High Renewable Electricity Assessment of Gas-Electric Interface

prepared for

U.S. Department of Energy

Subcontract No. 7262876

The Regents of the University of California

Lawrence Berkeley National Laboratory

FINAL

December 8, 2016

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ACKNOWLEDGEMENT

This material is based upon work supported by the Department of Energy and the Lawrence Berkeley National Laboratory under Contract No. 7262876. Information presented in this report has been facilitated by the National Renewable Energy Laboratory (NREL) and is mainly based on the analytic approach formulated for LAI's gas-electric system interface study for the Eastern Interconnection Planning Collaborative. Within the Department of Energy (DOE) substantial input was provided by Sandra Jenkins, Carly Page, Kelly Lefler, Andrew Stocking, David Rosner, John Powell, and Aaron Bergman.

KEY FINDINGS

The natural gas system can deliver sufficient natural gas to balance a potential future electric grid with high penetrations of variable renewables. At increasing penetrations of variable renewable generation, natural gas demand swings are likely to grow in order to support variable renewable generators. The natural gas system can serve the potential electric sector demand for natural gas under a range of variable renewable energy deployment scenarios.

Demand for natural gas from increased gas-fired generation may make natural gas infrastructure expansions economic at some locations. No power outages are anticipated in any case considered by this analysis in part because electric system operators have a multitude of options available to mitigate potential shortfalls in gas supply and economic considerations are likely to reduce gas consumptions in times of high demand and potentially increase delivery capacity.

- **Imports to Liquefied Natural Gas (LNG) regasification facilities, which were assumed to be minimal in the U.S. Energy Information Administration's 2015 Annual Energy Outlook (AEO), may be an economic source of gas supply in New England.** New England has historically relied on LNG to support a significant amount of its natural gas consumption and has existing infrastructure to support LNG imports. Depending on market dynamics, utilizing existing LNG infrastructure could be an economic source of gas supply to address constraints.
- **There are not gas system constraints in the Marcellus-Utica region even with large renewables buildout.** The gas system in this region is highly interconnected and is able to serve electric sector demand in all baseline and VE shortfall cases, with no potentially-constrained generation.

In all of the scenarios considered by this analysis, gas-fired generation is increasingly utilized to support variable renewables. At the same time, total gas demand declines as renewable penetrations increase.

- **However, as variable renewable generation grows, usage patterns of natural gas change, becoming concentrated in intraday bursts**. At higher levels of potential future renewable penetration, the natural gas system can accommodate the swings in gas demand to support variable generation as overall gas consumption declines, freeing up delivery capacity. Even in a scenario where the deployment of electricity storage is reduced, gas system constraints are limited.

In New England, potential future intraday gas system constraints resulting from short notice balancing of variable renewable generation are small. In the limited circumstances where constraints were observed, these constraints are primarily the result of lateral pipelines which were not designed to accommodate large flows to run a gas-fired generator flat out at the highest output. For context, the New England region regularly sees gas system constraints today, and in the 2015 benchmark scenario, 73.1% percent of gas-fired power generation is constrained on the winter peak day.

EXECUTIVE SUMMARY

The study is designed to stress test the gas infrastructure in the U.S. portion of the Eastern Interconnection (EI) to examine the effects of introducing large amounts of variable renewable generation on the natural gas pipeline network. This study is not meant as a forecast, but rather as a tool to understand the interaction between natural gas, electricity, and variable renewable generation. We assessed the availability of natural gas for electric generation across three scenarios (High, Mid, and Low renewable energy penetration) in 2050 compared to gas deliverability in 2015. Our measure of comparison was *the difference between the level of natural gas demand in 2050 on a system unconstrained by transportation constraints versus the amount that can be delivered on today's natural gas transportation system with additions only to serve non-electricity related gas demand*. We call this difference "potentially-constrained generation." It is called "potentially-constrained" because this study does **not** take into account a number of factors that could alleviate these constraints including:

- **Natural gas price feedback impacts on demand,** Delivery constraints that lead to higher regional natural gas prices, which, in turn, will reduce natural gas demand in that region. This feedback is not represented in the modelling.
- **Electric market reforms that incentivize more gas delivery.** Electricity markets in some regions have modified capacity markets to incentivize deliverability of natural gas.
- **Additional natural gas pipeline expansions.** It is likely that there will be further natural gas infrastructure buildout by 2050 in addition to the limited expansions assumed in this study to meet LDC demand.
- **Alternative mitigation options that reduce gas-fired power plant demand for natural gas**. Electricity system operators and generators have many options to mitigate any issues associated with a gas deliverability constraint including re-dispatch, fuel switching and demand response.

As such, it is important to emphasize that, while a lack of potentially-constrained generation is a good indication that problems are unlikely in that scenario, the existence of potentially-constrained generation represents a need for further study as opposed to an indication of any reliability issue.

The primary goals of this study are threefold:

- Explore scenarios with high levels of renewable energy (RE) penetration in 2050 to identify potential gas infrastructure deliverability constraints across the EI. The renewable energy inputs are based on modeling conducted by the National Renewable Energy Laboratory (NREL).
- Identify potential impacts that may arise during periods of low wind and solar generation where the gas system must provide fuel to ramping gas-fired generators on short notice.

- Identify topics that would benefit from further study.

Approach: Three hypothetical renewable energy scenarios were analyzed: High RE (64%), Mid RE (43%), and Low RE (22%), as described in the Summary of Modeling Scenarios and Sensitivities (Table ES-1). Each scenario is based on an NREL study scenario,[1] in the year 2050. In order to "stress test" the capability of the natural gas system, LAI also constructed two sensitivities that replaced portions of the expanded capacities of electric storage resources (compressed air, pumped hydro, and battery) with additional gas combustion turbine capacity and thus additional gas demand. A more detailed hydraulic analysis[2] (see Section 1.5 for the approach) of the New England and the Mid-Atlantic regions was conducted to confirm initial modeling conclusions at the regional level and to test VE shortfalls requiring fast ramp ups of gas-fired generation, in both a constrained and an unconstrained region from the initial modeling, shown in Figure 71 (New England) and Figure 111 (Marcellus-Utica), respectively. This study also quantifies the amount of various mitigation measures that would be needed to eliminate the simulated 2050 constraints on fueling gas-capable generators.

Key Assumptions: The study assumptions are designed to stress test the gas infrastructure to examine the effects of introducing large amounts of renewable variable generation. This study assesses the ability of the natural gas transportation infrastructure in the EI to supply fuel to gas-fired electric generators given:

1) **No investment from the electric sector in natural gas transportation expansion.** All power demand is assumed to be served by interruptible transportation, which means that all gas utility demand (here defined as residential, industrial and commercial demand for gas) is met before power generation. In reality, some generators procure firm transportation which grants them higher priority access to gas transmission and generators can bid higher prices for pipeline capacity releases, both of which could relieve some of the constraints revealed in the modelling in real world scenarios.
2) **LNG imports are assumed to be zero across the EI except for fuel to supply one generator in New England for most scenarios** (Consistent with *AEO 2015*). In the LNG sensitivity, LNG imports into New England are assumed to remain at their average level in 2015.

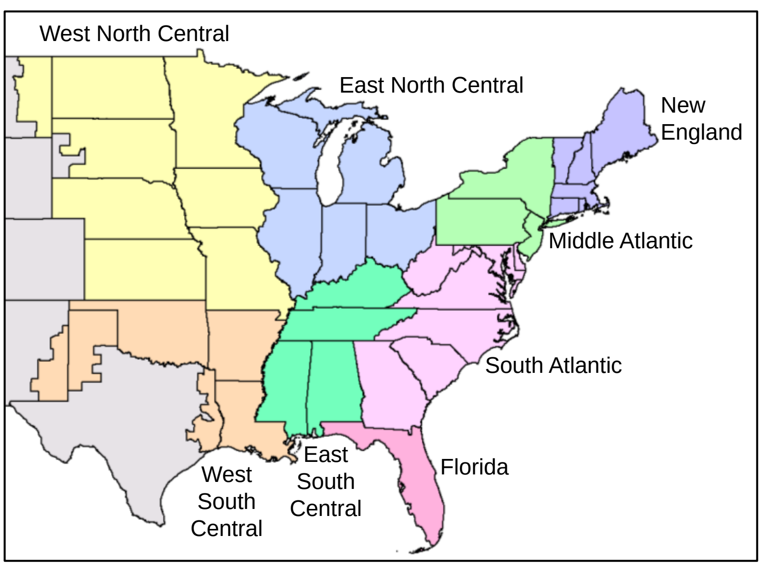
[1] The High RE scenario is based on the 80% National RPS scenario in NREL's July 2015 study, *2015 Standard Scenarios Annual Report*. The Mid RE scenario is built on the Base scenario in NREL's February 2016 *Impacts of Federal Tax Credit Extensions* study. The Low RE scenario is based on the Low Gas Price scenario in the same 2016 study. The RE capacity and energy production shares of the Mid RE scenario are about half way between those of the Low RE and High RE scenarios.
[2] The hydraulic modeling was performed in order to reveal how pipeline line-pack can be managed to support activation of quick-start gas turbine and combined cycle plants, and the ramp-up of already committed CC plants to supplant lost variable energy generation. The hydraulic detail was produced using the WinFlow-based pipeline simulation model of the interconnected pipelines and storage infrastructure across the U.S. portion of the Eastern Interconnection that was modeled in the EIPC study. Technical input parameters to the steady-state model include pipeline diameter, segment length, compressor horsepower, discharge temperature, velocity, maximum allowable operating pressure, and elevation.

3) **Sufficient supplies of natural gas** are assumed to be available to the gas system so that gas supply is not a limiting factor; instead the focus of the report is on pipeline constraints.

4) **Nuclear power units retire after 60 years of service**, Coal-fired units under 100 MW retire after 65 years, and larger coal-fired units after 75 years, or earlier if they begin to have very low capacity factors. Natural gas-fired plants retire after 30 years and renewable energy technologies are replaced in-kind at the end of their lives.[3] These retirement assumptions used by NREL underlie the capacity projections of this study, and differ from those used in modeling done for the Quadrennial Energy Review. For example, the QER assumes nuclear units retire after 80 years and has different assumptions for coal unit retirements.

5) **Renewable technologies considered as part of the scenarios** include co-fired (15%) biomass in coal plants, dedicated (100%) biomass steam plants, geothermal, hydropower, landfill gas, distributed photovoltaic (PV), utility-scale PV, concentrating solar power (CSP) with thermal storage, onshore wind, and fixed-bottom offshore wind. Storage technologies include pumped hydro energy storage (PHES), compressed air energy storage (CAES), and batteries. The (wind plus solar resource) variable energy (VE) portions of these scenarios are 56%, 38%, and 17% of total energy generation in the EI.

6) **The analysis assumes that peak gas utility sector gas demand and peak power generation sector gas demand days are coincident** in order to stress test the system. Gas sector and electric sector gas demand are not often coincident historically. All census regions are assumed to have gas local distribution company (LDC) demand growth between 2015 and 2050, consistent with EIA's AEO 2015. Industrial and commercial gas demand is artificially merged into residential demand served by LDCs in order to show all non-power sector demand as being delivered to LDC city gates.



The reporting regions correspond to the standard U.S. census regions, with three exceptions: (1) Florida is broken out from the rest of South Atlantic to allow closer review of constraints, (2) a portion of Montana is added to and a portion of South Dakota is removed from West North Central in order to align with EI boundaries, and (3) a portion of New Mexico is added to and most of Texas is removed from West South Central, again to align with EI boundaries.

[3] These operating life assumptions are those used in the underlying NREL scenarios.

Table ES-1. Summary of Modeling Scenarios and Sensitivities

2015	Baseline for results which include gas and electric assumptions (such as all interruptible contracts, etc.) to normalize results. Modeled with AURORAxmp and GPCM.	70 GW RE capacity 35 GW of RE that is Variable 276 GW Gas CT and CC capacity $2.69*/MMBtu Henry Hub gas
High RE	Based mainly on National 80% RPS scenario of July 2015 NREL 2015 Standard Scenarios Annual Report. This scenario results in 64% RE in the study region. Modeled with AURORAxmp and GPCM.	836 GW RE capacity 764 GW of RE that is Variable 427 GW Gas CT and CC capacity $11.28*/MMBtu Henry Hub gas
Mid RE	Central scenario of Feb. 2016 NREL Impacts of Federal Tax Credit Extensions study. This scenario results in 43% RE in the study region. Modeled with AURORAxmp and GPCM.	609 GW RE capacity 565 GW of RE that is Variable 540 GW Gas CT and CC capacity $11.28*/MMBtu Henry Hub gas
Low RE	Low Gas Price (LGP) scenario of the 2016 NREL study. Modeled with AURORAxmp and GPCM. This scenario results in 22% RE in the study region.	291 GW RE capacity 248 GW of RE that is Variable 611 GW Gas CT and CC capacity $5.45*/MMBtu Henry Hub gas
High RE SG (sensitivity)	Replaces about one-half of the incremental compressed air energy storage (CAES) and battery capacity and 30% of the incremental pumped hydro energy storage (PHES) capacity of the High RE scenario with an equal amount of additional simple-cycle combustion turbine (CT) capacity Modeled with AURORAxmp and GPCM.	836 GW RE capacity 764 GW of RE that is Variable 458 GW Gas CT and CC capacity $11.28*/MMBtu Henry Hub gas
Mid RE SG (sensitivity)	Same assumptions as High RE, with all incremental CAES capacity and PHES capacity replaced with simple-cycle CT capacity in the same locations. Modeled with AURORAxmp and GPCM.	609 GW RE capacity 565 GW of RE that is Variable 541 GW Gas CT and CC capacity $11.28*/MMBtu Henry Hub gas
Scenario + LNG (sensitivity)	Assumes 2015 LNG regasification levels at Canaport, Elba Island, Everett and Northeast Gateway for each of the 2050 scenarios to determine whether higher (than zero) LNG import levels could alleviate pipeline constraints. LNG sendout to pipelines is assumed to be zero in the main scenarios with imports limited to serving the one generator directly connected to the Everett terminal. Modeled with AURORAxmp and GPCM.	Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM
Hydraulic Analysis Constrained	Baseline and VE shortfall analysis for New England for the following scenarios: High RE SG, High RE SG LNG Sensitivity, and Mid RE, and the Mid RE LNG Sensitivity. Modeled with WinFlow and WinTran.	Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM
Hydraulic Analysis Unconstrained	Baseline and VE shortfall analysis for PJM in Marcellus-Utica West for the following scenarios: High RE SG and Mid RE. Modeled with WinFlow and WinTran.	Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM

^Nuclear retires at 60 years, and is 86 GW Nuclear capacity in the 2015 case and reduces to just under 7 GW in all other scenarios (which take place in 2050).
**Gas prices in 2015 $. Henry Hub price for 2015 baseline is based on historical actual data.*

Highlights of the GPCM and AURORAxmp analysis: The first stage of this report utilized an electric simulation model (AURORAxmp) and a natural gas simulation model (GPCM) to study the Eastern Interconnection (See Section 1.5 for approach).

- While total EI-wide annual and winter and summer peak day generator gas demands increase in 2050 for all three scenarios, some regions have less demand in the High RE and Mid RE scenarios in one or both peak seasons. Gas-fired resources are increasingly used for balancing variable energy (VE) generation and load, although total gas-fired generation and gas demand declines with higher renewable energy penetration.
- Sensitivity scenarios that substitute more gas-fired resources for electric storage resources (shown as the RE SG sensitivities in Table ES-1) do not significantly increase natural gas system constraints, but may make a small to moderate impact on days with high demand for non-variable energy resources.
- The High RE scenario results in less potentially-constrained generation in every region of the EI on the winter peak day than in the 2015 benchmark, suggesting that high renewable penetration is likely to reduce gas pipeline constraints in the winter.
- Lower renewable energy scenarios (Mid RE and Low RE) reveal some potentially-constrained generation relative to 2015 in the East South Central and South Atlantic regions and seasonal constraints in New England (winter) and Florida (summer) where natural gas continues to be used extensively if renewables aren't added as quickly.
- In a sensitivity where the LNG import facility in New England is utilized, potentially-constrained generation in New England is almost completely eliminated and, potentially-constrained generation in the South Atlantic region is reduced in the winter. LNG imports have a negligible effect on any regional constraints in the summer.

Highlights of the hydraulic analysis: Levitan and Associates also performed hydraulic modeling in one constrained (New England) and one unconstrained portion of the EI (Marcellus-Utica shale formation region of the Mid-Atlantic) in order to test the physical deliverability of pipelines in these regions.

- **In New England, potential future intraday gas system constraints resulting from short notice balancing of variable renewable generation are small**. In the limited circumstances where constraints were observed, these constraints are primarily the result of lateral pipelines which were not designed to accommodate large flows to run a gas-fired generator flat out at the highest output. This is unsurprising considering the region is already periodically constrained (in part due to upstream constraints that the region does not have control over), and as mentioned before, system operators in New England have options available to mitigate constraints without electric reliability failures using options for back stopping renewables, such as demand response.

- In the Marcellus-Utica location (covering portions of the Middle Atlantic, South Atlantic and East North Central Regions there were no constraints as the concentration of pipeline, storage and production resources allows the gas system to operate flexibly in responding to intraday ramping in normal operation.
- In both the New England and Marcellus- Utica regions, pipeline constraints were not found to result from a sudden increase in gas demand from the electric sector to back-stop variable generation.
    - In the hydraulic modeling, where there are no pipeline constraints during regular (no VE shortfall) operations, issues backstopping renewables unexpectedly do not occur. During times of peak demand where pipeline constraints exist, additional gas demand to backstop renewables does not drive an increase in those constraints.
    - The hydraulic model analysis on the scenarios with the liquefied natural gas (LNG) sensitivity, which adds imports to each of the three existing LNG terminals in New England, indicates that the full amount of LNG is able to reach generators to offset potentially-constrained generation. However, pipeline-specific operating restrictions may limit the flow of LNG by displacement to specific New England generators.

Highlights of the Mitigation Measures analysis: The analysis considered several mitigation measures for potentially constrained generation, including additional pipelines both intraregional and upstream of constraints, utilization of dual-fuel capability at gas-fired power plants, and demand response. It is important to note that each of the mitigation measures is proposed here as a singular and mutually-exclusive option to mitigate all potential constraints with just ONE of the three mitigation methods. Thus, the proposed mitigation measures are outsized relative to actual future constraints, which would typically be addressed with a portfolio of different mitigation strategies. The mitigation measures can be deployed together as a portfolio of options to meet power generation demands. Thus it is unlikely that any of these options would need to be built out to the maximum amount shown here. None of the three potential mitigation options have been evaluated in this report on the basis of economics or environmental impacts. System operators have additional mitigation methods not examined in this study such as energy efficiency, electricity transmission lines expansion, and LNG.

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LIST OF ABBREVIATIONS

AC	Alternating current
AECI	Associated Electric Cooperatives, Inc.
AEO 2015	Annual Energy Outlook 2015
CAES	Compressed air energy storage
CC	Combined cycle
CoV	Coefficient of variation
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Regulations
CSP	Concentrating solar power
CT	Combustion turbine
DOE	Department of Energy
Dth	Dekatherm
EI	Eastern Interconnection
ERCOT	Electric Reliability Council of Texas
EWITS	Eastern Wind Integration Transmission Study
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GESI	Gas-electric system interface
GJ	Gigajoule
GW	Gigawatt
GWa	Gigawatt average
GWh	Gigawatt-hour
HVDC	High voltage direct current
ISO	Independent system operator
ISO-NE	ISO-New England
ITI	Incremental technology improvement
LAI	Levitan & Associates, Inc.
LDC	Local distribution company
LNG	Liquefied natural gas
MATS	Mercury and Air Toxics Standards
MISO	Mid-Continent ISO
MMBtu	Million British thermal units
MSW	Municipal solid waste
MW	Megawatt
NREL	National Renewable Energy Laboratory
NYISO	New York ISO
O-G-S	Oil/gas steam
O&M	Operation and maintenance
PHES	Pumped hydro energy storage
PHMSA	Pipeline and Hazardous Materials Safety Administration
RE	Renewable electricity
ReEDS	Regional Energy Deployment System
SAM	System Advisor Model
Scf	Standard cubic feet
SERC	Southeast Electric Reliability Council
SPP	Southwest Power Pool
TMY	Typical Meteorological Year
TVA	Tennessee Valley Authority
ULSD	Ultra-low sulfur distillate
VE	Variable energy
VER	Variable energy resources
WECC	Western Electricity Coordinating Council
WIND	Wind Integration National Dataset

NOTE ON CONVERSION FACTORS

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or "MMBtu." Dekatherms (Dth) are also a standard unit of measurement. One Dth is equal to ten therms or one MMBtu. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = .948 MMBtu).

The standard measure of gas volume in the English system of units is standard cubic feet or "scf." The "s" for standard is typically omitted in expressing gas volume in cubic feet. Therefore "scf" is typically shortened to "cf." Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

The standard measure of gas volume in the metric system is cubic meters (m^3). The conversion between metric and English volume measures is 1 m^3 = 35.31 cf. There are a number of different volumetric conventions used in Canada and the U.S.

$$\textbf{1 Mcf} \approx \textbf{1 MMBtu = 1 Dth} \approx \textbf{1 GJ}$$

$$\textbf{1 Bcf = 1,000 MMcf} \approx \mathbf{10^6}\textbf{MMBtu} = \mathbf{10^6}\textbf{Dth} \approx \mathbf{10^6}\textbf{ GJ = 1 PJ}$$

Electric capability or power is expressed in energy units of one million Watts, or megawatts (MW), or scaled by 1000 to gigawatts (GW). Conventionally, the demand (or load) and supply of energy over time is reported as MW-hours (MWh) or GW-hours (GWh), which makes comparisons over different time periods or against capability less clear. To keep energy measurements compatible with capability, some reporting of energy flows in this report alternatively use time-normalized units of average megawatts (MWa) or average gigawatts (GWa).

1 INTRODUCTION

1.1 HIGHLIGHTS

- Assumption: This study assesses the ability of the natural gas pipeline infrastructure in the Eastern Interconnection (EI) to supply fuel to gas-fired power generators given: (1) different levels of anticipated and actual variable renewable generation, (2) no investment from the power generation sector in natural gas pipeline expansion, and (3) different levels of electricity storage technologies and LNG imports.

- Assumption: This study also quantified the amount of various mitigation measures that would be needed to eliminate the simulated 2050 constraints on fueling gas-capable generators.

1.2 OBJECTIVE

The principal goals of this study of the gas-electric interface with high renewable electricity penetration in the EI are:

- Test selected high RE penetration scenarios in recent NREL studies in order to identify the frequency and duration of gas infrastructure deliverability constraints.

- Formulate and assess high RE penetration scenarios that use more natural gas generation and less coal generation and electric storage capacity, reflective of currently lower natural gas price projections and Clean Power Plan (CPP) regulations that will heighten economic pressures on existing coal plants.

- Analyze the responsiveness of the consolidated network of pipeline and storage infrastructure on a peak winter day, peak summer day, and annual minimum gas demand day before and after variable energy generation anticipated and unexpected shortfalls in both a constrained and unconstrained region of the EI.

- Quantify the amount of various mitigation measures that would be needed to eliminate the simulated 2050 constraints on fueling gas-capable generators.

- Identify topics that would benefit from further study.

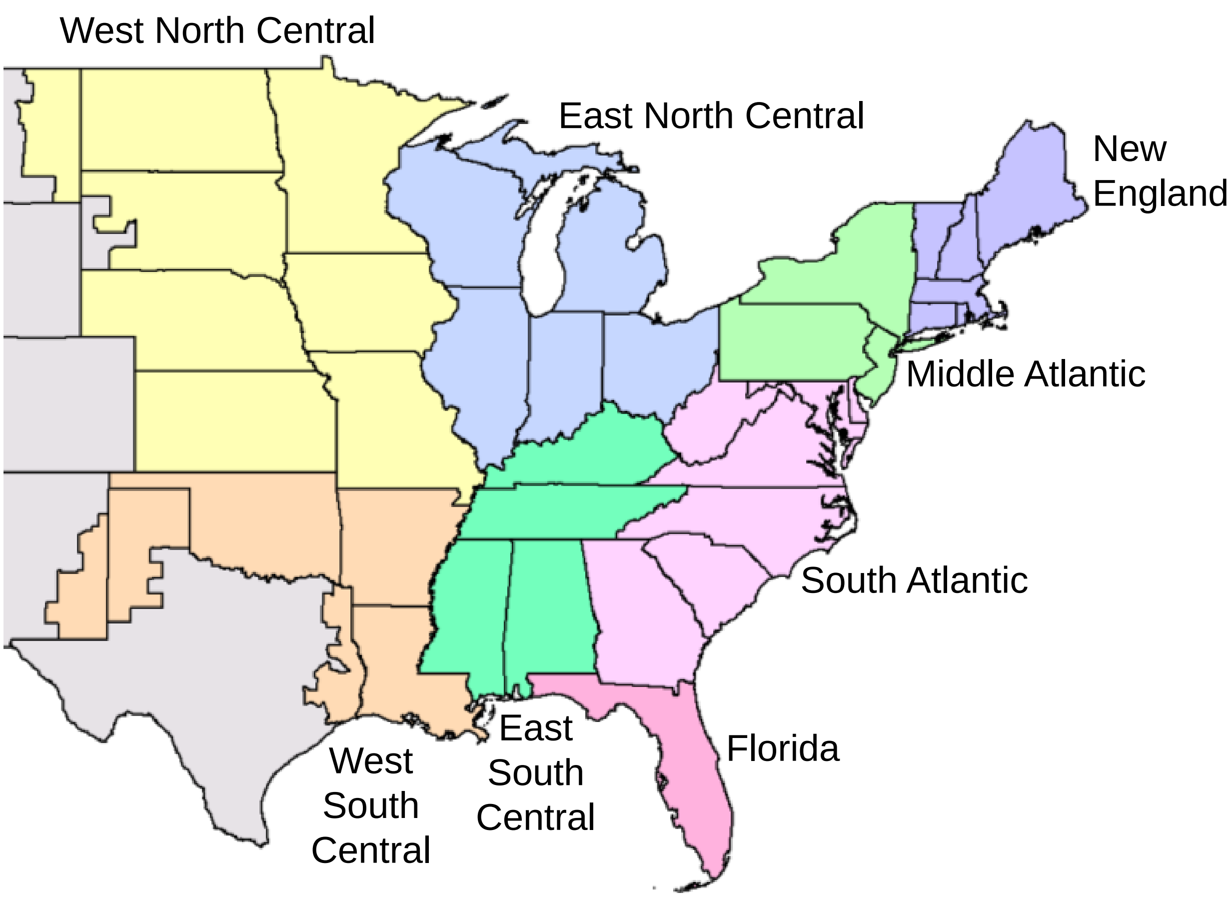
1.3 PROJECT DESCRIPTION

Consistent with the overarching renewable energy paradigm shift goals set forth by DOE for purposes of this study, LAI's analysis builds upon the research undertaken on behalf of EIPC in the Target 2 Gas-Electric System Interface (GESI) study and higher renewable energy scenarios of two NREL studies: the *2015 Standard Scenarios Annual Report*, and the *Impacts of Deferral Tax Credit Extensions on Renewable Deployment and Power Sector Emissions*.

1.3.1 Study Region

The study region includes the U.S. portion of the Eastern Interconnection (EI) electric grid, shown in Figure 1. For reporting purposes, summary results are provided for the entire EI and for eight Census regions or subregions. Because Florida has both electric transmission and gas pipeline constraints and large demands, it was broken out from the rest of the South Atlantic region. The electric and gas system models consist of many smaller zones or areas, discussed later.

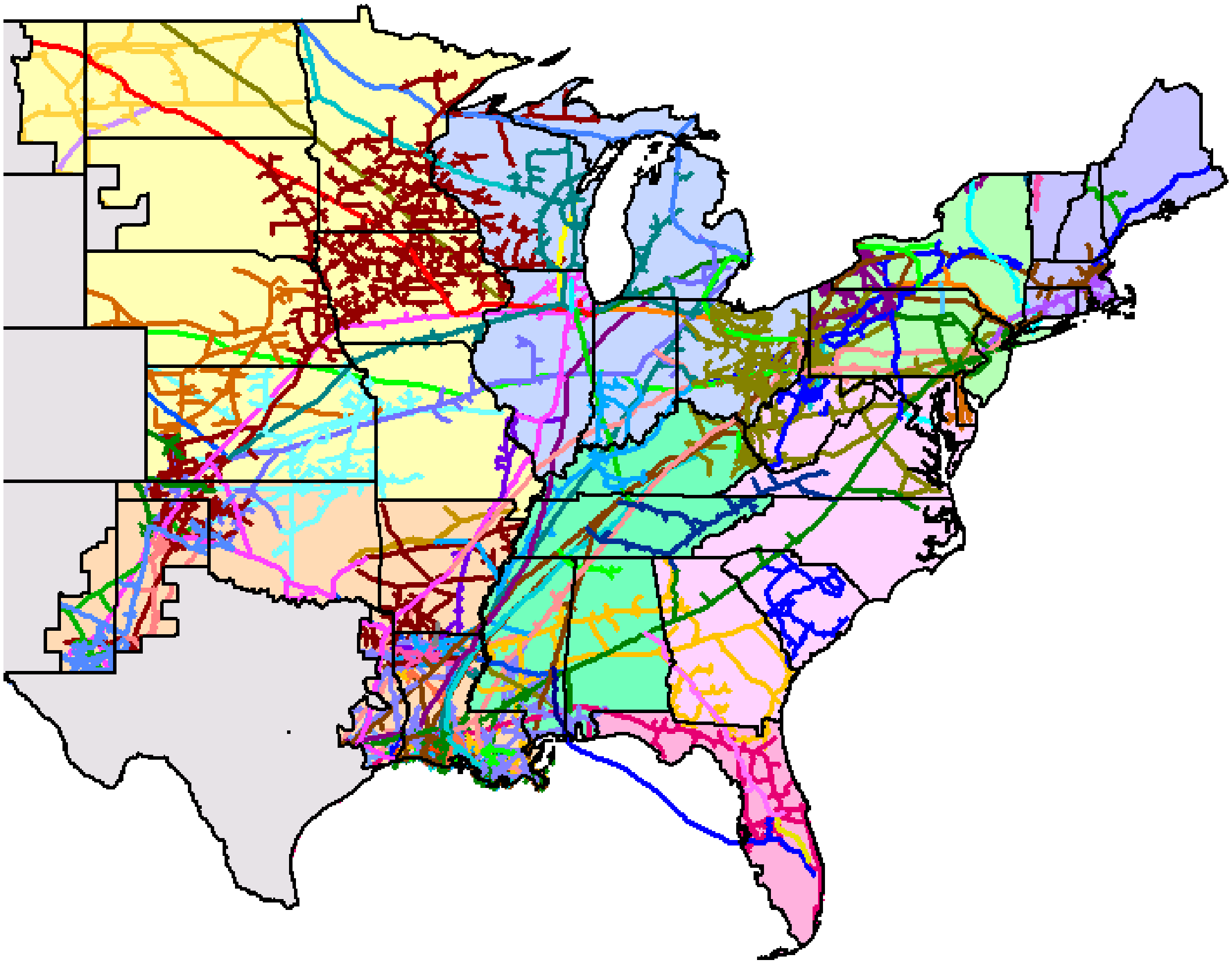
Figure 1. Reporting Regions



The reporting regions correspond to the standard U.S. census regions, with three exceptions: (1) Florida is broken out from the rest of South Atlantic to allow closer review of constraints, (2) a portion of Montana is added to and a portion of South Dakota is removed from West North Central in order to align with EI boundaries, and (3) a portion of New Mexico is added to and most of Texas is removed from West South Central, again to align with EI boundaries.

Figure 2 shows the interstate pipelines operating in the study region.

Figure 2. Interstate Pipelines Operating in the EI



The East North Central, East South Central, Middle Atlantic, West North Central and West South Central regions benefit from significant pipeline density and diversity. Florida, New England and South Atlantic have much less diversity and also less density.

1.3.2 Scenarios and Time Period

Three scenarios were analyzed in this Phase 1 study: (1) High RE scenario, (2) Mid RE scenario and (3) Low RE scenario. Each of these scenarios is based on NREL study scenarios. While NREL modeled these scenarios from 2010 to 2050, our analysis is restricted to 2050, when renewable energy penetration and electric demands under each of the scenarios reach their maximum levels.

In order to measure the impact of higher renewable electricity generation on the natural gas infrastructure, LAI selected three NREL scenarios from two studies that span the likely range of renewable energy penetration levels by 2050. The High RE scenario is based on the 80% National RPS scenario in NREL's July 2015 study, *2015 Standard Scenarios Annual Report*. The Mid RE scenario is built on the Base scenario in NREL's February 2016 *Impacts of Federal*

Tax Credit Extensions on Renewable Deployment and Power Sector Emissions study, and the Low RE scenario is based on the Low Gas Price scenario in the same 2016 study. The generating capacity and energy production shares of the Mid RE scenario are about half way between those of the Low RE and High RE scenarios. The selected NREL scenarios use "incremental" technology improvement (ITI) assumptions. The ITI assumptions were intermediate between the no improvement and evolutionary improvement scenarios in the NREL *Renewable Energy Futures* (2012) study. Load and fuel price forecasts from EIA's *Annual Energy Outlook 2015: with Projections to 2040* (*AEO 2015*) were used for all five scenarios.

The *Impacts of Federal Tax Credit Extensions* study assumed implementation of the Mercury and Air Toxics Standards (MATS) rules, Clean Power Plan (CPP) rules, and relatively low natural gas prices taken from the *AEO 2015* projections, which resulted in retirement or conversion to partial (15%) or 100% biomass fuel of coal-fired power plants. LAI made certain modifications to the generation and transmission resource capacity results of the earlier National RPS scenario for consistency with the two more recent NREL scenarios. Details are explained in Section 2.4.

For scenario benchmarking purposes, a simulation of actual 2015 conditions was also run using the same analysis procedures.

1.3.3 Sensitivities

In order to stress test the capability of the natural gas system to deliver more gas to power plants on days when variable energy production by wind and solar generating resources is quite low, LAI constructed two sensitivities that replaced portions of the expanded capacities of electric storage resources (compressed air, pumped hydro, and battery) included in the Mid RE and High RE scenarios. The Mid RE SG sensitivity replaces all incremental compressed air energy storage (CAES) capacity and pumped hydro energy storage (PHES) capacity with an equal amount of additional simple cycle combustion turbine (CT) capacity in the same locations. The High RE SG sensitivity replaces about one-half of the incremental CAES and battery capacity and 30% of the incremental PHES capacity of the High RE scenario with an equal amount of additional CT capacity. Only 47% of the incremental electric storage capacity from all three technologies was omitted in the High RE SG sensitivity because the High RE scenario had very large growth in electric storage capacity.

Using the *AEO 2015* fuel price projections and reflecting recent environmental regulatory developments in NREL's modeling of economic capacity expansion of generating technologies, together with LAI's assumed replacement of new electric storage resources with more gas-fired capacity, allows stress-testing of the natural gas infrastructure system's ability to support greater reliance on gas-fired generation resources for providing day-ahead scheduled and real-time generation.

An LNG Import sensitivity was run against all three scenarios to test the effects of 2015 LNG import levels in the 2050 market.

1.4 Summary of Scenarios and Sensitivities

Table 1. List of Scenarios and Sensitivities Evaluated in Study

Short Name	Short Description	Models / Data	
2015	Baseline for results which include gas and electric assumptions (such as all interruptible contracts, etc.) to normalize results.	AURORAxmp and GPCM	
	- RE resource capacity	69.82	GW
	of which, VE resource capacity	35.39	GW
	- Gas CT and CC capacity	276.31	GW
	- Nuclear capacity	86.18	GW
	- Henry Hub gas price	$2.69 [4]	/MMBtu
High RE	Based mainly on National 80% RPS scenario of July 2015 NREL 2015 Standard Scenarios Annual Report	AURORAxmp and GPCM	
	- RE resource capacity	836.15	GW
	of which, VE resource capacity	763.96	GW
	- Gas CT and CC capacity	426.67	GW
	- Nuclear capacity	6.71	GW
	- Henry Hub gas price	$11.28	/MMBtu
Mid RE	Central scenario of Feb. 2016 NREL Impacts of Federal Tax Credit Extensions study	AURORAxmp and GPCM	
	- RE resource capacity	608.56	GW
	of which, VE resource capacity	564.68	GW
	- Gas CT and CC capacity	539.40	GW
	- Nuclear capacity	6.71	GW
	- Henry Hub gas price	$11.28	/MMBtu
Low RE	Low Gas Price (LGP) scenario of the 2016 NREL study.	AURORAxmp and GPCM	
	- RE resource capacity	291.09	GW
	of which, VE resource capacity	247.86	GW
	- Gas CT and CC capacity	610.70	GW
	- Nuclear capacity	6.71	GW
	- Henry Hub gas price	$5.45	/MMBtu

[4] Gas prices in 2015 $. Henry Hub price for 2015 baseline is based on historical actual data.

Short Name	Short Description	Models / Data
High RE SG (sensitivity)	Replaces about one-half of the incremental compressed air energy storage (CAES) and battery capacity and 30% of the incremental pumped hydro energy storage (PHES) capacity of the High RE scenario with an equal amount of additional simple-cycle combustion turbine (CT) capacity	AURORAxmp and GPCM
	- RE resource capacity of which, VE resource capacity - Gas CT and CC capacity - Nuclear capacity - Henry Hub gas price	836.15 GW 763.96 GW 458.06 GW 6.71 GW $11.28 /MMBtu
Mid RE SG (sensitivity)	Same assumptions as High RE, with all incremental CAES capacity and PHES capacity replaced with simple-cycle CT capacity in the same locations.	AURORAxmp and GPCM
	- RE resource capacity of which, VE resource capacity - Gas CT and CC capacity - Nuclear capacity - Henry Hub gas price	608.56 GW 564.68 GW 540.63 GW 6.71 GW $11.28 /MMBtu
Scenario + LNG (sensitivity)	A sensitivity analysis assuming 2015 LNG regasification levels at Canaport, Elba Island, Everett and Northeast Gateway for each of the 2050 scenarios was conducted in order to determine whether higher LNG import levels could alleviate pipeline constraints. LNG sendout to pipelines is assumed to be zero in the main scenarios. LNG imports are limited to serving one generator that is directly connected to the Everett terminal	AURORAxmp and GPCM
	- Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM	

Short Name	Short Description	Models / Data
Hydraulic Analysis Constrained location in New England	Baseline and VE shortfall analysis for New England for the following scenarios: High RE SG, High RE SG LNG Sensitivity, and Mid RE, and the Mid RE LNG Sensitivity.	WinFlow and WinTran
	- Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM	
Hydraulic Analysis Unconstrained location in Marcellus-Utica	Baseline and VE shortfall analysis for PJM West for the following scenarios: High RE SG and Mid RE.	WinFlow and WinTran
	- Capacity mix, gas prices and other inputs are unchanged from the cases evaluated in AURORAxmp and GPCM	

1.5 APPROACH

Four modeling tools were utilized in different components of the analysis:

- EPIS Inc.'s AURORAxmp chronological dispatch simulation model to estimate hourly gas demands by individual power plant for multiple cases and scenarios across the Study Region;

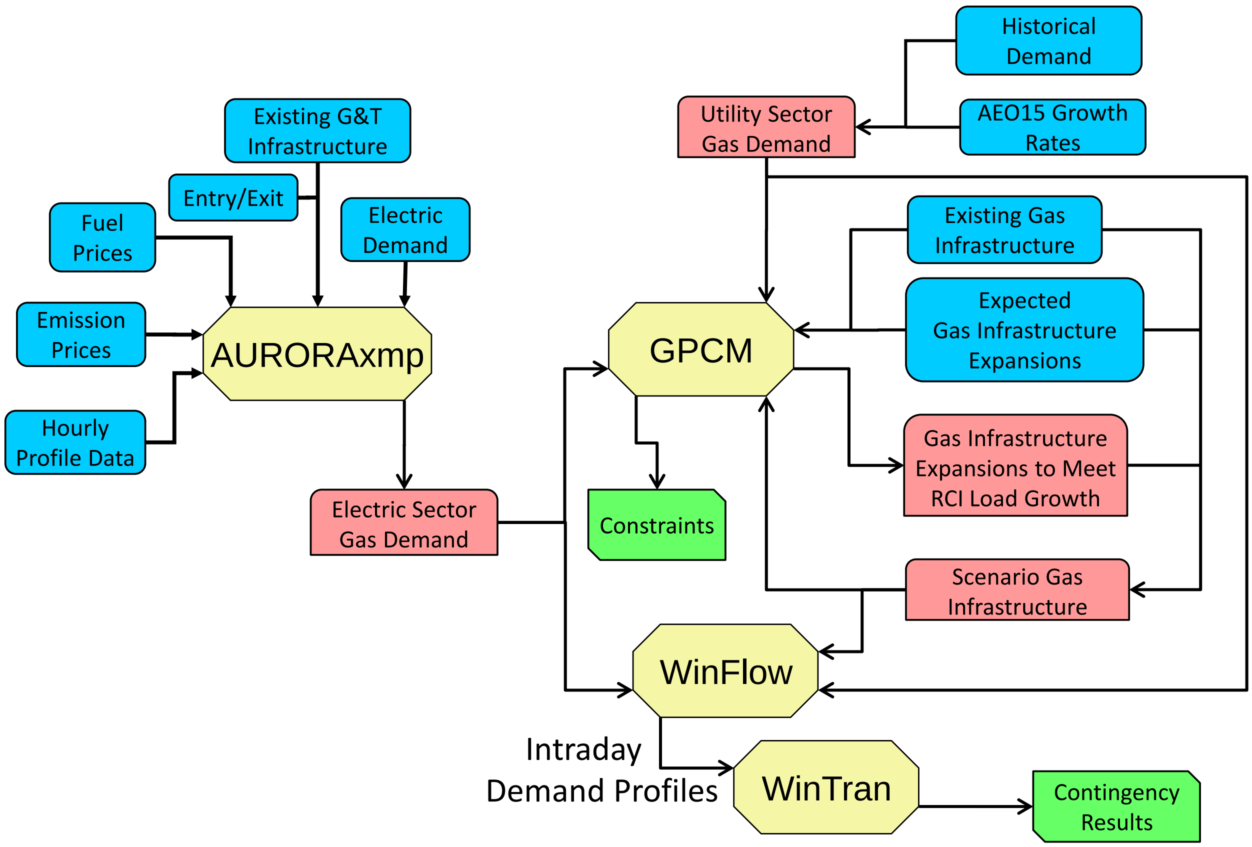
- RBAC Inc.'s GPCM to analyze pipeline and storage operations in light of complex market dynamics and prospective network bottlenecks;

- Gregg Engineering's WinFlow model to simulate the hydraulic flow of natural gas across the consolidated network of pipelines and storage facilities in the steady state;

- Gregg Engineering's WinTran model to simulate the intra-day transient flow of natural gas in response to postulated operational challenges resulting from VE shortfalls.

An overview of the analytical approach used in the study, including key inputs and outputs of the four simulation models and the data transfers between models, is shown in Figure 3.

Figure 3. Modeling Systems Overview



AURORAxmp simulation is hourly across the U.S. portion of the Eastern Interconnection. Generator startup lead times, startup gas quantities, and fuel ramping profiles together with hourly operational generator gas demands from AURORAxmp provide subhourly gas demands to WinFlow. GPCM takes total daily gas demand by plant from AURORAxmp, combines it with the gas utility sector demand, and tests the combined demand against the available gas infrastructure to determine how much of the generator gas demands can be transported by the pipelines.

Several key assumptions that may differ from reality were necessary due to lack of data or for the purposes of the analysis. First, the seasonal peak RCIT gas demand day and peak electric generator gas demand day are assumed to be on the same winter and summer days. Second, the natural gas infrastructure buildout to 2050 is driven entirely by RCIT peak day demand, with no expansion driven by electric generator gas demand. Third, spot gas prices paid by generators are assumed to not increase in response to delivery constraints in order to measure the magnitude of needed gas infrastructure development.

2 POWER GENERATION SECTOR GAS DEMANDS

This section describes the key scenario building block assumptions, data inputs, and results of the AURORAxmp model simulations, which was used to determine hourly gas demands for 2015 and for each scenario analyzed in 2050. We explain the basis for determining the generating resources and electric transmission capabilities that were included in each scenario used in the simulation model. The modeling of the resources for each scenario is discussed, with a focus on the interaction between renewable resources and gas-fired resources. The resource differences for each of the scenarios are summarized. Other key assumptions, including the fuel price and emission allowance price forecasts are addressed. In the final subsection, the gas demands for the electric generation sector are presented for each census region, under each scenario, year, and season.

2.1 HIGHLIGHTS

Highlights of this section are:

- Assumption: Renewable technologies include co-fired biomass (15%) in coal plants, dedicated (100%) biomass steam plants, geothermal, hydropower, distributed photovoltaic (PV), utility-scale PV, concentrating solar power (CSP) with thermal storage, onshore wind, and fixed-bottom offshore wind. Storage technologies include pumped hydro energy storage (PHES), compressed air energy storage (CAES), and batteries.

- Assumption: Coal units under 100 MW were assumed to retire after 65 years, and larger units after 75 years. Additional coal units were retired in the NREL scenarios if they were not used for generation or operating reserves for four consecutive years or if their average capacity factor fell below 50% for two years. Natural gas plants retire after 30 years and nuclear plants after 60 years. Only six recently completed or under-construction nuclear units were assumed to operate in 2050. Renewable technologies are replaced in-kind after they reach their assumed life. Potential capital investments in new nuclear, landfill gas, municipal solid waste (MSW), and oil/gas steam turbine plants were excluded from consideration.

- Assumption: Most remaining coal and oil-fired steam units are converted to partial or complete biomass or natural gas fuels. Electric and thermal storage technologies expand to complement higher variable energy (VE) generation by wind and solar resources.

- Assumption: A recent mid-range national forecast of CO_2 allowance prices of $81/st in 2050 was used to represent either extension of the current nine-state RGGI CO_2 cap-and-trade market or the additional costs of complying with the CPP. The Low RE and Mid RE scenarios reflect implementation of the U.S. Environmental Protection Agency's Clean Power Plan (CPP).

- Assumption: For 2046, the year of the RPS scenario used to represent 2050 demand, the constraint had a shadow value of $66/MWh. In order to minimize the curtailment of zero variable cost wind and solar energy in AURORAxmp, the High RE scenario included a $66/MWh renewable energy credit (REC). The Low RE and Mid RE scenarios were based on NREL scenarios that did not impose a national RPS, and little VE curtailment occurred in those NREL scenarios because of already low must-run resources.

- Assumption: Incremental electric transmission capabilities from 2015 to 2050 for the two NREL scenarios used for the Low RE and Mid RE scenarios were adapted to the AURORAxmp zonal transmission network.

- Result: For scenarios with higher renewable energy penetration, gas-fired resources are used increasingly for balancing VE generation and load, although total gas-fired generation and gas demand declines. Moreover, the diurnal hourly patterns and fluctuations of gas demand relative to average daily demand, increases with higher RE penetration.

- Result: Sensitivity scenarios that substitute more gas-fired resources for electric storage resources have minimal impact on annual gas-fired generation, but may make a small to moderate impact on days with high demand for non-variable energy resources.

- Result: While total EI-wide annual and winter and summer peak day generator gas demands increase in 2050 for all three scenarios, some regions have less demand in the High RE and Mid RE scenarios in one or both peak seasons.

- Result: In general, the storage capacity sensitivity cases did not alter annual or seasonal peak day gas demand much. . The main conclusion of this sensitivity case is that there would not be much additional gas demand by relying more heavily on additional CT capacity and less CAES and PHES capacity to support the growth of VE resources in the High RE and Mid RE scenarios.

2.2 NREL Scenarios Data Foundation

For this study, LAI built on the results of three economic capacity expansion scenarios recently completed by NREL with its Regional Energy Deployment System (ReEDS) model, a capacity expansion and dispatch optimization model of the contiguous United States. Similar to NREL's previous use of the ABB GridView hourly chronological production cost model to hone in on the details of electric system operations, LAI applied the AURORAxmp model for more detailed, hourly chronological analysis of the transmission and generation capacity expansion results of ReEDS that were run from 2010 to 2050 for the selected scenarios. NREL provided results of ReEDS simulations for the variables and years requested by LAI to use in formulating the database for the scenario runs.

Detailed electric system operational model inputs and assumptions and detailed results are described in Appendix A. Other background details of the three NREL scenarios used in this study may be found in two NREL reports that included the scenarios: *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions* (February 2016) and *2015 Standard Scenarios Annual Report: U.S. Electric Sector Scenario Exploration* (July 2015). ReEDS results for 2010, its base year, and 2050 (for the Low Gas Price Extension and Base Gas Price Extension scenarios from the *FTC Extensions* report) and 2046 (for the 80% National RPS scenario from the *Standard Scenarios* report) have been adapted for inclusion in the AURORAxmp database, along with certain default EPIS data and other data and assumptions specified by LAI. The AURORAxmp data inputs for the three NREL-derived scenarios achieve a high level of correspondence to the data inputs and outputs of the ReEDS model. Throughout this section, key points of similarity or difference from the ReEDS scenario data and assumptions are noted.

2.3 Electric System Model

AURORAxmp is a comprehensive electricity system modeling software and database package.[5] AURORAxmp simulates the unit commitment and economic dispatch of individual generating units based on their individual operating characteristics, and the flows of energy over the electric transmission grid. The model objective is to minimize system economic production costs subject to meeting energy demand, operating reserve, and resource availability constraints. Modeled operating reserves included regulation, spinning, and non-spinning operating reserve requirements by region. Thermal generation technology modeled characteristics included maximum capacity, minimum load, heat rate curves, fuel and emissions costs, minimum “up” (operating) and “down” (offline) times, and non-fuel variable O&M expense. Hydro resources included monthly hydro energy availability and flow-related constraints. Solar and wind resources were modeled with hourly energy profiles.

AURORAxmp is a relatively fast model that enabled practical run times (taking a little over one day) of hourly chronological dispatch of power plants in a multi-zone, transmission-constrained system. For this study, LAI used AURORAxmp’s transport transmission (zonal) modeling capability.

2.4 Zonal Topology, Loads, Resources

NREL provided results from its ReEDS model of electric transmission and generation resource capacity expansion for each scenario for each of the balancing areas across the contiguous U.S. region. The ReEDS balancing areas consist of one or more contiguous counties within a state. After review of these results, LAI decided to rely on the zonal boundaries of its AURORAxmp database. The load and resources areas in AURORAxmp conform closely to electric distribution company franchise areas that report load data, and its transmission zones (consisting of one or more areas) are configured to follow the

[5] EPIS, Inc. has licensed the AURORAxmp software and database to users since its founding in 1996. LAI is a licensee of AURORAxmp.

boundaries of ISO/RTO energy market price zones for which transmission transfer capabilities are available from various industry sources.[6]

In order to represent similar load, resource, and transmission assumptions as modeled by NREL, LAI undertook a mapping exercise to assign generation resources in 2050 from ReEDS balancing areas to AURORAxmp areas so that aggregate capacities by technology are the same for each set of counties that define a ReEDS balancing area. Similarly, the expanded transmission capabilities in 2050 that resulted from each ReEDS scenario simulation were mapped to the zone-to-zone transmission links represented in AURORAxmp, by aggregation or disaggregation, as needed.[7]

2.4.1 Electric Load

The same electric demand projections to 2050 were used for all scenarios, based on the *AEO 2015* Reference case load growth rates to 2040 (its final year) and extrapolated to 2050, as done by NREL in its 2016 study. The 2040 electric load levels are lower in the *AEO 2015* Reference case than in its previous AEO 2014 Reference case, which was the basis for NREL's 80% National RPS scenario. To make the three RE scenarios as consistent as practical, we used the same lower 2050 demand levels for the High RE scenario as for the Low RE and Mid RE scenarios.

The default EPIS data for the hourly electric load shapes by area were used because they have more detail than the Census region-based load shapes used in ReEDS. Moreover, they are based on more recent data reported by individual utilities. The base year hourly load shapes for 2012 were increased to 2015 actual levels for the benchmark analysis and to 2050 scenario levels based on the *AEO 2015* Reference case, mentioned above. To be consistent with NREL's ReEDS modeling, the same hourly load shapes were projected to 2050. That is, peak, average, and minimum load growth rates were assumed identical for each area. Also following the NREL approach, demand response and new energy efficiency and electric vehicle demands were not modeled.

2.4.2 Electric Transmission Resources

The representation of electric power transfer capabilities between zones is based on the EPIS default 2015 set of existing transmission transfer limits. This data set is more recent than the NREL base transmission system assumptions, taken from 2006 studies for each of the three interconnections. Some of the links modeled in AURORAxmp have different capabilities by flow direction, while ReEDS assumes the same bi-directional transfer capabilities. Because of this difference as well as the different sets of balancing areas (ReEDS) or zones (AURORAxmp) and links used in the two models, incremental transmission

[6] One change from the EPIS default representation was to split its MISO South zone into the three MISO load-resource zones covering that control region. The three zones are basically one each for Arkansas, Louisiana (with eastern Texas), and western Mississippi.

[7] One difference between the two models pertains to the demarcation of balancing areas. Whereas ReEDS represents New York State with two balancing areas, Long Island and the rest of the State, the AURORAxmp topology models four zones that represent aggregations of NYISO market zones: Upstate (zones A to F), Hudson Valley (zones G to I), New York City (zone J), and Long Island (zone K).

capability from 2010 and 2050, with adjustments for recent expansions in the EPIS database, for the two NREL 2016 scenarios used for the Low RE and Mid RE scenarios were added to the AURORAxmp data representing 2015 transmission capabilities. Because the earlier NREL 80% National RPS scenario was based on higher electric load growth, its transmission expansion results for 2046, which has about the same demand as for 2050 in the *AEO 2015* Reference case, were used in order to avoid overbuild. Default EPIS transmission loss rates for each link were used.

The ReEDS model includes transmission imports to the Eastern Interconnection from the Western Electric Coordinating Council (WECC) interconnection boundary from Montana to New Mexico, the Electric Reliability Council of Texas (ERCOT) boundary, and from Canada. LAI has represented the same external region power imports that resulted from the three selected ReEDS scenarios.[8]

Table 2 shows the transmission expansions adapted from the three NREL scenarios to the transmission infrastructure existing in 2015. Demand for new transmission capacity is much greater in the High RE scenario, including a massive expansion of interconnections with ERCOT and WECC. The Canadian transfer capability is smaller in the scenarios in 2050 than in the 2015 baseline because the NREL model did not include existing or potential HVDC transmission links with Quebec. The transmission capabilities in the 2046 results of NREL's 80% National RPS scenario were used to represent 2050 in the High RE scenario due to its lower load growth rates.

Table 2. Transmission Capability, 2015 and 2050 RE Scenarios[9]

	2015	High RE	Mid RE	Low RE
Internal				
Total Transfer Capability (GW)	298.9	716.0	393.7	327.0
Increase, 2015 to 2050		140%	32%	9%
External				
Canada (GW)	5.1	3.6	3.8	3.8
ERCOT (GW)	0.1	9.7	3.5	1.8
WECC (GW)	0.8	19.6	1.5	1.1
Total Transfer Capability (GW)	6.0	33.0	8.8	6.6
Increase, 2015 to 2050		451%	47%	11%

The larger expansions in the Mid RE and High RE scenarios relative to the Low RE scenario are related to the complementary investments in transmission to allow export of wind and solar generation surpluses from more productive regions, such as West North Central and West South Central, to higher load regions in the Midwest and East.

[8] The same power imports were used for each hour represented in AURORAxmp for the RE scenarios in 2050 that corresponds to the one of the 17 annual time slices (four time-of-day period and four seasons plus a peak load sub-period of the top 40 hours within the summer afternoon period) modeled in ReEDS.

[9] AURORAxmp uses transfer capability in MW from one zone to another, which cannot be summed like the ReEDS MW-mile measure because each zone-to-zone link so their summations over multiple links in Table 1 are not necessarily proportional to the magnitude of their capital investment.

2.4.3 Generation and Storage Resources

The three selected NREL scenarios only allowed commercial technologies available as of 2010. NREL assumed the capital cost and operational improvements over the 40 year study period. However, potential capital investments in new nuclear, landfill gas, municipal solid waste (MSW), and oil/gas steam turbine plants were excluded from consideration. Also, the 80% National RPS scenario did not allow new fossil plants with CCS or IGCC plants because its minimum RE constraint effectively prevents reliance on slow-starting and slow-ramping technologies to backstop VE resources. The reason for these technology restrictions is NREL's focus on grid integration of renewables.

Renewable technologies include co-fired (15%) biomass in coal plants, dedicated (100%) biomass steam plants, geothermal, hydropower, landfill gas, distributed photovoltaic (PV), utility-scale PV, concentrating solar power (CSP) with thermal storage, onshore wind, and fixed-bottom offshore wind. Incremental biomass was restricted to supply from energy crops and advanced harvesting methods. Incremental hydropower was restricted to run-of-river plants. Utility-scale PV includes both fixed-angle and single-axis rotating panel technologies.

Storage technologies include pumped hydro energy storage (PHES), compressed air energy storage (CAES), and batteries. Potential new PHES projects were restricted by NREL to the projects that had received Federal Energy Regulatory Commission (FERC) preliminary permits or pending preliminary permits. A resource assessment by NREL identified possible locations for CAES plants, based on local geology. CSP with thermal storage is a hybrid generation and storage technology that is included in the solar category rather than the storage category when technologies are aggregated by fuel type in this report.

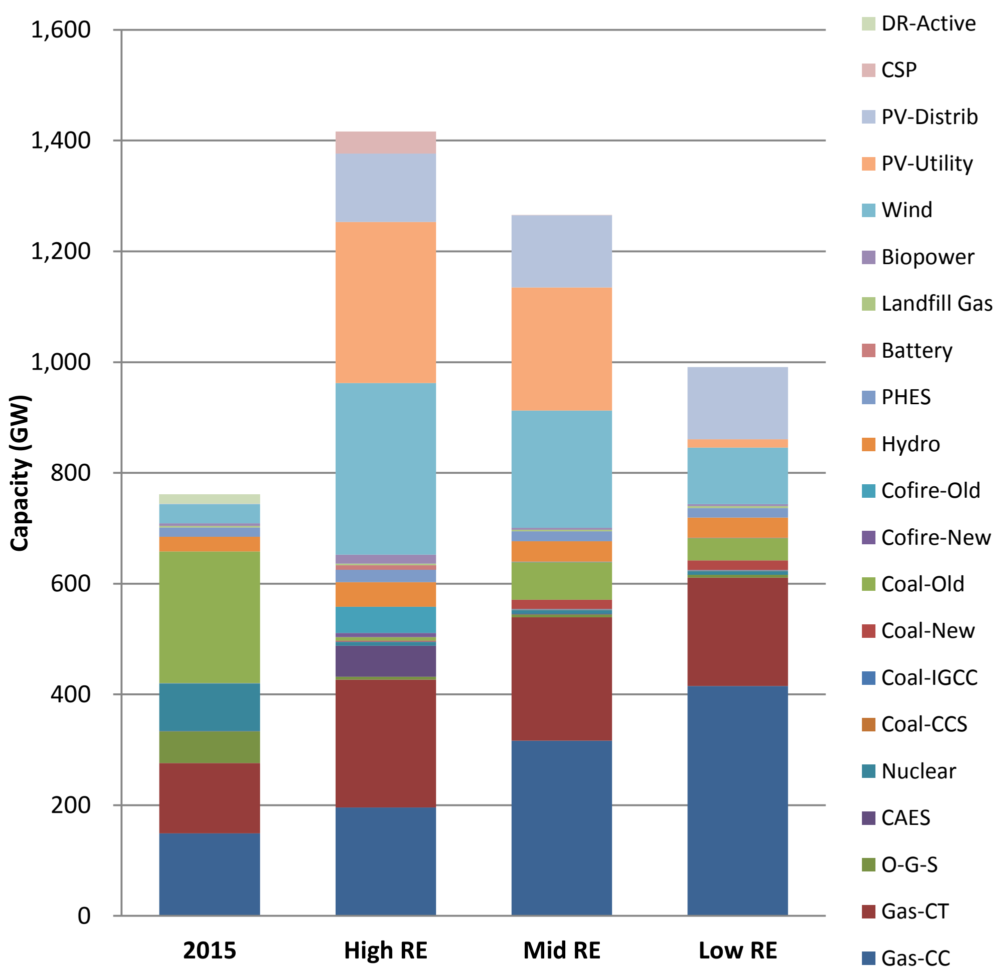
In the NREL scenarios, coal units were assumed to retire after 65 years for units smaller than 100 MW and after 75 years for larger units. Additional units not used for generation or operating reserves for four consecutive years were retired. Further coal capacity was retired if the average capacity factor for the coal fleet in a ReEDS balancing area fell below 50% for the previous two years. Natural gas plants and nuclear plants were assumed to retire based on their age. Natural gas plants retire after 30 years and nuclear plants after 60 years. Existing oil-gas steam units were assumed to not retire. Renewable technologies are replaced in-kind after they reach their assumed life.

2.4.3.1 <u>Scenario Resources</u>

Scenarios are generally based on the least-cost capacity expansion results of the corresponding NREL scenarios. However, the NREL base year for the ReEDS simulations was 2010, so LAI included existing 2015 capacities of landfill gas and MSW plants, a CAES plant, and a few other differences not reflected in the NREL scenario results. A comparison of total generation capacities by technology and scenario at the state area level with the corresponding NREL scenario capacity results for the EI verified that they are in close agreement.

Figure 4 shows the total capacity mix by technology for the actual 2015 generation resources located in the EI and for the three RE scenarios in 2050. The stack of technologies is ordered by fuel type. At the top, only the 2015 actual resource composition includes active demand response (DR). Next are the three solar technologies and wind. These four represent the VER technologies that require other technologies for backup. Across the three RE scenarios, the total capacity of the four gas-fired technologies (CC, CT, Oil-Gas-Steam, and CAES) at the bottom of the bar stacks are in approximate inverse relation to the VER capacity.

Figure 4. EI Resource Capacity by Technology, 2015 and 2050 RE Scenarios



Low and uncertain capacity factor solar and wind resources account for most of the differences in total capacity across the three 2050 scenarios. Nuclear, coal, and oil-gas steam capacities are much lower than in 2015 in all three scenarios.

Some CSP capacity and expansion of CAES capacity is represented in the Mid RE scenario. Much more is represented in the High RE scenario because storage capability is more important for balancing VE generation. The Mid RE and High RE scenarios also have some growth in PHES capacity. Biomass feedstocks are redeployed from co-firing in the Mid RE scenario to dedicated thermal plants in the High RE scenario. Consistent with reporting by NREL, MSW steam boiler plants are included in the landfill gas category even though they are distinct technologies that use refuse biomass fuel. While contributing less than other renewable technologies, geothermal and hydro resources were expanded faster than recently observed trends. Today, there is only 49 MW of geothermal capacity in the EI; hence, it is not represented in this or other figures in the report. The only offshore wind is 37 MW in the High RE scenario, so it is reported together with onshore wind.[10] Only 6.7 GW of nuclear capacity at the two recently completed Watts Bar units and four units now under construction in the EI (two Vogtle units and two V C Summer units) are in operation in 2050.[11] All other existing nuclear units are assumed to be retired before 2050.

Most new storage capacity is provided by CAES plants, with small amounts of additional PHES, in the Mid RE and High RE scenarios, and utility-scale batteries in the High RE scenario.

To simplify the presentation of capacity mix assumptions, Figure 5 shows the technologies aggregated into fuel type categories, with the two VER categories at the top of the bars and gas-fired resources, other than CAES which is included with storage resources, at the bottom of the bars.

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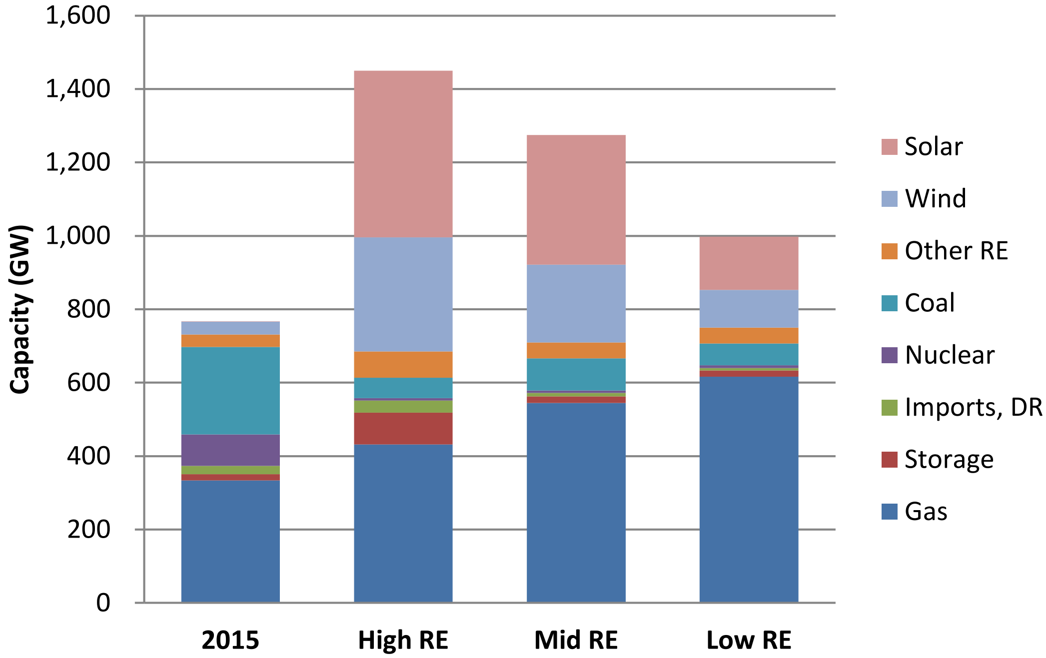
[10] The 30 MW Block Island wind farm is expected to be online by the end of 2016. While more off-shore wind capacity than found in the NREL scenarios may materialize by 2050 in response to state mandated procurement objectives, off-shore and on-shore wind may be regarded as close substitutes regarding CO_2 reduction goals. To the extent gas-constrained regions in 2050 are located along the Atlantic Seaboard, off-shore wind has the potential to disproportionately mitigate gas-electric constraints.

[11] NREL had also included the two partially-constructed Bellefonte nuclear units in Alabama in its scenarios, but TVA decided on May 5, 2016 to sell the site as surplus property, so that capacity was excluded from this study.

Figure 5. EI Resource Capacity by Fuel Type, 2015 and 2050 RE Scenarios

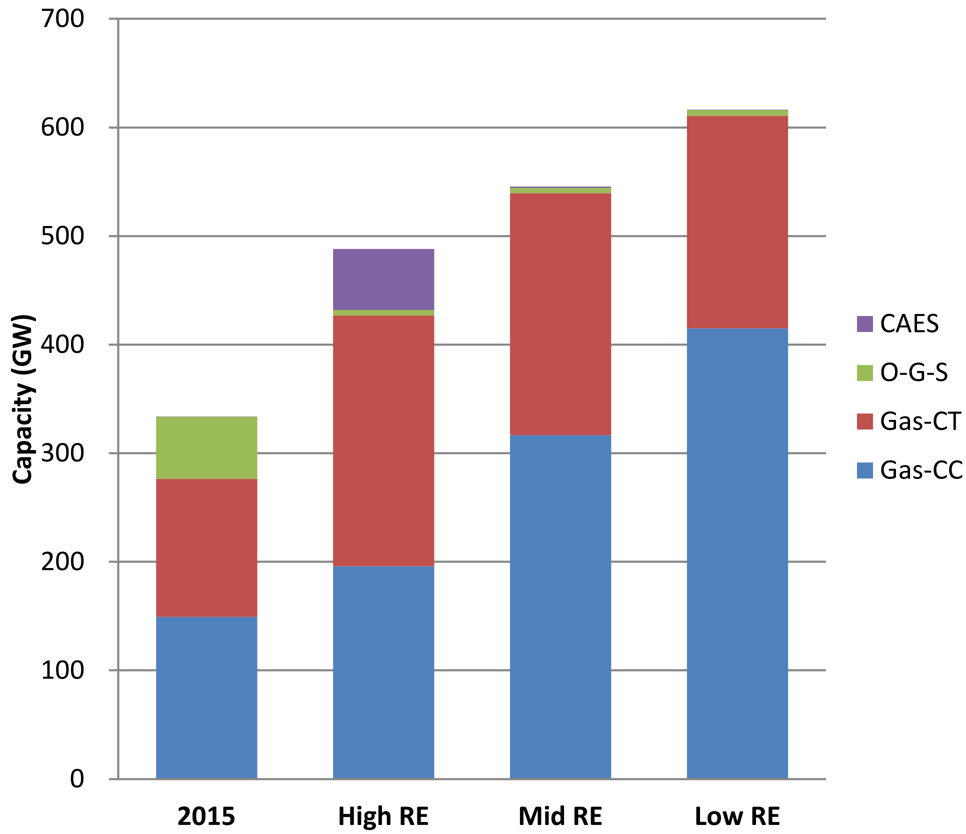


Import capability expands considerably over 2015 in the High RE scenario. The 2050 scenarios do not include any active DR, while in 2015 it contributes as much capacity as electric storage. CAES underlies the "Elec+Gas" fuel category and steam units use 15% biomass in the "Coal+Bio" fuel category.

Gas-fired technology capacities are shown in Figure 6. Future 2050 gas-fired capacity is larger in all three RE scenarios than in 2015. No new oil-gas-steam generation plants are built, so that technology has the same small capacity contribution of about 5 GW across all three RE scenarios. CAES capacity remains at the current 110 MW in the Low RE scenario, and about 1.2 GW is added in the Mid RE scenario and 56.1 GW in the High RE scenario. CT capacity is slightly higher in the Mid RE and High RE scenarios relative to the Low RE scenario as there is more need for quick-start, fast-ramping generators to backstop VE generation.[12]

[12] The ratio of CC to CT capacity was about 1.2 in 2015, and in 2050 is about 2.1 for the Low RE scenario, 1.4 for the Mid RE scenario, and 0.9 for the High RE scenario. The Low RE scenario CC/CT ratio is similar to the typical optimal economic blend from capacity planning analyses over the past two decades. The CT component of a CAES unit has fast start and fast ramping characteristics similar to those of a standard CT, so the ratios of faster/slower starting and ramping units would be higher by including both CT and CAES capacity in the denominator.

Figure 6. EI Gas-fired Generation Capacity by Technology, 2015 and 2050 RE Scenarios



Gas CT and CC capacities are larger than in 2015 in all three 2050 scenarios, while oil-gas steam capacity declines by about 90% in all three scenarios. CAES is a significant portion of gas-fired capacity in the High RE scenario, at about the same capacity by 2050 as oil-gas steam units in 2015.

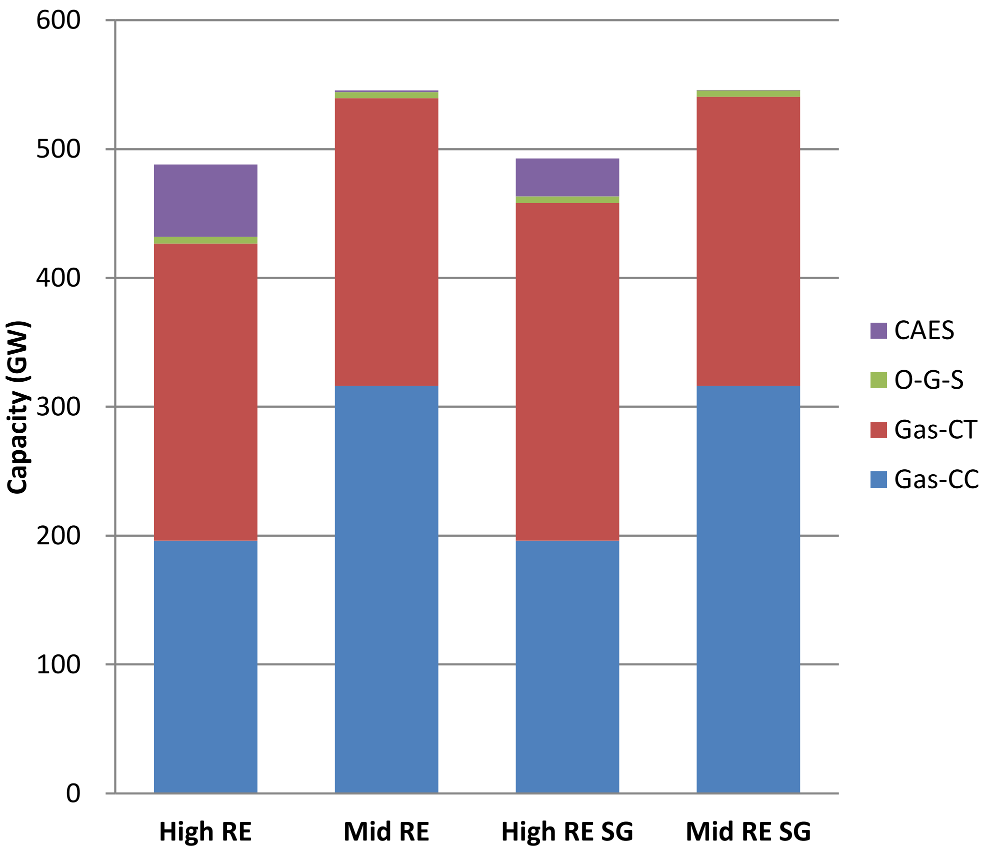
The capacity mixes vary by region. Much of the expanded gas-fired capacity is in the central part of the EI where much of the retired coal and nuclear capacity is located. In the High RE scenario, which sees substantial growth of electric storage capacity, battery and CAES capacity is concentrated in the Texas and Oklahoma panhandles, and CSP capacity along the border of WECC and southern Florida.

2.4.3.2 <u>Sensitivity Resources</u>

Expansion of CAES capacity in the NREL studies may be optimistic as there is no deployment in either bedded salt or porous rock formations. Currently, the U.S. has only one 110 MW CAES installation, McIntosh unit 5, in Alabama. Also, the ReEDS results may have been biased in favor of storage technologies over gas-fired technologies due to modeling only 17 time slices per year. For these reasons, and the siting approval and project financing challenges (requiring a rate of return premium due to higher risk) experienced by PHES developers in recent decades, LAI also investigated two sensitivity tests of additional demands on the gas system by substituting additional CT capacity for some of the growth in storage capacity in the High RE and Mid RE scenarios.

The High RE and Mid RE scenarios were modified to substitute more CT capacity in place of some battery, CAES, and PHES capacity expansion. CSP with storage capacity was not changed because it is mostly a solar generation technology with limited storage capability. The Mid RE SG sensitivity replaced all 1.3 GW of the expanded CAES and PHES capacity in the Mid RE scenario with more CT capacity in the same locations. Because the High RE scenario has much more expansion of storage capacity, approximately one-half or 32.4 GW of its battery, CAES, and PHES expansion was replaced with more CT capacity in the High RE SG sensitivity. Due to individual plant size "lumpiness" considerations, new CAES and PHES units were either left alone or removed, rather than reducing unit capacities by 50%. Battery unit capacities were assumed scalable and reduced by 50%. Figure 7 compares the gas-fired capacity mixes of the two storage-gas (SG) substitution sensitivities with their parent scenarios. The total gas-fired capacity of each of the SG scenarios is slightly larger than the parent scenario because additional CT capacity also substitutes for expanded PHES and battery capacities, which are relatively small.

Figure 7. EI Gas-fired Generation Capacity by Technology, RE and SG Scenarios



The High RE SG scenario substitutes about 50% of expanded CAES, PHES, and battery storage capacity with additional gas CT capacity. The Mid RE SG scenario substitutes nearly all of its much smaller expansion of storage capacity with additional CT capacity.

2.5 FUEL PRICES

Actual monthly average gas, oil, coal, and uranium fuel prices were used for the 2015 benchmark case. *AEO 2015* was used as the basis for the scenario fuel price forecasts for 2050. Because *AEO 2015* projects to 2040, LAI extrapolated to 2050 based on the average growth rate in real fuel prices over the latter years of the AEO projections. GPCM was used to compute delivered monthly average gas prices at the array of pricing points or hubs across the EI. Coal prices differ by region, reflecting sourcing from different supply basins and different transportation costs. Nuclear fuel prices were based on the default fuel price settings in AURORAxmp.

