EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Study on Long-term Electric and Natural Gas Infrastructure Requirements in the Eastern Interconnection

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ICF Incorporated
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Glossary

Abbreviations

Abbreviation	Description
AECO	Alberta natural gas price hub
AEO	EIA Annual Energy Outlook
AGA	American Gas Association
API	American Petroleum Institute
Bcf	billion cubic feet
Bcfd	billion cubic feet per day
BLM	Bureau of Land Management
BOE	barrels of oil equivalent
Btu	British thermal unit
CDD	cooling degree days
D&C	drilling and completion (costs)
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
E&P	exploration and production
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EPA	U.S. Environmental Protection Agency
EUR	Estimated Ultimate Recovery
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
GOM	Gulf of Mexico
GW	gigawatts
HDD	heating degree days
IPP	independent power producer
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
kWh	kilowatt-hours
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
Mcf	thousand cubic feet
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	million British thermal units
MMcf	million cubic feet
MMcfd	million cubic feet per day

Abbreviation	Description
MW	megawatts
MWh	megawatt-hour
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NUG	non-utility generation
NYISO	New York Independent System Operator, Inc.
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
OFO	Operational Flow Order
PJM	PJM Interconnection, LLC
PSI	pounds per square inch
RACC	Refiner Acquisition Cost of Crude in the United States
SNG	synthetic natural gas
Tcf	trillion cubic feet
USGS	United States Geological Survey
WTI	West Texas Intermediate crude oil

Terms Used

Access – refers to the legal right to construct transmission and/or distribution facilities (on public or private land).

AECO (formerly Alberta Energy Company) – natural gas pricing hub located in Alberta, Canada.

Basis – the price differential for a commodity (such as natural gas) between two locations. In the case of natural gas, basis can refer to the difference between the NYMEX futures contract price at Henry Hub (the main U.S. natural gas hub) and the cash price at other locations. Basis can also refer to the difference in the cash price at two locations. Natural gas basis reflects the transportation costs, as well as regional supply and demand factors.

Brownfield Pipeline Expansion – the addition of a compression facility and/or compression looping to an existing pipeline.

City Gate – the location at which the interstate and intrastate pipelines sell/deliver natural gas to local distribution companies.

Cogeneration – the use of the waste heat generated during the production of electricity. Natural gas is a fuel often used in cogeneration at combined-cycle facilities.

Compression – during transportation and storage, natural gas is compressed at compression stations.

Cost of Service – the total cost of providing a utility service, including return on investment (of capital expenditures), operation and maintenance costs, administrative costs, taxes, and depreciation expenditures.

Cubic Foot – a common measurement of natural gas volumes, which is the amount of natural gas required to fill a volume of one cubic foot under standard temperature and pressure conditions.

Curtailment Plan – A contingency plan developed by local gas distribution companies in conjunction with state regulatory agencies to reduce deliveries to firm gas customers in the event of severe disruption to gas supplies or other emergency.

Curtailment Priority – The priority specified in a curtailment plan for each type of firm customer. The highest priority customer is the last to lose firm service in the event of severe disruption to gas supplies or other emergency.

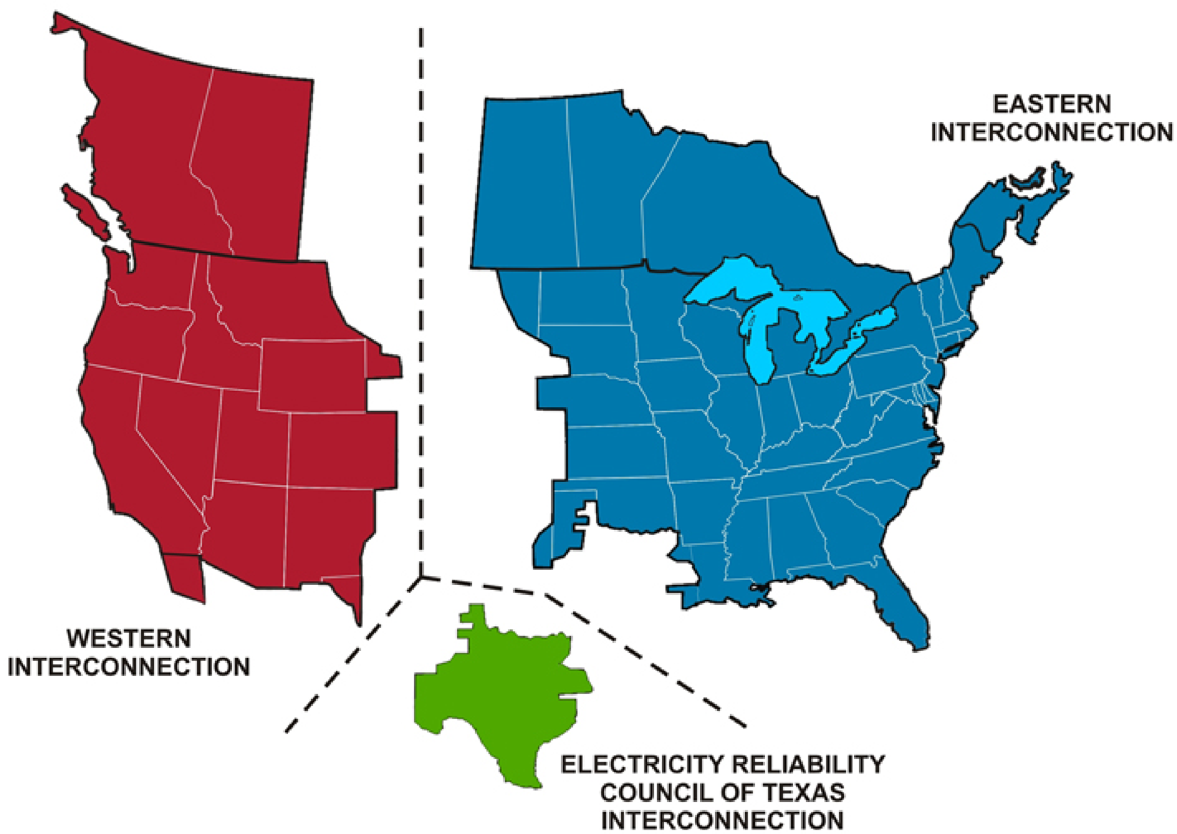
Delivery Point – a point along a pipeline at which the pipeline delivers natural gas to its customers. The city gate is a common delivery point for a pipeline (i.e., the point at which a pipeline delivers gas to an LDC).

Distribution Line – a pipeline network that transports natural gas from the transmission line (such as an interstate pipeline) to end-users' service line or other distribution lines. Large pipelines are laid in principal streets with smaller lateral lines connecting with the large pipeline via perpendicular side streets to form a grid.

Distribution Mains – pipelines transporting natural gas within a designated service area of an LDC.

Eastern Interconnection – one of two major alternating current (AC) interconnections in North America (the other is the Western Interconnection), in addition to three minor interconnections (Texas Interconnection, Quebec Interconnection, and Alaska Interconnection). The Eastern Interconnection extends from central Canada to the Atlantic Coast (excluding Quebec) in the north to the foot of the Rockies (excluding most of Texas) and eastward to Florida (see map below).

North American Interconnections



Source: U.S. Department of Energy (DOE).

Electric Day – a 24-hour period of time used by an electric utility for its system operation, usually beginning at midnight. Electric Days vary across independent system operator (ISO) regions.

Electric System Load Factor –a measure of utilization rate across the system defined as total system generation (MWh) over a selected time period divided by the product of the system peak load (MW) and the duration of the time interval over which the load factor is calculated (h).

End User – the final consumer of energy, as opposed to a seller (e.g., natural gas producer) or reseller (e.g., LDC, marketer) of the energy.

FERC (Federal Energy Regulatory Commission) – the federal agency tasked (among other duties) with regulated interstate natural gas pipelines and interstate natural gas sales as mandated in the Natural Gas Act.

Firm Customer – a pipeline customer (i.e., shipper) who has contracted for firm pipeline service.

Firm Service – a service offered to customers under contract with no interruptions, regardless of service class, except in the case of force majeure.

Fuel-Switching – the substitution of one fuel for another based on price and supply availability. A number of power generators have fuel-switching capabilities and are able to switch between natural gas and fuel oil, depending on the price differential between the two, as well as supply availability of fuel.

Gathering Lines – small-diameter pipelines that deliver crude oil or natural gas from a production area to a trunk line. **Gas Day** – a 24-hour period of time used by a pipeline for the operation of its system. Unlike the Electric Day, the Gas Day is currently uniform across the United States.

Greenfield Pipeline – the construction of a new pipeline.

Henry Hub – a pipeline interchange near Erath, Louisiana, where a number of interstate and intrastate pipelines connect via the Sabine Pipe Line header system. Henry Hub is the standard delivery point for the NYMEX natural gas futures contract.

Horizontal Drilling – the practice of drilling a horizontal section in a well (used primarily in a shale gas or tight oil well), typically thousands of feet in length.

Inch-miles – defined as pipeline diameter multiplied by length of the pipeline in miles.

Incremental (vs. rolled-in) Rates – FERC rate-making policy requiring pipeline expansions to be priced at the higher of actual cost-based rates for the new service or current system rates.

Independent System Operator (ISO) – an organization formed at the direction of the Federal Energy Regulatory Commission (FERC) to coordinate and monitor the region’s power system and to operate the wholesale market for electric power within its region.

Interruptible Customer – a pipeline customer (i.e., shipper) who does not have a firm service contract, and whose service can be interrupted.

Interruptible Service – a pipeline service contract that allows curtailment or cessation of service at the pipeline's discretion under certain circumstances specified in the service contract.

Load Duration Curve – a curve of electric or natural gas loads plotted in descending order of magnitude against time intervals, indicating the period of time a load was above a specific magnitude. The load duration curve shows the system demand over for a specific period of time (e.g., daily, monthly, annually).

Local Distribution Company (LDC) – a (natural gas) company that purchases bulk volumes of natural gas for its primarily residential and commercial consumer base. The LDC obtains the majority of its natural gas revenues from the operation of a retail gas distribution system, but usually does not operate the transmission system.

Looping – the addition of pipe segments to add capacity to an existing pipeline.

Marketer (natural gas) – a company other than a pipeline or LDC that purchases and resells natural gas or brokers the gas transactions for a profit. Marketers also arrange transportation and monitor deliveries and balancing. An independent marketer is not affiliated with a pipeline, producer, or LDC.

Natural Gas Liquids – components of natural gas that are in gaseous form in the reservoir, but can be separated from the natural gas at the wellhead or in a gas processing plant in liquid form. NGLs include ethane, propane, butanes, pentanes, and heavier hydrocarbons.

Natural Gas Load Factor – the ratio of average load to peak load during a period of time, indicating a pipeline capacity's utilization rate.

No-Bump Rule (or Flowing Gas No-Bump Rule) – a tariff provision governing interruptible transportation, which dictates that a shipper may temporarily lose its full contract volume rights if shipping a lower volume. Under the no-bump rule, a shipper flowing gas cannot be bumped (i.e., lose capacity) because a shipper with a higher priority in the interruptible transportation schedule increases its gas receipts within its transportation contract.

Operational Flow Order (OFO) – an order issued by a pipeline or LDC that restricts service or requires affirmative action by shippers in an effort to ensure the operational integrity of the pipeline or distribution system.

Oil and Gas Value Chain

- **Upstream Oil and Gas Activities** – consist of all activities and expenditures relating to oil and gas extraction, including exploration, leasing, permitting, site preparation, drilling, completion, and long-term well operation.

- **Midstream Oil and Gas Activities** – consist of activities and expenditures downstream of the wellhead, including gathering, gas and liquids processing, and pipeline transportation.
- **Downstream Oil and Gas Activities** – activities and expenditures in the areas of refining, distribution, and retailing of oil and gas products.

Oil and Gas Resource Terminology

- **Coalbed methane** (CBM) – recoverable volumes of gas from development of coal seams (also known as coal seam gas, or CSG).
- **Conventional gas resources** – generally defined as those associated with higher permeability fields and reservoirs. Typically, such a reservoir is characterized by a water zone below the oil and gas. These resources are discrete accumulations, typified by a well-defined field outline.
- **Economically recoverable resources** – represent that part of technically recoverable resources that are expected to be economically significant, given a set of assumptions about current or future prices and market conditions.
- **Original Gas-in-Place** – industry term that specifies the amount of natural gas in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.
- **Original Oil-in-Place** – industry term that specifies the amount of oil in a reservoir (including both recoverable and unrecoverable volumes) before any production takes place.
- **Proven reserves** – the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology.
- **Shale gas and tight oil** – recoverable volumes of gas, condensate, and crude oil from development of shale plays. Tight oil plays are those shale plays that are dominated by oil and associated gas, such as the Bakken in North Dakota.
- **Technically recoverable resources** – represent the fraction of gas in place that is expected to be recoverable from oil and gas wells without consideration of economic factors.
- **Tight gas** – recoverable volumes of gas and condensate from development of very low permeability sandstones.
- **Unconventional gas resources** – defined as those low permeability deposits that are more continuous across a broad area. The main categories are coalbed methane, tight gas, and shale gas, although other categories exist, including methane hydrates and coal gasification.

Opal – a natural gas pricing point in Wyoming designated for the Rocky Mountain region.

Peak-Day Demand – the maximum daily natural gas volume used during a specified period (e.g., annual).

Peak Shaving – a mechanism to reduce the peak demand for natural gas or electricity, such as high-deliverability natural gas storage or use of LNG.

Peaker Unit – a power plant designed to run infrequently during times of greatest demand for electricity on the system. These facilities are often characterized by relatively low capital cost and high operating cost relative to other types of dispatchable generation.

Peaking Capacity – a facility's capacity to meet incremental gas or electricity under extreme demand conditions, and is typically available for a limited number of days (e.g., the coldest winter days) at maximum capacity.

Pipeline Capacity – the maximum allowable throughput of a natural gas pipeline over a specific period of time. The pipeline capacity is specified in the pipeline design, rather than existing service conditions.

Pipeline Nomination – a request for a physical quantity of natural gas transportation service under a specific sales or transportation contract.

Pipeline Scheduling – a process through which natural gas nominations are consolidated by receipt point and contract, and verified with upstream and downstream parties. In cases where the verified capacity is larger than or equal to the total nominated volume, all nominated volumes are scheduled. However, if the verified capacity is less than the nominated volume, the nominated volumes are allocated according to the scheduling priorities.

Receipt Point – a point on a pipeline where the natural gas is received on the system.

Refiner Acquisition Cost of Crude Oil (RACC) – a refiner's cost of crude oil, which includes transportation costs and fees. The composite cost is the weighted average of domestic and imported crude oil costs.

Regional Transmission Organization (RTO) – as a third party independent operator of the transmission system and regional markets, an RTO is a voluntary organization of transmission owners, users, and other relevant entities who depend on reliable operation, coordination, transmission planning, expansion, and use of an electric system on a regional and interregional basis. RTOs are similar to ISOs but must meet the characteristics and functions outlined in FERC Order 2000 to receive this designation from FERC.

Shipper – an entity (such as a natural gas producer) that engages a pipeline for transportation of natural gas and retains the title to the natural gas during transportation on the pipeline.

Shipper Must Have Title – a FERC policy stating that shippers must retain the title to the natural gas in order to transport the natural gas on the pipeline.

SoCal – the pipeline pricing point located in southern California.

Spot Market – commodity transactions where the transaction period is short-term (such as within 10 days) and the contract duration is short (e.g., 30 days), relative to that of futures contracts.

Storage Service – a service in which natural gas is held for a customer for redelivery at a later date, and is utilized to account for the seasonality of natural gas (e.g., natural gas use peaks in the winter). Storage services are also critical during the peak period for many interstate natural gas pipelines and distributors.

Supply Hub – a location at which supply is available from more than one basin.

Swing Supply(ier) – refers to an alternative supplier (e.g., natural gas producer) that provides supply when demand is high and the customary supplier cannot meet demand.

Synthetic Natural Gas – a manufactured product from coal or oil that is chemically similar to natural gas and can be substituted for pipeline quality natural gas.

Tariff – a regulatory filing with either a federal or state commission listing the rates the regulated entity may charge its customers for service, as well as the terms and conditions of providing the service.

Unbundled Services – the natural gas industry is an unbundled industry in that each link in the natural gas value chain remains independent of the others and is not related to the ownership of the gas. For instance, pipelines do not own the natural gas they transport; the gas remains under title of the shipper (e.g., natural gas producer), with title transferred to purchaser (e.g., LDC, marketer) at the delivery point.

Conversion Factors

Volume of Natural Gas

1 Tcf = 1,000 Bcf

1 Bcf = 1,000 MMcf

1 MMcf = 1,000 Mcf

Energy Content of Natural Gas (1 Mcf is one thousand cubic feet)

1 Mcf = 1.025 MMBtu

1 Mcf = 0.177 barrels of oil equivalent (BOE)

1 BOE = 5.8 MMBtu = 5.65 Mcf of gas

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

1 MMBOE = 1 million barrels of crude oil equivalent

Energy Content of Other Liquids

Condensate

1 barrel = 5.3 MMBtu = 0.91 BOE

Natural Gas Plant Liquids

1 barrel = 4.0 MMBtu = 0.69 BOE (actual value varies based on component proportions)

Energy Content of Electricity

3,412 Btu/kWh

Abstract

This study provides a comprehensive analysis of the potential long-term infrastructure requirements for the electric and natural gas industries, including integration of the operational constraints of both industries into their infrastructure development. The electric industry appears to be on the threshold of undergoing considerable changes due to a number of structural and policy shifts that may require significant increases in the use of natural gas as a generating fuel relative to other fuels. An increasing number of natural gas supply sources are available to meet the needs of new electric facilities. However, accommodating these needs may require modifications to electric and natural gas operating and contracting practices to ensure timely and cost-effective services. This study examines natural gas infrastructure build-out needs over the range of policy futures explored in the Eastern Interconnection Planning Collaborative (EIPC) electric transmission study and demonstrates a methodology for co-optimizing power sector and natural gas sector infrastructure expansions. Reliability and resource adequacy are explored in the context of fuel infrastructure needs and the siting requirements for new gas pipelines are also discussed. This report sets forth methods for optimizing natural gas infrastructure in the context of future system needs and provides a blueprint for the joint consideration of power system reliability and natural gas fuel infrastructure adequacy in the context of anticipated increases in power sector demand for natural gas.

1 Executive Summary

1.1 Introduction

During the past decade, natural gas-fired power generation has risen significantly, from 17 percent to 27 percent of U.S. power generation. Due to generally low prices, superior environmental performance, dispatch flexibility, and relatively short construction cycles for new generation, gas use is expected to continue to increase in the future—both in absolute terms and as a share of total power generation fuel inputs. During the past two years, the subject of the interdependency of gas and electric service reliability has intensified in many forums. As the amount and dispatch of gas-fired generation increases, the interaction between the electric grid and the gas network can be stressed. These stresses have highlighted the similarities and differences in the structure, operation, business practices, and communications within and between the two industries.

Interest is focused on natural gas because it differs from other fuels used to generate electricity in that:

- Unlike coal and fuel oil, natural gas is not easily stored onsite; therefore, real-time delivery is critical to support generators.
- Natural gas is widely used outside the power sector (with resurgence in industrial sector use and expected new uses for LNG exports, in particular), and thus the demand from other sectors (e.g., coincident peaks during cold winter weather) critically affects supply for the power sector.
- Events that lead to constrained supply to power generators, such as 2014's winter polar vortex episodes, have occurred historically raising concerns about the adequacy of natural gas resources and delivery capability to satisfy increasing gas load, particularly load for power plants that have not firmly contracted gas supply and pipeline capacity.
- Natural gas is seen as playing a growing role in integrating variable generation, which will increase the need for system flexibility and may, therefore, put added strains on natural gas delivery infrastructure.

The primary concern and driver behind this study is determining whether gas supply will be adequate to serve power generation and non-power loads at all times. In most cases, the issue is whether there is adequate interstate pipeline capacity to provide sufficient gas to both firm and interruptible loads during peak winter demand periods, when residential, commercial, and some industrial customers are using gas for heating, and low-temperature-driven electric loads are also high. The underlying reason that this arises is that interstate pipelines are built to meet the firm contracted capacity at the time of construction. Pipeline developers must show the Federal Energy Regulatory Commission (FERC) that they have firm commitments to purchase the capacity equal to the capacity that they plan to build. There is no reserve margin or excess capacity. In most cases, the holders of this firm capacity are the local gas distribution companies that serve residential, commercial, and small industrial gas customers. During non-peak periods, they release their unused capacity to other users. Many merchant electric generators do not purchase firm pipeline capacity because they cannot cover the fixed monthly pipeline demand charges in the bid price that they offer to independent system operators (ISOs). When there is unused capacity, they can purchase space on the pipeline to fuel their plants. But, at peak demand times, there may not be any unused capacity, and generators may not be able to get gas delivered.

