus on demand during colder than average winters, we develop deficiency statements using the CELT 90/10 peak load forecast, net of passive demand response and behind the meter solar PV. This forecast reflects load at a level likely to be exceeded only 10 percent of the time. We translate the CELT seasonal peak loads and annual energy forecasts into an hourly load profile and assume that the system will need to carry 2,000 MW of reserves in every hour. [26,27]

Next, we develop a supply curve of available generation resources in each year, taking into account known additions and retirements. We start with the system as it exists today, including known retirements and additions. This includes the recent retirement announcement of the Pilgrim Nuclear facility. Going forward, we assume that all incremental Renewable Portfolio Standard (RPS) requirements are met through in-region wind resources, derated to 5 percent of nameplate capacity with respect to availability during peak periods, consistent with the ISO-NE Transmission Planning Technical Guide (2014).[28] We include all known retirements, based on a review of the current ISO-NE non-price retirement designations and Ventyx default retirements.[29]

With respect to imports, we follow the ISO-NE CELT convention and only include known imports with a firm capacity supply obligation through Forward Capacity Auction (FCA) # 9. That is, we assume – from a resource adequacy and reliability standpoint – that there are only 95 MW of 'firm'

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[26] We developed these hourly load shapes using the Ventyx PROMOD software, a widely used production cost model that simulates the dispatch of the electric generation sector. We describe our use of PROMOD in greater detail in Section V and Appendix 3. Ventyx develops these hourly load shapes based on the historical relationship of hourly data and system annual peak and energy. We reviewed PROMOD's annual load shapes to ensure consistency with monthly and seasonal peaks specified in the ISO-NE forecast.

[27] We recognize that our assumption of needing to carry 2,000 MW of reserves may to some extent be operationally redundant with our application of equivalent forced outage rates on all available resources. This represents an additional conservative assumption on our part, to ensure electric reliability is maintained in all hours.

[28] We recognize that the contribution of such resources at the time of winter peak could be higher than five percent. However, we assume five percent for the deficiency calculation consistent with our approach to evaluating system deficiencies from a reliability perspective.

[29] A full list of unit retirements is included in Appendix 3.

imports in 2019.[30] Existing imports may continue to participate in future capacity auctions, which could continue to provide an important non-gas resource during winter months. Finally, in estimating resource availability at the time of winter peak, we assume that dual-fuel units are available to operate on oil (and have sufficient oil supply), and we derate the total capacity of each resource by historical fuel specific equivalent forced outage rate demand (EFORd) (for dual-fuel capacity we apply the oil-fired EFORd rate).[31] Finally, we include all new resources that have cleared in recent Forward Capacity Auctions and, over the modeling period, add new generic dual-fuel natural gas capacity as needed to maintain at least a 14.3% reserve margin.[32]

Our assumption that existing oil-fired capacity will be available, and new capacity additions will be dual-fuel capable, reflects the outlook that recent market rule changes in New England will provide strong incentives for asset owners to ensure resource availability during potential scarcity hours. These incentives include (but are not limited to) the performance incentive program in the Forward Capacity Market, more flexible (hourly) pricing in the energy market, improved generator auditing procedures, and increased purchases and pricing levels in the reserve market. These market rule changes were designed, in part, to address periods of scarcity associated with potential constraints on the interstate natural gas pipeline system into the region.

With this complete supply curve and load forecast, we estimate the difference between total load and total non-gas fired resources in each hour of each year. This represents the total MW "need" that could be filled by gas-fired capacity. The total reliability deficiency is the difference between this electric sector need (for gas-fired generation) and the total quantity of natural gas fired generation that can be dispatched, given the hourly pipeline natural gas available to the electric generation sector. The deficiency is defined on an annual basis over the modeling horizon by (a) the maximum total magnitude of the deficiency, in MW and Bcf/day of need; (b) the frequency of deficiency events of any size in terms of number of days and number of hours per year; and (c) the duration of deficiency events in terms of the number of consecutive days over which a deficiency exists.

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[30] It is unlikely that imports will be as limited in all future years as reflected in this assumption. However, since *in any given year* of the modeling horizon potential import resources could decide to not take on a capacity supply obligation in New England (due, for example, to the exporting region's supply/demand conditions or relative pricing in other neighboring regions' capacity markets), we do not assume they will be available at the time of winter peak, consistent with our approach to evaluating system deficiencies from a reliability perspective. As with other assumptions we have made that may overstate demand or understate supply, to the extent this assumption is wrong we are overstating actual future system deficiencies.

[31] This information is provided through the North American Electric Reliability Corporation Generating Availability Data System. See: http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.

[32] We note that this is slightly above the 2018/19 net Installed Capacity Reserve (ICR) requirement of 13.9%, but is consistent with the long-run expected reserve margin forecast in the 2015-2024 ISO-NE Capacity, Energy, Load, and Transmission (CELT) Report.

Stressed System Deficiency Evaluation

In addition to our base-case deficiency evaluation, we also model additional scenarios to explore potential reliability needs in the event that some non-gas fired resources retire or other oil-fired units are otherwise unavailable. These scenarios generally describe conditions in which the electric system experiences an increase in gas demand, greater than that forecast in the base case. This includes limits on the total capacity of oil-fired resources available, and incremental retirements of non-gas fired capacity, as follows:

- Scenario 1: “Oil Unavailable” Scenario: While we expect our reduction of unit capacity for historical seasonal EFORd should to some extent already account for these factors, we make this adjustment in recognition of the fact that units could be unavailable for a number of reasons, including operating limitations under existing air quality permits, available oil supplies during winter events, or generator outages above and beyond historical outage rates. We assume that only existing fuel oil #2 units are available at the time of winter peak, and assume that all other existing resources (fuel oil #6 or unidentified) and other new dual-fuel capacity are available only on gas. This represents approximately 1,800 MW, which is 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel units in the future supply stack, including new resources.
- Scenario 2: “Gas-Only” Scenario: We assume the retirement of existing non-gas fired capacity in amounts equal to approximately 1,200 MW, with such capacity replaced by gas-only units (i.e., no dual-fuel capability). This sensitivity reflects, in part, the ability for generators to assume additional risk of non-performance under current pay-for performance rules, which don’t formally require dual-fuel capability. In this sensitivity, from a deficiency analysis perspective, *which* units retire is less important than the fact that the retirements be non-gas units, and that the capacity is entirely replaced by gas-only resources. In effect, this represents an absolute increase in the deficiency amounts.
- Scenario 3: “Stressed System” Scenario: A combination of the previous two scenarios.

B. Deficiency Statement Results

We find that under existing market conditions, there is no electric sector reliability deficiency through 2030, and therefore that no additional pipeline gas capacity is needed to meet electric reliability needs (Table 1). New England's existing market structure – including recent changes to address reliability during challenging system conditions (such as at the time of winter peak demand) – will likely provide the resources and operational practices needed to maintain power system reliability. This result reflects both the declining long-term forecast of peak winter demand and the increasing availability of new non-gas resources, including dual-fuel capable units that can generate on oil during peak winter periods. And as described in the previous section, we constructed the base case to include several assumptions that reflect worst-case planning scenario conditions, tending to overstate the "deficiency" beyond normal reliability planning practices.

Nevertheless, it is instructive to understand the vulnerability of the current system to increased system stress, above and beyond that already included in our base case. Under the most stressed scenario, we find that an electric reliability deficiency of approximately 1,675 MW arises in 2024, growing to 2,480 MW in 2029/30, occurring in 26 hours across at most nine days. These 26 hours represent a total energy deficiency of approximately 24,000 MWh over the full winter period in the stressed system scenario. There are only two days and four hours with a total deficiency greater than 2,000 MW in the 2029/30 winter in any scenario.

From the perspective of natural gas transportation capacity, this deficiency is the equivalent of approximately 0.42 billion cubic feet per day (Bcf/d), assuming that capacity must be available on a fully ratable basis and that the deficiency must be met entirely with natural gas fired generation.

In the following sections, we identify solution sets that could be used to meet both the peak deficiency and the duration/frequency. Here, the duration and frequency determines in part how often a given solution set will need to be used. The economic assessment compares this frequency of use with the total annual costs required to implement each solution set. This considers the tradeoffs associated with solutions or other market actions that involve fixed costs required throughout the year, and variable costs and actions that may be available on an as-needed basis.

Table 1: Electric Sector Reliability Deficiency Analysis, 2020-2030

Total Hours with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	3	4	4	4	4	7
Scenario 3 "Stressed System"	0	0	2	3	10	9	13	15	19	26

Total Days with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	2	2	2	2	2	3
Scenario 3 "Stressed System"	0	0	1	2	4	4	5	7	7	9

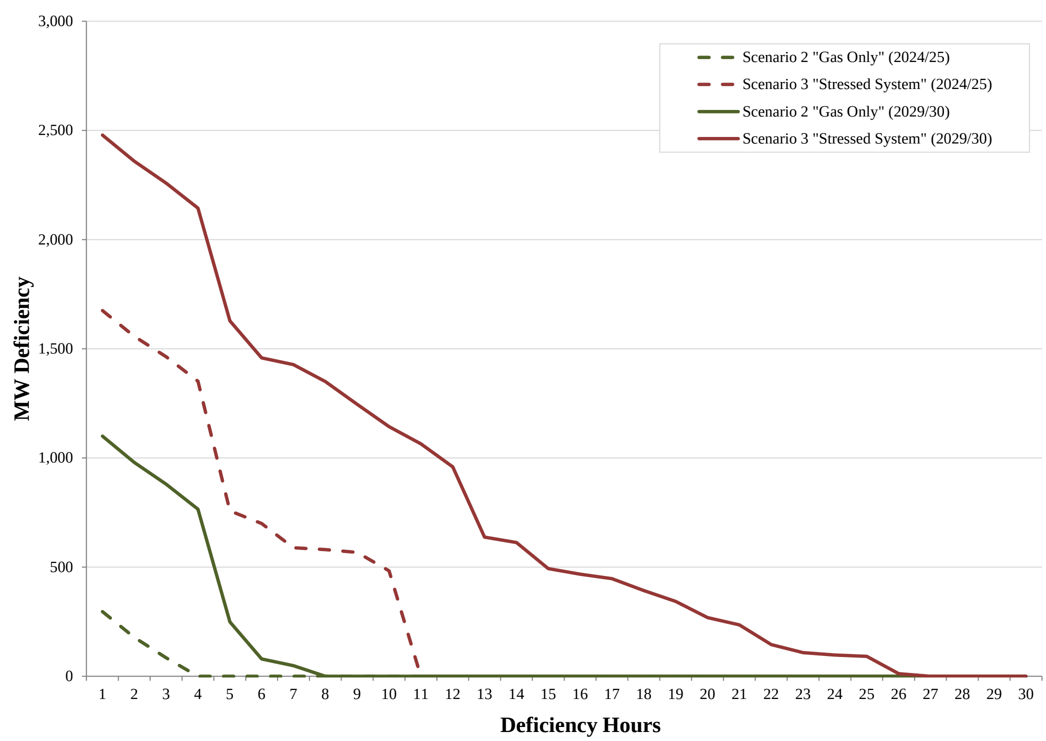
Peak Hour Deficiency (MW)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	296	576	699	433	743	1,100
Scenario 3 "Stressed System"	0	0	185	435	1,675	1,955	2,078	1,813	2,122	2,479

Peak Hour Deficiency (Bcf/hr)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0.0021	0.0041	0.0050	0.0031	0.0053	0.0078
Scenario 3 "Stressed System"	0	0	0.0013	0.0031	0.0119	0.0139	0.0148	0.0129	0.0151	0.0176

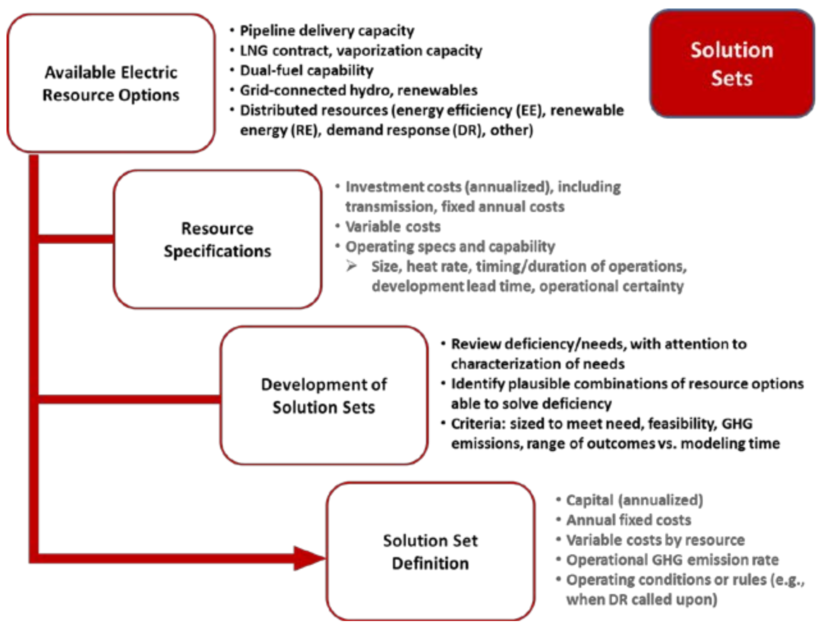
Figure 3: Deficiency Duration Curve (2024-25 and 2029-30)



IV. POTENTIAL ELECTRIC SECTOR PATHWAYS TO ENSURE RELIABILITY UNDER "STRESSED" SYSTEM CONDITIONS

A. Solution Sets

As noted in Section III, we find no deficiency in our base case analysis. Given this conclusion, there is no need to review solution sets as a response to a base case reliability need. Nevertheless, the continued reliance on oil-fired and dual-fuel generation, and possibly other variable solutions such as LNG, will likely continue to lead periodically to high winter prices due to natural gas constraints, and elevated carbon dioxide emissions from oil-fired generation used during winter peak periods. Consequently, while base case conditions do not require any changes from a reliability perspective, our stressed system scenario does identify potential deficiencies. Policy makers and stakeholders may wish to consider the potential cost and GHG emission implications of various solutions that could address the stressed system needs and may have the potential to lower customer costs, lower total GHG emissions, or both.



The fundamental purpose of identifying solution sets to meet the maximum deficiency is to demonstrate feasible options to meet system needs while providing different benefits for customers, through lower energy prices, lower GHG emissions, or both. Our focus is on resources that could plausibly emerge given economics and currently-known technological capabilities, and/or that are specifically under consideration by the region's states and stakeholders.

We develop these "solution sets" as various combinations of electric and/or natural gas resources that could reasonably and practically contribute to meeting the maximum deficiency under the stressed system scenario going forward. We focused on the following threshold requirements and criteria:

(1) Solution sets must, at a minimum, be able to provide or support enough power to satisfy the identified deficiency for the magnitude, frequency, and duration of the deficiency. Specifically, the resource(s) of the solution set must be able to produce or enable firm power output at the time of the most severe winter peak conditions, for as long and as often as needed. This not only limits resources available for the solution sets, it also establishes conditions on solution sets to ensure that the solution set can be counted on to meet the reliability deficiency at the time of winter peak.

For example:

- a three-hour demand response resource cannot satisfy a twelve-hour deficiency;
- solar PV cannot contribute to a deficiency that occurs when it is dark (as is generally the case with winter peak period deficiencies);
- pipeline capacity cannot be counted on unless primary firm transportation rights are guaranteed for electricity generation prior to winter operations;
- a transmission solution cannot be counted on unless backed by a "firm" capacity supply obligation that guarantees availability under winter peak conditions (for example, a contract backed by committed resources such as hydro, wind, or a combination of the two); and
- LNG cannot contribute to a deficiency unless the fuel is previously contracted for, with guaranteed storage, vaporization and pipeline delivery reserved and usable at the time of winter peak conditions.

(2) Solution sets must be feasible and practical from technology, market, and regulatory/policy perspectives, based on reasonable knowledge and expectations in place today. Thus, for example, new nuclear or coal capacity is assumed impractical from economic and siting/permitting policy perspectives; advanced grid-connected battery storage is not specifically considered a solution set alternative given current cost and development expectations; and reducing or shifting demand through advanced demand control technologies and new time-of-use rate structures is not considered given the regulatory and rate design issues that need to be settled before this could become a sizable resource.

(3) Solution sets should be sized and timed to address the identified deficiency. As a general rule, solution sets are assumed to be placed into service when and in amounts needed over the modeling horizon. However, in certain solutions sets where the resource in question is not easily scalable, the full size of the solution needed in the *highest* deficiency year may be assumed in place in the *first* deficiency year (e.g., high-voltage transmission to access distant low-carbon resources), or otherwise may be added generally timed to the deficiency, but in just a couple or few increments (e.g., natural gas pipeline capacity increases or new transmission investments).

We include outcomes that would normally flow from existing competitive market incentives, as well as outcomes that would require legislative or regulatory actions by states (and that have been considered in various forms by states). Below, we describe solution sets grouped into the following categories: (1) market driven outcomes that would likely flow directly from existing market incentives, to ensure fuel delivery security during times of scarcity (i.e., incremental dual-fuel capability and/or firm LNG commitments); (2) incremental pipeline transportation capacity sized at a minimum to meet the identified deficiency and dedicated for electricity generation at the time of winter peak through electric ratepayer funding; and (3) aggressive investment (whether from regulatory policy or technological change) in incremental energy efficiency and other renewable energy.[33]

Each solution set represents an incremental change to the electric generation sector, which will result in an increase in available electric supplies or a decrease in total electric demand. These solution sets include variable options (such as LNG or demand response) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency events and also during all other hours in the year (such as incremental pipeline capacity, new transmission capacity, or increased energy efficiency). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost of energy used to serve customers. We discuss these impacts in the next section.

In order to ensure a consistent and comparable analysis focused on electric ratepayers (who would pay for and be the primary beneficiaries of the investments), we conduct the financial analysis with ratepayers responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Also, in estimating costs for all solution sets, we assume costs based on current or known information and recent estimates, without presuming increased performance or declining costs for any resource or solution set. We match annualized benefits to annualized costs over the full modeling period and express all values in levelized real 2015 dollars.[34] Additional details on each solution set, including sources and assumptions for costs, are described in Appendix 2.