The *AEO 2015* Reference case fuel prices were used for the High RE and Mid RE scenarios. The *AEO 2015* High Oil & Gas Resource case natural gas prices were used for the Low RE scenario, while other fuels used the same mid-level prices from the Reference case. *AEO 2015* regional coal and ULSD prices in the "energy prices by sector and source" table were used. The oil product price for ultra-low sulfur distillate (ULSD) was used in AURORAxmp. This approach to the specification of scenario-specific fuel prices is similar to that used by NREL in its three scenarios, except that its earlier National RPS scenario used *AEO 2014* Reference case prices.

The forecast of nuclear fuel prices is driven by uranium (U_3O_8) prices, which are expected to amount to about 40% of total nuclear fuel costs over the forecast horizon. Nuclear fuel costs also include the costs of conversion (6%), enrichment (38%) and fabrication (16%).[13] No recent forecast of nuclear fuel prices was available from EIA. Therefore, LAI developed a forecast of nuclear fuel prices based on expected uranium prices that is consistent with EIA's available price forecasts.

[13] Nuclear fuel supply is comprised of mined and enriched U_3O_8, utility stockpiles of uranium, and secondary sources such as recycled spent fuel and recycled weapons grade uranium and plutonium.

Table 3. Annual Average Fossil Fuel Prices, 2015 and 2050 RE Scenario

Fuel and Location	Actual 2015	Scenario in 2050 High RE	Mid RE	Low RE
Natural Gas, Henry Hub	2.69	11.28	11.28	5.45
Distillate Fuel Oil, Average	15.03	39.63	39.63	39.63
Residual Fuel Oil, Average	10.24	N/A	N/A	N/A
Coal				
New England	2.72	5.06	5.06	5.06
Mid Atlantic	2.67	3.44	3.44	3.44
East North Central	2.21	3.26	3.26	3.26
West North Central	1.80	2.74	2.74	2.74
South Atlantic	2.67	4.03	4.03	4.03
East South Central	2.35	3.26	3.26	3.26
West South Central	2.09	3.19	3.19	3.19

Natural gas prices in 2050 for the Low RE scenario are about one-half those of the High RE and Mid RE scenarios. No RFO price was forecasted for 2050 because all remaining oil use is assumed to be ULSD.

2.6 Environmental Requirements and Assumptions

2.6.1 Emission Allowances Prices

Emission allowance price forecasts were included for fossil fuel generation. Sulfur dioxide (SO_2) and nitrous oxides (NO_x) allowance prices are forecasted at fairly low levels, based on current market conditions, and are applied to covered generators across the EI. For the 2015 baseline case, a CO_2 allowance price of $6.48/st was used nine-state RGGI CO_2 cap-and-trade market. A recent mid-range national forecast of a CO_2 allowance price of $81/st in 2050 was used to represent either extension of the RGGI CO_2 market to the entire EI or the additional costs of complying with the CPP.[14] The emissions allowance price forecast assumes that the reinstated Cross-State Air Pollution Regulations (CSAPR) essentially remain an extension of the federal NO_x and SO_2 cap-and-trade program under CAIR, applicable to states where CAIR currently applies.[15] Current CSAPR mid-range traded allowance prices ($/st) for NO_x and SO_2, shown in Table 4, were projected to remain constant through 2050.[16]

[14] Synapse Energy Economics, Inc., *Spring 2016 National Carbon Dioxide Price Forecast*, March 16, 2016, Table 1, Mid Case.
[15] Note that states there are a few states in the Study Region that are covered by CSAPR but are not covered by CAIR. To be consistent with the fuel price forecast, the CAIR state applicability has been retained.
[16] *Megawatt Daily*, March 15, 2016.

Table 4. Emission Allowance Prices

NO_x Annual	$ 85
NO_x Seasonal	$250
SO_2 Group 1	$ 2
SO_2 Group 2	$ 5

2.6.2 Greenhouse Gas Regulations

The Low RE and Mid RE scenarios reflect implementation of the Environmental Protection Agency's Clean Power Plan (CPP) in the 2050 generation capacity mix by technology and transmission capacity expansion, based on NREL's inclusion of potential carbon capture and storage technologies and CO_2 mass constraints for meeting CPP targets by 2030 in the corresponding two scenarios simulated in its February 2016 report, *Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions*. Those scenarios were, respectively, Low Gas Price Extension and Base Gas Price Extension, where "extension" refers to continuation of current federal tax credits.

2.6.3 Renewable Energy Credit

The High RE scenario is based on the NREL 80% National RPS scenario. This was accomplished in ReEDS by imposing a minimum 80% RE share of nation-wide generation constraint in the economic optimization model. For 2046, the year of the RPS scenario used to represent 2050 demand, the constraint had a shadow value of $66/MWh (2014 $).[17] In order to minimize the curtailment of zero variable cost wind and solar energy in AURORAxmp, the High RE scenario included a $66/MWh renewable energy credit (REC).[18] Instead, thermal resources that would otherwise stay online have more cost avoidance incentive to shut down during periods of high VE generation, and later incur additional start and ramping costs. The Low RE and Mid RE scenarios were based on NREL scenarios that did not impose a national RPS, and little VE curtailment occurred in those NREL scenarios. Hence, no REC value was included in the 2015 case or the Mid RE and Low RE scenarios in 2050.

2.7 ELECTRICITY PRODUCTION SIMULATION RESULTS

2.7.1 2015 and RE Scenario Generation

Electric system simulation results are presented here to provide the reader with a sense of the electricity generation and other usual operational metrics for the peak winter and summer gas demand days. These metrics are reported at the annual and hourly levels. The

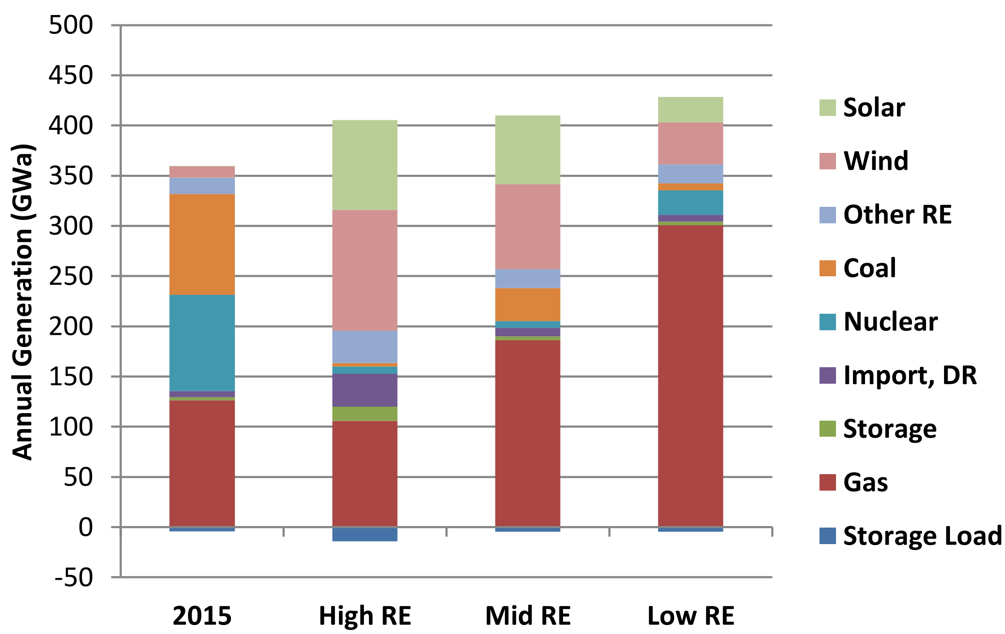
[17] The shadow value represents the opportunity cost of the RPS constraint. Its value was communicated from NREL to LAI.

[18] A REC operates differently than a market price or tax on CO_2 or GHG emissions, but has somewhat similar impacts in tilting capacity and generation towards more renewable resources. The largest exceptions are nuclear and large-scale hydro energy, which have no CO_2 emissions but are not included in RPS programs.

peak gas demand day is used as the peak day criterion instead of the more typical peak electric load day criterion. This is because the primary purpose of this study is to analyze the stress on gas infrastructure. The peak gas demand day is determined by a combination of high electric load, which requires more gas-fired generation, and lower than seasonal average VE generation. Additional generation by gas-fired, other fossil-fired, and storage resources fill the supply gap whenever there is less VE generation.

Based on inclusion of all production costs and operational constraints, and a renewable energy credit in the High RE scenario, AURORAxmp resulted in about 64% RE generation in the EI, compared to 70% by ReEDS.

Figure 8. EI Annual Generation by Fuel Type, 2015 and 2050 by RE Scenario

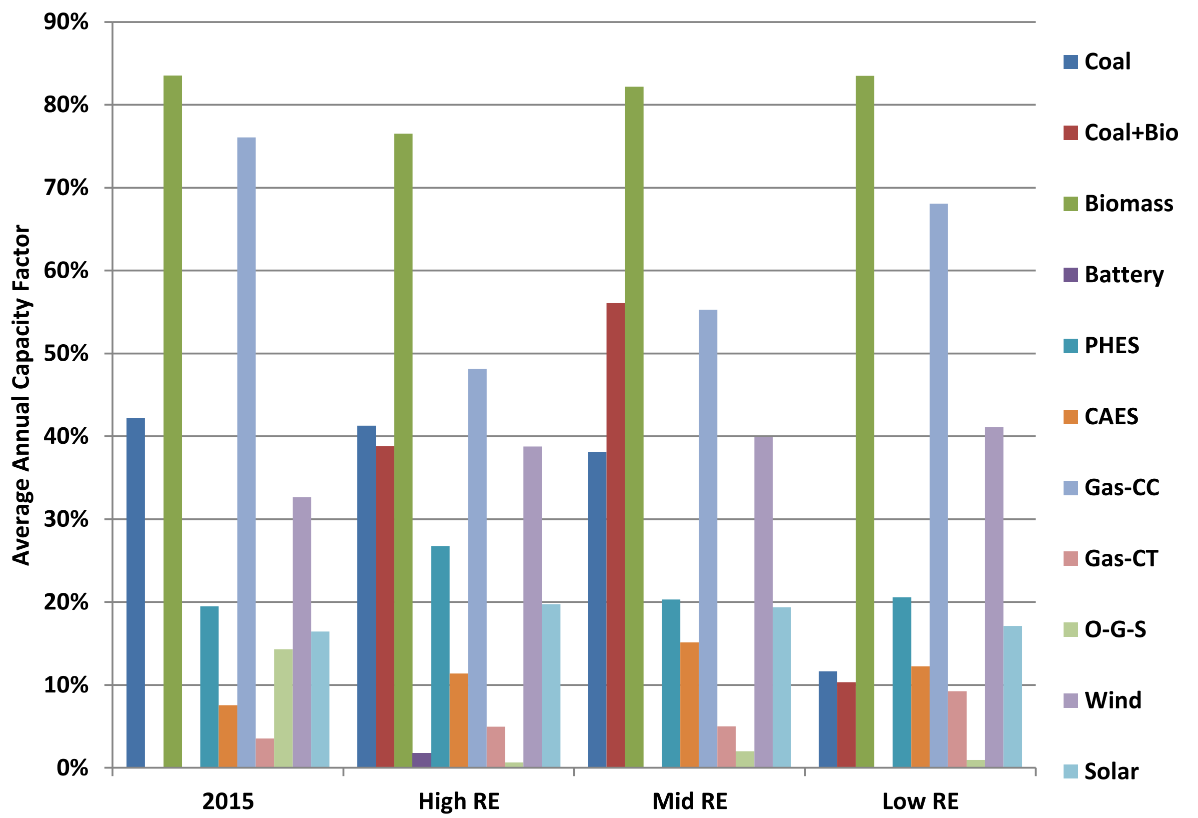


Higher RE penetration in the 2050 scenarios than in 2015 displaces much coal-fired generation, and nuclear generation is much less due to retirements. Annual gas-fired generation is lower than for 2015 in the High RE scenario, and higher in the Mid RE and Low RE scenarios. Electric demand for energy storage by CAES, PHES, and battery plants is shown as negative generation.

EI-wide annual average capacity factors by technology category for the more dispatchable generation and storage technologies in Figure 9 indicate that coal and coal/biomass co-fired steam generation capacity factors are significantly lower in both the Low RE scenario and the High RE scenario. In the Low RE scenario, coal and coal/biomass cofired steam generation are lower due to the cross-over in the cost of generation by gas-fired technologies. In the High RE scenario, they are lower due to more utilization of rapid-starting and ramping generation resources to complement fluctuations in VE generation. Battery capacity is only in the High RE scenario, with a 2% average capacity factor. PHES has capacity factors greater than 20% in all three RE scenarios. CAES has between 11% and 15% capacity factors in all three RE scenarios. These two storage resources appear to provide more of the net (of VE) load-following need than CT plants, which has about 5% capacity factor in the

High RE and Mid RE scenarios and 9% in the Low RE scenario, which has much less expansion of storage resources. The bulk of gas-fired generation is by CC plants, which have a steady progression in average capacity factors, from 48% in the High RE scenario, to 55% in the Mid RE scenario, and 68% in the Low RE scenario.

Figure 9. EI Annual Average Capacity Factor by Technology, 2015 and 2050 by RE Scenario

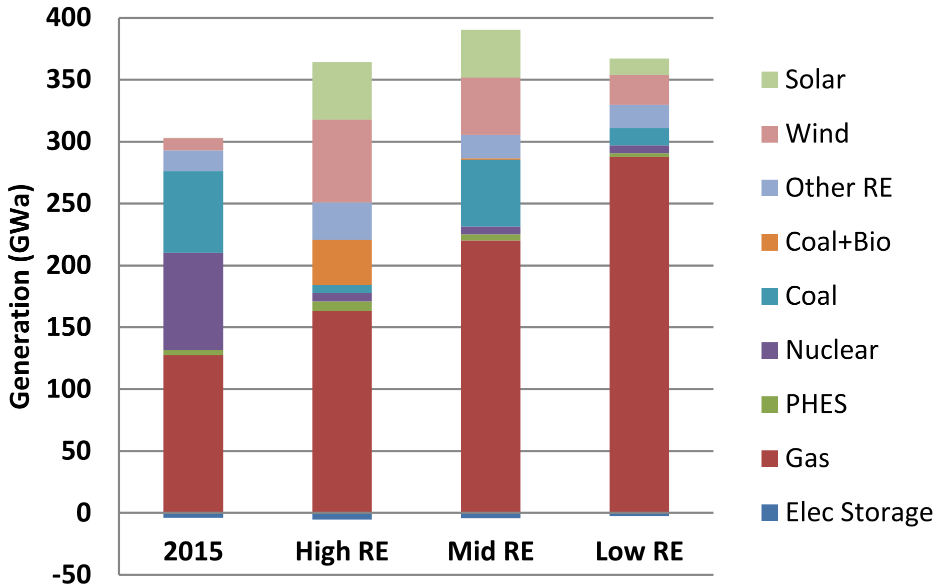


Wind and solar capacity factors increase over 2015 levels in the 2050 scenarios due to technical progress. PHES and CAES capacity factors increase significantly in the High RE scenario due to more demand for storage. Coal and cofire capacity factors decline markedly in the Low RE scenario due to low gas prices. CC and O-G-S capacity factors decline and CT capacity factors increase in the 2050 scenarios.

Over all three RE scenarios, PHES and CAES plants average over one start per day, flattening net load (load minus VE generation) over morning and evening daily peaks. In contrast, CT plants average about one start every three days, with most occurring during peak demand periods.

The winter peak gas demand day in 2015 is December 14, and in 2050 is January 20 in all three scenarios. Gas-fired generation on the 2050 winter peak day is larger in all three scenarios than for 2015. Gas-fired generation in the High RE scenario is about one-half that of the Low RE scenario (Figure 10), with the Mid RE scenario at an intermediate level. The Mid RE scenario has the most coal-fired generation (including the 85% share of coal-biomass co-firing) of the three scenarios in 2050, and nearly as much as in 2015. The Mid RE scenario has the most coal generation on the winter peak day because the Mid RE and High RE scenarios are based on substantial increases in natural gas prices relative to coal prices, making coal more competitive, while the High RE scenario has much less coal-fired capacity as a result of its minimum 80% RE constraint.

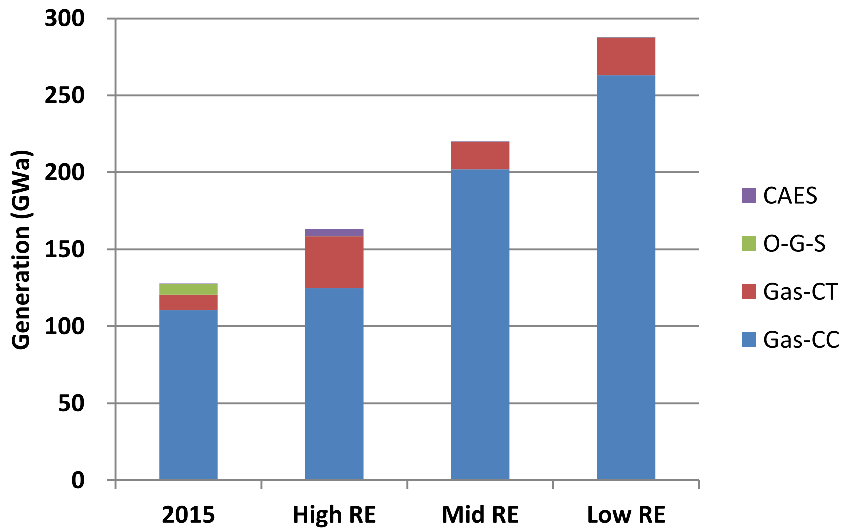
Figure 10. EI Winter Peak Day Generation by Fuel Type, 2015 and 2050 RE Scenarios



Generation in 2050 differs by scenario due to varying levels of imports and electricity demand for energy storage. VER generation in 2050 has 11, 8, and 4-fold increases over 2015, respectively, in the High, Mid, and Low RE scenarios. Gas-fired generation in 2050 increases 28%, 73%, and 126%, respectively, in the High, Mid, and Low RE scenarios.

Focusing on gas-fired generation by technology on the peak winter day (Figure 11), peaking CT and CAES units together generate more than twice as much in the High RE scenario as in the Mid RE scenario while CC plants generate slightly more than one-half as much in the High RE scenario. The share of total gas-fired generation by peaking CT and CAES units is about three times as much in the High RE scenario as for the other two RE scenarios.

Figure 11. EI Winter Peak Day Generation by Gas-fired Technology, 2015 and 2050 RE Scenarios



The High RE scenario in 2050 has much more gas-fired generation by quick-start CAES and CT plants relative to slower-starting O-G-S and CC plants than in 2015, which is related to greater hourly variation in gas-fired generation in the High RE scenario compared to 2015, resulting from large swings in VER generation.

Stress on gas infrastructure is a function of the fluctuations of gas demand within a day as well as the total daily demand. The hourly profile of gas demand by generators increases in amplitude as the penetration of RE generation becomes larger. One indicator of the impact that VE generation has on diurnal fluctuations in gas-fired output is the coefficient of variation (CoV) of hourly gas-fired generation within a day. Another relative indicator is the ratio of maximum to minimum hourly generation. These descriptive statistics for winter hourly gas-fired generation on the peak gas day for 2015 and for the three RE scenarios in 2050 are shown in Table 5.

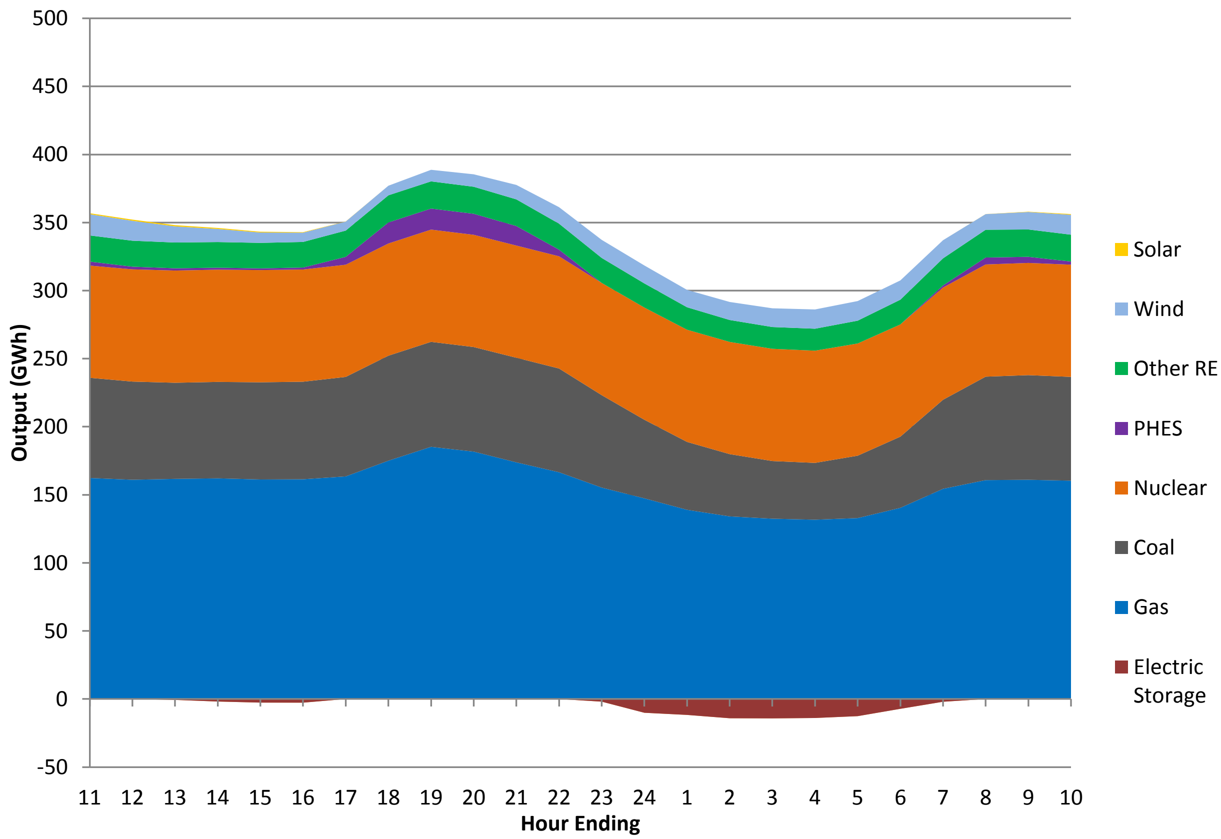
Table 5. Winter Peak Day Hourly Gas-fired Generation Cycling indicators

Case	2015	High RE	Mid RE	Low RE
Mean (GWa)	157	183	245	334
Max (GWa)	185	273	323	385
Min (GWa)	132	98	155	302
SD (GWa)	15	48	42	26
CoV	0.10	0.26	0.17	0.08
Max/Min	1.4	2.8	2.1	1.3

The 2050 winter peak day in the High RE scenario has much more hourly absolute and relative fluctuation in gas-fired generation than in 2015, while the Mid RE scenario is intermediate, and the Low RE scenario has slightly less diurnal cycling than in 2015.

The next four charts (Figure 12 to Figure 15) show hourly generation for the winter peak gas day, starting at 10 am EST, for the 2015 and RE scenarios in 2050.[19] These graphs show how gas-fired generation provides net load-following service as well as contributing to meeting demand during high load hours. This set of charts for the winter peak gas demand day is just one possible pattern that results from random weather variations that impact VE generation as well as electric load.

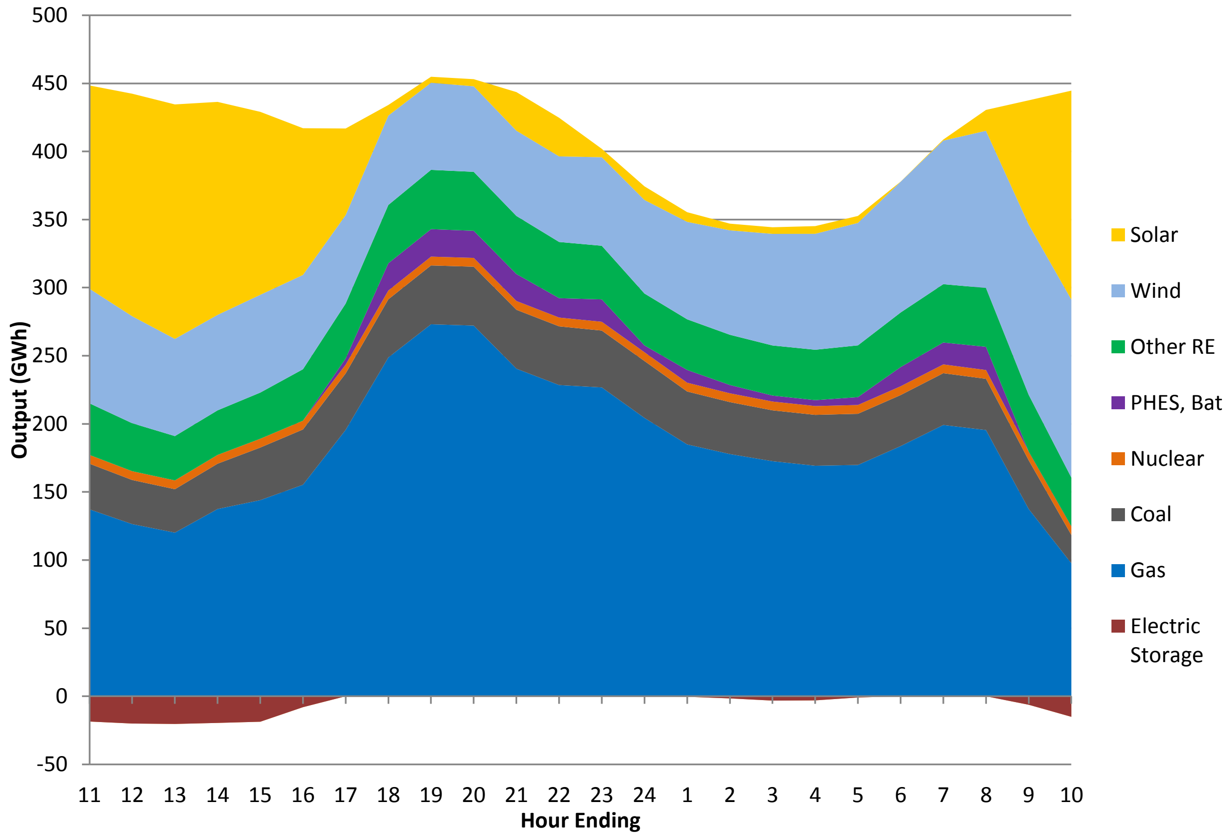
Figure 12. EI Winter Peak Day Hourly Generation by Category, 2015



In 2015, there was very little solar generation and a small amount of wind generation in the EI on the winter peak day. Coal, oil, and nuclear steam generation contributed about as much as gas-fired generation. Gas-fired generation peaks around 7pm, after a two hour ramp up.

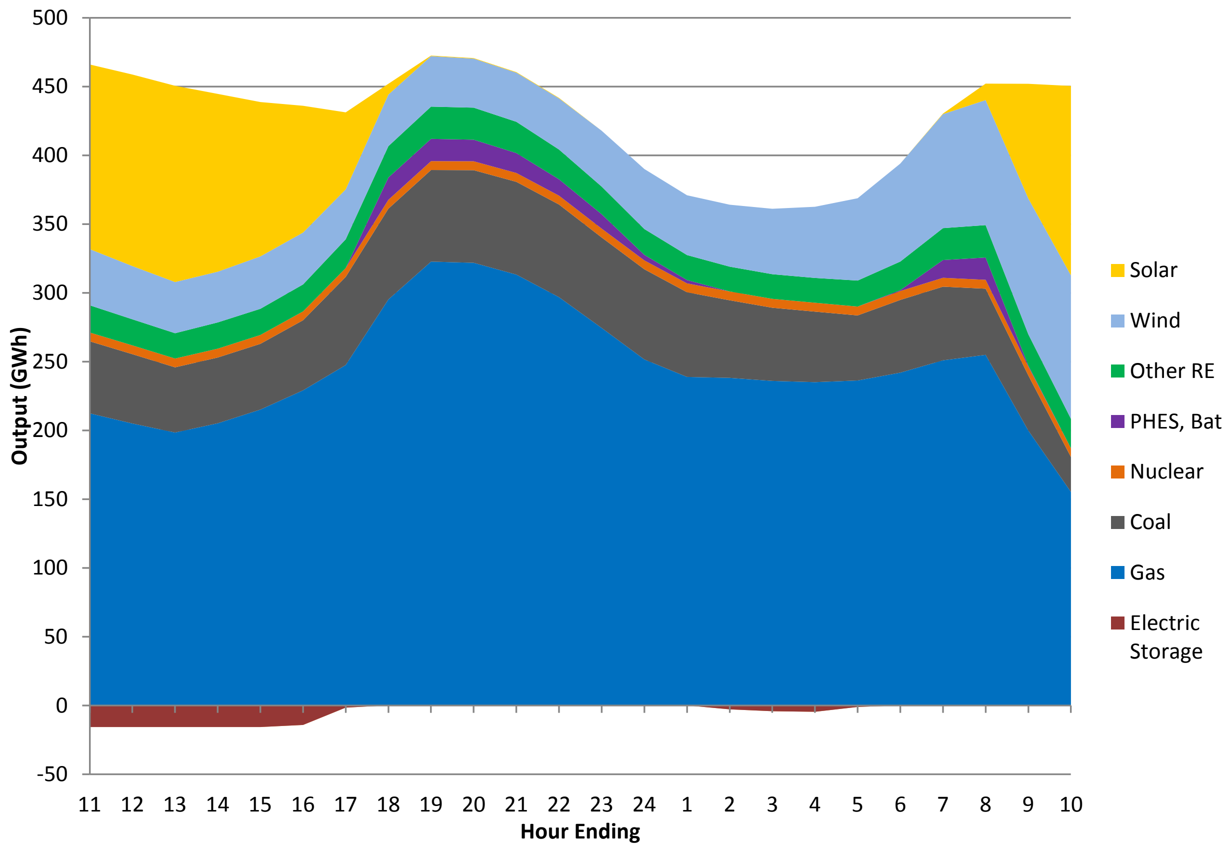
[19] The charts indicate the hour ending time.

Figure 13. EI Winter Peak Day Hourly Generation by Category, 2050 High RE Scenario



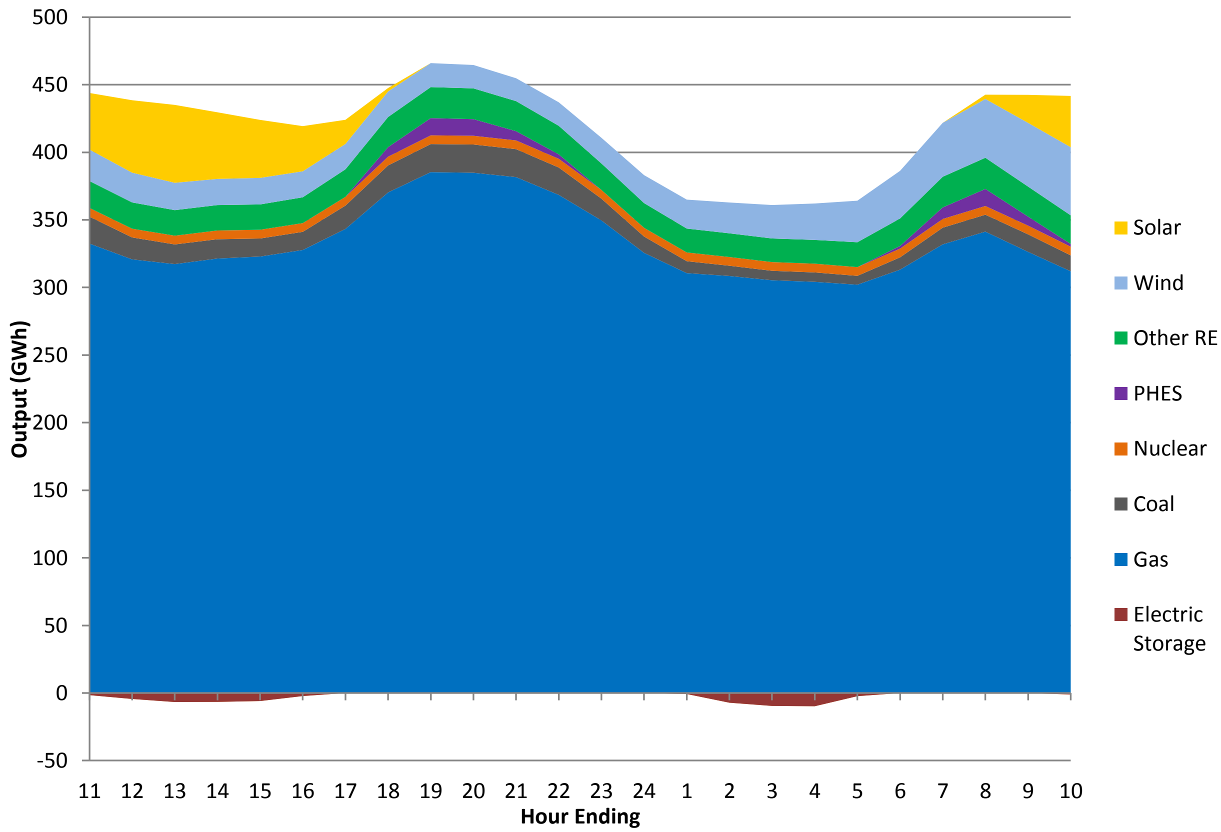
With the rapid decline in the large amount of solar generation between 1pm and 5pm of the 2050 winter peak day in the High RE scenario, gas-fired generation more than doubles over the four hour span. However, this steep ramp up is counterbalanced by low gas-fired generation during the solar generation hours, allowing use of more line-pack. Solar generation at night is from thermal storage at CSP plants, which are a significant resource in the High RE scenario.

Figure 14. EI Winter Peak Day Hourly Generation by Category, 2050 Mid RE Scenario



The hourly profile of gas-fired generation in the Mid RE scenario on the winter peak day has a pattern similar to that of the High RE scenario, but with less amplitude due to less VER generation.

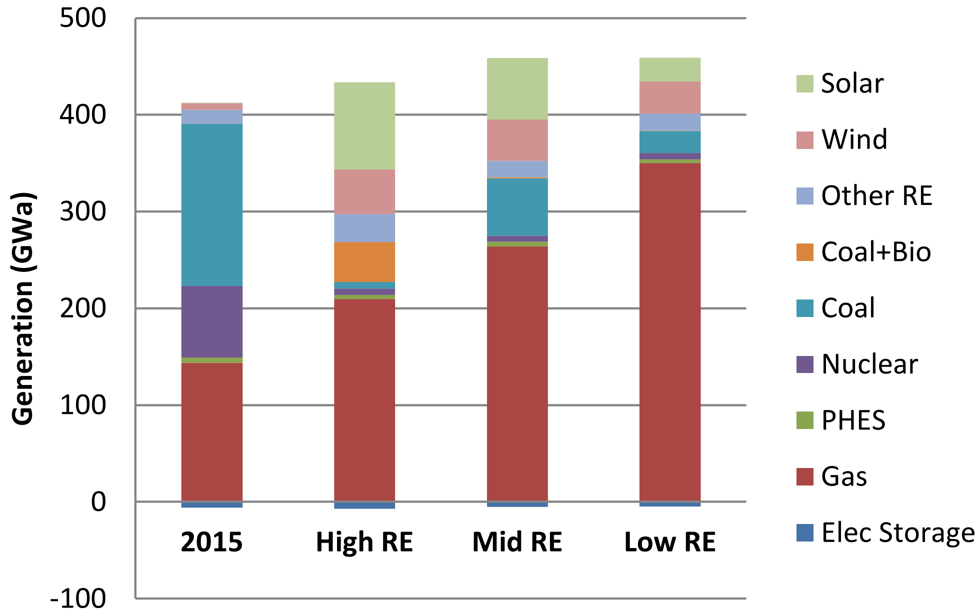
Figure 15. EI Winter Peak Day Hourly Generation by Category, 2050 Low RE Scenario



The Low RE scenario is the most gas-intensive in its generation mix of the three scenarios for the 2050 winter peak day, and has less diurnal amplitude than in 2015.

On the summer peak day in 2015, coal and nuclear generation contributed more than half of generation, and gas-fired generation provided most of the remainder. On the 2050 summer peak day, many CT and CAES units, and the few remaining oil/gas steam units, run in addition to CC plants, which generate the most, as shown in Figure 16.

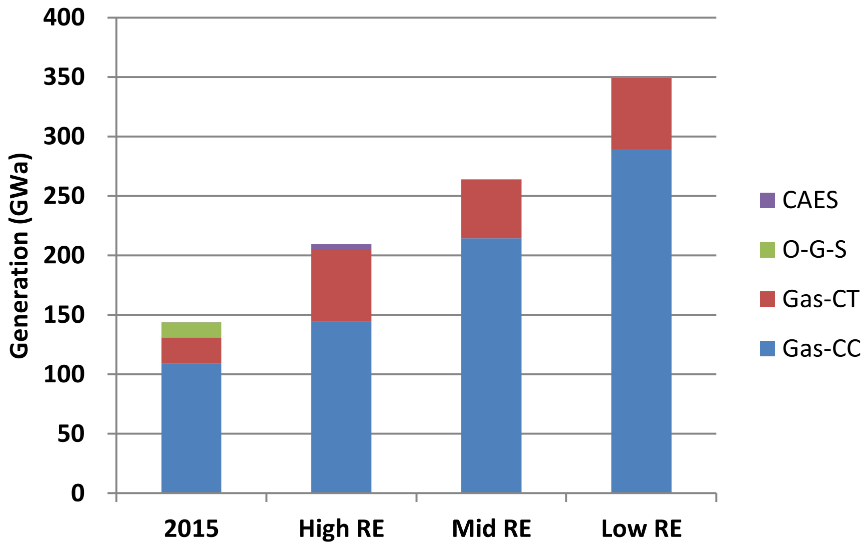
Figure 16. EI Summer Peak Day Generation by Fuel Type, 2015 and 2050 RE Scenarios



Total summer peak day generation is higher in the 2050 scenarios than in 2015 and varies by scenario due to differences in imports and additional generation for electric storage demands. VER generation in 2050 has 20, 15, and 8-fold increases over 2015, respectively, in the High, Mid, and Low RE scenarios. Total gas-fired generation is about 46%, 84%, and 144% greater than in 2050 than 2015 in the High RE, Mid RE, and Low RE scenarios, respectively.

Summer peak day generation by gas-fired technologies for 2015 and the three RE scenarios is compared in Figure 17. Generation on the peak summer day in 2050 by CT and CAES units is slightly larger in the High RE scenario than the Low RE scenario, while the Mid RE scenario has the smallest generation by gas-fired peaking resources. Generation by CC units is less than one-half as large in the High RE scenario as the Low RE scenario.

Figure 17. EI Summer Peak Day Generation by Gas-fired Technology, 2015 and 2050 RE Scenarios



Relative to the winter peak day, the summer peak day has more gas-fired generation by higher-cost CT and O-G-S units than for the corresponding winter peak day for each case in order to cover the higher demand on the summer peak day. There is less CAES generation during the 2050 summer peak day than the winter peak day in the High RE scenario, likely due to relatively higher electric energy costs for air compression in summer.

Summer power generation sector gas demand across the EI is generally higher than during the winter in the majority of the regions. With increased solar energy generation, the daily pattern of net load (after VE generation) to be served by gas-fired and other flexible generation and storage technologies, daily ramps become larger. Both the predictable diurnal cycle of solar generation and the weather-driven forecast uncertainties of VE generation contribute to the challenges for gas-fired and storage resources to follow net load swings. For the EI-wide summer peak day, the CoV of hourly gas-fired generation, and the ratio of maximum to minimum gas-fired generation are considerably larger than for the winter peak day of the same year and scenario, as shown in Table 6. However, there is less total demand on the gas infrastructure during summer than in winter.

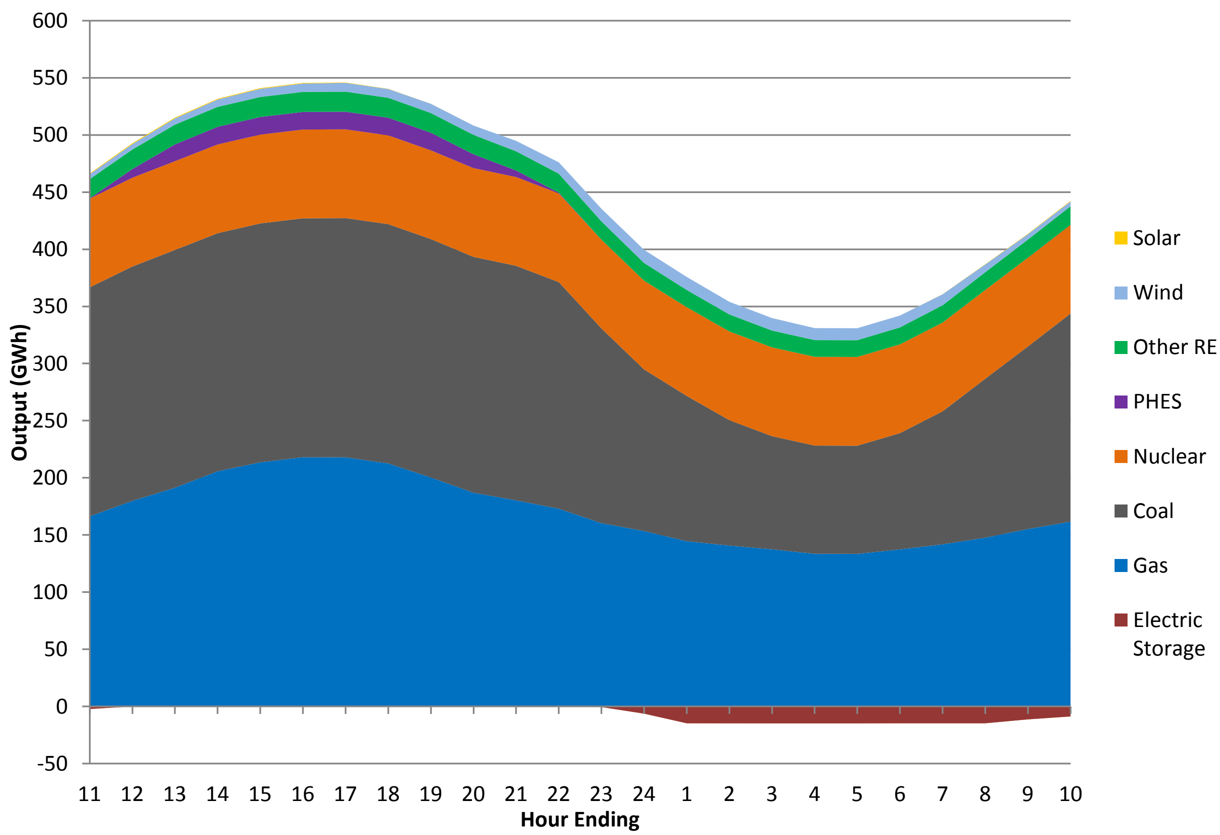
Table 6. Summer Peak Day Hourly Gas-fired Generation Cycling indicators

Case	2015	High RE	Mid RE	Low RE
Mean (GWa)	171	236	301	399
Max (GWa)	218	380	427	505
Min (GWa)	133	132	216	294
SD (GWa)	29	85	72	75
CoV	0.17	0.36	0.24	0.19
Max/Min	1.6	2.9	2.0	1.7

The 2050 summer peak day in the High RE scenario has much more hourly absolute and relative fluctuation in gas-fired generation than in 2015, while the Mid RE scenario is intermediate, and the Low RE scenario has slightly more diurnal cycling than in 2015.

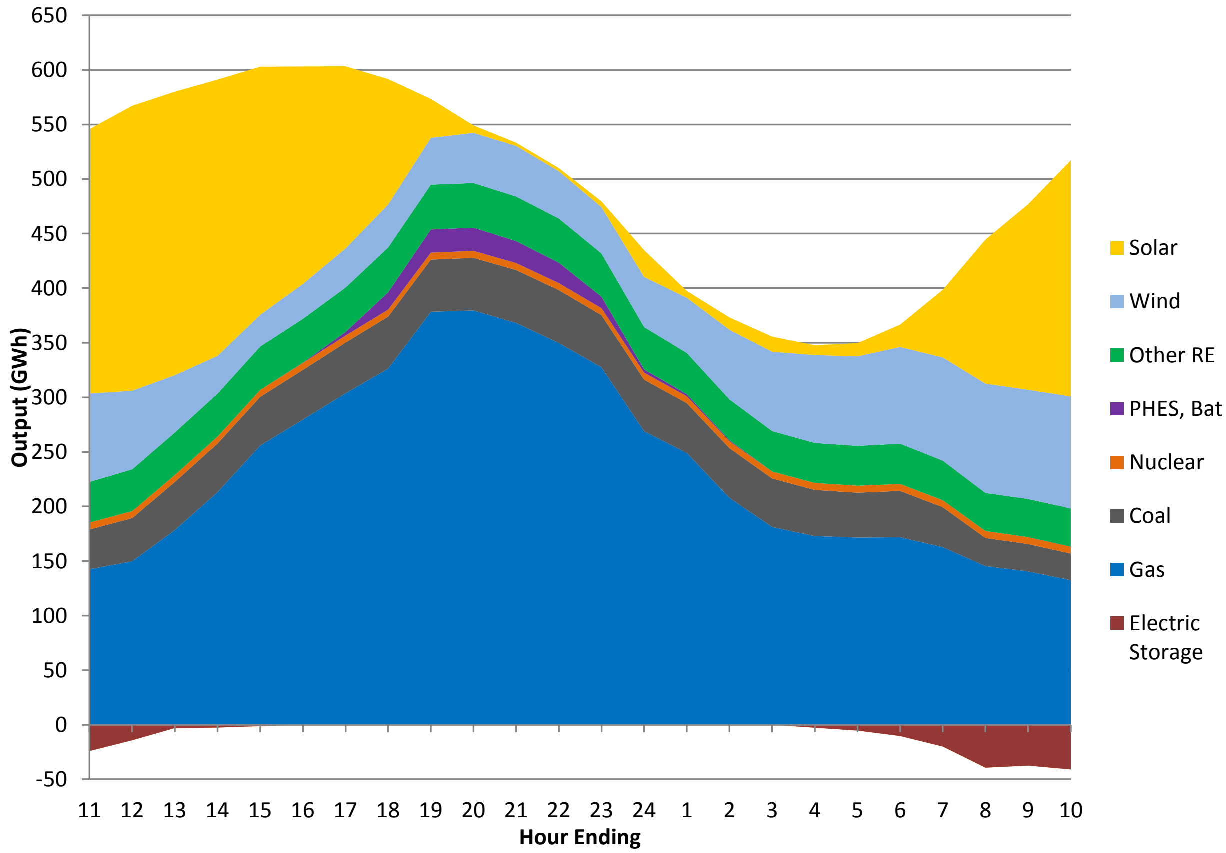
As previously seen in the daily profile charts for the winter peak day, hourly ramps and fluctuations increase with greater VE generation on the summer peak day (Figure 18 to Figure 21).

Figure 18. EI Summer Peak Day Hourly Generation by Category, 2015



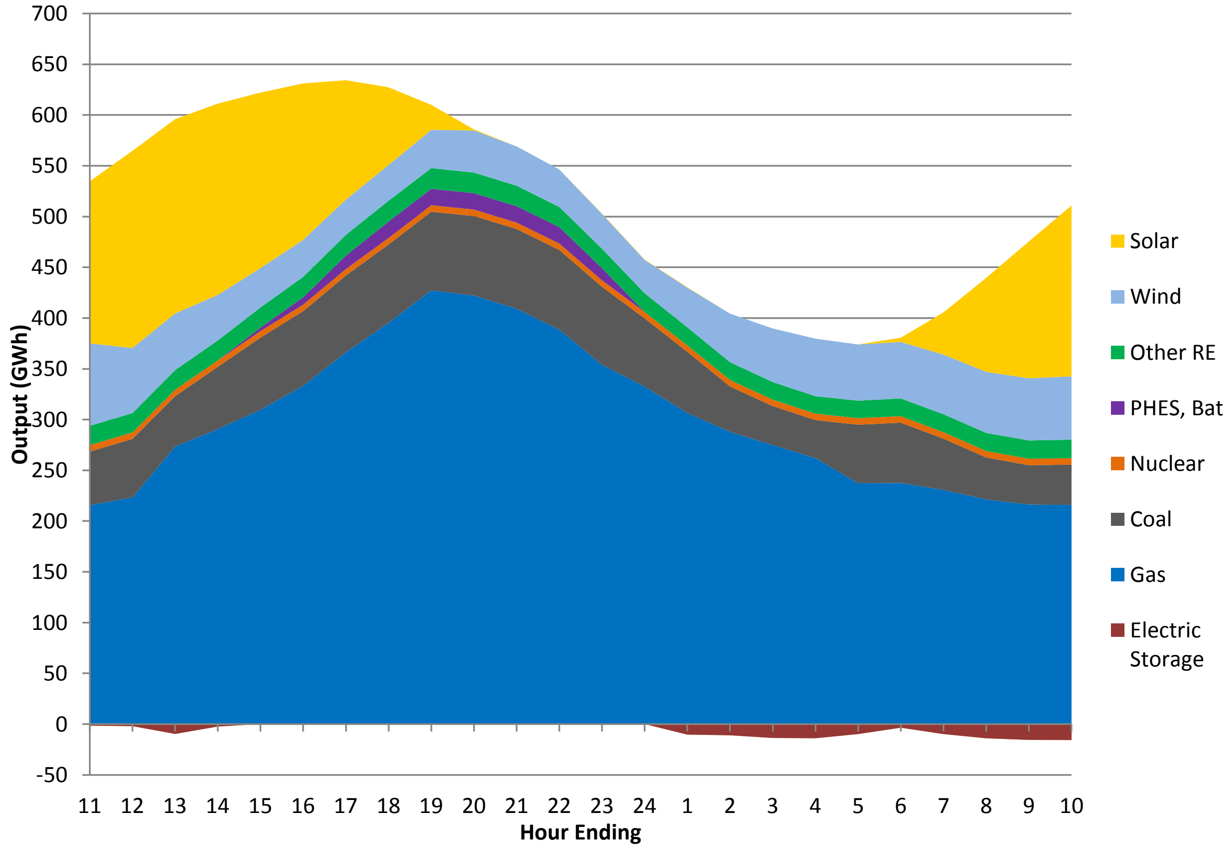
On the 2015 summer peak day, gas-fired generation peaks between 3pm to 4pm, when electric load peaks, and has a small diurnal cycle.

Figure 19. EI Summer Peak Day Hourly Generation by Category, 2050 High RE Scenario



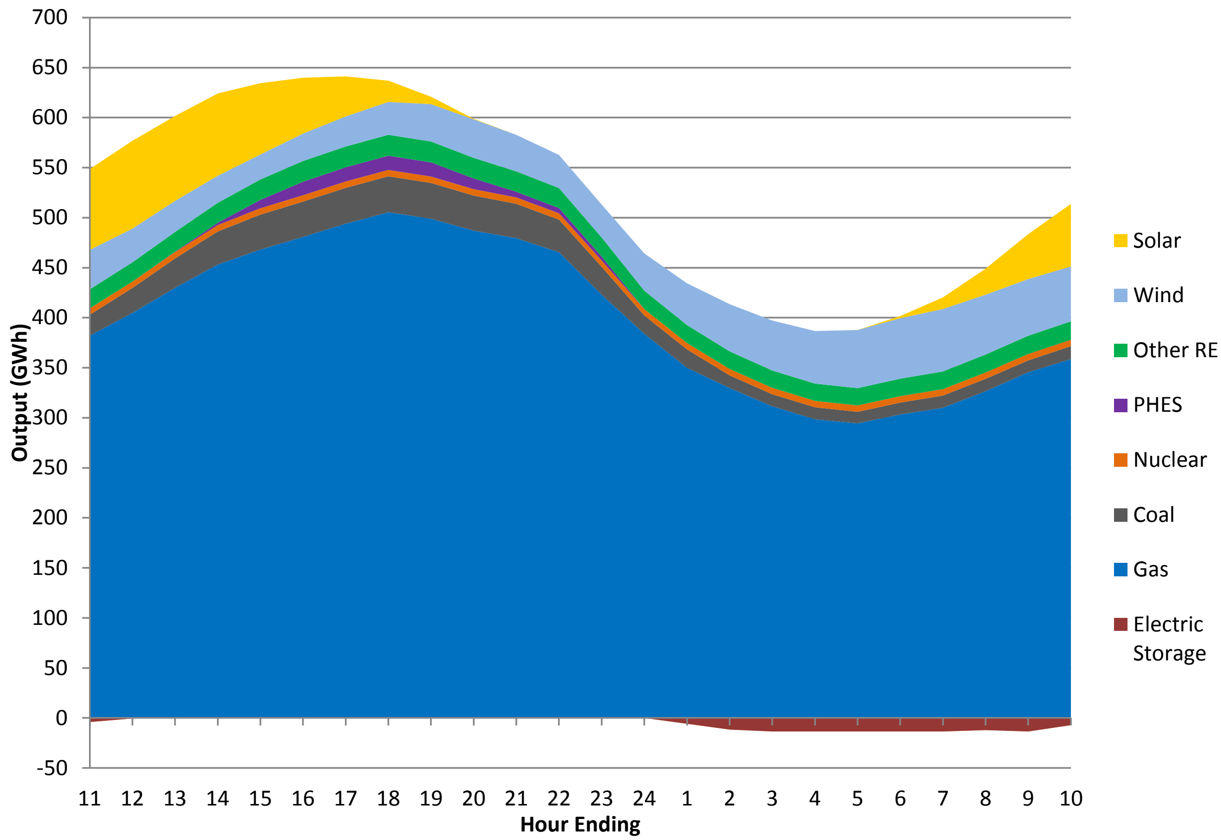
On the 2050 summer peak day of the High RE scenario, the large contribution of solar generation during the peak load daytime period results in a later peak in gas-fired generation, around 7pm, and causes much larger ramp up and down of gas-fired generation. However, this steep ramp up is counterbalanced by low gas-fired generation during the solar generation hours, allowing use of more line-pack. Solar generation at night is from thermal storage at CSP plants, which are a significant resource in the High RE scenario.

Figure 20. EI Summer Peak Day Hourly Generation by Category, 2050 Mid RE Scenario



On the 2050 summer peak day of the Mid RE scenario, the moderate contribution of solar generation during the day also delays peak gas-fired generation by about an hour, compared to 2015, and induces a moderate increase in ramp up and ramp down, relative to 2015.

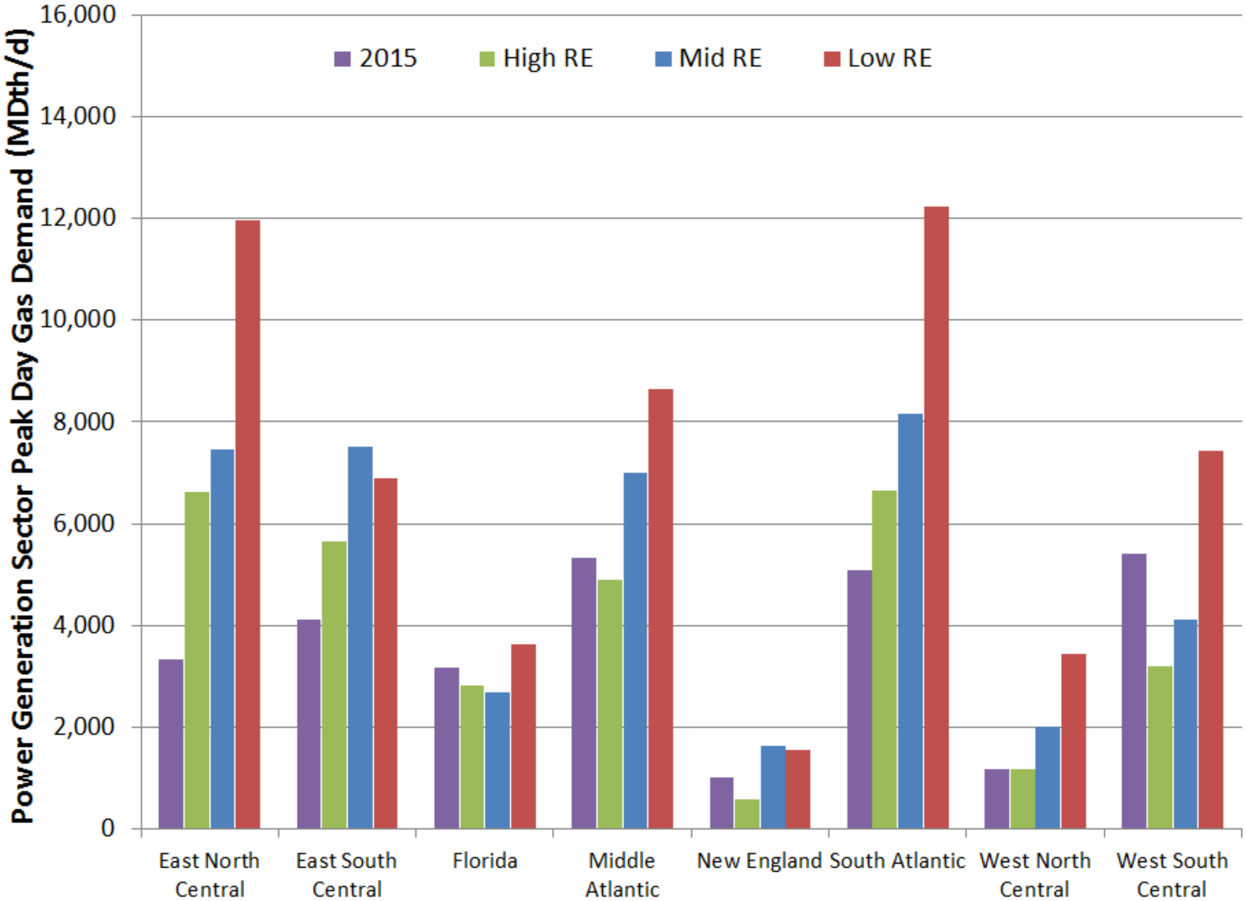
Figure 21. EI Summer Peak Day Hourly Generation by Category, 2050 Low RE Scenario



On the 2050 summer peak day of the Low RE scenario, the increases in solar and wind generation do not result in much change from 2015 in the diurnal pattern of gas-fired generation, and low gas prices result in more gas-fired generation than the other scenarios.

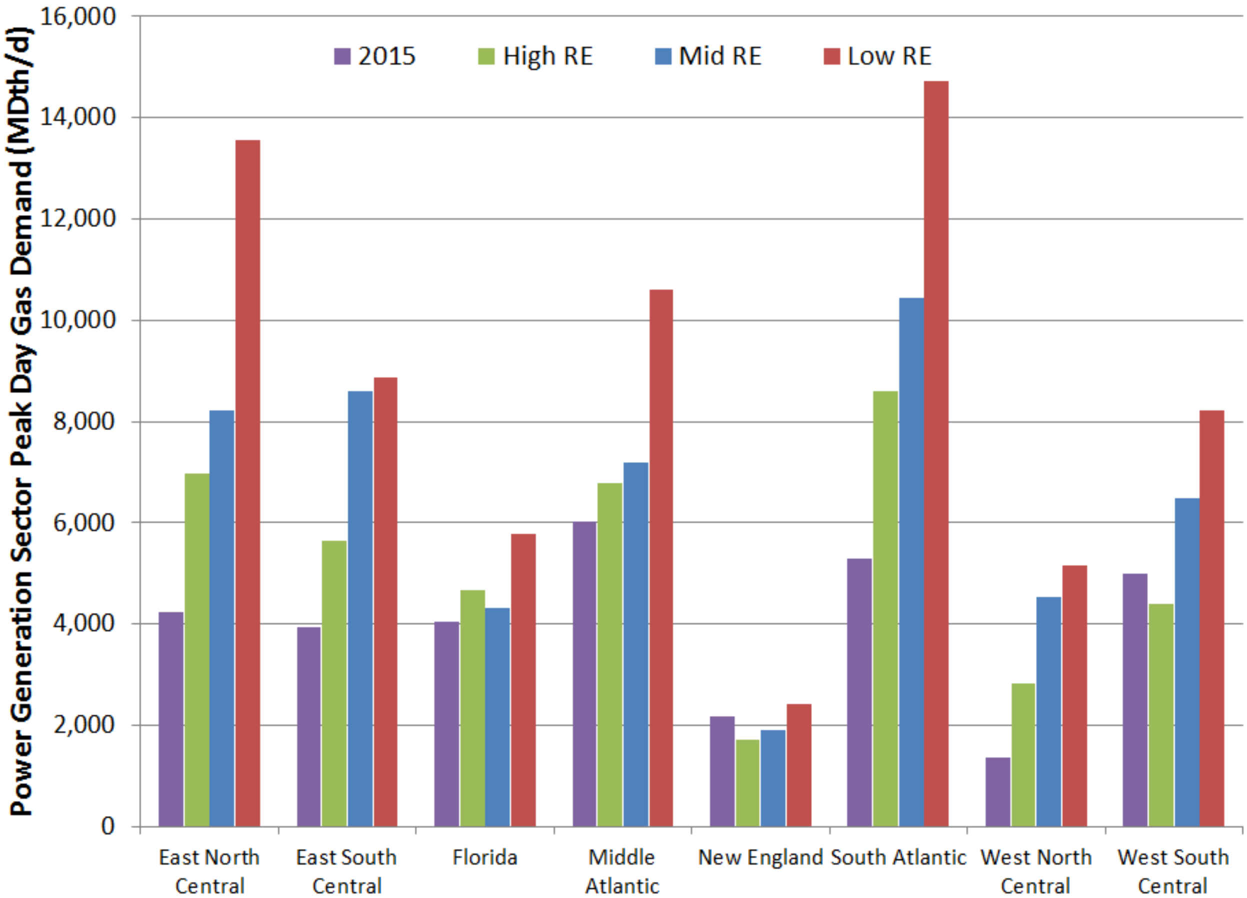
Figure 22 and Figure 23 compare the total power generation sector gas demand by census region in 2015 and the three 2050 scenarios for the winter and summer peak days, respectively. Interestingly, while total EI-wide annual and winter and summer peak day generator gas demands increase in 2050 for all three scenarios, some regions have less demand in the High RE and Mid RE scenarios in one or both peak seasons.

Figure 22. EI Peak Day Gas Demand – Power Generation Sector – Winter



Winter peak day generator gas demand in 2050 declines from 2015 in Florida and West South Central in both the High RE and Mid RE scenarios, and declines in the Middle Atlantic and New England regions in the High RE scenario. The Low RE scenario has the largest increase over 2015 winter peak day generator gas demand in the regions that now have the most coal-fired generation.

Figure 23. EI Peak Day Gas Demand – Power Generation Sector – Summer



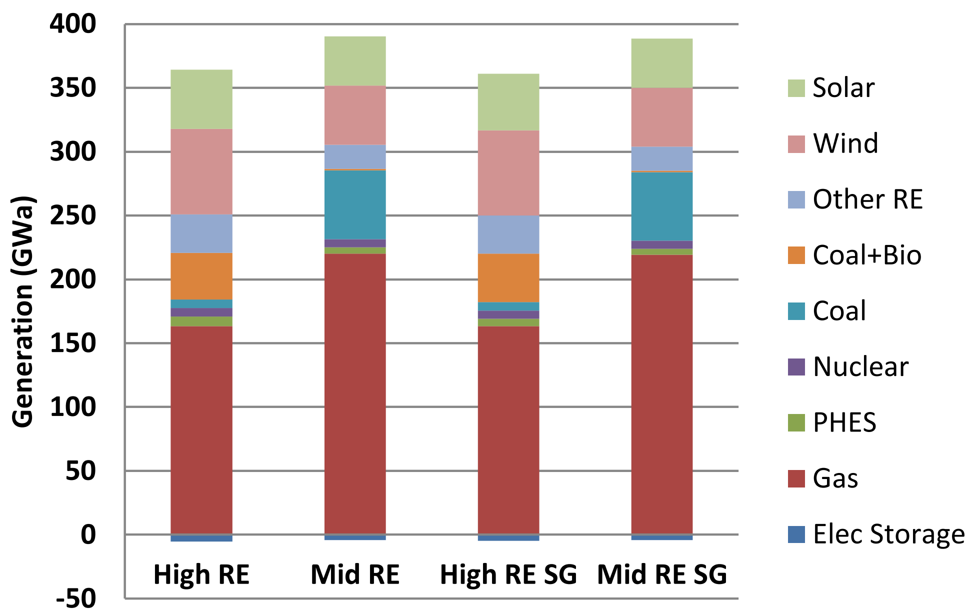
Summer peak day generator gas demand in 2050 declines from 2015 in New England and West South Central in the High RE scenario. The Low RE scenario has the largest increase over 2015 summer peak day generator gas demand in the regions that now have the most coal-fired generation.

2.7.2 Storage / Gas Sensitivity Generation

The Mid RE storage sensitivity case replaced all incremental electric storage capacity with an equal amount of CT capacity, and the High RE storage sensitivity replaced about one-half of incremental electric storage capacity with CT capacity in order to stress test gas infrastructure. In general, the storage capacity sensitivity cases did not alter annual or seasonal peak day gas demand much. The main conclusion of this sensitivity case is that there would not be much additional gas demand by relying more heavily on additional CT capacity and less CAES and PHES capacity to support the growth of VE resources in the High RE and Mid RE scenarios. Five factors contribute to this outcome. First, storage resources usually do not have high capacity factors, since they are often only economic to operate for a few hours at a time or only a few days over a year. Second, only the High RE scenario had a large expansion in CAES and PHES capacity. Third, CAES, which also uses gas, although more than twice as efficiently as CT technology, provided most of the increased storage capacity in the High RE scenario. Fourth, coal, biomass, and cofired biomass-coal generation also changed slightly in the SG sensitivities. In addition to these four factors, which apply at all times of the year, on winter and summer peak gas demand days, hourly energy prices tend to be flatter, thereby reducing the opportunity for economic dispatch of electric storage resources. Figure 24 to Figure 27 compare winter and summer peak day generation by fuel type and by gas-fired technology for the base High RE and Mid RE scenarios and their SG sensitivities.

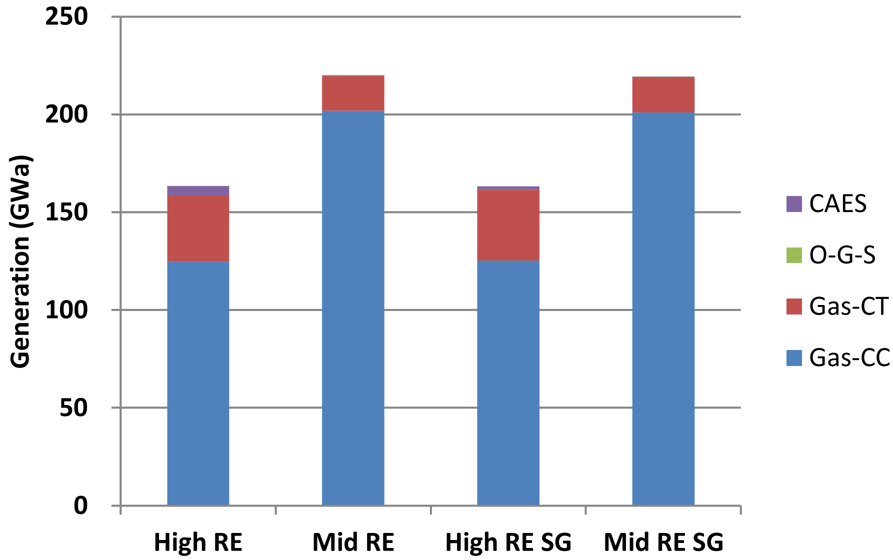
On the winter peak day of 2050 in the High RE scenario, total generation is 3.0 GWa less in the SG sensitivity than the base High RE scenario (Figure 26), of which 2.9 GWa is due to reduced electric load for storage. Gas-fired generation by CC and CT units increase due to the reduction in capacity and net output of CAES and PHES plants. In contrast, on the 2050 winter peak day in the Mid RE scenario, total generation in the EI is 1.7 GWa less in the SG sensitivity than the base Mid RE scenario, as a result of less utilization of PHES and CAES electric storage resources.

Figure 24. EI Winter Peak Day Generation by Fuel Type, 2050 by SG Sensitivity



Within the Gas category, non-CAES gas-fired generation in the High RE SG sensitivity on the winter peak day is 3.0 GWa higher than for the High RE scenario, while CAES generation is 3.0 GWa lower. Non-CAES gas-fired generation in the Mid RE SG sensitivity on the winter peak day is actually slightly less than in the base Mid RE scenario. PHES generation is 1.9 GWa lower in the High RE SG sensitivity than for the High RE scenario.

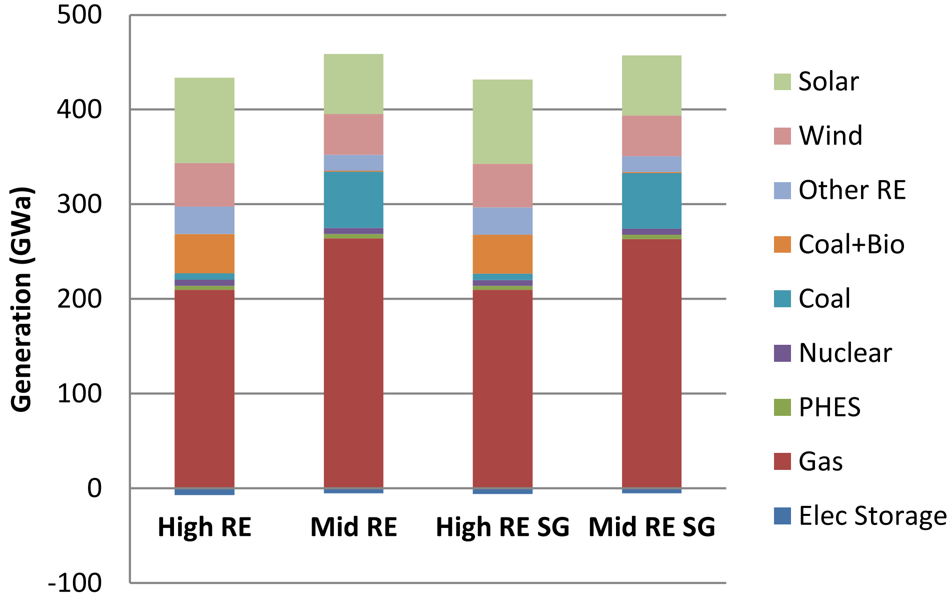
Figure 25. EI Winter Peak Day Generation by Gas-fired Technology, 2050 by SG Sensitivity



Both CT and CC generation increase slightly in the High RE SG sensitivity on the 2050 winter peak gas demand day. CT generation increases while CC generation decreases in the Mid RE sensitivity on the winter peak day.

On the summer peak day of 2050 in the High RE scenario (July 28/29), total generation is 1.9 GWa less in the SG sensitivity than the base High RE scenario (Figure 26), of which 1.2 GWa is due to reduced electric load for storage. Gas-fired generation by CC and CT units increase due to the reduction in capacity and net output of CAES and PHES plants. In contrast, on the 2050 summer peak day in the Mid RE scenario (July 27/28), total generation in the EI is 1.7 GWa less in the SG sensitivity than the base Mid RE scenario, as a result of less utilization of PHES and CAES electric storage resources.

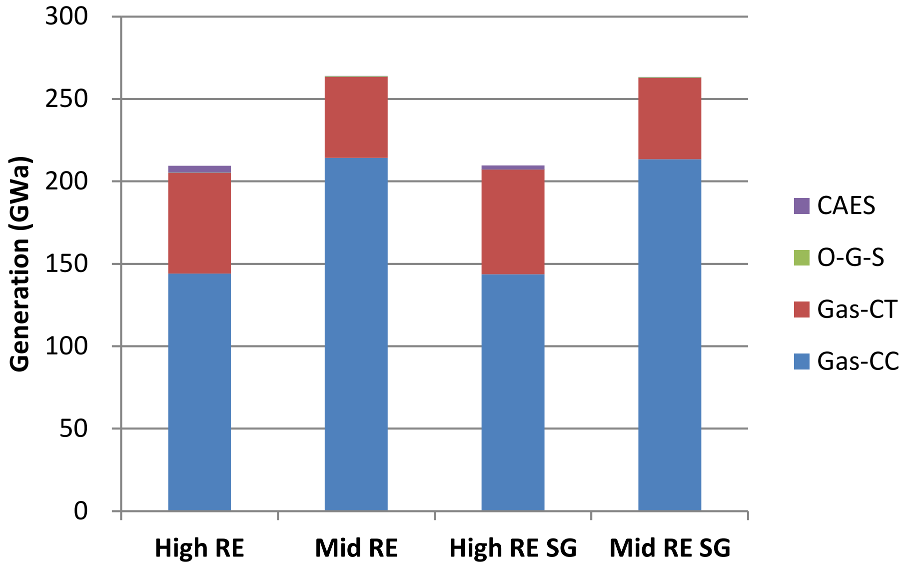
Figure 26. EI Summer Peak Day Generation by Fuel Type, 2050 by SG Sensitivity



Within the Gas category, non-CAES gas-fired generation in the High RE SG sensitivity on the summer peak day is 2.0 GWa higher than for the High RE scenario, while CAES generation is 1.7 GWa lower and PHES generation is 0.7 GWa lower. Non-CAES gas-fired generation in the Mid RE SG sensitivity on the winter peak day is actually slightly less than in the base Mid RE scenario.

Gas-fired generation on the peak summer day in 2050 is slightly greater in the High RE SG sensitivity than the High RE scenario for CT and CC units while it falls from 5.0 to 3.0 GWa for CAES units as a result of their nearly 50% smaller capacity. Total gas-fired generation is slightly less in the Mid RE SG sensitivity than the base Mid RE scenario.

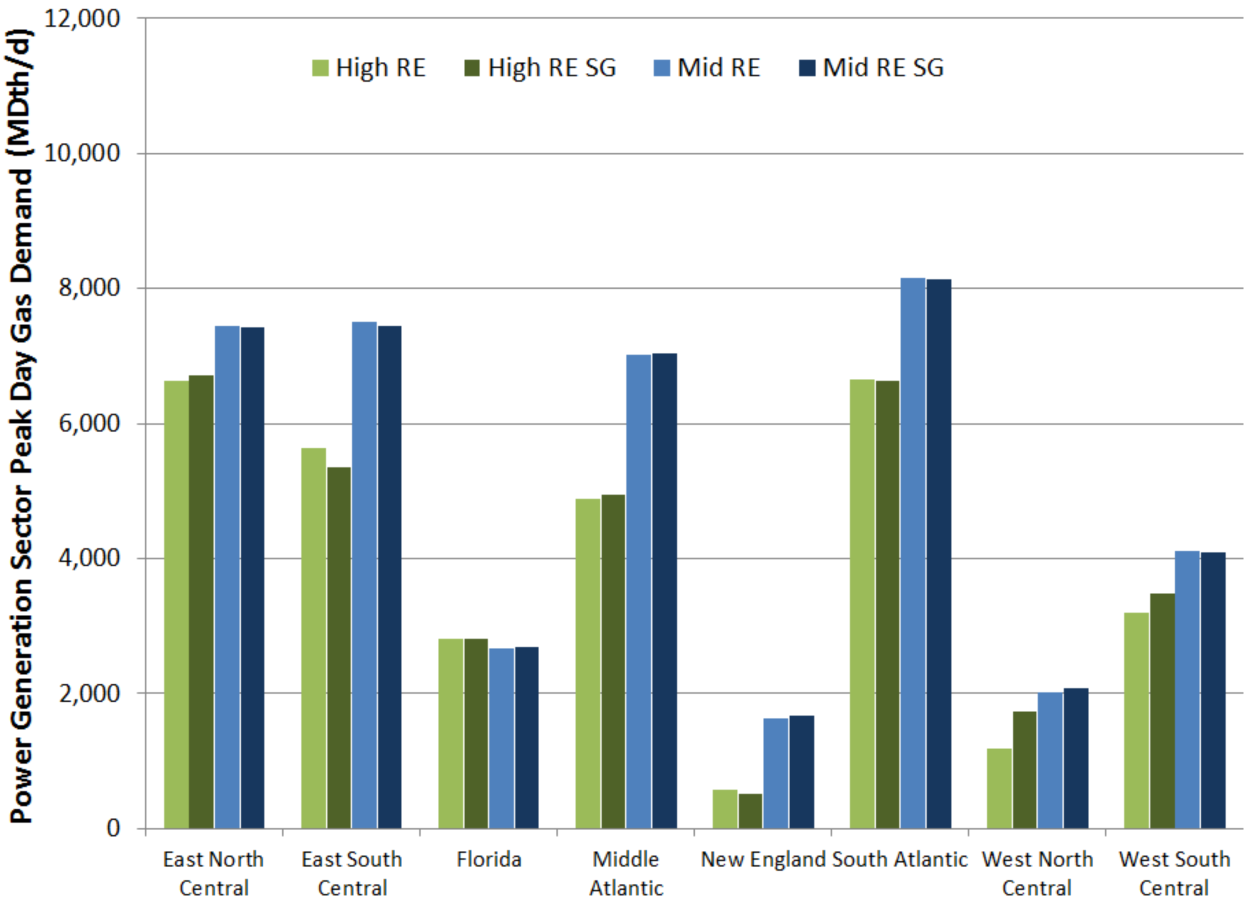
Figure 27. EI Summer Peak Day Generation by Gas-fired Technology, 2050 by SG Sensitivity



Both CT and CC generation increase slightly in the High RE SG sensitivity on the 2050 summer peak gas demand day. CT generation is constant while CC generation decreases slightly in the Mid RE sensitivity on the summer peak day.