This study was prepared by ICF working with the National Association of Regulatory Utility Commissioners (NARUC) and Eastern Interconnection States Planning Council (EISPC). In performing the study ICF also interacted with the members of the EISPC collaborative process, and others in the electric and gas industry to catalog, analyze, and explain short- and long-term operational, contractual, and planning concerns related to issues arising from the increasing interdependency between the electric and natural gas sectors in the Eastern Interconnection. At the request of EISPC this study focused on determining what amount of natural gas infrastructure[1] would be needed by 2030 to supply power generators and other gas users in Eastern Interconnect footprint. The use of natural gas for electric power generation was to be taken from the three "Futures" scenarios defined in the Eastern Interconnection Planning Collaborative (EIPC) Phase II study and natural gas in non-power sectors was to be taken from ICF proprietary analysis and forecasts of natural gas markets.

The specific questions EISPC requested ICF to address in this study include:

1) What concerns do stakeholders now have regarding gas-electric interdependency and its implications for system infrastructure planning? What are the origin, nature, relevance, and implications of each concern? How will the expected growing reliance on natural gas by power generators affect those concerns, particularly those that relate to inadequate natural gas supply for power generators?
2) What are ongoing and planned efforts by various parties in the United States to assess natural gas and electric infrastructure requirements? What limitations exist (anti-trust considerations, competitive concerns, proprietary data, security matters) that make difficult or prevent efforts by the natural gas and electric industries from engaging in periodic long-term assessments of infrastructure needs?
3) What infrastructure options exist for mitigating inadequate natural gas and alternative fuel supplies, and what is the cost of each?
4) Given the specific electricity consumption levels, power plant builds, electric transmission build-outs, demand response, and energy efficiency deployment levels envisioned in the Eastern Interconnection through 2030 in the three EIPC "Futures" scenarios, what are the implications on total natural gas consumption volumes and patterns?
5) What analytic tools or models exist that can be used to co-optimize expansions of the natural gas and electric systems? Which of these tools/models are available and feasible to employ in this effort to describe a hypothetical co-optimized electric-gas system for the

[1] The term "natural gas infrastructure" as used in this report excludes local distribution company mains and service lines and related assets and investments.

Eastern Interconnection through 2030? What are the pros and cons of each feasible approach, and what is the recommended methodology, taking into account comments and recommendation received through the collaborative process?

6) What is the description of the natural gas infrastructure needed in the Eastern Interconnection through 2030, taking into consideration the three Futures scenarios and their associated electric infrastructure and natural gas fuel requirements? What specific gas infrastructure needs to be built (e.g., gas pipelines, underground storage fields, peak-shaving plants), where will it be built, and at what cost?

7) What reliability metrics (e.g., a loss of load probability [LOLP] of 2.4 hours or less per year) are used by electricity system planners and how can the adequacy of natural gas supply fit into such metrics. For example, if natural gas demand for power generation exceeds supplies in certain markets, what would be the effect on these metrics? Can it be demonstrated that sound economics of resource adequacy have been used in developing the projected fuel infrastructure so that the cost of marginal fuel supply infrastructure (e.g., gas pipelines, gas storage fields, alternative fuel backup facilities) would be approximately equal to the value of lost electric load?

8) What federal and state siting requirements, laws, and regulations affect the siting of new infrastructure? To what degree do these create impediments to construction? What state actions might be warranted to expedite these processes?

9) What additional analysis would be beneficial to the United States in terms of identifying future infrastructure needs, making timely permitting and construction more likely, or improving the operation of existing infrastructure?

These questions are addressed in seven sections of this report plus several appendices. This first section provides the key takeaways. The second section provides background on gas/electric integration issues, summarizes stakeholder concerns and catalogues ongoing efforts to study and resolve various issues. The third section presents a range of future demand for natural gas within the Eastern Interconnection and provides the methodology and results of ICF's analysis of what new natural gas infrastructure will be needed to satisfy that demand. The fourth section covers the questions related to what tools are available to co-optimize new investments in natural gas and electric infrastructure and presents an example of how one such tool can be applied. The fifth section addresses electric power systems' resource adequacy metrics and how those metrics can incorporate fuel supply adequacy. The environmental approval process for new infrastructure is the subject of sixth section and ICF's recommendations for future analyses on these subjects are contained in the seventh section. Several appendices at the end this report contain additional details on projected future gas demand profiles, infrastructure options and costs, and the expected amounts and costs of natural infrastructure that might be needed by 2030 in the Eastern Interconnection.

1.2 Key Findings

The key findings of this report are summarized below by subject area.

Issues, Concerns, and Ongoing Efforts: ICF reviewed available reports, participated in various forums, and interviewed market participants to identify what concerns market participants had related to gas/electric integration and what efforts were underway to address them. Gas-electric coordination concerns exist across all regions of the United States but are most acute where gas-fired power generation sees fast growth and power generators rely on interruptible natural gas pipeline transportation. Exhibit 1-1 briefly summarizes the primary concerns facing market participants. These include short-term concerns related to daily operations, communications, scheduling and coordination; mid-term issues related to tracking and coordinating electric and natural gas system scheduled construction and maintenance outages; and long-term concerns regarding market design, cost recovery, contracting, and planning that affect the ability to build adequate new infrastructure. These concerns are being addressed in several forums at the national, regional, and state levels by federal and state government agencies and industry groups. Some of the most important ongoing efforts are aimed at better coordinating daily electric and natural gas markets to improve their coordination and efficiency and modifying electricity market structures to provide incentives and means for gas-fired power generators to secure adequate year-round natural gas or alternative fuel supplies, including during days of peak winter natural demand.

Exhibit 1-1: Main Gas-Electric Coordination Concerns

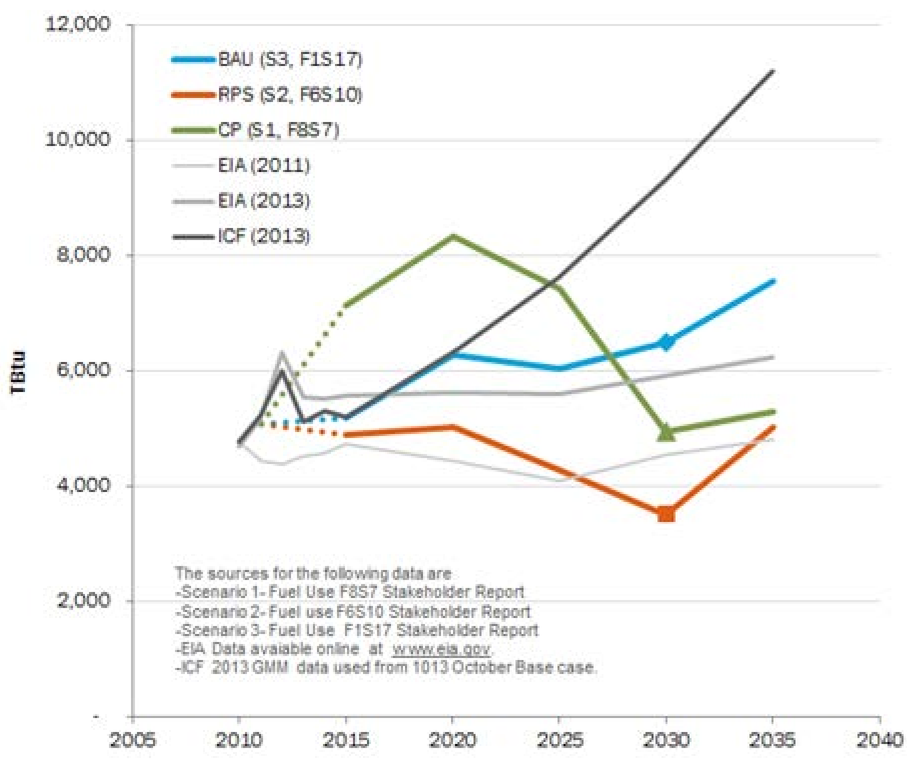
Main Concern	Issues	Efforts to Address Concern
Market Design Concerns		
Infrastructure Planning Mismatches	• Natural gas pipelines are built on a firm contract basis, not interruptible service • Gas-fired power generators rely mainly on interruptible service contracts in organized markets (e.g. PJM), though use of interruptible service in the U.S. Southeast is not an issue, where firm gas contracts are used when needed, based on integrated resource planning • Gas-fired generators relying on highly congested pipelines face supply access issues	• Pipeline expansions, particularly in the U.S. Northeast • FERC's Show Cause Order (RP14-442) proposes to allow multi-party firm transportation service contracts • NERC Operating Committee compiled guidelines for cold weather event reliability issues • Consideration of a dual fuel requirement
Differing Time Scales	• Gas Day determined by NAESB, and Electric Day gas nominations differ by region, leading to unfair advantages for earlier bid markets	• FERC's NOPR proposes to move Gas Day schedule to better align with the power sector • ISO-NE moved bidding window up two hours • Considering moving Gas Day and Electric Day to more closely align
Incongruent Definition of Resource Adequacy	• Natural gas resource planning is based on peak day conditions (i.e., extreme weather), while the power sector planning is driven by reserve capacity (i.e., reliability concerns)	• Various regions, including NYISO, to run cold weather scenarios to assess various factors affecting gas-electric coordination • ISOs such as ISO-NE and NYISO require more frequent fuel surveys during times of short supply • ISOs such as NYISO are developing formal processes for determining reliability needs
Communications		
Lack of Communications	• Scheduled outages are not coordinated within the gas sector or with power sector coordination	• FERC's NOPR aims to improve communication between gas and power sectors • ISO-NE developing a platform for information-sharing between natural gas and power sectors

Main Concern	Issues	Efforts to Address Concern
Cost Recovery		
Differences in Cost Recovery	• Gas sector cost recovery is designed on long-term contracts and "incremental" new infrastructure pricing • Power sector cost recovery in organized markets is divided into market products and discrete services but effective mechanisms to recover fuel infrastructure costs and the capital expenditures for ensuring fuel adequacy are not always present • Power sector cost recovery can differ by market, with some gas-fired generators making unauthorized pipeline overruns	• Various ISOs/RTOs will provide pay-for-performance measures • Various ISOs/RTOs are implementing Winter Fuel Programs to maintain additional fuel (i.e., oil) supplies
Alternative Contracting Mechanisms	• Gas-fired generators' reliance on non-firm gas capacity has created supply access issues in a number of markets (such as ISO-NE) • Alternative contracting, such as pay-for performance, higher payments for generators with firm service, pipeline contracts between firm and interruptible	• Capacity release pipeline contracts and multi-party firm transportation contracts • FERC deciding on implementing a natural gas trading platform • ISO-NE implementing a pay-for-performance mechanism, as well as continuing its Winter Fuel Reliability Program, in which ISO-NE stores liquid fuels

Source: Compiled from various sources by ICF.

Future Natural Gas Demand for Power Generation: ICF analyzed the three EIPC Phase II's "Futures" scenarios to determine their implications on natural gas use for power generation in the Eastern Interconnection. The results of this analysis are shown in Exhibit 1-2 along with other estimates from other sources. EIPC Scenario S1, referred to as the "Combined Policy Scenario" or CP, models the effect of carbon constraints and a reduction in the demand for energy. This scenario has a CO_2 price that is nationally implemented throughout the country and also reflects accelerated deployment rates for energy efficiency, and demand response. The combination of energy efficiency, demand response, and higher energy prices leads to a 19 percent reduction in demand in the Eastern Interconnection. EIPC Scenario S2 (referred to as the "Renewable Portfolio Standard" or RPS) is characterized by the regional procurement mandates for local renewable energy. It requires that 30 percent of the load in each of seven regions in the Eastern Interconnection be met by renewable resources by 2030. Although the level of electricity demand remained broadly consistent with the "Business-As-Usual" case (EIPC S3 or BAU), changes in the generation mix appreciably impact the fuel use in this scenario. As shown in Exhibit 1-2, the increased deployment of renewables displaced generation from other sources such that power sector natural gas use was the lowest among the three scenarios.

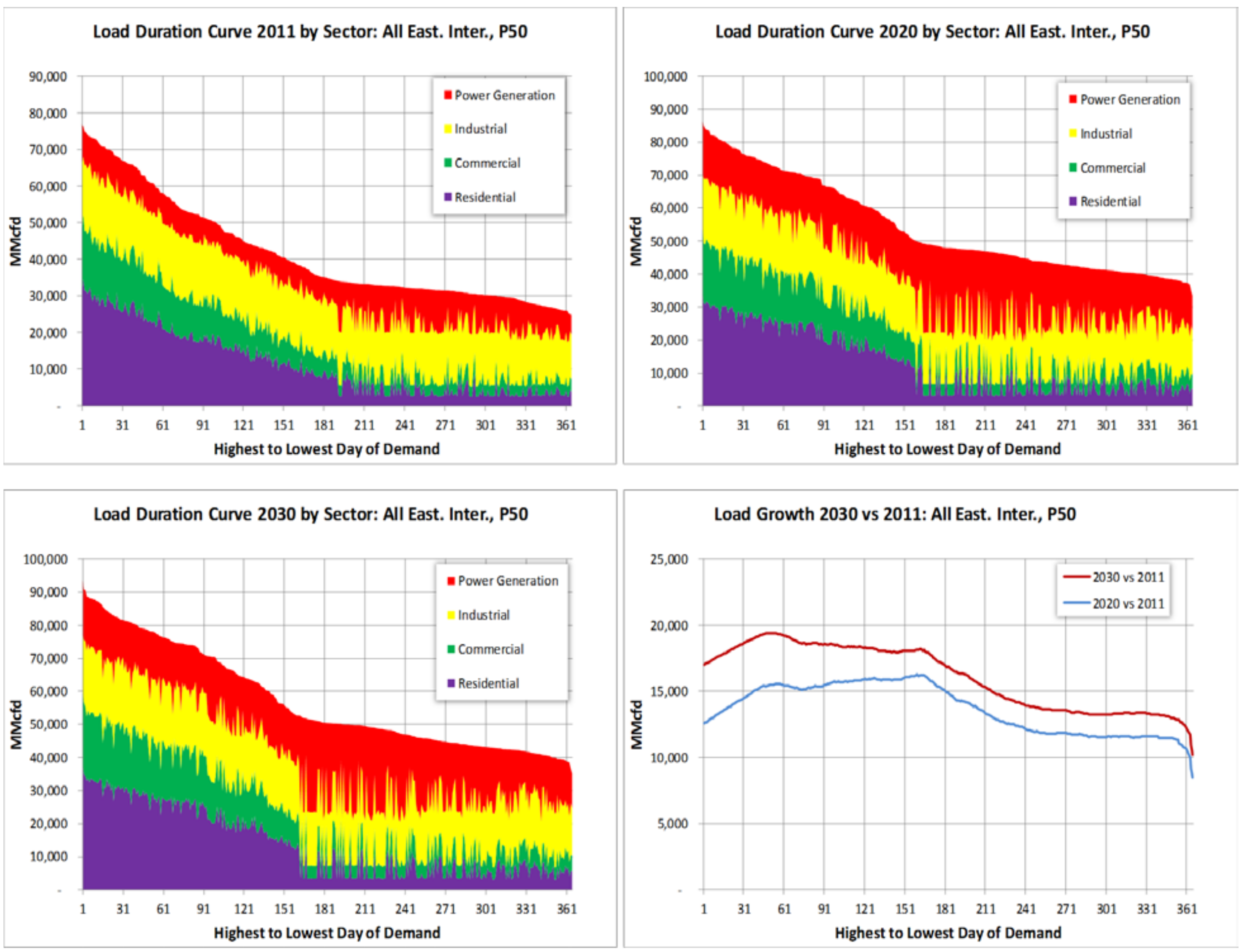
Exhibit 1-2: Eastern Interconnection Power Sector Gas Use (trillion Btu/ year)



Source: Eastern Interconnection Planning Collaborative. Phase I Modeling Results. Available at: http://eipconline.com/Modeling_Results.html.

Future Natural Gas Demand for All Sectors: ICF combined the power generation gas consumption estimates from the three EIPC Futures scenarios with its own forecasts for non-power sector to estimate total natural gas demand within the Eastern Interconnection. Demand estimates were made on monthly, daily and hourly bases. Also, alternative forecast were prepared under nine different weather cases representing specific probabilities of occurrence. The results for S3/BAU daily demand by sector are shown below in Exhibit 1-3 for the sum of all areas in the Eastern Interconnection under expected (P50) weather case. Average daily demand is expected to grow from 41.8 billion cubic feet per day (Bcfd) in the 2011 EIPC base year and to 57.4 Bcfd in 2030. The coincident daily peak grows by 19.2 Bcfd between 2011 and 2030 and the non-coincident peaks grow by 24.1 Bcfd.

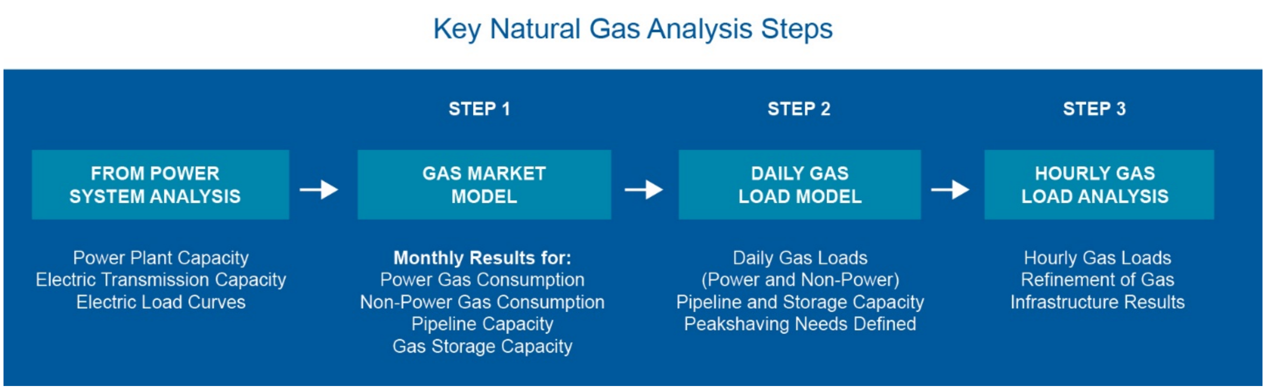
Exhibit 1-3: Eastern Interconnection Daily Gas Load by Sector Gas Use in BAU (MMcfd)



Source: ICF

<u>Methodology for Determining Infrastructure Requirements</u>: Infrastructure requirements were determined through the three-step process depicted in Exhibit 1-4. The gas usage from the three EIPC power gas use scenarios was combined with a single ICF forecast of non-power gas use in the Eastern Interconnection and all gas use outside of the Eastern Interconnection was simulated under expected (P50) weather in ICF's Gas Market Model® (GMM) to assess overall North American natural gas supply, demand, and infrastructure utilization. The GMM® simulates future month by month natural gas production, consumption, pipeline flows, and storage injections/withdrawals. New infrastructure is added in GMM® so as to bring locational basis (the difference in natural gas prices at two locations) in line with the cost of new pipeline capacity and to make monthly natural gas price patterns consistent with the cost of seasonal storage. This Step 1 analysis was further refined in Step 2 by looking at how daily natural gas loads would be met under a range of weather outcomes and in Step 3 by looking at the expected future pattern hourly natural gas loads. Steps 2 and 3 were used to verify the GMM® pipeline and seasonal storage builds and to estimate short-term storage, fuel switching investments, and the degree to which gas demand might be unmet under severe weather scenarios.

Exhibit 1-4: Key Natural Gas Analysis Steps



<u>Options for Supplying Natural Gas and Alternative Fuels:</u> The ICF analysis of daily demand for natural gas included a stochastic optimization to determine the optimal mix of infrastructure that would most economically meet the weighted average demand of the nine weather cases. The following options were available to meet daily demand under the nine weather cases:

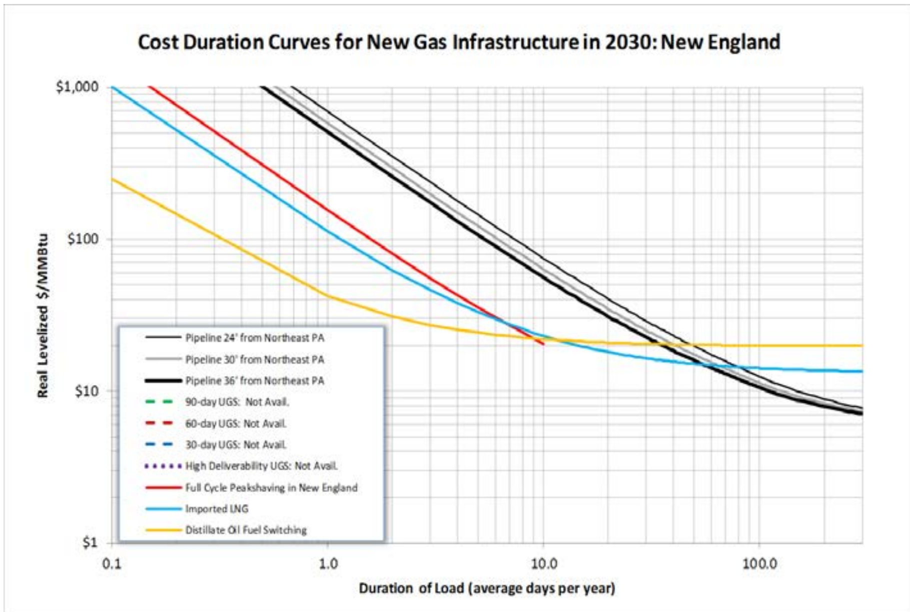
- Expanding node-to-node pipeline capacity,
- Adding depleted reservoir or aquifer underground storage (where feasible),
- Building high deliverability underground storage (where feasible),
- Adding LNG peak-shaving plants,
- Expanding fuel switching at power plants or industrial facilities,
- Curtailing demand when the cost of meeting demand exceeded the presumed customer's willingness to pay.