Market-Driven Outcomes

Solution Set 1(a): "Status Quo" – Dual-Fuel

The first solution set reflects the market-driven evolution of the region's resources that would likely occur absent any major steps taken by states to achieve alternative resource outcomes. This market outlook assumes, in effect, the status quo. We compare all other solution sets to this outlook. It assumes neither any specific non-market actions to fund the development of natural gas pipeline capacity for use by electric generators, nor funding for transmission and/or long-term contracts to acquire distant low-carbon resources with firm winter commitments. Finally, it does not assume any technological breakthrough or change in state policies to increase distributed renewable and efficiency resources in the region beyond current expectations.

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[33] Broadly, this solution set represents increased investment in renewable and other distributed technologies of various types and sizes (grid-connected wind/hydro, energy efficiency, demand response, distributed generation). A solution set focused on energy efficiency represents the likely lowest-cost distributed approach, based on our review of previous studies.

[34] We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or new incremental gas pipeline, will necessarily have lifetimes beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments beyond 2030, nor do we consider any potential benefits to the electric generating sector beyond that point. We discuss the implications for these remaining costs further in Section V.

This outlook recognizes that current market incentives are *not* sufficient to cause many power generators to enter into major advanced commitments for firm natural gas pipeline transportation to cover winter peak operations at full output. Instead, and in response to incentives to ensure operation during times of scarcity, market participants would add dual-fuel capability and ensure sufficient alternative fuel is on site to maintain availability at the time of winter peaks. The costs associated with these alternatives are estimated in the assessment phase and compared with other solution set options. This solution option reflects the fact that there is substantial potential capacity for incremental dual-fuel capability within New England, both in the form of reactivating mothballed capability and adding new dual-fuel capability at existing units.

Dual-fuel capability is added at existing units, with annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). Total annualized incremental dual-fuel capacity costs are assumed to be $6,856/MW, based on information identified in Schatzki and Hibbard (2013), and include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of duel fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis, potentially overstating the cost impact of this solution on ratepayers. This solution set is referred to a “Dual-fuel (SS 1a)”.

Solution Set 1(b) – Firm LNG

As an alternative to adding dual-fuel capability, gas-fired power plants could enter into seasonal or annual contracts on a single or multi-year basis for the delivery (prior to winter peak, or timed for winter peak), storage and regasification of LNG, along with firm delivery of the associated gas to existing gas-only generating resources, if and as needed for fuel supply during winter peak conditions. Existing incentives in the region’s wholesale markets could lead generating resources to take this approach to ensure availability and operation during times of winter scarcity absent any specific actions taken by states. Thus we include an LNG option as an alternative market-driven solution set with the maximum amount of assumed LNG capability that is available set to an estimate of the region’s LNG vaporization capacity, net of estimated LDC use.

Consequently, we assume that net deliverable natural gas capacity for electricity generation associated with the regional LNG facilities is limited by what is used by LDCs during winter peak conditions – which we assume to be equivalent to the full Maritimes & Northeast (M&N) pipeline capacity (limiting contributions from Canaport, which is included in the total existing pipeline capacity described above) and a portion of the Distrigas storage and vaporization capacity assumed to be used by LDCs.[35]

[35] Individual LDCs contract for firm capacity from the Distrigas facility, with the intent that required storage amounts are full as of December 1st in each year. ICF/ISO-NE (2014) reports that 20 percent of the LNG received at

LNG storage and vaporization is contracted for in amounts not more than the full shipment quantities needed to meet the identified deficiency. That is, we do not assume that electric generators or ratepayers pay for firm LNG commitments beyond the quantity required to cover the estimated deficiency. This requires total annual volumes at least equal to the cumulative deficiency need across the winter, which we estimate could be covered by one shipment of LNG, or approximately 3 Bcf. It also requires availability of vaporization capacity up to 0.42 Bcf/d on the maximum deficiency day; we estimate that at least 0.5 Bcf/d vaporization capacity from LNG facilities would be available for electricity generation on peak winter days. Information on potential structures for such contract arrangements, including contract terms and fixed annual and variable costs, were provided to AGI by LNG representatives and Environmental Defense Fund. Our estimate of the cost of this solution set is based on a 90-day term charter arrangement, with a demand charge of $200,000, escalated annually with inflation, and variable charges based primarily on Henry Hub pricing plus a processing cost of $3.50 per Dth, shipping costs of $1.50 per Dth, and delivery charges of $0.16/Dth, all escalating annually with inflation. This solution set is referred to as “Firm LNG (SS 1b)”.

Incremental Pipeline Transportation

Solution Set 2 – Incremental Pipeline

The incremental pipeline transportation outlook assumes the development and construction of new interstate pipeline capacity in amounts needed to address any potential deficiency through 2030. Given the identified size of need, we make no assumption as to whether this new capacity would be added as new development or as an expansion of existing supplies. It is assumed that the costs associated with any incremental pipeline capacity developed to meet electric reliability needs would be fully collected from electricity ratepayers on a cost of service basis.[36] We assume that the minimum incremental pipeline capacity that would be needed to meet a power system need would be sized to meet the peak hourly deficiency identified in the deficiency analysis. We also assume that a pipeline (expressed in Bcf/d) is available on a fully ratable basis (i.e., the minimum size of a pipeline is equal to 24 times the peak hourly need). We model a solution set sized to meet the deficiency need, and placed in service in increments and in time consistent with the emergence of the need. This solution set is directly comparable to other solution sets designed to meet the identified reliability need.

Distrigas goes to National Grid’s greater Boston-area distribution system, and another 10 percent is delivered by truck to off-site LNG peak shaving facilities. Thus, for the purposes of our study, we assume that 70 percent of the total Distrigas facility regas capability (0.5 Bcf/d) is available to help meet any identified electric sector reliability need. For solution set development, therefore, we limit the maximum quantity of LNG available from Distrigas and available as a potential solution set to 0.5 Bcf/day.

[36] As discussed above, the focus of the analysis is on pipeline capacity that could be used to meet identified *electric system reliability* needs. We do not assess whether there is a need for incremental pipeline capacity to meet gas LDC needs, or whether power system needs (or lack thereof) should affect considerations related to development and construction of new pipeline capacity for use by gas LDCs.

In this solution set, 0.3 Bcf/d of new pipeline capacity reserved for electricity generation is added in 2024, in-service for the 2024/25 winter, and 0.12 Bcf/d of capacity reserved for electricity generation is added in 2028, in-service for the 2028/29 winter. We assume that total capital costs for the 0.3 Bcf/day installation are approximately $788 million, with a first year cost of service of $140 million. Costs for the 0.12 Bcf/day installation are assumed to scale linearly by size. This solution set is referred to as "Incremental Pipeline (SS 2)".

Energy Efficiency (EE), Demand Response (DR), and Renewable Energy (RE)

We develop three solution sets that represent an increase in energy efficiency and renewable energy. The first is focused on increases in energy efficiency and demand response in amounts sufficient to eliminate the potential deficiency on the electric system. While there are many renewable and distributed resources available to the electric sector, we limit the first modeled solution set to just EE and DR, since in our judgment this is likely to be the lowest-cost combination of renewable/distributed resources that could address the deficiency.[37] Other solution sets combine EE with the addition of firm imports of low carbon (likely hydropower) resources over existing or new transmission lines.

Solution Set 3(a) – Energy Efficiency and Demand Response

This solution set combines incremental annual energy efficiency investments plus demand response over time as needed to meet the maximum deficiencies annually. By 2030, this amounts to approximately 1,300 MW of winter peak EE[38] and 1,100 MW of DR. We truncate measure lives for all EE measures and programs at ten years, with complete annual installations starting in 2020 and concluding in 2030. This solution set is focused on the likely lowest-cost distributed approach to address identified deficiencies. We assume that incremental EE is available at a cost of $0.067/kWh, and to account for the incremental degradation of EE on a $/kWh basis, we further assume that EE costs increase at a rate of 7.45 percent annually. Our estimate is based on our review of recent filings of actual energy efficiency program data, including the Massachusetts Program Administrators' draft Program filings for 2016-2018 and the Northeast Energy Efficiency Partnerships' Regional Energy Efficiency Database (REED). We index the cost of demand response to recent bids offered into the PJM capacity market.[39] This solution set is referred to as "EE/DR (SS 3a)".

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[37] This is based on our review of the Synapse/DOER (2015) study, which includes the total, incremental quantities of capacity and energy that could be developed for Massachusetts, including appliance standards, energy efficiency (residential, commercial/industrial, and large industrial), and incremental renewables, including landfill gas, anaerobic digestion, biomass, combined heat and power, solar, and on- and off-shore wind.

[38] Load profiles are developed based on historical program administrator data.

[39] We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, "Analysis of the 2017/2018 RPM Base Residual Auction." October 6, 2014, Table 18.

Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)

This solution set combines annual energy efficiency investments plus firm winter delivery commitments from low-carbon resources, in amounts sufficient to meet the annual deficiencies over time. By 2030, this amounts to approximately 1,300 MW of winter peak EE, with 1,100 MW of firm winter capability added in 2020. This solution set assumes that imports are delivered using existing transmission capacity. We assume that, in order to meet reliability needs, this interconnection would need to be accompanied by a firm capacity supply obligation equal to the full capability, and a commitment to ensure firm delivery of the capacity at the time of winter peak. We assume that the cost of firm capacity during winter peak is equal to the levelized cost of new hydroelectricity capacity, based on recent levelized cost of electricity EIA data. This solution set is referred to as "EE/Firm Imports (Existing Transmission) (SS 3b)".

Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)

Solution Set 3(c) is the same solution set as 3(b), except imports are delivered assuming new transmission capacity is required. We assume that new transmission capacity for 1,100 MW costs an additional $1.4 billion. This solution set is referred to as "EE/Firm Imports (New Transmission) (SS 3c)".

Table 2: Summary of Solution Sets

Solution Set	Description	Key Assumptions
Market Driven Outcomes		
SS 1a: Dual-fuel Capacity	Annual increases of 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026.	• Annualized costs of $6,856/MW
SS 1b: Firm LNG Capacity	Firm delivery of LNG dedicated for electricity generation with a 5-year contract and rolling renewals; Annual contract quantity available in increments of 3 Bcf.	• Contract includes daily demand charge and variable costs indexed to Henry Hub, plus relevant adders
Incremental Pipeline Capacity		
SS 2: Incremental Pipeline	Incremental capacity added incrementally to meet need; 0.3 Bcf/day in 2024 and 0.12 Bcf/d in 2028.	• Costs indexed to proposed pipelines, maximum reservation charge of $39/dth-month • Total capital costs of $788 million, first year costs of $140 million (0.3 Bcf/d) • Costs represent full cost of service, including return on equity, taxes, and depreciation
Energy Efficiency, Demand Response, and Renewable Energy		
SS 3a: Energy Efficiency and Demand Response	Total of 1,300 MW peak winter Energy Efficiency by 2030, with 950,000 MWh installed annually, 2020-2030. Total demand response of 1,100 MW by 2030.	• Total lifetime costs of $0.067/kWh, including all incentives and participant costs • Demand Response costs indexed to recent capacity market bids
SS 3b: Energy Efficiency and Firm Imports (Existing Transmission)	Same EE as SS 3a, plus an additional 1,100 MW of firm imports of distant low-carbon energy. We present total ratepayer costs two ways: assuming imports use existing transmission lines (with no incremental cost) and assuming imports require new transmission capacity.	• Firm imports priced at the levelized cost of new hydropower capacity, using EIA data, $4.3 billion for 1,100 MW capacity facility
SS 3c: Energy Efficiency and Firm Imports (New Transmission)		• Incremental new transmission capacity (SS 3c) available for $1.4 billion, including all cost of service obligations

B. Infrastructure Scenarios

In addition to solution sets that meet the above criteria, we separately consider two infrastructure "scenarios" that are larger than needed to meet the deficiency and/or installed as the maximum total need in the first modeling year (e.g., installed before the identified need). This includes both a natural gas pipeline and a transmission scenario. These infrastructure scenarios model extensions of the reliability solution sets, and allow us to consider potential economic and ratepayer impacts beyond the scope of the current study. In order to avoid confusion, we review the results of these scenarios separately, since they are not comparable to the solution sets (i.e., not "fitted" to the identified reliability need). The purpose of analyzing infrastructure investments made earlier and/or larger than necessary is to explore the potential range of cost and emission impacts to ratepayers. Both infrastructure scenarios are assumed to be in-service in 2020, with immediate and comparable reductions in the volatility of natural gas prices at Northeast trading hubs.

Infrastructure Scenario 1 – Larger and Earlier than Necessary Gas Pipeline

We model the incremental addition of a 0.5 Bcf/day pipeline, where the full amount of capacity is reserved for electricity generation. The pipeline is added in 2020, in-service for the 2020/21 winter. Total capital costs for the 0.5 Bcf/day installation are approximately $1.3 billion, with a first year cost of service of $233 million. This scenario is referred to as "Larger Pipeline (IS 1)".

Infrastructure Scenario 2 – Earlier than Required Transmission Investment

Similar to the larger/earlier than required pipeline, we also model a transmission infrastructure scenario which considers the full addition of the 2,400 MW of new capacity in 2020. This is more directly comparable to a natural gas infrastructure scenario which is also sized above the reliability need. Both scenarios recognize the lumpy nature of infrastructure investments and consider the potential for more immediate price suppression benefits. This scenario involves the one-time addition of 2,400 MW of firm winter commitments in 2020. We assume that new transmission capacity for 1,100 MW costs $1.4 billion consistent with the EE/Firm Imports (New Transmission) (SS 3c) solution set, with the remainder (1,300 MW) delivered over existing transmission lines at no incremental cost. The cost of firm energy commitment backed by new hydropower is based on the same costs as the EE/Firm Imports (Existing Transmission) (SS 3b) and the EE/Firm Imports (New Transmission) (SS 3c) solutions, scaled to meet the full 2,400 MW need. This scenario is referred to as "Earlier Transmission (IS 2)".

V. ASSESSMENT

A. Method

Each solution set has a unique impact on total system natural gas utilization, natural gas prices, cost of implementation, the total cost of energy used to serve customers, and GHG emissions.

To compare the impact of solution sets on electric ratepayers in a consistent manner, we take two steps. First, we estimate the total potential up-front cost to ratepayers to “implement” each solution set, with a consistent focus on the annual costs likely to be incurred by ratepayers associated with solution set resources. This includes, for example, an estimate of the cost of service for firm pipeline investments, new transmission, contracts for capacity with distant low-carbon resources, LNG storage/vaporization, or annual costs for incremental EE/DR. We evaluate these costs for each solution set using consistent financial assumptions, and translate them into annualized costs that would be collected from electricity consumers over the forecast horizon.

However, the impact on electricity consumers is not limited to annual costs to implement solution sets. Since each solution set has a unique impact on the marginal price of electricity due to changes in the anticipated dispatch of system resources, each solution set also leads to a unique annual cost to the region’s ratepayers for electricity market purchases. Consequently, in the second step we carry out production cost modeling through 2030 for each solution set, including an integrated gas-electric model to simulate the impacts of each solution set on natural gas prices, in order to establish the total cost to load to meet electric sector needs over the forecast horizon. The production cost modeling is also used to identify annual total system emissions of CO_2 in order to inform our evaluation of each solution set from the perspective of states’ GHG reduction goals and obligations.

The total cost to electric ratepayers combines the results of steps one and two. Specifically, we combine the annual costs to implement each solution set with its impact on total cost to load using production cost modeling results, in order to establish the total annual cost to the region’s electricity consumers associated with each solution set. As described earlier, in our view there is a “status quo” outcome that is likely to occur absent any specific or extraordinary legislative or regulatory action taken by states – namely, a market-driven outcome involving the addition of dual-fuel capability on some portion of the region’s existing gas-only generating resources. To clearly compare the different impacts of each solution set using consistent methods and metrics, and relative to status quo outcomes, we compare each solution set to the Dual-fuel (SS 1a), market-driven dual-fuel capability solution set, on the basis of total annual cost to electric ratepayers and GHG emissions.

In the previous section, and in more detail in Appendix 2, we summarize our estimates of annual ratepayer implementation costs. In the next section, we summarize our approach to the production cost modeling approach. Appendix 3 provides greater detail on modeling inputs, methods, and assumptions.

Production Cost Modeling

We use the PROMOD production cost model to simulate the economic dispatch of generators used to meet system load in every hour of the year over the full ten year period, 2020 to 2030. PROMOD is a widely accepted and commonly used model. The PROMOD simulation engine considers the full mix of available resources and minimizes the total cost to load based on economic and operational criteria, subject to system transmission/operational constraints. To do so, it dynamically solves for the locational marginal price (LMP) in every hour on a zonal basis. LMPs reflect both the system load in each zone and the costs of the marginal (or last) unit required to meet demand in that hour. In ISO-NE, natural gas units were the marginal unit, setting LMPs, approximately 70 percent of the hours in 2014.[40] In our base case market outlook, natural gas continues to be the dominant fuel, and natural gas units provide more than 54 percent of all generation throughout the modeling period. Across all scenarios, natural gas provides at least 48 percent of all generation.

Our PROMOD runs for solutions sets reflect distinct expectations regarding the price of delivered natural gas. Since the New England system relies so heavily on natural gas to provide both baseload and peak generation, the price of delivered natural gas is a key driver in determining the total cost to load for New England ratepayers. In previous winters, high natural gas prices, driven in part by increased demand from the electric generation sector, led to increased electricity costs for electric sector ratepayers during winter periods. Going forward, natural gas prices will continue to reflect changes in the underlying supply and delivery of natural gas to local trading hubs. The "basis differential" – that is, the difference between delivered natural gas prices in New England and the price of natural gas supplies (typically, at Henry Hub) – will continue to reflect the balance of available supply/transportation, and the total demand for delivered gas in Northeast markets. During periods of winter peak demand, delivered natural gas prices will continue to reflect the impact of high utilization of existing natural gas infrastructure in the region.

Each solution set identified in section IV is designed to meet the peak hour deficiency, under the most stressed system scenario. These solution sets are designed to meet the identified need through some combination of increasing total available electric supplies or by decreasing total electric sector demand. Either effect – an increase in available supplies or a decrease in total demand – will potentially lower natural gas prices. To ensure the production cost modeling reflects these changes, we separately model natural gas prices for each solution set.