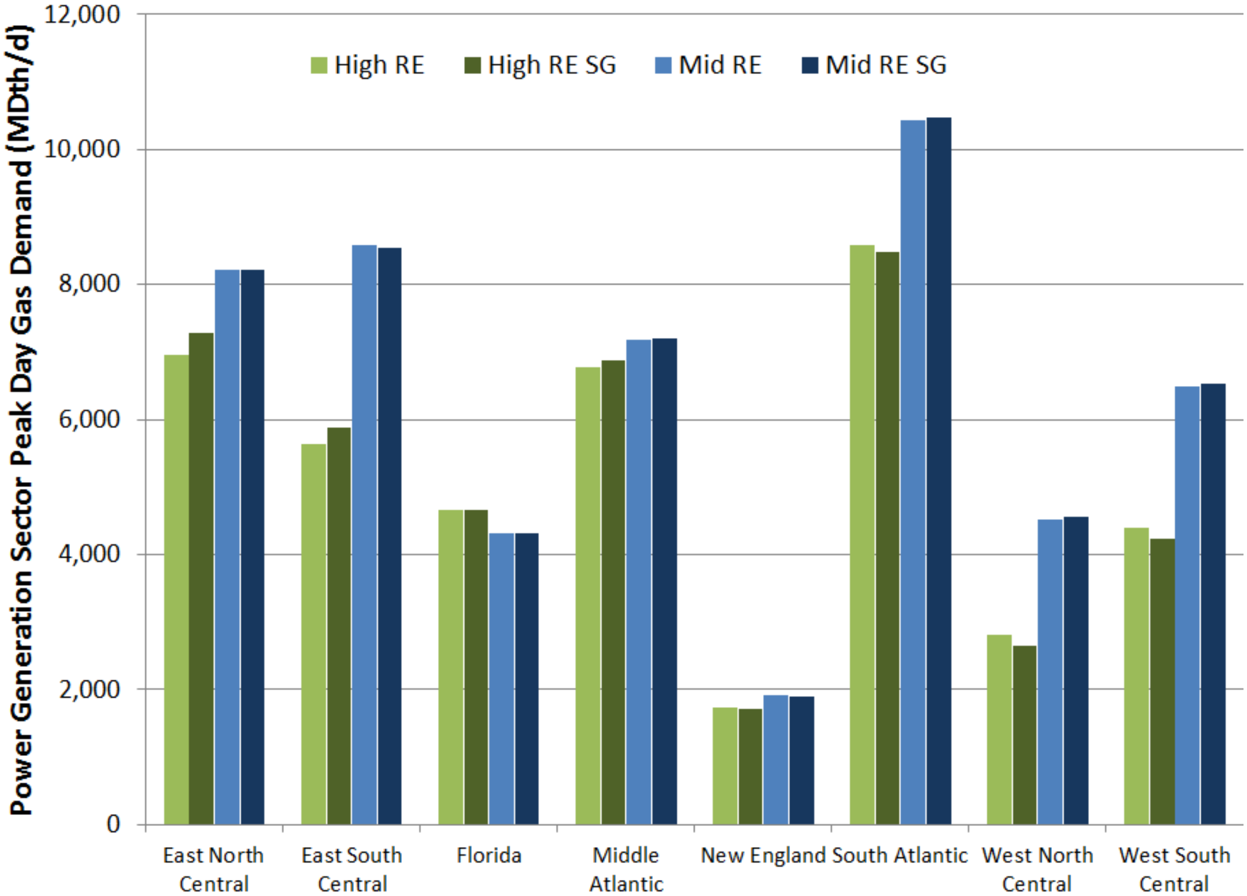
Figure 28 and Figure 29 compare total power generation sector gas demand by census region in 2015 and the three 2050 scenarios for the winter and summer peak days, respectively. There is not a direct correspondence between the regions with decreases in storage generation and regions with increases in generator gas demand. The main reason is that storage technologies also increase load during storage operation, and PHES and batteries use more electric energy for storage than is generated. Zonal transmission flow changes in the sensitivities also contribute to some of the regional changes in generator gas demand.

Figure 28. EI Peak Day Gas Demand – Power Generation Sector – Winter – SG Sensitivities



Regional changes in winter peak day generator gas demand do not exhibit a consistent relationship with the regional changes in generation by storage resources, which are mainly in West North Central, East North Central, South Atlantic, and East South Central.

Figure 29. EI Peak Day Gas Demand – Power Generation Sector – Summer – SG Sensitivities



Regional changes in summer peak day generator gas demand do not exhibit a consistent relationship with the regional changes in generation by storage resources, which are mainly in West North Central, East North Central, and East South Central.

3 NATURAL GAS MARKET ASSUMPTIONS

3.1 HIGHLIGHTS

- Assumption: Natural gas supply is assumed to be adequate to meet demand through 2050. In accord with the study paradigm, natural gas supply is always sufficient at pipeline receipt points in all supply basins.

- Assumption: Consistent with *AEO 2015*, LNG exports are expected to increase in all scenarios. LNG export terminals are mostly located along the Gulf coast, based on the list of terminals that are already under construction, approved by FERC or in FERC pre-filing. Also consistent with *AEO 2015*, LNG imports are expected to be the same low volume in all scenarios. LAI has assumed that all LNG imports in 2050 will be allocated to serving the fuel needs of a gas-fired power generator currently supplied directly by the Everett LNG terminal in Boston. The 2015 "benchmark" has been analyzed both with and without actual historical LNG sendout to pipelines from the Canaport, Cove Point, Elba Island, Everett and Northeast Gateway terminals. The 2015 benchmark without LNG sendout is compared to the 2050 scenarios that are consistent with the *AEO 2015* LNG import assumptions. To determine the extent to which constraints may be alleviated, the 2015 benchmark with LNG sendout is compared to a separate 2050 LNG Import sensitivity assuming 2015 LNG import levels from all terminals **except** Cove Point, which is converted to an export terminal.

- Assumption: Gas demand to serve all gas utility sector and LNG export customers is met by firm pipeline transportation in 2050. Firm-contract-backed pipeline capacity expansions are added where necessary to assure adequate deliverability to gas utility sector and LNG export customers.

- Assumption: Gas demand to serve a power generation sector customers is assumed to be met through non-firm (interruptible) pipeline transportation. Hence, all gas utility sector and LNG export gas demand is met before power generation sector gas demand is served. No pipeline capacity expansions will be added specifically to supply gas to power generators. Currently, some generators do have firm pipeline transportation that entitles those generations higher priority access to pipeline capacity. If these or other generators choose to pay for firm pipeline transportation capacity in 2050, some of the pipeline constraints revealed in the study results would be alleviated.

- Assumption: The level and profile of gas utility sector demand in 2050 is based on historical pipeline delivery data and growth rates in *AEO 2015*. The average growth rate over the last ten years of the *AEO 2015* forecast (2031-2040) is used to extrapolate growth rates from 2040 to 2050. The gas utility sector includes all residential, commercial, industrial and transportation end-users.

- Assumption: Peak gas utility sector gas demand and peak power generation sector gas demand days are coincident.

- Interim Result: All census regions show overall positive gas utility sector gas demand growth between 2015 and 2050. There is a greater differential between winter and summer peak day demand in the northern portion of the EI, where winter heating demand for gas is greater.

- Interim Result: The combined power generation sector and gas utility sector gas demands show that Florida is summer peaking in the 2015 benchmark and all three 2050 scenarios, which means that total summer peak day demand is higher than total winter peak demand. East South Central and West South Central are each summer peaking in two scenarios, and West North Central is summer peaking in one scenario.

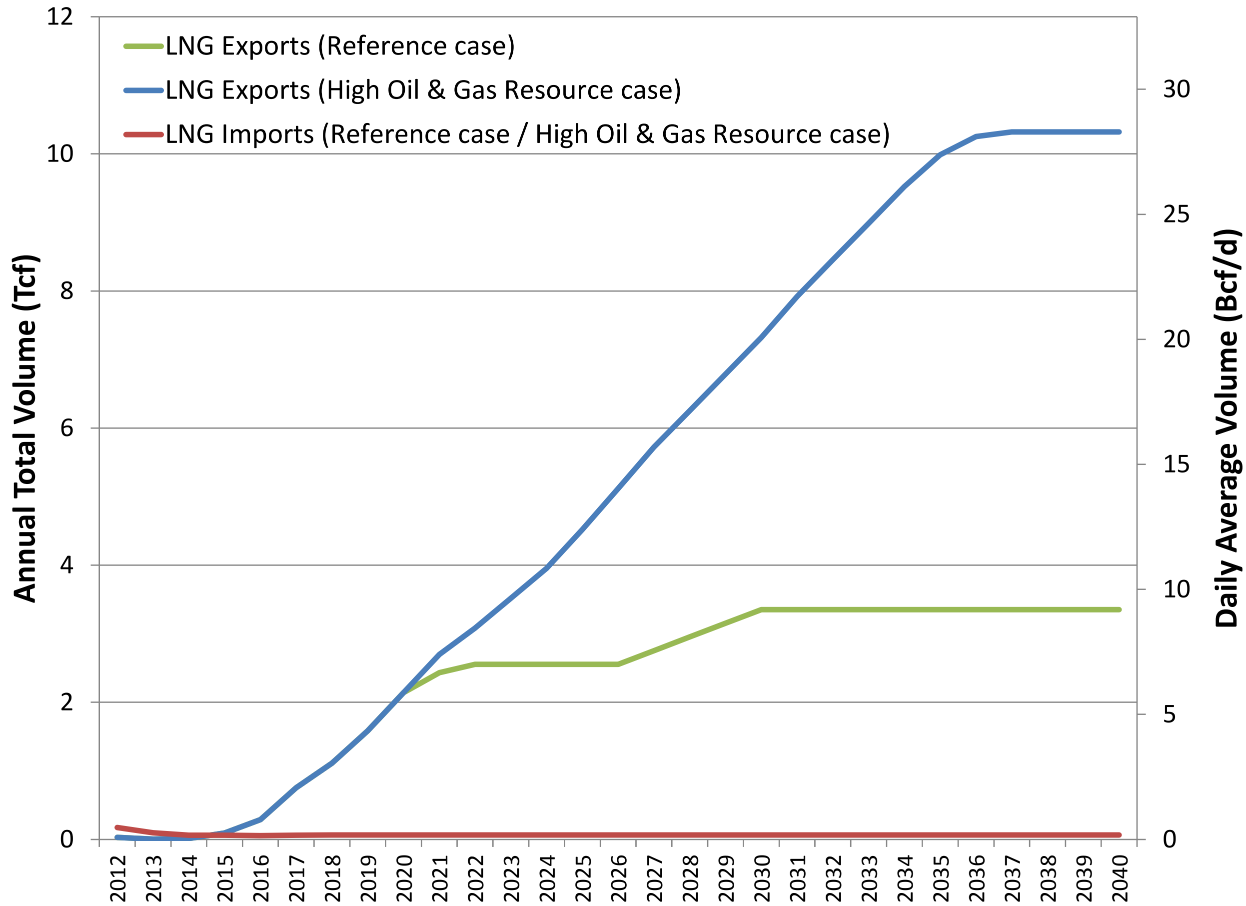
3.2 Natural Gas Supply

The continued rapid development of gas production from shale formations has radically changed the market and operational dynamics of the pipelines serving the EI. Prolific production of both shale and conventional gas supplies has centered the study objectives on gas infrastructure capability and responsiveness. The analysis assumes that there is enough production capacity and supply available to support the full pipeline flow capability across the EI.

3.3 LNG Imports and Exports

Figure 30 illustrates the *AEO 2015* projections for LNG imports and exports through 2040. As discussed below, the import volumes are negligible relative to the high growth in exports over the forecast period.

Figure 30. *AEO 2015* LNG Import and Export Projections



LNG exports and imports are constant during the last five years of the *AEO 2015* forecast period, and are assumed for purposes of this study to be maintained at the same levels in 2050. LNG exports are significantly higher in the High Oil & Gas Resource case than in the Reference case, reflecting higher gas production. LNG imports are the same in both cases, but are much lower (although non-zero) than exports.

The *AEO 2015* Reference case projects that the U.S. will export 3.4 Tcf of LNG in 2040, or 9.2 Bcf/d. No growth in exports is shown after 2030. Exports in 2050 are therefore assumed to be the same as in 2040. Consistent with this forecast, the Mid RE and High RE scenarios assume that the five LNG export terminals currently approved and under construction will be operating in 2050: Sabine Pass (3.5 Bcf/d), Cameron/Hackberry (2.1 Bcf/d), Freeport (1.8 Bcf/d), Cove Point (0.82 Bcf/d) and Corpus Christi (2.14 Bcf/d). The total capacity of these export terminals is 10.4 Bcf/d, which is slightly more than the projected average daily exports in 2050. However, since the export terminals will not necessarily run at full capacity throughout the year, the operation of these facilities is consistent with the *AEO 2015* Reference case.

The *AEO 2015* High Oil & Gas Resource case projects that the U.S. will export 10.3 Tcf of LNG in 2040, or 28.3 Bcf/d. No growth in exports is shown after 2037. Exports in 2050 are therefore again assumed to be the same as in 2040. Consistent with this forecast, the Low RE scenario assumes that 16 additional terminals and terminal expansions will also be operating in 2050. These incremental terminals include:[20]

- Three terminals and one expansion that are approved but not yet under construction: Lake Charles (2.2 Bcf/d), Magnolia/Lake Charles (1.08 Bcf/d), Cameron/Hackberry expansion (1.41 Bcf/d incremental) and Southern/Elba Island (0.35 Bcf/d);

- Five terminals and one expansion with pending applications before FERC: Golden Pass/Sabine Pass (2.1 Bcf/d), Gulf/Pascagoula (1.5 Bcf/d), Freeport expansion (0.34 Bcf/d incremental), Calcasieu Pass/Cameron Parish (1.41 Bcf/d), Texas/Brownsville (0.55 Bcf/d) and Rio Grande/Brownsville (3.6 Bcf/d); and

- Six terminals currently in pre-filing: CE/Plaquemines Parish (1.07 Bcf/d), Louisiana/Plaquemines Parish (0.3 Bcf/d), Downeast/Robbinston (0.45 Bcf/d), Eagle/Jacksonville (0.075 Bcf/d), Annova/Brownsville (0.94 Bcf/d) and Port Arthur (1.4 Bcf/d).

Again, the total capacity of the export terminals is slightly more than the projected average daily exports in 2050. Assuming a less than 100% capacity factor, the operation of these facilities is consistent with the *AEO 2015* High Oil & Gas Resource case.

AEO 2015 projects, in both the Reference and High Oil & Gas Resource cases, that the U.S. will import 65 Bcf of LNG in 2040, or an average of 178 MMcf/d. *AEO* 2015 shows flat import volumes from 2018 to 2040. The same volume has therefore been extrapolated to 2050. This is approximately the amount of LNG needed to fuel the power plant currently directly served by the Everett import terminal in Boston. LAI has therefore allocated the full forecasted amount of imported LNG to meet this plant's demand in all scenarios. No other demands are assumed to be met through regasified LNG from Everett in 2050 for the three primary scenarios.

For the 2015 benchmark, actual sendout from LNG terminals into pipelines in constrained regions was incorporated in the peak day analysis.[21] The values used in the analysis were determined based on the sendout volumes from each terminal on the seasonal coincident peak sendout days across all five terminals, which occurred on January 8, 2015 and August 7, 2015. These sendout volumes are listed in Table 7.

[20] Source: FERC list of existing, approved and proposed LNG terminals

[21] Operations at the two Gulf import terminals listed by DOE as receiving LNG cargoes in 2015 (Freeport and Sabine Pass) were not included in the analysis due to (1) the absence of regional constraints and (2) lack of availability of historical sendout data.

Table 7. 2015 Peak Day LNG Sendout Volumes to Pipelines

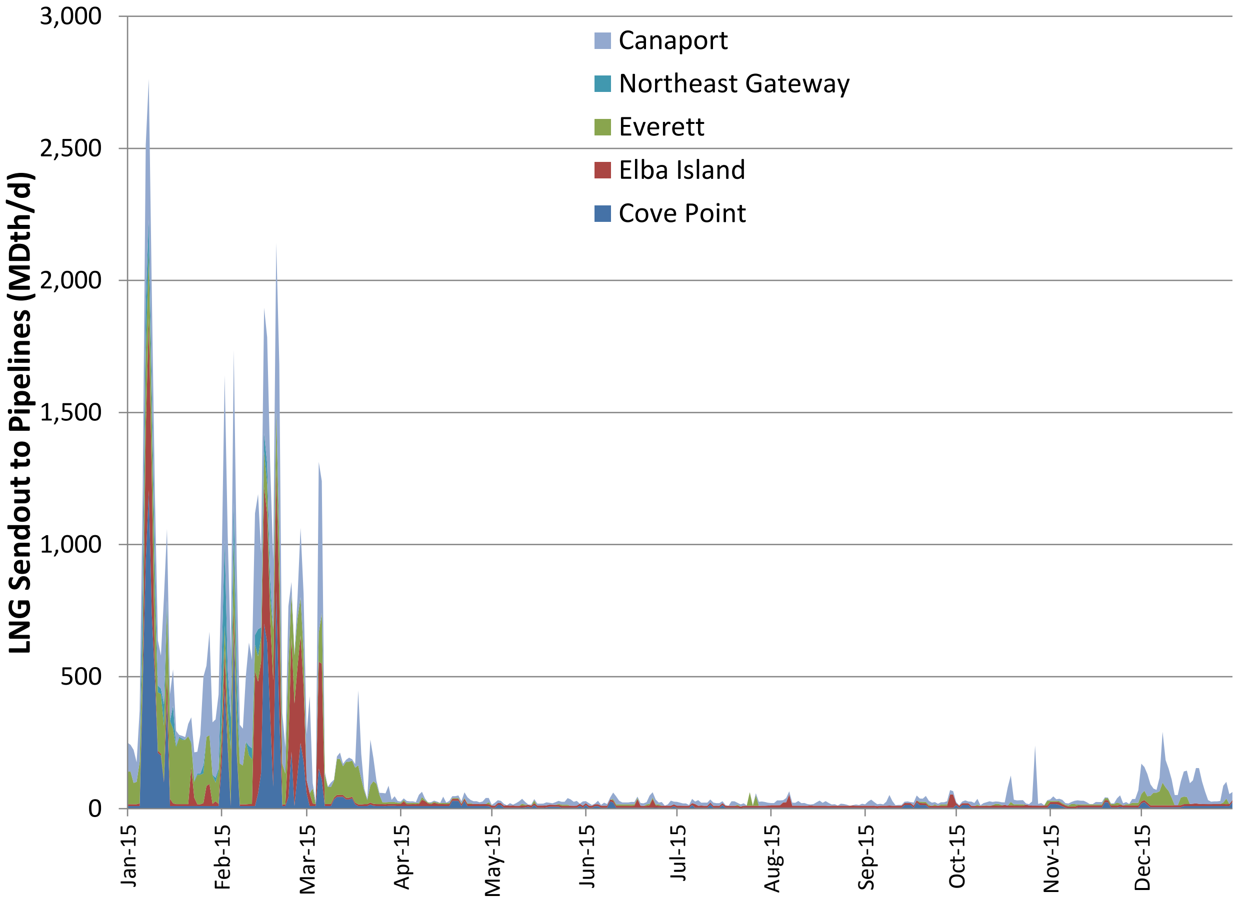
Terminal	Winter Peak Day Sendout (MDth/d)	Summer Peak Day Sendout (MDth/d)
Canaport	531	12
Cove Point	1,206	4
Elba Island	653	50
Everett[22]	255	0
Northeast Gateway	119	0
Total	2,764	66

These values reflect LNG sendout to connected pipelines from each terminal on the seasonal coincident peak days, which occurred on January 8, 2015 and August 7, 2015. The same values are applied to the 2050 LNG Import sensitivity analysis, except Cove Point, which is assumed to convert to an export terminal and therefore will not be available for imports in the future.

LNG sendout from these terminals for each day in 2015 is shown in Figure 31. This chronological data set was used in the analysis of seasonal constraint frequency and duration.

[22] Does not include sendout to the directly-connected power plant.

Figure 31. 2015 Daily LNG Sendout Volumes to Pipelines



In 2015, LNG sendout was highly variable during January and February. LNG sendout in December was significant, although much lower than the peak volumes in January and February. Reflecting the price sensitivity of LNG imports, summer LNG sendout from the terminals was reasonably consistent, but trivial compared to winter sendout. Destination-flexible cargoes generally do not come to the U.S. because gas prices in the E.U. and Asia are higher.

In order to develop an appropriate 2015 benchmark for comparison to the 2050 results, two 2015 cases were prepared, both with and without LNG imports. The 2015 benchmark less LNG imports was developed for comparison to the primary 2050 scenarios, which are consistent with *AEO* 2015 and do not include any pipeline sendout from LNG terminals. The 2015 benchmark including LNG imports was developed for comparison to a 2050 LNG Import sensitivity. This sensitivity analysis, assuming 2015 LNG regasification levels for each of the 2050 scenarios, was conducted in order to determine whether higher import levels could alleviate pipeline constraints. For this sensitivity, the 2015 seasonal peak day sendouts were assumed to occur on the coincident peak days, and the chronological sendout volumes were applied to the seasonal analysis.[23] The exception to this treatment is Cove Point, which

[23] LAI did not explore FERC jurisdictional wholesale market design and/or state energy policy changes that would be required to revitalize LNG imports in 2050 relative to the market conditions included in *AEO 2015*.

is assumed to convert from an import to an export terminal and no longer be able to import LNG cargoes in the 2050 LNG Import sensitivity.

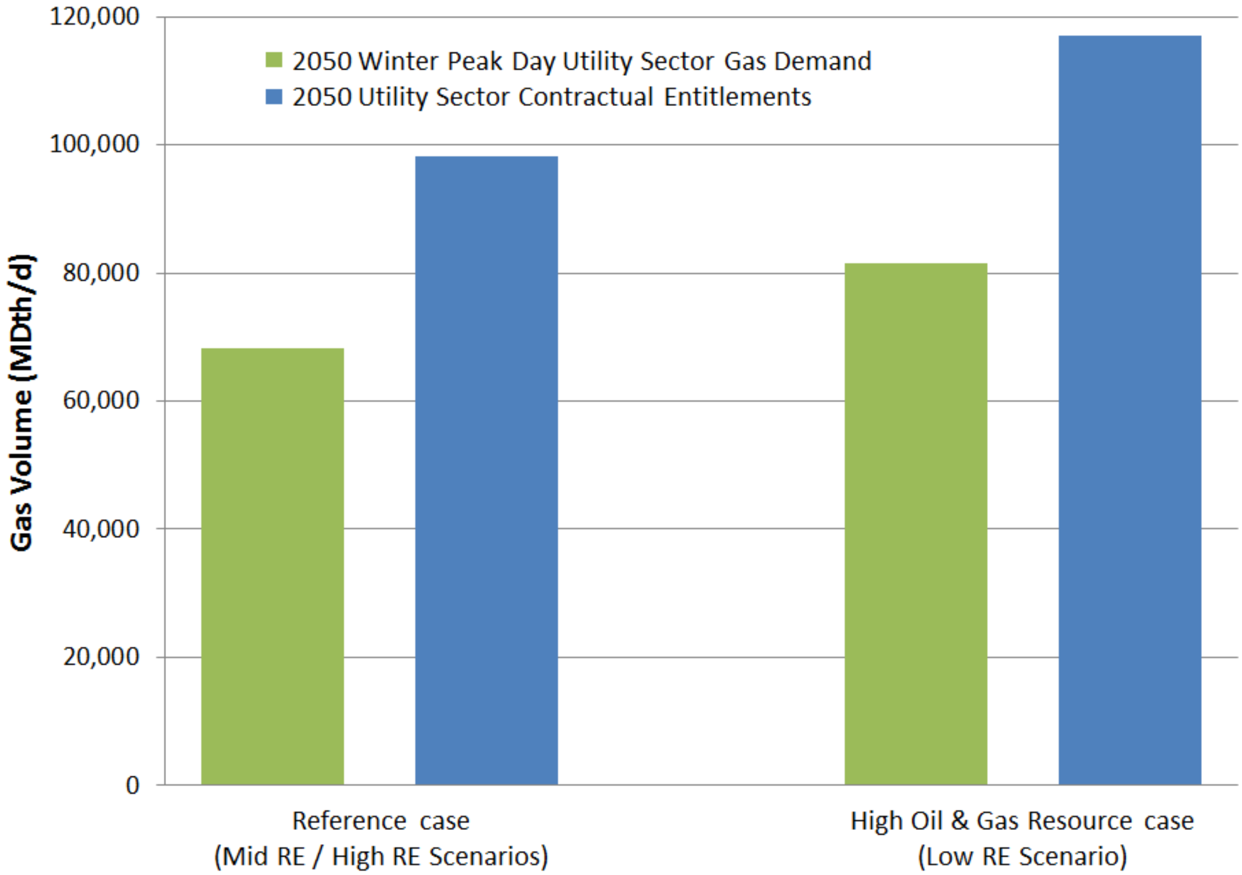
3.4 NATURAL GAS INFRASTRUCTURE

Two primary assumptions drive the natural gas infrastructure buildout to 2050: (1) all gas utility sector gas demand is met and (2) no generators have rights to firm transportation in 2050.

Gas utilities are required by state regulators to hold sufficient supply and transportation arrangements to meet forecast winter peak demand. The statistical definition of a peak day varies by gas utility, and, in some instances, even within a state. Moreover, not all state regulatory commissions require state-jurisdictional gas utilities to make forecasts publicly available.[24] Therefore, in order to ensure consistency across the EI study region, each customer's non-coincident peak day demand during the historical period studied for the gas utility sector demand forecast was extrapolated to 2050 based on the census region growth rates in both the *AEO 2015* Reference and High Oil & Gas Resource cases. The maximum annual non-coincident peak day requirement between 2015 and 2050 was assumed to be the amount of pipeline capacity held by a given customer. Figure 32 illustrates the differential between total contractual entitlements assumed for the gas utility sector to hold adequate supply to meet design day demand and total coincident peak day gas utility sector demand in 2050 for the Reference case (Mid RE and High RE scenarios) and High Oil & Gas Resource case (Low RE scenario). In effect a reserve margin, this differential between the design peak day utilities will be required to contract for and the expected actual peak day demand represents pipeline capacity that is available to meet electric sector demand in each scenario on the seasonal peak days.

[24] Utility sector customers that are not gas utilities, for example, industrial customers that are directly connected to interstate pipelines, do not have the same requirements to hold sufficient pipeline capacity to support forecast peak day demand. For consistency, the same method has been applied to all utility sector customers.

Figure 32. Gas Utility Sector Winter Peak Day Gas Demand v. Contractual Entitlements



State-regulated gas utilities must maintain pipeline transportation and gas storage contracts sufficient to serve their design peak day demand, represented by the blue bars. The green bars represent gas utility sector demand on the coincident winter peak day to illustrate the difference between the design day demand that utilities must plan for and expected actual demand.

LNG exports were treated similarly to gas utility sector customers. All terminal operators are assumed to hold sufficient pipeline capacity to be able to deliver gas to meet the peak liquefaction capability of each facility, thereby ensuring the timely availability of LNG to meet rigid export shipping schedules. The export terminals are assumed to operate at maximum capacity on the seasonal peak days, resulting in no differential between contractual entitlements and peak day demand that is available for electric sector customers to use.

Unlike gas utility sector customers, electric sector customers are assumed not to hold *any* pipeline capacity in 2050. Currently, most generators do not hold firm contracts for mainline transportation capacity, relying instead on other transportation arrangements.[25] Some generation owners do hold mainline capacity rights, but existing contracts will have expired

[25] In Florida and TVA, the majority of existing generators have firm pipeline capacity to serve all or most of each generator's maximum daily requirement. Throughout the rest of the EI, the percentage of generation that has an assured fuel supply through pipeline transportation is small.

by 2050.[26] To the extent that specific generators may be expected to hold a contract for mainline interstate pipeline capacity in 2050, that contract may represent a need for additional pipeline capacity beyond that which is outlined in this section, particularly in areas that are revealed to be constrained.

In order to fulfill the gas utility sector contractual obligations described above, substantial pipeline facilities were added across the EI. The exact configuration of new pipeline facilities needed to keep pace with gas utility sector demand in 2050 is highly speculative. Hence, a simplifying model approach was used in GPCM. This simplifying approach uses GPCM's Auto-Expand feature to add pipeline capacity to keep pace with the forecasted increase in gas utility sector and LNG export gas demands. This feature applies the required pipeline capacity expansions to existing pipeline segments in lieu of new pipeline pathways from existing producing basis to market centers.[27] The resultant pipeline capacity expansions revealed by GPCM were then built into the fixed 2050 infrastructure for the Mid RE/High RE and Low RE scenarios. As a result, there are no unserved gas utility sector or LNG export demands in 2050 in the Mid RE/High RE and Low RE scenarios. The majority of the generic additions support gas flows into the northern portion of the EI. Other additions support LNG exports from the Gulf of Mexico.

3.5 Gas Utility Sector Gas Demand

For this study, the combined gas needs of residential, commercial, industrial and transportation end-users, whether they are directly connected to pipelines or served by LDCs, are referred to as the gas utility sector. Using historical pipeline delivery data, LAI developed a profile of daily gas demand for gas utility sector customers throughout the EI.[28] Each customer's total daily demand and the sum of all customers' total daily demands were calculated. The demands of each customer on the EI's winter and summer peak gas utility sector gas demand days were then used as the basis for the forecast. The starting peak day demands were escalated based on the growth rates by census region in *AEO 2015*, which are shown in Figure 33 for the Reference case and in Figure 34 for the High Oil & Gas Resource case.[29] The *AEO* 2015 forecast only extends to 2040. To extend the forecast to 2050, the average growth rates from the last ten years of the *AEO 2015* forecast (2031 to 2040) are applied from 2041 to 2050. While the long-term growth rates for all regions are between 0% and 2% in both cases, each region's growth rate in 2050 is higher in the High Oil & Gas case than in the Reference case. Consistent with the application of fuel price forecasts in the electric simulation model, the gas utility sector demand for both the High RE and Mid RE

[26] While pipeline transportation contracts can be extended, we have assumed for purposes of this study paradigm that no extensions occur.

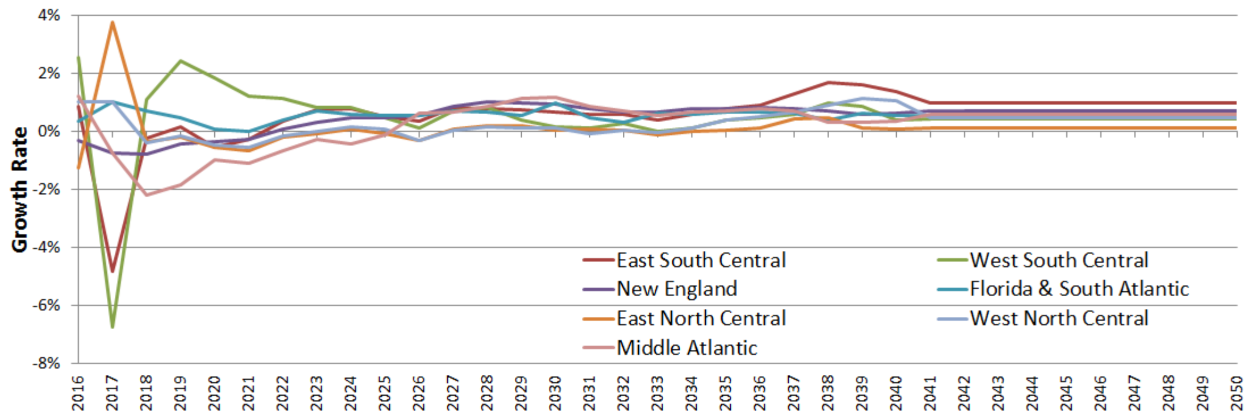
[27] GPCM's auto-expand feature was run using expected utility sector and LNG export capacity requirements with all electric sector demands set to zero.

[28] Throughout this report, "customer" refers to customers of pipelines (typically LDCs, generators or industrials), not individual end-users.

[29] For each census region, the growth rates for the four sectors (residential, commercial, industrial and transportation) were load weighted to arrive at a combined growth rate.

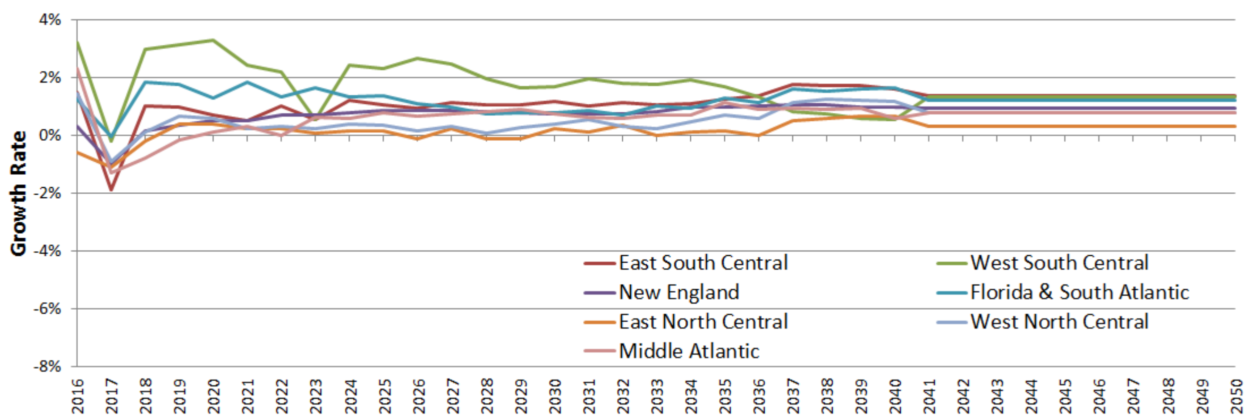
scenarios is based on the *AEO 2015* Reference case and the gas utility sector demand for the Low RE scenario is based on the *AEO 2015* High Oil & Gas case.

Figure 33. Gas Utility Sector Gas Demand Growth Rates– *AEO 2015* Reference case



AEO 2015 growth rates are used through 2040. From 2041 to 2050, growth rates are extrapolated based on average growth rates from 2031 to 2040.

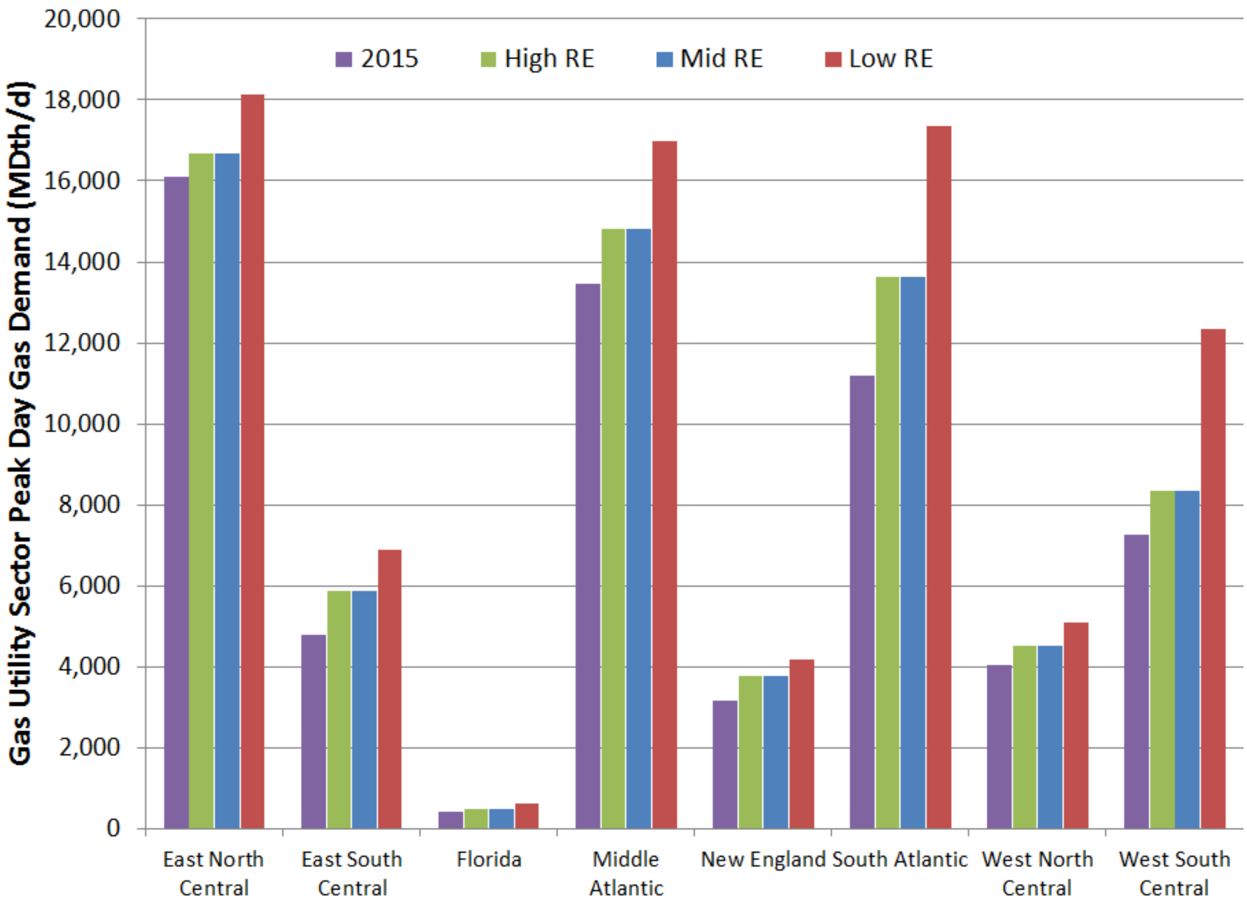
Figure 34. Gas Utility Sector Gas Demand Growth Rates– *AEO 2015* High Oil & Gas Resource case



AEO 2015 growth rates are used through 2040. From 2041 to 2050, growth rates are extrapolated based on average growth rates from 2031 to 2040.

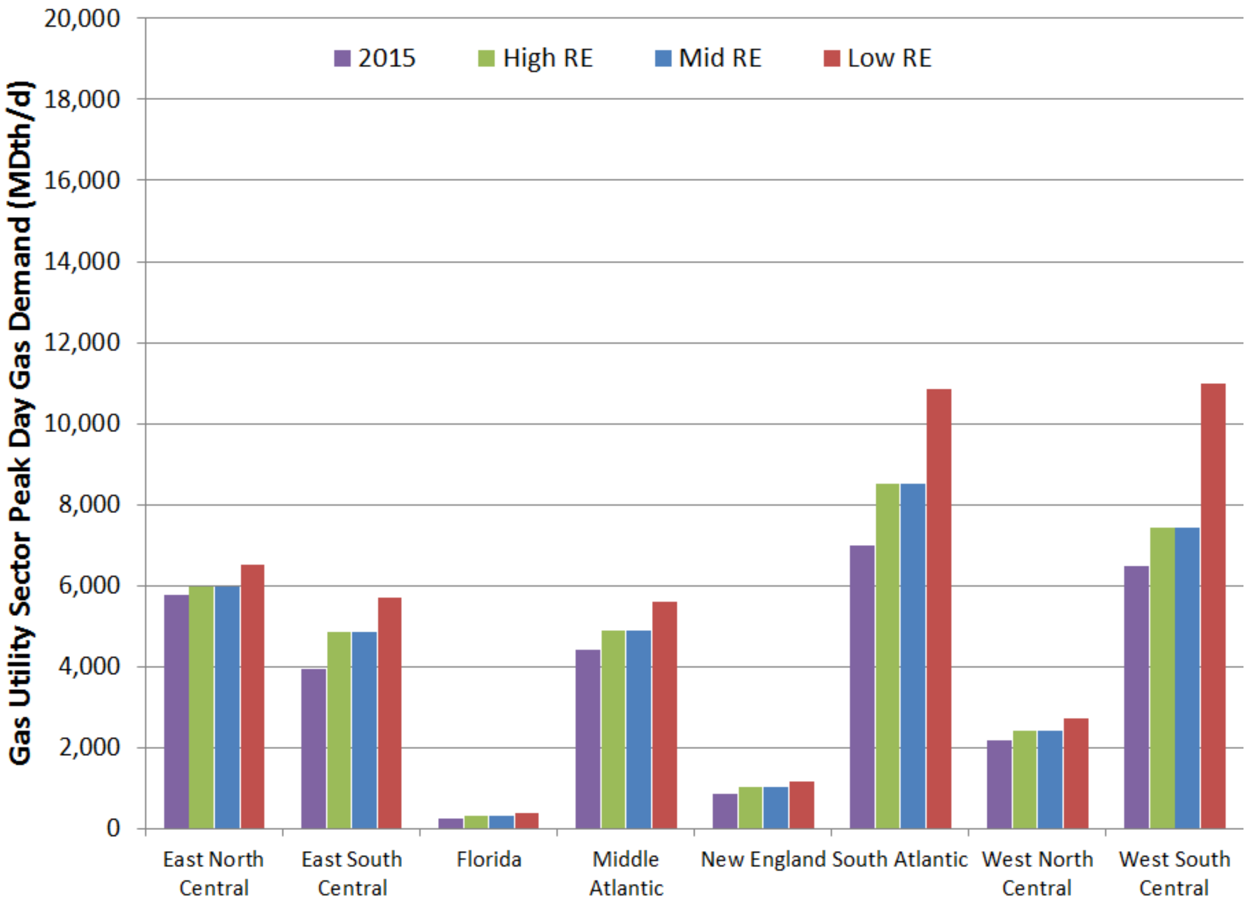
Figure 35 and Figure 36 compare the total gas utility sector gas demand by census region in 2015 and the three 2050 scenarios for the winter and summer peak days, respectively. Each census region's growth is net positive between 2015 and 2050 in both *AEO 2015* cases and for both seasons. Summer peak day demand is lower in each region than winter peak day demand. The ratio of summer peak day demand to winter peak day demand is higher in the southern portion of the EI, represented by the East South Central, Florida / South Atlantic and West South Central regions, than in the northern portion of the EI, represented by East North Central, Middle Atlantic, New England and West North Central, due to the higher winter heating demand in the north. While fuel for electric heating is part of the electric sector demand, usage of gas for direct heating, in which gas is delivered to and burned in an end user's on-site heating system, is part of the gas utility sector demand. On the opposite end of temperature management spectrum, air conditioning is achieved entirely or nearly entirely through electric usage, and therefore does not affect gas utility sector demand in the summer.

Figure 35. EI Peak Day Gas Demand – Gas Utility Sector – Winter



The 2015 data series represents historical actuals. The High RE and Mid RE scenarios are based on the *AEO 2015* Reference case. The Low RE scenario is based on the *AEO 2015* High Oil & Gas case. All regions show net growth over the forecast period, with higher growth in the Low RE scenario. All regions have higher gas utility sector demand on the winter peak day than on the summer peak day.

Figure 36. EI Peak Day Gas Demand – Gas Utility Sector – Summer



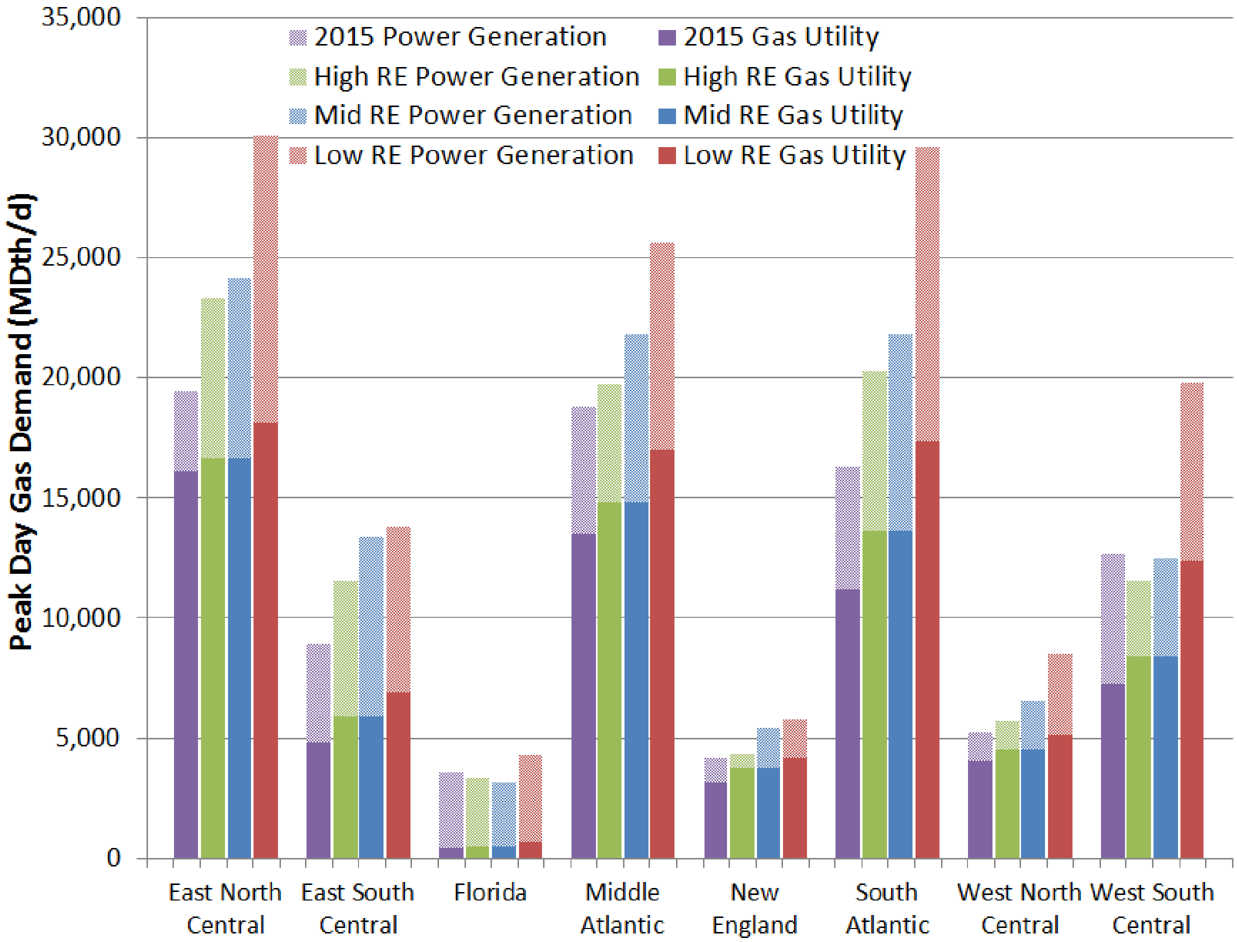
The 2015 data series represents historical actuals. The High RE and Mid RE scenarios are based on the *AEO 2015* Reference case. The Low RE scenario is based on the *AEO 2015* High Oil & Gas case. All regions show net growth over the forecast period, with higher growth in the Low RE scenario.

3.6 Combined Gas Demand Forecasts

For purposes of this study, the peak seasonal power generation sector and gas utility sector gas demands have been assumed to occur on the same day. It was assumed that the maximum winter power generation sector gas demand occurs on a very cold day when gas utility sector gas demand is also highest. In the summer, gas utility sector gas demand is lower and not temperature sensitive. The assumption about the seasonal coincidence between peak gas utility sector and peak power generation sector gas demands does not significantly affect the derivation of total gas demand on the summer peak day.

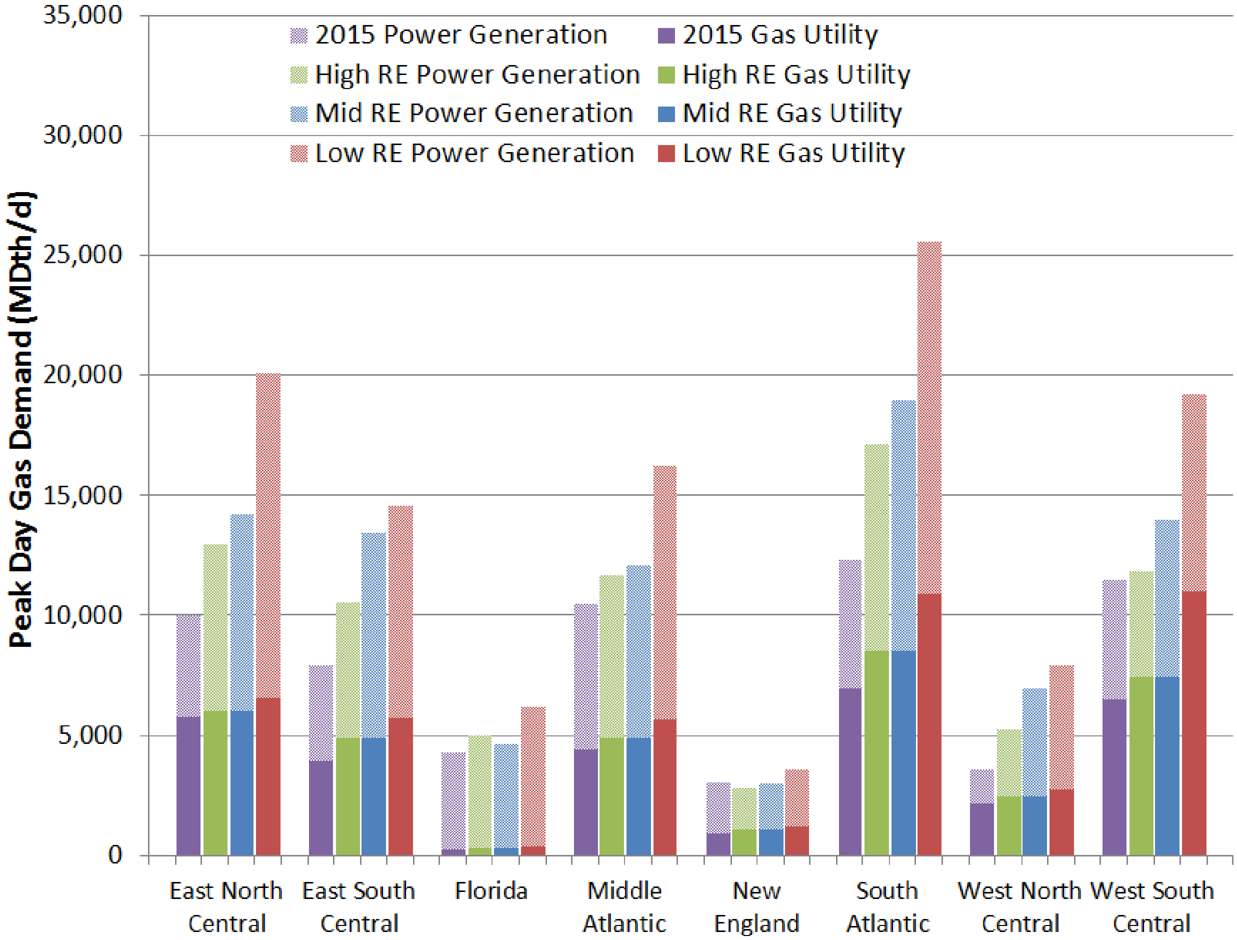
Figure 37 and Figure 38 show the combined gas demands for the power generation and gas utility sectors on the winter and summer peak days in 2015 and 2050. Comparing the total demands in each region between the winter and summer peak days shows that only Florida is summer peaking in both the 2015 benchmark and all three 2050 scenarios, with a higher total gas demand on the summer peak day than on the winter peak day. East South Central is summer peaking in the Mid RE and Low RE scenarios, and West South Central is summer peaking in the High RE and Mid RE scenarios. West North Central is summer peaking in only the Mid RE scenario. Summer peaking occurs when the differential between electric sector demand on the summer and winter peak days is greater than the differential between gas utility sector summer and winter peak days.

Figure 37. EI Peak Day Gas Demand – Winter



In the northern regions, winter peak day gas demand is more heavily weighted toward gas utility sector demand than in the southern regions, although even in the southern regions, with the exception of Florida, the gas utility sector represents the majority of peak day demand.

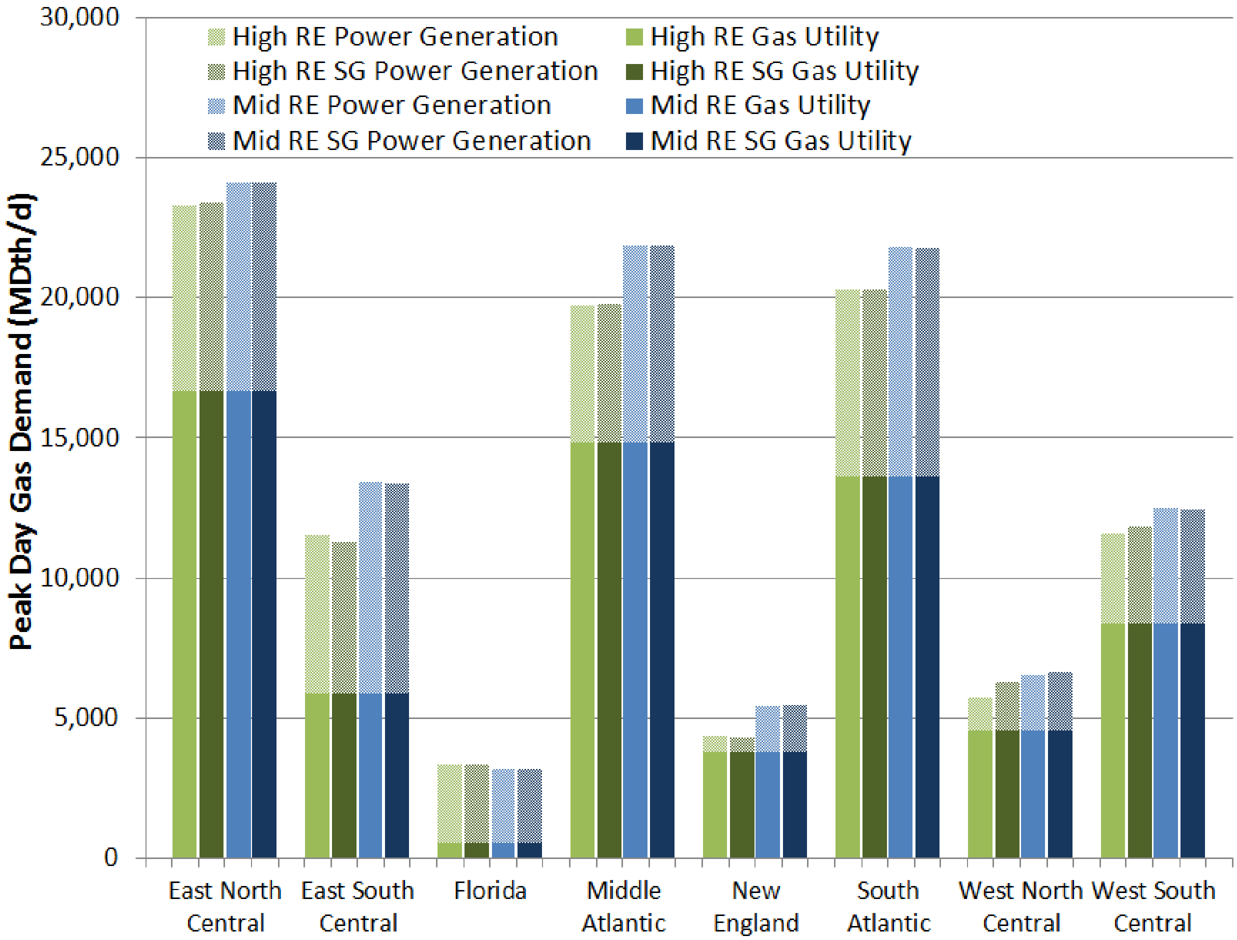
Figure 38. EI Peak Day Gas Demand – Summer



On the summer peak day, gas demand is more heavily weighted toward the electric sector in all regions relative to the winter peak day in the previous figure. Florida is summer peaking, with higher total gas demand than on the winter peak day, in all scenarios. East South Central and West South Central are each summer peaking in two scenarios. South Atlantic, while classified as a southern region, includes some states with significant winter heating needs, and is therefore winter peaking.

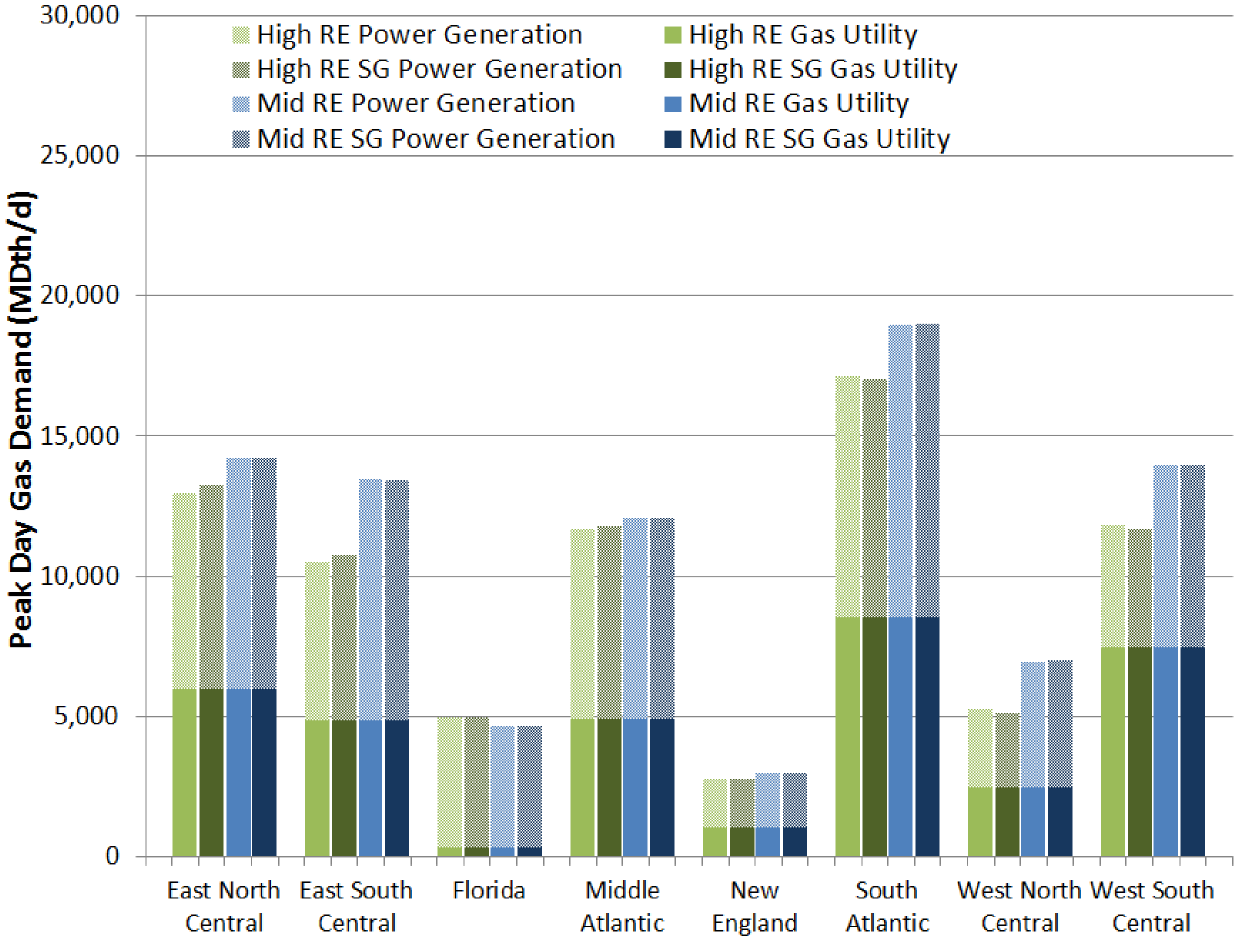
Figure 39 and Figure 40 show the combined gas demands for the electric and gas utility sectors under the storage technology sensitivity. The gas utility sector demands are the same for all four scenarios / sensitivities shown in these figures because they are all based on the *AEO 2015* Reference case. Comparing seasonal peak days for the sensitivities reveals that summer peaking conditions are relatively consistent with the main scenarios. The only deviation is that West South Central is summer peaking in the High RE SG sensitivity, but not in the High RE scenario due to the summer peak day electric sector demand decreasing slightly in the sensitivity while it increases slightly on the winter peak day.

Figure 39. EI Peak Day Gas Demand – Winter – Storage Technology Sensitivity



The storage technology sensitivity results in only small changes to electric sector gas demand in all regions on the winter peak day.

Figure 40. EI Peak Day Gas Demand – Summer – Storage Technology Sensitivity



The storage technology sensitivity results in only small changes to electric sector gas demand in all regions on the summer peak day.

4 GAS INFRASTRUCTURE CONSTRAINTS

4.1 HIGHLIGHTS

- Assumption: The availability of natural gas for electric generation across three scenarios (High RE, Mid RE and Low RE) was compared to gas availability in 2015. The basis of comparison was the power generation sector demand for natural gas that is unconstrained and therefore deliverable. The difference between total power generation sector gas demand and unconstrained power generation sector gas demand is described as "potentially-constrained generation." Potentially-constrained generation represents an electricity system operating at a higher cost than the theoretical lowest cost of operation due to the need for mitigation measures to ensure electric system reliability. Such mitigation measures can include electric demand reduction, fuel switching and/or additional pipeline capacity to serve generators. In some cases, the 2015 benchmark results show a high percentage of potentially-constrained generation. It is reasonable to assume that potentially-constrained generation in the benchmark can be mitigated without adverse electric system operating effects such as voltage reductions or blackouts. Hence, potentially-constrained generation is not synonymous with curtailment of electric service.

- Assumption: Potentially-constrained generation was analyzed across eight regions of the EI for winter and summer seasonal peak days, with peak gas utility sector gas demand and peak power generation sector gas demand assumed to occur on the same day. This seasonal peak day coincidence assumption increases stress on the gas pipeline system, particularly in northern regions with high gas utility sector gas demand for winter heating. Two sensitivities were conducted:

    - One-half of electricity storage in the High RE scenario and all electricity storage in the Mid RE scenario were replaced with gas-fired generating capacity. With less electricity storage, we would expect the demand on natural gas generation to increase and thus the potentially-constrained generation to increase. This sensitivity represents an upper bound on potentially-constrained generation.

    - LNG sendout to pipelines in New England and South Atlantic was maintained at 2015 levels to lessen potentially-constrained generation. Under the *AEO 2015* LNG import assumptions used in the three primary scenarios, most LNG import terminals are no longer operating in 2050. Nevertheless, their continued operation might be warranted by market conditions represented in the model to avoid the need for more expensive mitigation measures. This scenario represents a lower bound on potentially-constrained generation.

- Result: The High RE scenario results in less potentially-constrained generation in every region of the EI on the winter peak day than in the 2015 benchmark. This suggests that high renewable penetration is likely to reduce gas pipeline constraints in the winter. On the summer peak day, East South Central and South Atlantic experience some incremental potentially-constrained generation relative to the 2015 benchmark. Other regions experience less potentially-constrained generation than the 2015 benchmark. These results suggest that operational costs of the electric system would be less in a High RE scenario.

- Result: The Mid RE and Low RE scenarios result in incremental potentially-constrained generation relative to the benchmark in East South Central and South Atlantic in both the winter and summer, New England in the winter, and Florida in the summer. These results stem from the assumption that pipeline capacity expansion will not keep pace with power generation sector gas demand in the absence of pipeline expansions earmarked for power generators. Other regions of the country experience fewer or no pipeline constraints and thus less expensive electricity generation.

- Result: In the first set of sensitivities, replacing electricity storage with natural gas capacity has a small effect on potentially-constrained generation, sometimes increasing both the power generation sector gas demand and potentially-constrained generation and sometimes reducing both the power generation sector gas demand and potentially-constrained generation. The substitution of natural gas capacity for electricity storage has impacts across the EI that are location-specific. The small differences in either direction are consequences of electric system dispatch optimization.

- Result: In the second set of sensitivities, maintaining LNG import capability and sendout at 2015 levels at the Canaport, Everett and Northeast Gateway terminals significantly reduced the potentially-constrained generation in New England. Maintaining LNG capability and sendout at Elba Island also reduced the potentially-constrained generation in South Atlantic in the winter. It has a negligible effect in summer.

- Result: To understand whether the peak day results are typical of seasonal conditions for a given scenario or sensitivity, that is, whether potentially-constrained generation on the peak day persists throughout the season, a daily analysis was conducted for the three-month winter and summer seasons. From this analysis, seasonal and regional results were grouped into three categories:

    - Persistent constraints: In these cases, the level of potentially-constrained generation was relatively consistent throughout the season for a set of assumptions. This group has two subgroups, divided by whether the level of persistent potentially-constrained generation is greater than or less than approximately 100 GWh per day. Persistent constraints with a high level of potentially-constrained generation include:

        - South Atlantic/Winter/Low RE (scenario, LNG sensitivity),
        - South Atlantic/Winter/Mid RE (scenario, SG sensitivity, LNG sensitivity),

  - Florida/Summer/Low RE (scenario, LNG sensitivity), and
  - South Atlantic/Summer Low RE (scenario, LNG sensitivity).

  Persistent constraints with a low level of potentially-constrained generation include:

  - East South Central/Winter/Mid RE (scenario, SG sensitivity, LNG sensitivity),
  - East South Central/Winter/Low RE (scenario, LNG sensitivity),
  - Florida/Winter/Low RE (scenario, LNG sensitivity),
  - East South Central/Summer/Mid RE (scenario, SG sensitivity, LNG sensitivity),
  - East South Central/Summer/Low RE (scenario, LNG sensitivity),
  - Florida/Summer/Mid RE (scenario, SG sensitivity, LNG sensitivity), and
  - Florida/Summer/High RE (scenario, SG sensitivity, LNG sensitivity).

  Persistent constraints would most likely require a pipeline-based solution for mitigation.

- Intermittent constraints: In these cases, the level of potentially-constrained generation varied between zero and a low level (less than 100 GWh per day), with the constraint occurring infrequently during the season. Intermittent constraints include:

  - Florida/Winter/Mid RE (scenario, SG sensitivity, LNG sensitivity),
  - Middle Atlantic/Winter/Mid RE (scenario, SG sensitivity, LNG sensitivity),
  - Middle Atlantic/Winter/Low RE (scenario, LNG sensitivity),
  - South Atlantic/Winter/High RE (scenario, SG sensitivity, LNG sensitivity),
  - East South Central/Summer/High RE (scenario, SG sensitivity, LNG sensitivity),
  - South Atlantic/Summer/High RE (scenario, SG sensitivity, LNG sensitivity), and
  - New England/Winter/Mid RE (LNG sensitivity).

  Intermittent constraints are more likely to be able to be alleviated through electric-side mitigation measures such as electric demand response or alternate fuel usage at dual-fuel power plants.

- Inconsistent constraints: In these cases the level of potentially constrained generation is persistent or relatively persistent, but varies between less than 100 GWh per day and greater than 100 GWh per day. South

Atlantic/Summer/Mid RE (scenario, SG sensitivity, LNG sensitivity) is persistently constrained. New England/Winter/Low RE (scenario, SG sensitivity, LNG sensitivity) is persistently constrained except in the LNG sensitivity when it is constrained on approximately one-half of the days in the season. New England/Winter/Mid RE (scenario, SG sensitivity) is somewhat persistent, with the constraint occurring on approximately one-third of the days in the scenario and one-half of the days in the SG sensitivity. Inconsistent constraints may be best suited to a combination of mitigation measures.

4.2 APPROACH

The identification of gas constraints across the EI is based on market research, statistical analysis and use of simulation models to reveal the location of potentially-constrained gas-fired generation on the peak day during the winter and summer of 2050. The power generation and gas utility sector gas demands described in the previous sections were combined to test the capability of the natural gas infrastructure in the EI. The combined peak demands were tested in GPCM to identify the constrained pipeline segments that limit fuel deliveries to gas-fired generators after all gas utility sector and LNG export customers are fully served. Delineation of constrained gas pipeline segments and the resultant potentially-constrained generation does not signify either a pipeline design or operating flaw. Similarly, it does not signify any adverse impact to electric system reliability, insofar as no mitigation measures have been applied to either the electric and/or gas systems to lessen or eliminate the constraints. This nomenclature is meant only to signify insufficient pipeline capacity to serve the coincident demands of gas-fired generators under a specific set of market, economic and environmental assumptions formulated to define each of the scenarios or sensitivities.

The frequency and duration of constraint events during the remainder of the summer and winter seasons were extrapolated based on the location and magnitude of the infrastructure constraints identified on the peak day and daily seasonal demand profiles. For gas utility sector customers, the seasonal demand profiles are based on historical delivery data. For electric sector customers, the seasonal demand profiles are taken directly from the AURORAxmp model results. Because the chronological seasonal demand profiles are aligned for the two sectors, the peak demands in each sector are not necessarily coincident for purposes of the seasonal analysis.

4.3 PEAK DAY RESULTS

Figure 41 shows the winter peak day results for 2015 and the three 2050 scenarios.[30] The results are also summarized in Table 8. To put the 2050 results in the context of the 2015 benchmark, it is important to understand what the benchmark represents. For the power generation sector, the 2015 benchmark represents the amount of gas demand resulting from 2015 market conditions of load, generation capacities, transmission capabilities, generator

[30] As discussed in section 3.3, the 2015 benchmark that is compared to the three 2050 scenarios does not include LNG imports.

operating characteristics, and fuel and emission allowance prices. The 2015 benchmark does not represent actual historical power generation sector gas demands. It can be assumed that the potentially-constrained generation was offset through available mitigation measures, for example, dispatch of dual-fuel generators on oil, dispatch of non-gas capable units, dispatch of gas-fired resources in non-constrained locations, increased transmission interchange and/or electric demand reduction.

The East North Central, West North Central and West South Central regions do not have any potentially-constrained generation in either the 2015 benchmark or any of the three 2050 scenarios. At the other end of the spectrum, the South Atlantic region has potentially-constrained generation in the 2015 benchmark and in all three 2050 scenarios. South Atlantic is highly affected because Georgia, South Carolina and North Carolina rely on only two pipelines for gas supply – Southern and Transco. Once the deliverability limit of those two pipelines is reached, no other generation can be served, as indicated by the relatively consistent amount of unconstrained generation across the three scenarios. While the percentage of generation that is potentially constrained is higher in the 2015 benchmark than in any of the three 2050 scenarios, the more important consideration is the amount of potentially-constrained generation. In the High RE and Mid RE scenarios, the amount of potentially-constrained generation is less than in the 2015 benchmark. In 2015, however, LNG is a significant mitigation measure in South Atlantic, offsetting roughly one-half of the potentially-constrained generation, as discussed in more detail in section 4.3.2. Therefore the non-LNG market mechanisms that offset the potentially-constrained gas-fired generation in 2015 may be able to similarly offset the potentially-constrained generation in 2050, assuming that any required alternate-fuel resources have not been retired. However, the mitigation burden, and therefore the potential cost, is larger in the Mid RE scenario. In the Low RE scenario, the amount of potentially-constrained generation is more than double that in the 2015 benchmark, and is therefore less likely to be offset by alternate-fuel resources and other market mechanisms. This results in higher mitigation costs associated with measures such as expanded pipeline capacity.

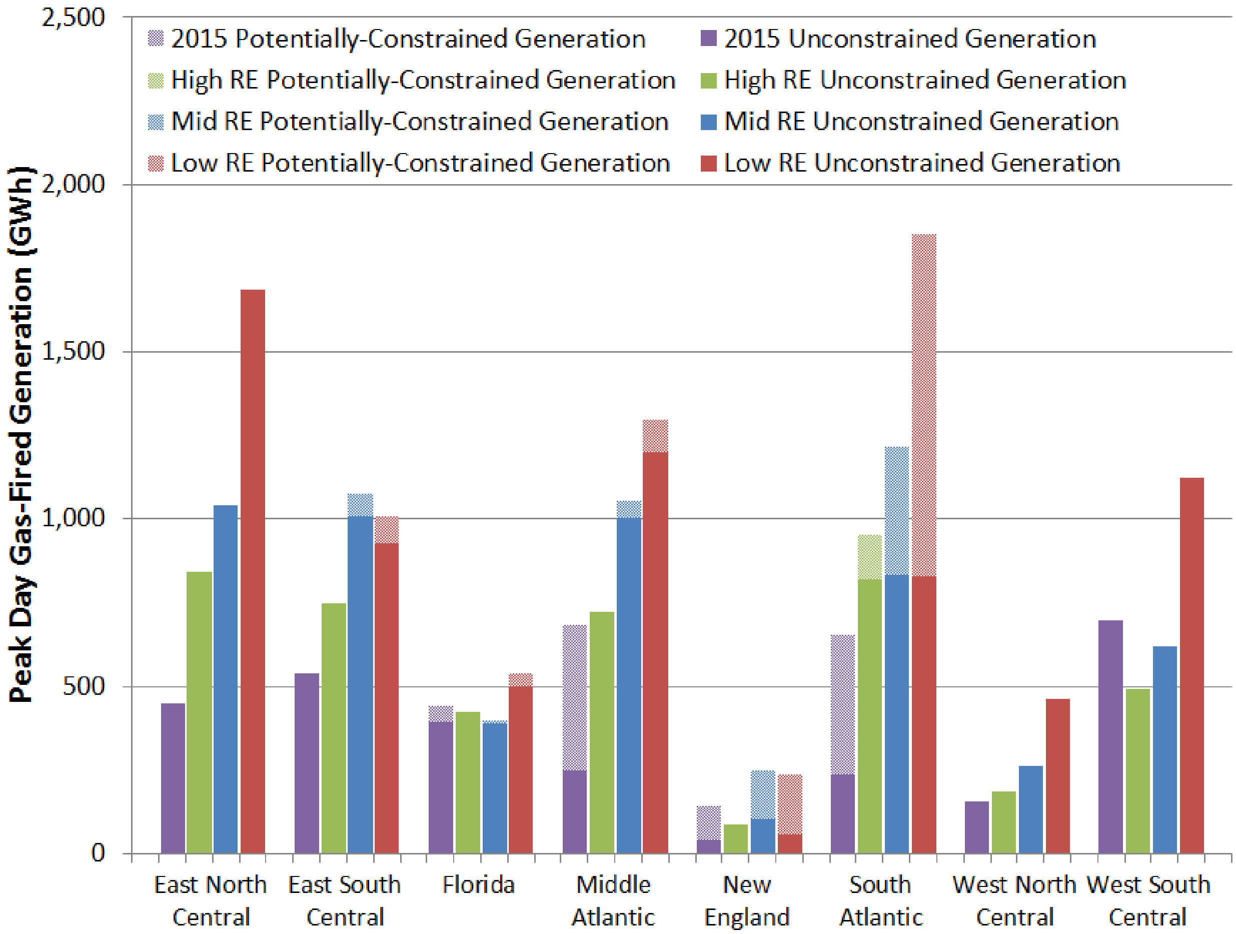
East South Central's potentially-constrained generation results from the same constraints that affect South Atlantic. Although East South Central does not have any potentially-constrained generation in the 2015 benchmark, the relatively small percentage of potentially-constrained generation and higher pipeline density may indicate that lower-cost mitigation measures, such as shifting power generation demand to plants served by other pipelines could relieve the constraint.