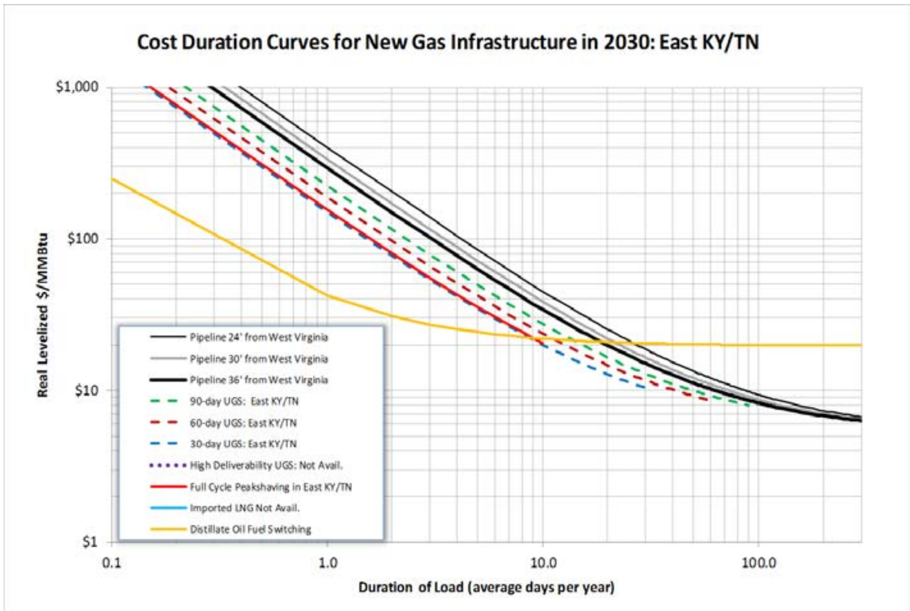
The cost of meeting demand with these options was based on the gas infrastructure cost algorithms adjusted for regional differences. The application of those cost algorithms leads to different infrastructure development in each region due to such differences as:

- Existing infrastructure and its utilization for local and downstream gas consumption,
- Geology that impacts the feasibility, design and cost of underground storage, and the distance to any such suitable storage sites,
- Location of and distance to gas supply basins,
- Regional gas pipeline construction costs,
- Existence of and/or maximum capacity potential for each option,
- Volume and temporal distribution of incremental gas loads.

One way of representing the relative economics of different infrastructure options to meet daily gas demands is to create a “cost duration curve.” As shown in the two examples presented below in Exhibit 1-5, the x-axis of the cost duration curves represents how many days each year a given level of gas load exists. The y-axis of the cost duration curve shows dollars per MMBtu of energy service. Options with relatively high capital costs and relatively low variable costs (such as gas pipelines) will tend to be the lowest cost option for loads that last for 100 days or more per year. This is because the high capital costs can be spread over more days (more Btus of energy service) resulting in a low $/MMBtu cost. On the other hand options with low capital costs, but high variable costs (such as fuel switching to No. 2 distillate oil) tend to be the lowest cost options for loads of short duration.

Exhibit 1-5: Examples of Cost Duration Curves





The two examples of cost duration curves shown in Exhibit 1-5 show the GMM® node for New England (wherein underground storage is not feasible but imports of LNG are) and the GMM® node for East Tennessee/Kentucky (wherein some kinds of underground storage are available, but LNG imports are not). The different size pipelines are represented by black lines in the cost duration curves. Different kinds of underground storage are represented by dashed lines. The solid red line represents LNG peak-shaving plants, the solid blue line is LNG imports and the solid yellow line is fuel switching to No. 2 fuel oil.

Where feasible, underground storage is often a lower cost option than gas pipelines for loads lasting fewer than 100 days per year. Underground storage remains the lowest cost option down to about 15 or 10 days of duration, at which point other options such as fuel switching, imported LNG or peak shaving are the most economic options. Note that the x-axis goes down to 0.1 days per year. This represents a load that is expected to occur one day every 10 years. Meeting such infrequent loads cost several hundreds of dollars per MMBtu because the capital cost are allocate to only a few units of energy leading to very high costs per unit.

Requirements for New Natural Gas Infrastructure and Its Costs: New pipeline additions will be driven by recent developments in unconventional gas supply particularly in the Northeast and Southwest. More specifically, in the Northeast new pipeline projects will originate from the growing Marcellus and Utica. In the Southwest, project developers will focus on the Eagle Ford and Haynesville shale plays.. The Southwest is also seeing substantial load growth, especially in the form of gas exports to Mexico and at LNG terminals, and increasing petrochemical gas use. The southeastern and central states will see sizable capacity increases, primarily because a significant number of coal plants are expected to be retired, and gas-fired capacity will be serving as the primary replacement.

Pipeline capacity increase will largely follow production and market growth over the next 10 years. Other required infrastructure additions that come along with transmission capacity additions include laterals for new points of consumption and new processing capacity to handle the increased volume of gas in the system. Exhibit 1-6 and Exhibit 1-7 show the infrastructure requirements by scenario.

Exhibit 1-6: 2014–2030 Lower 48 Natural Gas Infrastructure Requirements

Infrastructure Requirement by Type	Combined Policy (S1)	RPS (S2)	BAU (S3)
Total Well Completions	763,073	686,484	725,062
Miles of Transmission Mainline	14,153	9,369	11,527
Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants	8,826	5,014	7,676
Miles of Gas Gathering Line	190,219	170,807	180,619
Inch-Miles of Transmission Mainline	446,098	285,900	354,089
Inch-Miles of Laterals to/from Power Plants, Storage Fields, and Processing Plants	153,328	83,804	125,818
Inch-Miles of Gathering Line	703,485	637,274	670,484
Compression for Pipelines (1000 HP)	4,186	2,423	2,852
Compression for Gathering Line (1000 HP)	5,537	4,672	5,329
Gas Storage (Bcf Working Gas)	581	349	488
Processing Capacity (MMcfd)	21,557	18,552	21,016

Source: ICF GMM® and EADSS.

To support the incremental gas movements that are anticipated, substantial investment is required. Exhibit 1-7 shows required investment in new natural gas transmission capacity by various categories. These infrastructure needs between 2014 and 2030 are projected to total $182.6B in the Combined Policy (S1) Scenario, $131.7B in the RPS (S2) Scenario, and $156.9B in the BAU (S3) Scenario, the bulk of which is comprised of gas transmission lines, as shown in Exhibit 1-7.

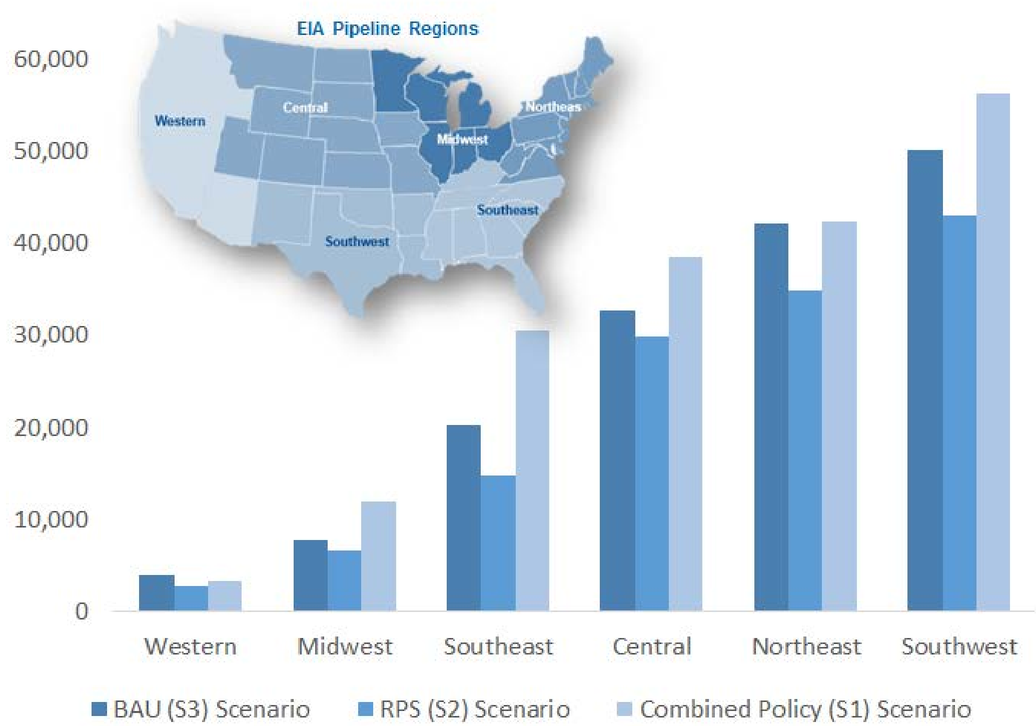
Exhibit 1-7: 2014–2030 Lower 48 Natural Gas Infrastructure Investment Expenditures (2012$ Million)

Infrastructure Requirement by Type	Combined Policy (S1)	RPS (S2)	BAU (S3)
Gas Transmission Mainline Pipe	$66,540	$43,289	$53,212
Laterals to/from Power Plants, Gas Storage and Processing Plants	$23,862	$13,361	$19,728
Gathering Line (pipe only)	$22,531	$20,350	$21,450
Gas Pipeline & Storage Compression	$11,034	$6,416	$7,556
Gas Gathering Line Compression	$15,647	$13,273	$15,104
Gas Lease Equipment	$16,843	$14,815	$15,865
Gas Processing Capacity	$17,380	$14,982	$16,960
Gas Storage Fields	$8,788	$5,226	$7,029
Lower-48 U.S. States	**$182,624**	**$131,712**	**$156,904**

Source: ICF GMM® and EADSS.

Exhibit 1-8 shows the geographic distribution throughout the U.S. of natural gas infrastructure expenditures for the three scenarios on the basis of EIA pipeline regions. A table of the underlying data is available in Exhibit 3-36

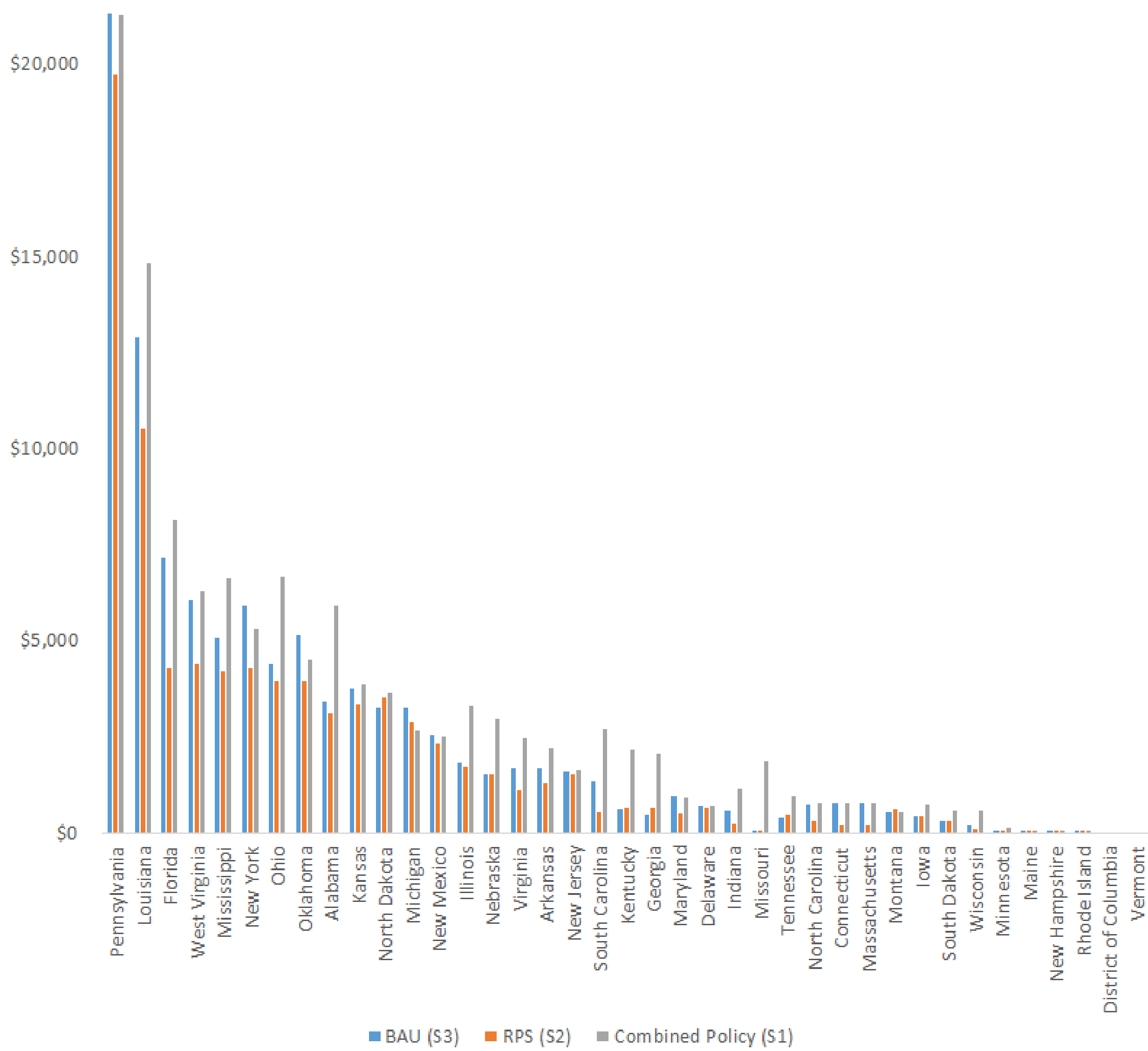
Exhibit 1-8: U.S. Lower 48 States Regional Natural Gas Infrastructure Investment Expenditures by Scenario



Source: ICF GMM®. and EADSS.

Exhibit 1-9 below shows total infrastructure expenditures by state for the Eastern Interconnection. A table of the underlying data is available in Exhibit 3-37.These infrastructure needs between 2014 and 2030 are projected to total $121.9B in the Combined Policy (S1) Scenario, $83.3B in the RPS (S2) Scenario, and $101.1B in the BAU (S3) Scenario.

Exhibit 1-9: 2014-2030 Total Expenditures (Millions of Real 2012 Dollars)



Source: ICF GMM®. and EADSS.

Options for Co-Optimizing Natural Gas and Electric Systems: Many planning tools currently exist for projecting capacity expansion needs for either the natural gas sector or the power sector. There are a handful of tools that attempt to jointly optimize new builds across both sectors through a variety of analytical approaches.

While the objectives of resource planning in both the power and natural gas sectors include finding an efficient resource mix to meet the projected demand, and to maintain or improve system reliability, solutions from a single sector's planning may jeopardize the reliability of the other sector due to their interdependence. Co-planning in the power and gas sectors can therefore be advantageous because of such reliability concerns. However, both the power and natural gas sectors have distinct physical and market characteristics, and different reliability requirements. To simply put together all the constraints in representing such characteristics and requirements in both sectors into a single optimization model would result in an unmanageably complex and cumbersome model. On the other hand, as pointed out in the previous section, existing multi-sector co-optimization models' spatial or temporal resolution might be too coarse to identify reliability issues, which often arise in local areas and across short time scales.

Nevertheless, cross-sector co-optimization can yield important benefits and can often identify solutions not available through iterative solutions that treat each sector separately. One such approach is demonstrated here using ICF's IPM natural gas module. In the scenario explored here, the model identified a solution with a total overnight construction cost through 2030 that was $7.5 billion or 1.5 percent lower than an equivalent iterative approach. While the power sector costs were higher, this was offset by lower fuel infrastructure costs which resulted in a net lower cost for the system as a whole. This further underscores the potential for co-optimization to lead to cost reductions across sectors and to identify low cost solutions not typically available through other means.

<u>Reliability Metrics and Effects of Fuel Adequacy:</u> There have been recent indications that economics of current resource adequacy practices, namely 1-in-10 LOLE based planning, is under increasing levels of scrutiny by policy makers. An economics-based approach to resource adequacy addresses some of the limitations of the physical reliability perspective provided by the 1-in-10 standard. It provides a framework for reflecting the customers' willingness to pay for varying levels of reliability, as well as the risk-mitigation benefits of higher reliability requirements not accounted for in traditional physical reliability metrics. Thus, in addition to estimating the value of avoided load curtailments, the economics-focused view on reliability considers both the potential to reduce other reliability-related costs, such as expensive energy purchases to meet peak demand, and the insurance value of reducing the likelihood of high cost shortages. It is important to note, however, that the economic optimal at which the average total system cost is minimized would not necessarily be at the point where end users costs are minimized. In other words, direct costs experienced by consumers through the delivered costs for fuel and power might be higher in the cost-optimal case in order to avoid overbuilding fuel infrastructure that would lead to higher total costs. However, assuming efficient cost recovery mechanisms and long term market equilibrium, the cost optimal solution will provide the lowest long term costs to consumers as well as the lowest cost to the economy as a whole.

<u>Impediments to Infrastructure Development Caused by Environment Permitting:</u>

Siting natural gas pipelines and other natural gas infrastructure requires an understanding of the major impacts and concerns associated with the facilities themselves, as well as an understanding of the permitting, consultation, and environmental review requirements of federal and state agencies. Pipeline siting typically proceeds in a two-step process to take all the issues and authorities into account and to avoid undue delays and project opposition. First, there is a screening-level analysis of alternatives to support initial selections of a preferred route and reasonable alternatives. Second, there is a more detailed analysis to support final selections and approval. If federal approval is needed, this detailed analysis would include scoping, consultation, and review of impacts and mitigation measures. Although federal regulations can be the binding restraint with regard to the siting of natural gas infrastructure, state policies and regulations can influence infrastructure siting decisions and provide a more rigorous stringency requirement. The EISPC EZ Mapping tool is well positioned to help inform these processes and could be leveraged in several key ways to facilitate better siting outcomes. Several groups have put forth their own recommendations for streamlining the federal permitting process.