Our baseline natural gas forecast reflects the current outlook for delivered natural gas prices to the Algonquin and Dracut City Gates, based on futures contracts out to 2022.[41] Beyond 2022, we assume that monthly prices continue to grow at the two year compound average growth rate observed in the futures prices.[42] This allows for growth in the underlying commodity price of gas, as observed at Henry Hub, and for growth in the monthly basis differentials observed at Algonquin and Dracut. Over the modeling period, delivered natural gas prices at the Algonquin City Gates increase from a low of

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[40] ISO New England's Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, Figure 2-17.

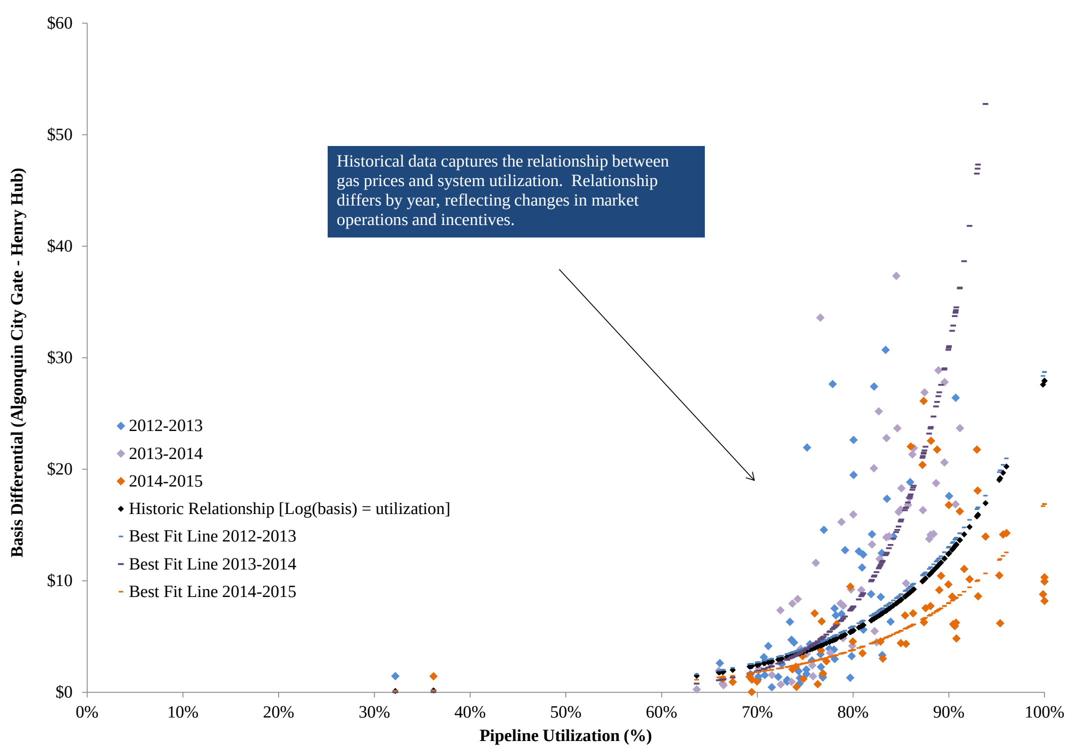
[41] We rely on futures prices as reported by OTC Global Holdings and reported by SNL Financial.

[42] This growth rate is approximately 4 to 5 percent for all months.

approximately $8.00/MMbtu in winter 2020 to a high of $11.50/MMbtu in winter 2029/30 and in the base case, continuing to reflect high winter basis differentials relative to the Henry Hub forecast.

To model the impact of each solution set on natural gas prices, we examine the historical relationship between pipeline utilization and the basis differential between the Algonquin City Gate and the Henry Hub price series for the previous three winters. As shown in Figure 4 gas prices in the most recent year (despite being a very cold year) remained lower at similar levels of utilization, as compared to 2012/13 and 2013/14. This relationship may reflect a number of factors that will continue to be in place going forward, including greater use of LNG and increased oil-fired capacity (in part due to the ISO-NE winter reliability program), and greater coordination between the electric and natural gas sectors. We develop our forecast of future gas prices based on the historical relationship between gas prices and system utilization. This method is consistent with several previous studies. First, we estimate the statistical relationship between gas prices and pipeline utilization, based on the relationship in each winter (2012/12, 2013/14, and 2014/15). This relationship captures the non-linear relationship between pipeline utilization and prices – for example, reducing utilization from 95 percent to 90 percent has a greater impact on prices than a similar five percentage point reduction, from 80 percent to 75 percent (see Figure 4). The utilization-price relationship begins to moderate at approximately 80 percent utilization.

Figure 4: Pipeline Utilization and Natural Gas Prices, Winters 2012-2015



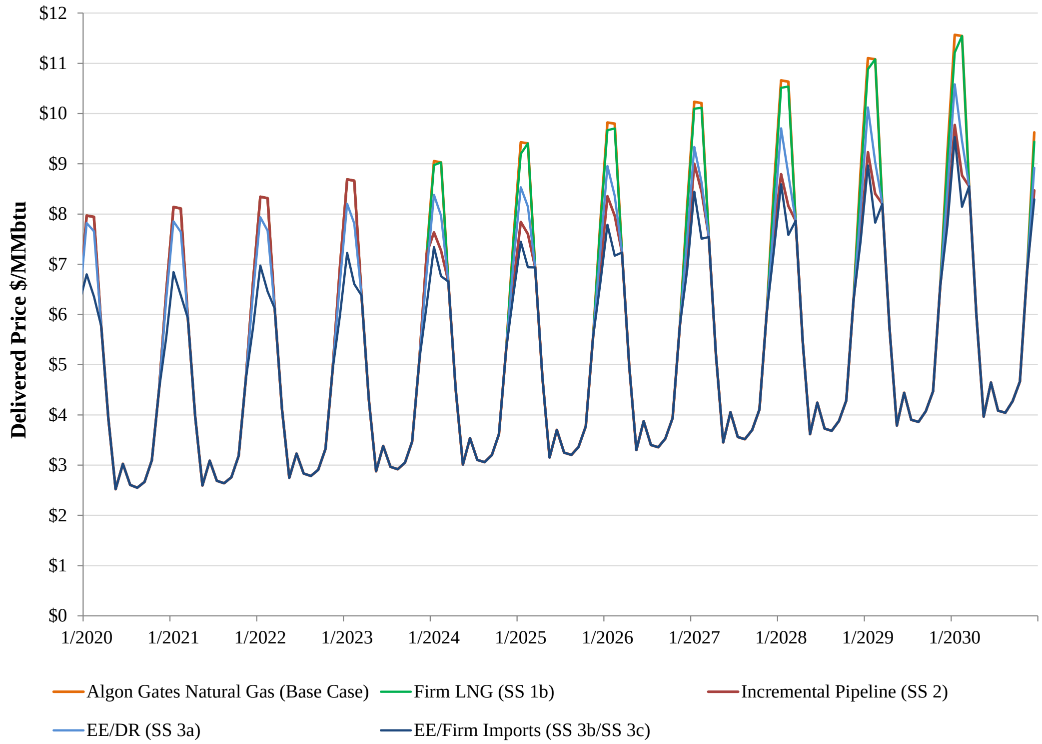
Notes:
[1] Daily utilization is based on the sum of LDC, End-User and Power Plant demand divided by system capacity.
[2] Basis differentials are the difference between Henry Hub and the Algonquin City Gate.

Next, for each solution set, we then estimate the change in daily utilization (relative to the status quo Dual-fuel (SS 1a) market outlook) that would be expected for either an increase in total capacity (both Firm LNG (SS 1b) or Incremental Pipeline (SS 2)) or a decrease in total demand from the electric sector[43] (EE/DR (SS 3a), EE/Firm Imports (Existing Transmission) (SS 3b), EE/Firm Imports (New Transmission) (SS 3c)). Using the relationship illustrated in Figure 4, we translate the estimated change in utilization into a percent change in natural gas prices, relative to the existing market outlook for natural gas prices.[44] The final natural gas price curves for each solution set are illustrated in Figure 5. These gas price curves reflect the fixed and variable nature of the different solution sets. Solution sets that include energy efficiency, which is assumed to be added incrementally in each year, decline in price gradually each year. In contrast, the addition of incremental transmission and natural gas capacity has more immediate and permanent reductions in natural gas prices.

[43] For this purpose we assume that energy efficiency or imports displace marginal natural gas fired generation with a 7,600 Btu/kWh heat rate. Further, we assume that variable LNG supplies are available during identified deficiency days, and do not impact prices in every day of the month.

[44] We estimate the change in utilization and corresponding percent change in prices for each day in the winter modeling period. We assume that variable solution sets – like firm LNG or demand response – only impact gas prices during identified deficiency days. Solution sets in operation for every hour are assumed to reduce utilization on all days. As a final step, we estimate the monthly percent change in natural gas prices as the weighted average of the estimated daily changes. This monthly change represents the final input to the production cost model, and captures the expected change in prices relative to the original market outlook.

Figure 5: Forecasted Natural Gas Prices, By Solution Set



Finally, to develop our comparison of solution sets, we use PROMOD to model the impacts of each solution set – including the gas price forecast from Figure 5 – on the dispatch of power system operations and outcomes. Here, the difference between each simulation and our market outlook scenario represents the direct incremental impacts of a given solution set on the power system. These simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched and their operational characteristics.

Our use of a production cost model also allows us to estimate the locational marginal price, total generation, and GHG emissions. Both measures account for the hourly dispatch of resources to meet system load. Importantly, this dispatch captures these aggregate impacts for every hour in every year of the modeling period. We use these outputs, in combination with the estimated solution set costs identified in Section IV.A, to quantify the total change in ratepayer costs and GHG emissions between solution sets.

B. Results

In this section we provide the results of our cross-sectional analysis of the impacts of solution sets designed to address the stressed system deficiency. Results are presented as differences relative to the market driven outcome (Dual-fuel (SS 1a), with respect to (1) annualized changes in total costs to electric ratepayers (including both electricity prices and implementation costs) and annualized changes in total emissions, (2) the annual trajectory of GHG emissions and regional climate goals, and (3) additional factors relevant to each scenario. We also provide the results of our infrastructure scenarios: Larger Pipeline (IS 1) and Earlier Transmission (IS 2)).

1. Annualized Ratepayer Impacts – Total Costs and GHG Emissions

Solution Sets

The cost to electric ratepayers in New England associated with the solution sets evaluated here would include either up-front and annual investment and fixed costs or contract obligations in order to make the solutions happen. This could include cost-of-service recovery for long-term investments or contractual obligations for natural gas pipelines, transmission lines, or contracts for firm winter capacity (e.g., from distant low-carbon resources); it could also include annual or market costs for incremental dual-fuel capability, reservation costs for deliverable LNG, or annual investments in EE and DR capability. Absent such commitments up front, one cannot assume that the resource would be available to meet power system needs at the time of winter peak demand, and thus such resources would not represent solutions from the perspective of power system reliability.

The costs to electric ratepayers for each solution set also depends on how operation of that solution set affects price setting in wholesale power markets. As noted earlier, certain solution sets are targeted to and may only operate during the time of deficiency need (e.g., Dual-Fuel (SS 1a), Firm LNG (SS 1b)), and thus only affect power system prices in limited hours throughout the year. Others, such as Incremental Pipeline (SS 2), and EE/Firm Imports (SS 3b/SS 3c), have the potential to affect power system prices in a much larger number of hours throughout the year.

At the same time, costs to electric ratepayers for each solution set also depend on how operation of that solution set affects the ability of the region to meet its climate goals going forward. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. We present the GHG emission trajectory of each solution set immediately following results for ratepayer costs.

Table 3: Evaluation of Electric Reliability Solution Sets, Annualized Impacts

Negative Dollar Values represent lower costs than the Market Outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to Market Outlook Dual-fuel (SS 1a)

Solution Set	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
Market Outlook				
Firm LNG (SS 1b)	-$45	$18	-$27	-0.03
Incremental Natural Gas Capacity				
Incremental Pipeline (SS 2)	-$127	$66	-$61	0.08
Energy Efficiency, Demand Response, and Renewable Energy				
EE/DR (SS 3a)	-$247	$101	-$146	-1.86
EE/Firm Imports (Existing Transmission) (SS 3b)	-$502	$404	-$98	-4.86
EE/Firm Imports (New Transmission) (SS 3c)	-$502	$604	$102	-4.86

Notes: All values for Table 3 and Figure 6 are presented in levelized, real $2015, millions, unless otherwise noted. Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks.

With this in mind, our analysis of ratepayer costs in the present study is specifically focused on identifying the net impact of both the implementation costs of each solution set and the resulting impact to electricity market costs to load. The results, shown in Table 3 and Figure 6, may be described and summarized as follows:

- All impacts are relative to the status quo Dual-fuel (SS 1a) solution set; thus, in Table 3 and Figure 6 all results represent *differences* from the status quo solution outcome. It is useful to note that in these estimates we assume that the implementation cost of the market outlook dual-fuel solution set – namely the cost of converting gas-only capability to dual-fuel capability – would be completely paid by electric ratepayers.
- Firm contracts for the storage and delivery of LNG-based gas as needed during winter peak conditions (SS 1b) – represents the lowest implementation cost solution set, which would cost ratepayers $18 million more per year than the dual-fuel solution set. This solution would also reduce electricity market costs to load by roughly $45 million, leading to net annual ratepayer savings of approximately $27 million per year. This solution set would lead to a slight decrease in emissions over time (0.03 million metric tons annually) relative to the dual-fuel solution set.
- Incremental Pipeline (SS 2) capacity sized to meet the deficiency would deliver substantial price suppression benefits to the region, amounting to approximately $127 million in savings per year.

Since the cost to implement this solution would be approximately $66 million per year, the net impact on ratepayers would be a net savings of approximately $61 million annually, relative to the status quo outcome. This solution leads to an increase in GHG emissions of 0.08 million metric tons per year relative to the dual-fuel solution set due to an increase in total fossil fired generation.

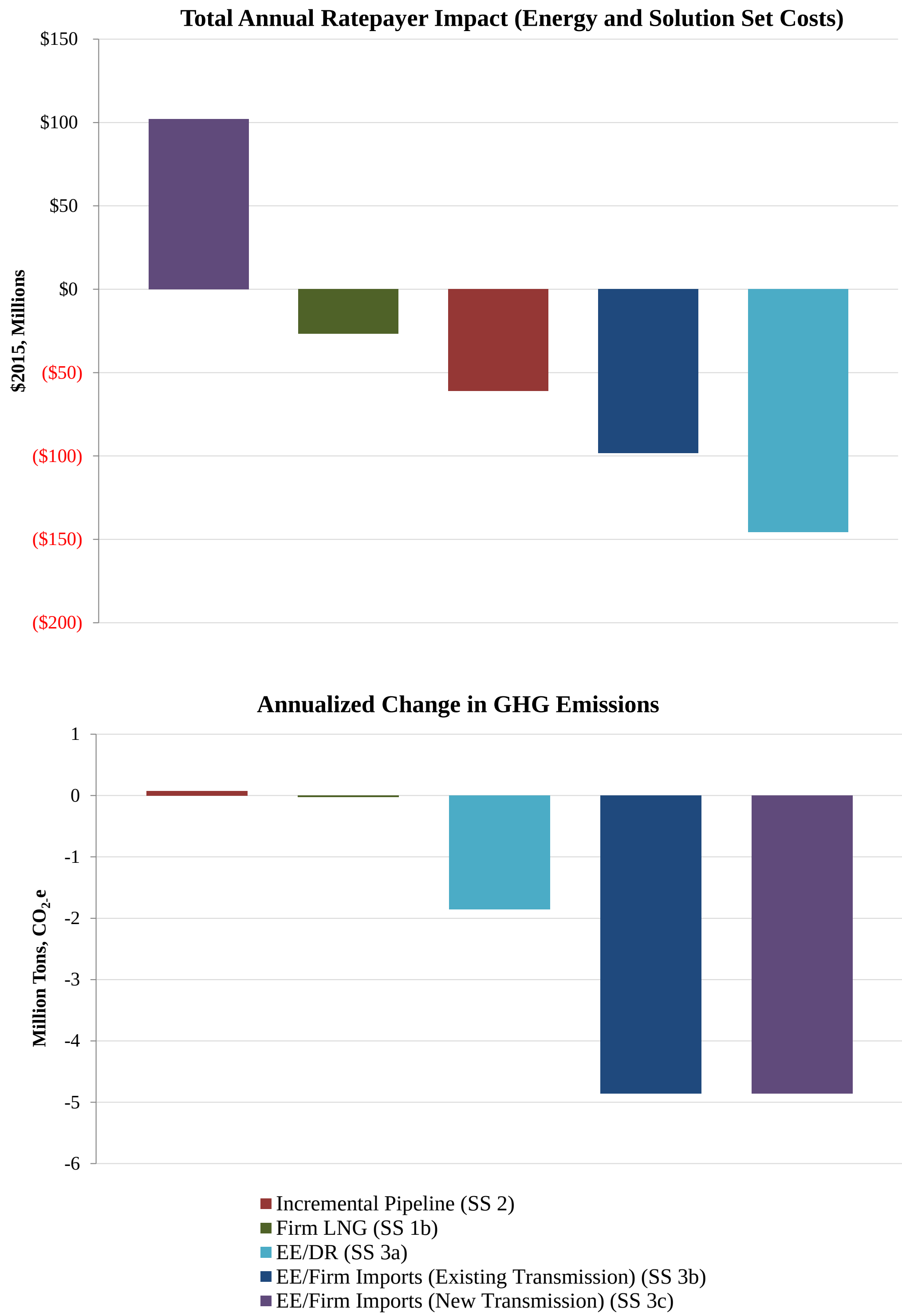
- The EE/DR (SS 3a) solution set provides the lowest total cost solution accounting for changes in both energy and implementation costs and would save ratepayers approximately $146 million per year, relative to the dual-fuel option. The $146 million savings (relative to the dual-fuel solution set) include reductions in electricity market costs of $247 million per year and annual costs of $101 million to install EE measures. This solution set lowers total annual emissions by 1.86 million metric tons per year.
- The EE/Firm Imports (Existing Transmission) (SS 3b) solution would provide annual ratepayer benefits of roughly $98 million per year relative to the dual-fuel solution set. While the EE/firm Imports (existing transmission) solution produces far greater annual energy market savings ($502 million per year), the estimated cost to procure capacity and energy on a firm basis year-round significantly cuts into electricity market savings.[45,46] This solution set lowers total annual emissions by 4.86 million metric tons per year, the largest reduction among all solution sets.
- And if instead, the same set of incremental firm winter imports required new transmission capacity (SS 3c), total ratepayer costs would be $102 million per year higher relative to the dual-fuel solution. A solution involving new firm imports would also reduce annual emissions by 4.86 million metric tons per year.