In Florida, both the percentage and volume of potentially-constrained generation in the Mid RE and Low RE scenarios are less than in the 2015 benchmark, indicating that the constraints can likely be mitigated by existing or lower-cost mitigation measures. Florida has much less pipeline diversity than most of the other EI regions, but a large portion of the existing pipeline capacity into and within Florida is contracted to generators, thus creating future headroom for the power generation sector. Consistent with the study design, the amount of capacity in Florida does not increase during the forecast period. Hence, no new gas pipeline capacity is dedicated to serve gas-fired generation in 2050.

In Middle Atlantic, significant expansions on several of the pipelines serving the region to meet increases in gas utility sector demand between 2015 and 2050. Due to the incomplete usage of the gas utility customers' firm transportation capacity, the pipelines are able to increase deliverability of non-firm gas to power generation customers, resulting in lower amounts of potentially-constrained generation in 2050 than in 2015. Because potentially-constrained generation is much lower in the Mid RE and Low RE scenarios than in the benchmark, that future constraints can likely be mitigated through lower-cost measures.

New England has a significant percentage of potentially-constrained generation in the 2015 benchmark and in the Mid RE and Low RE scenarios. This is primarily due to upstream constraints in the Middle Atlantic region, as well as constraints associated with supply from Canada, that limit boundary flows into New England on the peak day. These regional operating constraints are compounded by the lack of LNG imports. The amount of potentially-constrained generation in New England is larger in both the Mid RE and Low RE scenarios than in 2015 when LNG is not considered, indicating that higher-cost mitigation measures may be required to meet electric demands. Analysis of the LNG Import sensitivity, discussed in section 4.3.2, reveals that LNG is the primary mitigation factor in the 2015 benchmark. When LNG imports are included, potentially-constrained generation is reduced to zero in the 2015 benchmark. This indicates that if LNG is not available as a mitigation measure in 2050, the potential cost of mitigating constraints in New England could be higher.

Figure 41. Gas Infrastructure Limitations – Winter Peak Day



East South Central experiences constraints in 2050 that did not occur in 2015, indicating the potential need for implementation of new mitigation measures. Florida and Middle Atlantic have less potentially-constrained generation in 2050 than in the 2015 benchmark, indicating that lower-cost mitigation measures may be sufficient to relieve the constraint. New England has more potentially-constrained generation in the Mid RE and Low RE scenarios than in the 2015 benchmark, which was relieved by LNG imports (not reflected in the figure), indicating that more expensive mitigation measures will likely be needed, particularly in the absence of future LNG imports. South Atlantic has potentially-constrained generation in all cases, with the cost of potential mitigation increasing from the High RE and Mid RE scenarios, which are less affected than the 2015 benchmark, to the Low RE scenario which has more than double the amount of potentially-constrained generation as the benchmark.

Table 8. Potentially-Constrained Generation – Winter Peak Day

Region	2015	High RE	Mid RE	Low RE
East North Central	--	--	--	--
East South Central	--	--	65 GWh (6.1%)	78 GWh (7.8%)
Florida	47 GWh (10.6%)	--	9 GWh (2.3%)	37 GWh (6.9%)
Middle Atlantic	434 GWh (63.5%)	--	54 GWh (5.1%)	97 GWh (7.5%)
New England	106 GWh (73.1%)	--	144 GWh (57.9%)	176 GWh (74.9%)
South Atlantic	417 GWh (63.8%)	133 GWh (14.0%)	386 GWh (31.7%)	1,025 GWh (55.3%)
West North Central	--	--	--	--
West South Central	--	--	--	--
Total	1,003 GWh (30.3%)	133 GWh (3.0%)	658 GWh (11.1%)	1,414 GWh (17.2%)

This table shows the data underlying the graphical presentation in Figure 41.

Figure 42 shows the summer peak day results for 2015 and the three 2050 scenarios. The results are also summarized in Table 9. LAI has made the simplifying assumption that PHMSA-related pipeline safety and integrity testing is performed during the shoulder season, thereby allowing certificated pipeline capability to be available in full on a summer peak day across the EI.[31] The East North Central, Middle Atlantic, New England and West South Central regions do not have any potentially-constrained generation in the 2015 benchmark or any of the three 2050 scenarios. West North Central has a small amount of potentially-constrained generation in the 2015 benchmark but none in the 2050 scenarios. This result indicates that the constraint will be resolved through a pipeline capacity expansion to serve increased gas utility sector gas demand.

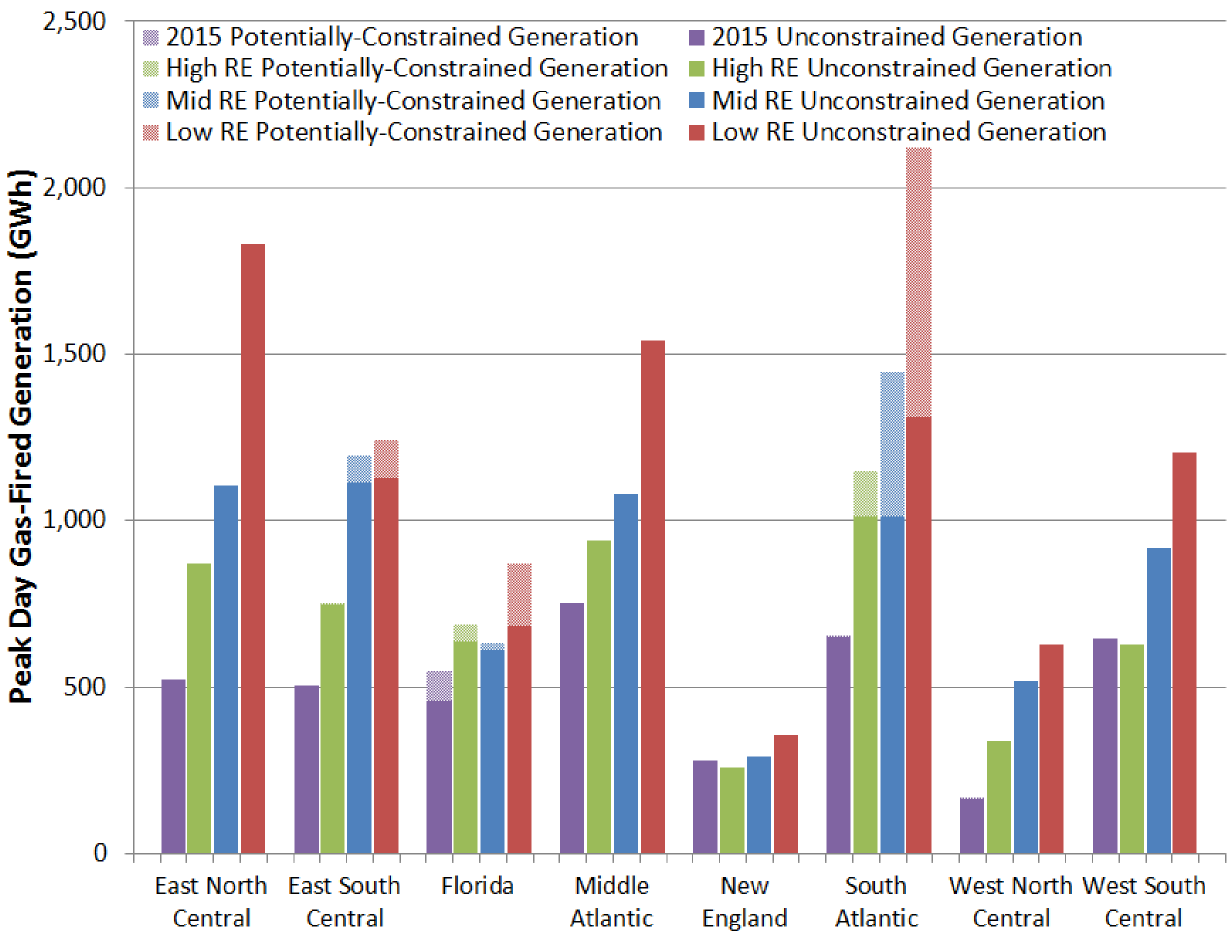
East South Central, Florida and South Atlantic are each affected by pipeline constraints to varying degrees in each of the three 2050 scenarios. The small amount of potentially-constrained generation in South Atlantic in 2015 is the result of a constraint on Eastern Shore, which is resolved in 2050. The potentially-constrained generation in East South Central and South Atlantic in 2050 is the result of the same constraints on Southern and Transco that occur on the winter peak day. This 2050 constraint does not occur in 2015, indicating that new mitigation measures would likely be needed. If a permanent solution to

[31] To the extent increasingly stringent PHMSA inspection requirements lengthen the pipeline maintenance season to the summer, the frequency and duration of constraint events may be underestimated.

the winter peak day constraints is implemented, such as the addition of incremental pipeline capacity, the summer peak day constraints would also be reduced.

In Florida, the potentially-constrained generation in 2015 and in the Mid RE and High RE scenarios is the result of a constraint on the Gulfstream pipeline, which does not deliver gas to any gas utility sector customers, only to generators and interconnections with other pipelines.[32] The amount of potentially-constrained generation resulting from this constraint is lower, on both a percentage and absolute basis, than in 2015, indicating the feasibility of mitigation with existing measures. In the Low RE scenario, both Gulfstream and Florida Gas Transmission are constrained, resulting in a higher amount of potentially-constrained generation than in the 2015 benchmark, indicating that higher-cost mitigation would likely be required.

Figure 42. Gas Infrastructure Limitations – Summer Peak Day



Florida's potentially-constrained generation in the Mid RE and High RE scenarios is less than in the 2015 benchmark, but incremental mitigation may be required for the Low RE scenario. East South Central and South Atlantic

[32] Because Gulfstream does not serve any utility sector customers, it is not assumed to have any capacity expansion between 2015 and 2050, in accordance with the infrastructure expansion assumptions discussed previously in this report.

experience constraints in 2050 that did not occur in 2015, indicating the potential need for implementation of new, more costly, mitigation measures, particularly in South Atlantic.

Table 9. Potentially-Constrained Generation – Summer Peak Day

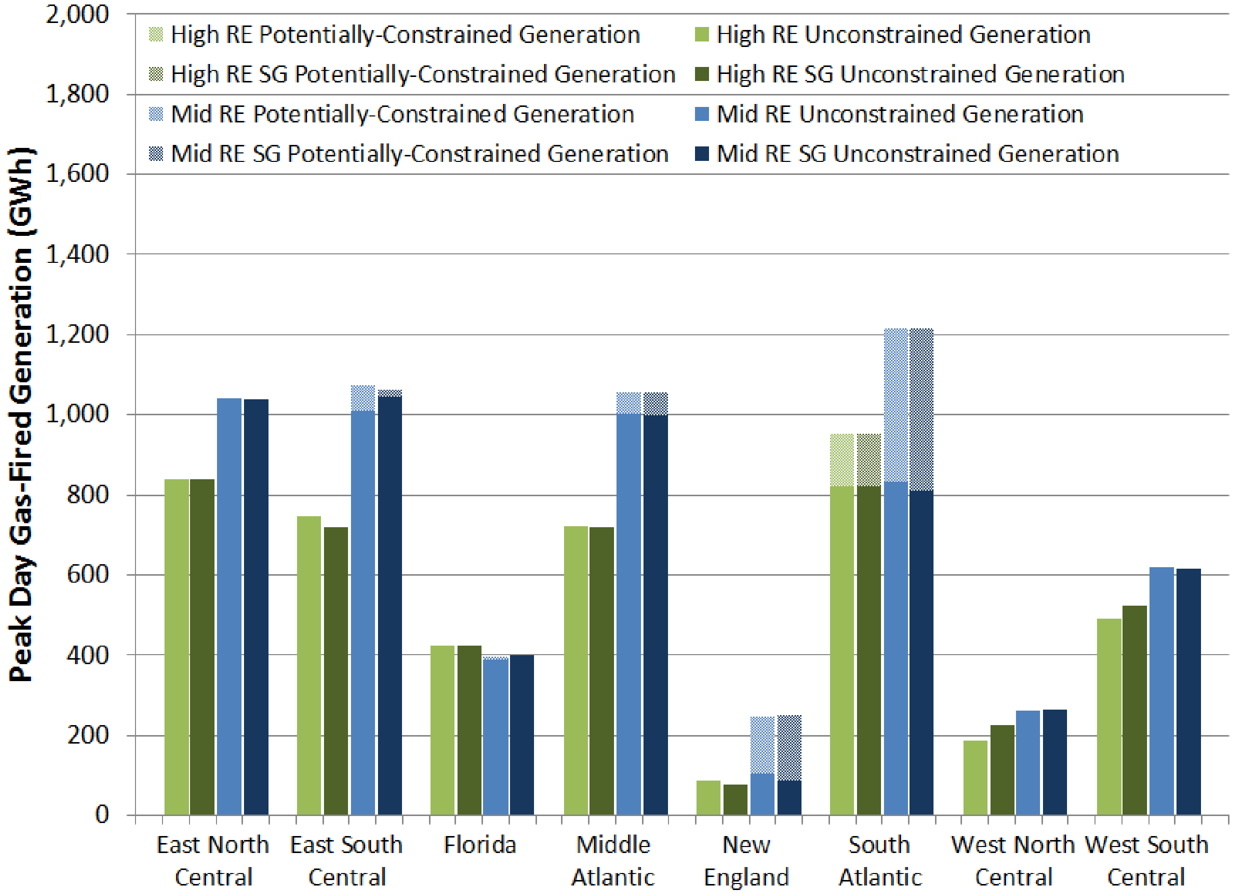
Region	2015	High RE	Mid RE	Low RE
East North Central	--	--	--	--
East South Central	--	6 GWh (0.7%)	84 GWh (7.0%)	116 GWh (9.3%)
Florida	90 GWh (16.3%)	51 GWh (7.5%)	21 GWh (3.4%)	186 GWh (21.4%)
Middle Atlantic	--	--	--	--
New England	--	--	--	--
South Atlantic	7 GWh (1.1%)	138 GWh (12.0%)	435 GWh (30.0%)	809 GWh (38.2%)
West North Central	4 GWh (2.2%)	--	--	--
West South Central	--	--	--	--
Total	101 GWh (2.5%)	195 GWh (3.5%)	541 GWh (7.5%)	1,111 GWh (11.4%)

This table shows the data underlying the graphical presentation in Figure 42.

4.3.1 Storage / Gas Sensitivity

Figure 43 and Table 10 show the effects of the SG sensitivity relative to the High RE and Mid RE scenario results on the winter peak day. The results of the High RE SG sensitivity are similar to the High RE scenario, with only slightly less potentially-constrained generation in South Atlantic. Overall there is less potentially-constrained generation in the Mid RE SG sensitivity than in the Mid RE scenario. East South Central and Florida have less potentially-constrained generation in the SG sensitivity, while Middle Atlantic, New England and South Atlantic have more potentially-constrained generation. The similarity to the scenario results indicates that the required mitigation measures would also be similar. Relative to the benchmark results shown in Figure 41 and Table 8, the High RE SG sensitivity is within the range of 2015 potentially-constrained generation in South Atlantic, and the Mid RE SG sensitivity is within the 2015 range for Florida, Middle Atlantic and South Atlantic, indicating that lower-cost mitigation measures are likely to be available in these regions. The Mid RE sensitivity results are outside the 2015 range, although not significantly so on a volumetric basis, for East South Central and New England, indicating the potential need for higher-cost mitigation.

Figure 43. Gas Infrastructure Limitations – Winter Peak Day – SG Sensitivity



The SG sensitivity has very limited impacts on winter peak day electric sector gas demand. It therefore has a similarly limited impact on potentially-constrained generation relative to the 2015 benchmark.

Table 10. Potentially-Constrained Generation – Winter Peak Day – SG Sensitivity

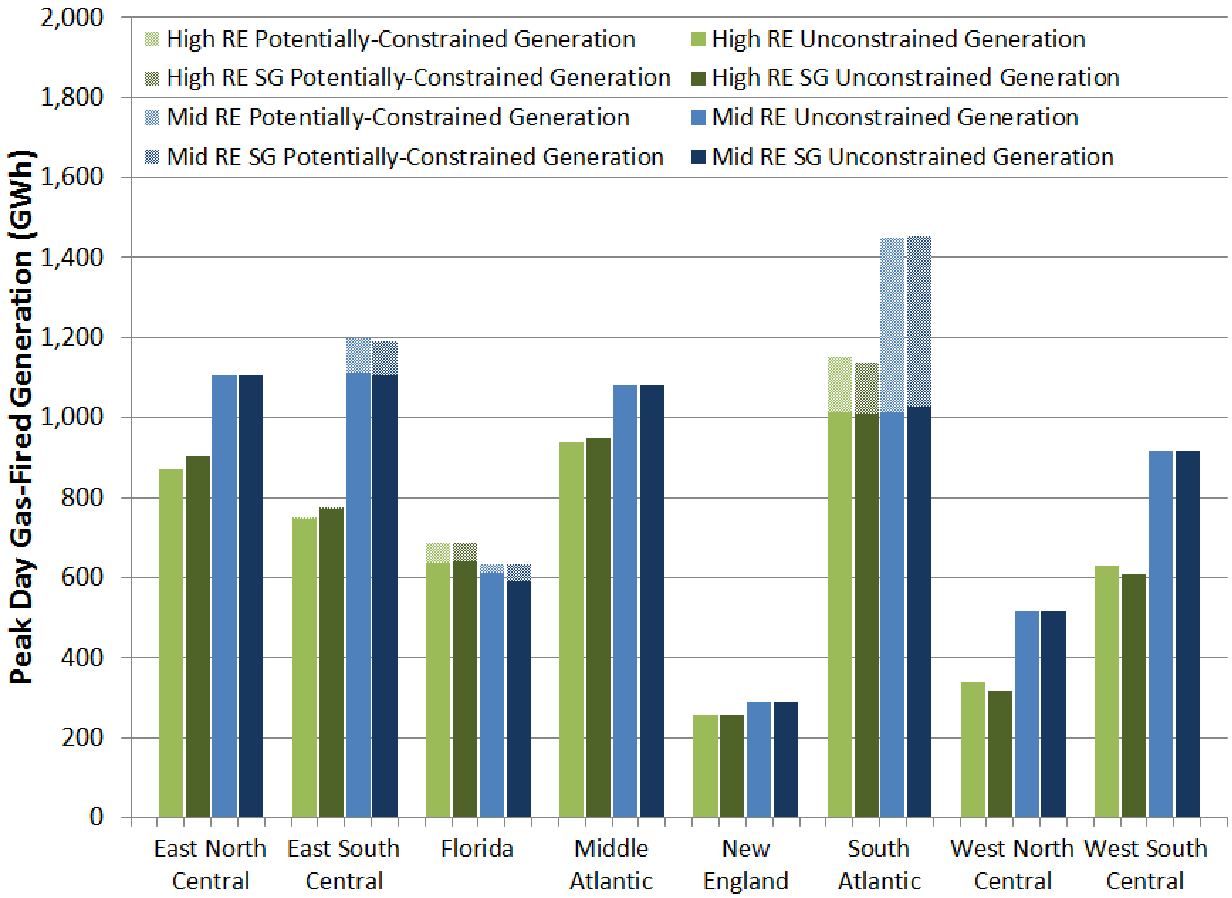
Region	High RE	High RE SG	Mid RE	Mid RE SG
East North Central	--	--	--	--
East South Central	--	--	65 GWh (6.1%)	16 GWh (1.5%)
Florida	--	--	9 GWh (2.3%)	--
Middle Atlantic	--	--	54 GWh (5.1%)	59 GWh (5.5%)
New England	--	--	144 GWh (57.9%)	165 GWh (65.3%)
South Atlantic	133 GWh (14.0%)	129 GWh (13.6%)	386 GWh (31.7%)	403 GWh (33.2%)
West North Central	--	--	--	--
West South Central	--	--	--	--
Total	133 GWh (3.0%)	129 GWh (2.9%)	658 GWh (11.1%)	643 GWh (10.9%)

This table shows the data underlying the graphical presentation in Figure 43.

Figure 44 and Table 11 show the effects of the SG sensitivity relative to the High RE and Mid RE scenario results on the summer peak day. As on the winter peak day, the High RE SG sensitivity results are similar to the scenario, with potentially-constrained generation slightly decreased in the three regions subject to constraints (East South Central, Florida and South Atlantic). Comparing to the benchmark in Figure 42 and Table 9, Florida's potentially-constrained generation is within the 2015 range, while East South Central (to a very slight degree) and South Atlantic are outside the 2015 range, indicating the need for more costly potential mitigation, particularly in South Atlantic.

The Mid RE SG sensitivity deviates more than the High RE SG sensitivity on the summer peak day, but less than the Mid RE SG sensitivity on the winter peak day. East South Central has approximately the same amount of potentially-constrained generation, but it represents a slightly larger share of the total regional generation. Florida's small amount of potentially-constrained generation doubles, and South Atlantic's potentially-constrained generation decreases slightly. Again, Florida's potentially-constrained generation is within the range of the 2015 benchmark, while East South Central and South Atlantic are outside the range of the benchmark, requiring new mitigation measures.

Figure 44. Gas Infrastructure Limitations – Summer Peak Day – SG Sensitivity



The SG sensitivity has very limited impacts on summer peak day electric sector gas demand. It therefore also has a similarly limited impact on potentially-constrained generation relative to the 2015 benchmark.

Table 11. Potentially-Constrained Generation – Summer Peak Day – SG Sensitivity

Region	High RE	High RE SG	Mid RE	Mid RE SG
East North Central	--	--	--	--
East South Central	6 GWh (0.7%)	3 GWh (0.4%)	84 GWh (7.0%)	84 GWh (7.1%)
Florida	51 GWh (7.5%)	47 GWh (6.9%)	21 GWh (3.4%)	42 GWh (6.6%)
Middle Atlantic	--	--	--	--
New England	--	--	--	--
South Atlantic	138 GWh (12.0%)	128 GWh (11.2%)	435 GWh (30.0%)	426 GWh (29.3%)
West North Central	--	--	--	--
West South Central	--	--	--	--
Total	195 GWh (3.5%)	178 GWh (3.2%)	541 GWh (7.5%)	552 GWh (7.7%)

This table shows the data underlying the graphical presentation in Figure 44.

4.3.2 LNG Import Sensitivity

Figure 45 and Table 12 show the effects of the LNG Import sensitivity relative to the High RE, Mid RE and Low RE scenario results on the winter peak day. The 2015 benchmark is also shown with and without LNG sendout from the import terminals, as described in section 3.3. LNG sendout reduces potentially-constrained generation in the benchmark and all scenarios where it is applied in a region that has potentially-constrained generation. East South Central, West South Central, Florida, West North Central and West South Central are not affected by the LNG Import sensitivity, with the results in each region unchanged from the respective scenarios.

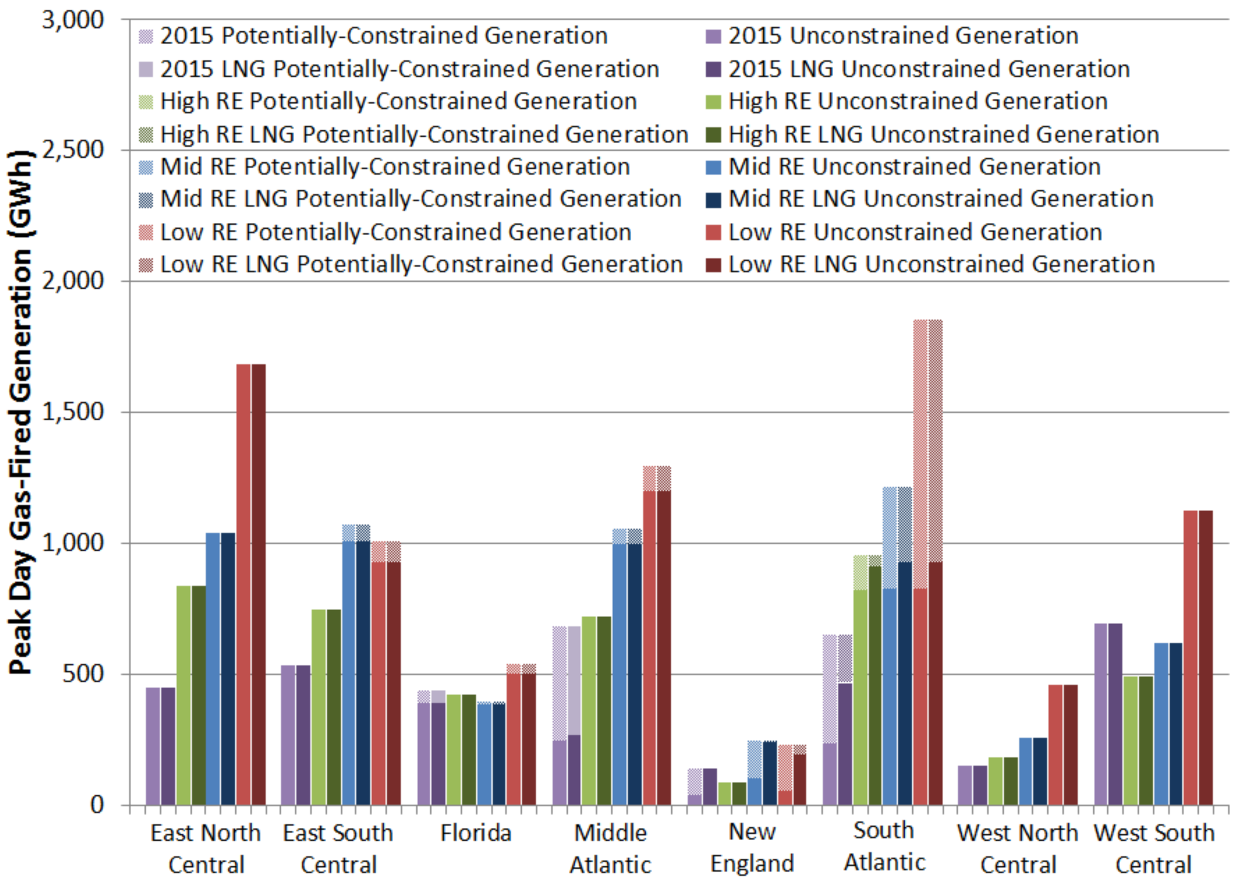
New England sees the largest percentage reduction in potentially-constrained generation when LNG imports are included because (1) it receives more LNG sendout than any other region, and (2) it has less total generation than any other region. In the 2015 benchmark, LNG imports substantially reduce potentially-constrained generation, with a small amount of LNG overage available to offset potentially-constrained generation in Middle Atlantic via displacement. [33] In the Mid RE sensitivity, LNG sendout offsets 95% of the potentially-constrained generation in New England, significantly reducing, although not eliminating, the need for other mitigation measures, and increasing the likelihood that lower-cost mitigation measures would be sufficient to offset the remaining potentially-constrained generation. In the Low RE sensitivity, LNG offsets 75% of the potentially-constrained

[33] Assessment of LNG transportation logistics as well as the required wholesale electric market structure to support increased LNG imports has not been addressed in this study. Also, delivery issues associated with lower scheduling priorities affecting shipments via displacement to gas-fired generation throughout New England are outside the scope of this analysis.

generation, but the residual potentially-constrained generation is large enough, relative to New England's total generation, that more significant mitigation measures would likely be required.

In South Atlantic, LNG imports reduce potentially-constrained generation in the 2015 benchmark by approximately one-half, leaving other mitigation measures to account for the remaining 184 GWh of potentially-constrained generation. In the High RE scenario, the potentially-constrained generation both with and without LNG is less than in the with-LNG benchmark. Mitigation could therefore likely be achieved at a relatively low cost. In the Mid RE and Low RE sensitivities, the amount of potentially-constrained generation is greater than in the with-LNG benchmark by 50% and 400%, indicating the likely need for higher-cost mitigation measures even after LNG imports are considered, to a much greater degree in the Low RE sensitivity.

Figure 45. Gas Infrastructure Limitations – Winter Peak Day – LNG Import Sensitivity



Accounting for potential winter peak day LNG sendout through the LNG Import sensitivity offsets most of the potentially-constrained generation in New England, although there is still more than in the 2015 benchmark in both the Mid RE and Low RE scenarios. In South Atlantic, the High RE sensitivity potentially-constrained generation is less than in the 2015 benchmark, while the Mid RE and Low RE sensitivities have more potentially-constrained generation than in the 2015 benchmark.

Table 12. Potentially-Constrained Generation – Winter Peak Day – LNG Import Sensitivity

Region	2015	2015 LNG	High RE	High RE LNG	Mid RE	Mid RE LNG	Low RE	Low RE LNG
East North Central	--	--	--	--	--	--	--	--
East South Central	--	--	--	--	65 GWh (6.1%)	65 GWh (6.1%)	78 GWh (7.8%)	78 GWh (7.8%)
Florida	47 GWh (10.6%)	47 GWh (10.6%)	--	--	9 GWh (2.3%)	9 GWh (2.3%)	37 GWh (6.9%)	37 GWh (6.9%)
Middle Atlantic	434 GWh (63.5%)	412 GWh (60.3%)	--	--	54 GWh (5.1%)	54 GWh (5.1%)	97 GWh (7.5%)	97 GWh (7.5%)
New England	106 GWh (73.1%)	--	--	--	144 GWh (57.9%)	7 GWh (2.7%)	176 GWh (74.9%)	40 GWh (16.9%)
South Atlantic	417 GWh (63.8%)	184 GWh (28.1%)	133 GWh (14.0%)	39 GWh (4.0%)	386 GWh (31.7%)	288 GWh (23.7%)	1,025 GWh (55.3%)	926 GWh (49.9%)
West North Central	--	--	--	--	--	--	--	--
West South Central	--	--	--	--	--	--	--	--
Total	1,003 GWh (30.3%)	642 GWh (19.4%)	133 GWh (3.7%)	39 GWh (1.1%)	658 GWh (13.5%)	424 GWh (8.7%)	1,414 GWh (17.2%)	1,178 GWh (14.4%)

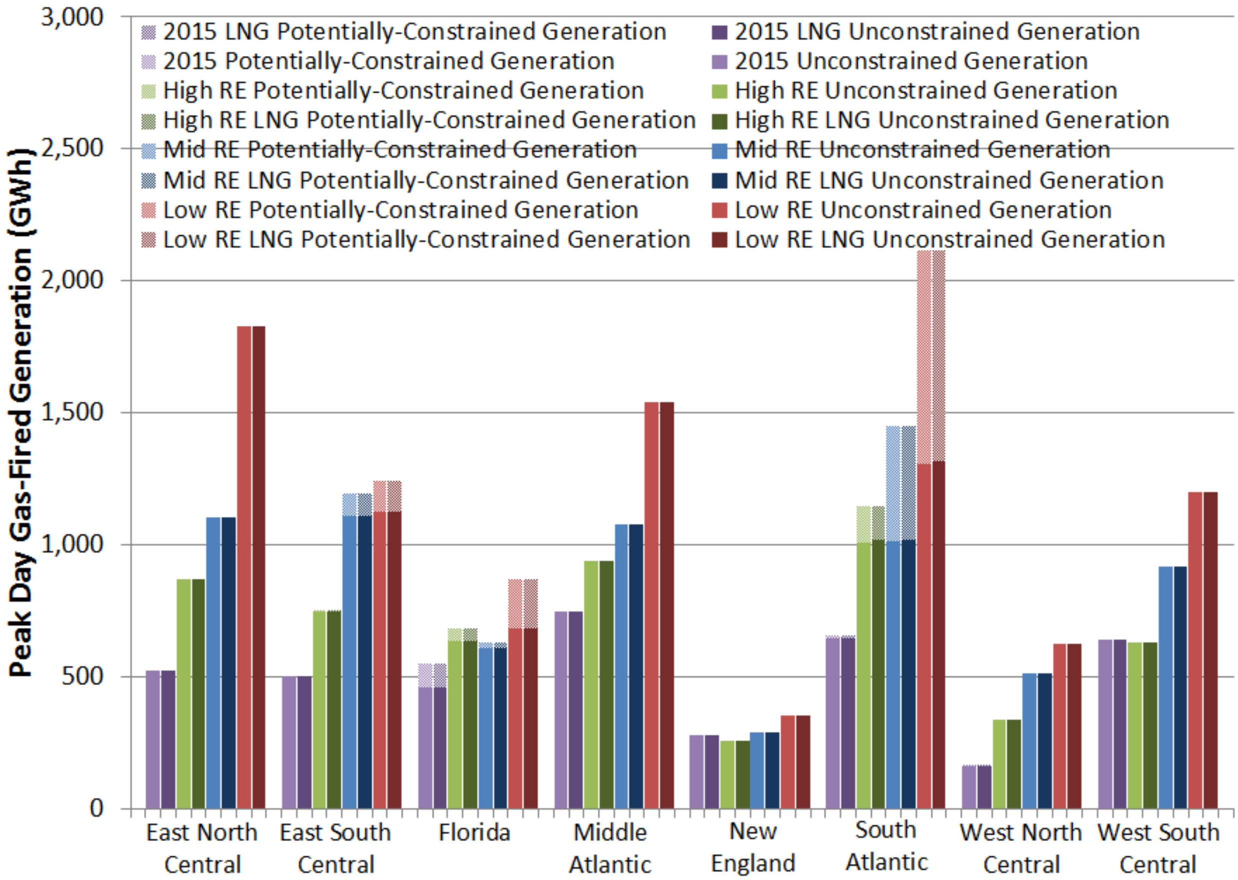
This table shows the data underlying the graphical presentation in Figure 46.

Figure 47 and Table 13 show the effects of the LNG Import sensitivity relative to the 2015 benchmark, High RE, Mid RE and Low RE scenario results on the summer peak day. The only region with a change on the summer peak day due to LNG imports is South Atlantic, where Elba Island and Cove Point have 50 MDth/d and 4 MDth/d, respectively, of LNG sendout.[34] New England has a small amount of summer peak day LNG sendout from Canaport (12 MDth/d), but the region does not have any potentially-constrained generation in the benchmark or the three scenarios. The results are therefore unchanged from the scenario.

In the 2015 benchmark, South Atlantic's potentially-constrained generation is the result of a constraint on Eastern Shore which is not mitigated by LNG imports from either Cove Point or Elba Island. There is therefore no change in the benchmark's sensitivity results. For the three 2050 scenarios, LNG imports from Elba Island are able to provide minimal constraint mitigation, but the volume of LNG imports is so small relative to the amount of potentially-constrained generation that the impact is negligible.

[34] Cove Point is only relevant for purposes of the 2015 benchmark because the terminal is assumed to convert to an export terminal before 2050.

Figure 47. Gas Infrastructure Limitations – Summer Peak Day – LNG Import Sensitivity



Accounting for potential summer peak day LNG sendout through the LNG Import sensitivity results in a slight decrease in potentially-constrained generation in South Atlantic in the three 2050 scenarios, but the results relative to the 2015 benchmark are largely unchanged from the scenarios.

Table 13. Potentially-Constrained Generation – Summer Peak Day – LNG Import Sensitivity

Region	2015	2015 LNG	High RE	High RE LNG	Mid RE	Mid RE LNG	Low RE	Low RE LNG
East North Central	--	--	--	--	--	--	--	--
East South Central	--	--	6 GWh (0.7%)	6 GWh (0.7%)	84 GWh (7.0%)	84 GWh (7.0%)	116 GWh (9.3%)	116 GWh (9.3%)
Florida	90 GWh (16.3%)	90 GWh (16.3%)	51 GWh (7.5%)	51 GWh (7.5%)	21 GWh (3.4%)	21 GWh (3.4%)	186 GWh (21.4%)	186 GWh (21.4%)
Middle Atlantic	--	--	--		--	--	--	--
New England	--	--	--		--	--	--	--
South Atlantic	7 GWh (1.1%)	7 GWh (1.1%)	138 GWh (12.0%)	132 GWh (11.4%)	435 GWh (30.0%)	428 GWh (29.6%)	809 GWh (38.2%)	802 GWh (37.8%)
West North Central	4 GWh (2.2%)	4 GWh (2.2%)	--	--	--	--	--	--
West South Central	--	--	--	--	--	--	--	--
Total	101 GWh (2.5%)	101 GWh (2.5%)	195 GWh (3.5%)	188 GWh (3.3%)	541 GWh (7.5%)	534 GWh (7.4%)	1,111 GWh (11.4%)	1,104 GWh (11.3%)

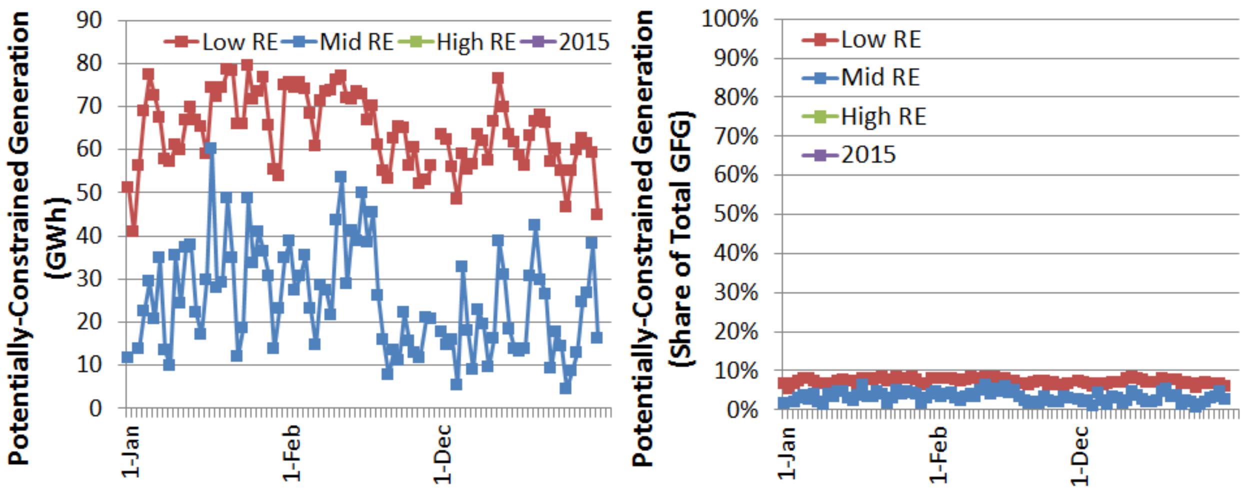
This table shows the data underlying the graphical presentation in Figure 47.

4.4 Frequency and Duration of Constraints

For each of the regional results in this section, all the scenarios or sensitivities that are relevant to a figure are listed in the legend, although if there are no days with potentially-constrained generation indicated for a specific scenario or sensitivity, no data points will be shown. If a data point is shown for a day within a scenario or sensitivity, there is potentially-constrained generation on that day, although the amount or percentage of potentially-constrained generation may be small if the data point is close to the x-axis. The number of data points shown therefore indicates the frequency of the constraint. Consecutive days with potentially-constrained generation are connected by lines to indicate the duration of the constrained condition. Each set of results includes two figures, one volumetric and one proportional. The y-axes of the volumetric figures vary between figures are intended to show a comparison of the 2050 results to the corresponding benchmark for purposes of mitigation consideration, since the cost of mitigation is in most cases more closely related to the volume of potentially-constrained generation than the share of total generation represented by the potentially-constrained generation. All proportional figures are presented on the same y-axis scale from 0 to 100% in order to facilitate an at-a-glance review of the relative impacts of constraints on the different census regions within the same time period (winter peak day or summer peak day), and on the same census region between time periods.

Figure 48 shows the winter seasonal constraints for the East South Central region. There is no potentially-constrained generation in the 2015 benchmark, and for the Mid RE and Low RE scenarios, all or the majority of the potentially-constrained generation in East South Central results from a constraint on Transco in the South Atlantic region that limits interconnection flows to the East Tennessee pipeline. In the Mid RE scenario, a portion of the potentially-constrained generation is additionally the result of a constraint on Southern Natural. In both scenarios, the constraints are relatively low impact, but persistent. The pipeline density in East South Central is high enough that the potentially-constrained generation may be able to be shifted to plants served by other pipelines, which would be a relatively low cost mitigation measure compared to expanding the pipeline capacity of the constrained infrastructure. Due to the persistence of the constraint, even though the volume is low, the use of electric demand reduction or alternate-fuel usage is likely less relevant. There is no potentially-constrained East South Central generation in the High RE scenario.

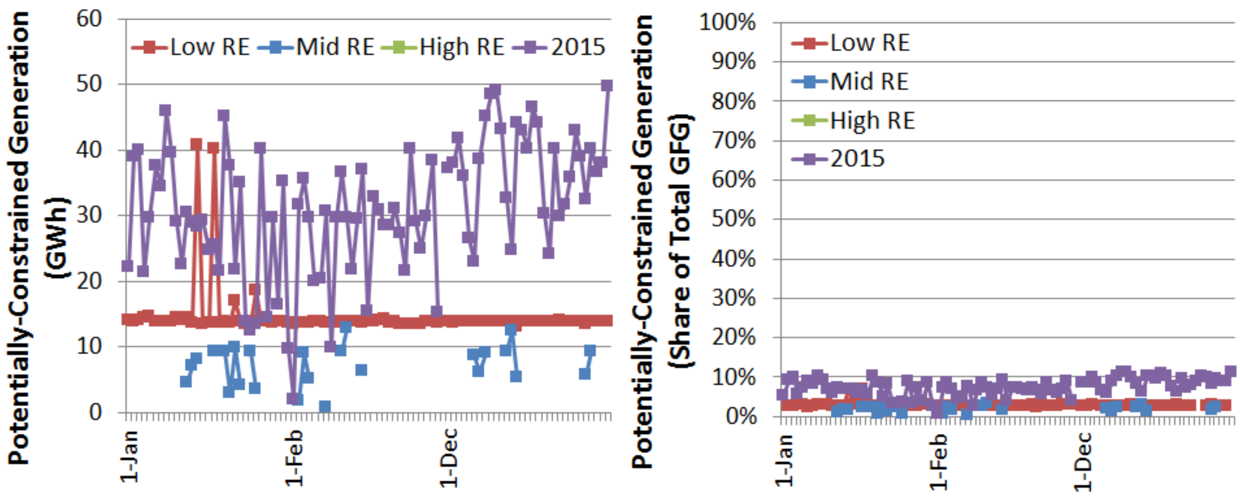
Figure 48. Gas Infrastructure Limitations – Winter Season – East South Central



There is no potentially-constrained generation in East South Central generation in the 2015 benchmark. In the Mid RE and Low RE scenarios, potentially-constrained generation occurs persistently throughout the winter season. Comparing to Figure 49, Figure 50, Figure 51 and Figure 52 for regional context during the winter shows that East South Central is more affected by potentially-constrained generation than Florida and Middle Atlantic in 2050, and less affected by potentially-constrained generation than New England and South Atlantic. Comparing to Figure 53 for seasonal context shows that East South Central has slightly lower potentially-constrained generation during the winter than the summer.

Figure 49 shows the winter seasonal constraints for Florida. As described above, Florida's total gas demand is heavily weighted toward the power generation sector and peaks during the summer. Hence, the pipelines that serve Florida are not significantly stressed during the winter months relative to their summer-targeted capacity. The Low RE scenario shows a consistent but small amount of potentially-constrained generation due to a constraint on Southern Natural. Potentially-constrained generation occurs persistently in both the Low RE scenario and the 2015 baseline. The spikes in the Low RE scenario correspond to days when a constraint on Florida Gas Transmission is also limiting gas flows, and while the specific days with spikes do not correspond to the most constrained days in the 2015 benchmark, even the highest potentially-constrained volumes are within the range of the benchmark, indicating the relative low cost mitigation is likely possible. The Mid RE scenario shows a similar level of potentially-constrained generation as the Low RE scenario due to the same Southern Natural constraint, but the constraint occurs much less frequently due to the lower overall demand level, indicating a reduced need for mitigation than in the benchmark. There are no days with potentially-constrained generation in the High RE scenario.

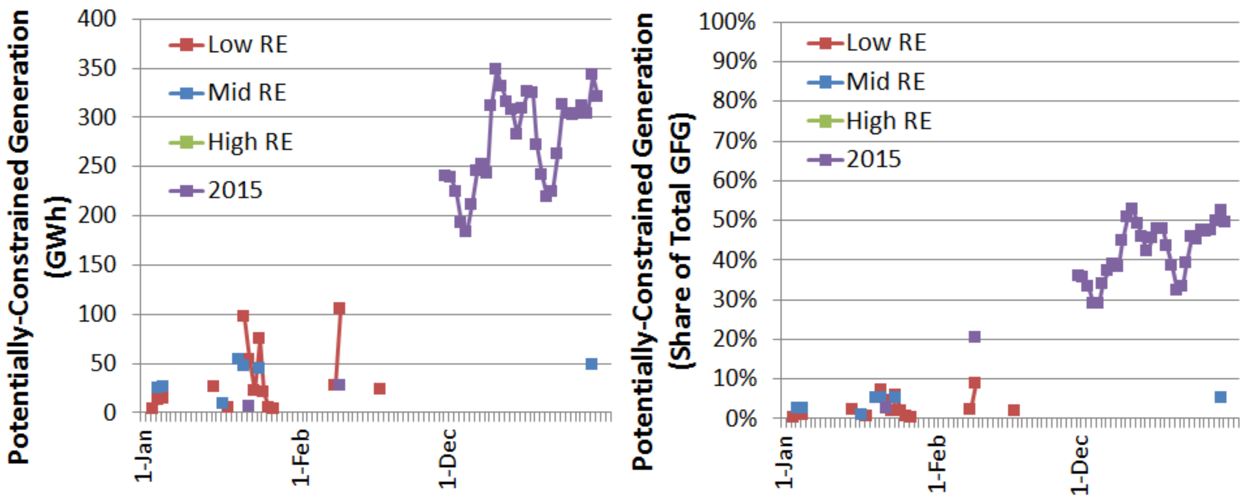
Figure 49. Gas Infrastructure Limitations – Winter Season – Florida



There is no potentially-constrained generation in Florida during the winter in the High RE scenario. Mid RE scenario potentially-constrained generation is intermittent and less than in the 2015 benchmark for all days. Low RE scenario potentially-constrained generation is persistent, although less than the 2015 benchmark on most days on both a volumetric and percentage basis. Of the seven days with higher Low RE scenario demand than benchmark demand, only two represent spikes significantly above the scenario's average volume of potentially-constrained generation, and both are within the oscillation range of the benchmark. On a percentage basis, Florida is more affected by potentially-constrained generation than Middle Atlantic in 2050, and less affected by potentially-constrained generation than East South Central, New England and South Atlantic. Comparing to Figure 54 for seasonal context shows that Florida has more potentially-constrained generation during the summer than during the winter, consistent with the region being summer peaking.

Figure 50 shows the winter seasonal constraints for the Middle Atlantic region. Total gas demand in Middle Atlantic is winter peaking, with limited capacity available for power generation sector demand on days with the highest gas utility sector demand. In the 2015 benchmark, constraints on Columbia Gas, Iroquois, Millennium, Texas Eastern and Transco result in significant potentially-constrained generation in December that is much higher on both a volumetric and percentage basis than any 2050 scenario results. Constraints on Texas Eastern and Transco result in intermittent potentially-constrained generation in the Mid RE and Low RE scenarios, particularly in January and February. A constraint on Columbia Gas also contributes to the potentially-constrained generation in the Low RE scenario. The intermittency of the constraint and low volume relative to the benchmark indicate that lower-cost mitigation measures should be available. No potentially-constrained generation occurs in the High RE scenario.

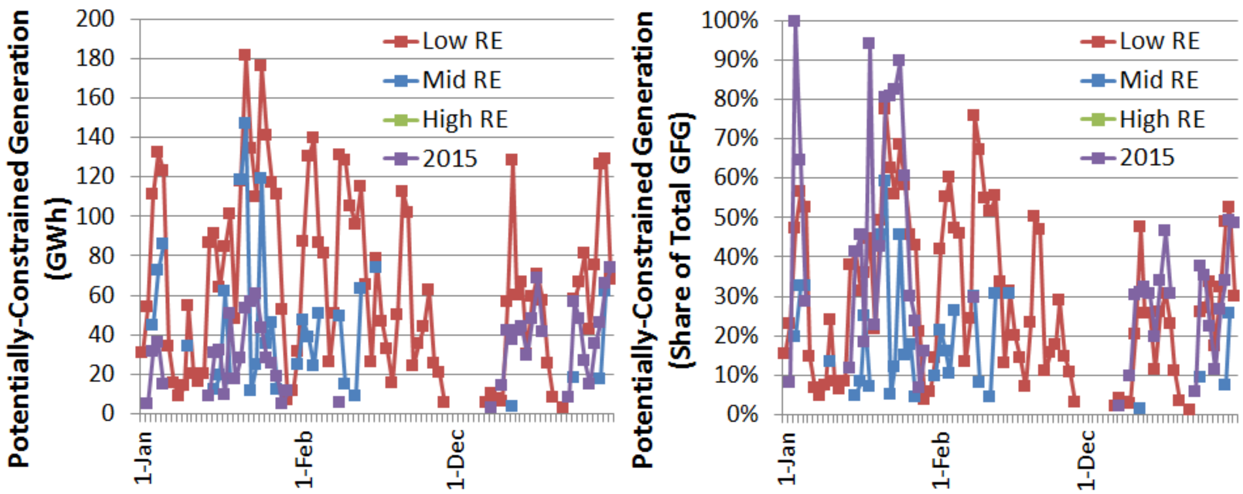
Figure 50. Gas Infrastructure Limitations – Winter Season – Middle Atlantic



Middle Atlantic/s potentially-constrained generation in the Low RE and Mid RE scenarios is intermittent throughout January and February and less than the potentially-constrained generation that occurs persistently in December in the 2015 benchmark. The difference in timing of the constraints (January and February vs. December) likely does not affect the relevance of 2015 benchmark mitigation measure being relevant in 2050.

Figure 51 shows the winter seasonal constraints for New England. Constraint occurrence is similarly moderately persistent in the 2015 benchmark (40 days) and Mid RE scenario (30 days), and much more persistent in the Low RE scenario (82 days). On a percentage basis, the 2015 benchmark shows a higher share of potentially-constrained generation, but on a volumetric basis both the Mid RE and Low RE scenarios have much more potentially-constrained generation than the benchmark. The potentially-constrained generation is not due to constraints within New England, but rather on pipeline segments upstream of New England in the Middle Atlantic region – specifically on Tennessee, Millennium and Texas Eastern – and also in Canada. The high variation in the volume of potentially-constrained generation indicates that a combination of long and short duration mitigation measures would likely be the most economical way to relieve the constraint. For example, if new pipeline capacity is added to relieve the constraint, it could be targeted at the mid-range of potentially-constrained generation shown in the volumetric graph, with dual-fuel capability and/or electric demand reduction used to contribute to mitigation on the days with peak potentially-constrained generation.. The potential of LNG imports to contribute to constraint mitigation is addressed in the LNG Import sensitivity results described below. No potentially-constrained generation occurs in the High RE scenario.

Figure 51. Gas Infrastructure Limitations – Winter Season – New England



New England is significantly affected by potentially-constrained generation in the Mid RE and Low RE scenarios. The percentage of gas-fired generation that is potentially-constrained in the 2050 scenarios is within the benchmark range, but the corresponding volume of potentially-constrained generation is much higher in the 2050 scenarios than in the benchmark. While the constraint is persistent, it is not persistent at its highest level, instead oscillating frequently between higher and lower amounts of potentially-constrained generation. The peak percentage of potentially-constrained generation in New England is higher than in South Atlantic, but the volumes of potentially-constrained generation are much higher throughout the season in South Atlantic, particularly in the Low RE scenario.

Figure 52 shows the winter seasonal constraints for the South Atlantic region. In the 2015 benchmark, constraints on Transco, Columbia Gas and Eastern Shore result in potentially-constrained generation levels comparable to the High RE scenario in January and February and to the Mid RE scenario in December. In all three 2050 scenarios, the majority of the potentially-constrained generation is due to a constraint on Transco that limits deliveries to (1) generators directly served by Transco and (2) generators served by the downstream Carolina Gas Transmission pipeline that is dependent on deliveries from Transco for system supply. Also in all three scenarios, generation served by Dominion Cove Point is potentially-constrained due to the volume and steady flow of natural gas to the Cove Point terminal for liquefaction to support the LNG export regime.[35] In the Mid RE and Low RE scenarios, a portion of the potentially-constrained generation is the result of a Southern Natural constraint. The final contributing constraint in the Low RE scenario is on Columbia Gas. The High RE scenario shows only intermittent constraints and a relatively low share of potentially-constrained generation, which could likely be mitigated through lower-cost mitigation measures based on its similarity to the 2015 benchmark. The Mid RE scenario shows persistent constraints resulting in potentially-constrained generation levels similar to, but in some cases higher than, the range of potentially-constrained generation volume in the benchmark, indicating the need to increased mitigation costs. The Low RE scenario results indicate that a significant volume (and percentage) of regional gas-fired generation would be persistently potentially-constrained each day during the season due to the high

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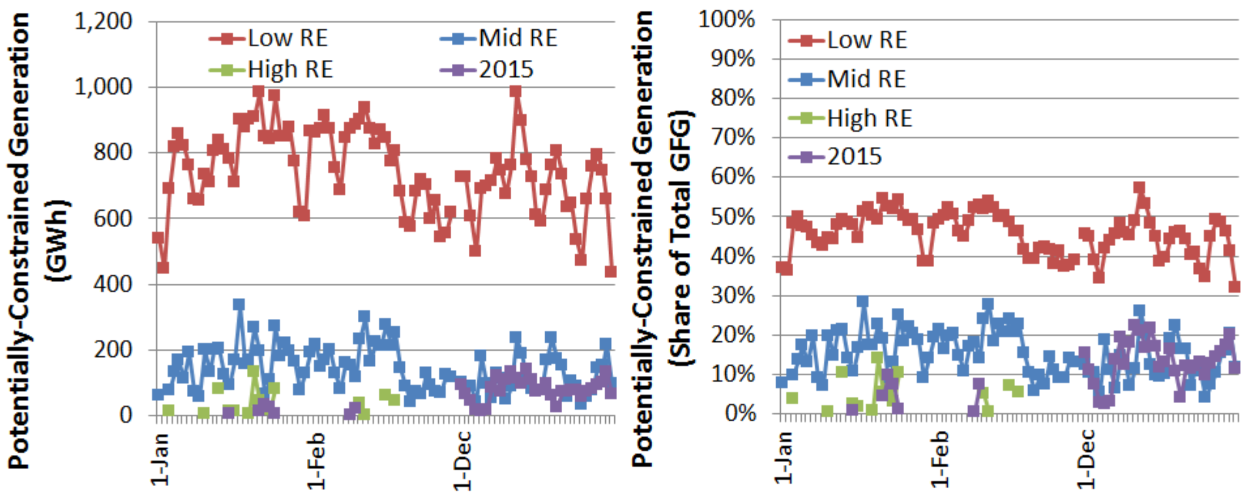
[35] The potential redeployment of natural gas from storage at Cove Point during pipeline congestion events has not been incorporated in this analysis.

concentration of gas utility sector gas demand in the region relative to the limited pipeline density. At this sustained level of potentially-constrained generation, pipeline capacity expansion would likely be required to reduce the constraint.

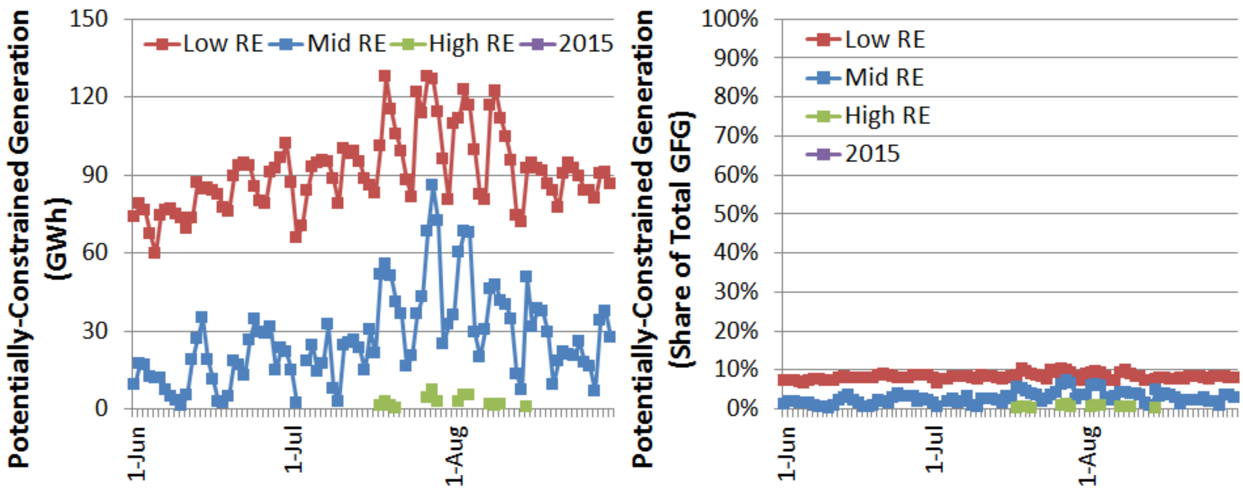
Figure 52. Gas Infrastructure Limitations – Winter Season – South Atlantic



Potentially-constrained generation in South Atlantic shows similar patterns across the three 2050 scenarios, with persistent potentially-constrained generation in the Mid RE and Low RE scenarios. South Atlantic is more affected than every region except New England, which has higher peak potentially-constrained generation, although it is less persistent. Comparing to Figure 55 for seasonal context shows that South Atlantic is more affected by constraints during the winter than during the summer.

Figure 53 shows the summer seasonal constraints for the East South Central region. There is no potentially-constrained generation in the 2015 benchmark, therefore all potentially-constrained generation in 2050 is incremental. Similar to winter conditions, the potentially-constrained East South Central generation in all three 2050 scenarios results from a constraint on Transco in the South Atlantic region that limits interconnection flows to the East Tennessee pipeline. The occurrence of potentially-constrained generation is intermittent and minor in the High RE scenario, but persistent in the Mid RE and Low RE scenarios. In conjunction with the winter results, the persistence of this constraint indicates the need for a pipeline-based mitigation measure, either re-dispatch to plants served by other pipelines (lower cost), or pipeline capacity expansion (higher cost).

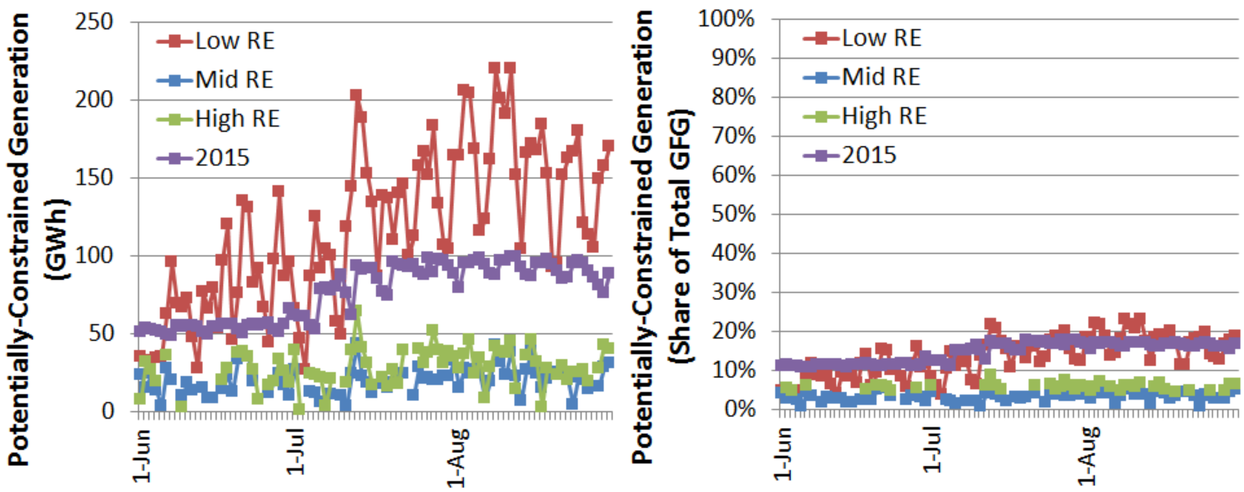
Figure 53. Gas Infrastructure Limitations – Summer Season – East South Central



Potentially-constrained generation in East South Central, all of which is incremental to the unconstrained 2015 benchmark, is slightly higher during the winter than during the summer, with an intermittent constraint affecting a small amount of generation occurring in the High RE scenario.

Figure 54 shows the summer seasonal constraints for Florida. In the 2015 benchmark and the High RE and Mid RE scenarios, the potentially-constrained generation in Florida is the result of a constraint on Gulfstream. Gulfstream does not serve any gas utility sector demand, only power generation sector demand. The constraint therefore occurs when the total gas demand of the generators connected to the pipeline is greater than the capacity of the pipeline. Potentially-constrained generation in both the Mid RE and High RE scenarios is less than in the 2015 benchmark on both a volumetric and percentage basis, indicating that the Gulfstream constraint can be mitigated through existing lower-cost measures. In the Low RE scenario, the Gulfstream constraint is compounded by a constraint on Florida Gas Transmission. Similar to Gulfstream, the majority of Florida Gas Transmission's existing capacity is contracted by generators, rather than gas utility sector customers. If the generation owners were to continue the current business practice with respect to meeting fuel assurance objectives through firm transportation pipeline capacity entitlements, it is likely that the potentially-constrained generation in Florida would be materially reduced or eliminated.

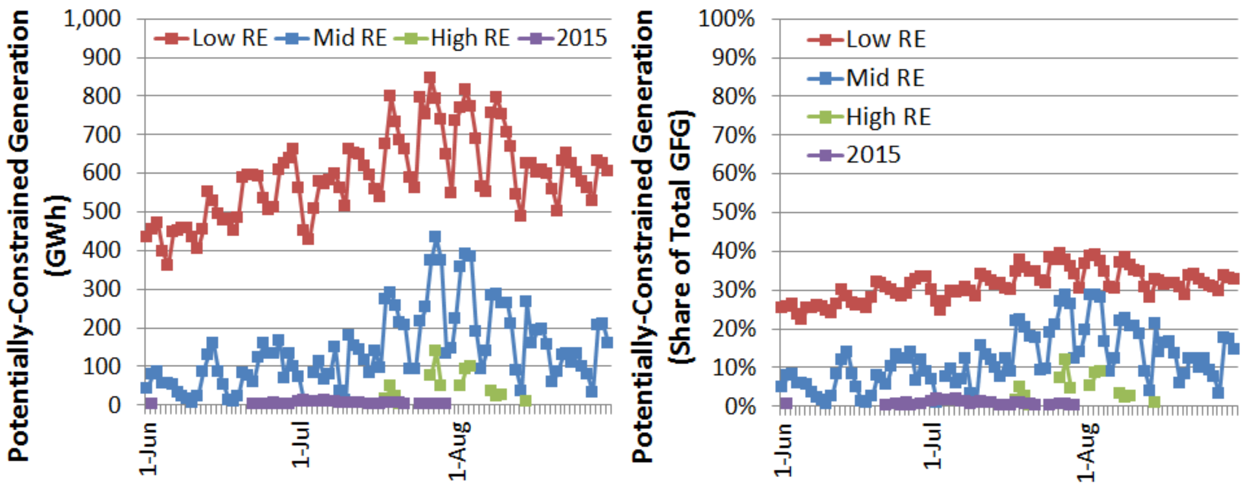
Figure 54. Gas Infrastructure Limitations – Summer Season – Florida



Potentially-constrained generation in Florida is higher during the summer than during the winter in the benchmark and in all three 2050scenarios, due to power generation sector gas demand, and therefore total gas demand, being higher during the summer. Constraints are persistent in all cases. Potentially-constrained generation in the High RE and Mid RE scenarios is consistently below the 2015 benchmark. In the Low RE scenario, however, potentially-constrained generation is consistently above the 2015 benchmark, doubling it (or more) on several days, indicating the likely need for more costly total mitigation measures.

Figure 55 shows the summer seasonal constraints for the South Atlantic region. While the region as a whole is winter peaking, total gas demand in the southern states (Georgia, North Carolina and South Carolina) is approximately equal on the summer and winter peak days, with similar seasonal demand curves – gas utility sector demand is reduced, but less so than in northern states with high winter heating demand, and the increased summer power generation sector demand approximately makes up the difference. As previously discussed, the southern South Atlantic states also have limited pipeline connections, as both Transco and Southern Natural face high power generation sector gas demand throughout the summer. These factors result in the persistent occurrence of constraints in both the Mid RE and Low RE scenarios that are much higher than the 2015 benchmark, when the only regional constraint is on the Eastern Shore pipeline. The persistence and volumetric degree of potentially-constrained generation in these scenarios is indicative of the need for pipeline capacity expansion. An intermittent constraint is also seen in the High RE scenario at a higher volume than the 2015 benchmark, but a much lower volume than the Mid RE scenario. These constraints could potentially be mitigated through lower cost measures.

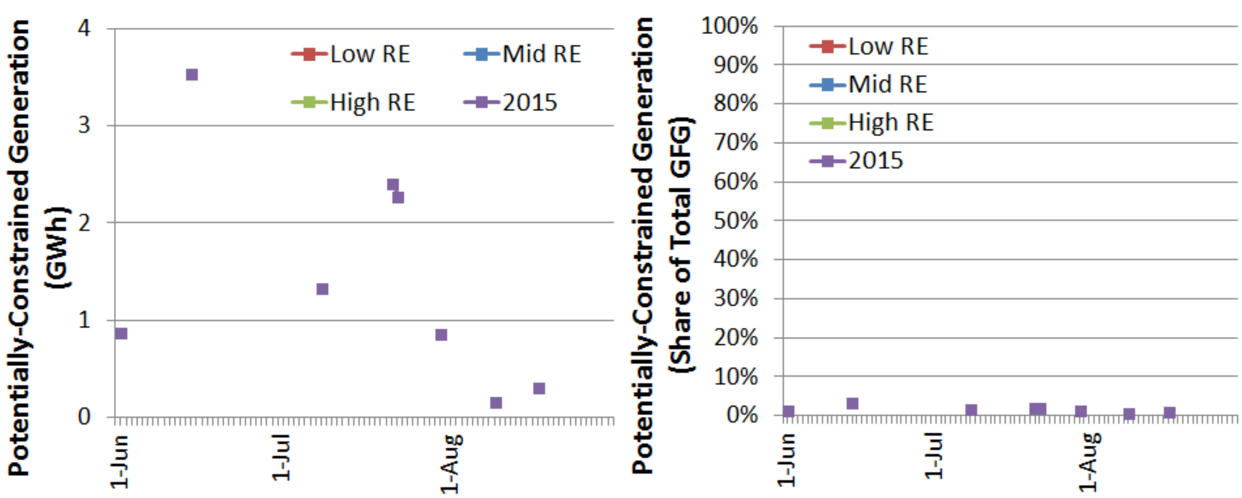
Figure 55. Gas Infrastructure Limitations – Summer Season – South Atlantic



The 2015 benchmark exhibited negligible potentially-constrained generation in South Atlantic. The much higher persistent volumes of potentially-constrained generation are indicative of the need for pipeline capacity expansion in the region in the Mid RE and Low RE scenarios. Relative to the winter results for South Atlantic, the summer season potentially-constrained generation is only slightly lower volumetrically, affirming the persistent need for expensive mitigation. The intermittent High RE constraint is also similar to the corresponding winter results and is more likely to be mitigable through lower cost measures.

Figure 56 shows the summer seasonal constraints for the West North Central region. A minor intermittent constraint occurs in the 2015 benchmark due to a constraint in Texas Eastern's Zone M1, but it is mitigated between 2015 and 2050 by pipeline capacity expansions to meet gas utility sector gas demand needs.

Figure 56. Gas Infrastructure Limitations – Summer Season – West North Central

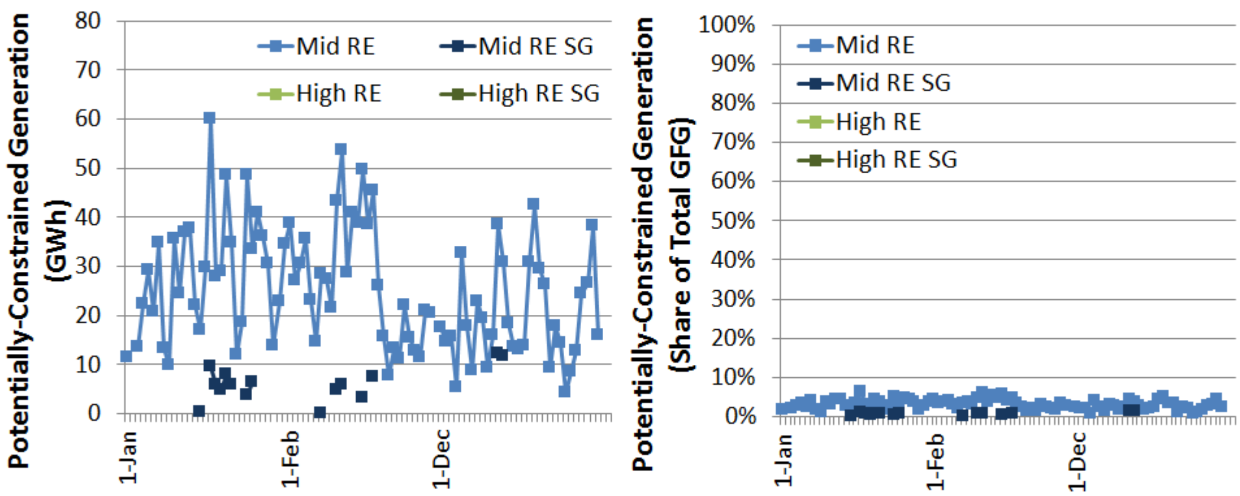


West North Central experiences a trivial amount of potentially-constrained generation intermittently during summer in the 2015 benchmark. This constraint does not occur in 2050 because the affected pipeline segment is expanded to meet utility sector load growth.

4.4.1 Storage / Gas Sensitivity

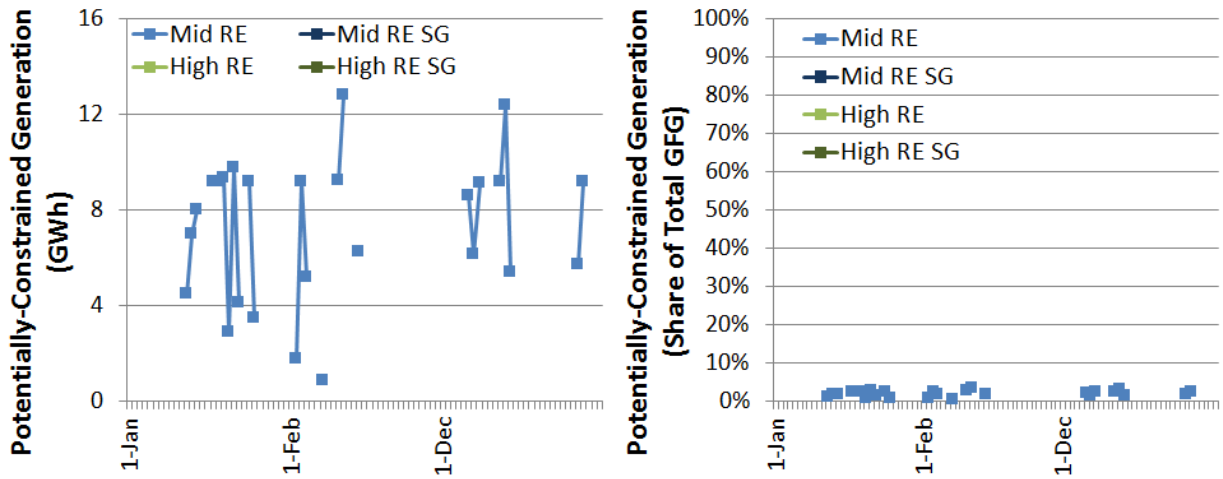
Because the total gas demand in the SG sensitivities does not represent a significant departure from the scenarios in most cases, the frequency and duration of constraints are similar to the scenario results. The following five figures show the sensitivity results for the regions with occurrences of potentially-constrained generation relative to the corresponding scenario results. The gas infrastructure and utility sector demand forecasts are common to all four of the data sets in these figures. Differences are due solely to variation in the power generation sector demand forecasts. While the differentials between the Mid RE and High RE scenarios are clear, the relative differentials between the scenarios and corresponding sensitivities are in most cases nearly undistinguishable. This corresponds to the result that on the scale of the electric sector gas demand, the sensitivity changes are not highly significant. Only the South Atlantic region has potentially-constrained generation in the High RE scenario during the winter.

Figure 57. Gas Infrastructure Limitations – Winter Season – East South Central – SG Sensitivities



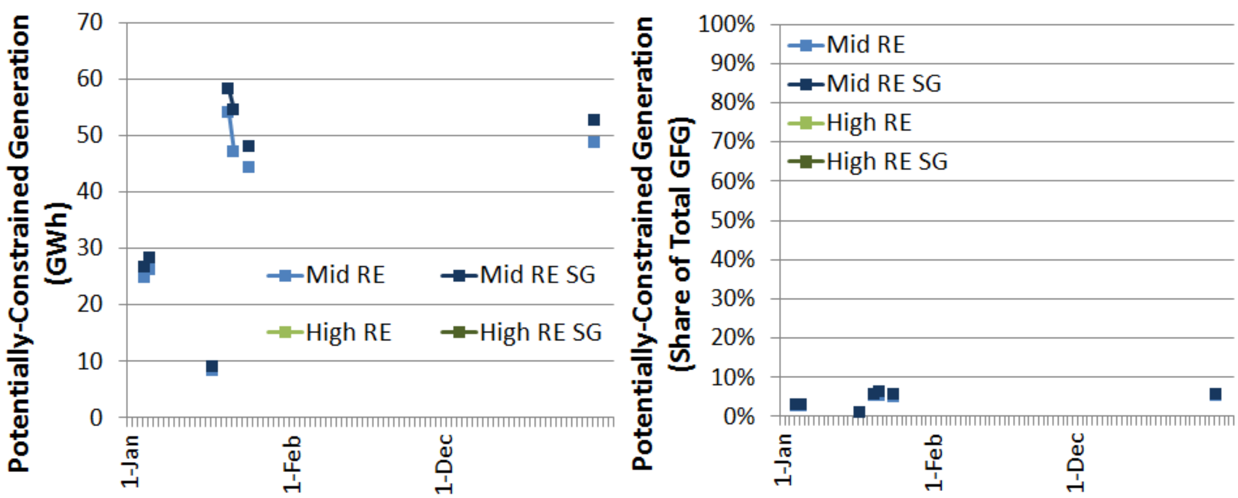
The amount of potentially-constrained generation is slightly reduced in the Mid RE SG sensitivity relative to the Mid RE scenario, which also reduces the frequency and duration of constraints.