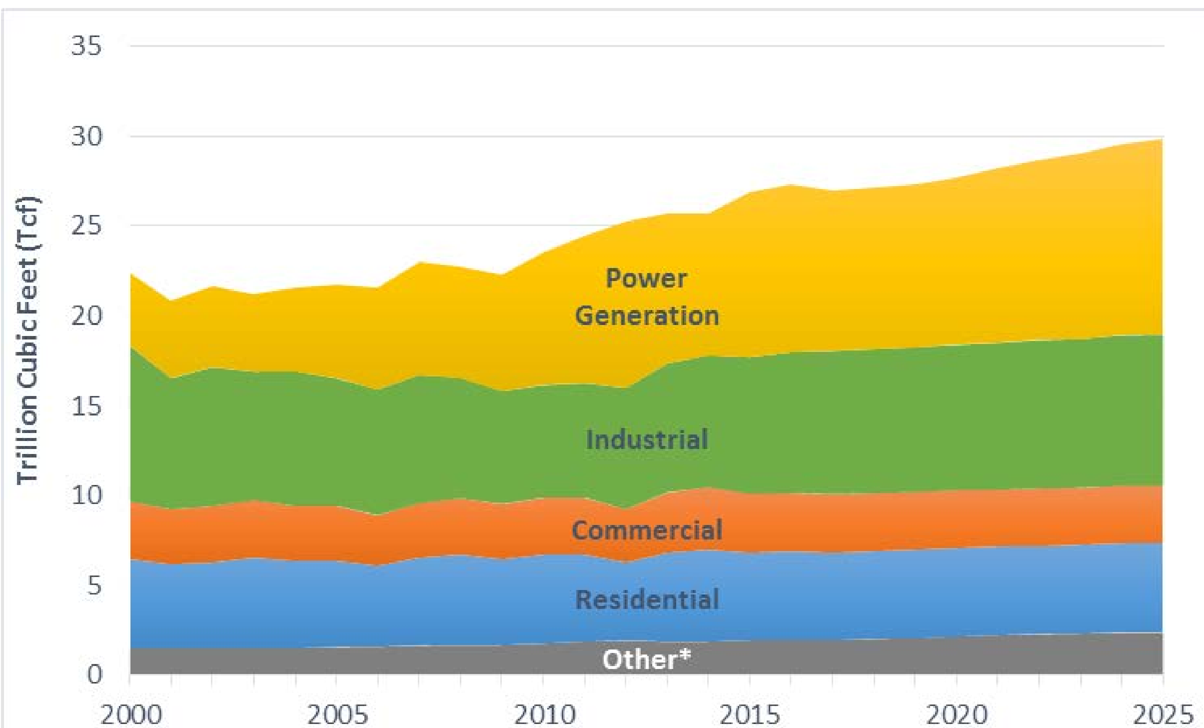
Recommendations for Future Analyses: Going forward, the integration of fuel supply availability and interdependence in power sector resource planning carries significant importance for accurate electricity resource planning. Many of the uncertainties surrounding the question of natural gas and alternative fuel adequacy are the same as those that affect other aspects of power systems planning. These include uncertainties in future economic growth, effects of conservation and changes in consumer behavior, the role of renewables, distributed generation, and the status of new environmental rules that can affect coal and other generation. Therefore, any periodic efforts to monitor and analyze these factors can also help in answering questions related to fuel adequacy. Beyond that, the most thorough and accurate integration of natural gas supply into resource adequacy planning would be accomplished by expanding the standard loss of load modeling framework to include the gas supply and alternative fuel networks. This includes collecting data on their current and expected future capacities and likely future utilization under various weather scenarios. However, given the state of resource adequacy planning in the power sector (i.e., lack of consensus on metrics and modeling tools), wide-scale development and implementation of such modeling tools may not be feasible in the short term. In this context, the problem can be divided into two phases. The long-term goal should be development of an integrated planning tool as described in the Layer 3 analysis. In the short term methodologies could be developed to supplement standard loss of load modeling studies using the Layer 1 and Layer 2 analyses described in Section 5. We also believe that these efforts at quantifying future fuel adequacy and its impact on electric resource adequacy can be enhanced by further research into specific data requirements for such planning including: statistical modeling of weather distributions and climate trends on fuel infrastructure needs; disaggregation of historical benchmark statistics on plant outages caused by fuel inadequacy versus other causes; and development of historical database of reliability and availability for fuel infrastructure in including natural gas pipelines and fuel delivery systems. Finally, we recommend a periodic review of regional infrastructure needs in the Eastern Interconnection to help to track developments and trends across the region. EISPC is in a unique position to develop a periodic review of regional fuel infrastructure needs in cooperation with fuel suppliers and consumers.

2 Catalog of Concerns and Ongoing Efforts

As North American power generators increasingly turn to natural gas, concerns over the incongruent nature of natural gas and power markets have come to the fore. In particular, the ability to maintain electric system reliability during times of natural gas supply access constraints has become a key focus for independent system operators, regional transmission organizations, market participants, federal and regional regulators, and other government agencies. The power and natural gas sectors differ in a number of ways, including market structure, infrastructure attributes, regulatory steps, cost recovery mechanisms, planning procedures, and operating practices. Gas use in the power sector is forecast to see the fastest growth of all sectors between 2013 and 2025, comprising over 36 percent of total U.S. Lower 48 domestic natural gas consumption over the next decade (up from 33 percent in 2013), according to ICF estimates.

> *"As we have seen over the last few years, natural gas is being used much more heavily in electricity generation. This trend appears likely to accelerate as coal-powered generation is retired, renewable energy resources require more backup by natural gas plants, and low natural gas prices encourage more use of gas" – Federal Energy Regulatory Commission*
>
> Source: *FERC. "Natural Gas - Electric Coordination" Web page. Available at: http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp.*

Exhibit 2-1: U.S. Lower 48 States Domestic Natural Gas Consumption by Sector



Source: ICF GMM® August 2014.

* Includes pipeline fuel and lease & plant (lease & plant refers to natural gas used in drilling operations and as a fuel in processing plants).

2013–2014 Winter Cold Snaps and Impacts on Gas-Electric Coordination

The 2013–2014 severe winter weather, particularly the January 6–7, January 22, January 27, and February 6 events, underscored key gas-electric coordination issues, in addition to the importance of fuel diversity. The extreme winter weather brought up key issues of reliability and pricing volatility, and market participants continue to struggle with maintaining reliability in the natural gas and power sectors, while also striving for price stability.

New York Independent System Operator, Inc. (NYISO), Midcontinent Independent System Operator, Inc. (MISO), and PJM Interconnection, LLC (PJM) set electric demand winter records, with ISO New England Inc. (ISO-NE) nearing its historic winter peak. The Midwest experienced consistently cold weather extremes. California experienced high natural gas prices, despite the relatively mild weather. This highlights the interconnected nature of U.S. gas markets, as natural gas destined to California was often diverted to other higher-priced markets, leading to supply access issues and escalating gas prices in California.

Overall, the natural gas system responded well to higher demand levels. Firm natural gas service was not curtailed, although producers reported at least 1.5 Bcfd in well freeze-offs. Insufficient pipeline capacity (rather than adequacy of natural gas supply) led to supply access issues in a number of regions, particularly New England. This led to extreme price escalation, with record-breaking prices seen in January.

Unusually high natural gas prices were seen in a number of markets for short durations over several cold snaps, particularly in regions with natural gas pipeline bottlenecks, such as the in U.S. Northeast. Spot gas prices reached $70/MMbtu in Philadelphia, PA, and reached $100/MMbtu during intraday trading in the Mid-Atlantic, with PJM prices spiking to $123/MMbtu during the January 22nd cold snap. These price spikes were likely due to high natural gas demand, pipeline capacity issues, and gas supply access issues, rather than market manipulation. Despite these price spikes, supply region prices such as Henry Hub remained relatively low compared to historical cold snaps.

Due to high power demand, high natural gas prices, and power plant outages, there were unusually high electricity prices, as well, with peaks of between $300 and $700 per MWh. High power prices correlated with natural gas price spikes, as natural gas is on the margin at many facilities.

Fuel oil as a substitute for natural gas was vital to maintaining reliability over the cold spells. In particular, New England's Winter Reliability Program, which increased oil inventories significantly, allowed the region to maintain fuel supplies. However, many regions experienced issues with inventories, fuel replenishments, and permitting limits on burning oil.

In several regions, such as PJM, nuclear and coal plants proved useful in meeting peak demand, particularly in cases where natural gas plants were unavailable due to supply access or mechanical failures. Growing reliance on natural gas-fired generation, coupled with the retirement of expensive coal and nuclear plants across several regions, highlighted reliability concerns that will compound in the future. In the future, gas-electric coordination will gain critical importance in regions anticipating coal and nuclear retirements that will be replaced with gas-fired generation. Coal and nuclear contributed to power sector reliability when gas supplies were tight or gas-fired facilities experienced weather-related maintenance issues.

Natural gas and power markets performed well and measures were taken to ensure there were no firm power or natural gas load curtailments. However, the extreme weather highlighted stresses on the natural gas and power systems that must be addressed to avoid serious reliability issues in the future.

Source: FERC Technical Conference, 1 April 2014. Available at:
https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7272&CalType=%20&CalendarID=116&Date=04/01/2014&View=Listview.

The 2013–2014 severe winter weather highlighted key gas-electric coordination issues, in addition to the importance of fuel diversity, including key concerns of reliability and pricing volatility. Market participants continue to struggle with maintaining reliability in the natural gas and power sectors, while also striving for price stability. While natural gas and power markets performed well and measures were taken to ensure no firm power or natural gas load curtailments, the extreme weather highlighted stresses on the natural gas and power systems that must be addressed to avoid serious reliability issues in the future.

Independent System Operators and Regional Transmission Organizations (ISOs/RTOs) must focus on reliability, although differences in the physical and process limitations between natural gas and power sectors create additional reliability hurdles. Market participants must factor in the need for pipeline capacity, further alignment of Gas Days and Electric Days, and provide proper sequencing of nominations. Impending nuclear and coal retirements will likely be replaced with gas-fired generation, further emphasizing the need for improved gas-electric coordination. As the industry moves more toward natural gas-fired generation, gas-electric coordination and natural gas supply access become imperative factors in ensuring system reliability. Exhibit 2-2 below highlights key gas-electric concerns and remedial efforts.

Gas-electric coordination concerns exist across all regions. However, regions where gas-fired power generation sees fast growth and power generators rely on interruptible natural gas pipeline transportation face the most severe reliability issues. Exhibit 2-2 shows the primary concerns facing market participants, and includes market design concerns such as differences in infrastructure planning in the electric and gas sectors, communication mismatches between the two industries, and cost recovery mechanisms.

Exhibit 2-2: Main Gas-Electric Coordination Concerns

Main Concern	Issues	Efforts to Address Concern
Market Design Concerns		
Infrastructure Planning Mismatches	• Natural gas pipelines are built on a firm contract basis, not interruptible service • Gas-fired power generators rely mainly on interruptible service contracts in organized markets (e.g. PJM), though use of interruptible service in the U.S. Southeast is not an issue, where firm gas contracts are used when needed, based on integrated resource planning • Gas-fired generators relying on highly congested pipelines face supply access issues	• Pipeline expansions, particularly in the U.S. Northeast • FERC's Show Cause Order (RP14-442) proposes to allow multi-party firm transportation service contracts • NERC Operating Committee compiled guidelines for cold weather event reliability issues • Consideration of a dual fuel requirement
Differing Time Scales	• Gas Day determined by NAESB, and Electric Day gas nominations differ by region, leading to unfair advantages for earlier bid markets	• FERC's NOPR proposes to move Gas Day schedule to better align with the power sector • ISO-NE moved bidding window up two hours • Considering moving Gas Day and Electric Day to more closely align
Incongruent Definition of Resource Adequacy	• Natural gas resource planning is based on peak day conditions (i.e., extreme weather), while the power sector planning is driven by reserve capacity (i.e., reliability concerns)	• Various regions, including NYISO, to run cold weather scenarios to assess various factors affecting gas-electric coordination • ISOs such as ISO-NE and NYISO require more frequent fuel surveys during times of short supply • ISOs such as NYISO are developing formal processes for determining reliability needs
Communications		
Lack of Communications	• Scheduled outages are not coordinated within the gas sector or with power sector coordination	• FERC's NOPR aims to improve communication between gas and power sectors • ISO-NE developing a platform for information-sharing between natural gas and power sectors

Main Concern	Issues	Efforts to Address Concern
Cost Recovery		
Differences in Cost Recovery	• Gas sector cost recovery is designed on long-term contracts and "incremental" new infrastructure pricing • Power sector cost recovery in organized markets is divided into market products and discrete services but effective mechanisms to recover fuel infrastructure costs and the capital expenditures for ensuring fuel adequacy are not always present • Power sector cost recovery can differ by market, with some gas-fired generators making unauthorized pipeline overruns	• Various ISOs/RTOs will provide pay-for-performance measures • Various ISOs/RTOs are implementing Winter Fuel Programs to maintain additional fuel (i.e., oil) supplies
Alternative Contracting Mechanisms	• Gas-fired generators' reliance on non-firm gas capacity has created supply access issues in a number of markets (such as ISO-NE) • Alternative contracting, such as pay-for performance, higher payments for generators with firm service, pipeline contracts between firm and interruptible	• Capacity release pipeline contracts and multi-party firm transportation contracts • FERC deciding on implementing a natural gas trading platform • ISO-NE implementing a pay-for-performance mechanism, as well as continuing its Winter Fuel Reliability Program, in which ISO-NE stores liquid fuels

Source: Compiled from various sources by ICF.

2.1 Market Design

2.1.1 Infrastructure Planning Market Design Mismatches

In regions such as the U.S. Northeast, natural gas pipeline capacity expansion is a significant issue, without which reliability and pricing concerns cannot be fully be addressed. Natural gas supply access was a significant factor in the price spikes seen during the various cold snaps over the 2013–2014 winter. However, mismatches between the power and natural gas infrastructure planning processes create barriers in implementing infrastructure expansion plans.

Organized wholesale electric capacity markets typically provide no more than a three-year outlook, and market structures in some regions provide only a very near-term price signal. By contrast, new pipeline capacity can only be constructed after FERC has issued a Certificate of Public Convenience and Necessity (CPCN) in accordance with the Natural Gas Act. To obtain the certificate, the pipeline must obtain binding commitments from shippers to enter into firm service contracts for a term of at least 10 years.

2.1.1.1 Natural Gas Pipeline Planning

Natural gas pipeline development and construction largely depends on firm service contracts. To construct natural gas pipeline facilities that meet interstate commerce requirements, developers must obtain a Certificate of Public Convenience and Necessity from the Federal Energy Regulatory Commission (FERC), which requires the pipeline to demonstrate a "market need." This is achieved through binding precedent agreements for the new capacity with ten or more years of firm service contract commitments.[2, 3, 4, 5] Therefore, it is difficult to rely on interruptible transportation (IT) or capacity that is released by firm shippers (e.g., capacity released to power generators) when not otherwise required.

However, when gas local distribution company (LDC) capacity is not fully utilized (e.g., peak heating load), pipelines generally have unused capacity that can be sold as IT or sold in the capacity release market by firm capacity holders. There are instances where constrained pipelines, such as Algonquin, have little or no capacity for IT, limiting generators to released capacity gas or capacity that is obtained by a natural gas marketer.[6]

If a generator (or the marketer obtaining gas for the generator) is able to obtain pipeline capacity, it must nominate gas using standardized North American Energy Standards Board (NAESB) procedures for nomination, confirmation, and scheduling. FERC regulations require

[2] Federal Energy Regulatory Commission (FERC). "Order Clarifying Statement of Policy," Docket No. PL-99-3-000 (15) (September 1999).

[3] FERC. "Order Clarifying Statement of Policy," Docket No. PL 99-3-001 (9 February 2000).

[4] FERC. "Order Further Clarifying Statement of Policy," Docket No. PL 99-3-002 (28 July 2000).

[5] FERC. "Statement of Policy on Maximizing the Quality, Objectivity, Utility, and Integrity of Disseminated Information and Request for Comments," Docket No. PL 02-3-000 (30 April 2002).

[6] ICF International. "Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies." Independent System Operator New England (ISO-NE), 18 November 2013: Holyoke, MA. Available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.

nomination and confirmation communications to the pipeline within FERC pre-approved pipeline tariff nomination cycle timelines.[7]

Interruptible Pipeline Service: Many pipelines have capacity that is unused by firm customers under "average annual operating" conditions and may be available for non-firm (interruptible) loads. During a nomination cycle timeline non-firm delivery requirements may be communicated to the pipeline. The pipeline can then deliver gas to facilities depending on the physical capabilities of the system. A desirable attribute of interruptible service for power generation customers, particularly those that generate a relatively low annual load factor, is that the shipper only pays for the volume of transportation service received, instead of a fixed monthly reservation fee for reserve capacity. However, interruptible service has the lowest service priority and is the first to be restricted or reduced during periods of high use.

New Pipeline Planning Process: Section 7 of the Natural Gas Act of 1938 grants FERC (and FERC's predecessor, the Federal Power Commission) the authority to issue a Certificate of Public Convenience and Necessity to natural gas companies (the Interstate Pipeline) if the company can demonstrate that the pipeline is in "the public" interest.[8] Without a Section 7 Certificate a pipeline cannot construct facilities or provide gas transportation service. The Certificate is important for purposes of eminent domain and a regulatory assurance that the pipeline will "have a reasonable opportunity to recover prudently incurred costs" including the return on the capital that is invested.[9] FERC regulation has evolved since restructuring to rely on pipeline shipping contracts to demonstrate the market need and the existence of supply. Contractual commitments by pipeline customers (i.e., shippers) provide the best method to evaluate need among other competing projects. In order to be included as part of the evaluation, the pipeline must present FERC with legally binding precedent agreements showing that the pipeline will be fully or nearly fully subscribed[10] for a minimum of ten years.

Shipper Regulations: There are two key FERC pipeline shipping rules, meant to ensure open pipeline access, that affect gas-electric coordination from the perspective of infrastructure expansions. These rules are meant to provide open access to the pipelines and ensure that secondary markets (such as capacity release and interruptible service contracts) are able to operate. In the absence of these rules, a shipper with pipeline capacity rights could ship gas on behalf of another entity, thereby potentially barring capacity release and interruptible service shippers (such as power generators) from shipping gas volumes. However, some argue that

[7] ICF International. "Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies." Independent System Operator New England (ISO-NE), 18 November 2013: Holyoke, MA. Available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.

15 USC 717h.

[8] "U.S. Natural Gas Act of 1938," section 7.

[9] ICF International. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." North American Electric Reliability Corporation (NERC), November 2012: Atlanta, GA.

[10] Generally FERC requires that more than 85 percent of the capacity is under contract.

these rules can create inefficiencies in moving volumes to key areas, particularly during times of short supply. The two key shipping rules are[11]:

- Shipper-Must-Have-Title Rule: This rule stipulates that a shipper moving natural gas through a pipeline must hold title (i.e., ownership) of the pipeline capacity, as well as the transported gas volumes.
- Buy-Sell Prohibition: A similar provision, this rule states that a shipper moving natural gas through a pipeline is barred from selling its gas to another capacity holder (i.e., another shipper with capacity rights to the pipeline) at one point along the pipeline and later buying the gas volumes again at a later point.

2.1.1.2 Power Sector Planning

Electric power sector resource planning is concerned with the expansion of generating capacity and new electric transmission, distribution and storage infrastructure in order to meet future demand in a defined planning area during peak hours. The planning efforts are concentrated around securing adequate investment in capacity and allowing for sufficient lead-time to complete construction and interconnection of new generating units before they are needed to meet demand.

In order to ensure resource adequacy, planning entities perform analyses that rely on detailed representations of the probabilistic nature of demand and generation. Such models attempt to capture the full range of uncertainty by modeling electric demand, forced outages and the variability of renewables as probability distributions. The ultimate goal of resource adequacy modeling is to calculate the reserve margin requirement (i.e., installed capacity requirement or planning reserves) that would result in the target reliability level. In resource adequacy studies planners predominantly use Loss of Load Expectation (LOLE) as the baseline metric. LOLE is generally defined as the expected number of days (or hours) for which available capacity is insufficient to serve the peak demand. Historically, the power industry has applied a one day in 10 year (1-in-10) LOLE standard in analyzing resource adequacy requirements or the adequate level of reserve margin requirements. The 1-in-10 standard typically refers to the resource adequacy level where electricity demand is curtailed due to the lack of resources for one day in a 10-year span, or 2.4 hours per year. Typical resource adequacy studies indicate that reserve margins of between 10 percent and 20 percent are needed to achieve 1-in-10 LOLE.

Ideally, the level of reliability should be set at a point beyond which willingness to pay for electricity services significantly diminishes or no longer exists due to the high cost of maintaining reserves. This threshold point is known as the Value of Lost Load (VoLL). The challenge of pricing VoLL stems from the relative inelasticity to price of electricity demand. During periods with insufficient supplies to meet firm electricity load there are few options available to the consumer in response to increases in the price of energy. Furthermore, the willingness to pay for electricity is not uniform across regions and customer classes and is therefore very difficult to predict.

[11] Available at: http://www.lexology.com/library/detail.aspx?g=a54db13c-4d23-4180-b2b5-1c95332b12d0.

A further complication is that in a deregulated market where bids to supply electricity are constrained by price caps (e.g., a cap equal to short-run variable costs), the last unit to be dispatched and which sets the energy price cannot recover its fixed costs (investment costs and fixed O&M) in the energy market. This discrepancy is exacerbated for “peaker” units that are expected to dispatch for only a limited number or hours or not at all.

In the United States, two market designs have emerged to enable generators to recover their fixed costs and to maintain adequate reserve margins: the energy-only market design and a bifurcated market design, consisting of both energy and capacity. Both mechanisms have advantages and disadvantages, so different planning entities are using different parameters to structure their markets. Currently ERCOT implements an energy-only structure, while most of the eastern RTOs (PJM, ISO-NE and NYISO) have centralized capacity markets.

<u>Energy-Only Market Design</u>: In the energy-only market design, energy prices are capped; currently, the highest cap is in ERCOT, which in 2015 is expected to gradually increase the cap to $9,000/MWh from today’s price of $5,000/MWh. Under this structure, generators recover their fixed costs during price spikes, i.e., scarcity pricing hours where prices are much higher than the variable operating costs of the marginal unit. Scarcity pricing conditions occur when there are insufficient supplies to meet firm electricity load and response reserve requirements. This can occur because: (1) the excess of supply over demand reaches a low enough level that there could be a shortage of operating reserves used to balance supply and demand and the market price is administratively set equal to the system-wide price of $9,000/MWh, or (2) suppliers with less than five percent market share bid above short-run costs and clearing prices reflect these bids.