[45] As discussed in Section IV, we estimate the costs of such a contract at the estimated levelized cost of new hydroelectric generating capacity, based on Energy Information Administration analysis. That is, we assume that to provide a firm winter delivery contract, the seller would need to construct new capacity to back such a contract, or otherwise compensate the provider (or the provider's ratepayers) at the cost of service value of the capacity now committed to the New England region. The same consideration applies to infrastructure scenario 2.

[46] If the seller of capacity/energy under such a contract either planned to or were contractually obligated to be a price taker in the region's forward capacity market, there could in theory be capacity market price suppression benefits in addition to the estimated energy market price suppression benefits. However, consistent with New England's buyer-side mitigation market rules, it is unlikely that such a contract would qualify as a state-exempt resource, or be allowed to reduce the clearing price for capacity in forward capacity auctions. The same consideration applies to the transmission solution sets and infrastructure scenarios. We discuss the implications for dynamic market interactions in greater detail in Section V.B.3, below.

Figure 6: Evaluation of Electric Reliability Solution Sets, Annualized Impacts

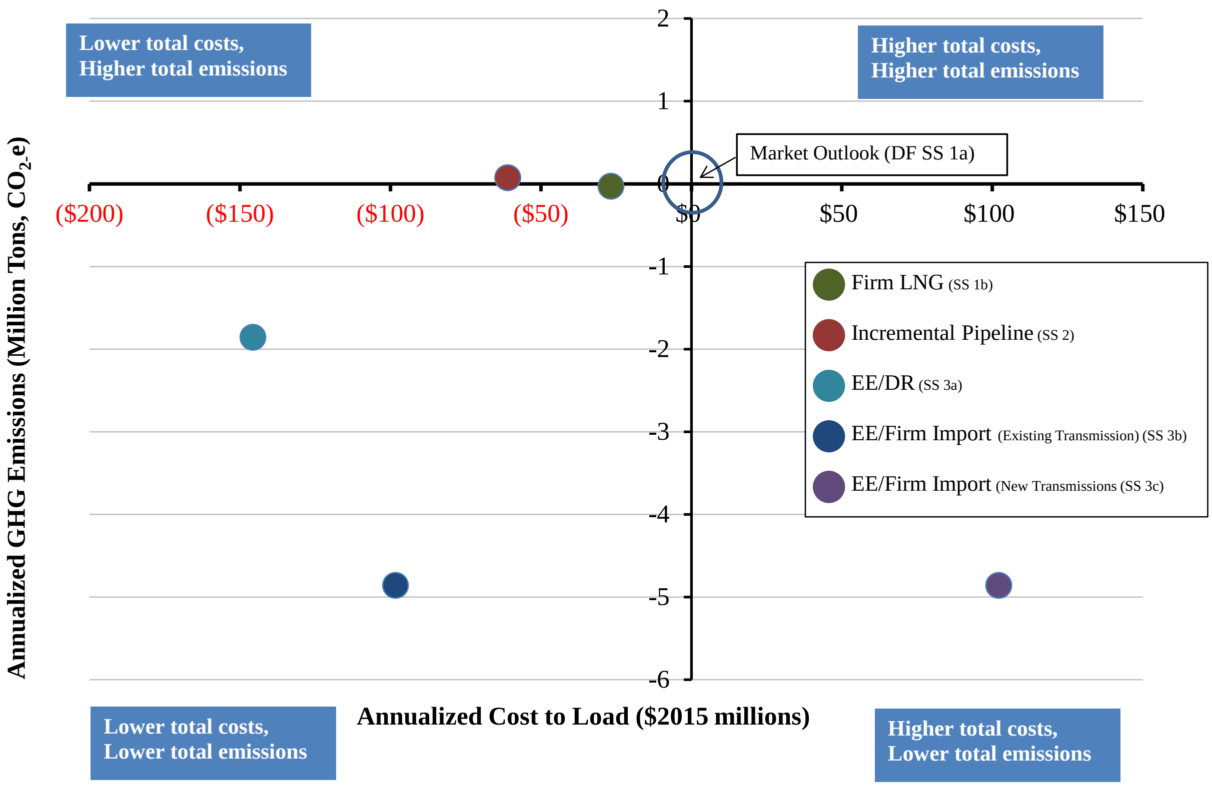
Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)



These solution sets present a wide range of both ratepayer impacts and GHG emissions impacts. As illustrated in Figure 6, only the EE/Firm Import (Existing Transmission) (SS 3b) solution ranks in the top two of all solution sets from both an annualized cost and annualized GHG emission benefit. Other solution sets present a wider range of performance on these two key metrics. EE/DR (SS 3a) provides the greatest cost savings, and the third greatest GHG reductions. Incremental Pipeline (SS 2) capacity provides the third highest ratepayer cost savings, but represents the worst option in terms of achieving regional GHG requirements.

As Figure 7 shows, only the EE/DR and EE/Firm Import (Existing Transmission) solution sets solve the stressed system reliability deficiency in a way that both reduces ratepayer costs and reduces GHG emissions relative to the current market outlook of relying on dual-fuel capability. In contrast, both the pipeline solution set and the firm LNG solution set can reduce total ratepayer costs but do not reduce total GHG emissions. Finally, a solution set that includes EE and the firm import of distant low-GHG energy over new transmission lines provides substantial GHG emission reduction benefits, but would lead to a net increase in total ratepayer costs after accounting for both the cost of firm energy and new transmission capacity. In general, however, imports without a firm commitment may be available at a lower cost, which could help the region meet its climate goals independently of a focus on reliability needs.

Figure 7: Annualized Cost and Emission Impacts, By Solution Set



Note: Pipeline solutions include an estimate for incremental in-region GHG emissions from fugitive methane leaks.

Infrastructure Scenarios

Meeting the reliability need through an earlier and/or larger than necessary infrastructure solution would lead to larger price suppression benefits for the region's electric ratepayers than a pure reliability focused solution. This is true of both the Larger Pipeline (IS 1) and Earlier Transmission (IS 2) infrastructure scenarios. These large investments in new infrastructure also carry immediate and long term cost implications, which must be balanced against these more immediate benefits. The results of these scenarios are presented in Table 4 below.

Meeting the deficiency completely through firm contracts for 2,400 MW of year-round transmission capacity and energy with provider(s) of distant low-carbon resource(s) in 2020 (Earlier Transmission IS 2) represents a scenario that meets the full deficiency in the first year of service.[47] This scenario generates by far the greatest total energy cost savings, of almost $576 million per year. However, the cost of the scenario, including contract costs plus the cost of new transmission, significantly exceeds this ratepayer benefit, leading to a net annual ratepayer *cost* of $284 million per year more than the status quo solution set.[48] However, the Earlier Transmission (IS 2) infrastructure scenario yields the largest and most sustained reduction in annual GHG emissions.

Similarly, the Larger Pipeline (IS 1) would generate total annual energy cost impacts of $309 million per year, against an annual carrying charge of $176 million, leading to net ratepayer benefits of $133 million per year. This scenario assumes that new pipeline capacity is added in 2020 and is fully available to the electric generation sector on a firm basis. This scenario assumes the greatest reduction in total basis differentials, which provide net ratepayer benefits each year that the pipeline is in-service. As discussed below, this scenario also creates a long-term obligation on ratepayers, which remains even if the value of the asset diminished or is limited for any reason, including the evolution of GHG reduction goals and obligations. It would also lead to the largest total GHG emissions of all solutions evaluated in the report, including market outlook Dual-fuel (SS 1a) solution. Lower gas prices result in greater fossil fired generation, which displaces both dual-fuel-oil-fired generation and imports of other economic energy resources located outside of ISO-NE. This could include the displacement of resources in neighboring regions, including gas, wind, or hydro imports. To the extent that greater in-region gas fired generation displaces gas fired generation from other Regional Greenhouse Gas Initiative (RGGI) states, it may not increase total RGGI emissions.

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[47] In contrast, solution sets that include EE/Firm Imports (SS 3b/SS 3c) are still phased in over time to meet the peak need.

[48] It should be noted that the price suppression benefits estimated for solution sets involving distant low-carbon resources (SS 3b/SS 3c/IS 2) may largely exist even if there is no firm contract for capacity, or full capacity costs to acquire this resource. This is because even without a firm capacity commitment, these resources could deliver inframarginal energy in many, if not most, hours of the year. However, absent the firm commitment and firm backing of reliable capacity, such a resource could not be counted on at the time of winter peak conditions, would have zero or near-zero value from the standpoint of winter reliability needs, and could not be considered a solution to a winter reliability deficiency.

Table 4: Evaluation of Infrastructure Scenarios, Annualized ($2015 million)

Negative Dollar Values represent consumer savings relative to market outlook Dual-fuel (SS 1a)
Negative Emissions represent a decrease in GHG emissions relative to market outlook Dual-fuel (SS 1a)

Scenario	[1] Cost of Energy (Cost to Load)	[2] Cost to Implement Solution Set	[3] = [2] + [1] Total Ratepayer Impact	GHG Emissions (million metric tons)
Incremental Natural Gas Capacity				
SCENARIO (IS 1) - Larger Pipeline (Sized Above Reliability Need)	-$309	$176	-$133	0.20
Incremental Transmission Capacity				
SCENARIO (IS 2) - Early Transmission (New and Existing Transmission Capacity, Firm Imports, 2,400 MW cumulative)	-$576	$860	$284	-6.65

2. Emissions of GHG Relative to States' Electric Sector Emissions Obligations and Objectives

Every New England state has made commitments to address the social, economic and environmental risks of climate change through binding CO_2 emission limits on the electric sector, state GHG reduction targets, and/or long-term multilateral commitments to achieve substantial reductions in GHGs over time.[49] Most recently, the New England Governors' (NEG) and Eastern Canadian Premiers (ECP) adopted a non-binding goal to reduce regional GHG emissions by at least 35-45 percent below 1990 levels by 2030.[50] In addition, EPA's Clean Power Plan (CPP) will result in binding obligations to reduce emissions of CO_2 from the power sector in all states nationwide.[51] Consequently, the GHG

[49] In Massachusetts, for example, the Global Warming Solutions Act (GWSA) established targets and requires the State to reduce total GHG emissions by 25 percent below 1990 levels by 2020 and 80 percent below 1990 levels by 2050. The GWSA includes GHG emissions from buildings, electric power generation, transportation and land use, and non-energy emissions, which considers plastics, solid waste, and other refrigerants. Reductions in the electric generation sector are estimated to provide approximately one third of all reductions anticipated in the 2020 plan; these include increased renewables and long-term contracts, including hydropower, retirements of older coal fired generation, and increased energy efficiency. See Commonwealth of Massachusetts "Global Warming Solutions Act 5-year Progress Report", December 30, 2013, Table 1. The plan estimates that 7.7 percent of all reductions will come from the electric power sector. This represents 28 percent of all reductions estimated in Table 1.

[50] Resolution 39-1 Concerning Climate Change, available: http://www.coneg.org/negecp.

[51] Vermont is currently not subject to control requirements under the CPP. The CPP establishes declining and final state GHG emissions goals beginning in 2022 and allows for multi-state compliance plans (including the use of regional programs like RGGI).

emission impacts of different solutions sets evaluated in this Report represent real and meaningful long-term impacts on consumers.

We evaluate GHG emission impacts of different solution sets using the metric of total emissions of CO_2 in New England as a proxy for considering the potential impact of each solution set's GHG trajectory on the difficulty and cost of meeting binding commitments and/or achieving states' long-term GHG goals.[52] In addition, we identify and discuss ways in which different solution sets may lead to GHG emissions outside the New England region or otherwise affect New England states' abilities to meet GHG reduction targets over time.

Each solution set represents a unique path forward with respect to GHG emissions. Figure 8 presents solution set emissions trajectories, where total annual GHG emissions in each scenario represent all in-region fossil fuel (and other carbon resources, such as biomass) generation based on the relevant PROMOD electric sector simulation. These emissions are compared to a projection of RGGI electric sector requirements, assuming that the current allowance cap continues to decline by 2.5 percent in each year after 2020.[53] The results may be described and summarized as follows:

- Each solution set includes declining emissions over the full study period, but by 2030 no single reliability solution would meet this projected RGGI target, even assuming all incremental RPS goals are met.[54]
- Under the market outlook Dual-fuel (SS 1a), natural gas continues to provide almost 50 percent of total generation, with continued reliance on oil-fired generation during winter months (amounting to more than 1,500,000 MWh by 2030).[55] This solution set fails to meet projected regional climate goals.

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[52] Under existing RGGI and potential future RGGI or CPP binding obligations, the New England states participate in an electric sector mass-based control program, with geographically broad trading of emission allowances among affected sources. In this context, the metric of actual CO_2 emissions may be viewed as indicative of the ultimate cost of allowances, and thus ratepayer cost of compliance. That is, while we do not attempt in this Report to forecast the impact of emission levels on marginal allowance prices, solution sets that lead to regional electric sector emissions exceeding the states' collective RGGI or CPP allocation or emission standards are likely to place upward pressure on allowance prices, marginal unit wholesale price offers, and ultimately costs to electric ratepayers.

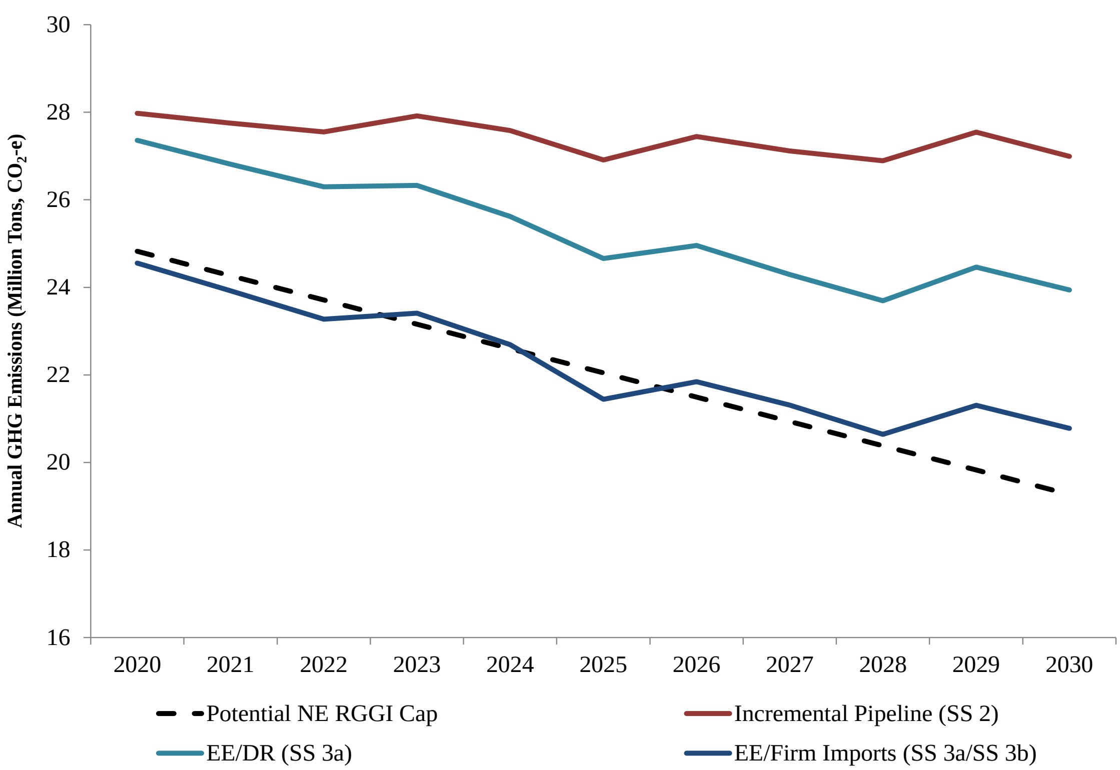
[53] In 2020, the total RGGI cap is 78 million short tons of CO_2. This cap includes the 6 New England States, plus New York, Maryland, and Delaware. Historically, New England's share of the regional cap has been approximately 35 percent. As described in Appendix 4, we found that RGGI emission targets are more stringent than assumed reductions from the electric sector as specified in GHG action plans and are also below the state targets set forth in the CPP.

[54] As discussed in Appendix 2, we assume a static CO_2 price that increases in real terms by 2.5 percent each year. That is, we do not model the potential dynamics of increasing CO_2 prices in response to any potentially binding constraints.

[55] For comparison, New England used oil for approximately 1,540,000 MWh in the 2013/14 winter. See Brandien, P. "ISO-NE Cold Weather Operations, Federal Regulatory Commission." April 1, 2014.

- The Firm LNG (SS 1b) solution set offsets a portion of the status-quo oil-fired generation, leading to a marginal reduction in oil-fired generation. Nevertheless, this solution set fails to set a carbon emission path consistent with long-term obligations and goals.
- The Incremental Pipeline (SS 2) solution set displaces the need for higher emitting oil-fired generation, but it also increases total fossil fired generation: gas fired generation meets 55 percent of total system load by 2030, an increase of almost 3 GWh (4 percent) in total generation relative to the market outlook (DF SS1a) solution set. Similar to the Firm LNG and dual-fuel solution sets, the incremental pipeline fails to meet projected regional climate goals.
- The EE/DR (SS 3a) solution set leads to meaningful reductions in natural gas-fired generation and would allow for gradual reductions in overall carbon emissions associated with the electric power generation sector. However, this solution set is still insufficient to meet climate goals throughout the full forecast horizon.
- Adding firm contracts for distant low/zero-carbon resources (instead of DR, which has a de minimis impact on CO_2 emissions) to EE solution sets significantly improves GHG trajectory outcomes. The EE/Firm Import (SS 3b/SS 3c) solution sets produce an immediate and long-term reduction in total CO_2 emissions in every year of the study period, and lead to the largest total reduction in in-region carbon emissions. While these solution sets still do not fully achieve the projected RGGI target for 2030, they lead to emissions that are more consistent with projected climate goals.

Figure 8: Annual GHG Emissions and Potential ISO-NE Climate Goals



Notes:

Pipeline emissions include an estimate for in-region GHG emissions from fugitive methane leaks. Emissions for Dual-fuel (SS 1a) and Firm LNG (SS 1b) are excluded for clarity; both solution sets report annual emissions that are within 0.15 million metric tons of the Incremental Pipeline (SS 2) solution set.