Figure 58. Gas Infrastructure Limitations – Winter Season – Florida – SG Sensitivities



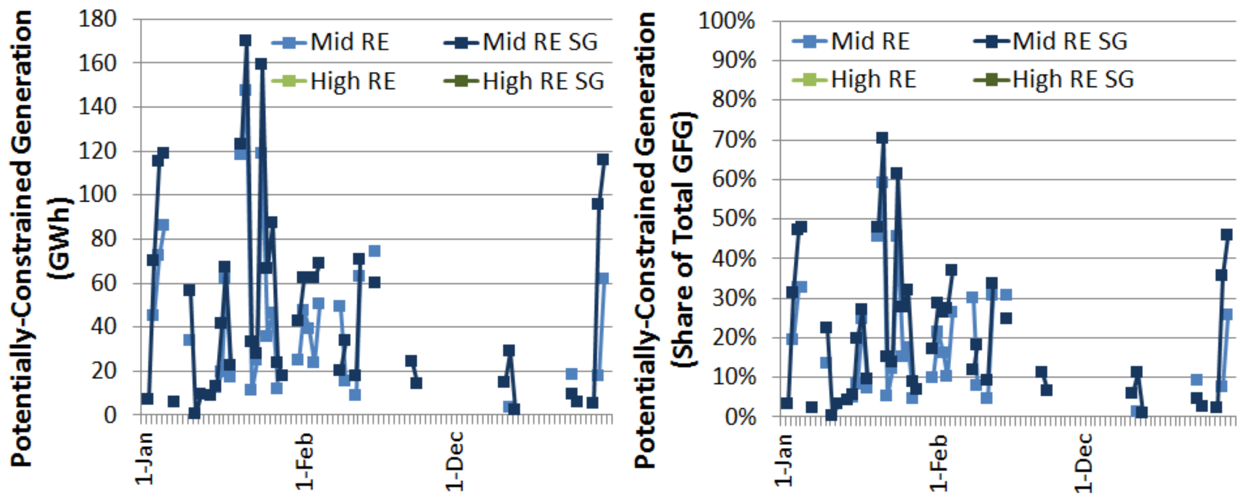
The potentially-constrained generation that occurs in Florida in the Mid RE scenario is eliminated in the Mid RE SG sensitivity.

Figure 59. Gas Infrastructure Limitations – Winter Season – Middle Atlantic – SG Sensitivities



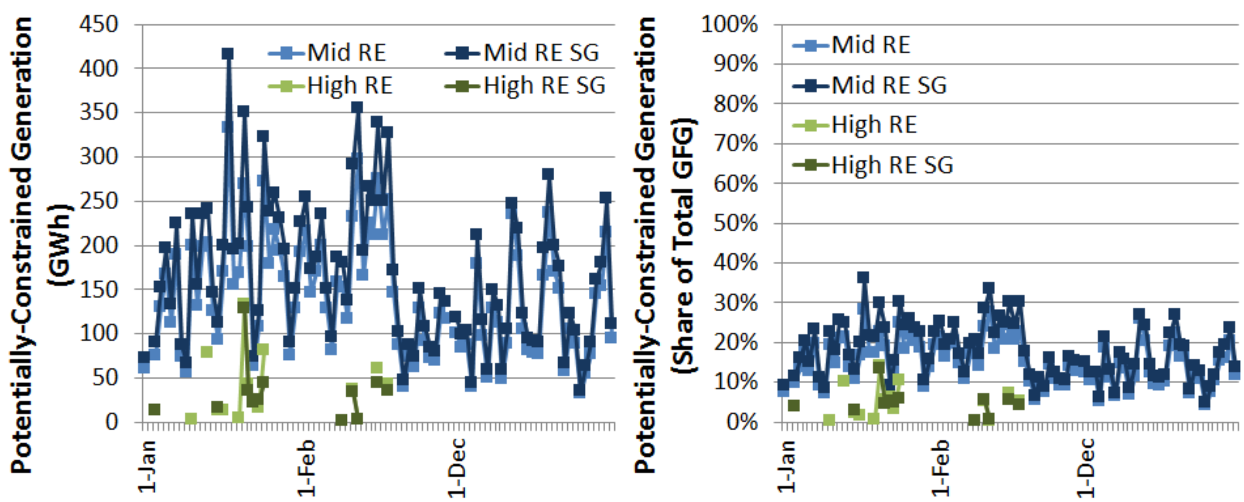
Potentially-constrained generation in Middle Atlantic is very slightly increased in the Mid RE SG sensitivity relative to the Mid RE scenario.

Figure 60. Gas Infrastructure Limitations – Winter Season – New England – SG Sensitivities



Potentially-constrained generation in New England is slightly increased in the Mid RE SG sensitivity relative to the Mid RE scenario on most days with potentially-constrained generation.

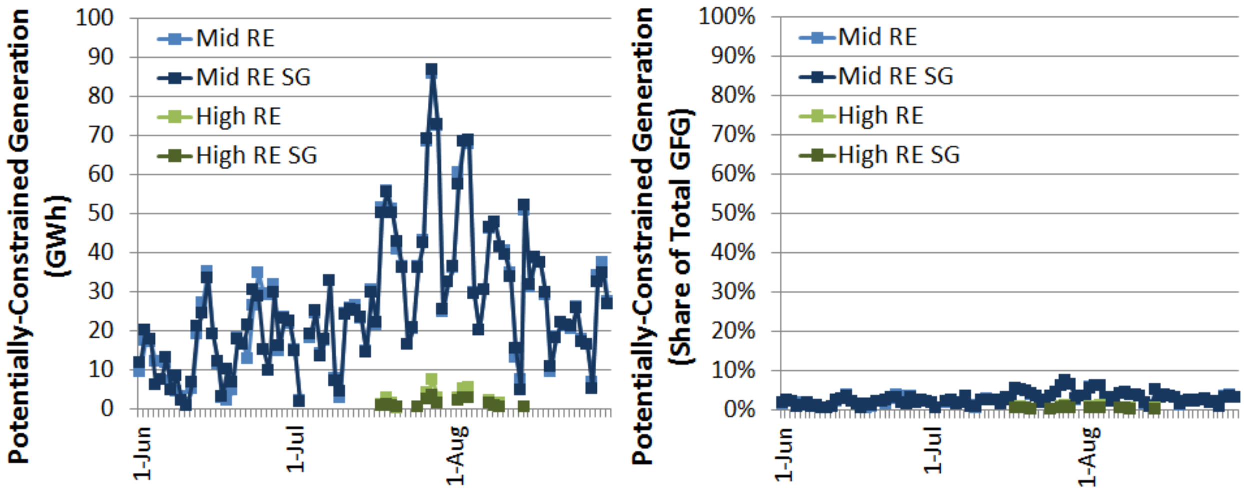
Figure 61. Gas Infrastructure Limitations – Winter Season – South Atlantic – SG Sensitivities



South Atlantic potentially-constrained generation is slightly increased in the Mid RE SG sensitivity and slightly decreased in the High RE SG sensitivity.

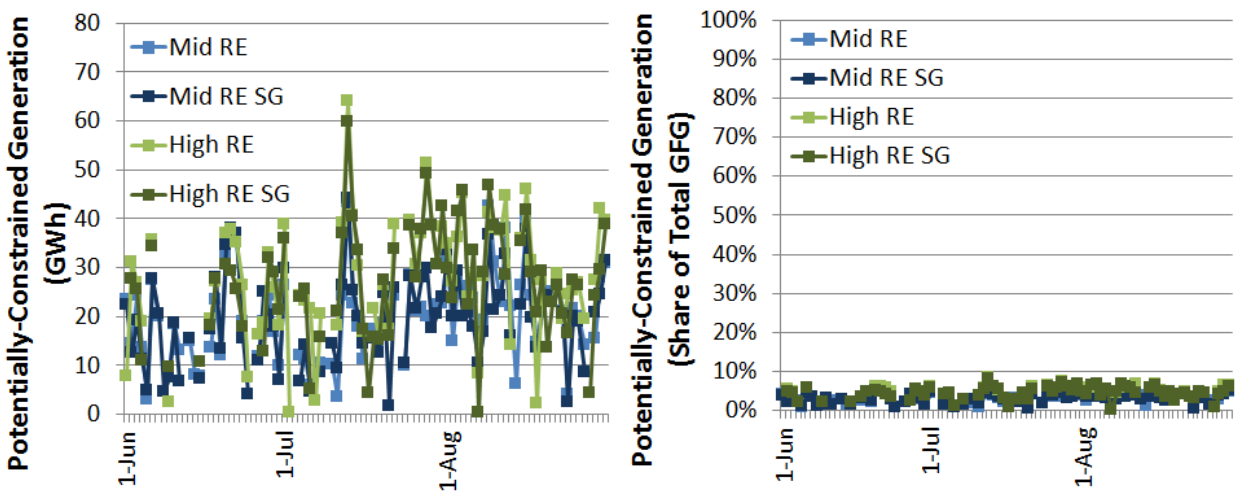
The following three figures show the summer seasonal constraints for the East South Central, Florida and South Atlantic regions. As with the winter results, the sensitivity results did not vary significantly from the corresponding scenarios, with more significant constraints in South Atlantic than in East South Central and Florida. Each sensitivity uses the same natural gas infrastructure and utility sector forecast as the base scenario. Therefore any variance corresponds to the changes in the power generation sector demand forecast.

Figure 62. Gas Infrastructure Limitations – Summer Season – East South Central – SG Sensitivities



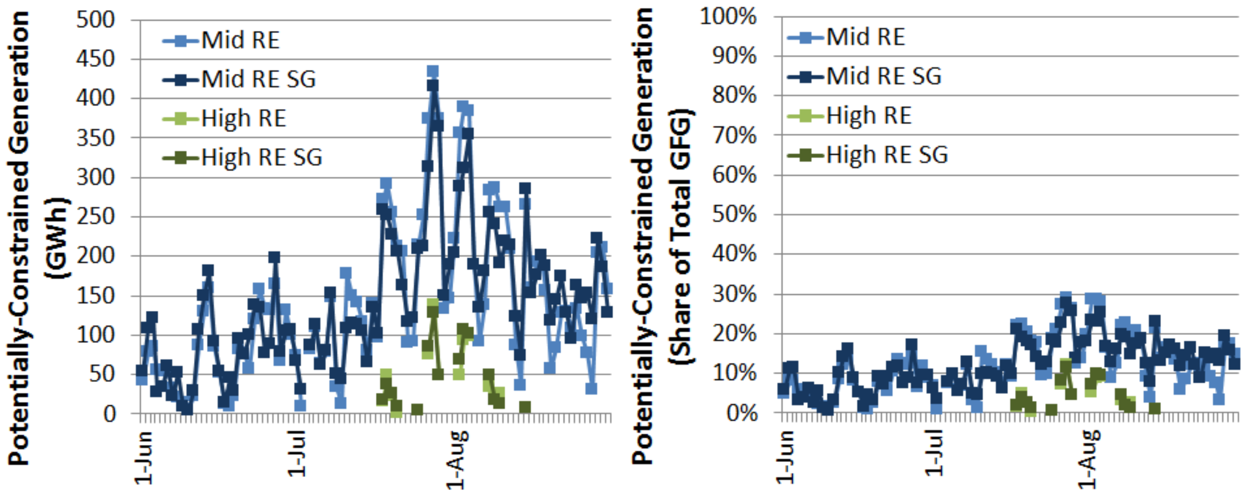
Both the Mid RE and High RE results in East South Central are trivially affected by the storage technology sensitivity, on most days slightly reducing the potentially-constrained generation.

Figure 63. Gas Infrastructure Limitations – Summer Season – Florida – SG Sensitivities



Both the Mid RE and High RE results in Florida are trivially affected by the storage technology sensitivity, with the High RE SG sensitivity showing slightly decreased potentially-constrained generation and the Mid RE SG sensitivity showing slightly increased potentially-constrained generation.

Figure 64. Gas Infrastructure Limitations – Summer Season – South Atlantic – SG Sensitivities



The storage technology sensitivity has an alternately positive and negative effect on potentially-constrained generation in South Atlantic throughout the summer, with small variations from the scenario results.

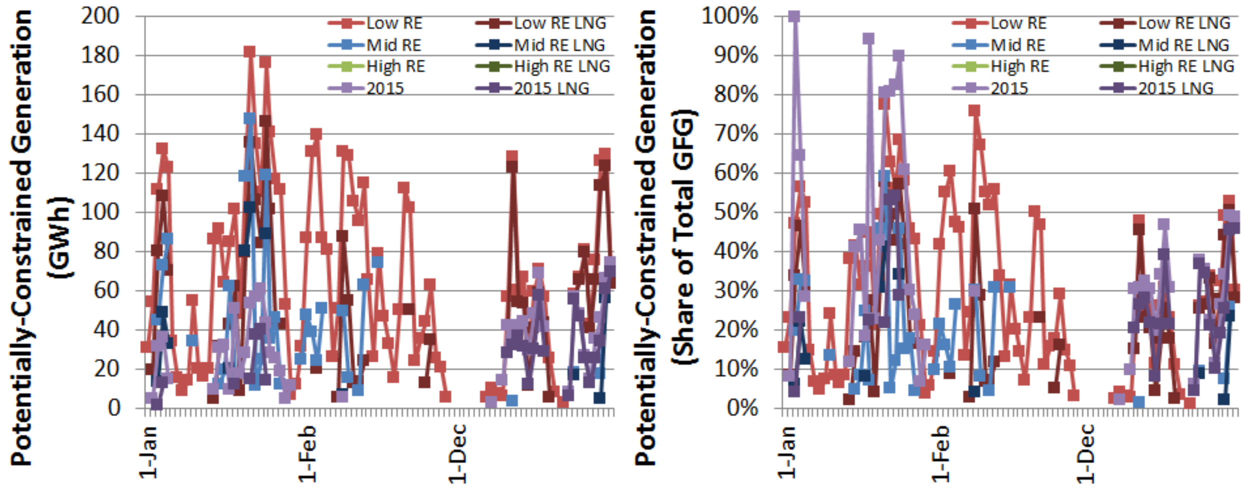
4.4.2 LNG Import Sensitivity

The following three figures show the impact of incorporating 2015 LNG sendout volumes in the 2015 benchmark and the three 2050 scenario results for the two regions with LNG import terminals and the Middle Atlantic region, which on some days receives the benefit of a small amount of LNG by displacement from the New England terminals when New England has more LNG sendout than potentially-constrained generation. The extent to which additional LNG sendout is deliverable to generators across New England and the Middle Atlantic via displacement has not been addressed in this study.

In New England (Figure 65), LNG sendout offsets all or a significant portion of the potentially-constrained generation, particularly in January and February.[36] When LNG sendout is contemplated as a mitigation measure, the number of days with potentially-constrained generation is reduced from 40 to 24 in the 2015 benchmark, from 30 to 11 in the Mid RE scenario, and from 82 to 44 in the Low RE scenario. With the volume and persistence of potentially-constrained generation reduced, the need for mitigation measures other than LNG is also reduced. Additionally, with the higher gas prices that would likely occur on days with high volumes of potentially-constrained generation, particularly in the Low RE scenario but also in the Mid RE scenario, incremental LNG sendout beyond the levels seen in 2015 would likely be economically justifiable, further mitigating the constraints.

[36] December exhibits smaller differentials in potentially-constrained generation between the scenarios and corresponding sensitivities because LNG sendout was lower in December 2015 than in January and February 2015.

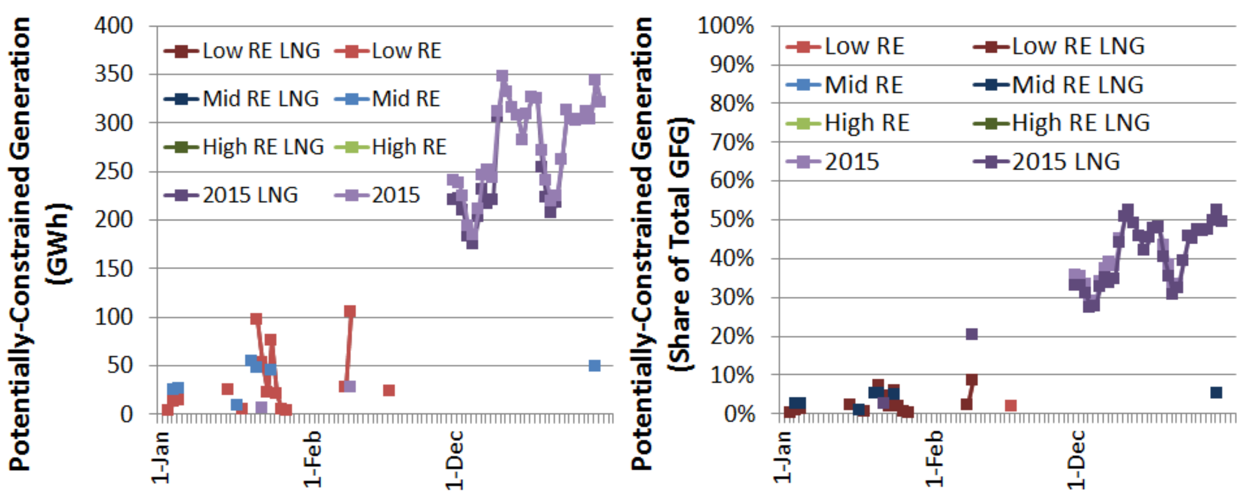
Figure 65. Gas Infrastructure Limitations – Winter Season – New England – LNG Sensitivity



LNG sendout significantly reduces potentially-constrained generation on many winter days in New England. Where the lighter-colored scenario lines can be seen in the figures, it means that potentially-constrained generation is reduced. LNG sendout in New England is intermittently high in January and February and lower in December. Accordingly, potentially-constrained generation is intermittently reduced in January and February and minimally affected in December.

LNG sendout that exceeds potentially-constrained generation in New England on a given day is applied to Middle Atlantic (Figure 66), where reduced downstream demand allows for more generation to be served on one day in mid-February relative to the Low RE scenario. The impacts of this adjustment are more visible in the 2015 benchmark in December, but there is minimal potentially-constrained generation in Middle Atlantic in December 2050.

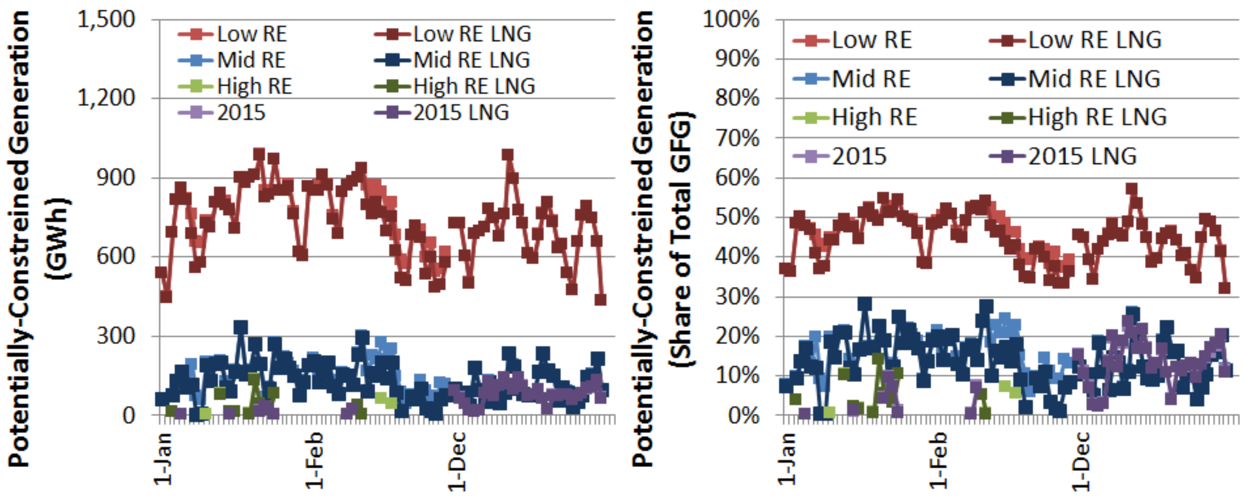
Figure 66. Gas Infrastructure Limitations – Winter Season – Middle Atlantic – LNG Sensitivity



On days when there is more LNG sendout in New England than needed to serve potentially-constrained generation, the overage is applied to Middle Atlantic by displacement. Days with potentially-constrained generation in Middle Atlantic typically also have high potentially-constrained generation in New England, therefore the 2050 sensitivities are only different from the scenarios on one day in mid-February for Low RE.

In South Atlantic (Figure 67), LNG sendout is highest in early January and late February. The volume of LNG sendout is however small relative the amount of power generation sector gas demand associated with potentially-constrained generation. The results are therefore affected to a much lesser degree than in New England.

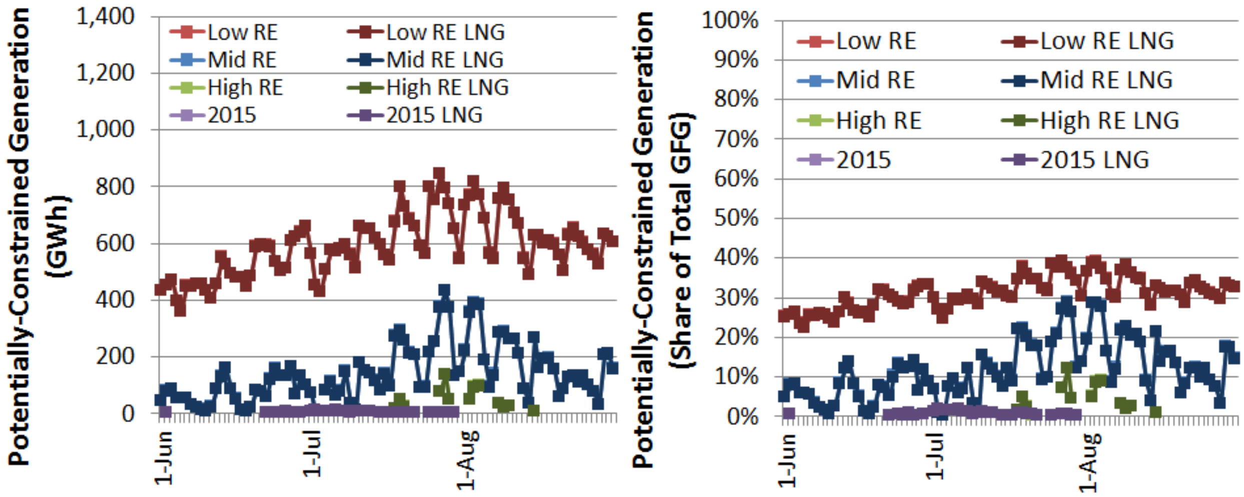
Figure 67. Gas Infrastructure Limitations – Winter Season – South Atlantic – LNG Sensitivity



Sendout from Elba Island, even at its highest 2015 levels, is small enough relative to the gas demand associated with potentially-constrained generation in South Atlantic that the LNG sensitivity is not as impactful as in New England. It does reduce potentially-constrained generation slightly, most significantly in early January and mid-February.

Figure 68 shows the summer seasonal constraints for the South Atlantic region after the incorporation of LNG sendout relative to the respective scenario results. The reduction in potentially-constrained generation is insignificant because LNG sendout from Elba Island was very limited during the summer of 2015, which is used as the sendout profile for the sensitivity. South Atlantic is the only region with a change in the summer results because New England and Middle Atlantic do not have any summer potentially-constrained generation in the scenarios.

Figure 68. Gas Infrastructure Limitations – Summer Season – South Atlantic – LNG Sensitivity



Sendout from Elba Island during the summer of 2015 was too small to have more than a trivially reductive effect on potentially-constrained generation in South Atlantic.

5 HYDRAULIC ANALYSIS

5.1 HIGHLIGHTS

- Scope: Hydraulic modeling was performed in one constrained and one unconstrained portion of the EI. The constrained portion covers New England. The unconstrained portion covers the Marcellus-Utica shale formation region of Ohio, West Virginia, western Maryland, and western Pennsylvania.

- Scope: To test the resiliency of the consolidated network of pipeline and storage infrastructure, three demand conditions were tested: winter peak day, summer peak day and annual minimum day. Each of these day type was analyzed before and after VE generation shortfalls.

- Approach: VE shortfall conditions tested the gas system's ability to accommodate increased electric sector gas demand following the realization of less variable energy generation than had been expected in the day-ahead schedule for winter and summer peak gas demand days and the annual trough gas demand day.

- Result: In the constrained New England region, potentially-constrained generation occurs at a small number of plants following VE shortfalls on the winter and summer peak days. Potentially-constrained generation also occurs in the baseline on the Mid RE winter and summer peak days, with severe potentially-constrained generation on the Mid RE winter peak day due to upstream boundary flow restrictions. Aside from the upstream New York boundary flow limitation effects, the potentially-constrained generation in New England is primarily the result of high gas demands on laterals which are not designed to accommodate the flow volumes without incremental pipeline capacity.

- Result: In the unconstrained Marcellus-Utica region, the gas system is able to serve the electric sector demand in all baseline and VE shortfall cases, with no potentially-constrained generation. The concentration of pipeline, storage and production resources in this region allows the gas system to operate flexibly in responding to intraday ramping in both normal operation and following a VE shortfall.

- Result: In both the constrained and unconstrained locations, the rate of increase in electric sector gas demand following the VE shortfall does not drive potentially-constrained generation.

5.2 OBJECTIVE

The purpose of the hydraulic analysis was to examine the feasibility of the gas network of pipeline and storage facilities to accommodate large ramp ups in gas-fired generation. A baseline (no VE shortfall) analysis examined generator gas demands on the winter and summer peak gas demand days and the annual minimum gas demand day under moderate

VE generation conditions. Then, a VE shortfall analysis was conducted to examine large ramp ups in gas-fired generation following an unexpected shortfall in wind and solar generation.

Additionally, an LNG Import sensitivity was analyzed for New England to determine the effects of applying 2015 seasonal peak day LNG sendout from the Canaport, Everett and Northeast Gateway terminals to the hydraulic models representing conditions in 2050.

Two regions, representing constrained and unconstrained locations were tested in the hydraulic analysis. New England was selected as an example of a constrained gas network region. The Marcellus-Utica shale formation region of Ohio, West Virginia, western Maryland, and Pennsylvania was selected as an example of an unconstrained region.[37] Certainly, there are other constrained and unconstrained regions across the EI.[38] The study scope was limited to performing this more detailed hydraulic analysis only to these two example regions.

The hydraulic analysis was also limited to the High RE SG scenario and the Mid RE scenario. The High RE SG scenario was selected because it represents the generation resource mix that has the largest relative daily ramp ups in generator gas demand, when solar generation declines in the late afternoon. The Mid RE scenario was selected because it includes much more gas-fired generation capacity while also including a substantial expansion of wind and solar generation capacity.

5.3 Approach

The pre- and post-VE shortfall assessment requires use of WinFlow, a steady state model, and WinTran, a transient flow model. The steady-state model of each pipeline system evaluated in the hydraulic analysis was constructed based on the Annual Report of System Flow Diagrams and Capacity (Form 567) filed with FERC in 2015.[39] These filings contains detailed information regarding capacity and hydraulic parameters for each pipeline segment, compressor station, pipeline interconnect, and other system components. Beyond the current infrastructure included in the filings, incremental capacity was added through pipeline looping and compressor station expansion or additions in order to meet the utility sector contractual entitlements forecast for 2050 based on the *AEO* 2015 Reference case while maintaining current delivery pressures. After the steady-state hydraulic models for pipeline systems of interest were tested and calibrated, they were converted into WinTran transient models, wherein hourly profiles of system operating conditions and demand profiles are simulated throughout the gas day.

Following construction of the models representing 2050 infrastructure, three demand conditions were tested, representing the High RE SG sensitivity: winter peak, summer peak

[37] The western New York state portion of the Marcellus-Utica region was omitted because shale gas development is not currently allowed by the State of New York.
[38] The hydraulic analysis has been performed in order to show how steady state and transient flow simulation models can reveal the resiliency of gas infrastructure by location when unexpected shortfalls in VER materialize. More extensive geographic testing across the EI was outside the scope of work.
[39] These filings are classified as Critical Energy Infrastructure Information (CEII).

and annual minimum days. The utility sector and electric sector demands were calculated using the same methods described previously. The WinFlow steady-state model incorporates the total daily gas demand for each utility sector and electric sector customer. The WinTran transient model applies an hourly profile to each demand, taken either from a standard utility sector demand profile or the electric simulation model. VE shortfalls related to reduction in variable energy generation from their day-ahead scheduled generation profiles were tested in order to determine the effects of an increase in electric sector gas demand on gas system pressures and flows at the afternoon time when the scheduled variable energy generation declines the most.

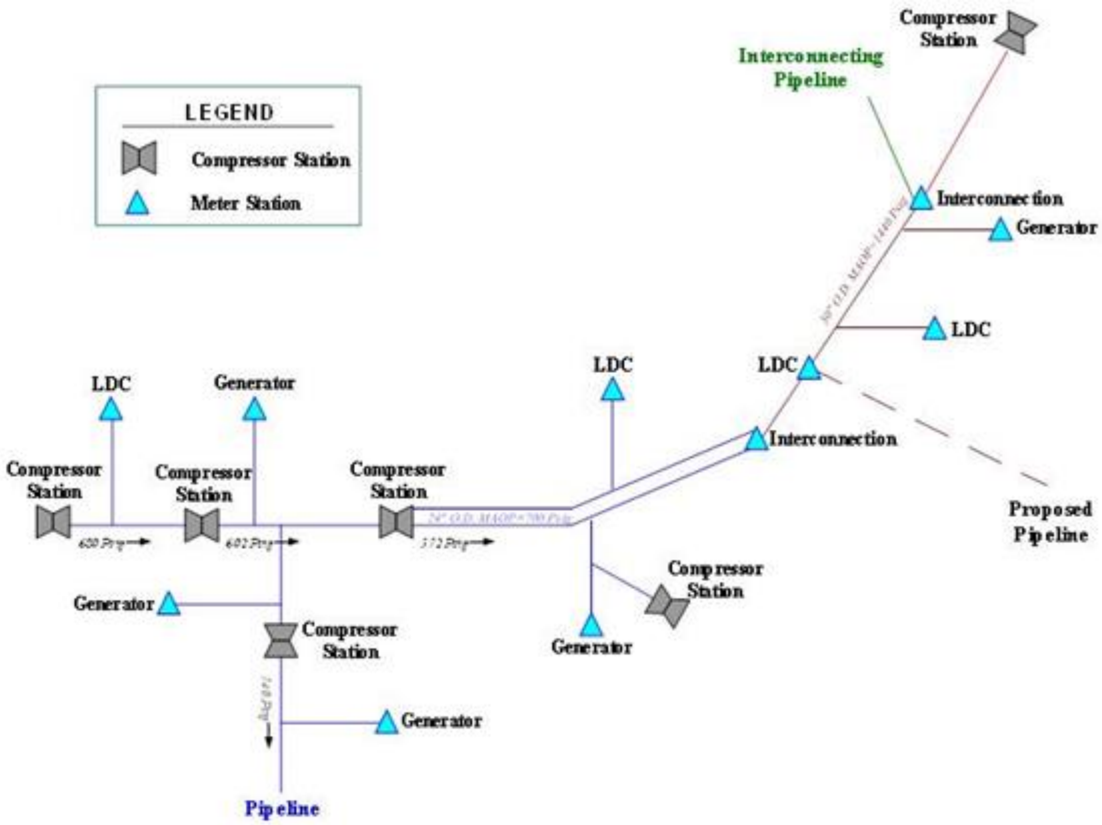
The VE shortfall transient analysis reveals whether, and for how long, the gas system can accommodate the changing needs of electric sector customers while respecting the delivery volume and pressure needs of utility sector customers. Other mitigation measures built into the re-optimization of the system with the increased gas demand following a VE shortfall include more complete utilization of pipeline interconnects, reversal-of-flow, and use of spare horsepower at compressor stations.

The LNG terminals in New England have no or minimal sendout on the summer peak day, Therefore, the LNG sensitivity is primarily applicable to the winter peak day. The same LNG import volume assumptions described in section 3.3 were applied here.

5.3.1 Natural Gas Hydraulic Modeling

Technical input parameters to WinFlow and WinTran include pipeline diameters, segment lengths, compressor horsepower, discharge temperatures, velocities, maximum allowable operating pressure, and elevation, among other factors. As shown in Figure 69, the models incorporate compressor stations, pipeline segments, interconnections, receipts from production and other supplies, storage injection / withdrawal points, and deliveries to utility and electric sector customers. Other model attributes pertaining to fluid flow in a pipe in relation to frictional losses require general flow equations. LAI exercised judgment where necessary to capture pipeline efficiency factors.

Figure 69. Example Hydraulic Model Schematic



This diagram illustrates the major components of the hydraulic models: pipe segments, compressor stations, and receipt and delivery meter stations.

Individual pipeline models relevant to the locations selected for analysis were consolidated into a network flow model in order to examine pipeline interaction effects. These consolidated regional models serve as the foundation for the transient flow analysis conducted in WinTran. Whereas WinFlow represents system operations based on ratable takes over a 24-hour period, the transient flow model allows observation of the change in pressure and flow within the gas-day in hours, minutes and seconds. LDC infrastructure downstream of interstate pipeline delivery meters was not included in the analysis.[40]

5.3.1.1 Steady-State Modeling Approach

The WinFlow steady state pipeline model simulates the interconnected pipelines and storage infrastructure serving each analysis location, and is used as the basis for the transient modeling described below. The starting point for the steady-state model development was each pipeline's FERC Form 567 filing for 2014.[41] Each model was then updated to include the incremental facilities that would be necessary to meet the contractual entitlements of utility

[40] All new gas-fired generators included in the electric simulation model were assumed to be directly connected to an interstate pipeline.
[41] These filings represent pipeline operations from January 1, 2014 to December 31, 2014, and were filed primarily in May 2015 for a May 31, 2015 filing deadline.

sector customers in 2050, calculated as described in section 3.5.[42] The segments that were expanded largely align with the expansions included in the GPCM model for the High RE/Mid RE scenarios although some incremental expansions were necessary to maintain delivery pressures across the systems.

The forecast of utility sector gas demand was allocated to specific pipeline meters by applying each meter's share of the peak day demands from the pipelines' FERC filings to the relevant customer's total forecast demand as calculated in section 3.5. The example in Table 14 illustrates an example of this *pro rata* demand distribution.

Table 14. Utility Sector Demand Allocation Example

Meter	2014 Peak Day Demand (MDth/d)	% of Total Peak Day Demand	2050 Winter Peak Day Demand (MDth/d)
A	72	18.0%	90
B	100	25.0%	125
C	34	8.5%	43
D	47	11.8%	59
E	54	13.5%	68
F	92	23.0%	115
Total	400		500

This table provides an example of how the gas utility sector gas demand forecast developed for the GPCM analysis was distributed across individual delivery meters in the hydraulic models.

The forecast of electric sector gas demand was allocated to specific pipeline meters based on each generator's location. For new generators assumed to replace existing generators, the demand was applied to the existing meter. In the case of existing generators served by LDCs, the demand was applied to an LDC delivery meter based on the proximity of the generator to the relevant gate stations. New generic generators were each applied to a new pipeline meter on a pipeline segment consistent with the plant's location parameters in the AURORAxmp and GPCM models.

5.3.1.2 Transient Modeling Approach

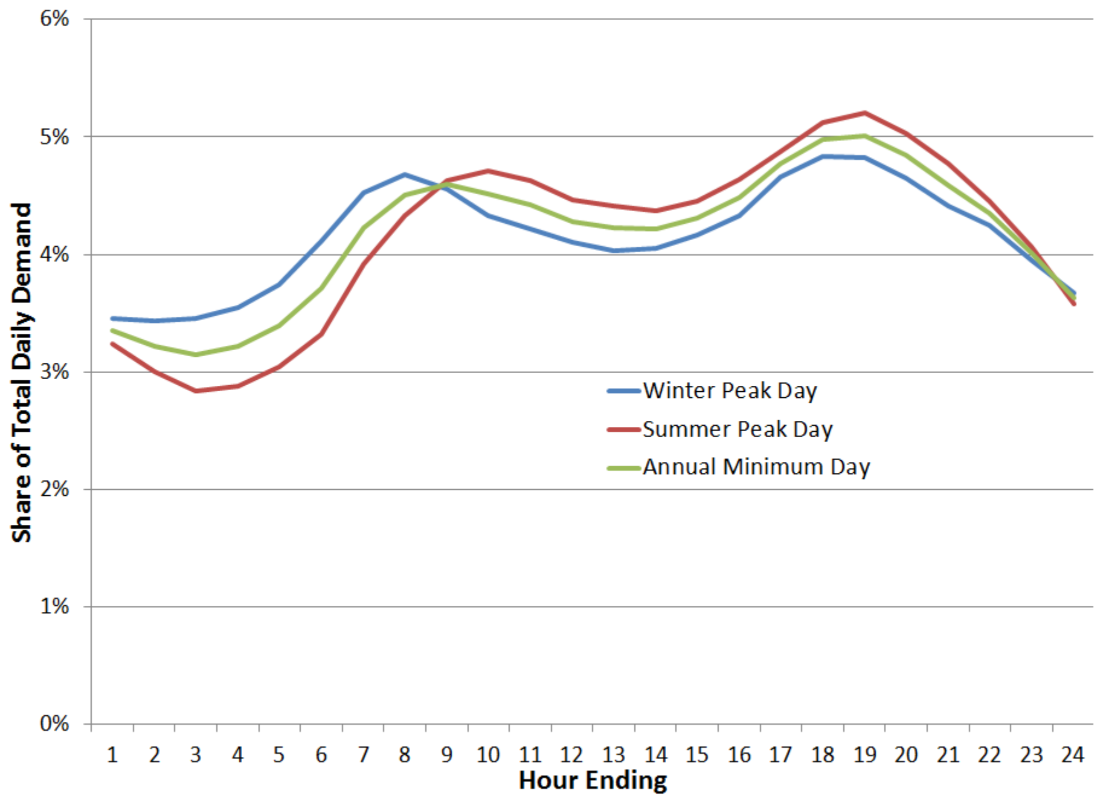
The major difference between the steady-state WinFlow model and the transient WinTran model is WinTran's ability to simulate changes in flow and pressure as gas receipts and deliveries change over the course of a day. Solutions can be achieved in WinTran so long as all system pressures remain positive, but the operational requirements of utility and electric

[42] The incremental facilities added to accommodate increased utility sector demand include loopline and compressor station expansion. More stringent PHMSA safety and inspection requirements are likely to result in new pipeline infrastructure that is certificated at higher MAOPs relative to present pipeline infrastructure, in part a reflection of greater internal wall thickness to ensure pipeline integrity. An array of uncertainty factors associated with pipeline improvements between now and 2050 supported the addition of new pipeline infrastructure in accord with existing MAOP limits. Hence, model solutions do not capture the effect of technology progress regarding additions to meet utility sector demand.

sector gas customers require higher minimum delivery pressures. For utility sector customers, LAI has assumed a minimum delivery pressure level of 275 pounds per square inch gauge (psig).[43,44] For electric sector customers, LAI has assumed a minimum pressure requirement of 375 psig, reflecting the anticipated need for on-site pressure boosters to supplement pipeline rendered supply.[45]

Intraday gas demand profiles are the driver of intraday pressure changes in the transient models. The intraday gas demand profiles for utility sector customers were developed using LAI's professional judgment and limited reporting of peak hour factors in LDC forecasts and other public sources and are differentiated seasonally as shown in Figure 70.

Figure 70. Seasonal Intraday Utility Sector Demand Profiles



There is limited public information on intraday utility sector demand profiles. The winter and summer peak day profiles were developed using LAI's professional judgment and limited reporting of peak hour factors in LDC forecasts and other public sources. The annual minimum day profile is the average of the two seasonal peak day profiles.

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[43] Using units of psig rather than psi indicates that the pressure is reported relative to atmospheric pressure instead of relative to zero.

[44] The local distribution system typically operate at pressures up to 200 psig, but the operating pressures of individual LDCs depend on the system configuration and customer requirements, among other factors.

[45] The new turbine technologies that are expected to be in service by 2050 will likely require much higher gas intake pressures than some of the plants operating today. These higher pressures will likely not be consistently achievable by pipelines at plant delivery points. Therefore generation plants in 2050 are likely to have on-site compression to supplement pipeline-rendered supply.

The intraday gas demand profiles for electric sector customers were taken from the simulation model results, representing both the baseline and VE shortfall cases. Baseline results for potentially-constrained generation may differ from those presented in section 4.3 because GPCM does not incorporate pressure considerations. For VE shortfall periods, the transient flow simulations reveal the operational impacts of a reduction in variable energy production, including the sustainability of gas-fired generation relative to the corresponding baseline while respecting the minimum delivery pressures described above.

To initialize each transient model run, LAI assumed that each electric sector customer's full gas demand is met. In the event that the pipeline and storage infrastructure is not adequate to meet all demands while maintaining the required minimum delivery pressures, gas deliveries to power plants were reduced until a model solution was achieved.[46] Details of these reductions are described in the relevant results sections.

5.3.2 Electric Simulation Modeling

To provide generator gas demands for the hydraulic modeling of base (non-VE shortfall) and VE generation shortfall conditions on the selected seasonal days, AURORAxmp was first rerun for just the month (January, April, July) of each peak or trough gas demand day in order to avoid spurious small differences in generator unit commitment and dispatch in the hours leading up to the start of each shortfall period. Then AURORAxmp was run for the VE generation shortfall conditions. These cases included reductions in realized VE generation from what had been expected the day before, when day-ahead generation schedules are determined.

The identification of the EI-wide coincident peak winter and peak summer gas demand days and the annual trough gas demand day already include below-average VE generation on the seasonal peak days and above-average VE generation on the annual trough day. As a further stress test of the ability of the gas infrastructure to support an unscheduled decline in VE generation, the profiles of the worst solar and wind days over a selected seasonal period for a selected region were identified and substituted in the VE shortfall simulations.[47] Hence, each VE shortfall case has a large ramp in generator gas demand, represented as a combination of the day-ahead scheduled generation from gas-fired resources over the shortfall period and additional real-time generation on short notice due to VE forecast uncertainty.

A reasonable VE generation forecast horizon for the VE shortfall analysis is between 1 and 8 hours. A 1-hour criterion would focus on the initial rapid ramp capabilities of fast-ramping and quick-start resources (gas, storage, hydro) to respond but limits the magnitude of the

[46] During a VE shortfall, pipeline operators would implement whatever actions are required to maintain system integrity. The model solutions estimated in this report do not necessarily represent the actions that would be taken by pipeline operators.

[47] Because scheduled VE generation is below average in the selected winter and summer peak days with the highest scheduled gas demand, the unexpected further drop in actual VE generation will not be as large as on a day with higher expected VE generation. This study did not examine days with higher expected VE generation, and resulting lower scheduled gas generation to see whether a larger shortfall in realized VE generation would create even more severe gas delivery problems.

ramp up. At the longer end of the range, an 8-hour criterion would still prohibit long startup time steam generation resources to be committed and would allow selection based on a larger magnitude ramp up, but would have a smaller average ramp rate than for a shorter horizon. A compromise that gives weight to both large ramp rate and large ramp magnitude was to utilize the mid-length horizon of 4 hours. A four-hour horizon is long enough to bring online CC plants in addition to CT and internal combustion units, but not long enough for oil-gas or coal-fired generators that have been offline for many hours. Hence, they require a long "cold" startup interval.

For the constrained example New England region and the unconstrained example PJM-West region, the 4-hour criterion was first used to identify the 4-hour periods with the largest ramp down in total VE generation on the peak and trough days. Then, separately for wind and solar generation, the single worst day, with the largest ramp down during the previously identified 4-hour window, was identified from the surrounding 60 days for region of the hydraulic analysis. The solar and wind hourly profiles for these worst days were applied in the VE shortfall runs, starting with the hour identified separately for each region that was the start of that region's worst shortfall.

The entire EI was simulated with the solar and wind profiles for the identified worst days, which accounts for the spatial correlations of weather patterns. This approach avoids the need to develop a large, complex matrix of spatial-temporal correlation coefficients to apply to the regions outside the region of study.

The VE shortfall simulations in AURORAxmp prevented CC and oil-gas-steam plants from having day-ahead unscheduled startups before the startup times assumed for these technologies, while CT units and CAES units were allowed to have unscheduled starts immediately after the start of the VE generation shortfall. For both the baseline and VE shortfall simulations, hourly fuel use profiles were sculpted to include 10-minute fuel ramp up (down) intervals beginning with the top of each hour. Start-up times for these technologies were assumed to be shorter and their ramp rates faster in 2050 than today, even without counting for any technical improvement. The main driver is that the need for quick-start and fast-ramping resources to load-follow VE resources will induce a substitution towards currently available new CT and CC units and operating configurations for CC plants that are more flexible but slightly more costly.

5.4 Constrained Location: New England

The New England pipeline infrastructure represented in the consolidated regional hydraulic model is shown in Figure 71. The hydraulic model includes the five interstate pipelines that serve generation in New England: Algonquin, Tennessee, Iroquois, M&N, and PNGTS.[48] The impact of gas flowing to and from western and Atlantic Canada is captured at northern boundary points, including M&N's interconnection with the M&N Canadian system at Baileyville, ME and PNGTS's interconnection with the Trans-Quebec Maritimes system at

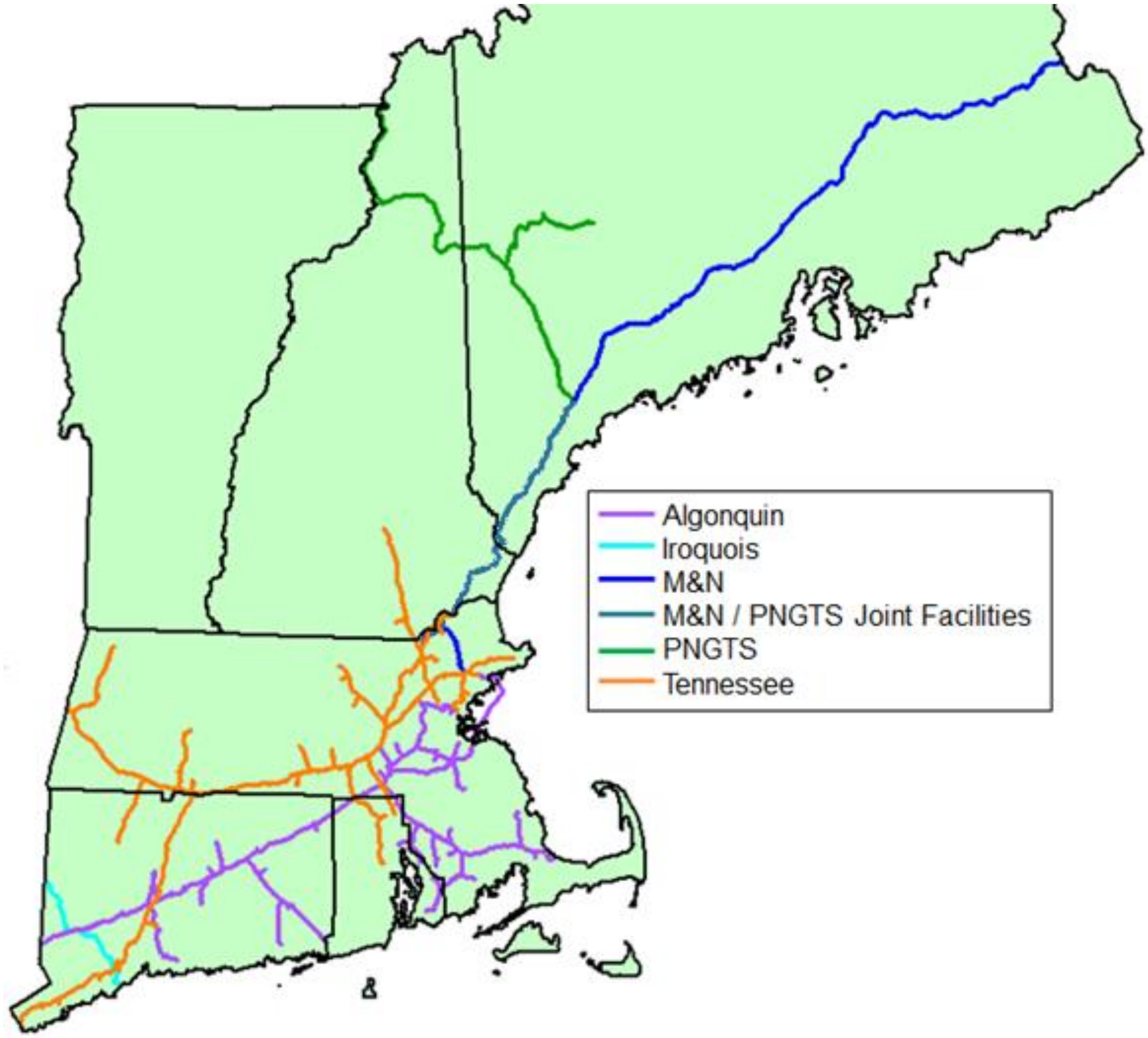
[48] Granite State is not included in the model because it serves only RCI customers. Therefore deliveries to Granite State by M&N, PNGTS, and Tennessee are classified as RCI deliveries.

Pittsburg, NH. Iroquois's interconnection with TransCanada at Waddington, NY is not directly included in the New England hydraulic model because it is outside New England, but gas received from TransCanada is included in the boundary flow at the NY-CT border. Iroquois also has a downstream boundary point in the New England hydraulic model, where gas flows across Long Island sound to Long Island and New York City. Gas flowing west-to-east on Algonquin and Tennessee is received at multiple boundary points between NY and CT and MA.

The consolidated New England model also includes receipt points on Algonquin and Tennessee from the Everett LNG import terminal, a receipt point on Algonquin from the Northeast Gateway LNG import terminal, and a receipt point on M&N from the Canaport LNG import terminal.[49] As described in section 3.3, no LNG sendout from these terminals into the respective pipeline connections are included in the scenarios or SG sensitivities. In the LNG Import sensitivity, sendout is assumed at these four receipt points. In all scenarios and sensitivities, the Everett terminal is assumed to fully serve all gas demand at the directly connected Mystic generator, this plant is therefore not included in the pipeline analysis in this section.

[49] Everett's sendout to the directly-connected generator and truck deliveries to satellite LNG storage facilities are not included in the hydraulic model, because they do not interact with the interstate pipeline network. To the extent that the LDCs' LNG storage tanks and, to a lesser extent, propane air tanks are filled by regasifying supplies received from the pipelines, those volumes are included in the RCI deliveries to the various citygate meters.

Figure 71. New England Gas Pipeline Map[50]



New England's gas infrastructure that is relevant to the hydraulic analysis in this study includes the five major interstate pipelines (Algonquin, Iroquois, M&N, PNGTS and Tennessee). The Granite State pipeline does not serve any generators and is therefore represented only by demands at interconnects with other pipelines. Vermont Gas is supplied by TransCanada and is not connected to the rest of New England's gas infrastructure.

5.4.1 Baseline Analysis

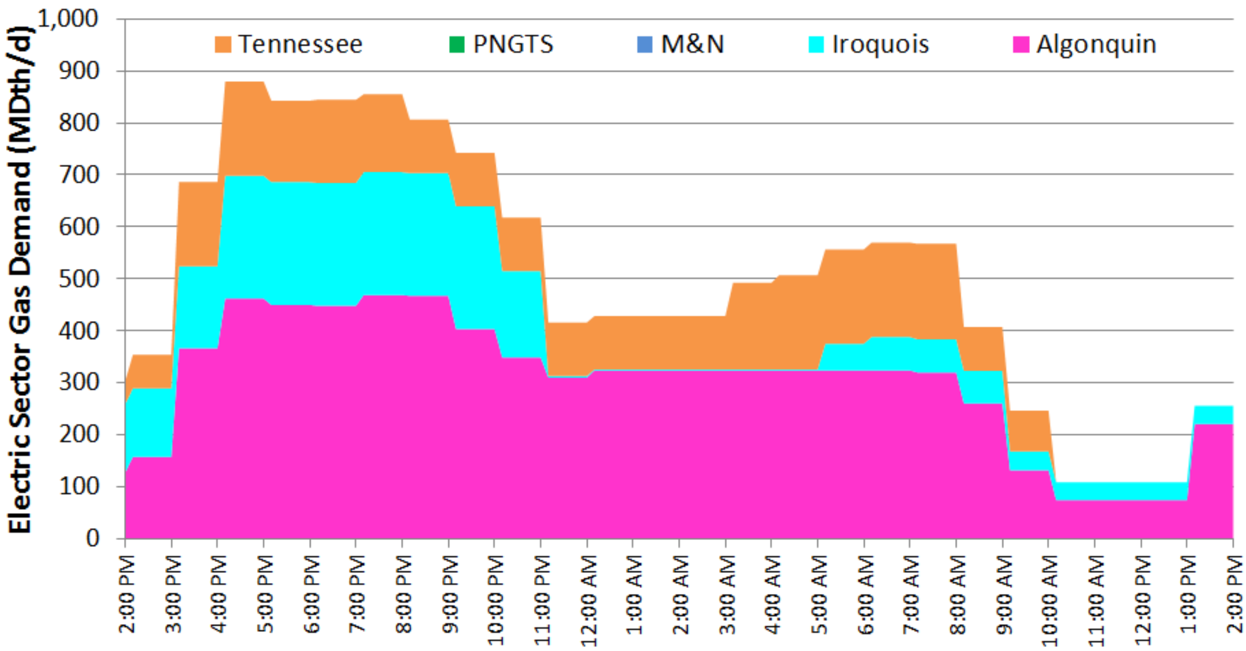
5.4.1.1 <u>High RE SG</u>

The following three figures show the amount of electric sector gas demand by pipeline over the course of the winter peak day (Figure 72), summer peak day (Figure 73) and annual minimum day (Figure 74). The total electric sector gas demand is highest on the summer

[50] The details of the pipeline infrastructure that defines the nodes and legs are taken from CEII filings at FERC and are therefore not included in this report.

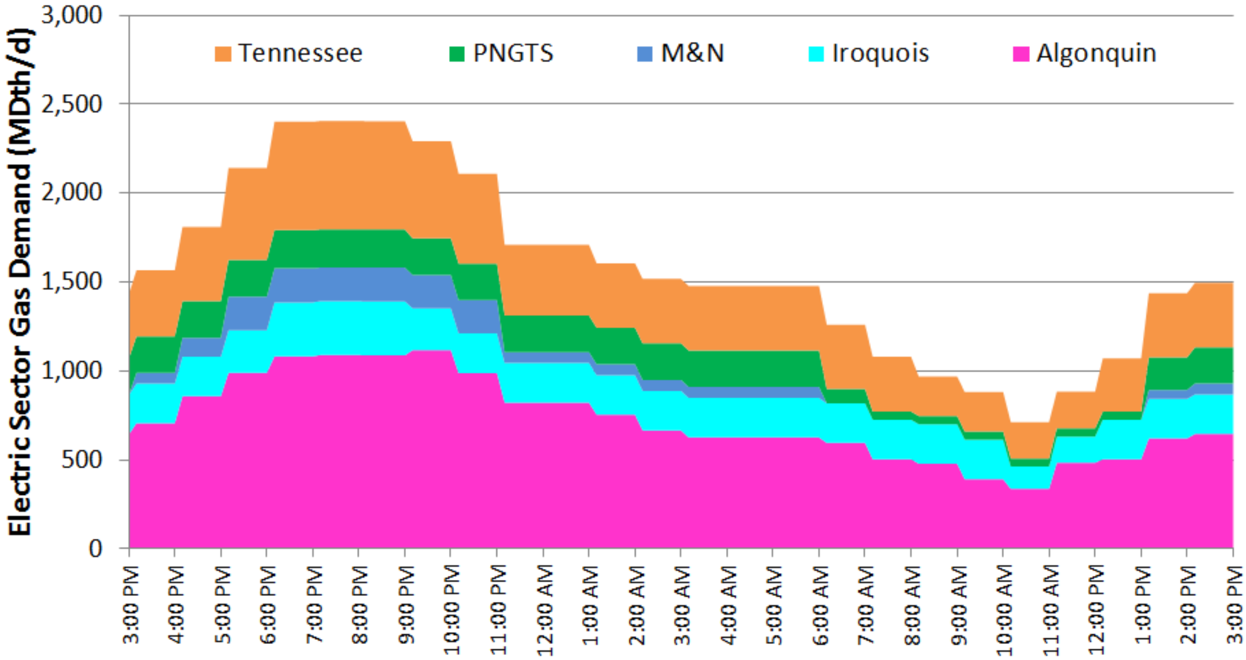
peak day and lowest on the annual minimum day. On all three days, Algonquin supplies the most generation and M&N supplies the least generation.

Figure 72. New England Baseline Electric Sector Gas Demand (High RE SG, Winter Peak Day)



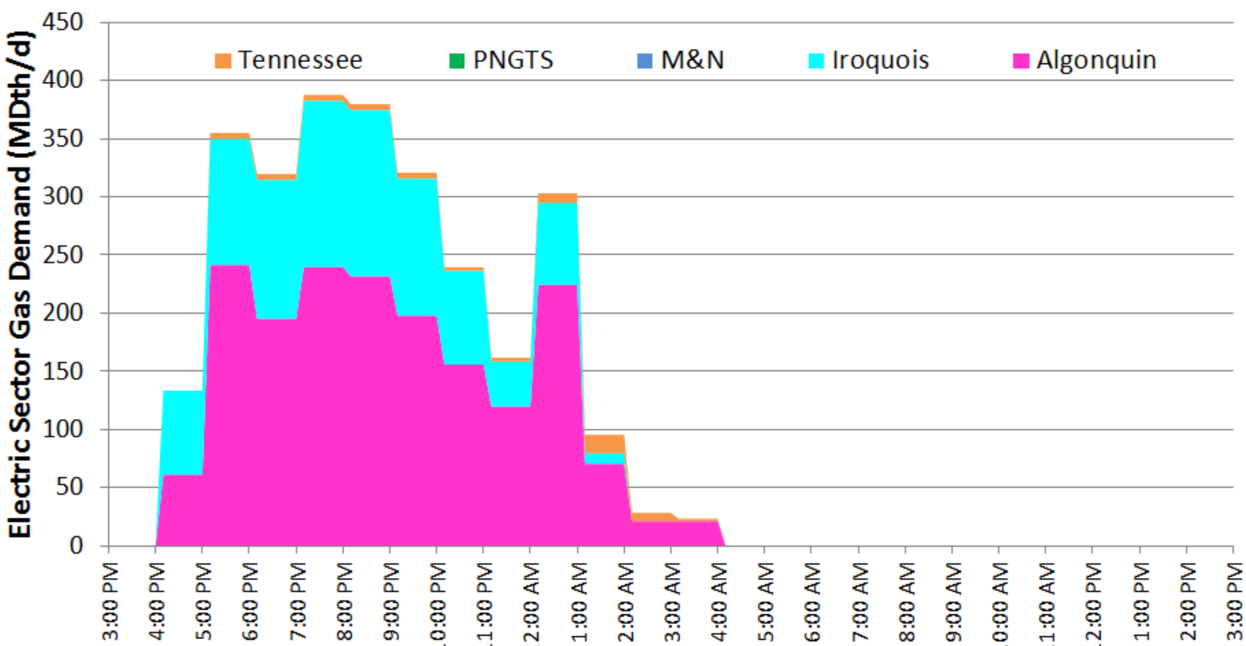
Algonquin serves the largest share of New England's High RE SG electric sector gas demand on the winter peak day. Iroquois and Tennessee alternate as the second-largest supplier over the course of the day. M&N and PNGTS do not serve any generation in this case.

Figure 73. New England Baseline Electric Sector Gas Demand (High RE SG, Summer Peak Day)



Algonquin serves the largest share of New England's High RE SG electric sector gas demand on the summer peak day, followed by Tennessee, Iroquois, PNGTS and M&N.

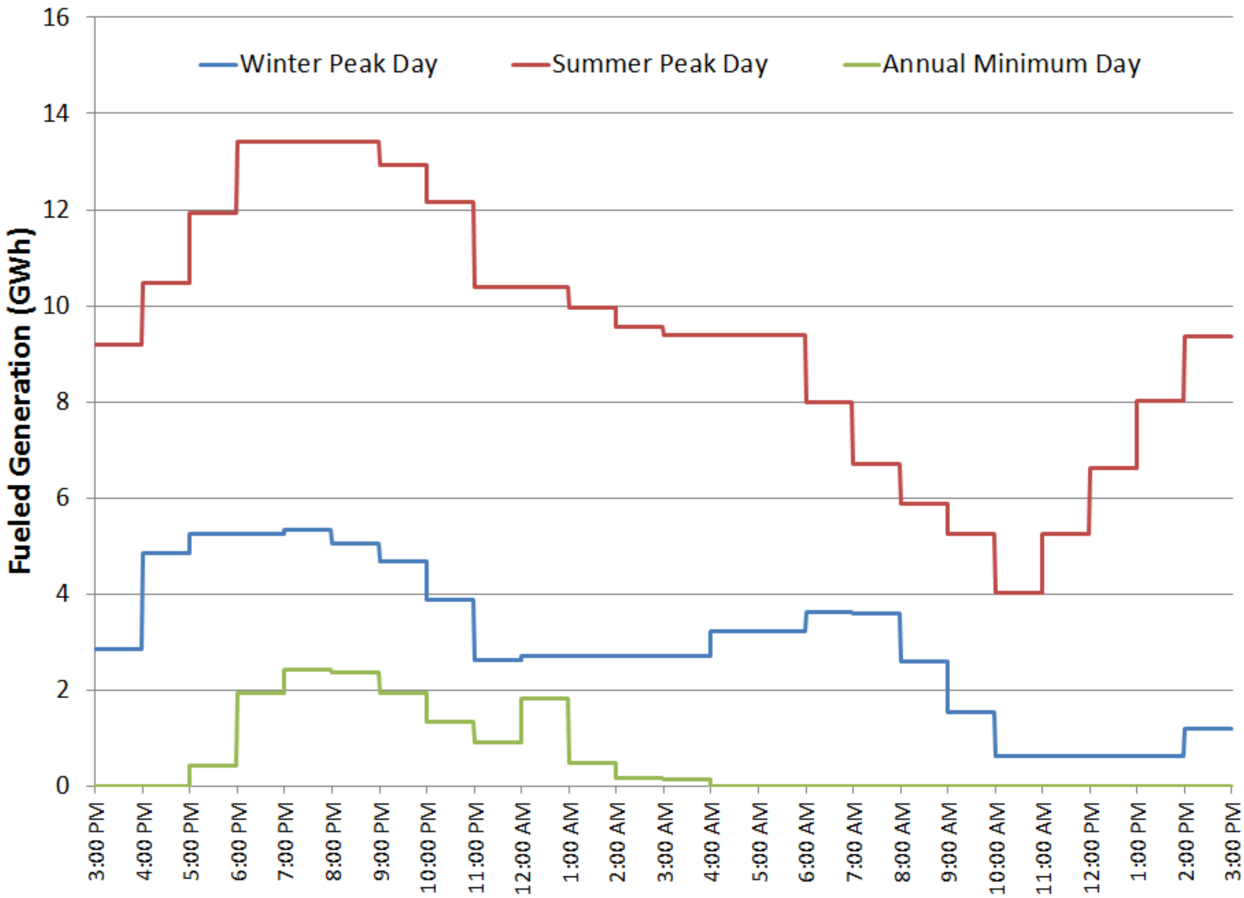
Figure 74. New England Baseline Electric Sector Gas Demand (High RE SG, Annual Minimum Day)



Algonquin serves the largest share of New England's High RE SG electric sector gas demand on the annual minimum day, followed by Iroquois. Tennessee serves only a small portion of the demand throughout the day.

The High RE SG transient model runs reveal that there is no potentially-constrained generation in New England on the winter peak day, summer peak day, or annual minimum day, which is consistent with the findings of the corresponding sensitivity in the GPCM analysis. Figure 75 shows the relative amounts and intraday patterns of scheduled generation on the winter peak day, summer peak day and annual minimum day under baseline conditions.

Figure 75. New England Baseline Unconstrained Generation (High RE SG)



The High RE SG transient model runs found that all power generation sector gas demand was able to be delivered while maintaining system operating pressures in the baseline condition for the three tested days: winter peak day, summer peak day and annual minimum day. This figure shows the total generation on each of these days, all of which is unconstrained, for a seasonal comparison.

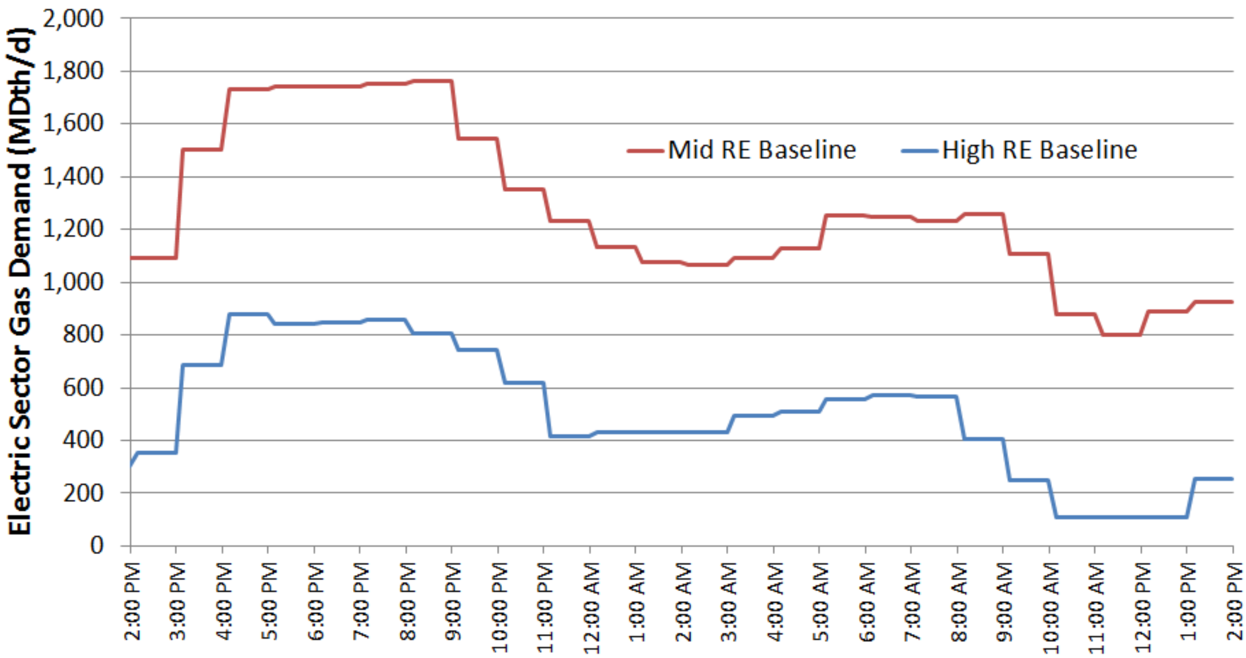
5.4.1.2 High RE SG LNG Sensitivity

There is no change to the gas demand for the LNG sensitivity analysis relative to the High RE SG. The only model change is to incorporate LNG sendout from the Canaport, Everett and Northeast Gateway terminals in the New England gas supply assumption. Because all generation is fueled in the High RE SG baseline, as discussed in the previous section, increasing the amount of available gas supply does not change the baseline results. Information on the LNG Import sensitivity parameters can be found in section 3.3

5.4.1.3 <u>Mid RE</u>

Figure 76 compares the hourly profile of electric sector gas demand between High RE SG and Mid RE for the winter peak day.

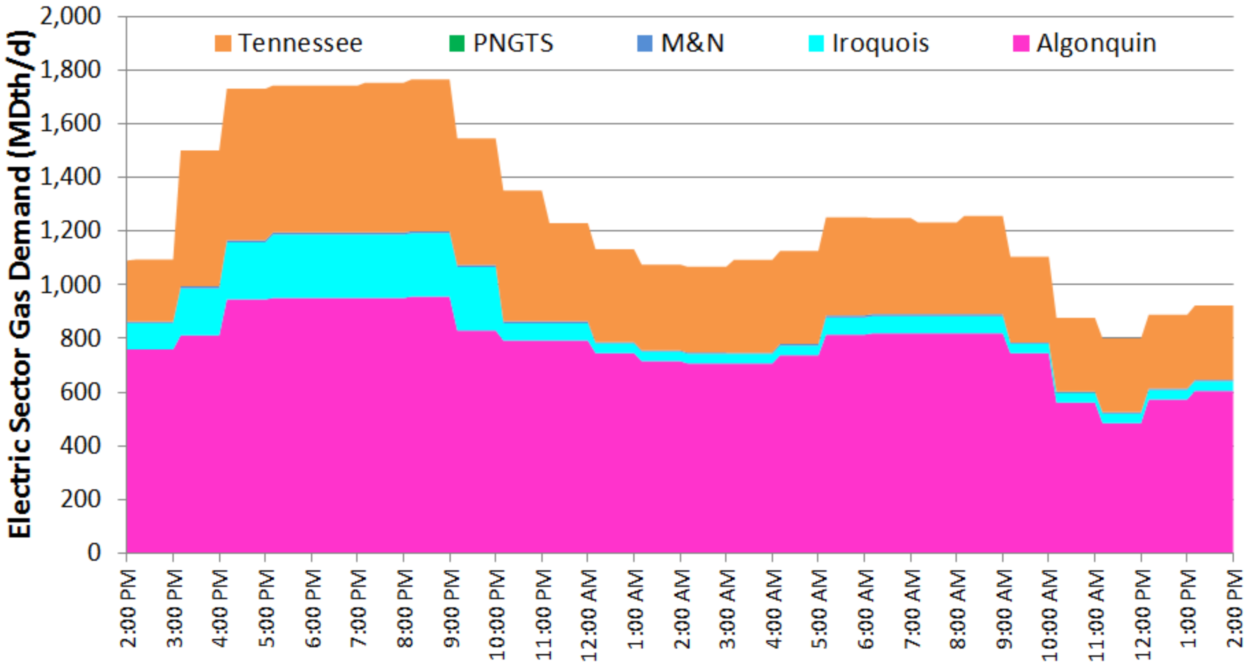
Figure 76. New England Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Winter Peak Day)



The Mid RE gas demand shows a similar profile to the High RE SG gas demand, at a volume approximately two to three times greater over the course of the day.

Figure 77 shows the amount of electric sector gas demand by pipeline over the course of the winter peak day.

Figure 77. New England Baseline Electric Sector Gas Demand (Mid RE, Winter Peak Day)

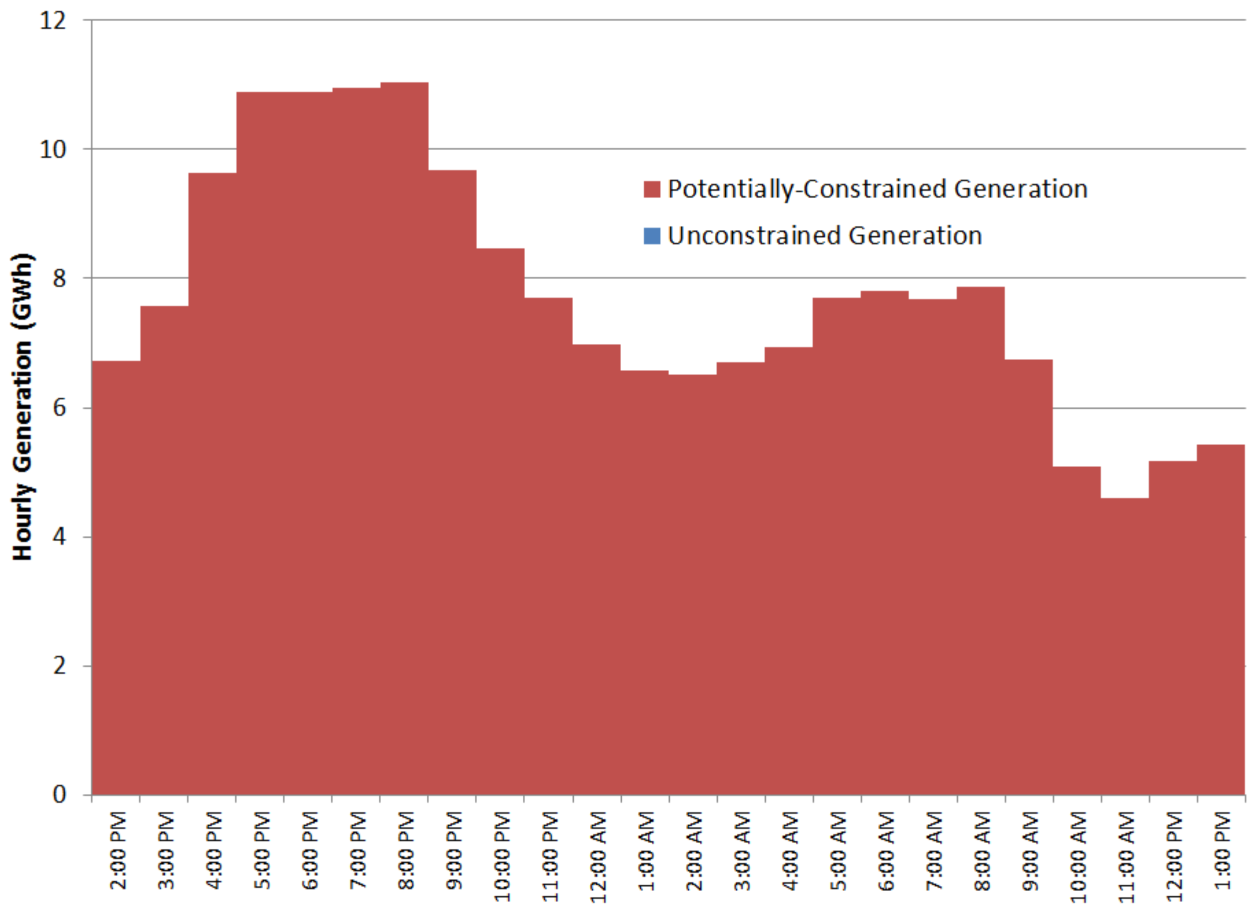


The winter peak day gas demand is spread across three pipelines, with Algonquin supplying the most generation, followed by Tennessee.

For the winter peak day, the Mid RE scenario GPCM analysis of the EI, discussed in section 4.3, indicated that upstream constraints in the Middle Atlantic region limit flows into New England, resulting in 58% of regional generation being potentially-constrained. For purposes of the hydraulic assessment, LAI has conducted two model runs with different boundary flow assumptions. First, with upstream boundary flows limited to the levels in the GPCM results to determine the full extent of baseline potentially-constrained generation when pressure considerations are incorporated, and second, with upstream constraints assumed to be resolved in order to test the New England pipeline infrastructure's ability to respond to the VE shortfall. The first model run, with upstream boundary flows limited, is of limited relevance for the VE shortfall analysis because system capability to serve generation will already be at its limit in the baseline.

To determine the effect of boundary flow limitations, it is first necessary to run the hydraulic model without the boundary flows to determine the extent of the demand reduction that is required to bring the boundary flow in line with the assumed limitation. The unconstrained boundary flows for the Mid RE winter peak day include average flow rates of 3,091 MDth/d of flow on Algonquin and 2,136 MDth/d of flow on Tennessee relative to respective limits from the corresponding GPCM run of 1,231 MDth/d on Algonquin and 2,343 MDth/d on Tennessee. Netting out the west-to-east flows indicates a required flow reduction of 1,653 MDth/d. As shown in Figure 77, the maximum total generator gas demand during the peak day is 1,765 MDth/d, and the total generator gas demand during the peak day (represented by the area of the chart) is 1,279 MDth/d, which indicates that all generation represented in the hydraulic is potentially-constrained, as shown in Figure 78 below.

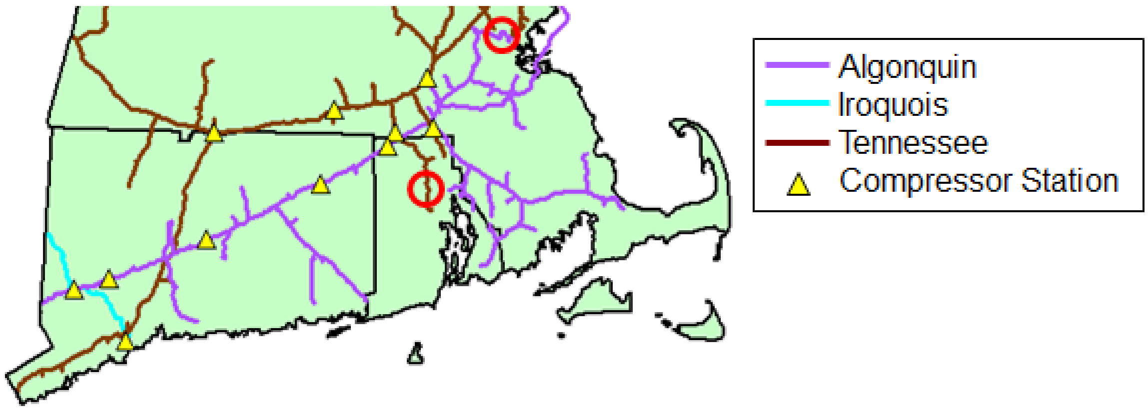
Figure 78. New England Baseline Potentially-Constrained Generation (Mid RE, Winter Peak Day, With Upstream Boundary Flow Limits)



All generation served by the pipelines in the hydraulic model is potentially constrained on the Mid RE winter peak when boundary flow limitations from New York into New England, and *AEO* 2015 LNG supply limitations are taken into consideration. Note that not all generation in New England is potentially-unconstrained, the generator that is directly served from the Everett LNG terminal and generators served by Vermont Gas with supplies from TransCanada are not included in the hydraulic analysis.