If prices spike sufficiently (at high enough levels and/or for long enough duration), new units are incentivized to enter as revenue exceeds the annual revenue requirements of new units. If, however, there are too few spikes and insufficient revenue, units will be retired or mothballed. The next unit in the supply stack then becomes the marginal unit and the process and revenue check is iterated.

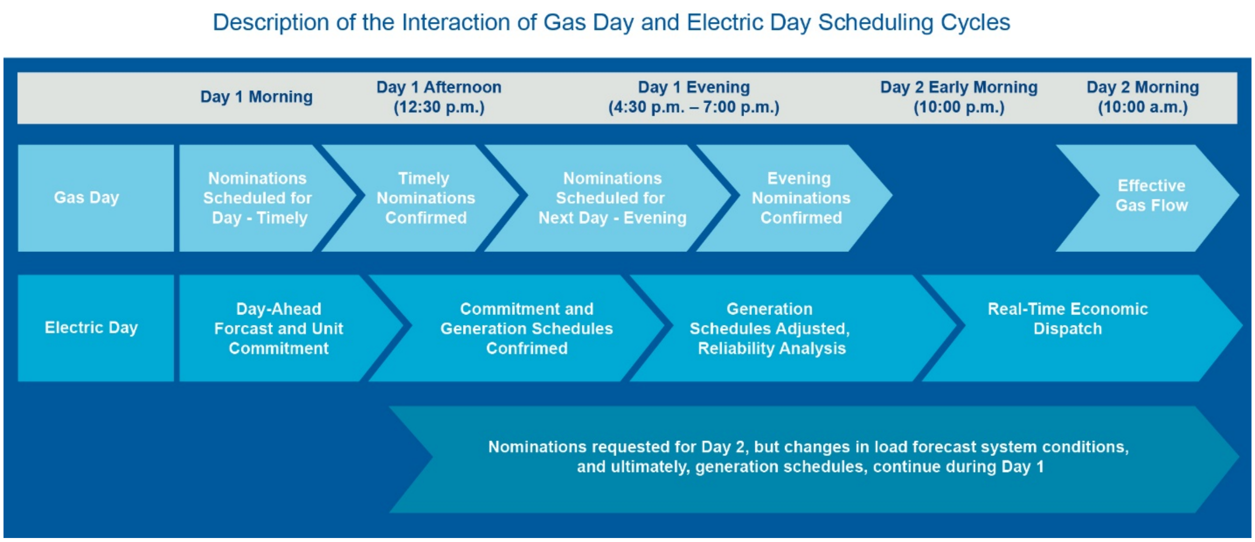
<u>Bifurcated (Energy and Capacity) Market Design</u>: In a bifurcated market design, capacity markets assure resource adequacy (i.e., meeting reserve margins) by providing generators with a way to recover capital and fixed operating costs. Generators are paid additional revenues for their per kilowatt (or megawatt) contribution to the installed capacity (e.g., $/kW-year, $/MW-day). These additional capacity price payments help maintain marginal existing capacity for reliability (i.e., avoid over-retirements) by covering future fixed costs and required capital investment retrofits. The payments also encourage new builds and provide capital investment recovery. In many capacity market designs, energy margins earned above a certain threshold (e.g., peaker net margin) are deducted from capacity payments. In regions where capacity markets exist, energy prices are typically capped at a much lower level than in energy-only markets. In such cases, energy prices are usually set below $1,000/MWh and usually must equal short-run variable costs.

2.1.2 Differing Timescales

As the supply of electricity is managed in sub-minute intervals, natural gas moves at only tens of miles per hour. Thus, pipelines must plan ahead for delivery. Pipelines must manage the rates at which natural gas is received and removed to manage the volume of gas on in each pipeline segment (i.e., line pack, which has substantial physical limitations available to manage fluctuations).

The natural gas procurement cycle has deadlines occurring several times per day and is not synchronized with electricity markets (see Exhibit 2-3 below). Electricity control areas and utilities in North America operate on various "Electric Days," while every natural gas pipeline in North America operates on a common "Gas Day" for the transportation (flow) of gas, commonly resulting in mismatches between the two.

Exhibit 2-3: Description of the Interaction of Gas Day and Electric Day Scheduling Cycles



Source: North American Electric Reliability Corporation (NERC). "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States" (98). December 2011. Available at: [http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.](http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf)

2.1.2.1 <u>Gas Day Schedules</u>

The Gas Day established by regulations through the NAESB and FERC begins at 10 a.m. Eastern Standard Time. The Gas Day is divided into four daily default cycles including Timely, Evening, Intraday 1, and Intraday 2, with each cycle including three processes designed to ensure reliable pipeline operation and pressure maintenance, including[12]:

- <u>Nomination</u>: The process used by firm capacity holders or shippers to request a specified volume of pipeline service for the next cycle or the next Gas Day. In order of priority, primary firm service is scheduled first, followed by secondary firm service holders, and finally interruptible service. If insufficient capacity is available to meet all

[12] NAESB. "NAESB Governance Documents." NAESB, 2013: Houston, TX. Available at: http://www.naesb.org/materials/gov.asp.

priority category service requests, lowest priority category service will be met on a *pro rata* basis. A pipeline may schedule *pro rata* interruptible service on one portion of the pipeline, while approving only secondary firm capacity on other pipeline segments.

- Confirmation: The second step in the process is a confirmation from the producer selling the gas that pipeline delivery at the designated receipt point will arrive to the shipper.
- Scheduling: The final step is communication that the scheduled gas volumes to the shippers to remove the gas at the designated delivery point.

Unlike electricity load balancing, natural gas pipeline deliveries typically occur at a maximum speed of 30 miles per hour under a constant pressure in order to maintain reliable service. Thus, a shipper will remove gas at the delivery point at the same time as gas is delivered to the pipeline receipt point (up to 1,000 miles upstream).

The NAESB timeline shows the minimum number of nomination periods, although pipelines can offer additional nominations as well. However, if capacity is not available or has previously been scheduled, then additional nomination periods are not feasible.

Exhibit 2-4 shows the standard NAESB timeline (in Central Standard Time) based on the nomination, confirmation, and scheduling steps described above. These four nomination windows are uniform across North America, which all natural gas pipelines offer.

Exhibit 2-4: Current Pipeline Nomination Cycles (CST)

Nomination Cycle	Nomination Deadline	Notification of Schedule	Nomination Effective	Bumping of IT
Timely *(Cycle 1)*	11:30 a.m.	4:30 p.m.	9:00 a.m. Next (Gas) Day	
Evening *(Cycle 2)*	6:00 p.m.	10:00 p.m.	9:00 a.m. Next (Gas) Day	Yes
Intraday 1 *(Cycle 3)*	10:00 a.m. Gas Day	2:00 p.m. Gas Day	5:00 p.m. Gas Day	Yes
Intraday 2 *(Cycle 4)*	5:00 p.m. Gas Day	9:00 p.m. Gas Day	9:00 p.m. Gas Day	No

Source: NAESB.

Individual generators or marketers make gas nominations based on initial fuel requirements for the following day. However, fuel needs can change dramatically between the initial period and actual gas nominations due to weather or other unexpected events. Despite this variation, gas nominations have already been locked in. Generators often overestimate fuel needs, rather than risk large imbalance penalties. This means that during times of short supply, fuel supplies are not allocated properly, with some generators with an oversupply, while others are short of supply.[13]

[13] North American Electric Reliability Corporation (NERC). "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States" (98). NERC, December 2011. Available at: http://www.nerc.com/files/Gas_Electric_Interdependencies_Phase_I.pdf.

2.1.2.1.1 Interregional Gas Nomination Scheduling Differences

Each region has its own timing for the generation unit commitments, with bid closing in the Day-Ahead Market ranging from 5:00 a.m. for NYISO to 12:00 p.m. for CAISO. Although the disparate timings give generators the opportunity to bid into more than one market, the timing creates advantages for markets with earlier bidding windows. For instance, while ISO-NE recently moved its nomination schedule earlier, ISO-NE's initial offers are due much later than are NYISO's (10 a.m. versus 5 a.m., respectively). Thus, New York markets can secure gas supplies earlier than ISO-NE, meaning that during peak demand days, ISO-NE could experience supply access issues.

While natural gas pipelines operate on a uniform schedule across North America, power market schedules differ by region. Market participants argue over the optimal offer to optimize market liquidity (i.e., lowest price and volume risks). For NYISO, its earlier electric offer schedule, relative to ISO-NE, means its gas-fired generation needs will be met before that of ISO-NE's. This means that during the coldest winter days (i.e., peak days), ISO-NE's gas-fired power generators will face natural gas supply access issues.

Altering power market schedules to operate on the same schedule would create another set of issues. Currently, the different NYISO and ISO-NE bidding schedules allow generators to sequence bids. A generator can bid into the NYISO market, and if not selected for NYISO dispatch, can then bid into the ISO-NE market. This allows for additional supply-side resources available by virtue of market sequencing, although the ISO with the earlier nomination schedule maintains an advantage over the other.

2.1.2.1.2 Gas Day Responsiveness to Electric Day Swings

Natural gas pipelines require high volume and high pressure loads, and are not designed to accommodate the large load swings seen in power markets, as gas-fired generators come on- or off-line with short notice. Sudden demand spikes can cause pipeline pressure to drop, thereby adversely impacting service to all pipeline customers.

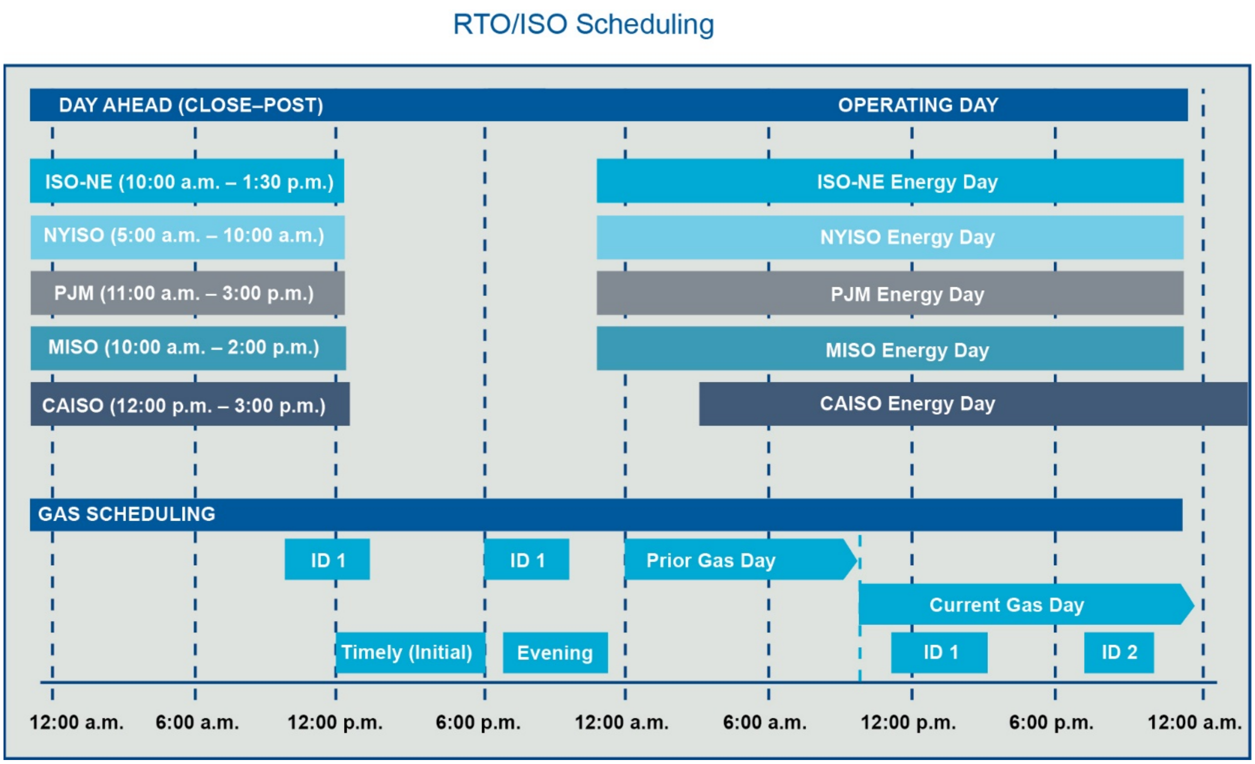
Uncertainty persists around whether final gas volume requirements are known during the gas pipeline nomination cycle, as well as if volumes in excess of confirmed nominations are removed, including specified allowances for hourly swings. If gas requirements are unknown within the gas pipeline nomination cycle, and interruptible load capacity is available (and factored into the pipeline operating plans), or if hourly swings are excessive, a pipeline would need to allocate, reserve, or construct pipeline-related facilities to provide "intra-cycle" services. Often this involves construction of pipeline services, adding additional capacity (through more pipeline, compression, or storage capacity). However, these expansions do not occur without a cost recovery mechanism.

In several markets, some gas-fired generators are able to gather gas volumes in excess of the level nominated, scheduled, and confirmed with the pipeline.[14] These gas volumes are typically replaced through balancing provisions, although timing gaps in replacement sometimes leads to pressure issues on the pipeline, affecting deliverability to customers all along the pipeline. Deliverability issues are particularly critical during peak utilization during cold winter days, which compound system stresses and supply access issues.

2.1.2.2 Electric Day Schedules

Within the electric sector, power generators serve hourly system needs, which can vary dramatically. Whereas the Gas Day schedule is uniform across North America, Electric Day schedules differ by region, as shown in Exhibit 2-5 below.

Exhibit 2-5: RTO/ISO Scheduling



Source: Revised from Goldenberg, M. "Coordination between Natural Gas and Electricity Markets." Slide 10. FERC. April 2013. Available at: http://www.ferc.gov/EventCalendar/Files/20130425072632-Staff%20presentation%204-25-13.pdf.

Note: ID denotes "Intraday."

2.1.3 Incongruent Definitions of Resource Adequacy

The natural gas and power industries approach system reliability concerns quite differently, particularly in the context of an unanticipated supply loss. A mechanical or other physical failure in a power sector results in an immediate loss of service, which could lead to service losses to

[14] Note that the gas nomination cycle is not synchronized to day-ahead or real-time operations of generation facilities, resulting in a potential disconnect in usage versus nomination.

millions of customers, under certain conditions. Thus, operators must respond instantaneously, and employ both resource adequacy and reliability measures to avoid system losses. In contrast, mechanical and other physical failures on natural gas pipeline systems often result in capacity reductions, rather than complete losses. Thus, natural gas pipeline outages lead to an allocation of capacity reductions based on customer priority class. First, interruptible service is curtailed, then firm service to secondary delivery points, and last firm service to primary points.[15] The disparate approaches to resource adequacy in the natural gas and power sectors, which encompass differences in contingency event probabilities and regulatory frameworks, create additional hurdles to integrating gas and electric resource adequacy measures.

Electric utility requirements for new generation are significantly different than pipelines and capacity expansions are driven by resource adequacy requirements and other elements of market design. Transmission infrastructure is also different as it is triggered by reliability criteria based on stressed system conditions. Both generation and transmission resources then have some level of reserve capacity or duplication in order to accommodate contingencies or abnormal weather conditions. Additionally, generation units typically follow hourly loads. Units used primarily for peak load conditions tend to operate during a limited number of hours. This means that, at least for peaking plants, when assessing annual gas volumes required, firm gas transportation service with fixed reservation charges is costly and excessive.

Only in markets where excess gas pipeline capacity is available can low capacity factor units rely on interruptible service with any degree of confidence of available supply. However, if growth in gas system requirements necessitates new pipeline capacity or when market conditions result in concurrent peak electricity and gas needs, the structural differences of the two industries lead to a mismatch between gas delivery service and electric generation requirements (particularly challenging in areas where a large quantity of reserve capacity is gas-fired).

2.1.3.1 Natural Gas Sector Resource Adequacy Planning

The gas industry (e.g., gas distribution companies) develops gas supply plans based upon peak (i.e., design day) conditions that are driven by extreme weather conditions. As a result, under "average annual operating" conditions, most pipelines have remaining capacity not in use by firm customers, and thus available for non-firm (i.e., interruptible) service. Pipelines can utilize facilities with spare capacity to deliver gas (up to the physical capacity limits), assuming non-firm delivery requests are made during the nomination cycle timeline. This process is typical for IT service or capacity release from the firm shippers.

[15] A firm gas pipeline contract will specify "primary" receipt and delivery point for which the shipper has full access. Additionally a firm shipper can use "secondary" receipt and delivery points when space is available at those locations. Whether using primary points, secondary points or a combination of the two, the firm shipper can nominate firm quantities only up to his firm contract quantity.

2.1.3.2 Power Sector Resource Adequacy Planning

The structure within the electric industry is fundamentally different. A combination of resource adequacy requirements and market design drives capacity additions, while reliability criteria under stressed system conditions often prompt transmission infrastructure planning changes. Thus, transmission and generation systems have an implicit level of reserve capacity available to accommodate contingencies or extreme weather conditions. In addition, power plant generation corresponds with hourly system needs. During peak conditions, the generation units mainly required operate at limited periods. Firm gas transportation service—based on fixed reservation fees that do not fluctuate by delivered gas volumes or time-of-day usage rates—is costly and excessive for these types of low-capacity factor facilities.

2.1.4 Market Design Recommendations

2.1.4.1 Infrastructure Expansions

Infrastructure expansions, particularly natural gas pipelines, are a key issue in addressing gas-electric coordination, particularly in the U.S. Northeast. Natural gas pipeline capacity, connecting new supply sources to demand markets, continues to expand. Regional efforts in the U.S. Northeast, in particular, are underway. For example, six New England governors signed an agreement in support of expanding the region's energy infrastructure, particularly natural gas. In response, the New England States Committee on Electricity (NESCOE) submitted a request to ISO-NE to increase natural gas pipeline capacity.[16] The initiative would increase firm pipeline capacity into New England by 1,000 MMcfd above 2013 levels.[17]

2.1.4.2 Gas and Electric Day Coordination and Sequencing

FERC issued three orders on March 20, 2014 to address the physical gas and Electric Day schedules.[18]

2.1.4.2.1 Gas Day Schedule Change[19]

The first order, the Notice of Proposed Rulemaking (NOPR) (Docket No. RM14-2), proposed nomination and scheduling timeline changes within the Gas Day schedule. All U.S. interstate natural gas pipelines are under the same schedule as dictated by NAESB. However, as the natural gas and power sectors continue to improve coordination, Gas Day changes are also necessary. The NOPR allows industry participants six months from the NOPR date of publishing

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[16] New England States Committee on Electricity. Email correspondence to Gordon van Welie, President and CEO ISO New England, Inc. "Re: Request for ISO-NE technical support and assistance with tariff filings related to electric and natural gas infrastructure in New England." 21 January 2014. Available at: http://www.nescoe.com/uploads/ISO_assistance_Trans___Gas_1_21_14_final.pdf.

[17] Ibid.

[18] Palmer, DA; Hardin, S. "Federal Energy Regulatory Commission (FERC) Issues Orders to Synchronize Gas and Electric Scheduling Deadlines." The National Law Review. 21 March 2014. Available at: http://www.natlawreview.com/article/federal-energy-regulatory-commission-ferc-issues-orders-to-synchronize-gas-and-elect.

[19] Coordination of the Scheduling Process of Interstate Natural Gas Pipelines and Public Utilities, Docket No. RM14-2, 146 FERC ¶ 61,201 (2014). Available at: http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf.

to develop a proposal changing the Gas Day. After that period, interested parties then have 60 days to comment on the proposal. However, if a consensus is not reached then interested parties have 240 days to comment on suggested changes. The NOPR proposed to move the start of the Gas Day from 9:00 a.m. CST to 4:00 a.m. CST to accommodate the early morning power usage. Some industry participants argue that gas-fired generators may not have sufficient gas supplies to meet early morning requirements, at a time when the Gas Day is closing. FERC argued that such issues can be resolved. The NOPR also advocated that the first Timely Nomination move from 11:30 a.m. CST to 1:00 p.m. CST. FERC argued that this move would provide gas-fired generators more time to secure gas supplies before Day Ahead market bidding windows are closed. The NOPR also proposed to add a fourth intra-day nomination time slot to provide more opportunities to alter gas supplies to accommodate changes in actual power demand.[20] Exhibit 2-6 shows the current and NOPR-proposed pipeline nomination cycles (CST).