The estimates in Figure 8 include an estimate for the potential in-region GHG emissions associated with fugitive emissions of methane on the pipeline transportation system for the incremental portion of natural gas use in the Incremental Pipeline (SS 2) (and also included in the Larger Pipeline (IS 1) infrastructure scenario). Using assumptions based on industry standards for pipeline, compressor and meter/regulation station losses, we find that these fugitive emissions could contribute an additional 0.47 million metric tons of CO_2-equivalent GHG.[56] Our estimate also does not include any GHG impacts associated with an increase in in-region natural gas consumption for residential needs. Specifically, in addition to gas-fired generation emissions and fugitive emissions from interstate pipelines, increases in natural gas consumption in the New England region could increase overall GHG emissions associated with CH_4 releases due to natural gas production, processing, and transport outside the New England region, as well as GHG emissions due to increased operation of compressor stations. This assumes that New England demand does not displace demand from other regions, which may be unlikely given the policy objectives of the CPP.

Finally, it should be noted that solution sets involving incremental firm capacity from distant low-carbon resources (SS 3b/SS 3c) could involve the development of new large hydro generation facilities, which also have potential GHG implications not accounted for in our analysis. Specifically, new dams inundate reservoir basins, which induces further decomposition of biomass and can lead to an increase in total GHG emissions, attributable to the facility's development. Recent research by Hydro Quebec found that these emissions are highest during the two to four years immediately following reservoir construction, and, on a CO_2-equivalent basis, can exceed the emissions of new gas fired generation before moderating and reaching levels consistent with existing lakes in later years.[57] To date, existing climate policies and renewable portfolio standards (which mostly exclude large hydropower facilities from eligibility) do not consider net emissions of large scale hydro imports, and any estimated net emissions

[56] These estimates assume a 21x global warming potential of CH_4 over a 100 year time frame, consistent with Massachusetts facility reporting guidelines. Recent estimates from the IPCC updated this value to 28x that of CO_2 for a 100 year timeframe and 84x the GWP for CO_2 for a 20-year timeframe. (Intergovernmental Panel on Climate Change AR5, Chapter 8, 2013).

[57] Teodoru et al. (2012) estimated the net CO_2 emissions associated with the construction of the 485 MW Eastmain-1 reservoir in the James Bay region of Northern Quebec, Canada, accounting for the pre-construction carbon footprint of the landscape and the actual measurements from the reservoir surface after inundation. They found that the net CO_2 equivalent emission rate for a new hydro dam in a boreal forest landscape could exceed the emissions of a new natural gas combined cycle unit over the first few years of the asset's life, and projected they would then decline to less than half of the assumed emissions of a NGCC over the remaining 100-year life of the hydro facility. Hydro Quebec supported and participated in the development of this study as part of a net greenhouse gas emission study. See http://www.eastmain1.org/en/index.html.

would depend on the unique site conditions of each reservoir site.[58] Over the long term, however, these net impacts may be considered under the joint climate plans formed by the New England Governors/Eastern Canadian Premiers (NEG/ECP), or to the extent they are considered by other regions, the price of long term import contracts may reflect the higher cost of meeting in-region climate risk reduction goals.

In contrast, imports that do not require a firm commitment could be based on other resources, including wind (on and off-shore) or existing hydro facilities. These resources could be used to meet regional climate goals, potentially at a lower cost than the firm commitment included here. However, this would not address a potential winter reliability need from a firm planning perspective and are not included here.

3. Market Interactions and Other Risk Factors

The sections above focus on quantifiable ratepayer cost and regional GHG emission impacts associated with different solution sets designed to address the identified reliability deficiency. In this section, we review and summarize qualitatively key factors to consider when evaluating the consumer and policy impacts of potential future outcomes. These factors are related to the competitiveness of wholesale markets and impacts on producers and social welfare; the impacts on the customers of natural gas LDCs; and the risks associated with different solution sets from the electric ratepayer perspective. Table 5 contains a high-level summary of a number of important additional qualitative considerations.

Interaction with competitive wholesale markets – In our assessment we specifically model the interaction of solution sets with wholesale market economic commitment and dispatch and the associated changes to energy market pricing and emissions. However, wholesale markets involve a more complicated and dynamic interplay between factors that cannot be fully captured in a production cost modeling of the electric system. This includes the potential impact of differences in energy market net revenues for producers and how producers may respond in turn, through their development of offers to provide capacity and ancillary services. It also includes the potential long-run impact on wholesale market competition that could arise from different approaches to addressing potential reliability deficiencies. An assessment of specific legislative or regulatory actions must carefully consider the balance between market competition, resource outcomes, and ratepayer risks.

The fundamental purpose of states moving to a competitive market structure was to remove the investment risk previously incurred by regulated utilities and borne by ratepayers, and to put that risk in the hands of those best able to manage it – namely, the competitive market participants that operate in both the electric and natural gas markets. While electricity markets remain relatively new, they have evolved rapidly, with the evolution of market design focused on achieving a structure that provides the

[58] In contrast, MA does require an analysis of the net lifecycle emissions that account for the "temporal changes in forest carbon sequestration and emissions resulting from biomass harvests, regrowth, and avoided decomposition" associated with Class II biomass facilities. See Renewable Energy Portfolio, MA 225 CMR 14.02.

right signals for market participants to pursue outcomes that represent, in the long run, the most efficient use of society's resources and the lowest possible costs for consumers.

Major long-term investments borne by captive ratepayers may look like a good proposition from the standpoint of short-term ratepayer savings. Indeed, as noted above we find modest ratepayer net benefits across a number of solution sets involving various forms of state-sponsored investment in resource outcomes (e.g., subsidization of natural gas pipelines, transmission, contract capacity, and energy efficiency/renewable resources). But intervention in markets should be carefully weighed against the risk that such actions can seriously interfere with competitive market dynamics by changing the relative prices of competing resources, artificially suppressing prices and producer revenues, and impeding the free entry and exit of current and future market participants. While in a limited short-run analysis such actions may look necessary and/or beneficial, in the long run they are also likely to interfere with competition, reduce market efficiency, and increase all-in consumer prices for energy, capacity and ancillary services.

Another consideration relates to our focus on *ratepayer impacts*. Since the context for our analysis is states' current consideration of having electricity consumers pay for natural gas infrastructure, we quantify in the Report differences in solution set impacts on electric ratepayers, or changes in "consumer surplus." When considering long-term ratepayer investments, this is generally the standard by which public utility commissions evaluate competing alternatives – namely, the total costs, risks, and benefits borne by the *ratepayers* who will be responsible for the cost burden of the investment or commitment in question. However, evaluating the broader efficiency of market outcomes should also consider the potential impact on *producer surplus* – that is, the impact on producer profits over time – with the ultimate goal of maximizing the combination of producer and consumer surplus, or total social welfare.

The solution sets evaluated in this Report would change the underlying economics of participation in wholesale markets by producers and affect the revenue flows to many market participants in both electric and natural gas industries. For example, investments in energy efficiency or natural gas pipelines would reduce energy market costs for consumers, but would also reduce revenues and profits for producers, and change revenue streams (positive and negative) for other participants in electricity and natural gas markets (e.g., energy efficiency providers and natural gas shippers/marketers/pipeline owners). Similarly, contracted capacity for an interconnection to a neighboring region could significantly suppress wholesale market prices, increasing revenues and profits to some producers (e.g., the owners of hydro assets backing power sales), and decreasing revenues and profits to other producers (e.g., owners of in-region generating assets).

The ultimate impact on total social welfare of all consumer and producer impacts is difficult to establish (and is beyond the scope of this Report), since over time the cost reductions and producer revenues lost in the energy market would be at least partially offset by increases in other markets, such as the forward capacity, reserve, and ancillary services markets, as generating asset owners increase offers to ensure economic viability, or otherwise retire and force new entry earlier than otherwise would occur. In short, reductions in total social welfare that arise from projects supported by non-market actions may discourage or otherwise displace projects that would have been more cost effective in the long run.[59]

Interaction between electric and natural gas ratepayers – Many natural gas LDCs contract with third parties for management of their natural gas supply and transportation assets, with the goal of maximizing the value of those assets. These arrangements often include a sharing of revenues among the portfolio managers, natural gas LDC shareholders, and LDC ratepayers. The addition of natural gas capacity that would in effect be owned by electric ratepayers and dedicated for use by electricity generators would increase available transportation capacity, and thereby decrease or eliminate the value of natural gas LDC assets that are often sold off for use by electricity generators; this would lower rebates to LDC ratepayers, and lower revenues to LDC shareholders and portfolio managers. That is, if electric companies hold firm capacity for use by electric generators, then it is unclear who will remain in the market to purchase large quantities of capacity release from other firm shippers. In fact, by securing firm capacity for electric generators, the resale capacity of LDC firm transportation rights will likely be lower, representing a net cost to natural gas ratepayers. Conversely, the electric ratepayer firm transportation assets may also have resale value, and allow through such resale a reduction in the cost obligation borne by electric ratepayers for the firm pipeline commitments. We expect, however, that this value may be minimal since the addition of electric ratepayer-funded transportation capacity would dramatically reduce the value of such capacity in many or most hours of the year. However, estimating the impact of such capacity resale by transportation asset owners (LDCs and electric ratepayers) is beyond the scope of this Report.

Ratepayer risk – Our financial analysis of different solution sets applies the same financial assumptions and approaches to ensure comparability and uses consistent decision rules related to the timing of the investments. The goal of structuring our analysis in this way was to present the ultimate impact on electric ratepayers using a consistent cost metric – namely, the expected total annual costs to electricity consumers, considering both the expenditures needed to implement the solutions and the annual impact on total energy market costs to load. All of our analyses evaluate impacts over the full forecast period (i.e., through 2030) on a net present value basis and then use these results to identify an annualized ratepayer impact.

While we believe this is the most fair and consistent approach to compare ratepayer impacts across solution sets, it does mask some important differences in the risk profiles of different approaches, and/or in the potential value (or lack thereof) associated with solution sets throughout and beyond the forecast horizon. As noted in Table 5, there are some significantly different risk profiles across solution sets; differences that are a function of the "lumpiness" of implementation costs, and the ability to adjust spending/implementation as new information becomes available over the forecast horizon.

Specifically, solution sets can be loosely grouped into "one time" and "incremental" approaches to addressing potential winter peak deficiencies. On the one hand, pipeline and transmission/capacity

[59] See Initial Comments of the Office of the Attorney General, in Re: D.P.U. 15-37, filed June 15, 2015, Section III.B.2.

additions (in both solution sets and infrastructure scenarios) require major one-time[60] investments and associated long-term ratepayer commitments that cannot be reversed if events do not proceed as expected, or if a change in winter demand or in supply technology options suggests an alternative path going forward.[61] In contrast, the other solution sets either have a minimal up-front cost impact on ratepayers (e.g., the Dual-fuel (SS 1a) and Firm LNG (SS 1b) solution sets), or in the EE/DR (SS 3a) solution set require ratepayer commitments that can vary (increase or decrease) each year as new information becomes available related to the magnitude of need and/or cost of various solution set options (i.e., changes in the cost of efficiency measures and programs, or renewable/distributed alternatives). While we have not attempted to quantify it in this Report, there may be a meaningful option value that should be attributed to the "incremental" approaches to address the stressed system deficiency. This is particularly true given our finding that, under our base case assumptions, we find no deficiency over the forecast horizon.

This option value may also be particularly important given the suite of GHG goals and commitments. Reliability solution sets that reduce GHG emissions provide an incremental economic benefit by potentially lowering the cost of future compliance strategies. In contrast, solution sets that fail to do so will require more significant investments at a later date. It is also important to note that these climate commitments were made, in part, with a consideration for the wide range of public health, economic, and environmental benefits associated with reduced GHG emissions and a recognition of the many other externalities associated with fossil fuel generation, though a full review of such externalities is beyond the scope of this Report.

[60] The EE/Firm Imports (SS 3b/S 3c) solutions require up-front commitments to contract for firm winter capability backed by resources that can deliver at the time of winter peak, and potentially one-time commitments to construct and pay for any transmission needed to deliver such capacity to load. The Incremental Pipeline (SS 2/ IS 1) solutions also require major up-front commitments, either on a one-time basis (in the infrastructure scenario) or in two separate pieces (in the solution sized to the stressed system deficiency).

[61] We realize that in theory regulatory commissions could disallow recovery of a portion or all investments made for new interstate pipeline capacity, transmission infrastructure, and/or capacity contracts. However, in practice we expect and assume that the costs associated with any of these solutions would be deemed prudent at the time of investment, and cost recovery would be pre-approved or largely assured through up-front regulatory findings.

Table 5: Risk Factors and Other Considerations Associated with Solution Sets

Solution Set	Other Considerations
Market Driven Outcomes	
SS 1a: Dual-fuel Capacity ("Status Quo")	• No up-front investment and requires no action on the part of legislatures or regulators • Dual-fuel upgrade costs may not be passed on to consumers (unless upgrade cost affects marginal capacity market prices), costs borne by producers represent a reduction in profits • Relying on oil during winter peak periods has only limited impact on winter gas prices; when oil prices are low, economic oil-fired generation can reduce on-site inventories leading into stressed winter conditions • Air quality permits often restrict total hours of oil-fired operation, though restrictions generally allow more hours of operation than needed to address winter peak reliability needs • Operation time at units will be limited by the quantity and size of oil storage tanks, ability to switch from gas to oil, and ability to replenish supplies, which can be challenging during extreme cold periods
SS 1b: Firm LNG Capacity	• No up-front costs to consumers; implementation costs reflected in energy market prices on as-needed basis • LNG use targeted to deficiency may have only limited impact on winter delivered gas prices • Creates flexibility with respect to intra-annual operations and allows for 5 year lead time for renegotiation or pursuit of alternative solution sets if needed • Contract prices and terms are untested at this point; firm commitments remain dependent on contract language and financial penalties; imports constrained by global price risk, global supply production risk • Prices would ultimately be set by few suppliers with limited competition
Incremental Pipeline Capacity	
SS 2: Incremental Pipeline:	• Major up-front investment creates long-term ratepayer cost obligation; obligation remains even if use or value of assets diminish or is limited for any reason (e.g., evolution of GHG reduction goals/obligations) • Increased certainty of solution set once approved; known in-service date allows for accountability and tracking of progress made by a single entity • Mechanism to guarantee firm transportation for electricity generation at winter peak is unknown • Increased capacity reduces or eliminates the value of existing capacity release benefits, which may lead to a net loss for gas ratepayers, LDC shareholders, and portfolio managers • Increased in-region flows may be used to serve other markets or LNG exports, potentially increasing pipeline utilization and reducing or eliminating price suppression benefits • Faces significant siting and regulatory challenges, potential local property value impacts and non-GHG environmental impacts • May increase GHG outside New England, and an associated increase in natural gas production and consumption would also increase non-GHG environmental impacts
Energy Efficiency, Demand Response, and Renewable Energy	
SS 3a: Energy Efficiency and Demand Response	• Up-front investment is annual, and can be adapted on an annual basis in consideration of actual need and changes in technology, policy and cost factors; actual technologies/programs relied on could adjust in response to technology and cost breakthroughs • Requires a sustained commitment by states for investment, likely over many years; absent a commitment the EE/DR solution cannot be counted on to meet deficiency in later years • Realization could be limited by ability to ramp up resources and providers; full suite of benefits are not immediately available • Requires robust monitoring and verification to ensure expected winter peak impacts are being realized • Annual costs are not certain – could either grow or decline in later years
SS 3b/c: Energy Efficiency and Firm Imports (existing and new transmission)	• (See above in SS 3a regarding EE) • Major up-front investment creates long-term ratepayer cost obligations; ratepayer obligation remains even if use or value of assets diminish or is limited for any reason • Must guarantee and price firm winter/year-round capacity; otherwise, cannot be counted on to address deficiency; availability and cost of a firm winter deliverable product is unknown

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VII. GLOSSARY

ACO	Annual Contract Quantity
AGI	Analysis Group, Inc.
AGO	Massachusetts Office of the Attorney General
AIM	Spectra's Algonquin Incremental Market pipeline project
Basis differential	The difference between delivered natural gas at trading hubs and the Henry Hub
Bcf	Billion cubic feet: a unit of natural gas
CELT	Capacity, Energy, Loads, and Transmission: ISO-NE annual planning document
CH_4	Methane
CO_2	Carbon dioxide
CPP	Environmental Protection Agency Clean Power Plan
Deficiencies	Periods when the electric system may not be able to meet peak electric demand
DOER	Massachusetts Department of Energy Resources
DR	Demand Response
Dth	Dekatherm: a unit of natural gas
ECP	Eastern Canadian Premiers
EE	Energy Efficiency
EFORd	Equivalent Forced Outage Rate on Demand
EIA	US Energy Information Administration
EPA	US Environmental Protection Agency
FCA	Forward Capacity Auction
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse gas emissions
GWSA	Global Warming Solutions Act
ICF	ICF International
ISO-NE	Independent System Operator of New England
LDC	Local distribution company, used for natural gas
LMP	Locational marginal price
LNG	Liquefied natural gas
M&N	Maritimes & Northeast Pipeline
$MMTCO_2e$	One million metric tons CO_2 equivalent
MW	Megawatts: a unit of power
NBP	United Kingdom’s National Boundary Point
NED	Kinder Morgan's Northeast Energy Direct pipeline project

NEEP	Northeast Energy Efficiency Partnership
NEG	New England Governors
NYISO	New York Independent System Operator
PFP	ISO-NE Pay-for-Performance Program
PJM	Pennsylvania, Jersey, Maryland Interconnection
PROMOD	An industry-standard electric market simulation model marketed by Ventyx
RE	Renewable Energy
REED	Northeast Energy Efficiency Partnerships Regional Energy Efficiency Database
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization

VIII. APPENDICES

1. Deficiency analysis

In this appendix, we provide additional detail on the deficiency analysis, specifically with respect to the methodology used to forecast natural gas demand and additional sensitivities of the key results presented in Table 1.