Transient analysis of New England using the Mid RE gas demands but not incorporating the upstream constraints reveals that if the boundary flows are not limited by upstream constraints, most power generation sector demand can be met, with two exceptions based on pressure requirements. The locations of the two plants at which gas demand is reduced are shown in Figure 79.

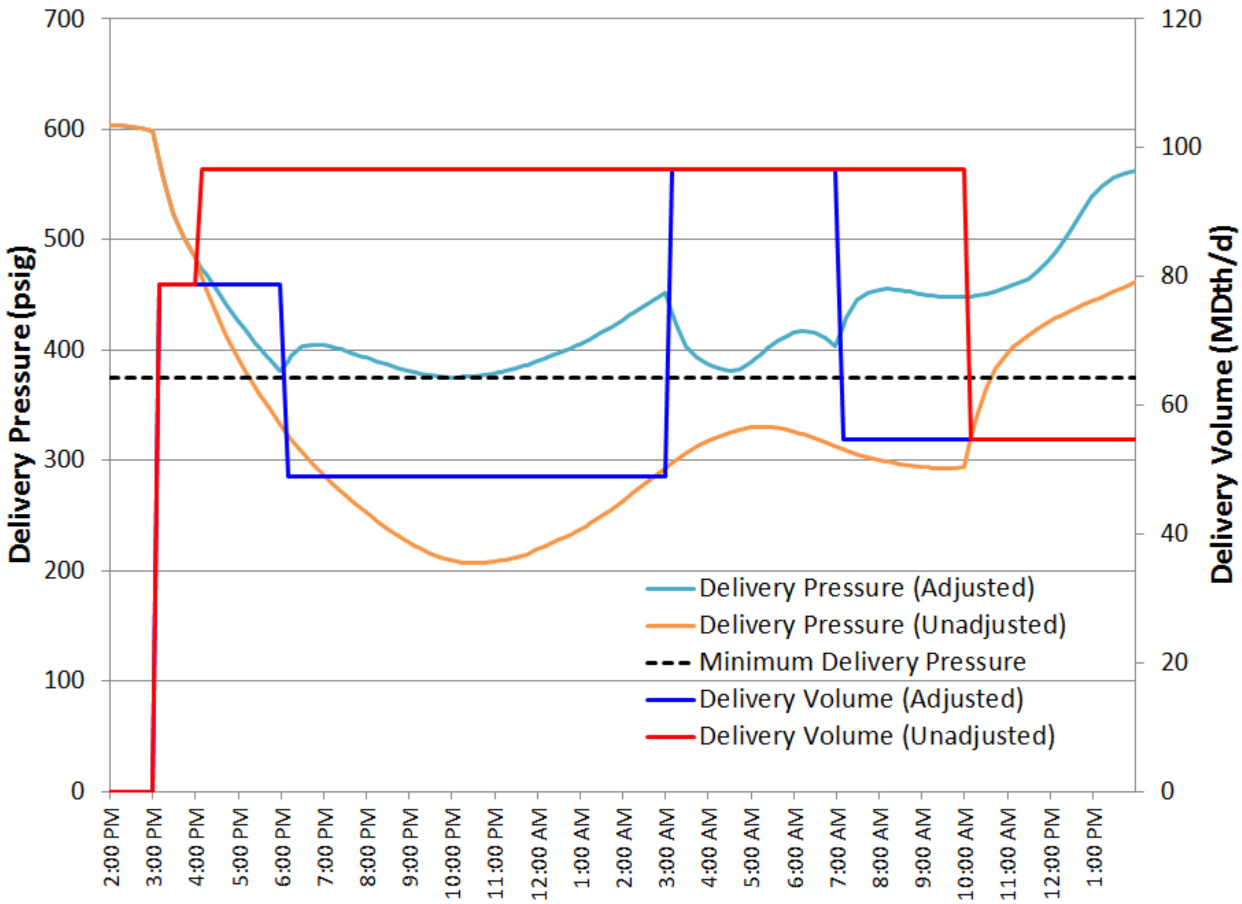
Figure 79. Generator Locations with Potentially-Constrained Generation (Mid RE Baseline, Winter Peak Day, No Upstream Boundary Flow Limits)



Potentially-constrained generation occurs at two plants operating in the baseline on the winter peak day. Both plants are located on laterals with pressure and flow restrictions.

The indicated plant in Massachusetts is located on a lateral along the Algonquin system with a low MAOP. Even with deliveries to the plant in question zeroed out, the operating pressure of the segment is below 375 psig. The full amount of generation at the plant has therefore been classified as potentially-constrained. The indicated plant in Rhode Island is located downstream of a compressor station which is operating at maximum horsepower, but which cannot achieve a high enough discharge pressure due to a high flow volume. The operating pressure downstream of the compressor station falls below both the electric sector and utility sector minimum pressure thresholds, as indicated by the orange line in Figure 80. By reducing gas deliveries to the plant, represented by the difference between the darker blue line and the red line in Figure 80, the plant delivery pressure increases above the thresholds, reflected in the light blue line.

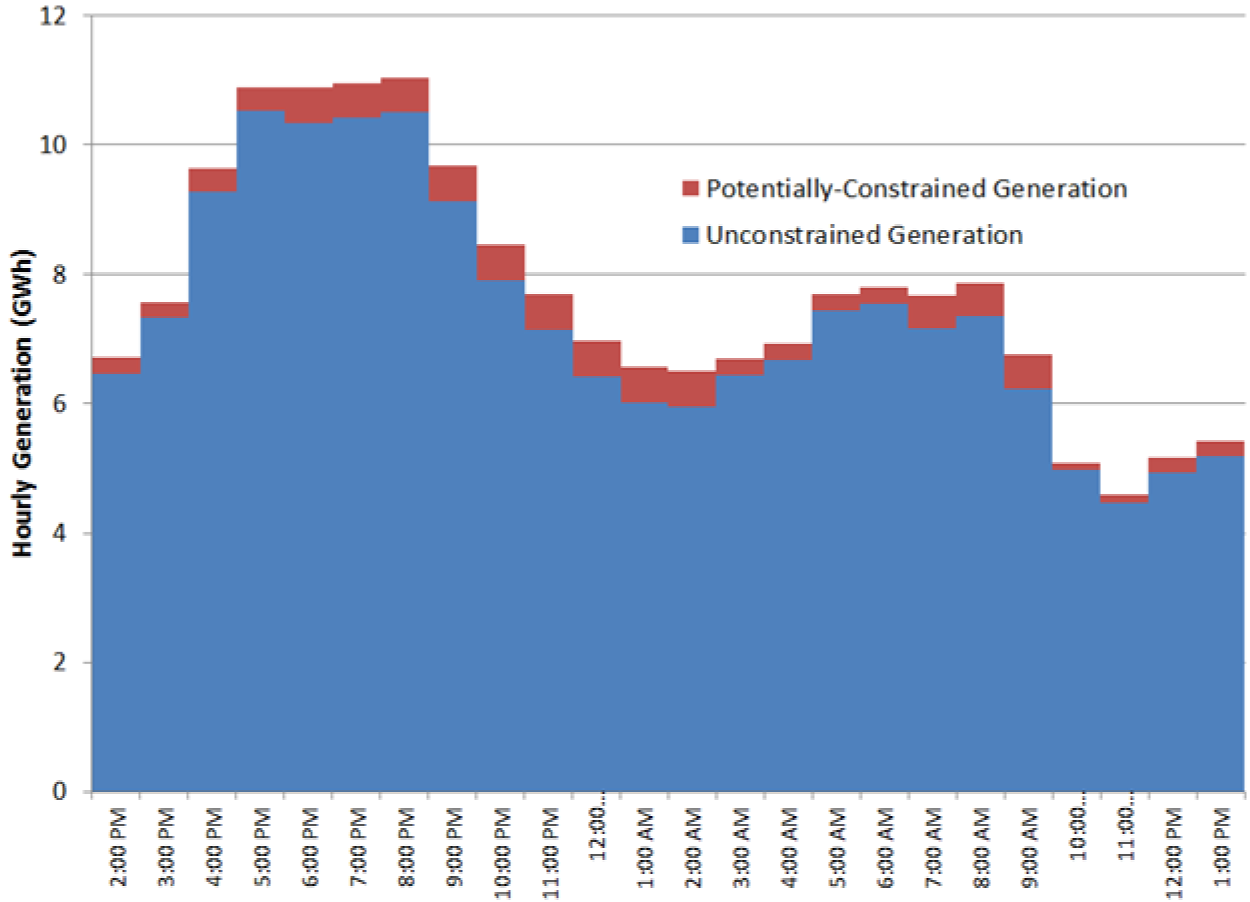
Figure 80. Adjusted RI Plant Delivery Volume and Pressure (Mid RE Baseline, New England Winter Peak Day, No Upstream Boundary Flow Limits)



The plant's baseline gas demand (represented by the red line) causes the delivery pressure (represented by the orange line) to drop below the 375 psig minimum delivery pressure threshold (represented by the dashed black line). Reducing the delivery volume (represented by the dark blue line) increases the delivery pressure to the plant (represented by the light blue line) above the minimum delivery pressure threshold, allowing the plant to continue operating. The difference between the red and dark blue lines represents the amount of unavailable gas and corresponds to the amount of potentially-constrained generation.

Figure 81 shows the resultant amount of baseline fueled and potentially-constrained generation on the winter peak day. The potentially-constrained generation represents a relatively small portion of the total generation. Because the potentially-constrained generation is the result of lateral constraints, it could likely be mitigated in the baseline by moving the generation to another plant during the day-ahead scheduling process.

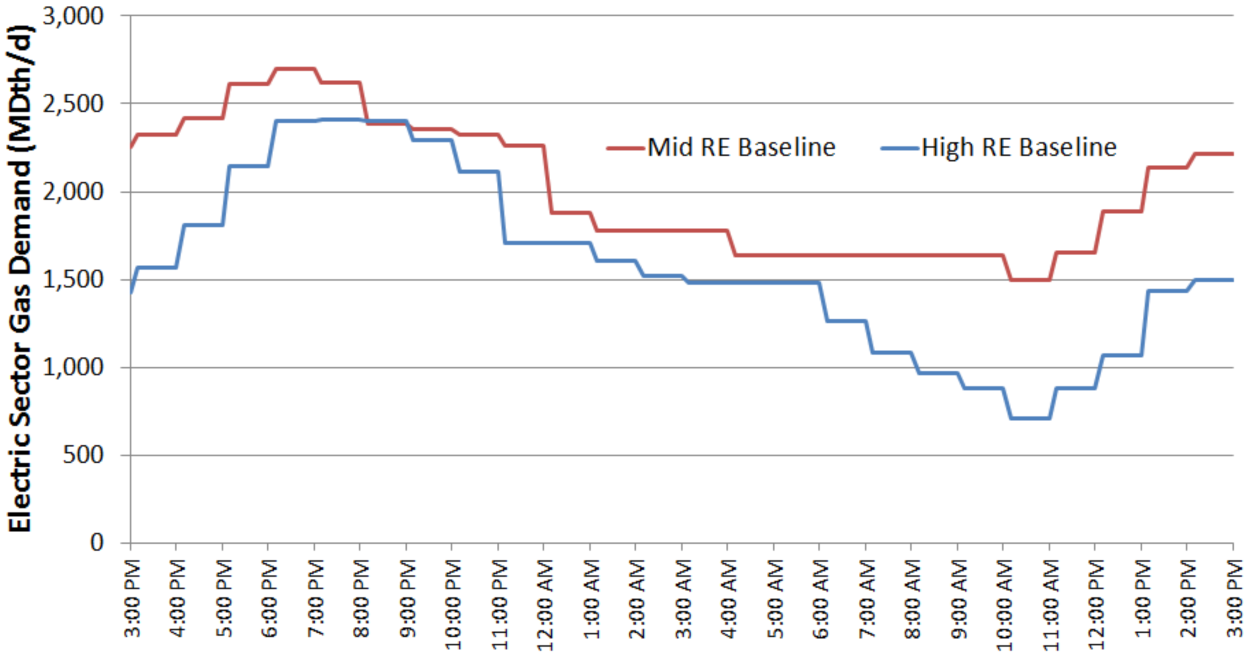
Figure 81. New England Baseline Potentially-Constrained Generation (High RE SG, Winter Peak Day, No Upstream Boundary Flow Limits)



Potentially-constrained generation occurs throughout the winter peak day due to the need to reduce the gas demand at a plant in Massachusetts to zero. Incremental potentially-constrained generation results from a demand reduction at a plant in Rhode Island that occurs intermittently during the day.

Figure 82 compares the hourly profile of electric sector gas demand between High RE SG and Mid RE for the summer peak day.

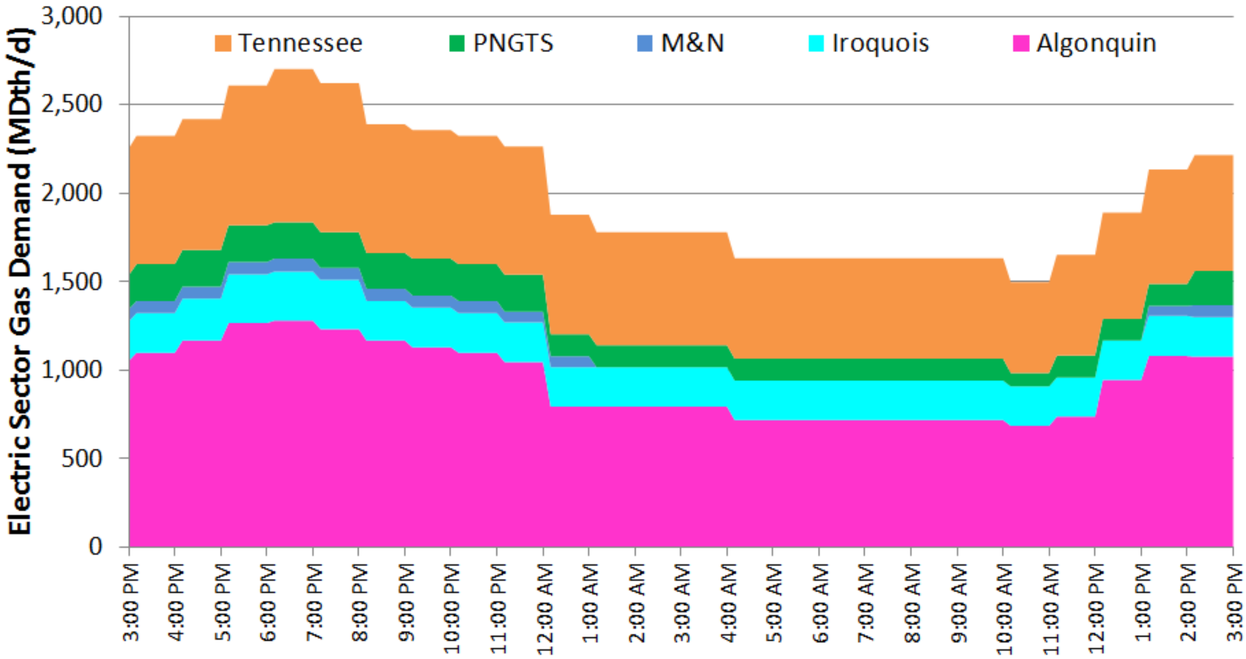
Figure 82. New England Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Summer Peak Day)



The evening peak volume is approximately the same between the two cases. The largest difference occurs during the morning hours.

Figure 83 shows the amount of electric sector gas demand by pipeline over the course of the summer peak day.

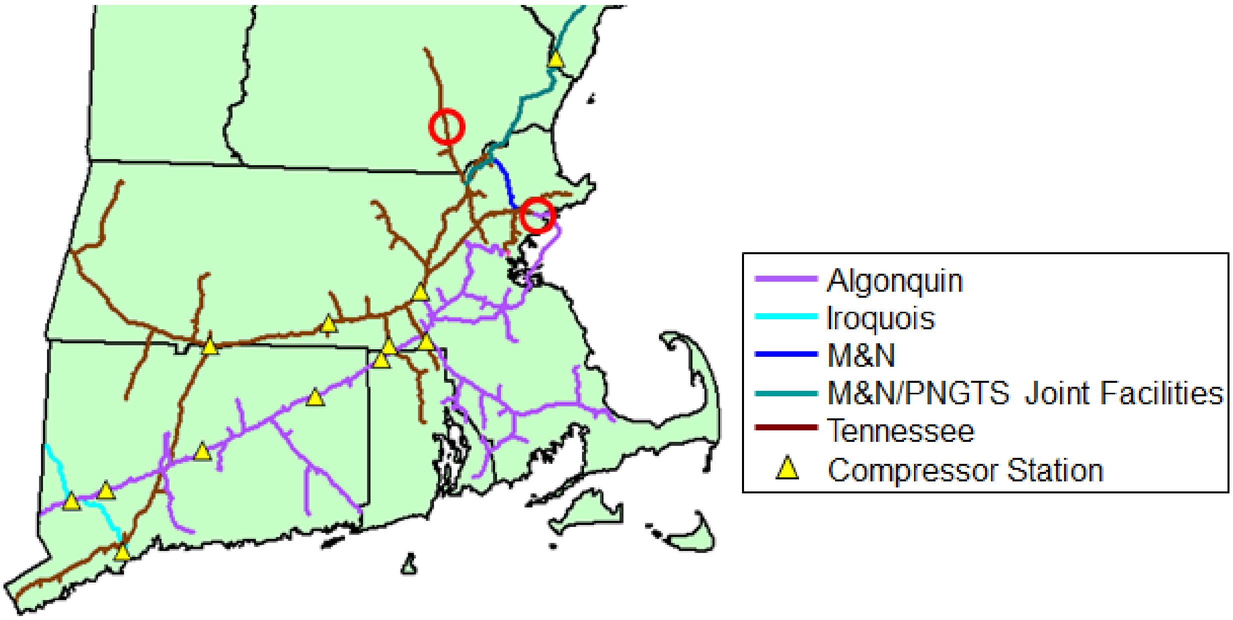
Figure 83. New England Baseline Electric Sector Gas Demand (Mid RE, Summer Peak Day)



The summer peak day gas demand is spread across three pipelines, with Algonquin supplying the most generation, followed by Tennessee.

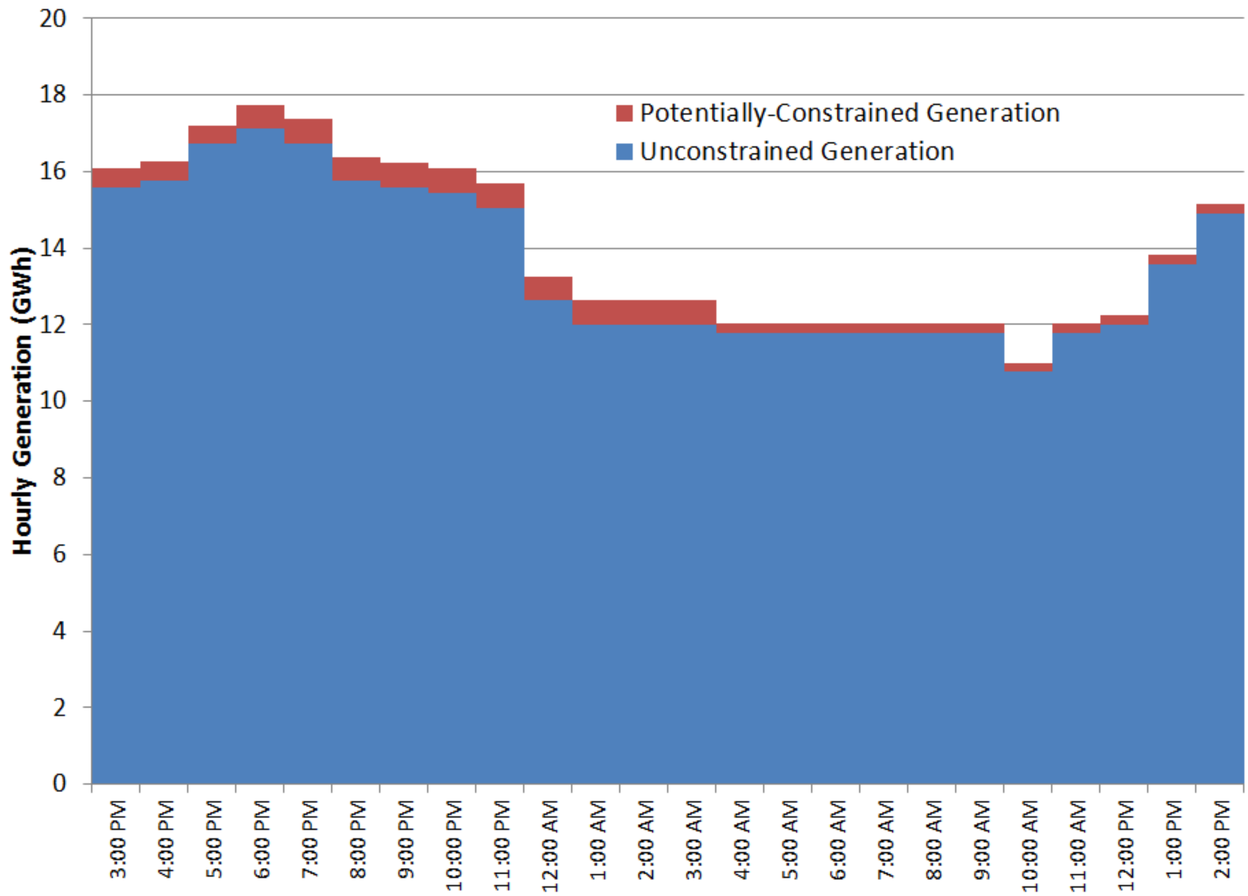
For the Mid RE summer peak day, only one model run was conducted because all New England generation is shown to be fueled in the GPCM results in section 4.3, indicating that Middle Atlantic constraints are not limiting factor for New England generation. The model run for the Mid RE baseline summer peak day reveals two plants with potentially-constrained generation, located as shown in Figure 84. The plant in New Hampshire is located on a Tennessee lateral which cannot support the full gas demand of several power plants. The plant in Massachusetts experiences a pressure constraint because of the south-to-north flow on Algonquin's Hubline that results from supply restrictions in Atlantic Canada.

Figure 84. Generator Locations with Potentially-Constrained Generation (Mid RE Baseline, Summer Peak Day)



The potentially-constrained baseline generation resulting from deliverability limitations at the indicated plants is shown in Figure 85.

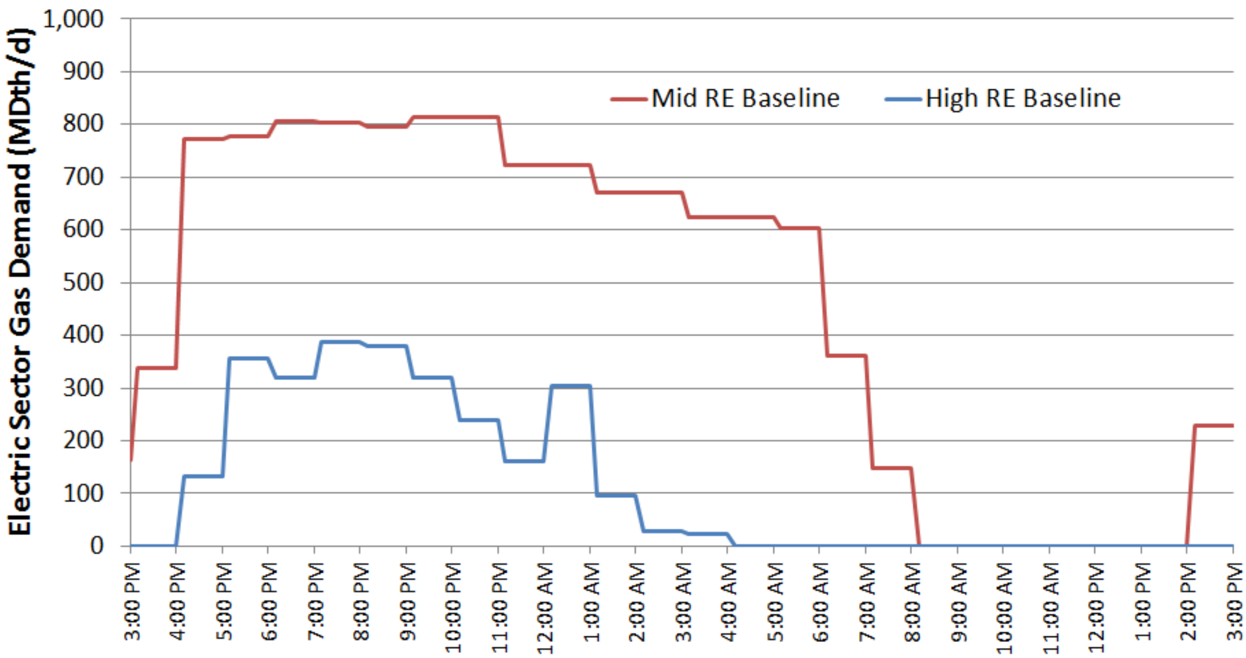
Figure 85. New England Baseline Generation (Mid RE, Summer Peak Day)



A small amount of New England generation is potentially constrained in the Mid RE baseline on the summer peak day.

Figure 86 compares the hourly profile of electric sector gas demand between High RE SG and Mid RE for the annual minimum day.

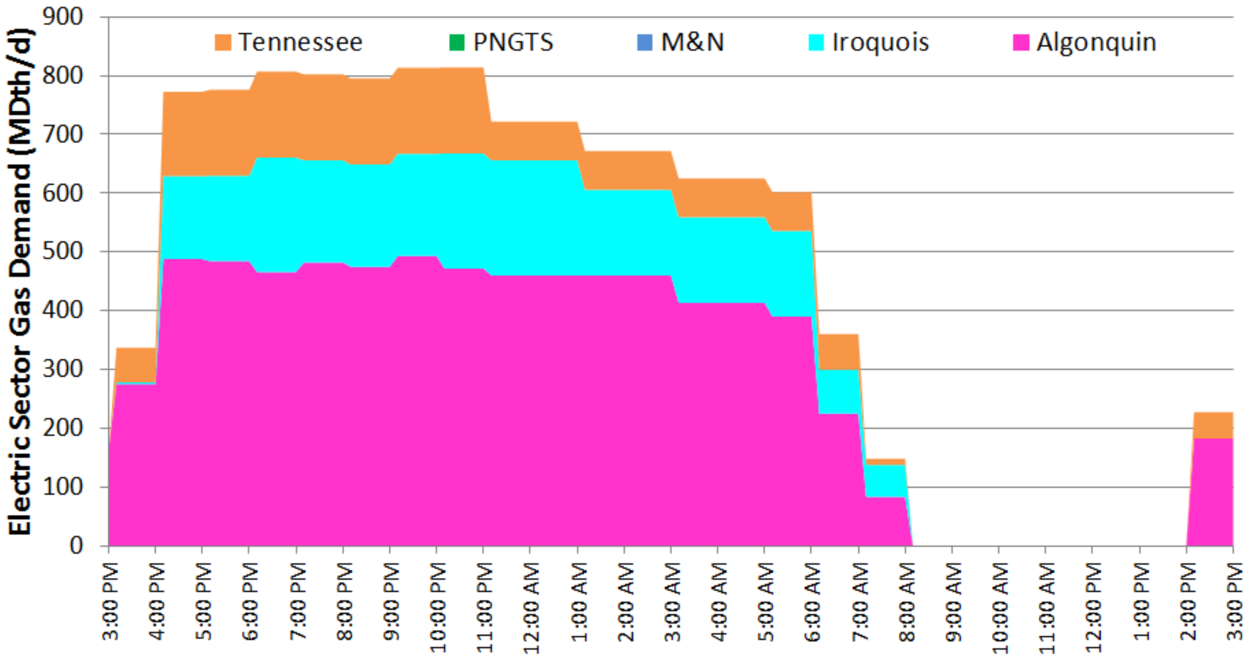
Figure 86. New England Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Annual Minimum Day)



The Mid RE gas demand approximately doubles the High RE SG evening peak, maintaining a high volume until the next morning.

Figure 87 shows the amount of electric sector gas demand by pipeline over the course of the annual minimum day.

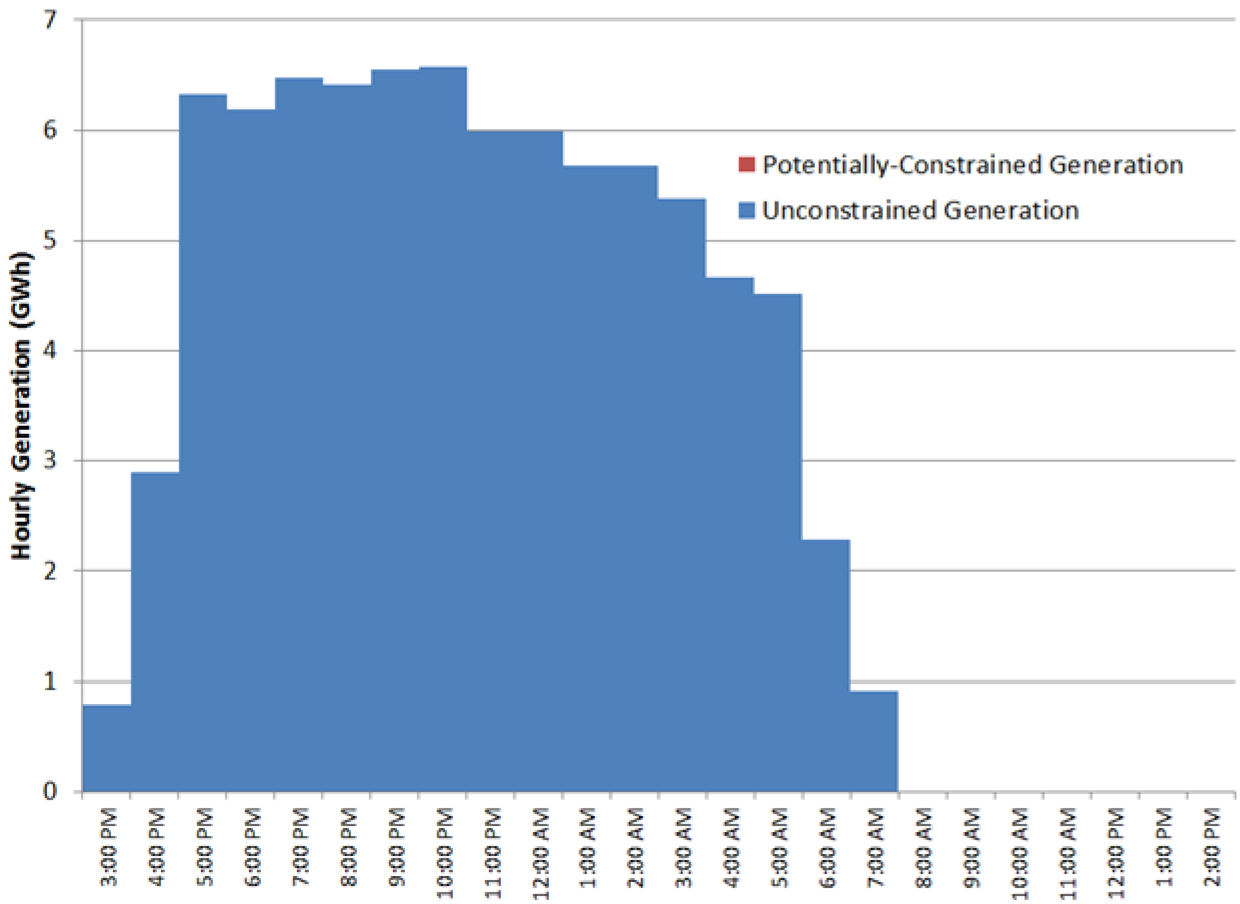
Figure 87. New England Baseline Electric Sector Gas Demand (Mid RE, Annual Minimum Day)



The annual minimum day gas demand is spread across three pipelines, with Algonquin supplying the most generation, followed by Iroquois.

Although a GPCM analysis of the annual minimum day was not conducted, it was assumed that only one model run, without boundary flow limitations, is needed because total gas demands are lower than on the summer peak day, which does not show upstream constraints. All Mid RE generation on the annual minimum day is fueled, as shown in Figure 88.

Figure 88. New England Baseline Generation (Mid RE, Annual Minimum Day)



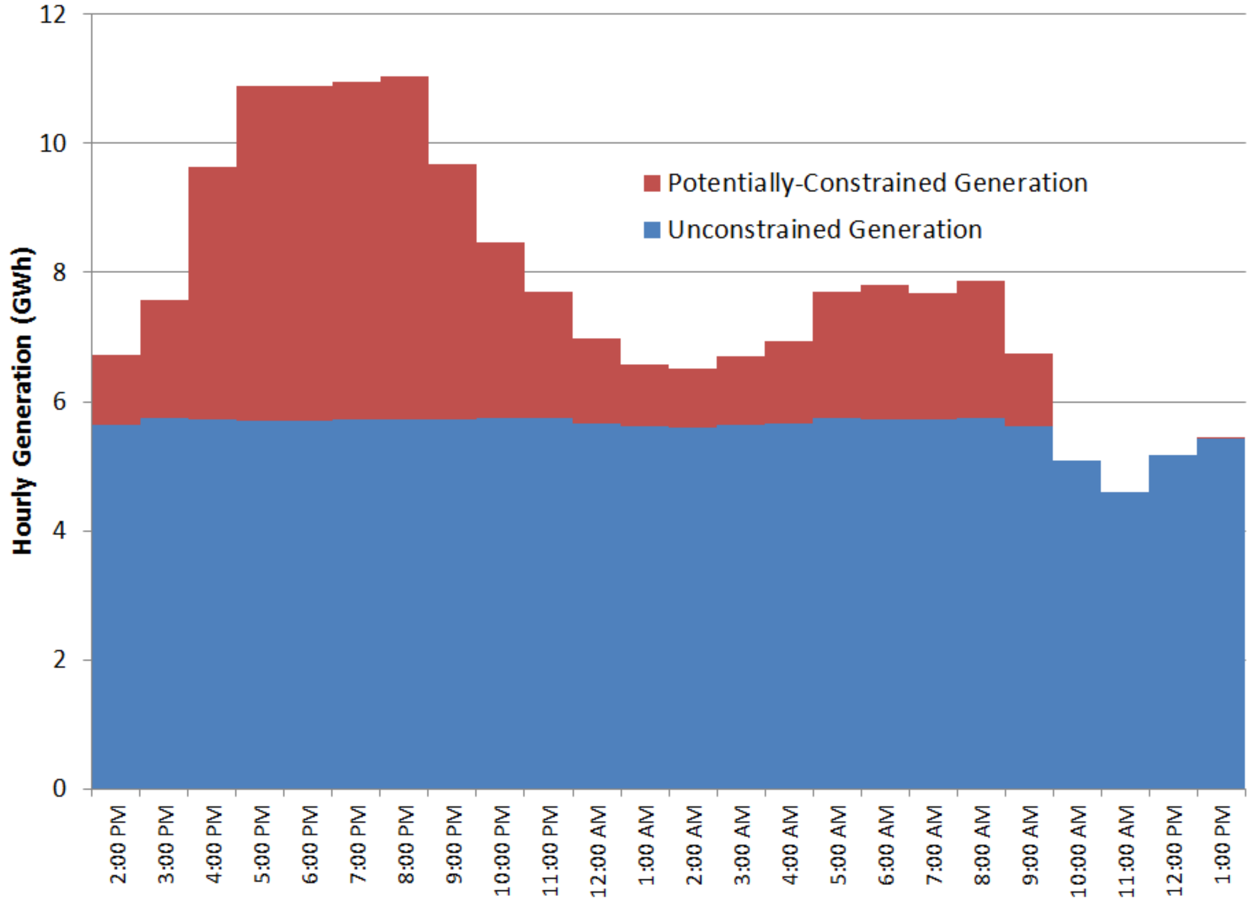
No generation is New England is potentially-constrained during the Mid RE baseline on the annual minimum day.

5.4.1.4 Mid RE LNG Sensitivity

There is no change to the gas demand for the LNG sensitivity analysis relative to the Mid RE case.[51] The only change to the model is to add a receipt volume from each of the three LNG terminals in New England. The inflow rates, which total 905 MDth/d, are assumed to be constant without hourly variation during the course of the day. Figure 91 shows the amount of generation that may shift to being unconstrained when the LNG volumes are available. The hydraulic model indicates that the full amount of LNG is able to reach generators to offset potentially-constrained generation, but pipeline-specific operating restrictions would likely limit the flow of LNG by displacement to specific New England generators.

[51] If upstream boundary flows into New England are assumed to be limited, in accord with the EI GPCM results, the addition to the LNG supply mix would have a similar effect of reducing potentially-constrained generation to that seen in section 0.

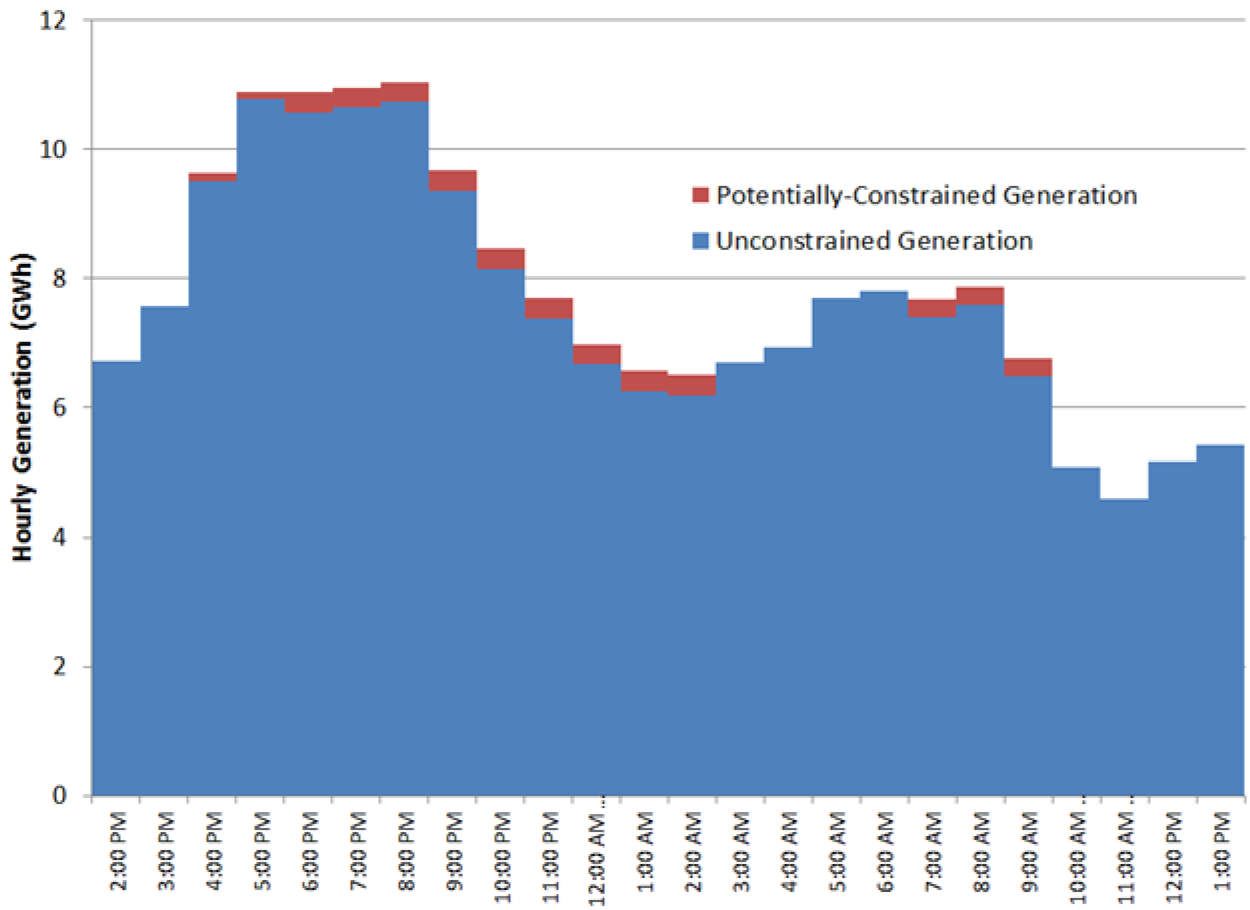
Figure 89. New England Baseline Potentially-Constrained Generation (Mid RE LNG Sensitivity, Winter Peak Day, With Boundary Flow Limits)



The availability of LNG enables the New England gas infrastructure to partially serve power generation gas demand, but there is still a significant amount of potentially-constrained generation.

If boundary flows into New England on the Mid RE winter peak day, one of the plants with potentially-constrained generation is located on the Algonquin lateral that connects to the Everett LNG terminal. Receiving LNG at the end of the lateral bolsters the operating pressure and allows the full quantity of gas to be delivered to the plant, reducing potentially-constrained generation as shown in Figure 90. There is no change to the potentially-constrained generation at the other plant that is affected by lateral constraints in the baseline.

Figure 90. New England Baseline Potentially-Constrained Generation (Mid RE LNG Sensitivity, Winter Peak Day, No Boundary Flow Limits)



The availability of LNG bolsters the operating pressure on the lateral connected to the LNG terminal, where one of the generators with unserved generation in the baseline is connected. With delivery pressure increased at the plant's delivery point, it is able to receive its full scheduled volume of gas. The second plant with potentially-constrained generation in the baseline is not affected by the addition of LNG to the system.

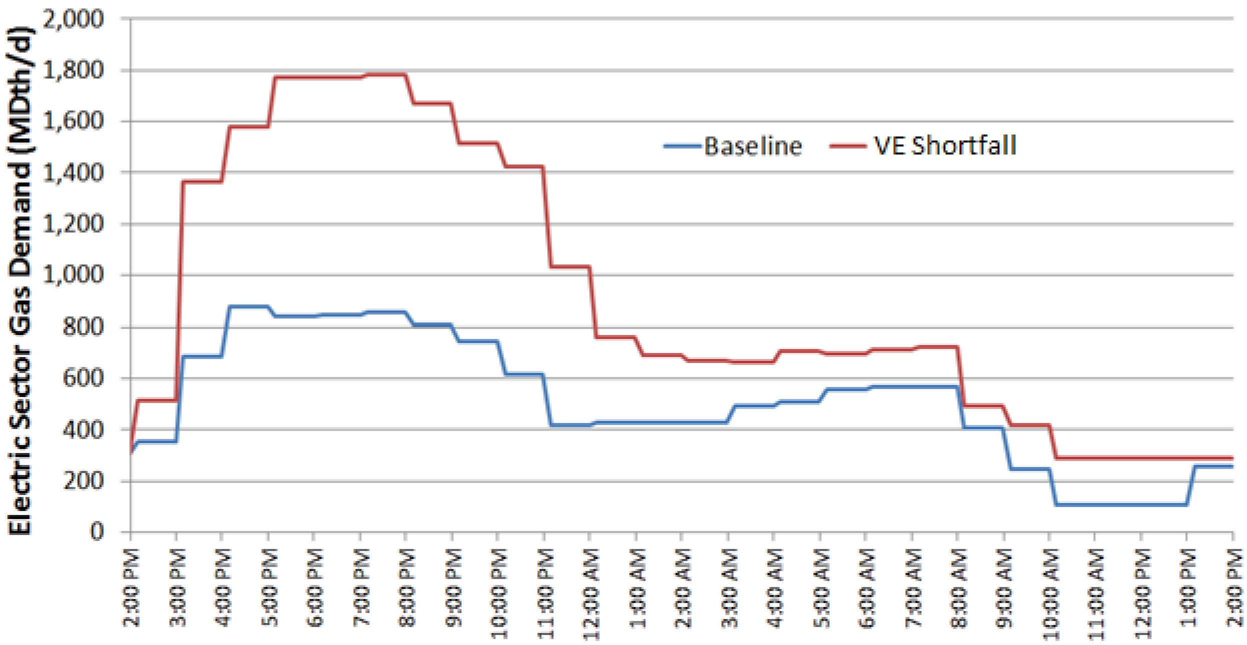
The LNG sensitivity has no impact on the summer peak day and annual minimum day because there is no LNG sendout from the Canaport, Everett and Northeast Gateway terminals outside of the winter season.

5.4.2 VE Shortfall Analysis

5.4.2.1 <u>High RE SG</u>

Figure 91 shows the electric sector gas demand for the 24-hour period following the VE shortfall period relative to the baseline demand on the winter peak day. There is a significant increase in gas demand relative to the baseline during the evening hours.

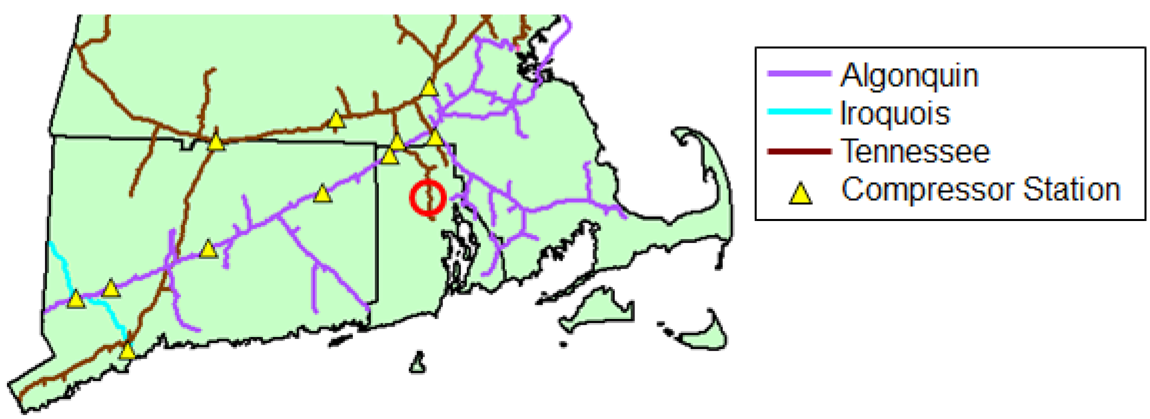
Figure 91. New England VE Shortfall Electric Sector Gas Demand (High RE SG, Winter Peak Day)



The evening peak following the VE shortfall is more than double that in the baseline.

Nearly all of the post-VE shortfall electric sector demand can be met while maintaining sufficient delivery pressures. The one exception is at a plant served by Tennessee near the end of a lateral in Rhode Island, indicated by the red circle in Figure 92.

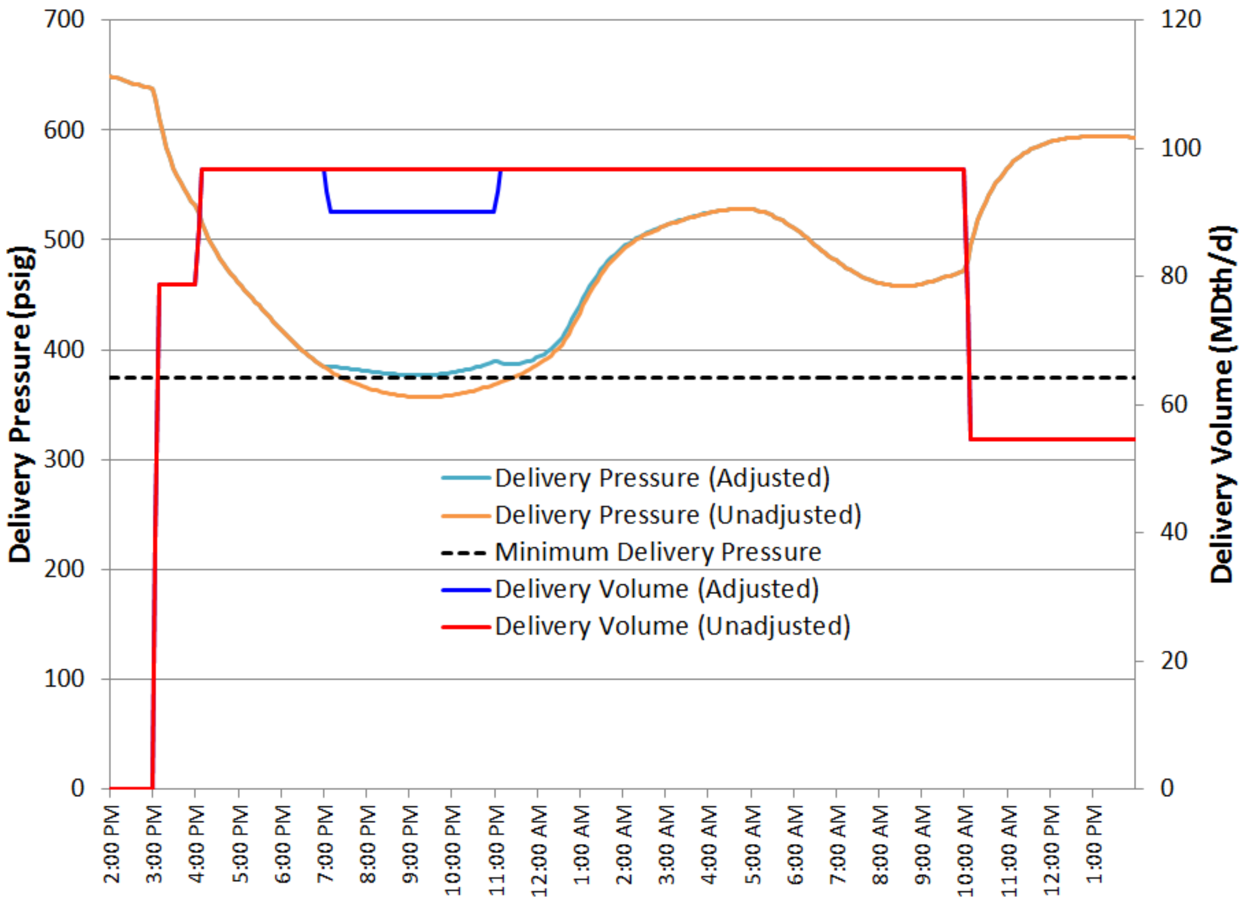
Figure 92. Generator Locations with Potentially-Constrained Generation (High RE SG, Winter Peak Day)



Following the start of the VE shortfall, delivery pressure drops below the minimum pressure threshold at a plant located on a lateral in Rhode Island.

The delivery pressure at this plant drops briefly below the 375 psig threshold during the evening hours following the start of the VE shortfall. In order to keep the delivery pressure above the threshold the amount of delivered gas must be slightly reduced for four hours. The change in delivery volume and pressure is shown in Figure 93.

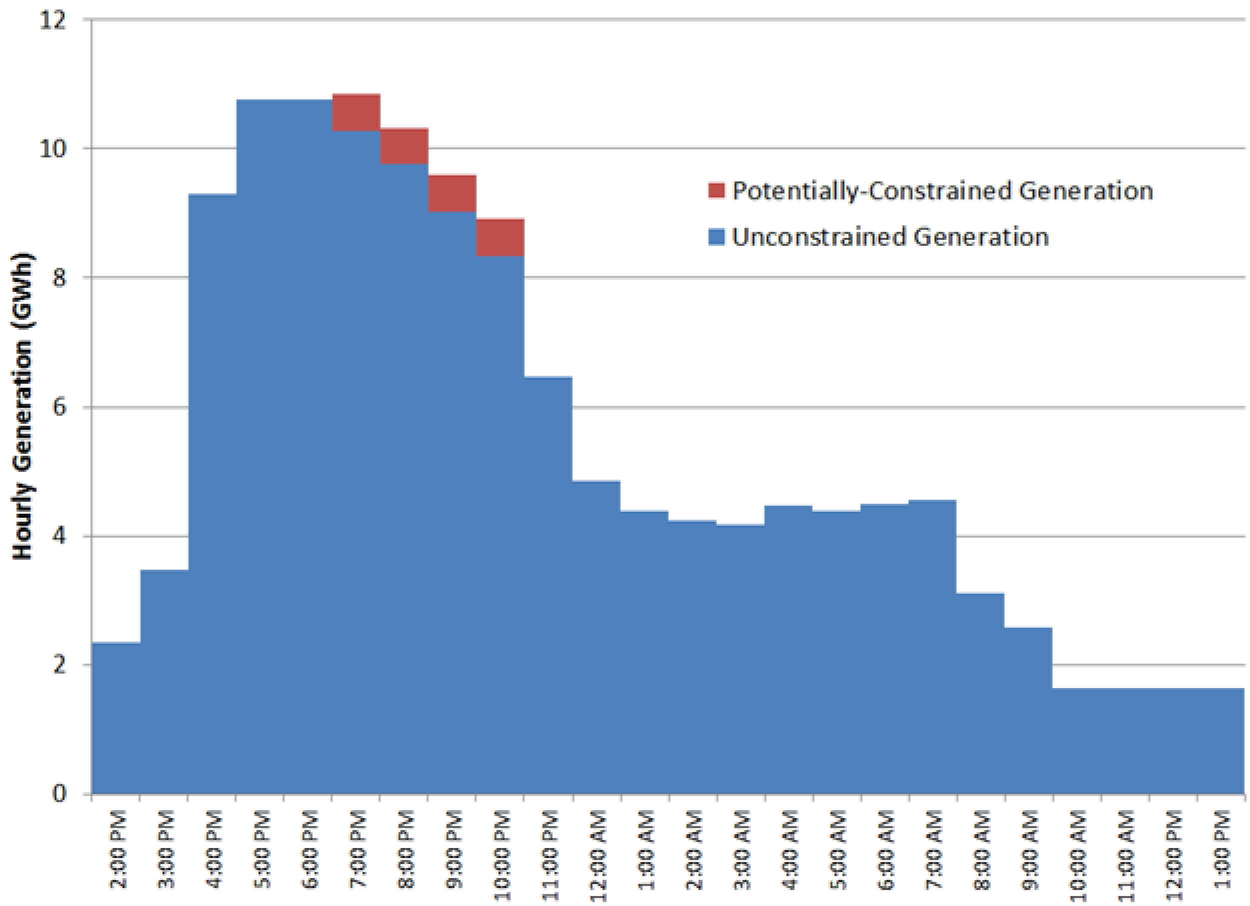
Figure 93. Adjusted Plant Delivery Volume and Pressure (High RE SG, New England Winter Peak Day)



The plant's post-VE shortfall gas demand (represented by the red line) causes the delivery pressure (represented by the orange line) to drop below the 375 psig minimum delivery pressure threshold (represented by the dashed black line). Reducing the delivery volume (represented by the dark blue line) increases the delivery pressure to the plant (represented by the light blue line) above the minimum delivery pressure threshold, allowing the plant to continue operating. The difference between the red and dark blue lines represents the amount of unavailable gas and corresponds to the amount of potentially-constrained generation.

This reduction in flow volume to protect delivery pressure results in a portion of the generation at the plant being potentially-constrained. Figure 94 shows the timing and magnitude of post-VE shortfall potentially-constrained generation on the winter peak day.

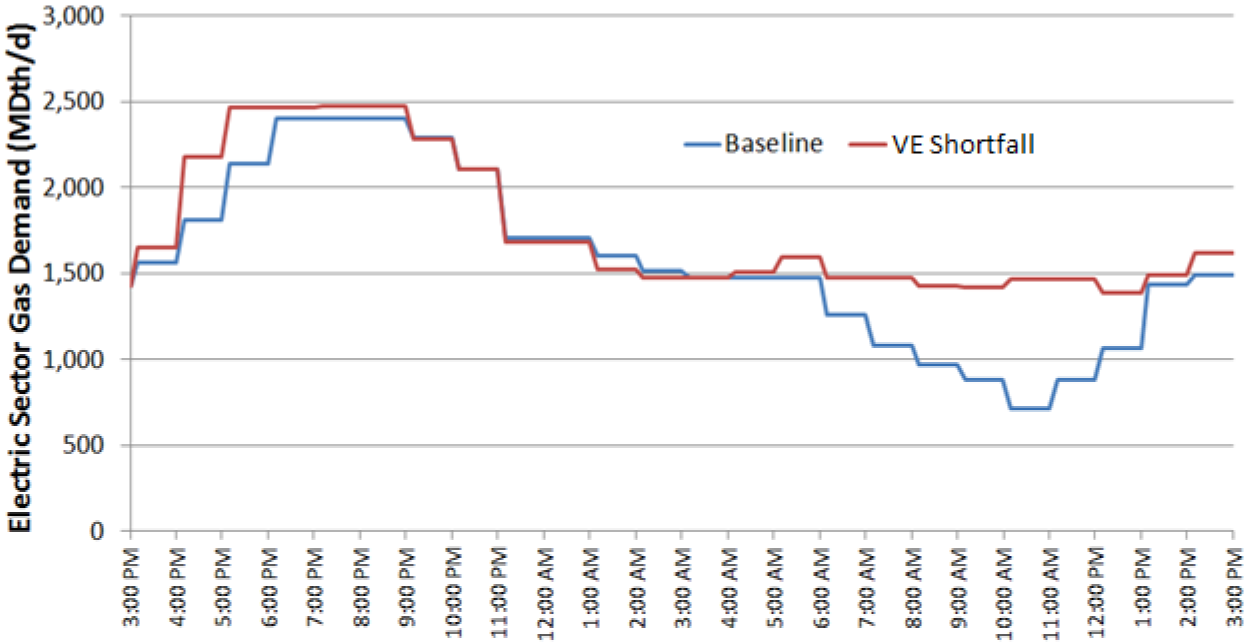
Figure 94. New England Post-VE Shortfall Potentially-Constrained Generation (High RE SG, Winter Peak Day)



Only a small amount of generation is New England is potentially-constrained following the High RE SG variable energy shortfall on the winter peak day.

Figure 95 shows the electric sector gas demand for the 24-hour period following the VE shortfall relative to the baseline demand on the summer peak day. With most gas-fired generation already operating at or near capacity in the baseline, the post-VE shortfall gas demand does not significantly increase in the evening hours. The most significant increase in gas demand occurs the morning after the start of the VE shortfall.

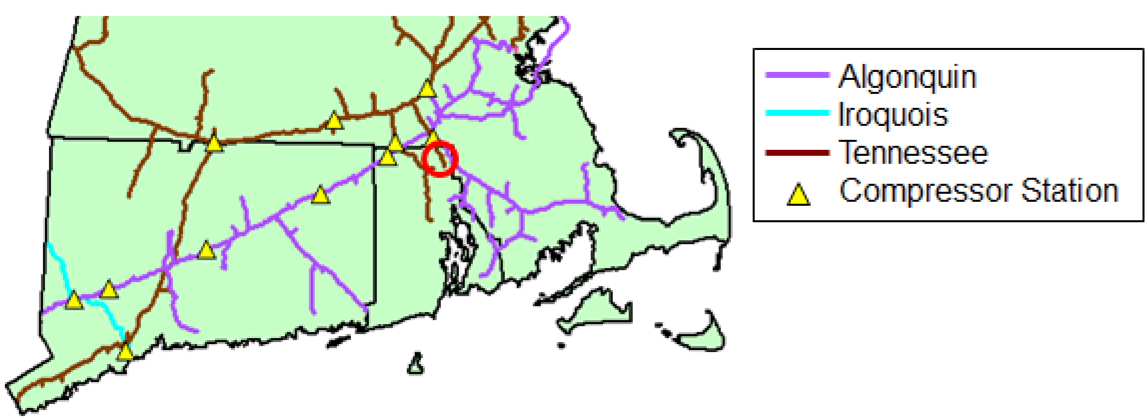
Figure 95. New England Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Summer Peak Day)



With gas-fired generators already operating at a high capacity factor, the evening ramp and peak following the start of the VE shortfall are not significantly different than in the baseline.

Nearly all of the post-VE shortfall electric sector demand can be met while maintaining sufficient delivery pressures. The one exception is again at a plant served by Tennessee near the end of a lateral in Rhode Island, indicated by the red circle in Figure 96.

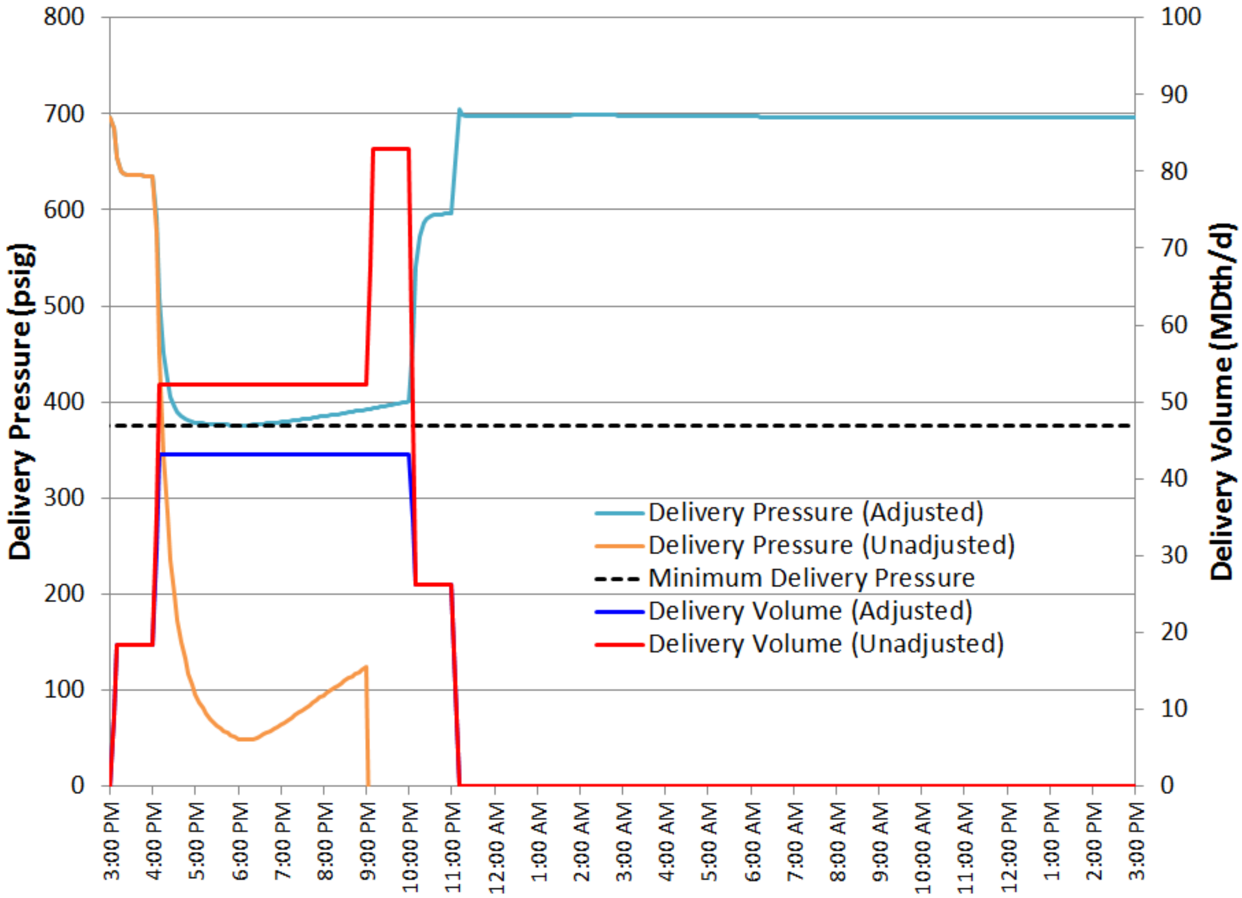
Figure 96. Generator Locations with Potentially-Constrained Generation (High RE SG, Summer Peak Day)



Following the start of the VE shortfall, potentially-constrained generation occurs at a plant located on a Tennessee lateral in Rhode Island.

An increase in gas demand at this plant significantly reduces the delivery pressure during the evening ramp up and peak, eventually dropping it to a negative value, as shown by the red and orange lines in Figure 97. In order to keep the delivery pressure above the threshold the amount of delivered gas must be reduced for six hours. The change in delivery volume and pressure is shown in Figure 97.

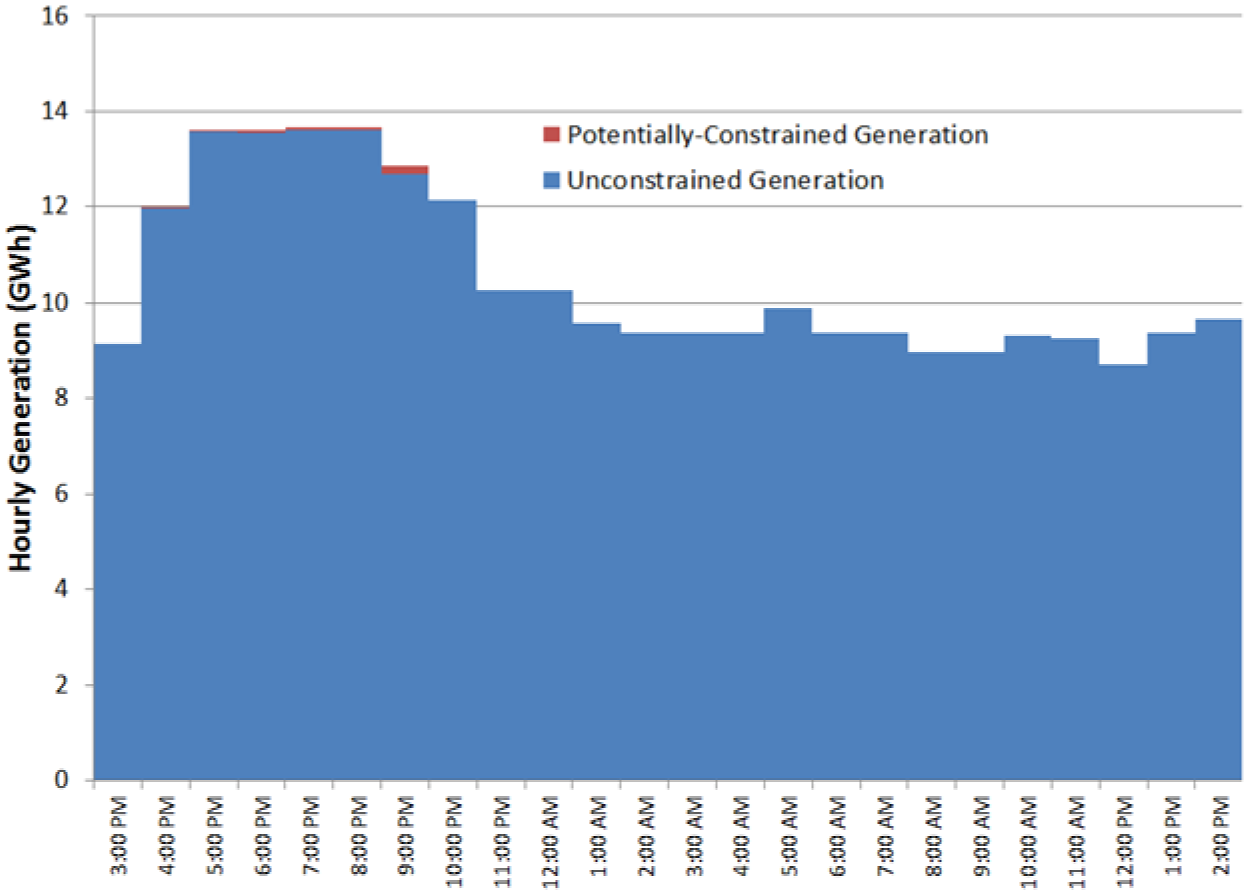
Figure 97. Adjusted Plant Delivery Volume and Pressure (High RE SG, New England Summer Peak Day)



Gas deliveries to one plant in Rhode Island are reduced for six hours following the High RE SG variable energy shortfall to maintain the delivery pressure to the plant.

This reduction in flow volume to protect delivery pressure results in a portion of the generation at the plant being potentially-constrained. Figure 98 shows the timing and magnitude of post-VE shortfall potentially-constrained generation on the summer peak day. Only a very small portion of the generation is potentially-constrained, indicating that this VE shortfall is not significantly impactful. This is consistent with the small difference between the baseline and VE shortfall electric sector gas demands.

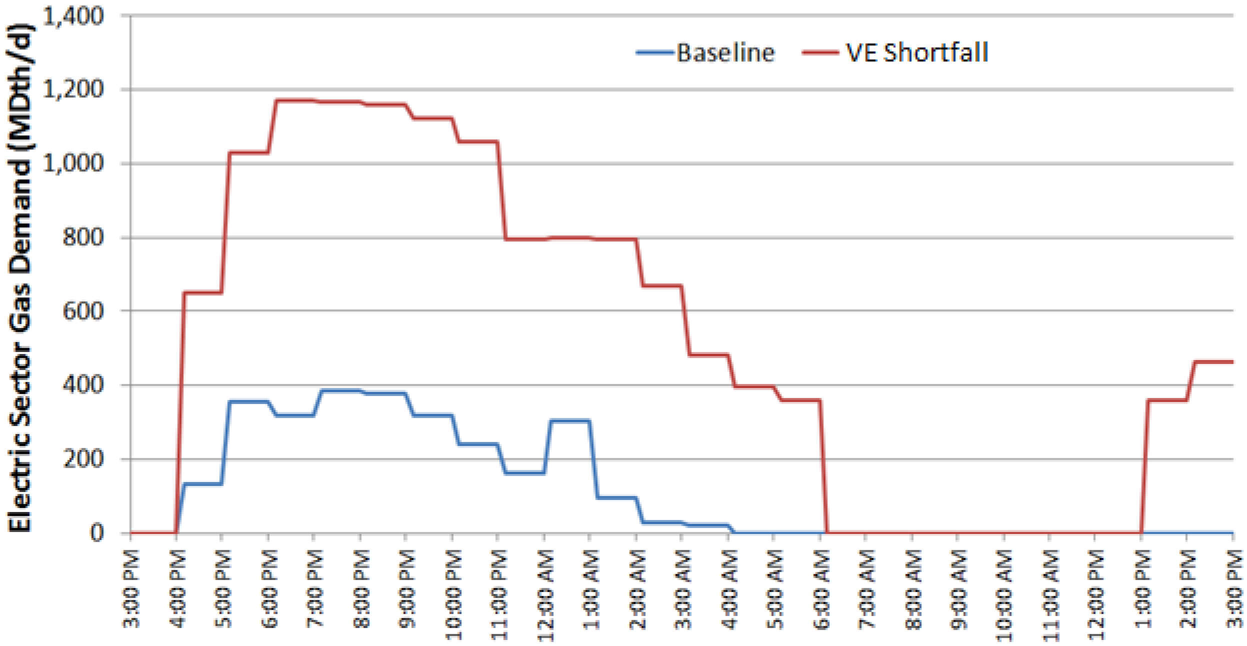
Figure 98. New England Post-VE Shortfall Potentially-Constrained Generation (High RE SG, Summer Peak Day)



A small amount of potentially-constrained generation occurs following the evening peak.

Figure 99 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the annual minimum day. There is a significant increase in gas demand, with peak hour demand approximately tripled relative to the baseline.

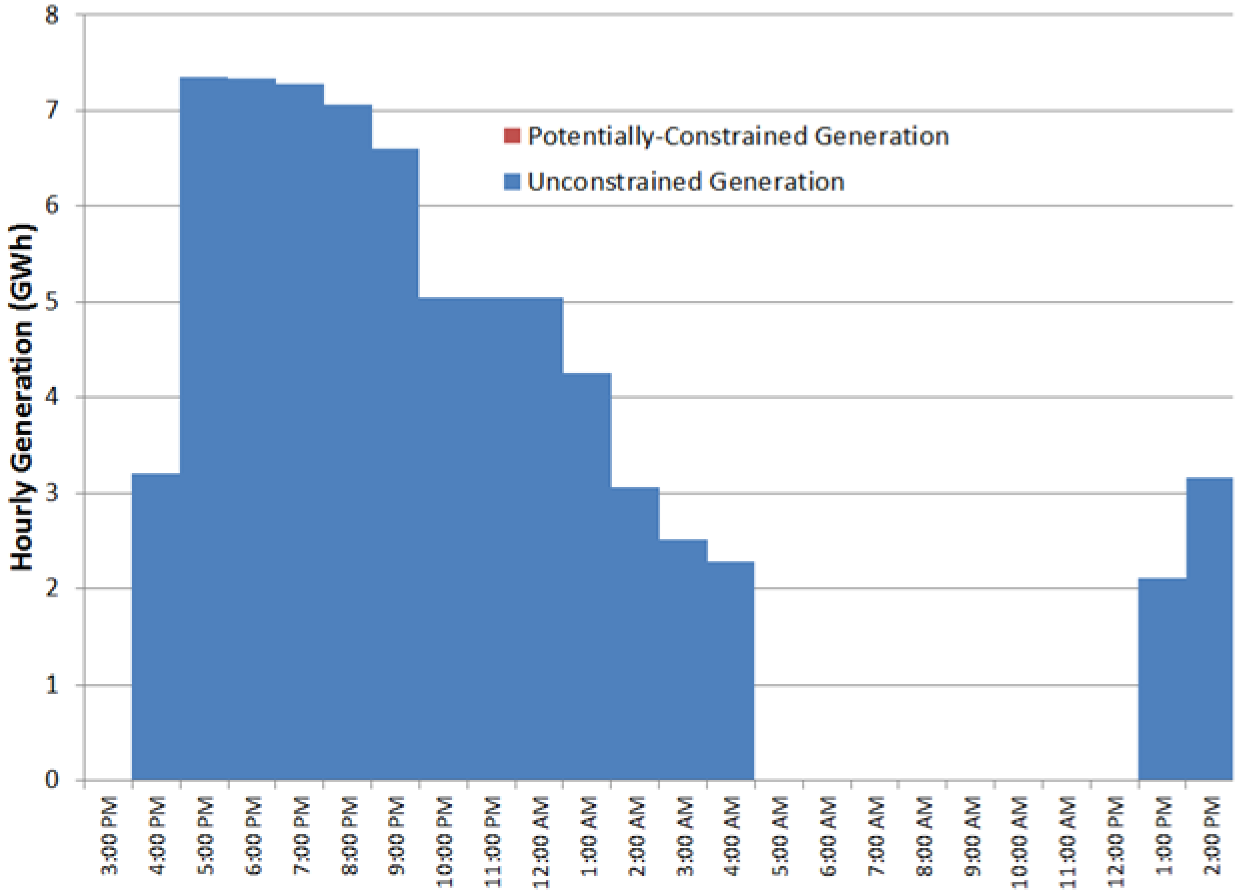
Figure 99. New England Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Annual Minimum Day)



The post-VE shortfall evening peak gas demand is triple that in the baseline, with a fast increase in demand.

All of the post-VE shortfall electric sector demand can be met while maintaining sufficient delivery pressures. There is therefore no potentially-constrained generation after the start of the VE shortfall on the annual minimum day, as shown in Figure 100.

Figure 100. New England Post-VE Shortfall Potentially-Constrained Generation (High RE SG, Annual Minimum Day)



No generation is New England is potentially-constrained following the High RE SG variable energy shortfall on the annual minimum day.