Exhibit 2-6: Current and NOPR-Proposed Pipeline Nomination Cycles (CST)

Nomination Cycle	Current vs. Proposed	Nomination Deadline	Notification of Schedule	Nomination Effective	Bumping of IT
Timely *(Cycle 1)*	Current	11:30 a.m.	4:30 p.m.	9:00 a.m. Next (Gas) Day	
	Proposed	1:00 p.m.	4:30 p.m.	4:00 a.m. Next (Gas) Day	
Evening *(Cycle 2)*	Current	6:00 p.m.	10:00 p.m.	9:00 a.m. Next (Gas) Day	Yes
	Proposed	6:00 p.m.	10:00 p.m.	4:00 a.m. Next (Gas) Day	Yes
Intraday 1 *(Cycle 3)*	Current	10:00 a.m. Gas Day	2:00 p.m. Gas Day	5:00 p.m. Gas Day	Yes
	Proposed	8:00 a.m. Gas Day	11:00 a.m. Gas Day	12:00 p.m. Gas Day	Yes
Intraday 2 *(Cycle 4)*	Current	5:00 p.m. Gas Day	9:00 p.m. Gas Day	9:00 p.m. Gas Day	No
	Proposed	10:30 a.m. Gas Day	2:00 p.m. Gas Day	4:00 p.m. Gas Day	Yes
Intraday 3 *(Cycle 5)*	Current				
	Proposed	4:00 p.m. Gas Day	6:00 p.m. Gas Day	7:00 p.m. Gas Day	Yes*
Intraday 4 *(Cycle 6)*	Current				
	Proposed	7:00 p.m. Gas Day	9:00 p.m. Gas Day	9:00 p.m. Gas Day	No

* Bumped IT shippers notified by 6:00 p.m. CST.

Sources: NAESB and Sutherland. "Legal Alert: FERC Issues a NOPR Reforming Gas Day and Two Orders to Improve Natural Gas – Electric Generation Industry Coordination." March 26, 2014.

The NOPR also further defines the "No Bump Rule." With the NOPR changes, the rule would state that after gas volumes are scheduled during the Gas Day, even if scheduled as interruptible service, the gas will not be "bumped" from the schedule, even if higher priority gas service (i.e., firm service) service nominates gas to flow during the intra-day nomination. This differs from the current rule, which dictates that the rule applies to the third (last) intra-day nomination only. This means that if a firm shipper makes a nomination in the first or second

[20] Palmer, DA; Hardin, S. "Federal Energy Regulatory Commission (FERC) Issues Orders to Synchronize Gas and Electric Scheduling Deadlines." The National Law Review. 21 March 2014. Available at: http://www.natlawreview.com/article/federal-energy-regulatory-commission-ferc-issues-orders-to-synchronize-gas-and-elect.

intra-day nomination schedules, a scheduled interruptible shipper can be bumped from the schedule.[21]

After releasing the proposed NOPR, FERC delayed any decisions in order to allow the North American Energy Standards Board (NAESB) the opportunity to propose an alternative to NOPR, giving NAESB until September 16, 2014 to propose an alternative. On June 18, 2014, NAESB released a status report, including[22]:

- No proposed alternative to the 4:00 a.m. CST start date as indicated in the NOPR
- Support for timely and evening nominations as proposed in the NOPR, but supported keeping the first intraday Gas Day nominations at 10:00 a.m., moving the second intraday nominations to 2:30 p.m., and adding a third (final) intraday nomination to be due at 7:00 p.m., applying the no-bump rule to the third Intraday Nomination Cycle

2.1.4.2.2 Gas and Electric Day Sequencing – Paper Hearing Order (EL14-22)[23]

The second order (Docket No. EL14-22) called on RTOs and ISOs to assess whether day-ahead scheduling practices need to better coordinate with natural gas pipelines, particularly in light of the NOPR regulatory changes. This order falls under the Federal Power Act sections 205 and 206 (Section 205 governs FERC's authority over public utility rates, terms, and conditions for interstate transport and sale of electric power, and Section 206 requires that revisions provide proof).[24] The Commission asserted that RTOs/ISOs should notify generators of Day Ahead bids clearing before the Gas Day's timely Nomination Deadline (proposed for revision at 1:00 p.m. CST). The order also stated that RTOs/ISOs should complete reliability commitments before the Gas Day's Evening Nomination Cycle (see Exhibit 2-7), as well as to show that other bidding deadlines, including reliability commitment processes, are reasonable.[25, 26]

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[21] Palmer, DA; Hardin, S. "Federal Energy Regulatory Commission (FERC) Issues Orders to Synchronize Gas and Electric Scheduling Deadlines." The National Law Review. 21 March 2014. Available at: http://www.natlawreview.com/article/federal-energy-regulatory-commission-ferc-issues-orders-to-synchronize-gas-and-elect.

[22] Ibid. "Can North American Energy Standards Board (NAESB) 'Fix' Federal Energy Regulatory Commission (FERC)'s Gas Scheduling Proposal? "The National Law Review. 23 June 2014. Available at: http://www.natlawreview.com/article/can-north-american-energy-standards-board-naesb-fix-federal-energy-regulatory-commis.

[23] California Independent System Operator Corporation et al., Order Initiating Investigation into ISO/RTO Scheduling Practices and Establishing Paper Hearing Procedures, Docket Nos. EL14-22 through 27, 146 FERC ¶ 61,202 (2014); Posting of Offers to Purchase Capacity, Docket No. RP14-442, 146 FERC ¶ 61,203 (2014). Available at: http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-2.pdf.

[24] PJM. Federal Power Act Sections 205 and 206 Fact Sheet. Retrieved from: http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/federal-power-act-sections-205-and-206.ashx.

[25] Ibid.

[26] Troutman Sanders LLP. "FERC Issues Series of Gas-Electric Coordination Orders." Washington Energy Report. Retrieved from: http://www.troutmansandersenergyreport.com/2014/03/ferc-issues-series-of-gas-electric-coordination-orders/.

Exhibit 2-7: Electric Commitment Results Publication Timeline (CST)

ISO/RTO	Time for Submission of Bids	Time for Publication of Day-Ahead Commitment Bids
California Independent System Operator Corporation (CAISO)	12:00 p.m.	3:00 p.m.
ISO New England Inc. (ISO- NE)	9:00 a.m.	12:30 p.m.
PJM Interconnection, LLC (PJM)	11:00 a.m.	3:00 p.m.
Midcontinent Independent System Operator, Inc. (MISO)	10:00 a.m.	2:00 p.m.
New York Independent System Operator, Inc. (NYISO)	4:00 a.m.	10:00 a.m.
Southwest Power Pool, Inc. (SPP)	11:00 a.m.	4:00 p.m.

Source: Coordination of the Scheduling Process of Interstate Natural Gas Pipelines and Public Utilities, Docket No. RM14-2,146 FERC ¶ 61,201 (40) (2014). Available at: http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf.

2.1.4.2.3 Multi-Party Firm Transportation Service Agreements – Show Cause Order (RP14-442)[27]

The other change in the NOPR requires pipelines to allow multi-party firm transportation service agreements, enabling multiple shippers to sign a firm service agreement for the same pipeline capacity (sharing the capacity).[28, 29]

The order (Docket No. RP14-442) related to the Natural Gas Act Section 5 (which states that FERC does not have the authority to limit natural gas pipelines from over-recovering from shippers).[30] The order requires that shippers post offers to purchase pipeline capacity released in tariffs. It remains unclear as to how the potential order would affect FERC's Shipper-Must-Have-Title and Buy-Sell Prohibition provisions, and if these rules would remain intact. FERC has long enforced the rules, with fines totaling millions of dollars for companies violating the rules; thus, any changes to these rules would be a dramatic change in FERC policies toward shipper regulations.[31]

2.1.4.2.4 Reliability Guidelines – Generating Unit Winter Weather Readiness

The North American Electric Reliability Corporation (NERC) Operating Committee compiled a list of reliability guidelines for cold weather events, covering safety, personnel roles and schedule, procedures, concern areas, testing, training, and communications. From past events, some areas of concern include level transmitters, pressure transmitters, flow transmitters,

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[27] FERC. Order to Show Cause. 146 FERC ¶ 61,203 (20 March 2014). Available at: http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-3.pdf.

[28] Coordination of the Scheduling Process of Interstate Natural Gas Pipelines and Public Utilities, Docket No. RM14-2, 146 FERC ¶ 61,201 (2014). Available at: http://www.ferc.gov/whats-new/comm-meet/2014/032014/M-1.pdf.

[29] Calpine Energy Services, L.P. Order Approving Stipulation and Consent Agreement, Docket No. IN07-24-000, 119 FERC ¶ 61,125 (2017). Available at: http://www.ferc.gov/EventCalendar/Files/20070509122244-IN07-24-000.pdf.

[30] Greene, JL. "Senate Energy Inquires into Nature of FERC's Section 5 Natural Gas Act (NGA) Investigations." Jennings Strouss, 19 March 2013. Available at: http://www.jsslaw.com/news_detail.aspx?id=227.

[31] Krantz, SM; Piczak, CT. "FERC pursues aggressive enforcement of the little-known shipper-must-have-title rule." Association of Corporate Counsel, 31 March 2008. Available at: http://www.lexology.com/library/detail.aspx?g=a54db13c-4d23-4180-b2b5-1c95332b12d0.

instrument air system, automatic valves, drains, water pipes, and fuel supply. These items should be addressed in a winter weather readiness plan.[32]

The measures recommend that companies develop a winter weather plan, train personnel on this plan and safety, and review the plan after each event to find areas of concern. These areas of concern are items that:

- Cause a safety hazard
- Can cause a unit to trip, affect unit startup, cause partial outages, cause damage to the unit
- Affect environmental controls
- Affect fuel or water supply to unit

2.2 Communications

2.2.1 Lack of Communication

Scheduled outages are not usually coordinated within the gas industry or between the gas and electric industries, although efforts to improve communication are on the rise. When operational data is available, such as the critical pipeline notices that are required by FERC although Orders 587-V and 698, the participants in each industry often have the basis to determine the relevance and importance of the information.

2.2.1.1.1 FERC Order 587

FERC Order 587, "Standards for Business Practices of Interstate Natural Gas Pipelines," was originally established in 1996 based on natural gas pipeline standards developed by the Gas Industry Standards Board (GISB), the predecessor to the North American Energy Standards Board (NAESB). The original order and successors included critical and non-critical notices required to be posted on the Transportation Service Providers (TSP) websites and delivered to affected shippers via Electronic Notice Delivery mechanisms. The order defined 12 notice types covering maintenance, intraday bumping, operational flow orders, and other issues, including[33]:

- <u>Capacity Constraints</u> – capacity constraints resulting from situations other than Operational Flow Order, Curtailment, or Force Majeure
- <u>Capacity Discount</u> – firm capacity offered at rate less than maximum tariff rate
- <u>Customer Services Update</u> – general customer service information
- <u>Gas Quality</u> – warnings of gas quality issues

[32] NERC. "Reliability Guideline: Generating Unit Winter Weather Readiness- Current Industry Practices." Available at: http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Generating_Unit_Winter_Weather_Readiness_final.pdf.

[33] NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012.

- Intraday Bump – warnings of bumping scheduled interruptible transactions
- Maintenance – scheduled repairs/maintenance that may impact service
- Operational Flow Order – issued to alleviate conditions that may impact safe operation

The Order has undergone a number of modifications, most recently on July 19, 2012, listed as FERC Order 587-V. The latest order includes the following standards[34]:

- Support of gas-electric interdependency – Described responsibilities under the Gas-Electric Operational Communication Standards circulated in FERC Order 698,[35] provided more details on each notice type, included 15 additional notice types meant to assist in identifying relevant pipeline system conditions and for shippers/interested parties of intraday pumps, operational flow orders, and other critical information by electronic method
- Capacity release upload information after elimination of Electronic Data Interchange (EDI)
- Related to the Electronic Delivery Mechanism (EDM)
- Related to the support of the Customer Security Administration (CSA) Process
- Pipeline postings of information regarding waste heat
- Technical maintenance revisions designed to more efficiently process wholesale natural gas transactions

2.2.1.1.2 FERC Order 698

FERC Order 698 also addresses gas-electric interdependency issues.[36] The order, established in 2007, arose from the stressful conditions and high gas and electric prices resulting from a cold snap in New England in 2003.[37] The order requires power plant operators (PPOs), interstate natural gas pipelines, transmission owners/operators, independent balancing authorities, and regional reliability coordinators to improve communication procedures to better coordinate transportation scheduling and gas-fired generator operations. Critical notices and planned service outages are defined to pertain to information on Transportation Service Provider conditions impacting gas flow schedules. Designated TSPs send PPOs operational flow orders and other critical notices from a designated TSP. TSPs communicate operational

[34] NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012.

[35] A similar FERC Order issued in 2007 that focuses on gas-electric interdependency issues, based on NAESB business practices. The order arose from cold weather conditions in the winter of 2003 that led to short-term reliability issues and high gas and electric prices.

[36] FERC. *Standards for Business Practices of Interstate Natural Gas Pipelines*. 18 CFR Part 284, Docket No. RM96-1-037; Order No. 587-V (2012). Available at: www.ferc.gov/whats-new/comm-meet/2012/071912/G-1.pdf.

[37] North American Energy Standards Board (NAESB). "Order 698 Effort." NAESB, 10 September 2007: Houston, TX. Available at: www.naesb.org/pdf3/update091207w5.doc.

flow orders, other critical notices, and non-critical notices by posting these orders and notices on their websites.

2.2.2 Communications Recommendations

2.2.2.1 Communication between Interstate Pipelines and Transmission Operators – 131115 and 131119 Order 787RM13-17-000

FERC modified parts of the current regulation to allow communication between interstate natural gas pipelines and electric transmission operators. Part 38 allows power transmission operators to share non-public information with natural gas pipelines. Part 284 of the Commission's regulation allows interstate natural gas pipelines to share non-public information with electric transmission operators to improve reliability between the two industries. The Commission has added a no-conduit rule to both Part 38 and 284 to protect the confidentiality of the shared information. This rule prohibits sharing operational information with third parties and marketing employees.[38] If an electric transmission operator or interstate pipeline has a tariff preventing the sharing of information in the rule, the entity must file under section 205 of the Federal Power Act (FPA) or section 4 of Natural Gas Act (NGA) to revise the restriction. The Commission may revisit the rule to determine efficacy of the information-sharing and its ability to improve reliability between the two industries.[38] While the rule allows sharing operational and customer specific information, FERC rejected defining a list of topics that this includes. FERC felt this would limit the intent of adding reliability where it is mainly targeting assisting during unforeseen issues.[39] According to ISO-NE and others, the communications between pipelines and ISOs allowed under the NOPR has improved transmission operations, particularly during the 2013-2014 Polar Vortex.[40]

2.3 Cost Recovery

2.3.1 Differences in Cost Recovery Mechanisms

In addition to the timeframe and the regulatory frameworks for infrastructure planning that differ between the natural gas and power sectors, the mechanism used for cost recovery differs significantly between the two industries.

2.3.1.1 Natural Gas Sector Cost Recovery

In natural gas, the cost recovery for transportation and storage infrastructure is designed upon long-term initial contracts to support construction and/or expansion combined with a rate design

[38] FERC. "Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators," Docket No. RM13-17-000; Order No. 787 (15 November, 2013).

[39] Soto, Andrew K. "Summary of Order No. 787 in FERC Docket No. RM13-17-000." 19 November, 2013.

[40] Brandien, P. "FERC ISO-NE Cold Weather Operations." Statement on behalf of ISO-NE. Presented at FERC Technical Conference. 1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401083935-Brandien,%20ISO-New%20England.pdf.

that includes virtually all infrastructure fixed costs as a fixed reservation charge. As the initial contracts for a pipeline expire, the contract terms replacing the initial set are determined by market conditions in conjunction with a regulatory "right of first refusal" granted to the original shippers.

In addition, the natural gas industry regulatory framework incorporates a rate design utilizing "incremental" pricing of new infrastructure. The result is that a new natural gas pipeline shipper into a market region will generally face a higher unit transportation rate than existing shippers. Natural gas production relies on a volumetric pricing structure to recover fixed costs.

2.3.1.1.1 Supply-Demand Imbalances in the Natural Gas Sector

Fluctuating gas-fired generator demand, unanticipated outages, rapid increases in spinning or other reserve capacities, and integration of variable energy resources (e.g., wind and solar) create significant variability in power demand, and by extension, natural gas pipelines. Despite this variability from gas-fired generators, pipeline operators must manage pipeline load variability to maintain safe operating pressure. During peak periods, the hourly variability tolerances are reduced.

In an effort to fulfil gas demand requirements, gas-fired generators have taken gas in excess of the volume that has been scheduled and confirmed by the pipeline to meet generation requests from the system operator. However, regulated pipelines deliver natural gas under standard tariff services that cannot be modified for individual generators. While gas volumes are eventually replaced through balancing provisions, the replacement timing does not prevent pressure issues that affect delivery pressures along the pipeline, sometimes creating imbalances.

An imbalance is the difference between the amount of natural gas that a shipper (e.g., natural gas producer) delivers to the pipeline at the receipt point and the amount a shipper (e.g., gas-fired generator) removes from the pipeline at the delivery point. Pipeline tariffs state how imbalances are recovered and what penalties to apply. The total cost of the imbalance and penalties usually exceeds the cost or value of the gas flowing on the pipeline, which deters pipelines from having imbalances.

Imbalances are assessed each day, although there have been discussions about assessing hourly imbalances or for periods aligned with the nomination cycles. However, no interstate pipeline has instituted such a system. As a result, currently, a shipper (such as a gas-fired generator) that takes more volumes off a pipeline than was scheduled (or a generator that takes less than was scheduled) is not penalized, assuming the pipeline imbalance is rectified during that day. Accordingly, the pipeline must be prepared to operate with variation in the amount of gas delivered to the pipeline and removed within the day.

A pipeline allows a shipper an "overrun" (i.e., removing more gas volumes than the shipper was scheduled for) whenever possible, as the pipeline can generate additional transportation revenue through overruns. However, delivery of unauthorized volumes reduces pipeline pressure in proximity to the delivery point, as well as along the pipeline. This is a critical problem during periods of peak use (such as cold winter days), particularly in regions with infrastructure constraints, such as New England.

During periods of peak requirements (such as cold winter days), pipelines issue a “Critical Notice” or “Operational Flow Order” (OFO) on a certain portion of the pipeline. During those periods, imbalance charges and penalties increase significantly in an effort to keep pipelines in balance during these constrained periods. For extreme overruns or during periods of capacity constraints, pipelines do have the option to install flow control valves at various locations such as delivery points, which pipelines can use to physically reduce gas volumes flowing to a facility that is taking more gas than it is entitled to. Pipelines are reluctant to take such actions against its customers, however, and shutting the valve on a customer is considered a “last resort.”

2.3.1.2 Power Sector Cost Recovery

There are two broad categories of cost recovery mechanisms in electric markets. In organized markets, cost recovery for generation is generally divided into three components 1) energy, 2) capacity, and 3) ancillary services. In various markets, the contribution toward cost recovery can differ in percentage terms. In addition, some markets are a hybrid with longer-term purchase power agreements. In more vertically integrated markets, cost recovery of generation is integrated into the planning process of the utility including generated power and purchased power.

RTO and non-RTO markets also operate with significant differences. For example, states without RTO operation have more bilateral and bundled retail power transactions. Among states operated by RTOs, some have provided retail competition whereas in the others, utilities must serve retail customers.

A number of regions—including the Northeast, Mid-Atlantic, and much of the Midwest—organize their markets under an RTO whose role is to expand competition in wholesale electricity generation. Given RTO reliance on private actors and market forces to determine the mix of generation, coordinating electricity and natural gas is more challenging in RTO regions.

In an organized market such as an RTO or ISO, scheduling and dispatch instructions are made by the central entity, while individual generation owners are responsible for securing fuel supply to meet the dispatch instruction. The prices to be paid for energy are established through competitive bids which are evaluated on the basis of each resource’s short-run marginal cost of operation. RTOs usually use indexed prices for fuel to prevent uncompetitive bidding rather than real time or as dispatched prices, which would be the more preferable option but are difficult to verify. As such, the fixed capital costs for fuel infrastructure cannot be recovered through this avenue because only variable fuel costs are allowed to be priced into the bid. As a result, cost recovery for capital expenditures associated with fuel adequacy must be pursued through other means which is a particular concern for natural gas in light of the role of the power sector in driving increased needs for new infrastructure and the other challenges discussed above.

Moreover, power market mitigations and price caps in certain central electricity markets (set by FERC at 1,000$/MWh) can fail to provide the appropriate price signals for generators to incur the cost of more secure fuel supplies. Firm natural gas transportation, which provides more supply security, may be perceived as unrecoverable sunk costs under these schemes.