Availability of Natural Gas for Electricity Generation

As described in Section III, we relied on daily scheduled pipeline and LNG deliveries to LDCs and end-users for the period December 1, 2012 to present using SNL Financial,[62] and the weighted average temperature for the ISO-NE Control Area collected by ISO-NE.[63] Figure A1 below shows the total demand and capacity for the period January to March 2015, and highlights that during peak periods, the system is fully constrained, with total scheduled deliveries net of LNG sendout (shown here as negative demand) approaching total pipeline capacity. Here, we rely on scheduled deliveries during the timely nomination cycle. Under the timely nomination cycle, natural gas is scheduled for delivery by 12:30 pm the day before. That is, the timely nomination gives the greatest assurance to shippers (including both LDCs and generators) that they will receive their nominated capacity. This assurance is necessary under a strict reliability perspective, since it is only the capacity not nominated by firm shippers during the timely cycle that is available to electric generators on an interruptible basis the following day. Other nomination schedules include the evening cycle (by 7 pm the day before, for delivery by 10 am the following day) and the intraday nomination cycles (which allow for nomination and delivery during the same day). Not considered here is the challenge of electric-gas coordination, and the simple fact that the natural gas day and electric generation day operate on different time schedules. We note that greater coordination by the gas and electric sectors has alleviated and can continue to alleviate potential constraints. For example, in recent winters, ISO-NE has advanced the day-ahead market timeline to allow for more time to procure gas and has maintained regular communications with gas pipeline operators.[64]

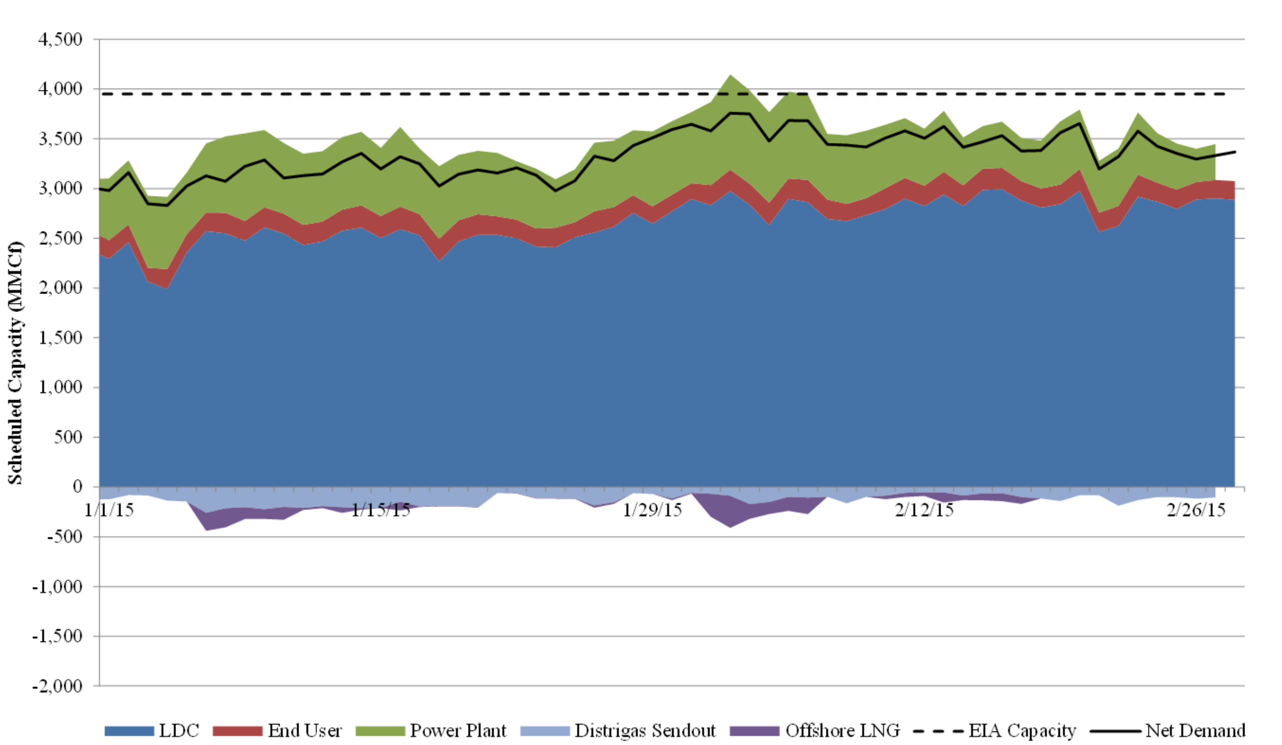
[62] SNL Financial is a data aggregation service that compiles electronic bulletin board data reported by each individual pipeline company. SNL classifies each delivery point based on available contract information.

[63] See ISO-NE, Zonal Information, available: http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[64] See Callan, W. ISO-NE Winter 2014/15 Review. Electric/Gas Operations Committee (EGOC) Teleconference, June 29, 2015. Available: http://www.iso-ne.com/committees/industry-collaborations/electric-gas-operations.

Figure A1: Scheduled Natural Gas Demand and Total Capacity, ISO-NE System

January – March 2015



Notes:

Total deliveries are the sum of LDC's, end-user, and power plant deliveries. LNG deliveries to the natural gas system are reflected as a reduction in total deliveries, instead of an increase in total capacity. Total capacity is based on EIA state to state data for existing interstate pipeline gas capacity.

Consistent with ISO-NE/ICF (2014), we developed a daily forecast of natural gas demand from LDCs and end-users based on the historical relationship between demand and weather. We developed two separate forecasts – one for winter conditions (defined as any day from December through February of each year, with total temperature less than 65 degrees Fahrenheit) and one for non-winter conditions (defined broadly as all days with temperature greater than 65 degrees Fahrenheit). The statistical relationship in Figure 1 of Section III is defined by Equation 1. Equation 2 provides the non-winter relationship.

$$\textbf{\textit{Equation 1}}: \ \textbf{\textit{Projected LDC Interstate Pipeline Demand in MMCf}} \ (\textbf{\textit{when temp}} < 65^{\circ}\,\textbf{\textit{F}}) \\ = (878 + 60.6 * EDD - 0.4 * EDD^2) * (Year - 2015)\text{^}(1.4\%)$$

$$\textbf{\textit{Equation 2}}: \ \textbf{\textit{Projected LDC Interstate Pipeline Demand in MMCf}} \ (\textbf{\textit{when temp}} > 65^{\circ}\,\textbf{\textit{F}}) \\ = (905 - 0.53 * EDD) * (Year - 2015)\text{^}(1.4\%)$$

Our use of the 1.4 percent growth rate, while consistent with recent studies, does not necessarily align with recent estimates for peak design day demand growth as filed in certain LDC long term supply plans. However, there are several important differences between our assumed growth rate of demand from existing pipelines and the *overall* growth rate of LDC demand. These differences include demand from capacity exempt customers, demand met by incremental supplies not available to the electric generation sector, and demand from power plants served by LDCs. We described these key differences in Section III, but provide additional detail here.

First, we apply the 1.4 percent growth rate to both LDC and end-user demand. We obtain historical data for these two sectors separately; end-users are defined as large (typically commercial/industrial) customers that connect directly to the interstate pipeline, typically before the city gate. Recent LDC filings have included plans that account for the return of some capacity exempt customers.[65] While this represents an increase in LDC forecasted demand, it is not a net increase in total demand for the system. These growth rates reflect, in part, growth for the LDC portfolio which includes new LDC customers and are not necessarily limited to new growth for all natural gas users. Because these capacity exempt customers are already captured in our end-user definition, a higher LDC-specific growth rate would double-count their forecasted take from the interstate natural gas pipeline system. Put another way, we assume that both LDC demand and end-user demand grows by 1.4 percent.

Second, our use of a lower growth rate reflects a more narrow view of incremental demand from the existing and approved interstate pipelines used in our base case deficiency statement. That is, this growth rate does not reflect incremental demand that could or will be met from new facilities or from LNG resources that are unavailable to meet electric sector demand.

We have made no assumption for how LDCs will meet incremental new demand, above this 1.4 percent growth rate. To do so would require, in part, an assessment of the cost and benefits of all possible supply strategies. Therefore, for the purpose of estimating incremental gas available to the electric generation sector, we assume that neither the incremental demand nor the associated incremental supplies to meet that demand are available to, or otherwise affect, the electric generation sector.[66]

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65 For example, National Grid included returned capacity-exempt load of 41,080 MMBtu/day in 2015/16 and beyond. Subtracting this demand from total firm design peak day would lower the estimated compound annual growth rate during this period from 2 percent to 1.6 percent. See National Grid, Long-range Resource and Requirements Plan, DPU Docket 15-36, Revised Forecast as filed July 10, Response to Information Request DPU-1-5, at page 18 and Table G23-D (Revised).

66 This includes the recent precedent agreements for new pipeline capacity with the Kinder Morgan Northeast Energy Direct (NED) pipeline. It also includes National Grid's most recent petition of approval for five new LNG contracts. These include a nine year contract with GDF Suez at the Distrigas facility, and agreements for new incremental liquefaction facilities. Because we are primarily concerned with LNG supplies to help meet a peak reliability deficiency in 2025 or later, we assume that contracted capacity at the Distrigas terminal becomes available to the electric generation sector. We do not include new LNG capacity from the proposed liquefaction facilities, which would be used to meet LDC peak design day demand. These new facilities would access the Algonquin pipeline at the current site in Providence, Rhode Island and the Tennessee pipeline at an undisclosed

Third, our estimates of historical demand at LDC city gates will necessarily include demand from the electric power sector served by those LDCs. This fact suggests that we will understate the total quantity of gas available to the electric generation sector and over-state the potential reliability deficiency.

However, as a sensitivity to the results presented in Table 1 of Section III, we also evaluated potential system deficiencies assuming that total natural gas demand from LDCs and end-users grows at compound annual growth rate of 2.2 percent over the life of the study and that the system adds 0.5 Bcf/day of incremental pipeline capacity – to meet LDC needs – in 2020. This capacity is not reserved for the electric generation sector and is only available on an interruptible basis throughout the winter months. We find that the peak deficiency in the stressed system case, considering both a higher growth rate and new capacity to serve that demand, is actually lower than the peak deficiency presented in Section III (see Table A1). This means that our definition of solution sets to meet a potential deficiency are robust to potential assumptions of higher LDC growth rate that could be met by new LDC supplies.

Table A1: Electric Sector Reliability Deficiency Analysis Sensitivity, 2020-2030

Assuming 2.2% growth in LDC/End User Demand and Incremental 0.5 Bcf/d LDC capacity in 2020

Total Hours with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	2	4
Scenario 3 "Stressed System"	0	0	0	0	4	5	5	5	12	17

Total Days with a Deficiency

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	1	2
Scenario 3 "Stressed System"	0	0	0	0	2	2	2	2	5	6

Peak Hour Deficiency (MW)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	173	764
Scenario 3 "Stressed System"	0	0	0	0	450	940	1,266	1,017	1,552	2,143

Peak Hour Deficiency (Bcf/hr)

2004 Weather Year, 90-10 Load	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Base Case	0	0	0	0	0	0	0	0	0	0
Scenario 1 "Oil Unavailable"	0	0	0	0	0	0	0	0	0	0
Scenario 2 "Gas-Only"	0	0	0	0	0	0	0	0	0.0012	0.0054
Scenario 3 "Stressed System"	0	0	0	0	0.0032	0.0067	0.0090	0.0072	0.0110	0.0152

Notes:

Includes the same assumptions described in Section III.

location in Massachusetts. See Joint Testimony of Elizabeth D. Arangio and John E. Allocca, Exhibit NGRID-EDA/JEA-1, D.P.U. 15-129, page 6, filed August 20, 2015.

2. Solution Set Costs

Each solution set described in Section IV represents an incremental change to the electric generation sector, which will either increase the total availability of fuel for natural gas and/or dual-fuel fired generation or decrease total electric demand during winter peak hours. These solution sets include variable options (such as Firm LNG (SS 1b) or demand response (as part of EE/DR SS 3a)) which can be called upon only during deficiency hours and also larger fixed options, which would be available both during the winter peak deficiency event and during all other hours in the year (such as Incremental Pipeline (SS 2) capacity, or EE/Firm Import (SS 3b/SS 3c) capacity). Each solution set, therefore, will have a unique impact on total system natural gas utilization, natural gas prices, and the total cost to load. We describe the impact of each solution set on natural gas prices in this Appendix.

We assume that ratepayers are responsible for the full cost to implement each solution set, including all fixed and variable costs associated with new investments based on existing cost-of-service principles that also recover return on rate base, depreciation, and taxes. Costs for each solution set are expressed in annualized terms, and in the assessment phase, we match annualized benefits to annualized costs over the full modeling period.[67] When appropriate, nominal costs are converted to real costs assuming a 2.5 percent inflation rate. All values are annualized over the period 2020 to 2030 in level-real terms assuming a 7 percent private discount rate.

Additional details on sources and specifications for solution set costs are described below.

Market-Driven Outcomes

Solution Set 1(a): "Status Quo" – Dual-fuel

Under the ISO-NE Pay-for-Performance (PFP) program, resources that clear in the forward capacity auction (starting with FCA #9 for deliverability in 2018/2019) will receive base capacity payments, and during periods of scarcity, resources that perform well will receive additional payments while those that fail to perform or perform poorly will receive a significant penalty charge. This places the financial risk (or benefit) of scarcity performance on individual generators and provides for an additional incentive to resources to increase unit reliability during periods of potential fuel shortage. This could include incremental dual-fuel capability or non-interruptible gas supply arrangements. The PFP program will be phased in over seven years and will not be fully available until 2025.

As described below, first, we develop our base case outlook for natural gas and dual-fuel capacity using the Ventyx simulation-ready data for the ISO-NE and Eastern Interconnection region, with adjustments to potential retirement dates and new additions based on our review of relevant planning documents published by ISO-NE. Second, we use a generic resource adequacy capacity market model and add new dual-fuel capable resources over time, in quantities sufficient to meet reliability requirements. We include more than 19.5 GW of natural gas fired capacity in 2020, representing 52 percent of total

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[67] We recognize that solution sets requiring an incremental capital expansion, for either a new transmission line or a new incremental gas pipeline will necessarily have a lifetime beyond 2030 and the end of our modeling period. We do not consider the remainder of ratepayer payments associated with these investments, nor do we consider any potential benefits to the electric generating sector in years after 2030.

system capacity. This capacity includes 9.6 GW of dual-fuel capacity, with 2.4 GW of that dual-fuel capacity assumed to come on-line after 2019.[68]

Under the existing market outlook, generators have incentives to perform during periods of peak winter demand, and to do so during periods of natural gas shortage or price spikes. However, individual units may be unavailable during winter peak for several reasons, such as generator outages beyond the assumed average EFORd, operating limits for total emissions, or limits on fuel availability and deliverability in generator storage tanks. They may also be unavailable as the full effectiveness of PFP is phased in over the seven year period. To account for this uncertainty, and as part of our stressed system deficiency statement scenario, we assume that all new dual-fuel capacity and all fuel oil #6 capacity is unavailable at the time of winter peak. This represents 20 percent of all existing dual-fuel capable units and approximately 40 percent of all dual-fuel capacity in our assumed future supply stack.

In the dual-fuel solution set, we add sufficient quantities of dual-fuel capability at existing resources to meet the deficiency. This includes 500 MW in 2022; 1,500 MW in 2024; and 400 MW in 2026 (for a total of 2,400 MW). The 2013 AGI review of the ISO-NE FCM PFP found that increased investment in dual-fuel represented the most cost effective investment, and that more than 11,000 MW – including 4,000 MW of mothballed capacity at existing dual-fuel units – was available.[69]

Based on that finding, we estimate that the total cost for the dual-fuel solution set can be met by existing resources with under- or unutilized capability, and total annualized incremental dual-fuel capacity costs are assumed to be $6,856/MW, consistent with that study, adjusted for inflation. These costs include both annualized capital costs and annual operating costs for fuel and operations and maintenance. Importantly, electricity consumers would only realize incremental costs for this solution if and to the extent that the addition of duel fuel capability on an existing resource affects capacity market prices as a marginal capacity resource, which may in fact be unlikely. Nevertheless, for comparison with other solution sets, we provide dual-fuel costs calculated as the full incremental cost on a cost of service basis.

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68 This estimate is in-line with other estimates of dual-fuel capability, including the publicly available totals reported in the ISO-NE CELT (2015) and the AGI's review of confidential individual generator data provided by ISO-NE as part of its assessment of the ISO-NE Forward Capacity Market Performance Incentives.

69 Schatzki, T. and Hibbard, P. "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives." September 2013, pages. 4 and 21, also Figure 3.

Solution Set 1(b) – Firm LNG

LNG plays an important role in the natural resource portfolio for ISO-NE customers, including local gas distribution companies (LDCs). It provides a flexible natural gas resource that can be used to meet peak demands, and at the same time, provides a hedge against daily volatility in delivered natural gas prices at New England city gates. In New England, there are two primary sources of LNG available to LDCs: facilities with direct import capability connected into the interstate pipeline system and off-system LNG resources that rely on trucked capacity and are available for peak shaving.

Table A2 summarizes LNG facilities and their known capacities. From an electric reliability perspective, we are primarily concerned with LNG supplies that can be used to provide incremental gas service to the electric generation sector during peak demand periods. Therefore, we assume that all LNG peak-shaving facilities owned and operated by LDCs (45 facilities representing a combined 1.4 Bcf/d capacity) are used to meet residential peak day needs and are not available to meet electric reliability demand.

In contrast, both the Canaport and Distrigas facilities are connected to the interstate natural gas pipeline system. Canaport is located in New Brunswick and interconnected to the Maritimes & Northeast (M&N) pipeline and supports North to South flows into New England. Canaport is one of several sources of natural gas to the M&N pipeline. As described below, we assume that the full capacity of the M&N pipeline (0.833 BCF/D) is available to New England customers in our deficiency statement. Therefore, we do not include any incremental LNG supplies from Canaport in our analysis.

The Distrigas facility, located in Middlesex, Massachusetts and interconnected to the Tennessee Gas Pipeline and Algonquin Pipelines, allows for the back-fill of natural gas into the interstate pipeline system with East to West flows. The Distrigas facility also provides LNG to the Mystic Generating Station, a 575 MW natural gas steam turbine. The Distrigas facility can store up to 3.4 BCF of LNG and can re-gas up to 0.715 BCF on a continuous basis. This represents 4.75 days of total sendout at maximum capacities.