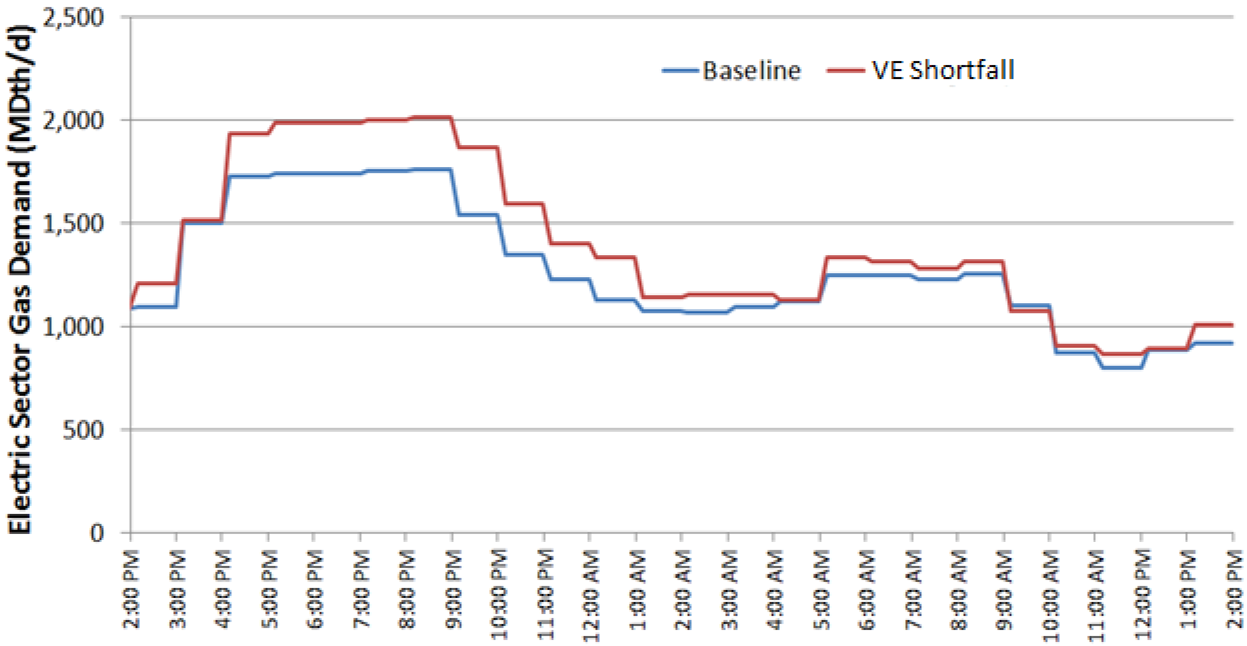
5.4.2.2 High RE SG LNG Sensitivity

On both the winter peak day and the summer peak day, the potentially-constrained generation occurs at plants located slightly downstream of compressor stations on laterals. In both cases, the compressor stations are operating at less than maximum horsepower and the limiting factor is the discharge MAOP from the compressor stations. Adding more supply in the form of east-end LNG would not change the limiting infrastructure factors, therefore the result of the LNG sensitivity are unchanged from those described in the previous section.

5.4.2.3 Mid RE

Figure 101 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the winter peak day. The largest increase in gas demand relative to the baseline occurs during the evening hours.

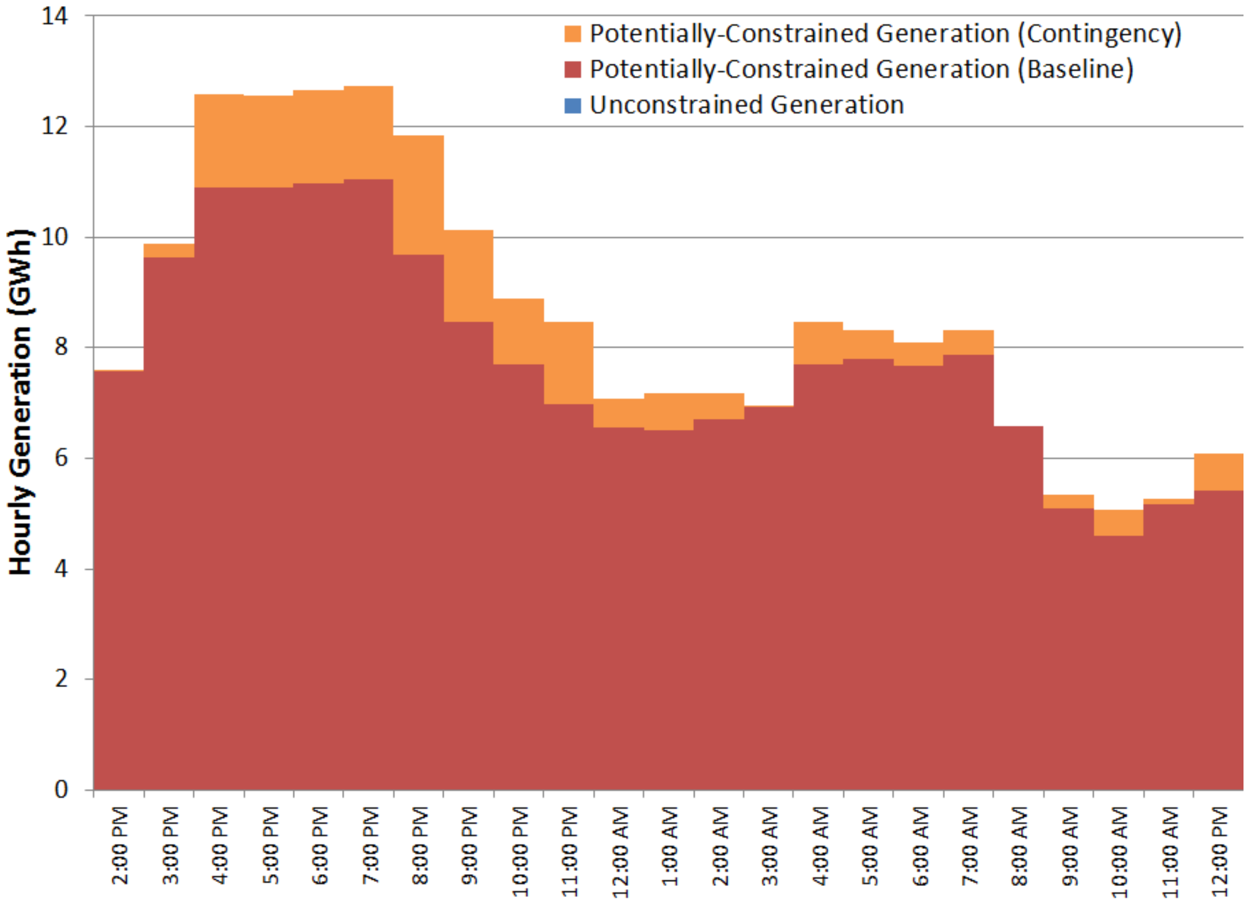
Figure 101. New England Post-VE Shortfall Electric Sector Gas Demand (Mid RE, Winter Peak Day)



The VE shortfall gas demand shows an initial small increase over baseline gas demand, with a higher increase during the evening peak. Following the evening peak, the VE shortfall case demand tracks the baseline demand reasonably closely.

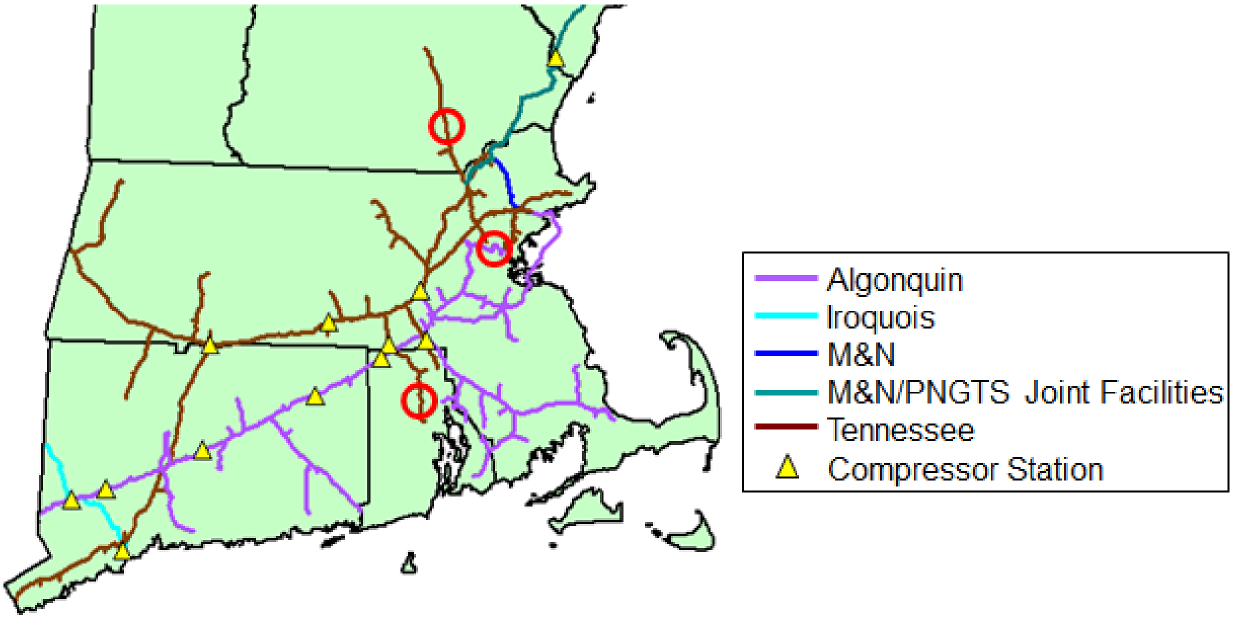
When boundary flow limits are incorporated in the analysis, all generation is potentially-constrained in the baseline, as discussed previously. With all generators affected by the constraint, the addition of incremental VE shortfall case generator gas demand increases the amount of potentially-constrained generation, as shown in Figure 102.

Figure 102. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE, Winter Peak Day, With Boundary Flow Limitations)



When boundary flow limits are not included in the analysis, there are three plants with potentially-constrained generation following the start of the VE shortfall, the locations of which are shown in Figure 103. The first two plants are those that have potentially-constrained generation in the Mid RE baseline. To the extent that incremental demand is modeled during hours with curtailments, it is also curtailed, leading to incremental potentially-constrained generation. The third plant is located on a Tennessee lateral in New Hampshire.

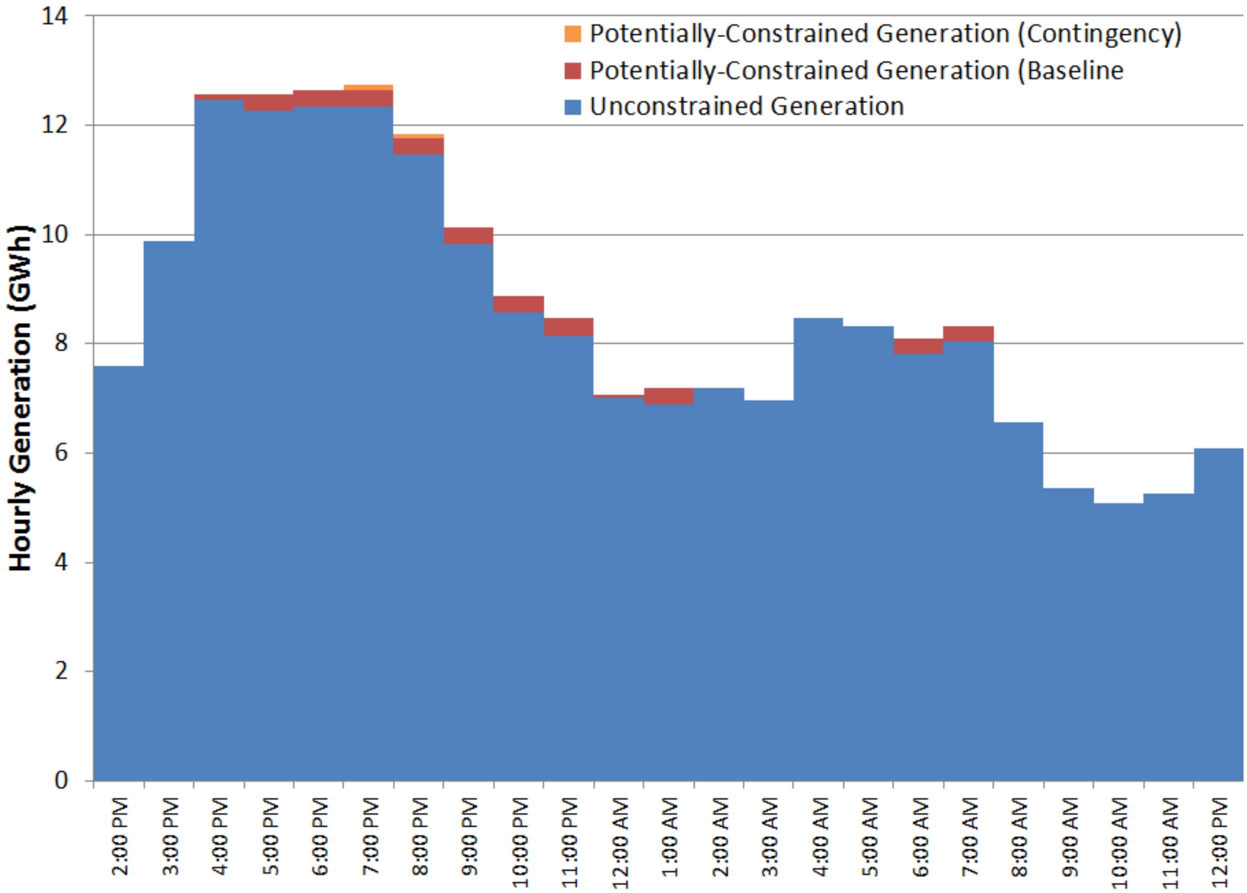
Figure 103. Generator Locations with Potentially-Constrained Generation (Mid RE, Winter Peak Day)



Three plants have potentially-constrained generation on the Mid RE winter peak day, including the two plants which had potentially-constrained generation in the baseline and a third plant located on a Tennessee lateral in New Hampshire.

Figure 104 shows the timing and magnitude of VE shortfall potentially-constrained generation on the winter peak day that results from decreases in gas deliveries at the three affected plants. The potentially-constrained generation is separated between the generation that was already potentially-constrained in the baseline, which comprises most of the potentially-constrained generation, and the incremental generation that is potentially-constrained in the VE shortfall case. Incremental potentially-constrained generation following the start of the VE shortfall occurs during four hours, two during the evening peak and two during the following morning.

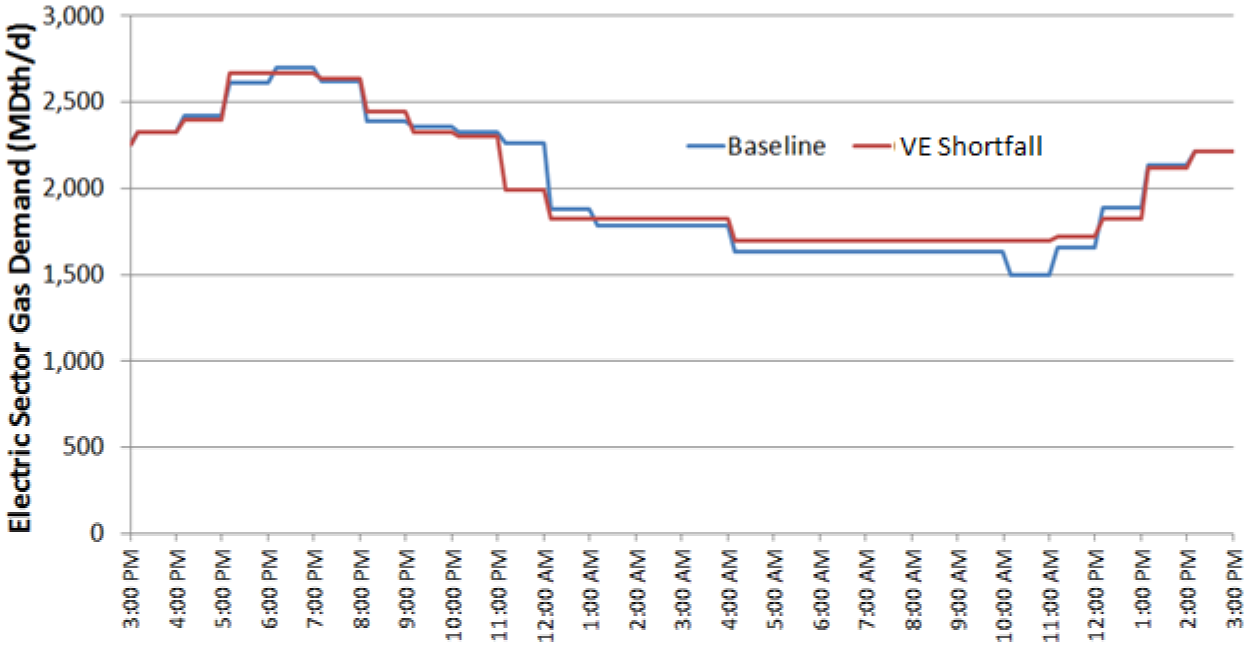
Figure 104. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE, Winter Peak Day)



Most of the generation that is potentially-constrained following the start of the VE shortfall was also potentially-constrained in the baseline.

Figure 105 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the summer peak day. With most gas-fired generation already operating at or near capacity in the baseline, the VE shortfall case gas demand does not significantly differ from the baseline demand.

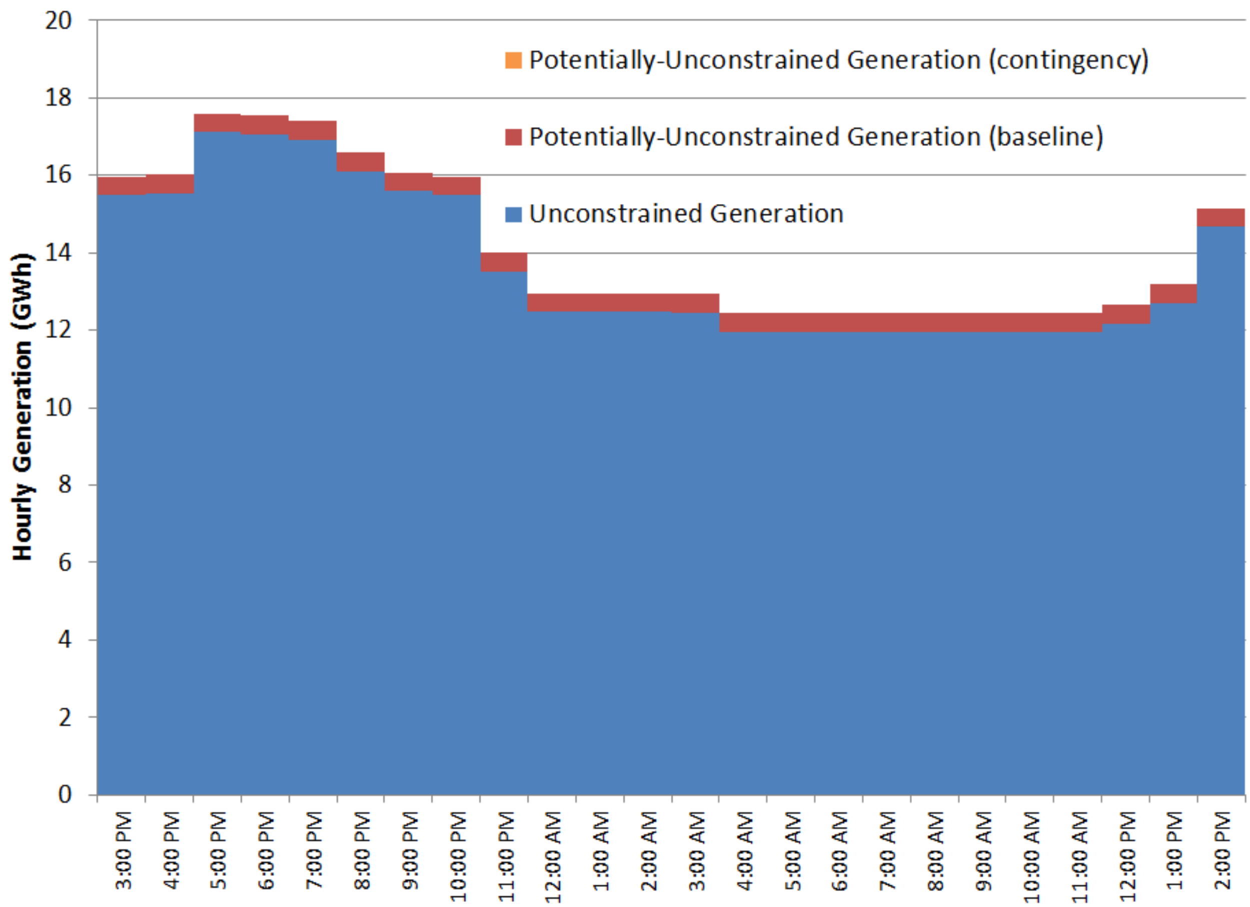
Figure 105. New England Post-VE Shortfall Electric Sector Gas Demand (Mid RE, Summer Peak Day)



The VE shortfall case gas demand tracks the baseline gas demand very closely.

With minimal changes from the Mid RE summer peak day baseline, no generation becomes potentially-constrained following the start of the VE shortfall, as shown in Figure 106.

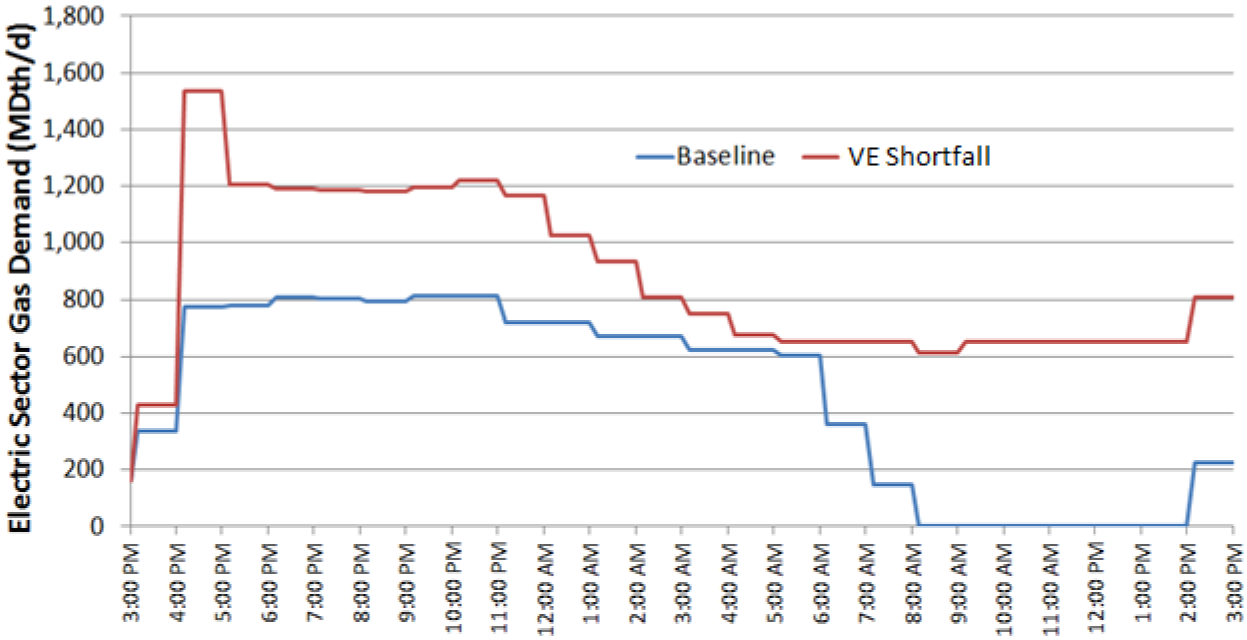
Figure 106. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE, Summer Peak Day)



With generators already operating near maximum capacity in the baseline, no incremental generation becomes potentially-constrained following start of the Mid RE summer peak day VE shortfall.

Figure 107 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the annual minimum day. VE shortfall case gas demand peaks for one hour during the late afternoon and then levels out through the rest of the day.

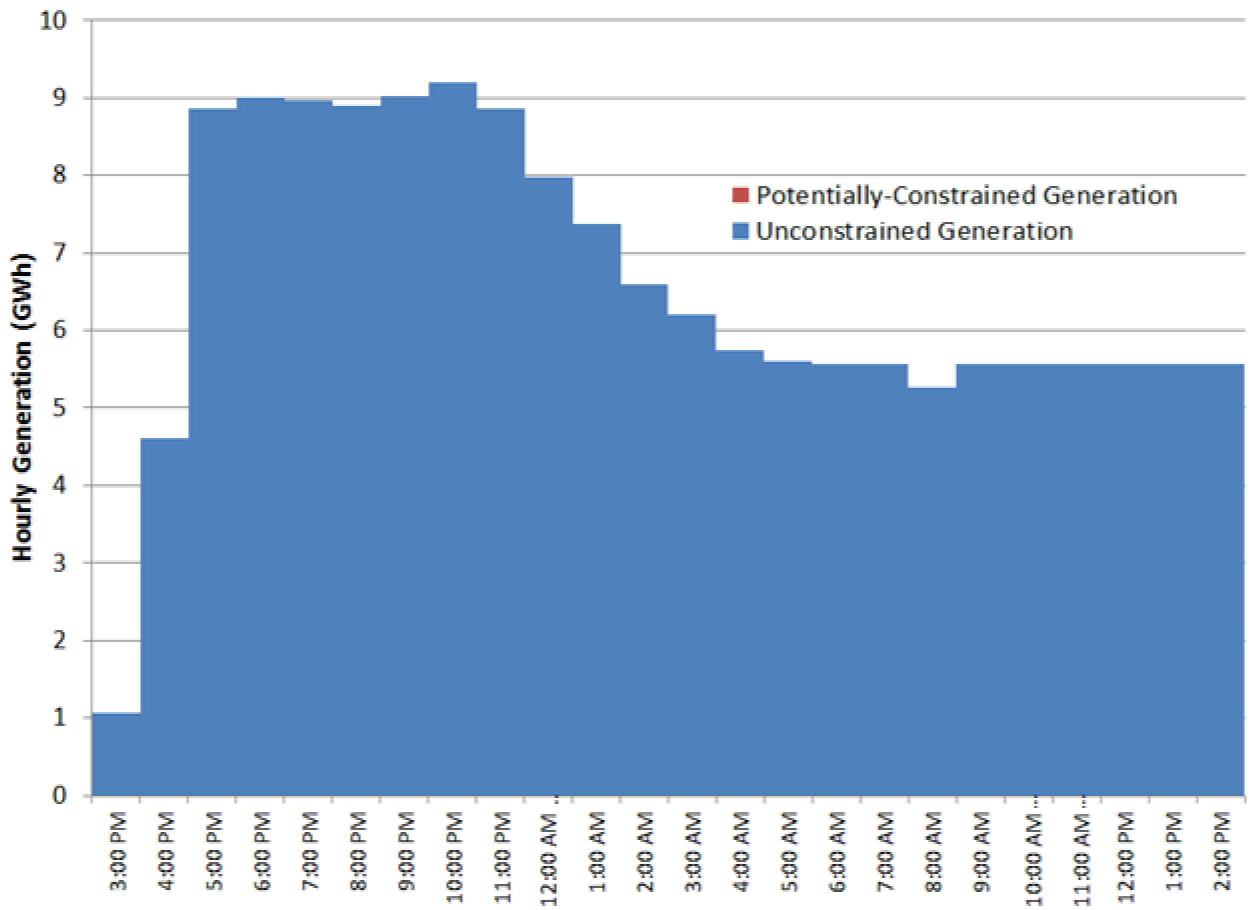
Figure 107. New England Post-VE Shortfall Electric Sector Gas Demand (Mid RE, Annual Minimum Day)



The VE shortfall case gas demand exhibits a rapid increase in the early afternoon and then levels out over the remainder of the model run.

All of the VE shortfall electric sector demand can be met while maintaining sufficient delivery pressures. While there is a fast increase in demand following the start of the VE shortfall, there is enough unused compression horsepower before the VE shortfall to maintain system pressures. There is therefore no potentially-constrained generation after the start of the VE shortfall on the annual minimum day, as shown in Figure 108.

Figure 108. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE, Annual Minimum Day)



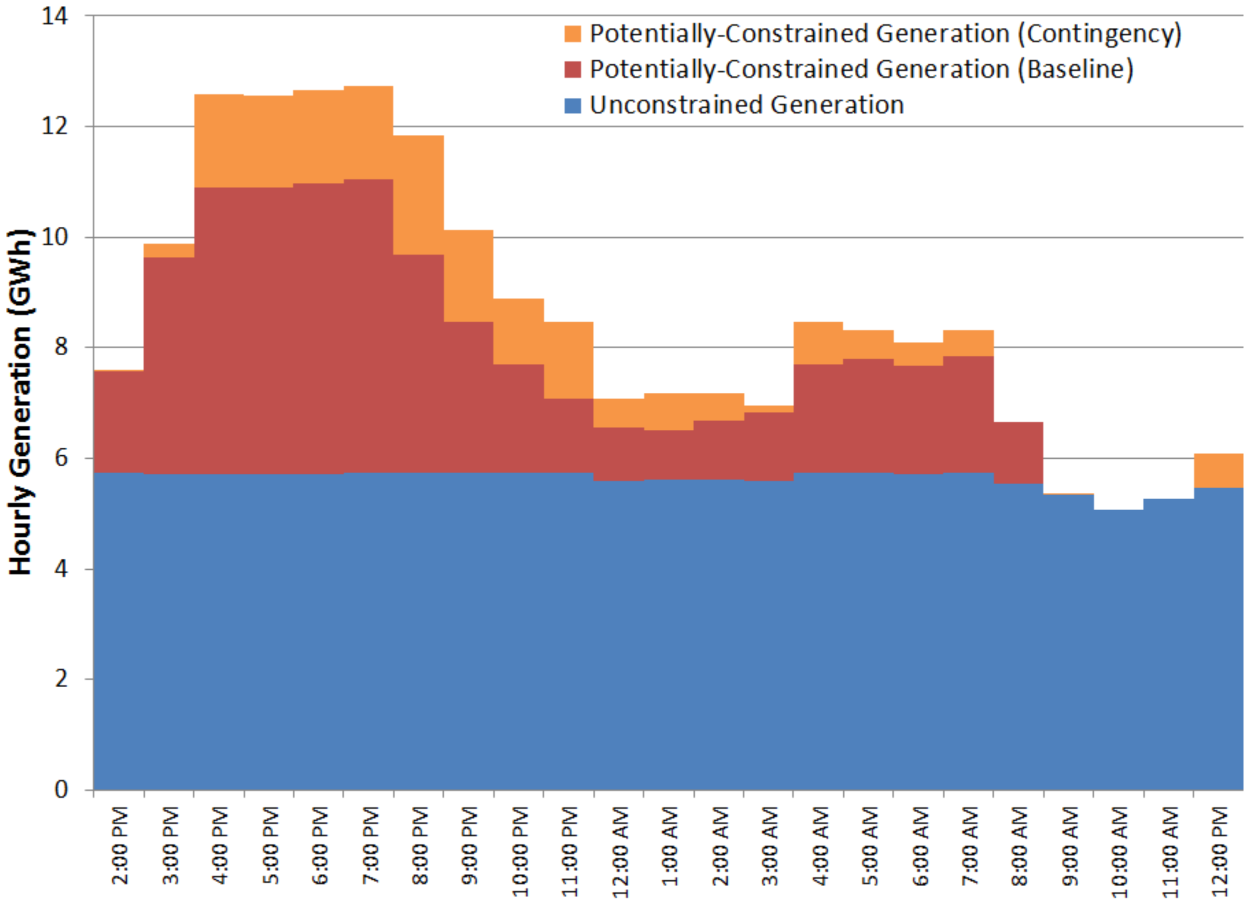
No generation is New England is potentially-constrained following start of the Mid RE variable energy shortfall on the annual minimum day.

5.4.2.4 Mid RE LNG Sensitivity

On the winter peak day with upstream boundary flow limits in effect, the amounts of unconstrained and potentially-constrained generation remain the same, with incremental

VE shortfall case generation being potentially-constrained to the extent it occurs during peak demand hours when no incremental LNG is available. These effects are shown in Figure 109.

Figure 109. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE LNG Sensitivity, Winter Peak Day, With Boundary Flow Limits)

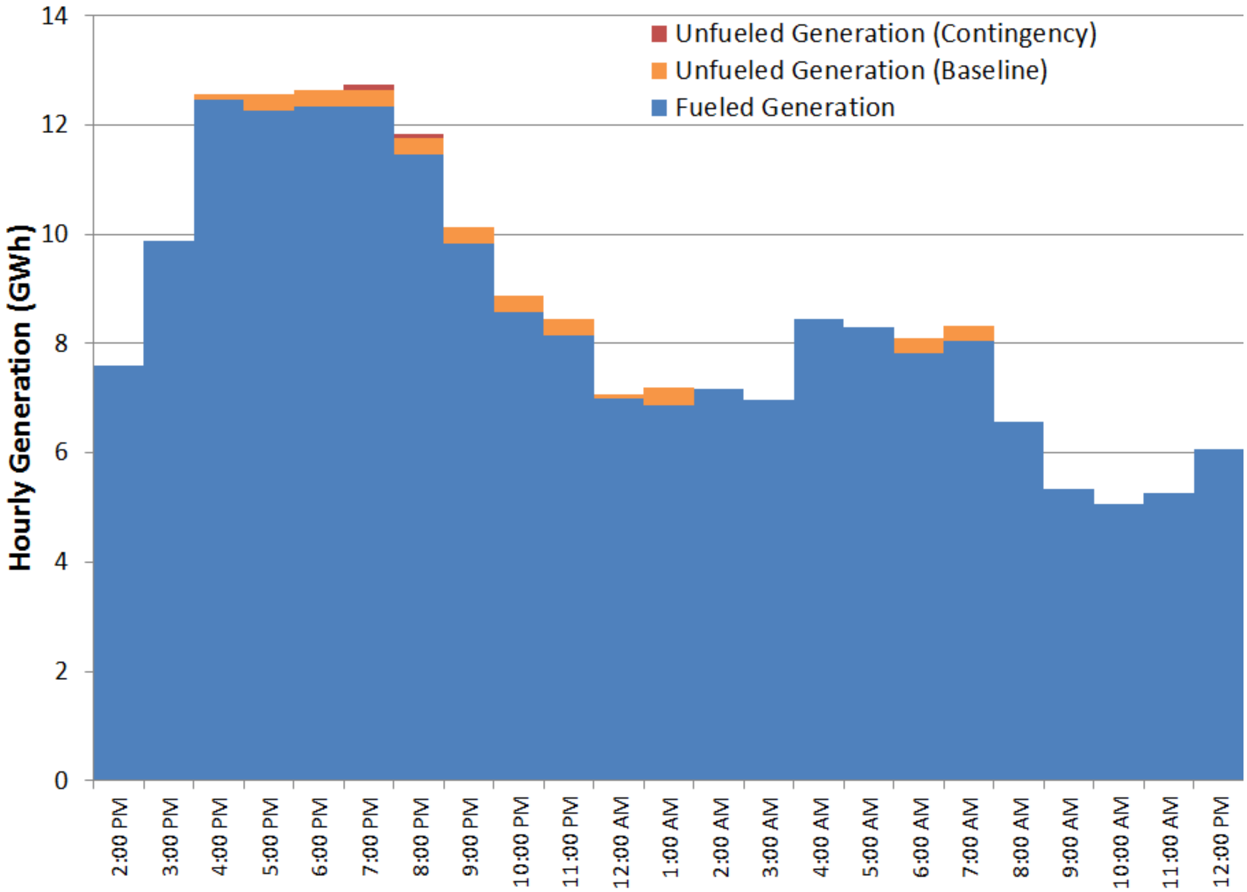


The baseline potentially-constrained generation is reduced in the LNG sensitivity, which reduces the total VE shortfall case potentially-constrained generation.

On the winter peak day without boundary flow limits, the majority of potentially-constrained generation following the start of the VE shortfall is carried over from the baseline. Baseline potentially-constrained generation is reduced in the LNG sensitivity, as discussed in section

5.4.1.4, therefore the same effects are seen following the start of the VE shortfall. The resultant potentially-constrained generation is shown in Figure 110.

Figure 110. New England Post-VE Shortfall Potentially-Constrained Generation (Mid RE LNG Sensitivity, Winter Peak Day, No Boundary Flow Limits)



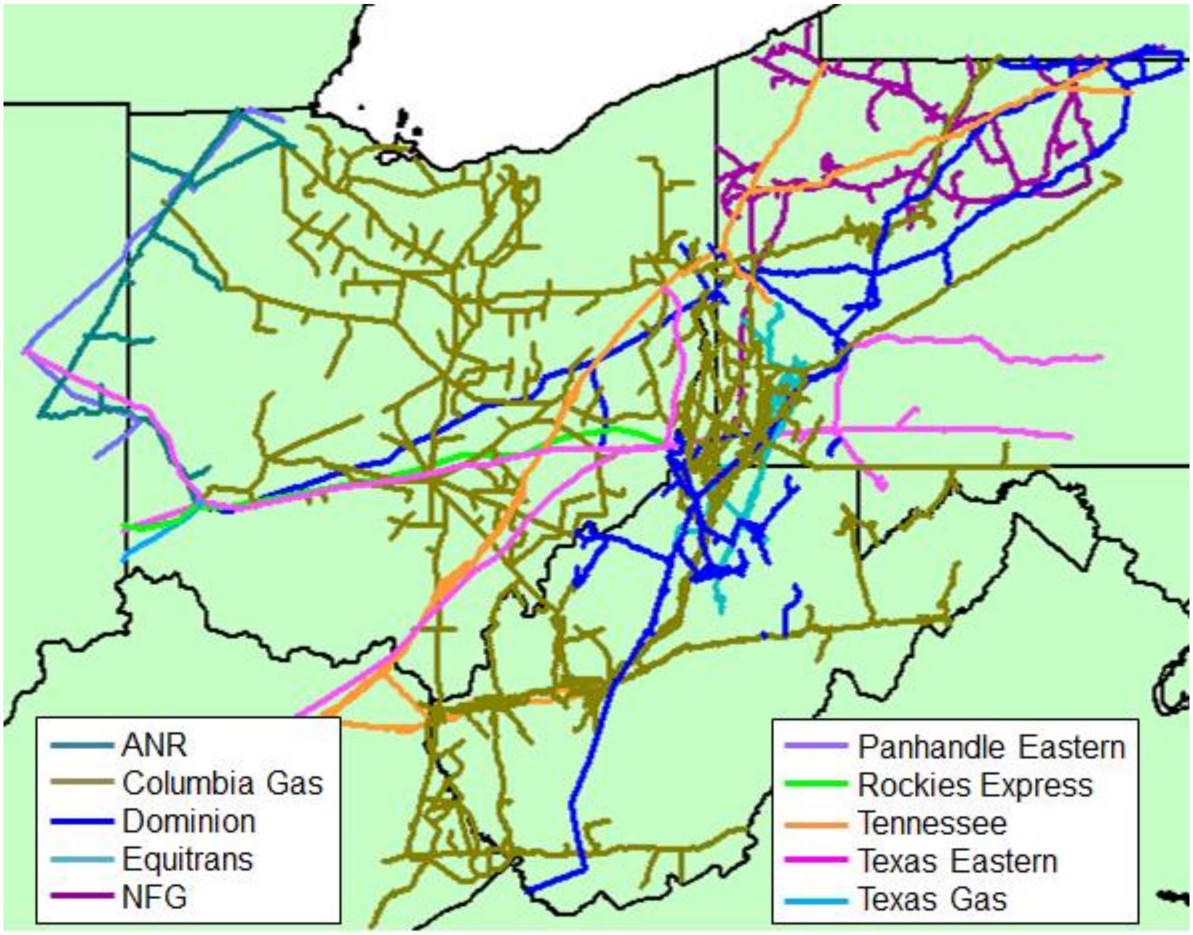
The baseline potentially-constrained generation is reduced in the LNG sensitivity, which reduces the total VE shortfall case potentially-constrained generation.

The LNG sensitivity has no impact on the summer peak day and annual minimum day because there is no LNG sendout from the Canaport, Everett and Northeast Gateway terminals outside of the winter season.

5.5 Unconstrained Location: Marcellus-Utica

The Marcellus-Utica pipeline infrastructure represented in the consolidated regional hydraulic model is shown in Figure 111. The model includes ten interstate pipelines that operate in Ohio, Pennsylvania and West Virginia: ANR, Columbia Gas, Dominion, Equitrans, NFG, Panhandle Eastern, Rockies Express, Tennessee, Texas Eastern, and Texas Gas. In general, this region represents the shale production region. From this region, gas flows east to eastern PJM, downstate New York and New England, north to upstate New York and Ontario, and northwest, west and south to MISO.

Figure 111. Marcellus-Utica Pipeline Map



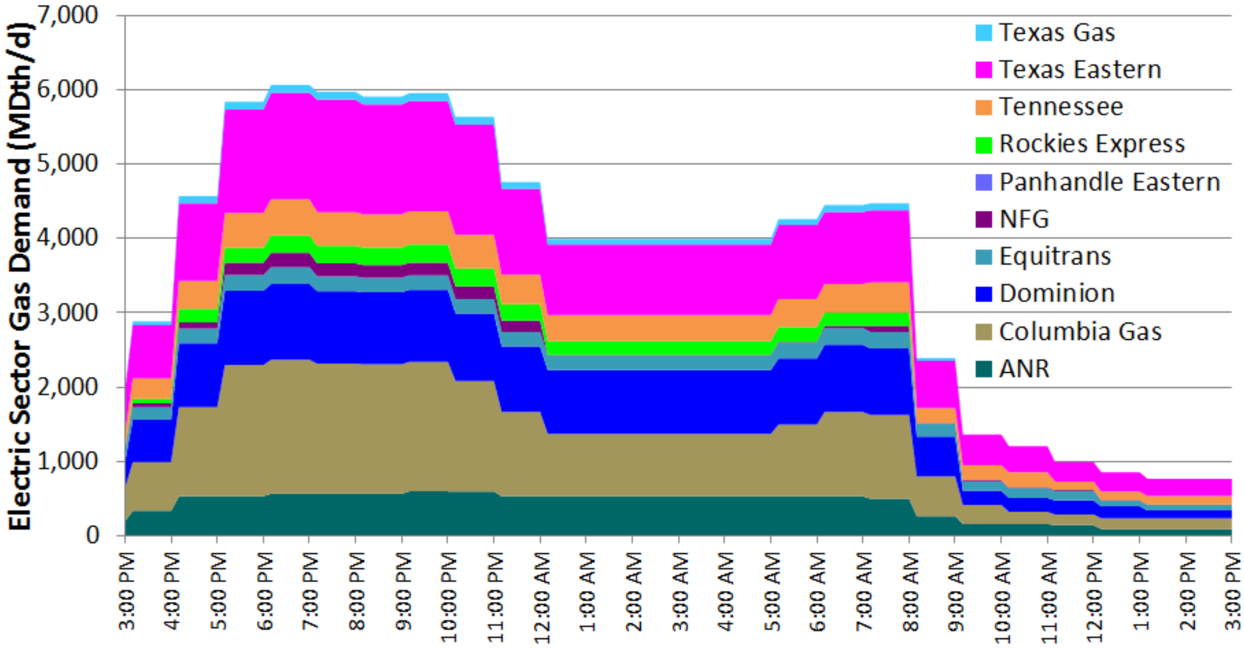
The Marcellus-Utica pipeline infrastructure included in the regional hydraulic model includes portions of ten pipelines: ANR, Columbia Gas, Dominion, Equitrans, NFG, Panhandle Eastern, Rockies Express, Tennessee, Texas Eastern, and Texas Gas.

5.5.1 Baseline Analysis

5.5.1.1 High RE SG

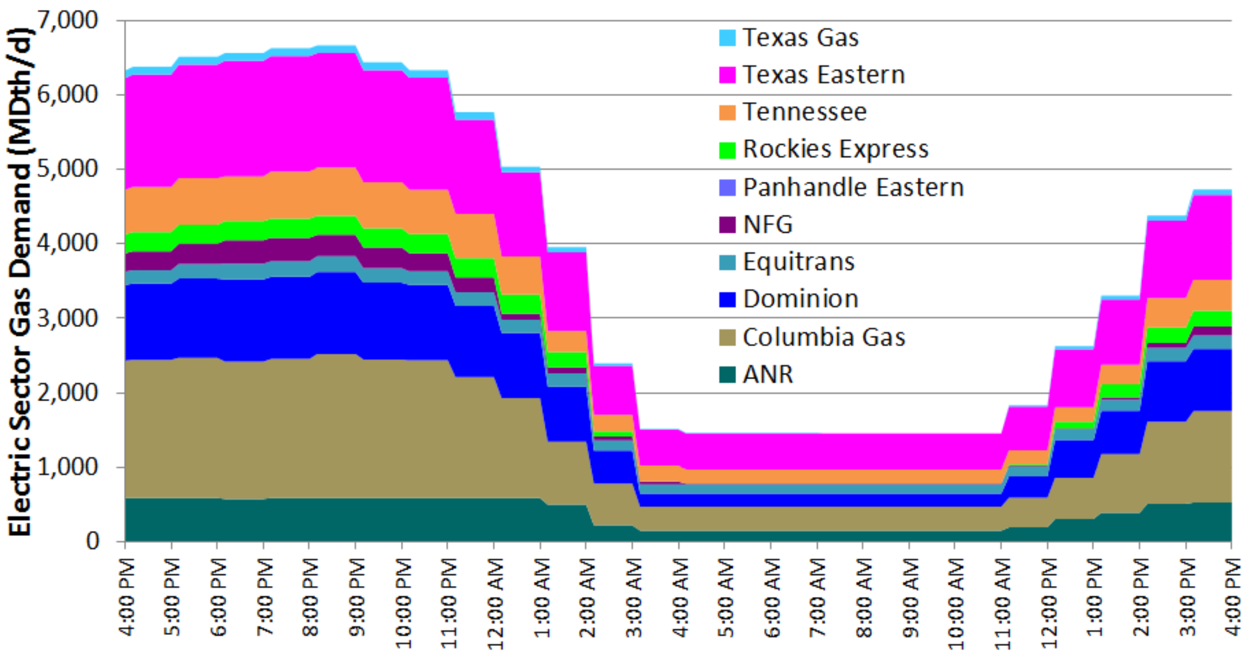
The following three figures show the amount of electric sector gas demand by pipeline over the course of the winter peak day (Figure 112), summer peak day (Figure 113) and annual minimum day (Figure 114). The total electric sector gas demand is highest on the summer peak day and lowest on the annual minimum day. On the winter and summer peak days, Columbia Gas and Texas Eastern serve the most generation. On the annual minimum day, Columbia Gas and Dominion serve the most generation, albeit at a much lower level than on the seasonal peak days. In all three cases, the electric sector demand is shared across many pipelines, reducing the ramping burden on any single pipeline.

Figure 112. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG, Winter Peak Day)



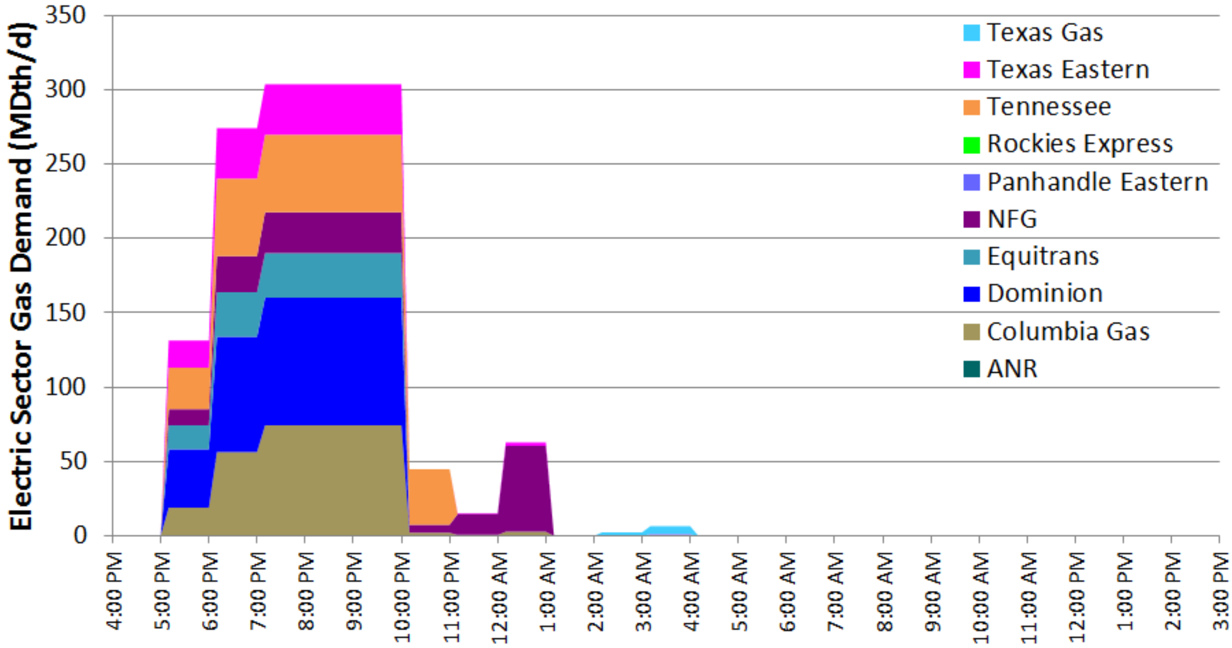
Electric sector demand is spread across nine pipelines, with Columbia Gas, Texas Eastern and Dominion representing the largest shares. Panhandle Eastern does not fuel any power plants in this case.

Figure 113. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG, Summer Peak Day)



Electric sector demand is spread across nine pipelines, with Columbia Gas, Texas Eastern and Dominion representing the largest shares. Panhandle Eastern does not fuel any power plants in this case.

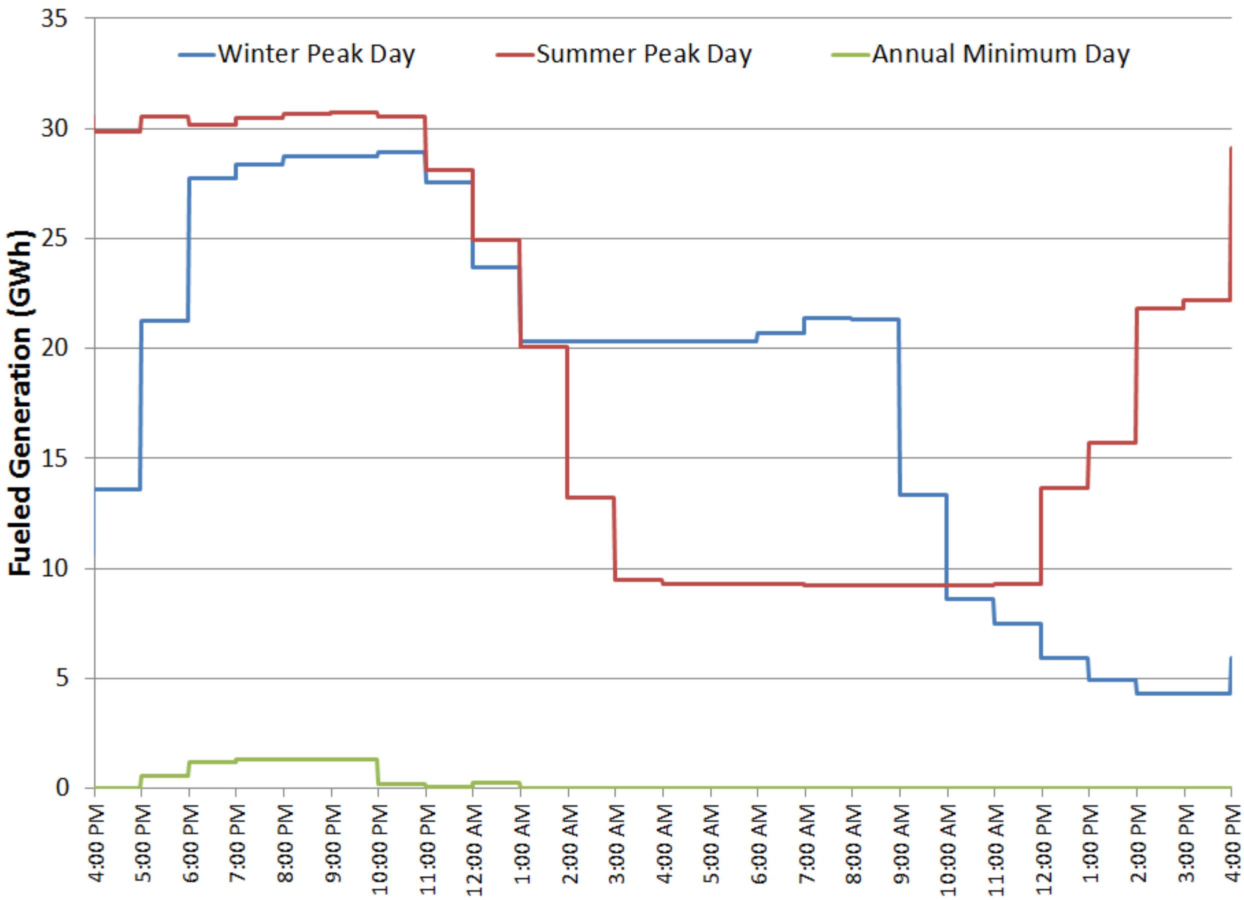
Figure 114. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG, Annual Minimum Day)



Electric sector demand during the peak hour is spread across six pipelines, with Dominion, Columbia Gas, and Tennessee representing the largest shares. ANR, Panhandle Eastern, Rockies Express and Texas Gas do not fuel any power plants in this case.

Figure 115 shows the relative amounts and intraday patterns of scheduled generation on the winter peak day, summer peak day and annual minimum day under baseline conditions. In all three cases (winter peak, summer peak and annual minimum), all electric sector gas demands are met, and all scheduled generation is therefore fueled.

Figure 115. Marcellus-Utica Baseline Unconstrained Generation (High RE SG)

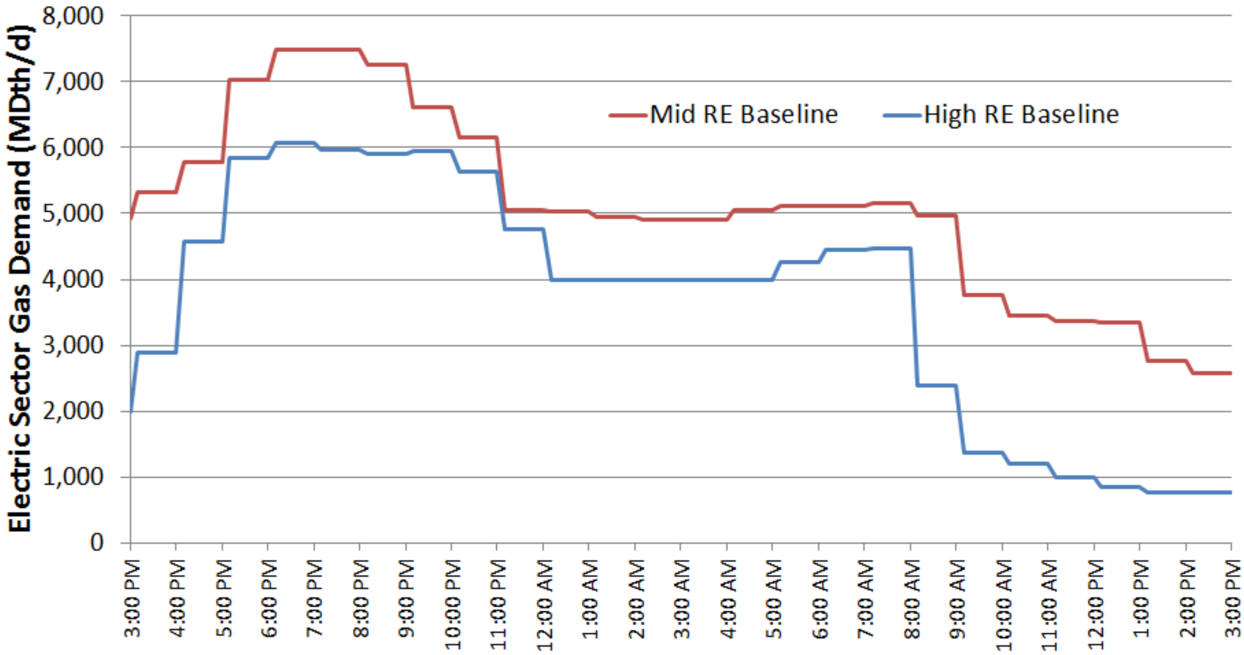


All baseline generation is fueled on each of the High RE SG days analyzed.

5.5.1.2 Mid RE

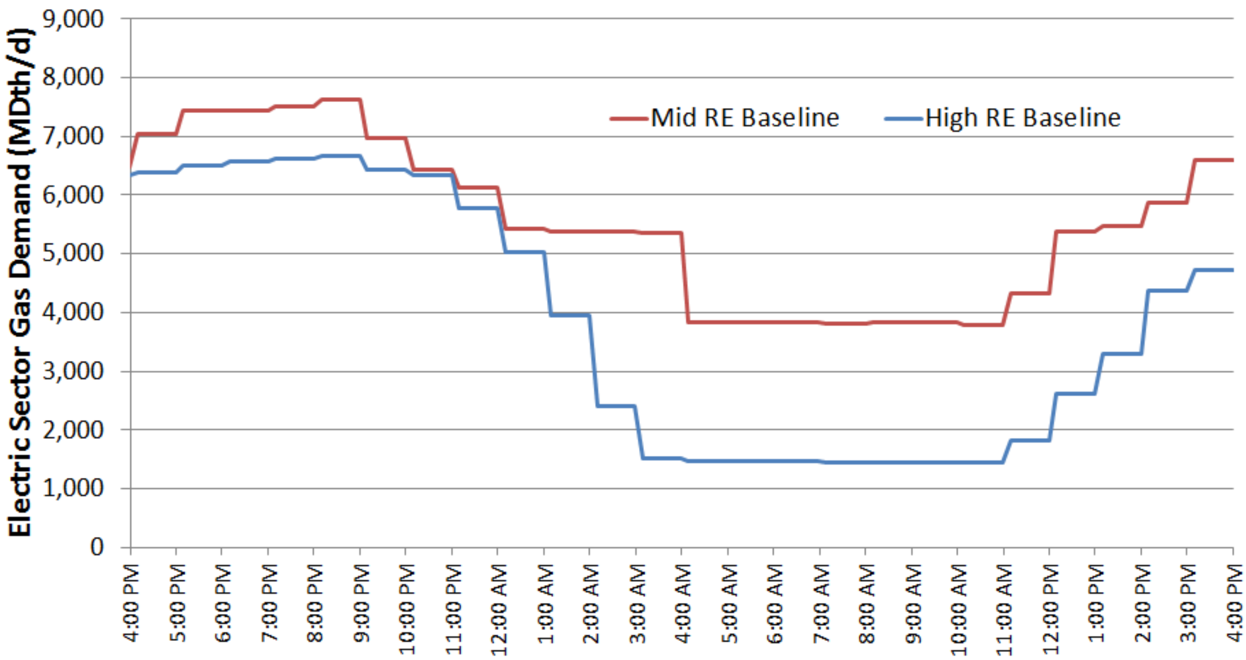
The following three figures compare the hourly profiles of electric sector gas demand between High RE SG and Mid RE for the winter peak day (Figure 116) summer peak day (Figure 117) and annual minimum day (Figure 118). On the winter peak day and the annual minimum day, the Mid RE electric sector gas demand is higher throughout the day than the High RE SG gas demand. On the summer peak day, the High RE SG and Mid RE gas demands are very similar, indicating that the gas-fired generators in the region are working near their peak capacity in High RE SG, with little headroom for increased generation in Mid RE.

Figure 116. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Winter Peak Day)



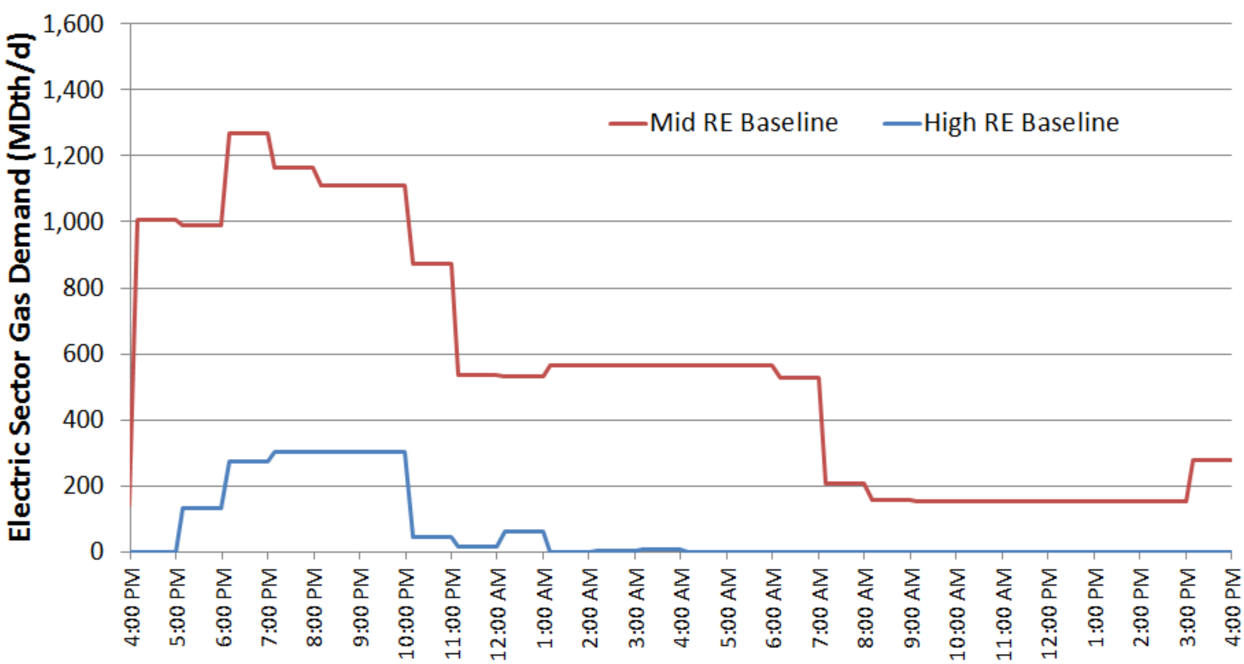
The Mid RE scenario represents an increase in electric sector gas demand over the entire duration of the winter peak day, with the largest difference during the afternoon hours leading into the evening peak after the tested 24-hour period.

Figure 117. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Summer Peak Day)



The Mid RE scenario represents an increase in electric sector gas demand over the entire duration of the winter peak day, with the largest difference during the morning hours.

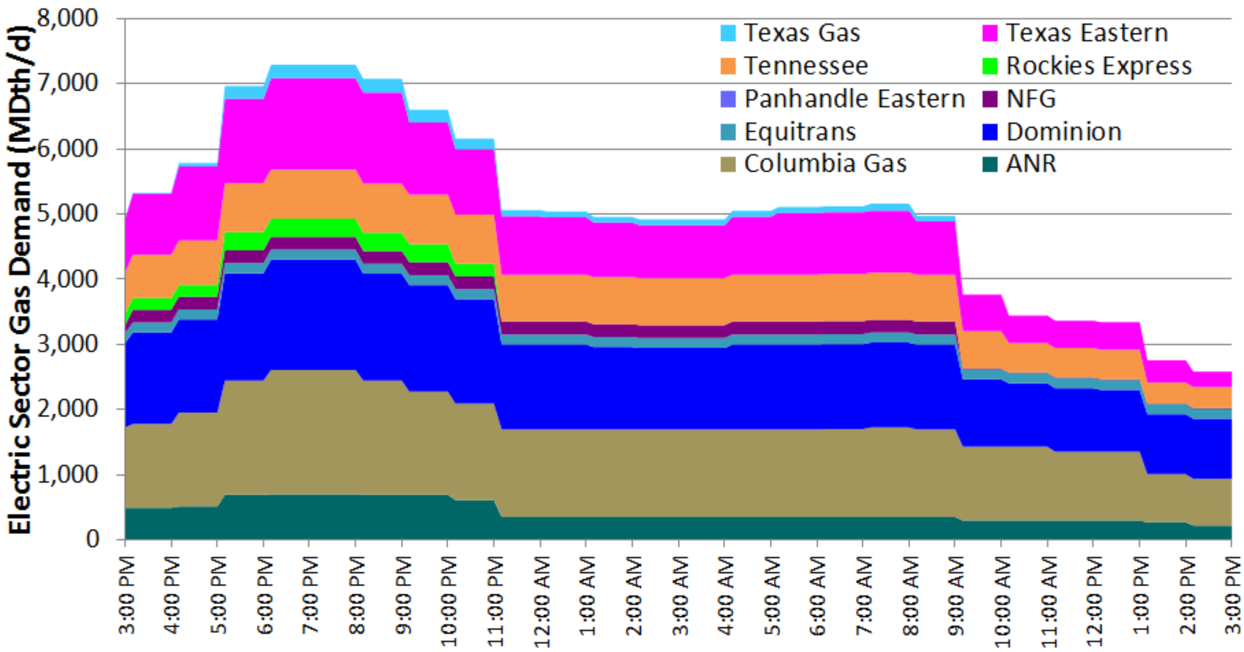
Figure 118. Marcellus-Utica Baseline Electric Sector Gas Demand (High RE SG v. Mid RE, Annual Minimum Day)



The Mid RE scenario represents an increase in electric sector gas demand over the entire duration of the winter peak day, with the largest difference during the evening peak hours.

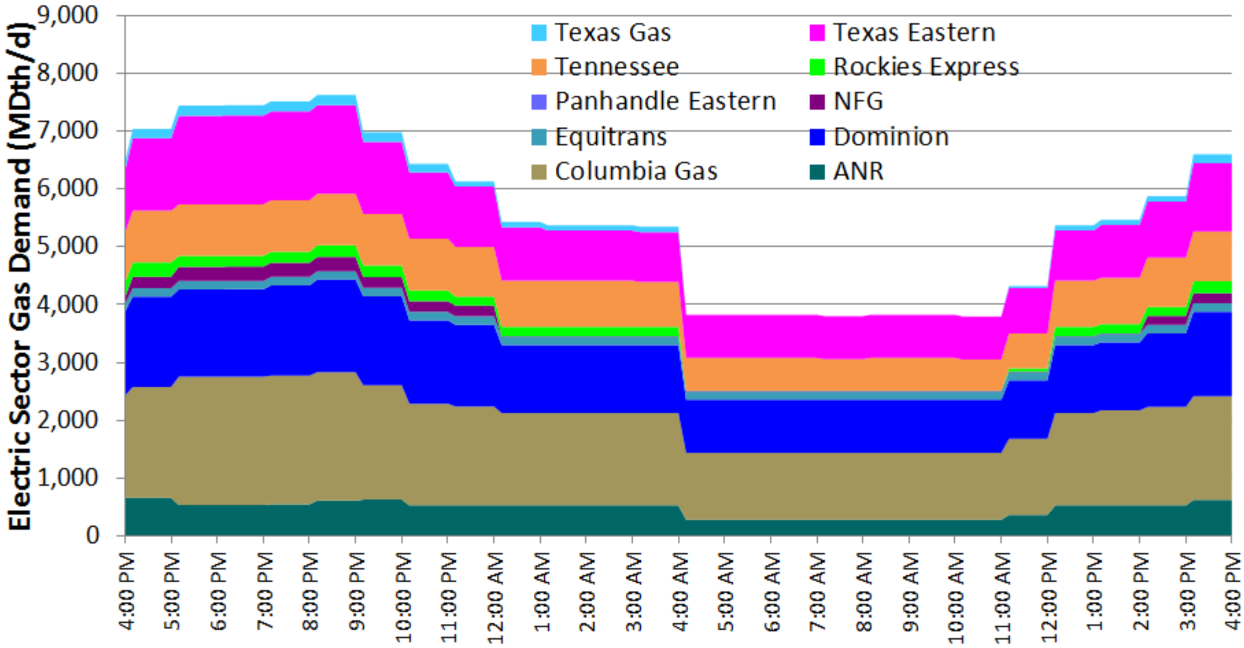
The following three figures show the amount of electric sector gas demand by pipeline over the course of the winter peak day (Figure 119), summer peak day (Figure 120) and annual minimum day (Figure 121). The total electric sector gas demand is highest on the summer peak day and lowest on the annual minimum day. The diffusion of demand across the array of pipelines is similar to that seen with the High RE SG gas demands, with Columbia Gas, Dominion and Texas Eastern serving the most generation.

Figure 119. Marcellus-Utica Baseline Electric Sector Gas Demand (Mid RE, Winter Peak Day)



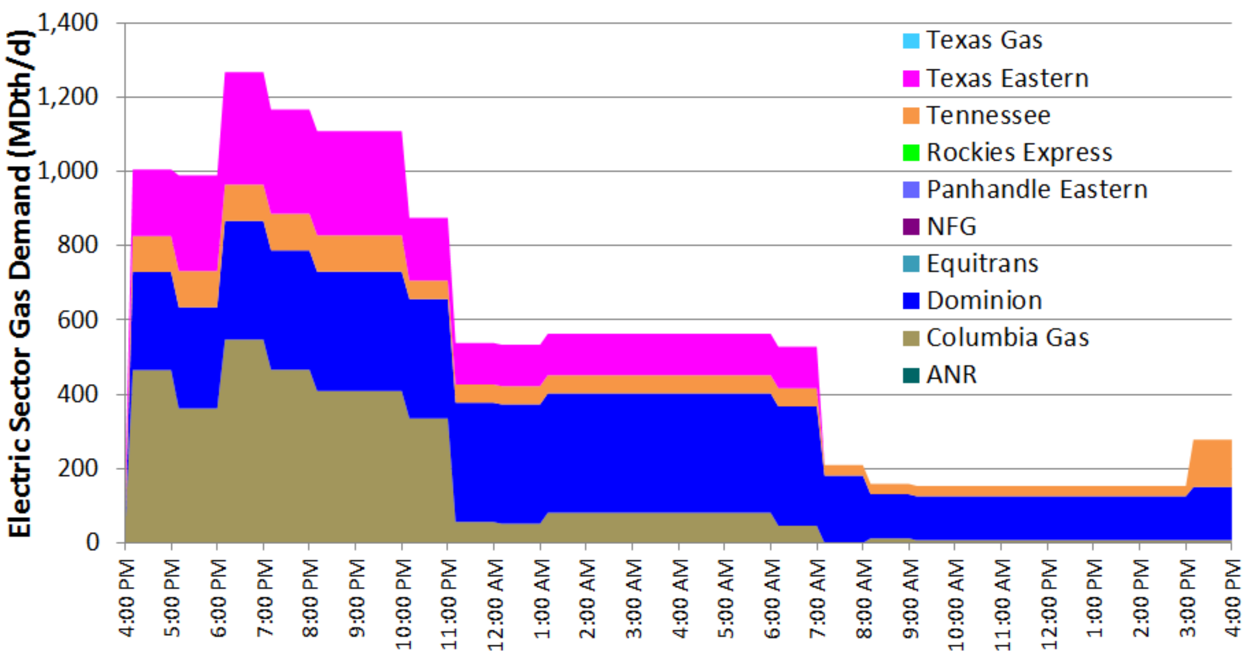
Electric sector demand is spread across nine pipelines, with Columbia Gas, Dominion and Texas Eastern representing the largest shares.

Figure 120. Marcellus-Utica Baseline Electric Sector Gas Demand (Mid RE, Summer Peak Day)



Electric sector demand is spread across nine pipelines, with Columbia Gas, Dominion and Texas Eastern representing the largest shares.

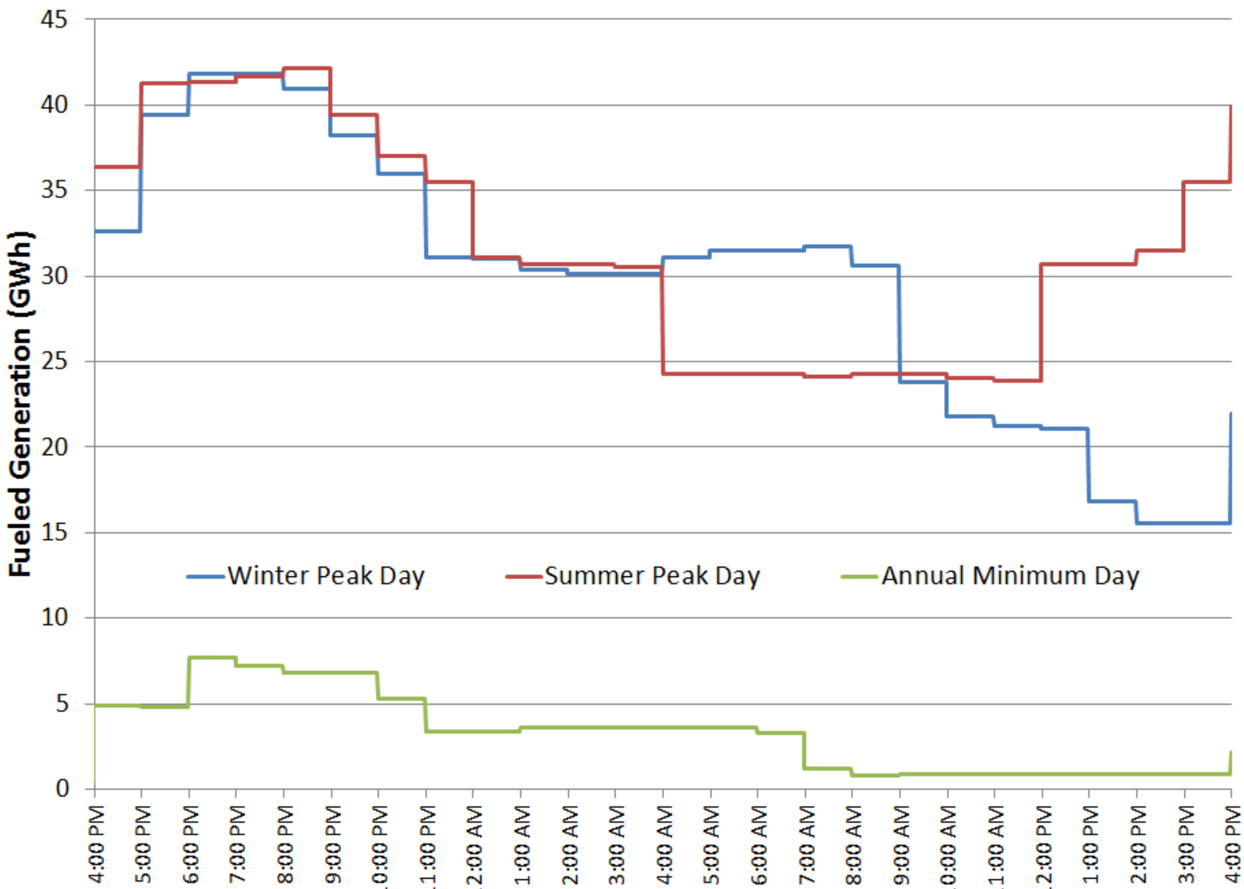
Figure 121. Marcellus-Utica Baseline Electric Sector Gas Demand (Mid RE, Annual Minimum Day)



Electric sector demand is spread across four pipelines during the evening peak, with Columbia Gas, Dominion and Texas Eastern representing the largest shares.

Figure 122 shows the relative amounts and intraday patterns of scheduled generation on the winter peak day, summer peak day and annual minimum day under baseline conditions. In all three cases (winter peak, summer peak and annual minimum), all electric sector gas demands are met, and all scheduled generation is therefore fueled. The evening peak generation on the winter and summer peak days is very similar, representing a high generator capacity factor. The annual minimum day peak generation level is approximately one-quarter of that on the seasonal peak days. The winter peak day intraday profile shows less of an overnight drop, while the summer peak day has a broader evening peak.