The other means for generators to recover their costs—centralized capacity markets—are similarly limited in their ability to support new generation capacity. The issue of market design comes into play again, since auctions such as those carried out in PJM and ISO-NE fundamentally separate generation capacity from its physical attributes.[41]

These market limitations exist across all centralized markets within the Eastern Interconnection. For ISO-NE, the existing Forward Capacity Market (FCM) rules include little incentive for capacity market resources to invest in the capability to operate at capacity under all fuel supply conditions (e.g., through firm gas contracts, dual fuel capability, or fuel storage arrangements).[42] Similarly, under current PJM market rules, generators are unable to reflect the cost of firm gas transportation in energy market offers as stated in PJM's *Manual 15: Cost Development Guidelines*.[43] Moreover, the rules for bidding in the capacity market do not explicitly address the ability to reflect the costs of firm gas transportation either. Section 6.8 of the *PJM Open Access Transmission Tariff (Attachment DD – Reliability Pricing Model)* runs through all cost components, but makes no references to fixed fuel charges. NYISO tariff requirements do not allow fixed costs to be recovered in day-ahead and real-time energy bids.[44] Firm gas costs are not reflected in Installed Capacity (ICAP) demand curves,[45] so there is no opportunity to recover firm gas costs.

In regions where bundled retail service is still the norm, such as MISO and SPP, there are more options for recovering fixed fuel cost because of the closer relationship between state commissions and entities with the obligation to serve the load. These entities, such as state jurisdictional utilities, MUNIs or Co-Ops, have an obligation to provide reliable electric service to customers at the lowest reasonable cost. Utilities conduct resource planning to ensure sufficient capacity to meet peak customer demand. Such planning efforts include the amount, timing, and type of resources needed to meet peak demand goals cost-effectively, considering various constraints, load growth expectations, reserve margins, emission limitations, renewable and energy efficiency requirements, and other public policy mandates.

[41] The Organization of MISO States' Motion for Leave to File and Answer to IMM and Capacity Suppliers, Docket No. ER11-4081-000 (14 October 2011). Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12791690.

[42] ISO New England Inc. (ISO-NE). "Addressing Gas Dependence." Strategic Planning Initiative. July 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

[43] PJM Gas Electric Senior Task Force Problem Statement. December 2013. Available at: http://www.pjm.com/~/media/committees-groups/committees/mrc/20131219/20131219-item-06-gestf-problem-statement.ashx.

[44] Comments from the Independent Power Producers of New York on the Coordination between Natural Gas and Electricity Market (Docket No. AD12-12-000). 30 March 2012. Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12931805.

[45] US Power Generating. Presentation to the NYISO Electric Gas Coordination Working Group. "Gas-Electric Coordination: A NYC Generator's Perspective." April 2013. Available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_egcwg/meeting_materials/2013-04-12/USPGGas-Electric_Coordination_Presentation.pdf.

The units in these regions cannot recover fixed costs in the energy market either. The market mechanism, Locational Marginal Pricing (LMP), which is a reflection of the determined energy and transmission congestion prices at specific points based on marginal generation costs, does not currently support inclusion of the cost of firm natural gas transportation or for firm fuel supply.[46] In MISO, the cost of firm service load-serving entities may be recovered through a Fuel Adjustment Clause in the local tariff.[47] In SPP, suppliers have the ability to negotiate a capacity-type payment in exchange for agreement to become a designated resource and be subject to the must-offer requirement. Non-designated resources, however, do not have this leverage to gain access to fixed cost recovery.[48] In New England, a recent proposal by NESCOE seeks to recover the costs of new infrastructure through ISO-NE regional tariff rates as described in section 2.1.4.1 above.

The third category of cost-recovery mechanism applies to the southeast United States and Florida, which have maintained the traditional utility regulatory model consisting of bilateral and bundled retail transactions. Under this type of system, vertically integrated utilities retain transmission system control, choosing generators to dispatch.

Any decision regarding the acquisition of fuel falls under the purview of the state regulatory body. If the fuel-related expenditure is deemed prudent, the state commission approves the recovery of the capital cost through a rate increase to be assessed on all captive ratepayers within the service territory of the utility. Utilities may not, however, earn a profit on fuel charges (they are pass-through costs). The majority of these charges are included in the fuel charge on customers' bills. This process, referred to as Fuel Cost Adjustment, works by capturing the per kilowatt-hour difference between the amount that the utility actually paid for fuel and purchased power in a given quarter and the amount that it was expecting to pay when the baseline was set. All other approved charges are included in the energy charge, which also includes the utilities' base rate charge.

This cost recovery mechanism allows electric utilities to procure firm fuel contracts more easily and benefit from the security of supply that they bring. For example, Southern Company specifies that the generation capacity that is designated to serve firm obligations must be firm in all aspects of delivering the associated energy. To this end, sufficient amounts of firm gas transportation and storage capacity are maintained for the reliable operation of such facilities when needed to satisfy system demand.[49]

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[46] MISO Electric & Natural Gas Coordination Task Force, "Issues Related to Ensuring Reliability Through Market Signals." August 2013. Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/ENGCTF/2013/20130815/20130815%20ENGCTF%20Item%2008%20Issues%20Related%20to%20Ensuring%20Reliability%20Through%20Market%20Signals.pdf.

[47] MISO Electric & Natural Gas Coordination Task Force Issue Summary Paper. "Continued Reliability Through Market Signals." November 2013. Available at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/AC/2013/20131211/20131211%20AC%20Item%2002%20Issue%20Summary%20Continued%20Relaibility%20Through%20Market%20Signals.pdf.

[48] Boston Pacific Company, "A Review of the Southwest Power Pool's Integrated Marketplace Proposal." December 2010. Available at: http://www.bostonpacific.com/assets/documents/BPCReviewofSPPIntegratedMarketplaceProposal_12_30_10.pdf.

[49] Comments from Southern Company on the Coordination between Natural Gas and Electricity Market (Docket No. AD12-12-000). 30 March 2012. Available at http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12932144.

The same is true of utilities in Florida, which typically also have firm pipeline transportation service, and utilize a combination of released firm or interruptible service to meet peak needs. What is more, FRCC requires new gas-fired generation capacity additions to hold firm gas transportation and storage.[50]

As the electric and gas industries become more integrated and the two sectors compete more directly for access to fuel supplies during periods of combined high peak demand, the issue of securing reliable fuel becomes more vital. However, under current market structures, it is challenging for peaking electric generators in particular to acquire firm gas supplies due to their intermittent needs and low load profiles. There are few certain cost recovery mechanisms to allow fixed costs associated to paying monthly pipeline tariffs for firm gas contracts to be recouped. While these cost recovery mechanisms differ between the wholesale markets in the Eastern Interconnection, the situation is especially acute in organized markets with implemented retail access, such as ISO-NE, NYISO and PJM. These markets do not allow the recovery of costs in either the energy or the capacity market. On the other hand, RTOs such as MISO and SPP or bilateral markets such as SERC and FRCC, offer more flexibility because their structures allow load serving entities with an obligation to serve to recover their costs from regulatory commissions.

2.3.2 Alternative Contracting Mechanisms

Many electric generators rely on non-firm gas capacity to avoid paying the fixed costs of gas transmission. While this may be adequate in some regions at times, it is clearly becoming problematic in some parts of the U.S. Northeast, where there may not be adequate gas delivery capacity to serve non-firm gas users during peak periods. This problem could be addressed in several different ways, for example, from the power side, by paying generators more for electricity that is backed by firm fuel service, or on the gas side, by developing alternative contracting mechanisms that allow gas users something in between firm and fully interruptible service.

2.3.3 Cost Recovery Recommendations

2.3.3.1 Trading Market Development

During the April 1, 2014 Technical Conference, FERC heard the American Forestry and Paper Association's (AF&PA) arguments for a natural gas trading platform.[51] While a trading platform would not supplant near-term pipeline infrastructure needs, a trading platform would allow ISOs/RTOs a more real-time mechanism to match generator needs with available supplies than is currently available.

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[50] FERC. "Staff Report on Gas-Electric Coordination Technical Conferences." Docket No. AD12-12-000 (November 2012). Available at http://www.ferc.gov/legal/staff-reports/11-15-12-coordination.pdf.

[51] Platts McGraw Hill Financial. "FERC Hears Plan to Change Gas Markets." Megawatt Daily. 4 April 2014. Available at: http://www.preti.com/webfiles/Platts%20April%204%202014.pdf.

In theory, a natural gas trading platform would increase visibility into the commodity and capacity supply situation in real time in order to[52]:

- Assist electric system operators to more efficiently and reliably identify potential constraints and prepositioning and dispatching generation accordingly.
- Permit generators to identify opportunities to timely respond to ISO dispatch requests.
- Enable firm or interruptible capacity holders to identify higher value allocation opportunities for scheduled deliveries.
- Allow pipelines to quickly determine the physical feasibility of short term transactions or reallocations of commodity.
- Eliminate price distortions caused by unequal access to or imperfect information on available natural gas volumes and capacity.
- Improve flexibility in new and existing natural gas infrastructure.
- Preserve existing benefits the no-bump rule by allowing real-time gas reallocation to highest value use.

2.3.3.2 Capacity Market Payments

As mentioned earlier, the power sector has two mechanisms to incentivize generators to perform during peak demand periods:

- Scarcity Pricing (i.e., high power market clearing prices)
- Capacity Market Payments (i.e., a payment in addition to the variable costs of operating a power generation facility that allows a generator to recover long-term fixed costs)

A number of regions, including PJM, are moving toward capacity market payments in an effort to improve reliability through incentivizing power sector participants build needed capacity (including generating capacity, transmission, and demand response). In PJM's case, the region maintains capacity through its Reliability Pricing Model (RPM), or annual forward auctions, based on reliability concerns and supply-demand dynamics. The auctions include a Variable Resource Requirement (VRR), which is based on the region's power demand curve. The VRR values capacity above the installed reserve margin, setting the clearing price at equilibrium with supply. In addition, locational clearing prices are set based on transmission import capabilities of specific areas.[53]

Capacity payments are made to generators and other market participants to have resources on hand at all times. However, New Jersey and Maryland have few power resources, supplementing demand needs with costly importers. These imports translate to much higher

[52] Sipe, Donald. "Information and Trading Platform for Natural Gas." FERC, 1 April 2014: Washington, D.C. Available at: http://www.ferc.gov/CalendarFiles/20140401084311-Sipe,%20PretiFlaherty.pdf

[53] Paulson, E. "Capacity Markets in Action: Challenges from the Purchaser's Point of View." Harvard Electricity Policy Group Forty-Eighth Plenary Session. Customized Energy Solutions. Available at: http://www.hks.harvard.edu/hepg/Panel%203/Erik_Paulson.pdf.

capacity payments than the PJM average. To address this disparity between these states and the rest of the region, PJM attempted to construct transmission connecting regions with cheaper capacity prices with New Jersey and Maryland.

After unsuccessful attempts at building transmission to cheaper capacity sources, New Jersey and Maryland moved toward mechanisms to promote the construction in-state gas-fired generation. In both states, this was done through capacity payments, in which new gas-fired generators would receive guaranteed payments to cover capital expenditures (i.e., capacity). These greenfield facilities are meant to act as reserve capacity during times high power demand.

In 2011, New Jersey created its Long-term Capacity Agreement Pilot Program (LCAPP) in an effort to develop 2,000 MW in gas-fired power generation within the state. Similarly, Maryland required its electric distribution companies to issue a request for proposals (RFP) to construct 1,500 MW in gas-fired generation. In both programs, the participating gas-fired generators are guaranteed long-term capacity prices for a period of 15 years with the stipulation that the generators participate in the PJM market.[54] These guaranteed capacity prices are known as Standard Offer Capacity Agreement (SOCA) prices.

Proponents of LCAPP and Maryland's RFP contend that the programs provide financial security to developers via price guarantees. As part of the LCAPP program, power plants sell capacity and if the auction price falls below the price guarantee, taxpayers make up the difference. In contrast, if the clearing prices exceed SOCA prices, the participating generators must pay the state the difference. NRG, Hess Corp, and Competitive Power Ventures participate in the 2,000-MW gas-fired LCAPP program.[55]

Capacity bidding takes place three years in advance. Generators bid into the market, and for LCAPP participants, if capacity prices clear below their guaranteed capacity prices, ratepayers make up the difference. Generators outside the LCAPP program argue that LCAPP generators, with guaranteed capacity prices, are able to underbid other generators, thus distorting the market.

In the 2012 auction, prices cleared well below the guaranteed capacity prices, translating to significant outlays for ratepayers. For instance, CPV's capacity price cleared at $167.46/MW-day in New Jersey, though under LCAPP, CPV's 2016 SOCA price was set at $286.03/MW-day, as shown in Exhibit 2-8.[56] This means that ratepayers must pay the difference.

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[54] Stark, RD; Simon, DR; Spahr, B. "Traps for Unwary Project Sponsors—The LCAPP Saga ." Electric Light & Power. January 2012. Available at: http://www.ballardspahr.com/~/media/Files/Articles/2012-02-13_LCAPP_Saga_Simon_and_Stark.

[55] Kaltwasser, J. "State releases new LCAPP numbers." 03 October 2012. Available at: http://www.njbiz.com/apps/pbcs.dll/article?AID=/20121003/NJBIZ01/121009938/0/frm-education-partnership-for-nurses/State-releases-new-LCAPP-numbers/&template=printart.

[56] Cannon Jr., G; Allen, CH. "Federal Court Finds New Jersey's Long-Term Capacity Pilot Project Unconstitutional." Akin Gump. 16 Oct 2013. Available at: http://www.akingump.com/en/experience/industries/energy/speaking-energy/federal-court-finds-new-jersey-s-long-term-capacity-pilot.html.

Exhibit 2-8: Schedule of Approved SOCAs

Delivery year ending (May 31st)	SOCA ($/MW-day)
2016	286.03
2017	294.61
2018	303.45
2019	312.55
2020	321.93
2021	331.59
2022	341.54
2023	351.79
2024	362.34
2025	373.21
2026	384.41
2027	395.94
2028	407.82
2029	420.05
2030	432.65

Source: LaRossa, R. "Re: Executed Standard Offer Capacity Agreement." Public Service Electric and Gas Company, 26 April, 2011: Newark, NJ.

Despite ratepayer price impacts associated with the LCAPP and RFP programs, proponents of the programs argue that without these in-state resources, New Jersey and Maryland customers would pay significantly more to import energy to their states, in addition to costly transmission expansions. The LCAPP and RFP programs remain highly contentious. Both New Jersey's LCAPP and Maryland's RFP have been subject to litigation, with opponents arguing that these programs give an unfair advantage to these facilities in the bidding process, which are potentially able to underbid competitors with guaranteed SOCA prices. U.S. District Courts have deemed both programs unconstitutional, arguing that the programs interfere with FERC's ability to regulate wholesale energy prices. The states are currently appealing the courts' decision.[57]

2.4 Gas-Electric Coordination Efforts by Selected Market Participants

The 2013-2014 winter weather highlighted a number of gas-electric coordination issues facing the natural gas and power sectors. For instance, winter peak power demand records for MISO, SPP, ERCOT, PJM, and NYISO were all broken.[58] During the cold snap, ISOs took preventive measures to help reduce the effects of the cold. While most systems operated adequately, more extreme or prolonged winter conditions could lead to serious reliability issues. The section below highlights key recent events, as well as ongoing efforts of various market participants in addressing gas-electric coordination issues.

[57] Simon, DR. "Opportunities and Challenges in the 1,500 MW Maryland RFP." Ballard Spahr LLP. 11 November 2011. Available at: http://www.ballardspahr.com/alertspublications/legalalerts/2011-11-11_opportunities_challenges_1500_mw_maryland_rfp.aspx.

[58] FERC. "Recent Weather Impacts on the Bulk Power System." 16 January, 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

2.4.1 FERC[59] [60]

FERC hosts quarterly technical conferences on gas-electric coordination, in which market participants, including ISOs/RTOs, gas pipeline operators, power generators, and others discuss gas-electric coordination efforts. The most recent technical conference took place on April 1, 2014, and focused on impacts of the cold winter weather on gas-electric coordination and reliability issues. Most participants agreed that while the systems met peak demand during the cold winter days, the extreme weather highlighted ongoing gas-electric coordination issues that must be addressed as natural gas takes on a more prominent role in the power sector. In addition, the winter weather underscored the importance of dual-fuel capabilities and communication between market participants in maintaining reliability.

All RTOs and ISOs provided winter 2013–2014 reliability plans to FERC in late 2013. Effective December 2013, a new FERC Final Rule permitted interstate natural gas pipelines and electric transmission operators to share operational information to promote the integration of the respective systems. The rule also restricts information from being disclosed to an affiliate or third party.

In 2013 the natural gas industry launched the Natural Gas Council Gas Day Initiative to evaluate opportunities to mitigate impacts and promote benefits of the Natural Gas Operating Day and scheduling natural gas nominations on a national level. Recommendations prepared by several committees will be submitted to the Natural Gas Council for consideration.

Due to a polar vortex event in January 2014 across the eastern United States residents experienced an average of 20 to 40 degrees below normal temperatures. NERC provided a presentation to FERC about the impacts on the bulk power system. Although the bulk power system remained stable and relatively reliable, generators did face operating challenges and had forced outages as discussed below.

System operators and generators prepared for the weather by deploying additional insulation, supplemental heating, and dual-fuel testing. To maintain adequate resources, scheduled outages were canceled or postponed and staffing needs were addressed. System operators broke winter peak demand records with higher than forecasted peak loads of 7 percent in PJM and 9 percent in MISO.[61] Region-specific action items are included in the sections below.

Due to the resulting need for natural gas, demand reached 137 Bcfd on January 7, 2014, setting a new winter record and leading to pipeline constraints in the Mid-Atlantic and the Northeast.[62] These constraints led to natural gas trades between $70 and $100/MMBtu in some areas.[63]

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59 FERC. “Gas-Electric Coordination Quarterly Report to the Commission,” Docket No. AD12-12-000 (19 December 2013). Available at: http://www.ferc.gov/legal/staff-reports/2013/dec-report.pdf.

60 FERC. “Recent Weather Impacts on the Bulk Power System.” FERC, 16 January 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

61 FERC. “Impacts on the Bulk Power System.” Item No: A-4 (6), 16 January 2014.

62 FERC. “Impacts on the Bulk Power System.” Item No: A-4 (6), 16 January 2014.

63 FERC. “Impacts on the Bulk Power System.” Item No: A-4 (16), 16 January 2014.

Furthermore, operational flow orders were issued among many interstate natural gas pipelines and there were reported pressure drops among local distribution companies leading to voluntary gas curtailments among non-essential customers. Other production impacts from well freeze-offs in major basins and supply drops from the Marcellus formation also contributed to disruptions. Electricity costs rose to $510/MWh in NYISO and $765/MWh in PJM as a result of high natural gas prices.[64] In response, oil-fired and dual fuel units were able to run more economically.

2.4.1.1 NOPR Adjustment

On July 18, 2013 FERC proposed measures to improve communication between gas and electric industries, based on information gathered from various technical conferences. The proposed rules would allow non-public operational information sharing between natural gas pipelines and electric transmission operators (including during day-to-day operations). In addition, the rule would also include a No-Conduit Rule to prohibit participants from publicly disclosing information shared, or using anyone as a conduit for information to release to a third party.[65] FERC issued a final ruling allowing interstate natural gas pipelines and public utilities to share non-public operational information to improve reliability and planning.[66]

2.4.2 NERC

The North American Electric Reliability Corporation (NERC) is an organization established to evaluate reliability of the bulk power system in North America. NERC's focus is on development and enforcement of reliability standards. NERC also assesses reliability annually via a 10-year assessment and winter and summer assessments; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is subject to oversight by FERC and the National Energy Board of Canada. In May 2013, NERC published a report on accommodating an increase in gas-fired power generation. The report included scenario assessments of reliability issues as gas-fired generation grows throughout the country. The 2013 report was a follow-on study to the 2011–2012 study identifying an increase in gas-fired generation and potential reliability issues.[67, 68] The 2013 report stressed the need for gas-electric coordination on a regional basis. In addition, the report recommended probabilistic risk-based analysis of regional challenges associated with increased dependence on natural gas. In addition, the report supported improved reliability and resource adequacy metrics to better reflect fuel disruption risks to gas-fired generation. The study also recommended expansion of

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[64] FERC. "Impacts on the Bulk Power System." Item No: A-4 (18), 16 January 2014.

[65] FERC. "Gas-Electric Coordination Quarterly Report to the Commission" (8–9). DOE, 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[66] Federal Energy Regulatory Commission (FERC). "Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators," 145 FERC ¶ 61,134. 18 CFR Parts 38 and 284, Docket No. RM13-17-000; Order No. 787. Available at: http://www.ferc.gov/CalendarFiles/20131115164637-RM13-17-000.pdf.

[67] The North American Electric Reliability Corporation (NERC). "2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power, Phase II." NERC, May 2013, Washington, D.C. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[68] NERC. 2012 Long-Term Reliability Assessment. NERC. November 2012: Washington, D.C. Available at: http://www.nerc.com/files/2012_ltra_final.pdf.

dual-fuel capabilities, an increase in mitigation strategies, an expansion of gas-electric infrastructure, and better information-sharing between market participants.