Table A2: Existing Liquefied Natural Gas Capability

Resource	Capacity	Assumption	Solution Set
Canaport	1.3 BCF/Day	Included in the Deficiency Statement, as a supply to the 0.833 BCF/D M&N Pipeline	Not Included in Solution Sets
Distrigas	0.715 BCF/Day	Historical Flows and Back-fill included in Demand Forecast	Non-LDC Capacity available for solution sets
Neptune[70]	0.635 BCF/Day	Out-of-Service; Potentially available at a higher cost, including fees to return to service	Not Available for solution sets
Northeast Gateway			
LNG Peak Shaving	1.4 BCF/Day	Used to meet LDC peak Demand in excess of forecast interstate pipeline demand	Not Available for solution sets

There is little publicly available information on the number or terms of LNG contracts with electric generators. Because LNG typically serves as a swing resource used to meet peak demand, economic theory suggests that LNG prices will typically be bounded by the opportunity cost of either selling LNG into alternative markets or purchasing the next available landed fuel resource, such as natural gas from pipelines or delivered oil for electricity generation. That is, variable costs for LNG supplies can be expected to be the higher of the price of oil or natural gas during constrained periods and high prices. Equally important, the current practice of using LNG as a swing resource includes additional risk that supplies may not be available or otherwise accessible during peak periods for a reliability deficiency challenge. LNG may be unavailable for physical reasons of force majeure, if for example, shipments can't land at an off-shore terminal due to winter storms, or may be unavailable for supply resources, if for example, world prices are higher in other markets which limit production or total U.S. sales.

To develop a comparable solution set for reliability purposes, we include both fixed and variable charges for a quantity of LNG that is fully reserved and guaranteed for delivery to the electric power sector. Information on potential structures for such contract arrangements was provided to AGI by LNG representatives and the Environmental Defense Fund through the Study Advisory Group process and presented to all Study Advisory Group members. They provided two potential contracts, described below.

[70] The Neptune facility received a five year suspension of its operating license from the U.S. Maritime Administration in summer 2013. See LNG World News, "Neptune Suspends LNG Deepwater Port Operations", July 29, 2013.

The first contracting model, (for the Base-Load LNG Solution) is for a land based terminal where the expected maximum deficiency quantity per hour (MHDQ) is converted to an Annual Contract Quantity (ACQ) for the subject year by multiplying such year's MHDQ by 24 (hours in a day) and then by 90 (days in the December 15 through March 15 deficiency period). This methodology substantially overstates the needed quantity (i.e., the Deficiency Quantity compared with ACQ), but the contributing Study Advisory Group members represented that this simplified approach is consistent with other contracts, which sizes the re-gasification need to the peak hour need, analogous to pipeline scheduling practices.

The second Contracting Model assumes a dedicated Floating Storage and Regasification Unit ship (FSRU) and a term charter arrangement for the same 90 day period. Under this second contracting model, the commensurate ACQ is the greater of the Total Deficiency Quantity (determined by the deficiency model) or 3 Bcf (3,000,000 Dth). The 3 Bcf quantity is the approximate capacity of an FSRU ship. To achieve this latter dedication, the FSRU would be chartered for the full period that it was docked at one of the two off-shore receiving facilities. This service could also be provided using the on shore Distrigas terminal with a similar commercial (i.e., demand charge) arrangement. Both options require a per day chartering fee, comparable to a pipeline demand charge (discussed below).

While not considered here, the relevant Study Advisory Group members indicated that potential hybrid entailing a base-load LNG component (i.e., using a land-based terminal) along with an FSRU component are also commercially and physically feasible: for example, a land-based quantity of LNG for the full 10-year period approximately equal to that in the first year of the Base-Load LNG Solution construct followed by FSRU supply as described above across the same period in the same fashion. Such a hybrid solution could achieve both reliability supply needs and more general price moderation or suppression owing to the addition to the New England market.

In recognition of the global dynamics surrounding the supply and demand of LNG, the variable cost component of fuel supplies for each contract is indexed to the highest of three trading hubs. In this model, proposed structure takes the highest of the: a) Henry Hub plus adders (discussed below); b) the United Kingdom's National Boundary Point (NBP) plus shipping to New England; and, c) 14.5 percent of Brent Crude Oil Index (used as the oil benchmark for LNG). At the current outlook of low oil prices, the "higher-of" price is likely to be set by Henry Hub, and oil prices can serve as a "cap" on future LNG prices. The "adders" for the Henry Hub pricing are: a) a 15% pricing adder for natural gas used to power liquefaction (the recognized sales price adder used at the Cheniere LNG export facility on the Gulf Coast); b) the processing cost; and, c) a shipping cost. Processing costs are based on fixed processing charges for subscribers to Cheniere, which are in the neighborhood of $3.50 to $3.60 per Dth of LNG output.[71] The shipping cost is estimated to be $1.50 per MMBtu bringing the processing cost ($3.50) plus shipping ($1.50) to a total estimated adder of $5.00 per MMBtu.

We base our estimate of an LNG solution set using the FSRU contract model described above. This includes a 90-day term charter arrangement, with a daily demand charge of $200,000, escalated

[71] Cheniere Energy, Inc. SEC Filing 8-K, August 2015, pages 24 -26.

annually with inflation, and variable charges using our forecast of Henry Hub pricing plus the indicated processing cost of $3.50 per Dth, shipping costs of $1.50 per Dth, and delivery charges of $0.16/Dth. All variable costs are assumed to escalate annually with inflation.

Incremental Pipeline Transportation

Solution Set 2 – Incremental Pipeline

Pipeline development costs can vary significantly based on a number of important factors, including whether the project is an expansion or a new development; the location and distance of the chosen route, including right of way easements and other land requirements; the total pipeline diameter, capacity and number of compressor stations used to deliver natural gas; and other factors, such as the financing structure used in the development. Here, we do not forecast a specific pipeline solution, but rather, include a generic estimate of pipeline capacity based on our review of recently completed and proposed pipeline developments, with costs expressed both in terms of development costs (on a $/inch-mile basis) and as total ratepayer costs (on a $/Dth-month maximum reservation charge basis). We index total costs to the two most recent announcements for both the Spectra AIM project[72] and the Kinder Morgan Northeast Energy Direct (NED) project and estimate total ratepayer costs using a maximum reservation charge of $39/Dth-month.[73]

Based on this review, we assume that total capital costs for the 0.3 Bcf/day installation are approximately $787.5 million, with a first year cost of service of $140 million. Costs for the 0.12 Bcf/day installation and the 0.5 Bcf/day installation are assumed to scale linearly by size. In practice, actual costs will depend on the specific project chosen, and costs may not scale linearly between capacities.

Energy Efficiency, Demand Response, and Renewable Energy

Solution Set 3(a) – Energy Efficiency and Demand Response

To develop the energy efficiency and demand response solution set, we draw from the energy efficiency capability estimates presented in the Synapse/DOER (2015) study. They estimate that the total incremental potential for appliance standards and residential, commercial, and industrial energy efficiency

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[72] The Spectra AIM project is a 0.342 Bcf/day expansion in New York, Massachusetts, and Connecticut, with a total estimated capital cost of $876 million, a capital recovery factor of 20 percent and a first year cost of service of $175 million, with a maximum monthly reservation charge of $42.58. See Spectra AIM Project, FERC Section 7(b) and 7(c) Application and Public Exhibits, FERC Docket No. CP14-96, February 2014, Exhibit P Tariff and Rates. We note that Synapse/DOER (2015) used the Spectra AIM costs in its analysis, with a linear adjustment to monthly reservation rates assuming 80 percent utilization over a five month period. In contrast, we do not forecast pipeline utilization and prices ahead of time; instead, ratepayers are responsible for the full cost of service, with the total pipeline utilization determined through the electric sector dispatch and modeling results.

[73] This assumes a 30 year depreciation schedule, a 10.4 percent nominal weighted average cost of capital, and recovery of federal and state income taxes.

at the time of winter peak is 590 MW of capacity. We make a simplifying assumption that the total feasible capability of such resources for the ISO-NE region is equal to 2.2 times that of the Massachusetts capability identified by Synapse, based on the portion of end-user load served in Massachusetts relative to the New England region as a whole, for a total of 1,300 MW of winter peak capacity. In contrast to Synapse, we consider this energy efficiency to be incremental to the current ISO-NE CELT forecast, which includes its own estimate of energy efficiency. Conversely, the Synapse estimate presented above is assumed to be incremental to Synapse's own adjustment of the CELT forecast. Their adjustment, which includes additional contributions from EE, is designed to account for uncertainty in ISO-NE's planning approach that may discount total EE contributions to load.[74] Therefore, our analysis does not include or consider any existing energy efficiency which is not already captured in the ISO-NE forecast.

We developed our cost estimate of incremental energy efficiency using the average of the lifetime cost of all planned programs, including incentives and participant costs, as identified in the 2016-2018 Massachusetts Program Administrator draft Joint Statewide Three-Year Electric and Gas Energy Efficiency Plan.[75] Our use of the total lifetime cost allows for an apples-to-apples comparison with other solution sets that also assign the full cost of each solution set to ratepayers. We use these Massachusetts' costs as an approximation for the average cost of incremental EE in the ISO-NE region. The Northeast Energy Efficiency Partnership (NEEP) reports energy efficiency program costs, excluding participant costs, for each state in its Regional Energy Efficiency Database (REED). The load-weighted average cost for all New England states in 2013 is equal to the Massachusetts program cost, which suggests that Massachusetts is a useful proxy for the region as a whole.

In the EE/DR (SS 3a) solution set, the remaining deficiency is met through the use of demand response, which can be called upon by ISO-NE during peak periods to reduce total load. To meet a peak deficiency in 2029/30, we include the cost for an incremental 1,100 MW of demand response at $31.06/MW-day, based on recent PJM capacity auction results.[76] We estimate that this demand response would be called upon in up to 26 hours during the 2029/30 winter.[77]

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74 ISO-NE assumes an annual increase in program costs of 5 percent, with an additional 2.5 percent inflation, and applies a 10 percent uncertainty adjustment or de-rate to estimated savings reductions in MA, RI, and ME. See Peterson, P. and Fields, S. "Challenges for Electric System Planning: Reasonable Alternatives to ISO-NE's Discounts for Uncertainty." Prepared for E4 Group, July 24, 2015.

75 This corresponds to the total resource cost in the Program Administrator filings, and it is used by program administrators to determine the cost effectiveness of individual efficiency programs. See Massachusetts Energy Efficiency Guidelines, §3.4, Department of Public Utilities Order 08-50-B, October 26, 2009.

76 We rely on PJM bid data because similar information is not readily available for ISO-NE. See Monitoring Analytics, Independent Market Monitor for PJM, "Analysis of the 2017/2018 RPM Base Residual Auction." October 6, 2014, Table 18.

77 Our use of 1,100 MW of DR is not a forecast of the total incremental DR that may be available over the full modeling period. For example, in the 2016-2018 draft resource plan, National Grid indicated a soft commitment to procuring up to 3,637 MW of commercial/industrial demand response over the three year period at a total program administrator cost of $23 million (Massachusetts Joint Statewide Three-Year Electric and Gas Energy

Solution Set 3(b) – Energy Efficiency and Firm Imports (Existing Transmission)

In addition to the EE/DR (SS 3a) solution set outlined above, we also consider a blended solution comprised of both energy efficiency and new incremental imports from hydropower and other new Class 1 renewables which could be used in support of regional climate goals EE/Firm Imports (SS 3b/SS 3c). The imports component of these solution sets is about half of that of amount proposed for procurement under Massachusetts Senate Bill 1965, submitted by Governor Baker in July 2015. Under this bill, utilities could procure up to 18,900,000 MWh of clean energy annually, or approximately 2,400 MW of capacity. If the bill is enacted as proposed, initial solicitations would occur no later than April 1, 2016.

To date, there exists little evidence for the potential cost of a long-term energy contract backed by significant quantities of hydropower or wind energy.[78] The purpose of the current solution set is not to model the potential costs or benefits of SB 1965, but rather, to estimate the potential costs and benefits of using imports to meet a peak winter deficiency need, as defined through our deficiency analysis. To meet this criterion, any imports must be available at the time of winter peak on a firm or guaranteed basis. Our solution set costs reflect that perspective.

The most likely source of firm winter imports will be provided by new hydropower supplied from Hydro Quebec. As a government owned public utility, Hydro Quebec is obligated to earn a return on any investments not used to serve its own customers. Accordingly, it sells power into external markets (IESO, ISO-NE, NYISO, PJM) whenever it is economic to do so, or when the cost of energy is higher abroad than the price it could receive in its own service territory. Going forward, Hydro Quebec will be expected to continue to provide energy when it is economic to do so based on market fundamentals. Because Hydro Quebec is itself a winter peaking system (meaning that it requires the majority of its capacity to meet its own demand), the opportunity cost of selling power during those winter months is higher than during a summer peak. The current analysis does not consider new resources from either New York or other Canadian provinces, although both could be used to provide new incremental import capacity.

As a conservative assumption, we estimate that the contract cost for a firm, long-term commitment of imports at the time of winter peak is equal to the capital cost of a new hydropower facility. This perspective suggests that either a) Hydro Quebec would need to build new hydro resources to back this firm commitment, or b) the opportunity cost of selling that power into the ISO-NE market would at least be equal to the cost it could receive at home. In developing our estimate, we rely on the levelized cost of electricity (LCOE) for new hydroelectric resources as reported by the EIA (2015). This estimate is exclusive of transmission costs and fixed or variable operations and maintenance expenses. Based on the assumed EIA capacity factor (54 percent), cost of capital (6.1 percent real after-tax weighted average cost of capital) and a 30 year asset life, we estimate that the total cost of an additional 1,100 MW of firm capacity would be $4.3 billion with an annualized cost of $387 million per year. A 2,400 MW firm commitment of capacity would cost $9.4 billion, or $843 million per year. Our use of domestic

Efficiency Plan, 2016-2018, filed April 30, 2015, page 444). Instead, our inclusion of 1,100 MW represents our judgment for the mix of resources that offers the lowest cost distributed resource solution set.

[78] In 2011, Vermont public utilities signed a long-term contract for up to 225 MW of peak electric energy supply from Hydro Quebec at a price of $58/MWh plus the cost of transmission.

hydroelectric costs represents a conservative estimate of potential costs developed in Hydro Quebec. For example, in its 2013 Annual Report, Hydro Quebec reported total capital costs of $6.5 billion for four generating stations at the 1,550 MW Romaine River facility now under construction, without consideration of the cost of the transmission links required to connect these stations to the Hydro Quebec system. We assume that any new facility is able to provide power throughout the year, consistent with the firm contract, and produce energy at a rate greater than the assumed EIA capacity factor.

We develop two EE/Firm Imports solution sets recognizing that the region has the potential to procure some firm capacity over existing transmission lines. For 2018, approximately 1,500 MW of import capacity cleared in the forward capacity auction and has a capacity supply obligation for 1,017 MW during the winter peak period.[79] Since we do not consider these existing imports in the deficiency analysis (because without a long-term commitment they are not obligated to provide power in any winter over the study period), in the EE/Firm Imports (Existing Transmission) (SS 3b) solution set, we include the potential for existing imports, priced at a long-term firm commitment. In actuality, these resources will likely continue to provide capacity and energy to the New England markets, on a year by year basis depending on economic conditions in other regions. If these resources bid into and clear the FCA, then the true incremental cost to consumers of this resource in any given year may be zero.

Solution Set 3(c) – Energy Efficiency and Firm Imports (New Transmission)

Finally, we model a second EE/Firm Imports (New Transmission) (SS 3c) solution set that includes both the cost of new firm energy and the incremental cost for new transmission to deliver that energy. We assume a total cost for new transmission capacity of $1.4 billion,[80] with a first year cost of service charge of $250 million. This cost is representative of a new 1,100 MW transmission line.

When considering the larger transmission infrastructure scenario, we assume that firm contracts totaling 2,400 MW make use of both existing and new firm transmission capacity. To the extent that a 2,400 MW of firm imports would require two transmission lines over the same distance, our estimate potentially underestimates this cost.

[79] In addition, the HQ-NE Phase II line has an energy import capability of 2,000 MW and a capacity import limit of 1,400 MW. See ISO-NE Regional System Plan, 2015, Table 4-9.

[80] In nominal dollars, this is approximately $1.6 billion for a 2020 in-service date.

Example LNG Term Sheet
(provided by Study Advisory Group members)

FSRU LNG Peak Supply Commercial Format – High Level Term Sheet
Prepared by Skipping Stone (9/30/15)
Purpose:

Core contract terms for ensuring a reliable supply of LNG during peak hours of winter at quantities sufficient to eliminate all projected/modeled hours of deficiency.

Term:

A rolling five years with the sixth year pricing and quantity to be agreed upon before the end of a set Contract Year.

> [To give provide supply certainty to Buyer and demand certainty for Seller, parties would delineate a Contract Year to negotiate and seek agreement on pricing and quantity of service for purchases and sales in the year(s) following the end of the then current 5 year term. Example: Assume initial contract year 1 is the winter of 2016/17 and initial contract year 5 is the winter of 2020/21. By a date certain (prior to the commencement of initial Year 2 (i.e., the winter of 2017/18) the parties agree on pricing and quantity for the 2021/22 contract year. In this way, should the parties be unable to agree on such terms, both parties have 5 years to make other plans and arrangements. Such a structure neither locks both parties into longer than a five year contract at any one time (absent mutual agreement to the contrary) nor (more importantly) forecloses the parties from pursuing other future supply arrangements for more than five years into the future.]

Annual Contract Period:

The Annual Contract Period is from December through March of the succeeding year (absent mutual agreement to the contrary).

Annual Contract Quantity (ACQ):

Parties agree to a minimum quantity of LNG for each subject Annual Contract Period. This is a take-or-pay quantity.

Monthly Contract Quantity (MCQ):

The parties agree that the Annual Contract Quantity is allocated as a percentage across each of the months of December through March of the Annual Contract Period; each an MCQ. Each MCQ is a take-or-pay quantity.

> [Example: 16.66% of the ACQ could be the December MCQ, 33.33% of the ACQ could be the January MCQ; 33.33% of the ACQ could be the February MCQ and 16.67% of the ACQ could be the March MCQ, or such other mutually agreeable, individual, MCQ Amounts such that the total of the individual MCQ's equals 100% of the ACQ.]

Vaporization Schedule:

Parties agree to minimum (if any) and maximum daily vaporization quantities (MinDVQ and MaxDVQ) such that each MCQ is vaporized. In addition, the parties agree on a maximum hourly quantity (MHQ) and hours of MHQ in any given day (subject to MaxDVQ and MCQ limits).