Figure 122. Marcellus-Utica Baseline Unconstrained Generation (Mid RE)



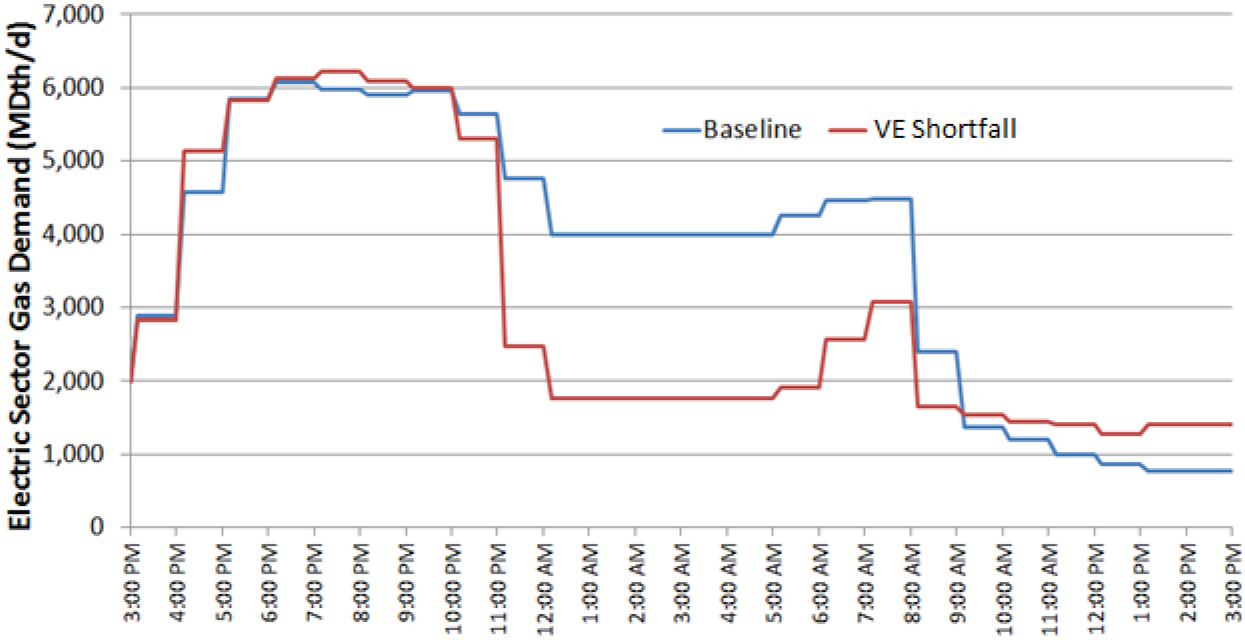
All baseline generation is fueled on each of the Mid RE days analyzed.

5.5.2 VE Shortfall Analysis

5.5.2.1 <u>High RE SG</u>

Figure 123 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the winter peak day. The gas-fired generators in the region are already operating at a high capacity factor in the baseline case. Therefore, there is limited incremental capacity available during the evening peak.

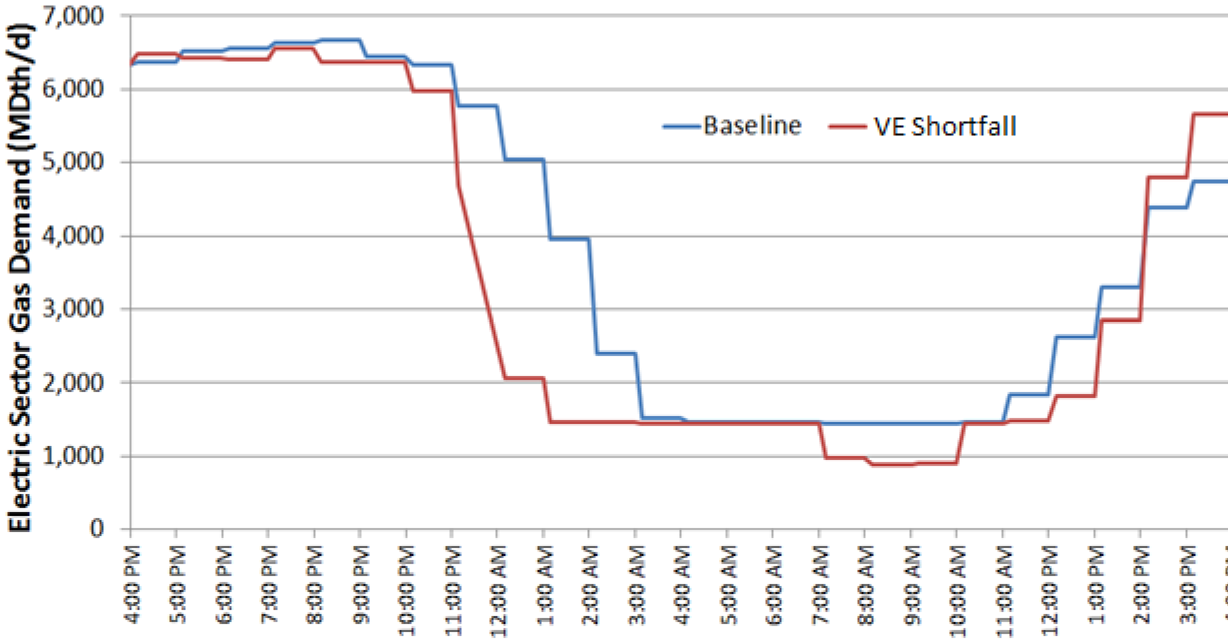
Figure 123. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Winter Peak Day)



Regional gas-fired generators are operating at a high capacity factor during the baseline evening peak. Therefore, the VE shortfall does not result in a significant incremental demand or ramp rate.

Figure 124 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the summer peak day. The profiles are again very similar, with limited gas-fired capacity available to ramp up during the evening peak following the start of the VE shortfall.

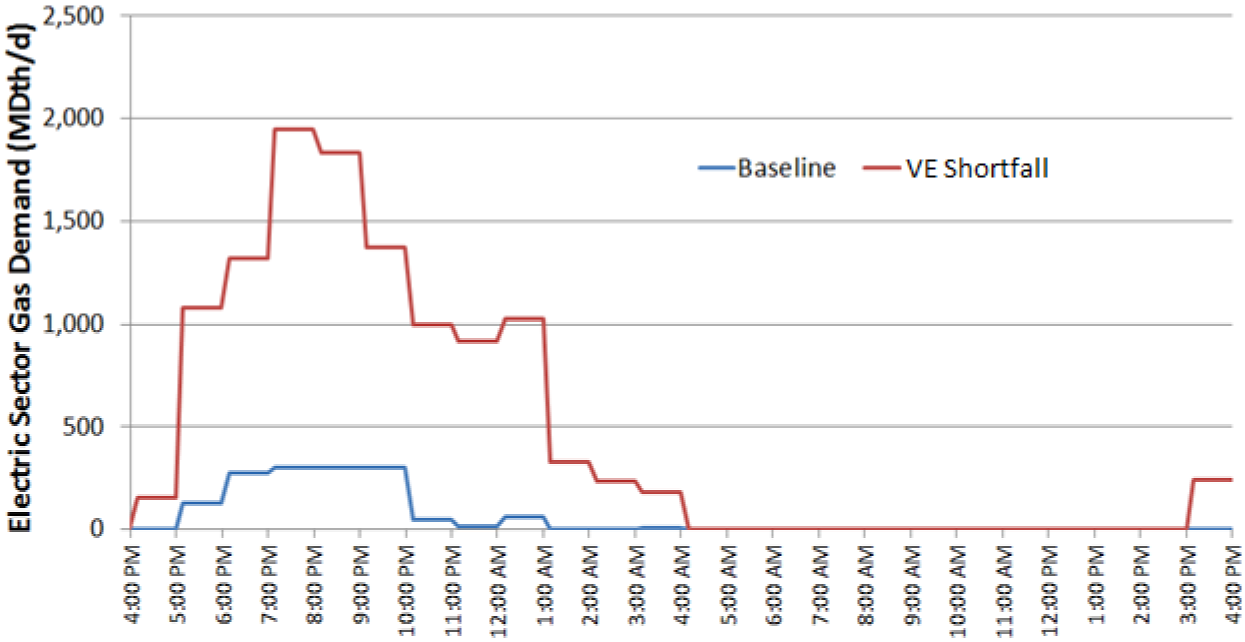
Figure 124. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Summer Peak Day)



Regional gas-fired generators are operating at a high capacity factor during the baseline evening peak. Therefore, a minimal increase occurs following the start of the VE shortfall. Baseline and VE shortfall case gas demands track very closely over the course of the day.

Figure 125 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the annual minimum day. The VE shortfall case gas demand during the evening peak is more than quadrupled relative to the baseline. While this is a significant change, the generators that ramp up following the start of the VE shortfall are located near storage and production resources, and the gas system is therefore able to accommodate the increased demand.

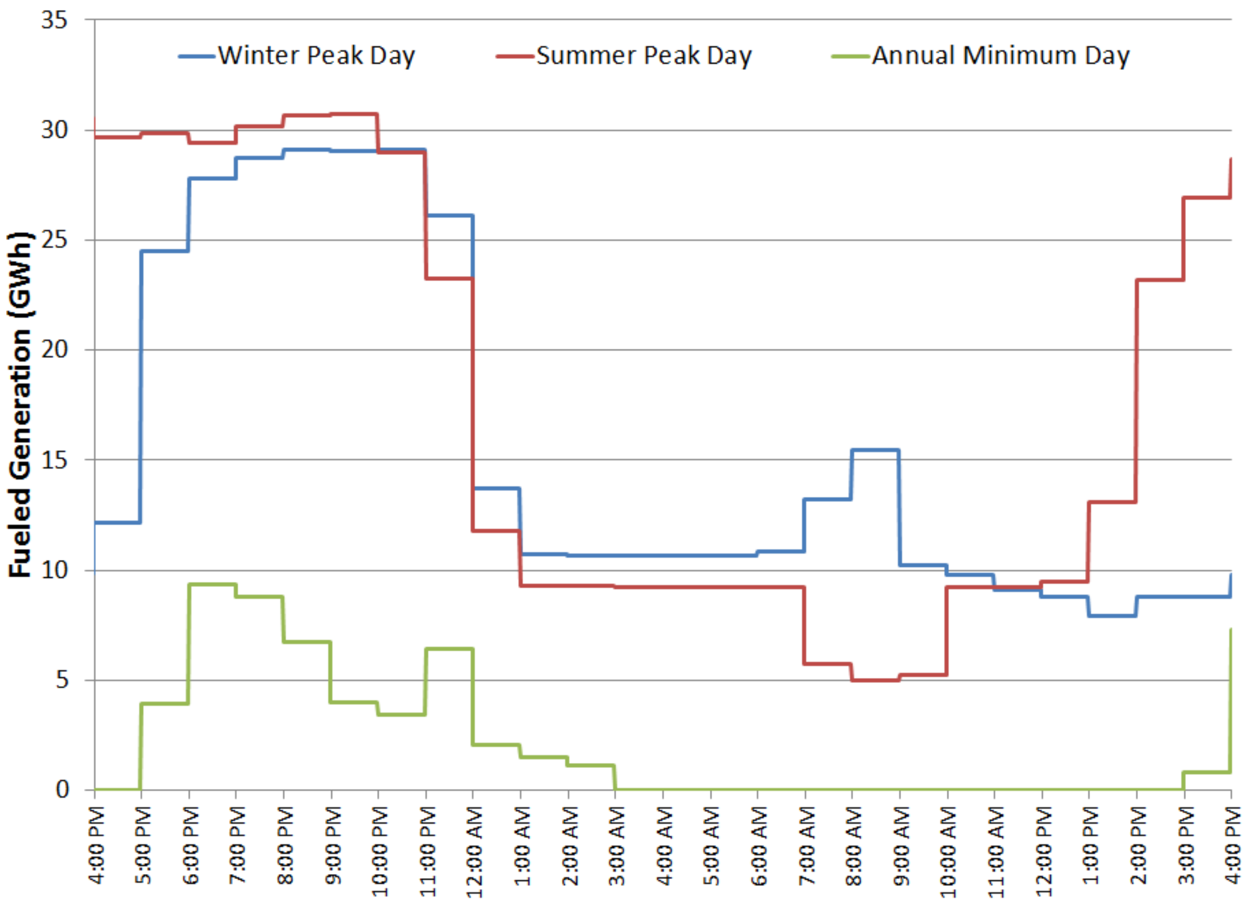
Figure 125. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Annual Minimum Day)



Regional gas-fired generators are operating at a very low capacity in the baseline and are therefore available to come online to offset the VE shortfall impacts. The evening peak after the start of the VE shortfall represents a five-fold increase over the corresponding baseline demand.

Figure 126 shows the relative amounts and intraday patterns of scheduled generation on the winter peak day, summer peak day and annual minimum day under baseline conditions. In all three cases (winter peak, summer peak and annual minimum), all electric sector gas demands are met after the start of the VE shortfall, and all scheduled generation is therefore fueled. The annual minimum day, which showed the largest increase in gas demand following the start of the VE shortfall, peaks at approximately one-third of the seasonal peak day generation levels.

Figure 126. Marcellus-Utica Post-VE Shortfall Unconstrained Generation (High RE SG)

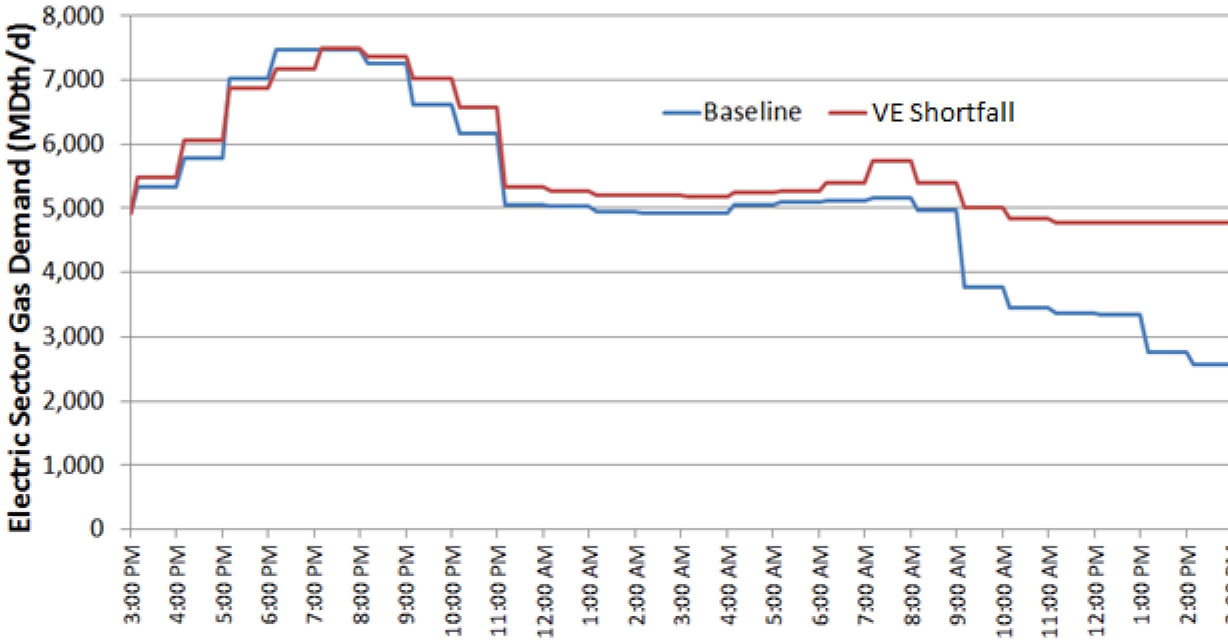


All VE shortfall case generation is fueled on each of the High RE SG days analyzed. While the annual minimum day VE shortfall case demand profile is much higher than the corresponding baseline profile in Figure 115, it is still much lower than the systems overall capacity and therefore can be accommodated by the gas system.

5.5.2.2 Mid RE

Figure 127 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the winter peak day. The VE shortfall case gas demand closely tracks the baseline gas demand until 9:00 a.m. on the day after it starts.

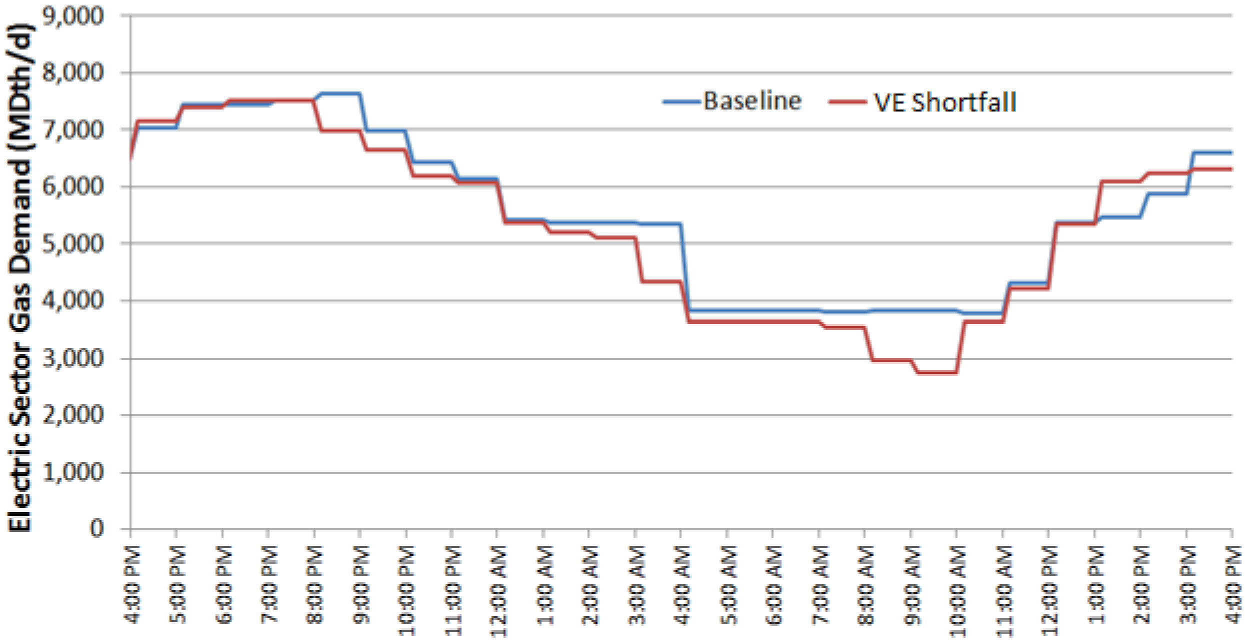
Figure 127. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Winter Peak Day)



Regional gas-fired generators are operating at a high capacity factor during the baseline evening peak. Therefore, the VE shortfall does not result in a significant incremental demand or ramp rate.

Figure 128 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the summer peak day. The VE shortfall case demand tracks the baseline gas demand throughout the 24-hour period following its start.

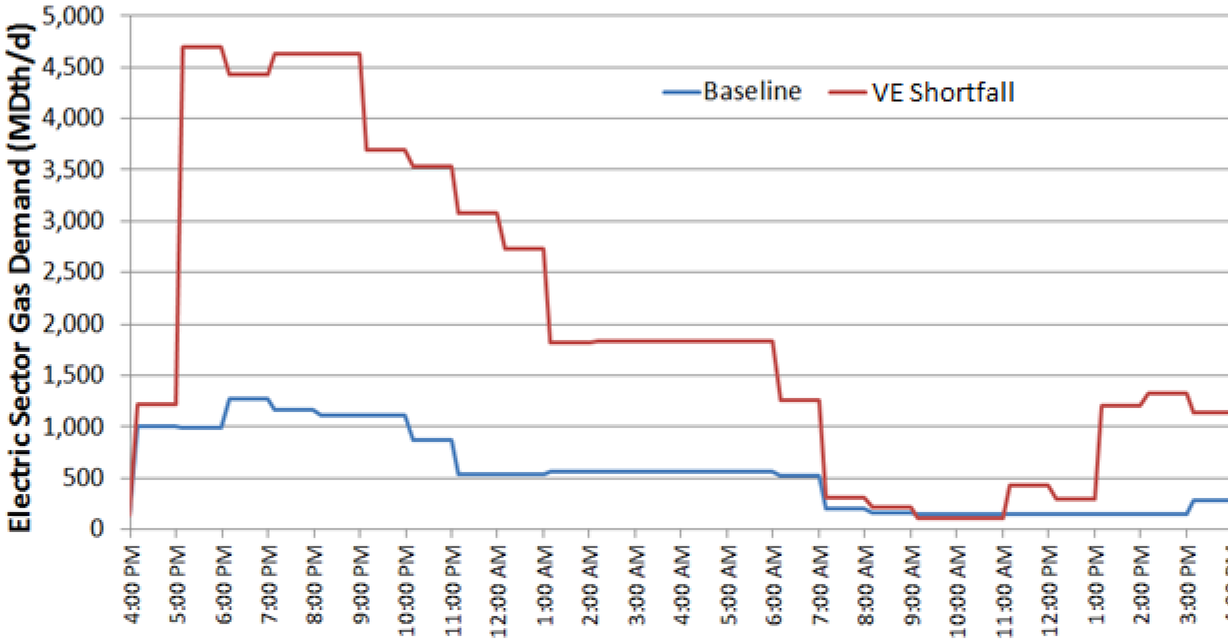
Figure 128. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Summer Peak Day)



Regional gas-fired generators are operating at a high capacity factor during the baseline evening peak. Therefore, the VE shortfall case does not result in a significant incremental demand or ramp rate.

Figure 129 shows the electric sector gas demand for the 24-hour period following the start of the VE shortfall relative to the baseline demand on the annual minimum day. With gas-fired generators operating at a lower capacity factor at the start of the VE shortfall, they are available to quickly ramp up to offset the reduction in variable energy. This increase in generation over the baseline continues until the next morning.

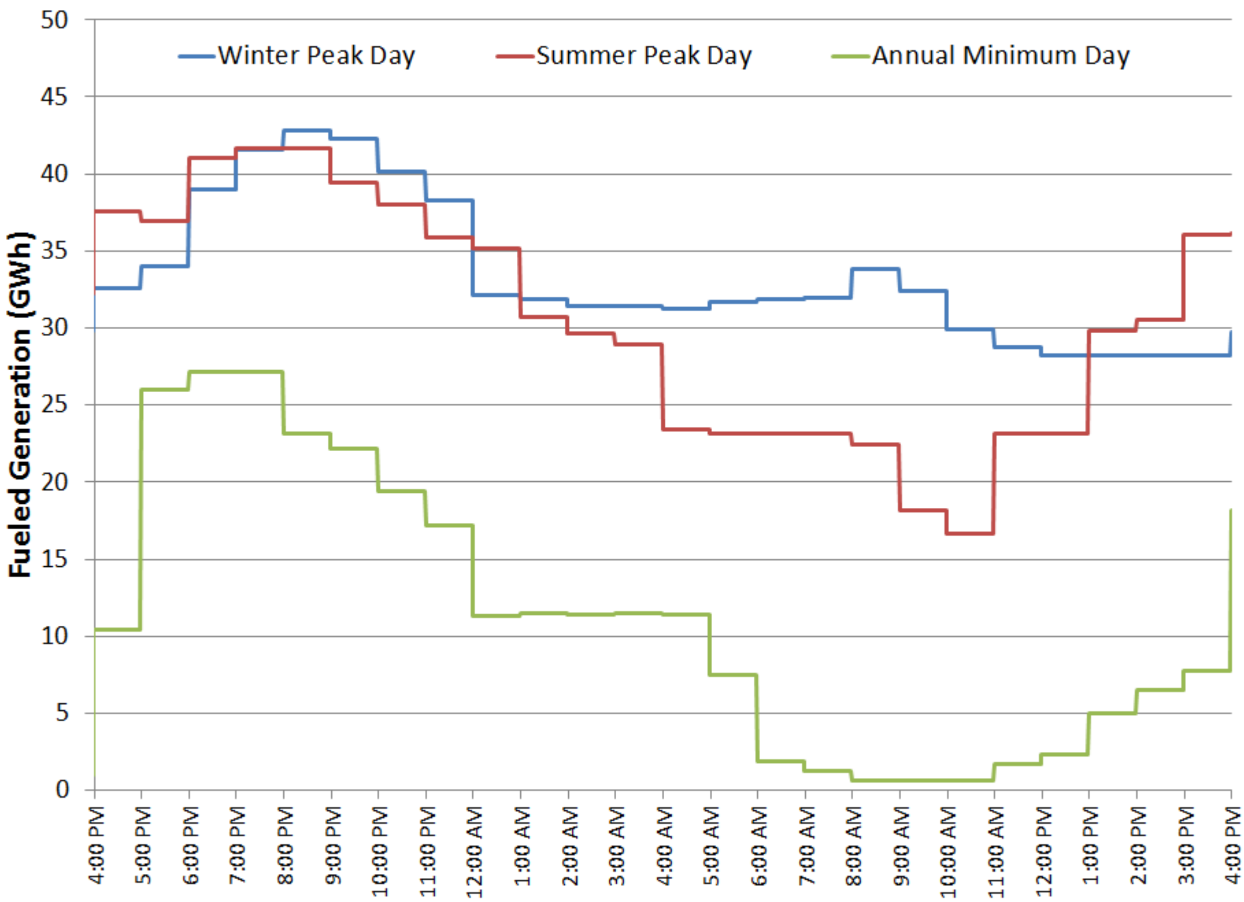
Figure 129. Marcellus-Utica Post-VE Shortfall Electric Sector Gas Demand (High RE SG, Annual Minimum Day)



The VE shortfall represents a significant increase over the baseline, with a fast ramp rate following the start of the VE shortfall leading into the evening peak.

Figure 130 shows the relative amounts and intraday patterns of scheduled generation on the winter peak day, summer peak day and annual minimum day under baseline conditions. In all three cases (winter peak, summer peak and annual minimum), all electric sector gas demands are met after the start of the VE shortfall, and all scheduled generation is therefore fueled.

Figure 130. Marcellus-Utica Post-VE Shortfall Unconstrained Generation (Mid RE)



All VE shortfall case generation is fueled on each of the Mid RE days analyzed. While the annual minimum day exhibits a fast increase in demand, the proximity of the generators with increased demand to production and storage resources and the diffusion of the demand increase across a number of pipelines enables the gas system to meet the demand without a disruptive reliance on line pack.

6 SYSTEM MITIGATION MEASURES

6.1 HIGHLIGHTS

- Scope: Three potential technical solutions to resolve potentially-constrained generation issues have been quantified as part of this analysis: incremental pipeline capacity, incremental dual-fuel capability, and incremental electric demand response.

- Caveat: Quantification of the three mitigation measures was simply a transformation of the potentially-constrained generation on the seasonal peak day into equivalent gas pipeline, dual fuel, or electric DR quantities.

- Caveat: Quantification of incremental pipeline capacity in this analysis does not encompass the distances spanned by the needed projects, limiting its usefulness.

- Caveat: None of the three potential technical solutions have been evaluated in this report on the basis of their economics or environmental impacts.

- Result: Incremental pipeline investments may be needed in a region upstream of the potentially affected region.

- Result: Adding incremental dual-fuel capability to gas generators to relieve potentially-constrained generation constraints across the EI would require increases in dual fuel capacity ranging from about 5% to nearly 60% relative to the 2014 actual dual fuel capacity. These calculated increases do not account for air permit and the transportation logistics associated with fuel oil replenishment during the peak heating season.

- Result: Incremental electric DR would require large increases across the cases from its current level in the EI.

6.2 INCREMENTAL PIPELINE IMPROVEMENTS

In order to ensure that generators receive the scheduled gas demand, incremental pipeline capacity can be added in cases with potentially-constrained generation. Pipeline capacity is added primarily through replacement pipe with a larger diameter, parallel pipes looping existing lines, or additional horsepower at either new or existing compressor stations. Incremental capacity can also be added through an increase in the operating pressure of an existing line, but this is not always possible depending on the location and operational characteristics of a pipe segment. LAI has quantified the amount of additional capacity that would be needed in each case with potentially-constrained generation based on the analysis results. LAI has not defined the nature of the specific improvements that would be needed, however. These capacity volumes are *in addition to* the generic additions that have been added to the hydraulic models to meet gas utility sector load in 2050.

Table 15 shows the amount of pipeline capacity that would be needed to avoid potentially-constrained generation across the EI on the seasonal peak days based on the results in section 4. A breakdown by region is also included, but it is important to note that the capacity additions to mitigate a region's potentially-constrained generation would not necessarily be located in the same region.[52] For example, New England and East South Central are affected by constraints in Middle Atlantic and South Atlantic, respectively. The 2015 benchmark values are also included for context, with the difference between a region's 2015 benchmark and a particular scenario or sensitivity representing the incremental pipeline capacity expansion.

To provide additional context, EIA's Natural Gas Pipeline Projects database indicates that 5,800 miles of pipeline was placed into service in the approximate area of the EI representing 45,436 MDth/d of incremental pipeline at a cost of $23.3 billion was placed into service from 2006 to 2010. From 2011 to 2015 an additional 1,700 miles of pipe was placed into service creating 24,970 MDth/d of pipeline capacity at a capital cost of $14.2 billion. This increase in pipeline capability does not represent the corresponding amount of incremental pipeline demand since in some cases multiple pipelines may be involved in a new or expanded gas transportation path. Focusing on the regions with persistent high-volume constraints identified in this analysis, specifically Florida, New England and the southern portion of South Atlantic, shows that 19% of the 2006 to 2010 pipeline expansion capacity (representing 12% of the miles and 11% of the cost) and 5% of the 2011 to 2015 pipeline expansion capacity (representing 34% of the miles and 20% of the cost) across the EI occurred in the constrained regions.

[52] Quantification of the length of pipeline additions into and within a potentially constrained (sub)region across the EI is not part of this assessment.

Table 15. Incremental Pipeline Capacity Solutions

Case	Seasonal Peak Day	Incremental Pipeline Capacity (MDth/d) EI Total	East North Central	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	West South Central
High RE	Winter	920	0	0	0	0	0	920	0	0
Scenario	Summer	1,397	0	37	344	0	0	1,016	0	0
High RE SG	Winter	876	0	0	0	0	0	876	0	0
Sensitivity	Summer	1,271	0	21	316	0	0	934	0	0
High RE LNG	Winter	267	0	0	0	0	0	267	0	0
Sensitivity	Summer	1,347	0	37	344	0	0	966	0	0
Mid RE	Winter	4,388	0	430	61	356	949	2,592	0	0
Scenario	Summer	3,895	0	553	144	0	0	3,198	0	0
Mid RE SG	Winter	4,295	0	107	0	387	1,098	2,702	0	0
Sensitivity	Summer	3,948	0	553	284	0	0	3,111	0	0
Mid RE LNG	Winter	2,830	0	430	61	356	44	1,939	0	0
Sensitivity	Summer	3,845	0	553	144	0	0	3,148	0	0
Low RE	Winter	9,317	0	515	248	645	1,168	6,741	0	0
Scenario	Summer	7,575	0	762	1,237	0	0	5,575	0	0
Low RE LNG	Winter	7,759	0	515	248	645	263	6,088	0	0
Sensitivity	Summer	7,525	0	762	1,237	0	0	5,525	0	0
2015	Winter	7,690	0	0	333	3,269	747	3,341	0	0
Benchmark	Summer	765	0	0	677	0	0	62	26	0
2015 +LNG	Winter	4,928	0	0	333	3,112	0	1,483	0	0
Benchmark	Summer	765	0	0	677	0	0	62	26	0

This table shows the incremental pipeline capacity that may be needed to alleviate the potentially-constrained generation in each region and in the EI as a whole on the seasonal peak days. The 2015 benchmark is provided for context. For each region the difference between the 2015 benchmark value and the 2050 value represents the incremental mitigation required if mitigation is achieved solely through pipeline capacity expansion.

Table 16 shows the amount of pipeline capacity that would need to be added in New England for each case in order to avoid potentially-constrained generation in the hydraulic analysis.[53] Of the baseline and VE shortfall cases evaluated hydraulically, all except the Mid RE and Mid RE LNG on the winter peak day have no potentially-constrained generation in the GPCM analysis. For those cases that are unconstrained in GPCM, the constraints found in the hydraulic models involve locationally-limited constraints that occur when a power plant's

[53] No hydraulic results are shown for Marcellus-Utica because there is no potentially-constrained generation across the array of tested cases and therefore no required mitigation.

gas demand in 2050 is more than can be delivered by the lateral from the pipeline mainline to the generation plant meter consistent with the minimum pressure requirements. In the Mid RE and Mid RE LNG on the winter peak day, the incremental pipeline capacity need listed in the following table is the result of upstream constraints. Hence, if boundary flows are allowed to flow into New England at full capacity, there would be no potentially-constrained generation.

Table 16. Incremental Pipeline Capacity Solutions (New England)

Case	Condition	Day Type	Incremental Pipeline Capacity (MDth/d)
High RE SG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	7
		Summer Peak	40
		Annual Minimum	0
High RE SG LNG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	7
		Summer Peak	40
		Annual Minimum	0
Mid RE	Baseline	Winter Peak	1,234
		Summer Peak	85
		Annual Minimum	0
	VE Shortfall	Winter Peak	1,364
		Summer Peak	85
		Annual Minimum	0
Mid RE LNG	Baseline	Winter Peak	337
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	461
		Summer Peak	0
		Annual Minimum	0

This table lists the incremental pipeline capacity needed to eliminate potentially-constrained generation associated with each run in the hydraulic analysis. The Mid RE and Mid RE LNG winter peak days require new pipeline capacity upstream of New England to increase boundary flows into the region. All other cases require new pipeline capacity on laterals serving power plants.

6.3 Incremental Dual-Fuel Capability

An alternative to increasing natural gas infrastructure to enable plants with potentially-constrained generation to receive their full quantity of gas demand is to add dual-fuel capability to the affected plants. The addition of dual-fuel capability means that potentially-constrained generation can switch to an alternate fuel when gas deliverability is impaired. While a given plant's scheduled output may not be fully potentially-constrained in a particular model run, dual-fuel capability would need to be added to a plant as a whole.[54] To calculate the incremental dual-fuel capacity needed, the potentially-constrained generation values have been divided by 24 to arrive at an average approximation of the need. To provide context for the results, in the first quarter of 2014, there were 101.7 GW of dual-fuel capable generation in the portion of the EI including the service areas of ISO-NE, MISO, NYISO, PJM and TVA.[55]

[54] In the GPCM results, plants are grouped together into customers with daily demand totals and the deliverability limitations are therefore neither plant-specific nor hour-specific.

[55] *Phase 2 Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study*. Eastern Interconnection Planning Collaborative, July 2, 2015. Section 8.

Table 17. Incremental Dual-Fuel Capability Solutions

Case	Seasonal Peak Day	Incremental Dual-Fuel Capability (GW)								
		EI Total	East North Central	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	West South Central
High RE Scenario	Winter	5.6	0	0	0	0	0	5.6	0	0
	Summer	8.4	0	0.2	2.1	0	0	5.8	0	0
High RE SG Sensitivity	Winter	5.4	0	0	0	0	0	5.4	0	0
	Summer	7.4	0	0.1	2.0	0	0	5.3	0	0
High RE LNG Sensitivity	Winter	1.6	0	0	0	0	0	1.6	0	0
	Summer	8.1	0	0.2	2.1	0	0	5.5	0	0
Mid RE Scenario	Winter	27.4	0	2.7	0.4	2.2	6.0	16.1	0	0
	Summer	22.5	0	3.5	0.9	0	0	18.1	0	0
Mid RE SG Sensitivity	Winter	26.8	0	0.7	0	2.4	6.9	16.8	0	0
	Summer	23.0	0	3.5	1.8	0	0	17.7	0	0
Mid RE LNG Sensitivity	Winter	17.6	0	2.7	0.4	2.2	0.3	12.0	0	0
	Summer	22.3	0	3.5	0.9	0	0	17.9	0	0
Low RE Scenario	Winter	58.9	0	3.3	1.6	4.1	7.4	42.7	0	0
	Summer	46.3	0	4.8	7.8	0	0	33.7	0	0
Low RE LNG Sensitivity	Winter	49.3	0	3.3	1.6	4.1	1.7	38.6	0	0
	Summer	46.0	0	4.8	7.8	0	0	33.4	0	0
2015 Benchmark	Winter	41.8	0	0	2.0	18.1	4.4	17.4	0	0
	Summer	4.2	0	0	3.7	0	0	0.3	0.2	0
2015 +LNG Benchmark	Winter	26.8	0	0	2.0	17.2	0	7.7	0	0
	Summer	4.2	0	0	3.7	0	0	0.3	0.2	0

This table shows the generator dual-fuel capability that would be needed to alleviate the potentially-constrained generation in each region and in the EI as a whole on the seasonal peak days, based on the GPCM modeling analysis. The 2015 benchmark is provided for context. For each region the difference between the 2015 benchmark value and the 2050 value represents the incremental required mitigation required if mitigation is achieved solely through dual-fuel capability.

Table 18 shows the amount of capacity that would need to be dual-fuel capable in New England for each case in order to avoid potentially-constrained generation, based on the hydraulic modeling analysis. These results represent the total capacity of all generators with any potentially-constrained generation. For context, in the first quarter of 2014, there were 6,766 MW of dual-fuel generation in New England.

Table 18. Incremental Dual-Fuel Capability Solutions (New England)

Case	Condition	Day	Incremental Dual-Fuel Capability (MW)
High RE SG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	596
		Summer Peak	426
		Annual Minimum	0
High RE SG LNG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	596
		Summer Peak	426
		Annual Minimum	0
Mid RE	Baseline	Winter Peak	11,048
		Summer Peak	1,012
		Annual Minimum	0
	VE Shortfall	Winter Peak	12,731
		Summer Peak	1,012
		Annual Minimum	0
Mid RE LNG	Baseline	Winter Peak	5,325
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	7,007
		Summer Peak	0
		Annual Minimum	0

This table lists the incremental dual-fuel capability needed to eliminate potentially-constrained generation associated with each run in the hydraulic analysis. The capability values are not increased for forced outages.

6.4 Incremental Electric Demand Response

A third solution to resolve potentially-constrained generation is to add incremental electric demand response resources that would reduce electric load by the amount of scheduled generation that is potentially-constrained.

Table 19. Incremental Electric Demand Response Solutions

Case	Seasonal Peak Day	Incremental Electric DR (GWh/d)								
		EI Total	East North Central	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	West South Central
High RE Scenario	Winter	133	0	0	0	0	0	133	0	0
	Summer	195	0	6	51	0	0	138	0	0
High RE SG Sensitivity	Winter	129	0	0	0	0	0	129	0	0
	Summer	178	0	3	47	0	0	128	0	0
High RE LNG Sensitivity	Winter	39	0	0	0	0	0	39	0	0
	Summer	188	0	6	51	0	0	132	0	0
Mid RE Scenario	Winter	658	0	65	9	54	144	386	0	0
	Summer	541	0	84	21	0	0	435	0	0
Mid RE SG Sensitivity	Winter	643	0	16	0	59	165	403	0	0
	Summer	552	0	84	42	0	0	426	0	0
Mid RE LNG Sensitivity	Winter	424	0	65	9	54	7	288	0	0
	Summer	534	0	84	21	0	0	428	0	0
Low RE Scenario	Winter	1,414	0	78	37	97	176	1,025	0	0
	Summer	1,111	0	116	186	0	0	809	0	0
Low RE LNG Sensitivity	Winter	1,178	0	78	37	97	40	926	0	0
	Summer	1,104	0	116	186	0	0	802	0	0
2015 Benchmark	Winter	1,003	0	0	47	434	106	417	0	0
	Summer	101	0	0	90	0	0	7	4	0
2015 +LNG Benchmark	Winter	642	0	0	47	412	0	184	0	0
	Summer	101	0	0	90	0	0	7	4	0

This table shows the electric DR that would be needed to alleviate the potentially-constrained generation in each region and in the EI as a whole on the seasonal peak days. The 2015 benchmark is provided for context. For each region the difference between the 2015 benchmark value and the 2050 value represents the incremental required mitigation required if mitigation is achieved solely through electric DR.

Table 20 shows the amount of incremental electric DR that would need to be added in New England for each hydraulically-evaluated case in order to avoid potentially-constrained generation. These results represent the total potentially-constrained generation across the duration of the constraint in each case.[56]

[56] This calculation of DR is illustrative, as this targeted application in response to a VE shortfall is unproven.

Table 20. Incremental Electric Demand Response Solutions (New England)

Case	Condition	Day	Incremental Electric DR (MWh/d)
High RE SG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	2,283
		Summer Peak	366
		Annual Minimum	0
High RE SG LNG	Baseline	Winter Peak	0
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	2,283
		Summer Peak	366
		Annual Minimum	0
Mid RE	Baseline	Winter Peak	185,265
		Summer Peak	12,981
		Annual Minimum	0
	VE Shortfall	Winter Peak	204,805
		Summer Peak	12,981
		Annual Minimum	0
Mid RE LNG	Baseline	Winter Peak	51,083
		Summer Peak	0
		Annual Minimum	0
	VE Shortfall	Winter Peak	69,810
		Summer Peak	0
		Annual Minimum	0

This table lists the incremental electric DR needed to eliminate potentially-constrained generation associated with each run in the hydraulic analysis.

Table 21 summarizes the comparison of potential mitigation measures across the scenarios and sensitivities tested, by region and seasonal peak day.

Table 21. Comparison of the Scale of Potential Mitigation Measures by Scenario and Sensitivity

Case	Seasonal Peak Day	Incremental Pipeline Capacity (MDth/d)							Incremental Dual-Fuel Capability (GW)							Incremental Electric DR (GWh/d)							No Capacity Needed	
		EI Total	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	EI Total	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	EI Total	East South Central	Florida	Middle Atlantic	New England	South Atlantic	West North Central	East North Central	West South Central
High RE Scenario	Winter	920	0	0	0	0	920	0	5.6	0	0	0	0	5.6	0	133	0	0	0	0	133	0	0	0
	Summer	1,397	37	344	0	0	1,016	0	8.1	0.2	2	0	0	5.8	0	195	6	51	0	0	138	0	0	0
High RE SG Sensitivity	Winter	876	0	0	0	0	876	0	5.4	0	0	0	0	5.4	0	129	0	0	0	0	129	0	0	0
	Summer	1,271	21	316	0	0	934	0	7.4	0.1	2	0	0	5.3	0	178	3	47	0	0	128	0	0	0
LNG Sensitivity	Winter	267	0	0	0	0	267	0	1.6	0	0	0	0	1.6	0	39	0	0	0	0	39	0	0	0
	Summer	1,347	37	344	0	0	966	0	7.8	0.2	2	0	0	5.5	0	188	6	51	0	0	132	0	0	0
Mid RE Scenario	Winter	4,388	430	61	356	949	2,592	0	27.4	2.7	0	2.2	6	16.1	0	658	65	9	54	144	386	0	0	0
	Summer	3,895	553	144	0	0	3,198	0	22.5	3.5	1	0	0	18.1	0	541	84	21	0	0	435	0	0	0
Mid RE SG Sensitivity	Winter	4,295	107	0	387	1,098	2,702	0	26.8	0.7	0	2.4	6.9	16.8	0	643	16	0	59	165	403	0	0	0
	Summer	3,948	553	284	0	0	3,111	0	23.0	3.5	2	0	0	17.7	0	552	84	42	0	0	426	0	0	0
Mid RE LNG Sensitivity	Winter	2,830	430	61	356	44	1,939	0	17.6	2.7	0	2.2	0.3	12	0	424	65	9	54	7	288	0	0	0
	Summer	3,845	553	144	0	0	3,148	0	22.3	3.5	1	0	0	17.9	0	534	84	21	0	0	428	0	0	0
Low RE Scenario	Winter	9,317	515	248	645	1,168	6,741	0	59.1	3.3	2	4.1	7.4	42.7	0	1,414	78	37	97	176	1,025	0	0	0
	Summer	7,575	762	1,237	0	0	5,575	0	46.3	4.8	8	0	0	33.7	0	1,111	116	186	0	0	809	0	0	0
LNG Sensitivity	Winter	7,759	515	248	645	263	6,088	0	49.3	3.3	2	4.1	1.7	38.6	0	1,178	78	37	97	40	926	0	0	0
	Summer	7,525	762	1,237	0	0	5,525	0	46.0	4.8	8	0	0	33.4	0	1,104	116	186	0	0	802	0	0	0
2015 Benchmark	Winter	7,690	0	333	3,269	747	3,341	0	41.9	0	2	18.1	4.4	17.4	0	1,003	0	47	434	106	417	0	0	0
	Summer	765	0	677	0	0	62	26	4.2	0	4	0	0	0.3	0.2	101	0	90	0	0	7	4	0	0
2015 + LNG Benchmark	Winter	4,928	0	333	3,112	0	1,483	0	26.9	0	2	17.2	0	7.7	0	642	0	47	412	0	184	0	0	0
	Summer	765	0	677	0	0	62	26	4.2	0	4	0	0	0.3	0.2	101	0	90	0	0	7	4	0	0

This table shows the incremental pipeline capacity, dual fuel, **or** electric demand response that may be needed to alleviate the potentially-constrained generation in each region and in the EI as a whole on the seasonal peak days. The 2015 benchmarks are provided for context, and the shading is relative to the respective benchmark (winter or summer, with or without LNG) for each column. For each region the difference between the 2015 benchmark value and the 2050 value represents the incremental mitigation required if **all mitigation is achieved solely through pipeline capacity expansion, incremental dual fuel, or electric DR**. Each of the mitigation measures is proposed here as a singular and mutually-exclusive option to mitigate all potential constraints with just ONE of the three mitigation methods. In reality a mix of these measures, and others, would be implement. This modeling shows that the South Atlantic during the Low RE scenario would require the most mitigation.

Table 22 summarizes the comparison of alternative solutions for meeting incremental electric demand in New England for the Mid RE scenario and three sensitivities, by gas demand condition and seasonal day type.

Table 22. Incremental Potential Mitigation Measures (New England)

Case	Condition	Day Type	Incremental Pipeline Capacity (MDth/d)	Incremental Dual-Fuel Capability (MW)	Incremental Electric DR (MWh/d)
High RE SG	Baseline	Winter Peak	0	0	0
		Summer Peak	0	0	0
		Annual Minimum	0	0	0
	VE Shortfall	Winter Peak	7	596	2,283
		Summer Peak	40	426	366
		Annual Minimum	0	0	0
High RE SG LNG	Baseline	Winter Peak	0	0	0
		Summer Peak	0	0	0
		Annual Minimum	0	0	0
	VE Shortfall	Winter Peak	7	596	2,283
		Summer Peak	40	426	366
		Annual Minimum	0	0	0
Mid RE	Baseline	Winter Peak	1,234	11,048	185,265
		Summer Peak	85	1,012	12,981
		Annual Minimum	0	0	0
	VE Shortfall	Winter Peak	1,364	12,731	204,805
		Summer Peak	85	1,012	12,981
		Annual Minimum	0	0	0
Mid RE LNG	Baseline	Winter Peak	337	5,325	51,083
		Summer Peak	0	0	0
		Annual Minimum	0	0	0
	VE Shortfall	Winter Peak	461	7,007	69,810
		Summer Peak	0	0	0
		Annual Minimum	0	0	0

This table lists the incremental pipeline capacity, dual fuel, and electric demand response needed to eliminate potentially-constrained generation associated with each run in the hydraulic analysis in New England. The Mid RE and Mid RE LNG winter peak days require new pipeline capacity upstream of New England to increase boundary flows into the region. All other cases require new pipeline capacity on laterals serving power plants. Dual fuel capability values are not increased for forced outages. This analysis shows that LNG, even at average import levels into New England, can significantly mitigate the need for pipeline expansion, dual fuel, and demand response.

APPENDIX A: DETAILS OF ELECTRIC SYSTEM MODELING

The electric simulation modeling was limited to operational commitment and economic dispatch modeling of the transmission and generation resources pre-defined for each scenario. Hence, the capital costs and annual fixed operations and maintenance costs for transmission and generation resources were not part of this study. The interested reader may refer to the referenced NREL studies for the capital costs and annual fixed costs used by the ReEDS model to produce the least-cost resource plans for each scenario.

Electric Transmission Resources

The transmission expansion assumptions used in AURORAxmp are in the form of transfer capability (MW) from one zone to another, which cannot be summed like the ReEDS MW-mile measure because each zone-to-zone link includes multiple lines with different characteristics. Their summations over multiple links shown in Table 1 are not necessarily proportional to the magnitude of their capital investment, which is also a function of their individual line distances, locations, voltages, and other factors.

While ReEDS represents high voltage direct current (HVDC) transmission lines in the West, ReEDS modeled only the alternating current (AC) transmission links within the Eastern Interconnection and misrepresented transmission from Quebec as an AC connection to VT instead of an HVDC connection to Massachusetts. Because the Northeast is more gas-constrained than most other regions in the EI, it is important to have a good representation of transmission capabilities. LAI therefore included the existing HVDC links from Quebec to Massachusetts and to New York while keeping total imports from Quebec to the Northeast at the same level as in the NREL scenarios. LAI also included the marine HVDC cables connecting Connecticut to Long Island (Cross Sound Cable), New Jersey to Long Island (Neptune Transmission Project), and New Jersey to New York City (Hudson Transmission Project). NREL did not assume any increase in transmission infrastructure from Canada to the U.S., but there are currently several proposed HVDC projects in various stages of development that would increase hydropower imports from eastern Canada (Ontario and Quebec), as well as the Maritime Link HVDC project from Newfoundland to Nova Scotia that will increase hydropower imports through New Brunswick to northern New England.

Demand for new transmission capacity is much greater in the High RE scenario, including a massive expansion of interconnections with ERCOT and WECC. The Canadian transfer capability is smaller in the scenarios in 2050 than in the 2015 baseline because the NREL model did not include HVDC transmission links with Quebec. The transmission capabilities in the 2046 results of NREL's 80% National RPS scenario were used to represent 2050 in the High RE scenario due to its lower load growth rates.

Generation Resource Operational Parameters and Cost and Performance Parameters

The previous NREL *Renewable Electricity Futures* (2012) study considered three technology improvement cases over the 40 year period: no technology improvement, incremental technology improvement based on a Black & Veatch 2012 study, and aggressive "evolutionary" technology improvement based on DOE studies. The NREL scenarios selected for the Low RE, Mid RE, and High RE scenarios assume the intermediate "incremental" technology improvement projections of capital and operating costs and performance.

The only operational parameter represented with technical improvement over time is energy conversion efficiency. Table A-1 shows the full-load heat rates used by technology, which improve between 2010 and 2030 vintage CC and CT technologies. In addition, wind and solar PV performance is expected to improve, but their improvements are captured more by declining capital cost per MW of installed capacity than improvements in capacity factors. The "EPIS" label in some table cells for heat rate indicates that the heat rates of existing fossil units are based on the individual heat rate values in the EPIS database. The multiplicative factors for retrofits from coal to natural gas and from coal to 100% biomass indicate the heat rate adjustment for the repowered fuel after conversion. The heat rates for the storage technologies that use electricity to store energy represent 3412 Btu/kWh divided by their cycle efficiency. In addition to using an electric motor to compress air, CAES uses natural gas in the combustion turbine during generation to supplement the energy of released compressed air.

Table A-1. Full Load Heat Rates by Technology and Vintage

Technology	Fuel-Tech Category	Vintage (Year)	Full Load Heat Rate(s) (Btu/kWh)	Fuel(s)
Coal IGCC-CCS	Coal-CCS	all years	8310	Coal
Coal IGCC	Coal-IGCC	all years	7221	Coal
Pulverized Coal, Existing	Coal-Old	all years	EPIS	Coal
Pulverized Coal, New	Coal-New	2010	9370	Coal
Pulverized Coal, New	Coal-New	2030-2050	9000	Coal
Natural Gas Combined Cycle	Gas-CC	2010	6680	NG
Natural Gas Combined Cycle	Gas-CC	2030-2050	6570	NG
Natural Gas Combustion Turbine	Gas-CT	2010	10020	NG
Natural Gas Combustion Turbine	Gas-CT	2030-2050	9500	NG
Natural Gas Steam Retrofit (Coal)	O-G-S	all years	0.96* EPIS	NG
Oil/Gas Boiler, Oil	O-G-S	all years	10650	RFO
Oil/Gas Boiler, Gas or Dual Fuel	O-G-S	all years	10650	NG, RFO
Nuclear	Nuclear	all years	10460	UR
Biopower, Dedicated	Biopower	all years	8780	Bio
Biopower, Co-fire Existing	Cofire-Old	all years	EPIS	15% Bio, 85% Coal
Biopower, Co-fire Retrofit	Cofire-New	all years	1.2 * EPIS	15% Bio, 85% Coal
Geothermal (Hydrothermal)	Geothermal	all years	13500	Geo
Landfill Gas	Landfill-Gas	all years	12000	LFG
Municipal Solid Waste Steam	Landfill-Gas	all years	EPIS	MSW
Batteries	Battery	all years	4549	Elec
Pumped Hydro Energy Storage	PHES	all years	4265	Elec
Compressed Air Energy Storage	CAES	all years	2730, 4000	Elec, NG

Emission rates in Table A-2 are mainly from NREL,[57] but a separate positive CO_2 emission rate for MSW incineration of refuse is used in addition to the negative CO_2 credit that NREL attributes to capture and combustion, typically by internal combustion engines, of methane that forms in sanitary landfills.[58] Technology and fuel-specific emission rates for NO_x, SO_2, CO_2, and Hg, and applicable emission allowance costs for all fossil-fueled facilities are simulated. All allowances are treated as variable operating costs.

Table A-2. Emission Rates by Technology

			Emission Rate (lbs/MMBtu fuel)			
Technology	**Fuel-Tech Category**	**Fuel Type**	**SO2**	**NOx**	**Hg**	**CO2**
Coal IGCC-CCS	Coal-CCS	Coal	0.062	0.085	0	20.5
Coal IGCC	Coal-IGCC	Coal	0.062	0.085	0	205
Pulverized Coal, Existing	Coal-Old	Coal	0.062	0.110	4.40E-06	205
Pulverized Coal, New	Coal-New	Coal	0.062	0.110	4.40E-06	205
Natural Gas Combined Cycle	Gas-CC	NG	0.003	0.035	0	119
Natural Gas Combustion Turbine	Gas-CT	NG	0.009	0.087	0	119
Natural Gas Steam Retrofit (Coal)	O-G-S	NG	EPIS	EPIS	0	119
Oil/Gas Boiler, Oil	O-G-S	ULSD	EPIS	EPIS	0	161
Oil/Gas Boiler, Gas or Dual Fuel	O-G-S	NG	EPIS	EPIS	0	119
Biopower, Dedicated	Biopower	Bio	0.080	0.000	0	0
Biopower, Co-fire Existing	Cofire-Old	15% Bio, 85% Coal	0.0647	0.0935	3.74E-06	174.25
Biopower, Co-fire New	Cofire-New	15% Bio, 85% Coal	0.0647	0.0935	3.74E-06	174.25
Landfill Gas	Landfill-Gas	LFG	0	0	0	-250
Municipal Solid Waste Steam	Landfill-Gas	REF	0	0	0	91.91
Geothermal (Hydrothermal)	Geothermal	Geo	0	0	0	17
Compressed Air Energy Storage	CAES	NG	0.009	0.087	0	119

The storage capacity and operational parameters that NREL used in ReEDS and other studies were adapted for use in AURORAxmp.[59] Each of the four storage technologies has relatively high storage cycle efficiency and substantial storage capacity, making them well-suited to complement VER generation (Table A-3). However, they differ in their rates of storage injection and need for certain geological features at the plant site.[60]

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57 Short et al., *Regional Energy Deployment System (ReEDS),* Technical Report NREL/TP-6A20-46534, December 2011.

58 MSW and geothermal CO_2 emission rates are from EIA, www.eia.gov/environment/emissions/co2_vol_mass.cfm.

59 Storage capacity hours are from NREL, *2015 Standard Scenarios Annual Report* (2015). Cycle efficiencies are from NREL, *Renewable Electricity Futures* (2012). Other CSP parameters are from NREL, *Annual Technology Baseline* (2015) and the NREL presentation of M. Hummon et al., *Modelling Concentrating Solar Power with Thermal Energy Storage for Integration Studies* (2013).

60 The storage recharge to generation-from-storage rates indicate the following by electric storage technology: Batteries can be fully charged in one-fifth the time that it takes to convert the chemical energy to electric power. The time to recharge a pumped hydro storage reservoir is proportional to its cycle efficiency because a reversible turbine is used for both pumping and generation. CAES takes four times as long to recharge the compressed air storage vessel with an electric motor as for generation with supplemental natural gas in a CT.

Table A-3. Energy Storage Parameters by Technology

Technology	Fuel-Tech Category	Storage Cycle Efficiency	Storage Capacity (hours)	Collection / Generation Capacity Solar Multiple	Storage Recharge Capacity (hours)
CSP with Storage	CSP	93%	6.0	2.0	
Batteries	Battery	75%	7.2		1.4
Pumped Hydro Energy Storage	PHES	80%	8.0		10
Compressed Air Energy Storage	CAES	125%	15.0		60

Variable operations and maintenance (O&M) costs, start costs, start fuel, forced and planned outage rates, and chronological constraints related to unit commitment and ramping are shown in Table A-4. Extra O&M costs for operating conventional power plants more flexibly (more starts, more ramping) in the future to follow VE generation were not represented. Some technologies were set to must-run at or above their minimum operating load, either because they have high startup costs and long start times (Coal IGCC, nuclear), use a free or negative cost fuel (landfill gas, MSW, geothermal), or are assumed to not be controllable by the grid operator (distributed PV).

Table A-4. Operation Costs and Chronological Constraint Parameters by Technology

Technology	Fuel-Tech Category	Variable O&M ($/MWh)	Must Run?	Minimum Load (%)	Ave. Heat Rate at Min. Load Factor (%)	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Ramp (Up) Rate (% Capacity / Minute)	Ramp Down Rate (% Capacity / Minute)	Startup Cost ($/MW Capacity)	Offline Ancillary Up Time (minutes)	Forced Outage Rate (%)	Planned Outage Rate (%)	Start Fuel (MMBtu / MW)
Coal IGCC-CCS	Coal-CCS	3.73	Yes	50	113			5	10		420	8.0	12.0	
Coal IGCC	Coal-IGCC	2.20	Yes	50	113			5	10		420	8.0	12.0	
Pulverized Coal, Existing	Coal-Old	6.72		40	106	24	12	2	4	129	120	6.0	10.0	14.50
Pulverized Coal	Coal-New	6.72		40	106	24	12	2	4	129	120	6.0	10.0	14.50
Natural Gas Combined Cycle	Gas-CC	3.58		50	113	6	8	5	10	79	45	4.0	6.0	0.24
Natural Gas Combustion Turbine	Gas-CT	13.45		60	105	0	0	8.33	16.66	69	2	3.0	5.0	1.53
Natural Gas Steam Retrofit (Coal)	O-G-S	4.74		40	106	24	12	2	4	129	120	6.0	10.0	14.50
Oil/Gas Boiler, Oil	O-G-S	4.74		30	117	10	8	4	8	129	240	4.0	6.0	
Oil/Gas Boiler, Gas or Dual Fuel	O-G-S	4.74		30	117	10	8	4	8	129	240	10.0	12.0	
Nuclear	Nuclear	2.23	Yes	98	100			0.5	0.5			4.0	6.0	
Biopower, Dedicated	Biopower	5.48		40	106	24	12	2	4	129	120	9.0	8.0	14.50
Biopower, Co-fire Existing	Cofire-Old	6.72		40	106	24	12	2	4	129	120	9.0	8.0	14.50
Biopower, Co-fire New	Cofire-New	6.72		40	106	24	12	2	4	129	120	9.0	8.0	14.50
Landfill Gas	Landfill-Gas	0.00	Yes	100								5.0	5.0	
Municipal Solid Waste Steam	Landfill-Gas	0.00	Yes	100								5.0	5.0	
Geothermal (Hydrothermal)	Geothermal	0.00	Yes	90				4	8			13.0	2.0	
Hydropower	Hydro	2.76		EPIS				200	200			5.0	2.0	
PV, Utility Transmission Connect	PV-Utility	0.00												
PV, Distributed	PV-Distrib	0.00	Yes											
CSP with Storage	CSP	3.08		15		1	1	10	25	10.27		6.0	0.0	
Wind, Onshore	Wind-On	0.00												
Wind, Offshore (Fixed-Bottom)	Wind-Off	0.00												
Batteries	Battery	64.76						1000	1000		1	2.0	1.0	
Pumped Hydro Energy Storage	PHES	0.00		33		0	0	200	200		1	4.0	3.0	
Compressed Air Energy Storage	CAES	2.20		60	105	0	0	200	200	69	2	3.0	4.0	1.53

Existing locations of coal plants were used to represent new coal and dedicated biomass plants to the extent possible. Existing gas-fired units (IC, CT, CC, CAES) are replaced with new units at existing locations, and pipeline or gas LDC connection information was relied on for existing gas-fired plant gas network assignments. Additional new gas-fired plants were assigned a connection to the nearest interstate pipeline. Excluding downstate New York on the New York Facilities System, in 2050 all additional gas plants are direct-connected to interstate pipelines in order to take advantage of high operating pressures, relative to local distribution service. These gas system locations were used to represent the appropriate locational gas prices for each gas-fired plant as well as for aggregation of gas demands by pipeline segment for analysis in GPCM.

Aspects of NREL's wind and solar databases are proprietary or otherwise not readily available. Hence, LAI downloaded NREL's publicly-available three years of 10-minute wind output data from its Eastern Wind Integration Transmission Study (EWITS) database, supplemented with the more recent seven years of 5-minute data from its Wind Integration National Dataset (WIND) Toolkit for areas in the Southeast not included in the EWITS database. We also used the NREL System Advisor Model (SAM) to specify technology characteristics and simulate output for distributed (rooftop or other fixed angle) PV, utility-scale (1-axis) PV, and CSP for all areas with capacity for these solar technologies in the NREL scenarios. One representative location for each of the ReEDS wind regions or balancing areas, the latter for solar resources, was simulated. SAM provides typical meteorological year (TMY) 8760 profiles but EWITS and WIND Toolkit provide multiple years of sub-hourly data that required processing into TMY profiles. A separate wind productivity class profile was represented for each wind class in a region with NREL scenario 2050 capacity greater than 1 MW.

Hydro monthly energy availability profile data by area in the EPIS database were used, both for existing hydro resources and new run-of-river hydropower capacity expansion. The EPIS profiles have a somewhat lower annual average capacity factor than the 55% capacity factor that NREL assumed for all locations.

System Operation Assumptions

AURORAxmp was set to simulate across the EI study region using a multi-pool algorithm, which iterates between optimizing unit commitment and economic dispatch within each control area separately and coordinating power transfers among control areas.

Control Areas

A simple, stylized representation of 10 power pool control areas in the Eastern Interconnection was represented in AURORAxmp. Modeled control areas include:

- ISO-New England (ISO-NE); Northern Maine
- New York ISO (NYISO)
- PJM

- Mid-Continent ISO (MISO) North/Central; Associated Electric Cooperatives, Inc. (AECI)
- MISO South
- Southwest Power Pool (SPP)
- Tennessee Valley Authority (TVA); Louisville Gas & Electric and KU Services (LGE)
- Southeast Electric Reliability Council (SERC) South
- Virginia-Carolinas (VACAR) Reliability Council
- Florida Reliability Coordinating Council (FRCC)

The representation is stylized for modeling purposes in two respects. First, three small control areas were included with much larger neighboring control areas. In actual operations, Northern Maine is part of the Maritimes area (with New Brunswick, Nova Scotia, and Prince Edward Island) controlled by the New Brunswick System Operator, AECI is its own control area consisting of five members in Missouri and Oklahoma, and LGE is a small municipal control area. Second, while MISO separates its very large control area into Central, North, and South operating regions, the MISO North and Central regions were combined, leaving MISO South as a separate control area from MISO North/Central. In actuality, there is only a thin corridor of transmission that connects MISO South to the rest of MISO, while MISO North and Central are heavily interconnected.

LAI included "hurdle" rates as $/MWh costs for transfers between transmission control areas, as is typically done in multi-zonal power system models. Hurdle rates represent actual market wheeling costs plus an additional "friction" charge for policies or scheduling inefficiencies between adjoining control areas.[61] The hurdle rates adopted for this study are based on the rates used in a 2012 EIPC study of electric transmission expansion scenarios for the Eastern Interconnection.[62] In contrast, NREL's representation of electric power transmission in ReEDS is costless, aside from modeling transmission losses.

Operating Reserves Regions and Requirements

In AURORAxmp, operating reserve regions were defined at the scale of control areas or smaller regions. Operating reserve requirements were set at the same levels as in ReEDS. Total contingency reserves were set to 6% of hourly load, of which at least half (3%) must come from spinning resources, while the remainder may come from quick-start (10 minute) non-spinning reserves. Frequency regulation reserves were set to 1.5% of load, for both regulation up and regulation down reserves. Contingency and regulation reserve requirements were set in proportion to demand, regardless of the generation technology mix. In addition, VE forecast uncertainty reserves was calculated for each scenario as a statistical function of wind and utility PV generation forecast uncertainty for the next hour, using a statistical approach similar to the NREL procedure used for ReEDS. In addition to

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[61] MISO has imposed a $10/MWh hurdle rate for power flows between MISO North/Central and MISO South. Other control areas do not employ internal hurdle rates.

[62] The previous EIPC study hurdle rates were reset to zero between zones that are now within the subsequent December 19, 2013 expansion of MISO to include the MISO South region, and the October 1, 2015 expansion of SPP to include Western Area Power Administration's Upper Great Plains Region, Basin Electric Power Cooperative, and Heartland Consumers Power District.

NREL's next hour persistence variable, the regression model also includes an expected or forecastable hourly change variable.[63]

The expected hourly change variable represents the average diurnal cycle of output, which is much greater for solar PV than for wind output. In many on-shore locations, wind speed is slightly greater at night than during the day, while PV output is zero overnight. Then the separate positive or negative forecast errors for wind and utility PV are summed, which cancels any opposite direction individual forecast errors.

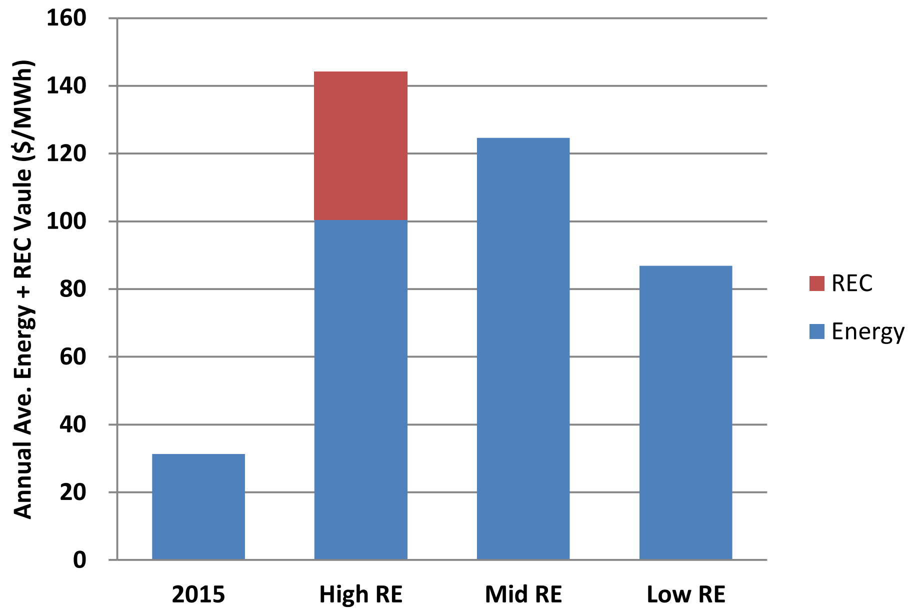
Following NREL, one-sixth of the hourly VE reserve requirements were added to the spinning reserve requirements and the remaining five-sixths to the non-spinning reserve requirements. NREL based this split on a statistical analysis of reserve requirements and dispatch, including sub-hourly net load variability and spatial diversity benefits, in its 2012 *RE Futures* study, based on earlier work by Zavadil et al. (2004).

Electric Energy Price and System Operation Results

This study has not been centered on economic impacts, as measured by market or shadow cost-based prices for energy, ancillary services, capacity, and renewable energy credits (RECs). Likewise, production cost impacts for generators or wholesale costs to consumers, including transmission costs, have not been central to primary research objectives associated with the RE scenarios and consequent constraints on gas infrastructure across the EI. Nevertheless, various price and cost data are available from the simulation results that provide a useful perspective on the performance of the model across the RE scenarios and sensitivities. Energy prices across the EI are compared in Figure A-1, which shows average annual energy prices in 2015 and in 2050 by RE Scenario. In addition, the $66/MWh shadow cost of the 80% national RPS constraint in that underlying NREL scenario is added to the average energy price for the 64% RE generation share in the High RE scenario as a REC value. The High RE scenario included a REC in order to minimize any economic curtailment of RE generation. In contrast, the 43% RE share in the Mid RE scenario and the 22% RE share in the Low RE scenario were not modeled by NREL with an RPS constraint in 2050, and had much less RE generation curtailment.

[63] The same linear regression equation was used to forecast next hour output of wind and solar PV by reserve-sharing region. The two independent variables are the previous hour's output and a 16-day centered (excluding the current day) moving average change in output for the next hour.

Figure A-1. EI Annual Average Energy Prices, 2015 and 2050 by RE Scenario

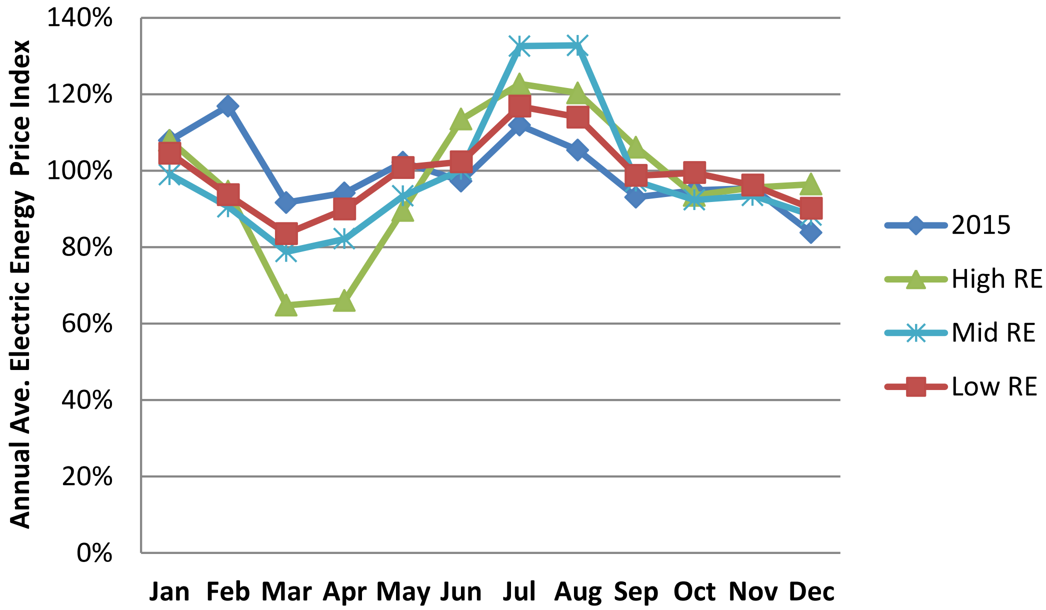


Annual average energy prices are much higher in 2050 than 2015 due to the rapid real price escalation rates for gas prices in AEO2015, which were extended from 2040 to 2050. In addition, the High RE scenario reflects a REC cost, approximated in the bar based on the RE generation share. The Low RE scenario has lower energy prices than the Mid RE scenario primarily due to its lower gas prices, while the higher gas prices in the High RE scenario do not result in higher energy prices because zero variable cost RE resources are often on the margin.

The next two price summary graphs include the REC adder in the High RE scenario energy prices.[64] Figure A-2 shows that as the RE share increases, average monthly prices have larger seasonal amplitude, with higher prices in peak summer and winter months, and lower prices in shoulder months. Figure A-3 shows that the higher penetration of solar PV and CSP generation in the High RE scenario has the impact of depressing afternoon prices, when solar output peaks, relative to the other three daily time blocks.

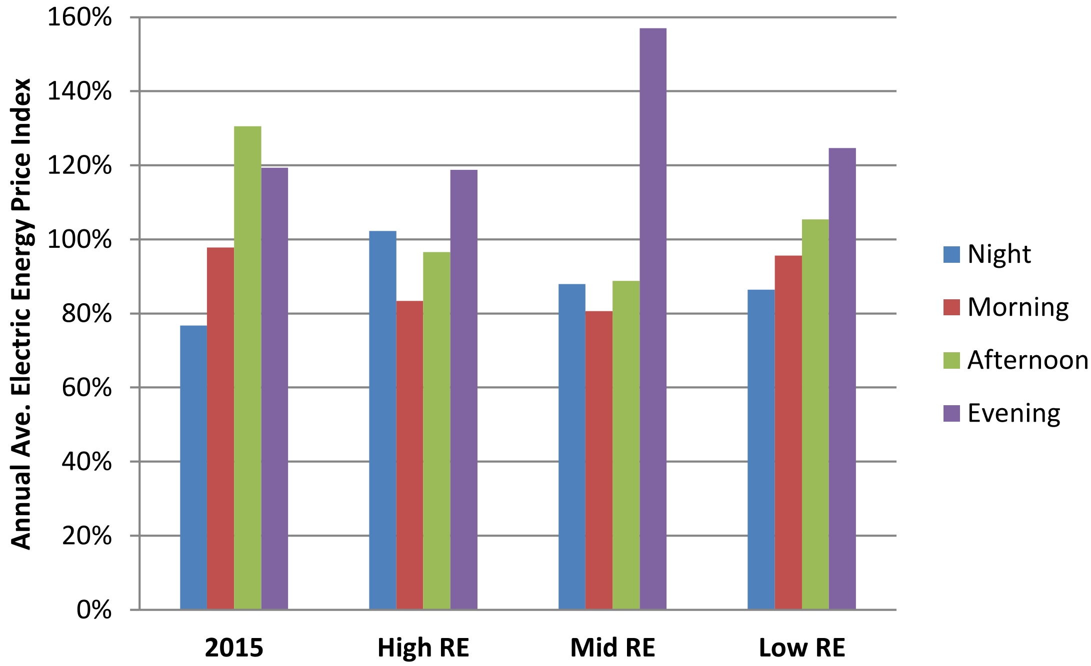
[64] As such, the "price" in the High RE scenario is a composite average revenue from all energy and renewable energy.

Figure A-2. EI Monthly Average Electric Energy Price Indexes, 2015 and 2050 by RE Scenario



The seasonal pattern of energy prices becomes much more pronounced as the RE share of generation increases across the three scenarios in 2050. In particular, energy prices are depressed in March and April relative to annual average prices in the High RE scenario, when load is low relative to solar and wind generation. These energy price indexes do not include the substantial REC charge required in the High RE scenario, so its prices appear lower than the Mid RE scenario prices in some months.

Figure A-3. EI Time-of-day Average Electric Energy Price Indexes, 2015 and 2050 by RE Scenario



The time-of-day pattern of energy prices changes considerably as the RE share of generation increases across the three scenarios in 2050. In particular, increasing solar energy penetration decreases daytime prices and increases nighttime prices.

The two SG sensitivities had minor price reduction impacts. EI-wide annual average energy price is reduced $0.76 in the High RE SG sensitivity relative to the High RE scenario, and by $1.57/MWh in the Mid RE SG sensitivity relative to the Mid RE scenario.[65] New England zones had small price increases in both the High RE SG and Mid RE SG sensitivities and New York and eastern PJM zones had slightly negative price changes in the High RE SG sensitivity and slightly positive price changes in the Mid RE SG sensitivity. The other zones had more significant price reductions for both SG sensitivities. Because changes in capital costs for the sensitivities are also negative (displaced PHES and CAES capacity have higher capital costs than that of the substituted CT capacity), it appears that the resource mixes in the SG sensitivities are more cost-effective than that of their underlying scenarios. While interesting, this result is not surprising because the ReEDS capacity expansion model cannot capture all the detail of an hourly chronological production cost model. Best practice is to follow initial screening of potential capacity expansion plans in a long-term capacity expansion model with more detailed simulation in a short-term commitment-dispatch model.

Spinning reserves from gas-fired plants played a major role in covering the need for VE forecast uncertainty. PHES and CAES also provide load-following reserves. VE generation

[65] This calculation does not include the second-order impact of slightly different REC value due to slightly different RE generation in the SG sensitivities.

was not curtailed in 2015 and in 2050 in the Low RE scenario, but the Mid RE scenario had 1.29% VE curtailment and the High RE scenario had 2.69% VE curtailment in 2050.

Utilization of the inter-zonal transmission system ranged from 17% in 2015 to 23% in 2050 for the Low RE scenario, 25% for the Mid RE scenario, and 37% in the High RE scenario. Transmission losses are larger as a result of both the expansion of the transmission system and its higher utilization in the three 2050 scenarios. AURORAxmp had similar generation dispatch to ReEDS, with slightly higher CF for natural gas plants, lower CF for coal-fired plants, and higher CF for CAES plants.

Additional operating reserve requirements were met by conventional and storage technologies. Conventional resources were used more for providing operational reserves and less for energy generation, compared to their current role.