> [Example: The MinDVQ (if any) and the MaxDVQ can be stated as percentages of MCQ. Likewise the MHQ can be set as a percentage of the MaxDVQ.]

Pricing:

For the Initial Five Year Annual Contract Periods the pricing shall the agreed upon at contract signing and shall be based upon the formulae on Exhibit A – Pricing attached hereto and made a part of the Agreement.

Allocation of Price:

The Price per MMBtu for each MCQ of each Annual Contract Period shall be allocated between a Fixed Amount and a Variable Amount by Buyer provided the sum of Fixed Amounts and Variable Amounts equals the ACQ times the Price for each ACQ as set forth in Exhibit A – Pricing. Such Fixed and Variable Amount per MMBtu shall be set by Buyer no later than 3 hours before the close of the NYMEX futures contract for the prompt month.

> [Example: Fixed and variable amounts are set no later than 12:00 noon on the last day of trading for the prompt month futures contract in order that the variable component of the Buyers MCQ is price responsive for Buyer's dispatch purposes.]

Other Terms and Conditions (as appropriate)

3. Electric System Model Overview: PROMOD

The PROMOD Model

PROMOD is an electric market simulation model marketed by Ventyx. PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load. This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load, and thus calculates Locational Marginal Prices ("LMPs") at individual nodes within the system. PROMOD and similar dispatch modeling programs are used to forecast electricity prices, understand transmission flows and constraints, and predict generation output. Ventyx simulation-ready data includes data on Eastern Interconnection network structure, resources, fuel prices, basis differentials, and demand.

We use PROMOD to model the impacts of each solution set on the dispatch of power system operations and outcomes, with the difference between each simulation and our market outlook scenario being the direct incremental impacts of a given solution set on the power system. These two simulation runs otherwise maintain the same inputs, in terms of power plants available to be dispatched, power plant operational characteristics, NO_x and SO_2 allowance costs, baseline load levels, and so forth. The market outlook Dual-fuel (SS 1a) case is benchmarked to actual power system operations in the historical months of the 2012-2014 time period (in New England, New York, PJM). With this as a starting point, several core assumptions (e.g., load levels that change as a result of energy efficiency investments, timing of generic capacity additions, natural gas prices that depend on each solution set) were changed, and the model re-run to simulate the solution set case. As described above, the simulation period covers the ten year period between 2020 to 2030. PROMOD outputs include changes in power plant operations, emissions, prices, customer payments, and producer revenues.

Fuel Prices in the Power Sector

As a starting point, we develop our base case outlook for natural gas prices using futures prices at the Algonquin Hub. These future prices reflect the current outlook for constrained winter months with high basis differentials relative to the Henry Hub price. Second, we assume that all distillate oil, residual oil, and coal prices are based on Ventyx fuel price forecasts.

We assume that these monthly prices represent the average expectation of fuel prices within each month, while recognizing that delivered natural gas fuel prices will be both higher and lower on individual days. These average prices also reflect the ability of dual-fuel capable units to switch from natural gas and burn fuel oil, when it is economic to do so. For example, in the 2013/14 winter, gas prices exceeded oil prices on 57 percent of winter days, with oil units dispatched in economic merit order.[81] At the same time, oil units may also be dispatched out-of-merit if needed to meet electric reliability.

Therefore, we estimate the total quantity of oil-fired and dual-fuel fired generation that would have been dispatched, based on the estimated total natural gas availability, as defined in the deficiency

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[81] Brandien, P. "Cold Weather Operations." ISO New England. Presentation to Federal Energy Regulatory Commission, April 1, 2014, page 14.

statement. This is a necessary step in order to capture the impact of daily variation in fuel prices and the potential for increased costs of oil-fired generation that may be dispatched out of merit for reliability purposes. We do this in three steps. First, we compare the total natural gas fired generation and total natural gas consumption, as dispatched by PROMOD based on the average monthly fuel prices, to the total quantity of available natural gas. Then, using the supply curve for each hour, we estimate the marginal generating unit based on the total cumulative natural gas consumption at the limit of available supplies. All incremental generation (the difference between dispatched natural gas generation and available natural gas generation) is assumed to be met in a cumulative fashion by the most efficient dual-fuel and oil-fired generators remaining in the supply curve. This estimates the total oil-fired generation and the total oil consumption on an hourly and daily basis. Finally, as a third step, we estimate the total "uplift" cost to dispatch this oil-fired generation, as the difference between the monthly natural gas price and the monthly oil price. This cost is added to the total cost to load from the production cost dispatch.

Power Plants: Existing Units, Unit Retirements and Additions

The set of power plants is based on actual plants operating within eastern PJM, NYISO, ISO-NE, Ontario, and MISO. We made changes to this dataset (to reflect unit retirements and power plant additions (e.g., to meet the states' RPS). Unit retirement decisions are based on assumed retirements in the PROMOD generator dataset, which rely on information from Ventyx as of September 2014. Some of these retirements have been adjusted as the result of a review of planning documents published by PJM, NYISO, and ISO-NE, along with press releases. Unit additions listed in PROMOD's generator dataset beyond FCA #9 have not been adjusted. Random generator outages for existing and new units were calculated once using PROMOD's algorithm, and fixed for each case. Similarly, scheduled generator maintenance is held constant between solution set modeling runs. Table A3 and A4 below provide generator retirements and additions reflecting these changes.

Table A3: Unit Retirements

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date	Retirement Date
Berlin GT 1	ISNE - Vermont	Oil	46	6/1/1972	6/1/2022
Brayton Point 1	ISNE - Rhode Island	Coal	247	8/1/1963	6/1/2017
Brayton Point 2	ISNE - Rhode Island	Coal	249	7/1/1964	6/1/2017
Brayton Point 3	ISNE - Rhode Island	Coal	638	8/1/1958	6/1/2017
Brayton Point 4	ISNE - Rhode Island	Oil	446	12/1/1974	6/1/2017
Cleary 8	ISNE - Massachusetts - Southeast	Oil	26	6/1/1966	6/1/2026
M Street Jet 1	ISNE - Boston	Oil	68	5/1/1979	6/1/2029
Middletown 3	ISNE - Connecticut - Central-Northeast	Dual Fuel	245	1/1/1964	6/1/2024
Montville 5	ISNE - Connecticut - Central-Northeast	Oil	42	1/1/1954	6/1/2020
Pilgrim	ISNE - Massachusetts - Southeast	Nuclear	680	12/1/1972	6/1/2019
Schiller 4	ISNE - New Hampshire	Coal	48	10/1/1952	6/1/2020
Schiller 6	ISNE - New Hampshire	Coal	49	7/1/1957	6/1/2020
South Meadow 11	ISNE - Connecticut - Central-Northeast	Oil	47	8/1/1970	6/1/2020
South Meadow 12	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 13	ISNE - Connecticut - Central-Northeast	Oil	48	8/1/1970	6/1/2020
South Meadow 14	ISNE - Connecticut - Central-Northeast	Oil	46	8/1/1970	6/1/2020
Vermont Yankee 1	ISNE - Vermont	Nuclear	619	11/1/1972	1/1/2015
West Medway 1	ISNE - Boston	Oil	55	7/1/1970	6/1/2020
West Medway 2	ISNE - Boston	Oil	53	3/1/1971	6/1/2021
West Medway 3	ISNE - Rhode Island	Oil	56	7/1/1970	6/1/2020

Sources:
Ventyx power plants database. ISO-NE non-price retirement requests and determinations.

Table A4: Unit Additions

Unit Name	Area	Fuel Type	Capacity (MW)	In-service Date
Bridgeport Harbor 6	ISNE - Connecticut	Natural Gas	475	6/1/2018
Medway Peaker - NEMA	ISNE - Massachusetts	Natural Gas	200	6/1/2018
Medway Peaker - SEMARI	ISNE - Massachusetts	Natural Gas	200	4/1/2018
Salem Harbor CC1	ISNE - Massachusetts	Natural Gas	692	6/30/2017
Towantic	ISNE - Connecticut	Natural Gas	785	12/1/2018
Wallingford 6/7	ISNE - Connecticut	Natural Gas	90	6/1/2018

Sources:
ISO-NE Forward Capacity Auction Results.

Renewables

RPS MWh targets by state are sourced from Lawrence Berkeley National Labs for PJM and NYISO and from the updated ISO-NE RPS Workbook for ISO-NE. Beginning in 2016, we assume that the region meets 100 percent of its incremental renewable target through in-region wind capacity. We add wind resources assuming a 25 percent capacity factor, based on historical generation identified in the SNL power plant database. Over the full modeling period, this adds approximately 4,000 MW of additional wind capacity. Within the resource adequacy model, we de-rate this capacity to 5 percent of nameplate, consistent with ISO-NE planning standards.

Generic Capacity Additions to Meet Resource Adequacy

After the incremental addition of renewable capacity and retirement of units as discussed above, we analyzed the extent to which each region's capacity satisfied forecasted resource adequacy requirements in each year, based on each region's capacity planning process. In ISO-NE, we assume a long-term reserve margin of 14.3 percent and add new generation in the first year of need in sufficient capacity to meet several years of need. We add new generic natural gas/dual-fuel capable combined cycle and gas turbine plants in each region as necessary to maintain resource adequacy. . The operating characteristics of these new plants are assumed to be the same as recently built natural gas generating units. The units were placed on the high-voltage transmission network in each region to maximize deliverability.

Emissions costs

We developed our base case CO_2 price forecast using the most recent RGGI auction results of $6.02/ton, and assume that prices increase by 2.5 percent in real terms each year, proportional to the decline in the RGGI allowance cap. NO_x and SO_2 allowance prices are based on Ventyx price forecasts.

Load Forecasts

Regional Transmission Operator (RTO) level load forecasts are provided by Ventyx, and based on RTO planning documents. ISO-NE data is based on EE-adjusted load from the 2015 CELT Report. PROMOD hourly load shapes were reviewed and calibrated to ensure consistency with seasonal peak demands identified by ISO-NE. NYISO data is based on EE- and PV- adjusted load from the 2014 Gold Book. PJM data is based on EE-unadjusted load from the 2014 PJM Load Forecast Report.

For the energy efficiency solution sets, total energy savings from each program type were divided among summer and winter on-peak and off-peak hours. This distribution of total savings was based on historical data from the final 2013-2015 Massachusetts Program Administrators report. From these load groupings, hourly state savings for each year were determined and modeled in each zone. Total state load savings were proportionally assigned to constituent service areas based on native load in each area.

4. Greenhouse Gases and Regional Climate Goals

Greenhouse gas emissions levels across all sectors for 1990 are based on state-reported historical emissions estimates. "Current" GHG emissions levels are based on state-reported historical emissions estimates, where available, and on business as usual projections otherwise. These "current" emissions levels reflect 2011 emissions levels, the most recent year of estimates available across the largest number of states, and emissions levels for adjacent years otherwise. Specifically, 2010 emissions levels are used for Rhode Island and 2012 business as usual estimates are used for New Hampshire.

Sector-specific emissions levels are based on explicitly labeled emissions categories, except for building emissions, which when not explicitly labeled are calculated as the difference between total emissions and the sum of non-energy, transportation, and electric-sector emissions.

Greenhouse gas emissions targets reflect state-reported emissions goals, illustrated in Table A5. We converted those goals, which are typically reported as a percentage reduction in emissions from baseline levels, to million metric tons of CO_2-equivalent ($MMTCO_2e$) limits using baseline emissions levels and given percentage reductions. Emissions goals are not available for each New England state in every year of interest, so emissions targets used in this report are based on actual values in available years and linearly interpolated values otherwise.

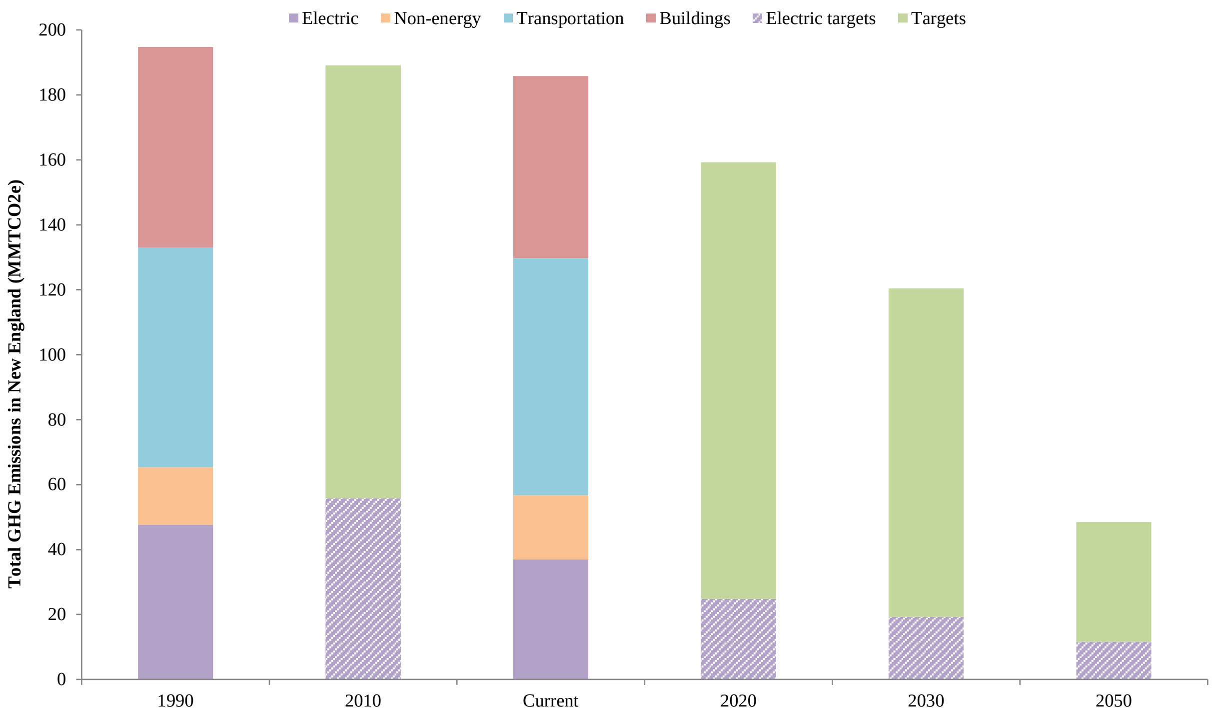
Table A5: Summary of State GHG Goals

State	Title of GHG Emissions Reduction	Type of GHG Emissions Reduction	Date of Adoption	GHG Emissions Milestone
Connecticut	Public Act No. 08-98	Action Plan followed by Legislation	Action Plan: 02/15/2005 Legislation: 10/01/2008	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels 2050: 80% Below 2001 Levels
Maine	PL 237	Legislation (Includes Request for an Action Plan)	Legislation: 09/13/2003 Action Plan: 12/01/2004	2010: Reduce to 1990 Levels 2020: 10% Below 1990 Levels
Massachusetts	Global Warming Solutions Act	Climate Protection Plan followed by Legislation	Protection Plan: 05/01/2004 Legislation: 08/01/2008	2020: 25% Below 1990 Levels 2050: 80% Below 1990 Levels
New Hampshire	New Hampshire Climate Action Plan	Action Plan	03/01/2009	2025: 20% Below 1990 Levels 2050: 80% Below 1990 Levels
Rhode Island	RI Executive Climate Change Coordinating Council	Legislation (Includes Request for an Action Plan)	05/01/14	2020: 10% Below 1990 Levels 2035: 45% Below 1990 Levels 2050: 80% Below 1990 Levels
Vermont	Executive Order #07-05	Legislation (Includes Request for an Action Plan)	Legislation: 12/05/2005 Action Plan: 10/26/2007	2012: 25% Below 1990 Levels 2028: 50% Below 1990 Levels 2050: 75% Below 1990 Levels

Source: Individual State Planning Documents

As part of our review, we compared estimated electric sector reductions to an assumed continuation of the RGGI CO_2 emissions caps and the mass based standard for new and existing generation under the Federal EPA Clean Power Plan. We found that assumed RGGI limits are consistent with assumed 2030 electric sector targets imputed from state-level greenhouse gas emissions targets and state-reported GHG action plans and also allow for a trajectory of emissions out to 2050 consistent with full state climate goals . Figure A2 illustrates the total greenhouse gas emissions and targets in New England, with the electric sector represented by the potential RGGI allowance targets.

Figure A2: Total Greenhouse Gas Emissions and Potential Targets, New England



Notes:
1. Emissions goals based on actual values in available years and linearly interpolated values otherwise.
2. Current levels of greenhouse gas emissions are based on 2011 where available and adjacent years where 2011 is unavailable.
3. Buidling emissions, when not explicitly specified on the state level, are calculated as the difference between total emissions and the sum of non-energy, transportation and electric emissions.

Sources used in Appendix 4:

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2. "Connecticut Greenhouse Gas Emissions Inventory 2012: Executive Summary," Connecticut Department of Energy and Environmental Protection, available at http://www.ct.gov/deep/lib/deep/climatechange/2012_ghg_inventory_2015/2012_ct_ghg_inventory_final.pdf retrieved on August 27, 2015.

3. "A Climate Action Plan for Maine," Department of Environmental Protection, December 1, 2004, available at http://www.eesi.org/files/MaineClimateActionPlan2004Volume%201.pdf, retrieved on August 19, 2015.

4. "Fifth Biennial Report on Progress Toward Greenhouse Gas Reduction Goals," Maine Department of Environmental Protection, January 2014, available at http://www.maine.gov/tools/whatsnew/attach.php?id=611577&an=1, retrieved on August 19, 2015.

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11. "Vermont Greenhouse Gas Emissions Inventory Update 1990 - 2012," Vermont Department of Environmental Conservation, June 2015, available at http://www.anr.state.vt.us/anr/climatechange/Pubs/Vermont%20GHG%20Emissions%20Inventory%20Update%201990-2012_June%20-2015.pdf, retrieved on August 14, 2015.

12. "First Control Period CO2 Allowance Allocation ", RGGI, Inc., July 2015, available at http://www.rggi.org/design/overview/allowance-allocation/2009-2011-allocation, retrieved on September 4, 2015.

13. "Summary Level Emissions Report," RGGI, Inc., August 31, 2015, available at https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true, retrieved on September 3, 2015.

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