2.4.3 Northeast

In addition to the regional efforts discussed below, in 2013 the EIPC commissioned an inter-regional study among five ISOs/RTOs in the United States, TVA and the IESO in Ontario, Canada to evaluate natural gas and electrical system infrastructure.

2.4.3.1 ISO-NE Area Issues[69]

The 2013–2014 winter weather put significant stress on New England's system, as ISO-NE neared its historic demand peak, while maintaining service to all firm customers. New England's winter power demand peaked in the middle of December at the height of the holiday lighting load, forcing ISO-NE to institute emergency measures, such as calling for demand response. The region saw milder weather over the cold snaps, leading to lower levels of forced outages than some other ISOs during those periods. New England saw large price spikes in natural gas and electricity during the cold snaps, driven largely by natural gas supply access issues. Uplift had a significant impact on regional prices, as well. In terms of lessons learned over the cold spikes, oil inventories were valuable in maintaining reliability, as gas supply access or mechanical failure was a significant issue.

ISO-NE will have 620 MW in nuclear plant closures in the near future, along with another 100 MW in coal unit shutdowns, leading to more reliance on gas-fired generation. Continued gas supply access issues will only exacerbate ISO-NE's price volatility and reliability issues during cold spikes, if gas infrastructure is not expanded.

Additional Pipeline Capacity Needed: Some argue that ISO-NE needs more gas pipeline infrastructure, although each state within the region has its own set of infrastructure issues, making siting pipelines difficult. Pipeline projects in the Northeast began at the end of 2013, although New England pipeline projects will not begin service until 2016 (Spectra Energy's Algonquin Incremental Market expansion). The Texas Eastern Pipeline New Jersey-New York expansion went into service in November 2013, alleviating price spikes in New York City (800 MMcfd project). Incremental Marcellus flows on the Tennessee Gas Pipeline Northeast Upgrade expansion (686 MMcfd). Williams' Northeast Supply Link expansion (250 MMcfd capacity increase) on the Transco system connected Marcellus gas to New York markets (Transco Zone 6 New York price hub) in the winter of 2014.[70]

[69] Brandien, P. "FERC ISO-NE Cold Weather Operations." Statement on behalf of ISO-NE. Presented at FERC Technical Conference.1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401083935-Brandien,%20ISO-New%20England.pdf.

[70] FERC. "Winter 2013–14 Energy Market Assessment Report to the Commission," Docket No. AD06-3-000 (October 2013). Available at: http://www.ferc.gov/CalendarFiles/20131017101835-2013-14-WinterReport.pdf.

Alignment of Gas-Electric Days: ISO-NE recommends alignment of the gas-electric physical day schedules (i.e., have them start and end at the same time), and other ISOs such as NYISO agreed.

Pay-for-Performance: ISO-NE said it needs to incentivize generators to perform during low-capacity times (i.e., pay for performance). ISO-NE and the New England Power Pool (NEPOOL) submitted two proposals to revise ISO-NE's tariff to expand the capacity market penalty payments. The proposals expand the definition of shortage event in the FCM to include 30-minute operating reserve deficiencies of at least 30 minutes. The proposals also modified the shortage event trigger to specific import-constrained capacity zones. The ISO-NE proposal sought an effective date of November 3, 2013, while the NEPOOL proposal sought an effective date of June 1, 2017 (i.e., the Capacity Commitment Period start for the next Forward Capacity Auction (FCA)).[71]

2.4.3.2 ISO-NE/NEPOOL Efforts

ISO-NE and NEPOOL are involved in a number of gas-electric efforts, which are discussed in more detail below. The Winter Reliability Program made a large impact on the region, with additional oil supplies allowing ISO-NE to maintain reliability during times of short supply, as well as moving its fuel surveys from weekly to daily in January. ISO-NE also filed with FERC to change its shortage event trigger from 10-minute reserves to 30-minute reserves in an effort to incentivize generators to perform better. The ISO is also implementing a gas usage tool to correlate heating degree days with available gas-fired capacity, along with hiring a natural gas supply coordinator. ISO-NE plans to implement an information exchange, allowing pipelines to better coordinate with generators in gas volume nomination and scheduling. ISO-NE is in strong support of FERC's proposed change in the Gas Day schedule to 4:00 a.m. Eastern Standard Time (EST).[72]

2.4.3.2.1 Performance Pay Tariff Revisions

ISO-NE and NEPOOL submitted two proposals to revise ISO-NE's tariff to expand the capacity market penalty payments. The proposals expand the definition of shortage event in the FCM to include 30-minute operating reserve deficiencies of at least 30 minutes. The proposals modified the shortage event trigger to specific import-constrained capacity zones. The ISO-NE proposal sought an effective date of November 3, 2013, while the NEPOOL proposal sought an effective date of June 1, 2017 (i.e., the beginning of the Capacity Commitment Period for the next FCA).[73]

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[71] FERC. "Order on Proposed Tariff Revisions," Docket No. ER13-2313-000 (1–2) (1 November 2013). Available at: http://www.ferc.gov/CalendarFiles/20131101164503-ER13-2313-000.pdf.

[72] Brandien, P. "FERC ISO-NE Cold Weather Operations." Statement on behalf of ISO-NE. Presented at FERC Technical Conference. 1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401083935-Brandien,%20ISO-New%20England.pdf.

[73] FERC. "Order on Proposed Tariff Revisions," Docket No. ER13-2313-000 (1 November 2013). Available at: http://www.ferc.gov/CalendarFiles/20131101164503-ER13-2313-000.pdf.

FERC accepted ISO-NE's proposal (effective date of November 3, 2013). Under the prior tariff, shortage events are defined as periods of reserve deficiency when the capacity resources are at least partially unavailable for 30 minutes or more, and the resource is assessed a penalty (against its capacity payment). There was ambiguity in the definition of operating reserve shortage, as ISO-NE defined this as the activation of the reserve constraint penalty factor for 10-minute non-spinning reserves for at least 30 minutes. To remove ambiguity, the two proposals opt to replace the phrasing with a more precise reference to reserve constraint penalty factor activation for 10-minute non-spinning reserves. The proposals also expand the definition of shortage event to include violating the 30-minute operating reserve requirement by 30 or more minutes in any capacity zone, as well as to remove exemptions for export-constrained capacity zones from the shortage event in certain circumstances.[74]

ISO-NE argued that the current shortage event definition is too restrictive, highlighting the fact that there has not been a shortage event since June 2010, but does not reflect the true conditions, as there have been a few extended periods of 30-minute reserve shortages when the system was stressed, and that the issue must be remedied as soon as possible. ISO-NE argued that on June 1, 2012, the reserve constraint penalty factor for 30-minute operating reserves was raised from $100/MWh to $500/MWh, and is now a more reasonable indicator of actual shortage conditions.[75] FERC has since largely accepted ISO-NE's proposal.

2.4.3.2.2 Day-Ahead Market Timing Changes

ISO-NE moved the time of day-ahead market two hours earlier starting in May 2013 to allow gas-fired generators to better manage natural gas procurement.[76] ISO-NE has commented that it would like a uniform Gas-Electric Day physical schedule as well.[77] In addition, the hourly offers and reoffers within the new timeframe reflect full costs and have greater flexibility[78]

2.4.3.2.3 Establishment of a Winter Reliability Program

The Winter Reliability Program was developed in response to operational issues during the 2012–2013 winter.[79] The Winter Reliability Program includes both fuel oil and demand response procurement, providing additional compensation for certain resources (dual-fuel and oil-fired generators to support fuel oil procurement and support winter demand response). ISO-NE targets equivalent of 2.4 million MWh in procurement, with ISO securing 83 percent of target for program.[80]

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[74] Ibid.

[75] Ibid.

[76] FERC. "Winter 2013–14 Energy Market Assessment Report to the Commission," Docket No. AD06-3-000 (11-12) (October 2013). Available at: http://www.ferc.gov/CalendarFiles/20131017101835-2013-14-WinterReport.pdf.

[77] FERC coordination between gas and electricity markets presentations, 17 October 2013. Peter Brandien – ISO-NE, Vice President of Systems Operations.

[78] Ibid.

[79] Ibid.

[80] FERC. "Winter 2013–14 Energy Market Assessment Report to the Commission," Docket No. AD06-3-000 (12) (October 2013). Available at: http://www.ferc.gov/CalendarFiles/20131017101835-2013-14-WinterReport.pdf.

2.4.3.3 NESCOE Efforts

The New England States Committee on Electricity (NESCOE) Gas-Electric Focus Group aims to find short-term solutions to reliability issues. The short-term plans are included in ISO-NE's Winter Reliability Plan and NESCOE is now turning to medium- to long-term issues. Phase III of its New England pipeline capacity study (conducted by Black & Veatch) has recently been completed. Phase II of the study reviewed natural gas demand trends and growth and cost projections over the next 15 years. Phase III assesses short-term strategies to manage reliability concerns, such as use of dual-fuel generation, demand response, and seasonal LNG purchases. Longer-term, cross-regional natural gas pipelines are recommended (providing twice the net benefits to New England consumers compared with firm Canadian energy imports).[81]

The three-phase study found that without infrastructure expansions or demand reductions (including non-natural gas distributed generation), New England will continue to experience capacity constraints on its system, which will likely lead to high natural gas and electricity prices.[82]

The study found that in the Base Case (assuming electric load growth projected by ISO-NE and 1.2 percent gas-demand growth annually, the Algonquin City-Gates basis (main hub for New England) will continue winter peaks of $3.00/MMBtu, and could exceed $9.00–$10.00/MMBtu daily through the 2015–2016 winter. However, the Algonquin Incremental Market (AIM) pipeline expansion (expected to be in service in 2016) is expected to alleviate the basis for five to six years, with basis falling below $2.50/MMBtu (toward $1.00/MMBtu), reducing daily volatility between 2017 and 2022.[83]

The report also found that extremely cold weather can be very costly in terms of satisfying gas supply requirements, while also creating reliability risks. In addition, based on New England's design-day, the region could face up to 500 MMcfd in natural gas needs without infrastructure resiliency and capacity expansions, potentially exacerbating reliability concerns. The study also concluded that while long-term solutions are required to satisfy reliability needs through 2029, short-term solutions such as dual-fuel generation, demand response, and short-term LNG purchases can offer benefits in the near term (between 2014 and 2016) until the AIM begins service in 2016.[84]

The study also found that without demand reduction, energy efficiency gains, or non-natural gas distribution generation, a cross-regional natural gas pipeline—1,200 MMcfd originating at the current Tennessee Gas Pipeline and Iroquois Pipeline interconnect in Schoharie County, New York and terminating at Tennessee Gas Pipeline interconnect with Maritimes & Northeast

[81] FERC. "Gas-Electric Coordination Quarterly Report to the Commission" (1-2). DOE, 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[82] Black & Veatch. "Natural Gas Infrastructure and Electric Generation: Proposed Solutions for New England," Phase III report. Prepared for the New England States Committee on Electricity. 26 August 2013. Available at: http://www.nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf.

[83] Ibid., 8–9.

[84] Ibid., 9–10.

Pipeline in Middlesex County, Massachusetts—provides larger net gains to regional consumers than alternatives such as electricity imports from eastern Canada.[85]

The study's main conclusion was that both short- and long-term solutions are needed to relieve the region's natural gas market constraints, in both the Base Case and High Demand scenarios. The study recommended the Cross-Regional Natural Gas Pipeline as the long-term solution and dual-fuel generation, demand response, and seasonal LNG purchases to alleviate gas constraints in the short-term. However, no long-term infrastructure solutions were needed under the Low Demand Scenario.[86]

2.4.4 Mid-Atlantic

On January 7, 2014 natural gas prices in Mid-Atlantic cities such as Richmond, Philadelphia, New Jersey, New York, and Boston all increased drastically compared to the previous day. The prices ranged from about twice as high to almost seven times as high as the previous day. Electricity prices followed the same pattern on January 7 in the NYISO and PJM, where prices increased drastically from the day before. [87] Despite the extreme weather, PJM and NYISO did not call emergency procedures.[88] The following sections discuss recent issues and ISO efforts in more detail.

2.4.4.1 NYISO Area Issues[89, 90, 91]

NYISO experienced five polar vortexes this past winter, setting a new power demand peak in early January 2014. NYISO set a winter peak of 26 GW, but did not require emergency procedures.[92] Despite the numerous cold spells during the 2013–2014 winter, NYISO remains a summer-peaking region. Natural gas prices were higher than oil prices consistently over January 2014 due to gas supply issues in the region, with natural gas prices that month often over $20/MMbtu. Demand response was activated in January 2014, due to cold weather power demand, and by late January, oil depletion set in as the region struggled with accessing oil supplies.

Over the cold snaps, dual-fuel became an important resource, with oil available when natural gas was in short supply. Due to the high oil burn rates, oil supplies were a good resource during short durations, although if the cold snaps had persisted, oil supplies would have run out. While

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[85] Ibid., 10–11.

[86] Ibid., 12-13.

[87] "Recent Weather Impacts on the Bulk Power System." 16 January, 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

[88] Ibid.

[89] Yeomans, W. "Cold Weather Operating Performance." Statement on behalf of NYISO. Presented at FERC Technical Conference. 1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401084016-Yeomans,%20NYISO.pdf.

[90] FERC. "Gas-Electric Coordination Quarterly Report to the Commission," Docket No. AD12-12-000,19 December 2013. Available at: http://www.ferc.gov/legal/staff-reports/2013/dec-report.pdf.

[91] FERC. "Recent Weather Impacts on the Bulk Power System." FERC, 16 January 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

[92] FERC. Impacts on the Bulk Power System, Item No: A-4 (11), 16 January 2014.

these oil inventories are useful for maintaining liability, oil's high burn rates are an issue that must be addressed in the future.

To promote gas-electric integration and increase gas awareness of pipeline conditions, NYISO began using a "gas-visualization" video board in December 2013. In the future the board will include real-time pipeline alerts and operational flow orders. The New Jersey-New York pipeline expansion is expected to alleviate natural gas constraints and increase supply access in NYISO and PJM.

2.4.4.2 NYISO Efforts

The 2013–2014 winter weather highlighted a number of reliability and supply access concerns. NYISO is exploring market changes to address cold snap issues, such as generator derates during prolonged cold periods to better value fuel assurance. In terms of reliability issues, NYISO plans to run cold weather scenarios, which will include varying dual-fuel supplies, among other factors. In addition, NYISO requested voluntary demand response among its customers to provide assistance to other RTOs with resource needs. Additional measures are addressed below.

2.4.4.2.1 New Pipeline Infrastructure

New pipeline infrastructure coming online, including the new pipeline expansion projects into New York City, total more than 1 Bcfd additional capacity to the city gate (not into the city). The Transco Northeast Expansion (250,000 DT/day) is another project in the region, along with Spectra NY-NJ (800,000 DT/day), a new project connecting New York and New Jersey. The Tennessee Northeast Upgrade (636k DT/day across the 300-line) is another expansion project. All were in operation November 1, 2013. FERC was impressed with NYISO's implementation of scarcity pricing and how it helped the region deal with the six-day heat wave in July 2013.[93]

2.4.4.2.2 Winter Fuel Preparations

The NYISO's fuel survey of all gas-fired, oil-fired, dual-fuel capable generators showed that the region will continue its ongoing pipeline maintenance coordination and expansion-related outages are expected to be completed November 1, 2014.[94]

2.4.4.2.3 Outage Coordination

Coordination of outages efforts include new operational procedures for gas-electric coordination, voluntary outreach procedures, a gas visualization board-in-control center, and a

[93] Yeomans, W. "New York ISO Electric-Gas Coordination Update." Statement on behalf of NYISO. Presented at FERC Technical Conference. 17 October, 2013. Available at: http://www.ferc.gov/CalendarFiles/20131017102314-NYISO.pdf.

[94] Ibid.

new control room with a new video board is a gas awareness video. NYISO has hired a consultant to assess infrastructure and supplies, as well.[95]

2.4.4.2.4 Gas-Electric Working Group

NYISO holds meetings through its Electric-Gas Coordination Working Group, which include assessment of dual-fuel capabilities and associated costs, grid security, historical pipeline constraints, the impacts of new pipeline additions on deliverability over the next five years, and potential gas system disruptions in the NYISO area.[96]

2.4.4.2.5 Day-Ahead Market Schedule

NYISO is still discussing market timing with stakeholders. Currently, the bidding closes at 5 a.m. (bids due at 5 a.m. and were posting in the past at 10 a.m. but have advanced that to 9:30 a.m. to help the generators). Some generators prefer price certainty (and like later market times) and some prefer volume certainty (and like earlier market times), and these issues are the main crux of the conundrum. The generators start ramping at 8 a.m. even though they do not receive commitments until 9:30 a.m.[97]

2.4.4.3 PJM Area Issues

PJM broke power demand records eight times over the 2013–2014 winter. The extreme weather caused stresses all along PJM's system, with fuel supply access and gas-fired mechanical problems, as well, which led to a number of forced outages and calls for demand-response measures. In early January, PJM went into scarcity pricing for a short time, and also took voltage reductions as a conservative action. Due to the extensive demand surges and various forced outages, uplift was a significant pricing issue. PJM experienced more uplift in January 2014 than all of 2013.

PJM anticipates a number of nuclear and coal retirements over the next few years. These retirements underscore PJM's future reliability concerns.[98] Within PJM alone, 25,000 MW in retirements have been announced, with another 14,500 MW (excluding nuclear) in potential retirements due to poor market conditions (primarily coal-fired plants).[99]

The region's shale gas infrastructure is growing, with pipeline expansions in NY-NJ also impacting PJM. Mid-market expansions are underway to deliver natural gas from supply regions (e.g., Bakken in the Midwest) to demand markets such as PJM. The region is replacing 1950s

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[95] Ibid.

[96] FERC. "Gas-Electric Coordination Quarterly Report to the Commission" (4). DOE, 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[97] Yeomans, W. "New York ISO Electric-Gas Coordination Update." Statement on behalf of NYISO. Presented at FERC Technical Conference. 17 October, 2013. Available at: http://www.ferc.gov/CalendarFiles/20131017102314-NYISO.pdf.

[98] Kormos, M. "Polar Vortex 2014." Statement on behalf of PJM. Presented at FERC Technical Conference. 1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401084146-Kormos,%20PJM%20Slides.pdf.

[99] Scheider, D. Presentation. Available at: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7272&CalType=%20&CalendarID=116&Date=04/01/2014&View=Listview.

compressors to significantly increase gas flows, with movement of gas occurring during the same time that coal is retiring (more than 20 GW of actual and announced deactivations between 2011 and 2016). The resource mix is changing—cleared installed capacity is moving to gas from coal (gas increasing, coal decreasing) and demand response is also increasing. The region has adequate winter reserve margins—it needs to maintain around 27 percent during the winter.

During the 2013 summer the PJM task force focused on reflecting fuel-related costs in markets and harmony of gas-electric schedules. PJM is assessing reliability issues to reflect fuel-related costs in the market, and how to improve this. More infrastructure is being installed November 2014 to increase reliability and dual-fuel capabilities, which are also very important.[100]

2.4.4.4 PJM Efforts

PJM set a winter peak of 141 GW and mitigated adverse impacts through demand response and energy purchases from neighboring markets.[101] To prepare for the polar vortex, PJM filed a FERC application for a week-long waiver of non-disclosure provisions, which allowed the RTO to engage in a unit-specific review of day-ahead plans with the interstate natural gas pipelines. Energy efficiency activities were also helpful during the cold weather conditions. PJM experienced high loads and challenging operating conditions (e.g., over half of PJM's gas-fired combustion turbines had mechanical issues during the January 7, 2014 cold snap) in January 2014. In response to these issues, PJM directed member utilities to implement a 5 percent voltage reduction.[102]

In addition to natural gas supply access issues and other operational challenges, PJM anticipates several power generation retirements in the 2015–2016 timeframe. PJM expects to rely more on energy imports and demand response in the near term, and gas-fired generation in the longer term, thus creating additional natural gas supply access issues. PJM continues to move toward a gas-dominated power market, although supply access dilemmas undermine grid reliability. In addition, some market participants argue that several scheduled retirements undervalue the generation (and the reliability those entities provide). Thus, some contend that PJM's near-term goal must include providing adequate compensation for these reliable resources, while long-term goals should focus on fuel diversity to provide grid reliability.[103]

With regard to additional gas-electric coordination issues, the region is exploring day-ahead timing issues further, although the electric side would be more exposed to risk if the day-ahead market timing is moved up. PJM will propose additional updates on this, but it has not proposed

[100] FERC coordination between gas and electricity markets presentations, 17 October 2013. Gary Helm, PJM, Senior Market Strategist.

[101] FERC, Impacts on the Bulk Power System, Item No: A-4 (10), 16 January 2014.

[102] Kormos, M. "Polar Vortex 2014." Statement on behalf of PJM. Presented at FERC Technical Conference. 1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401084146-Kormos,%20PJM%20Slides.pdf.

[103] Schneider, D. First Energy Solutions. Available at: https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7272&CalType=%20&CalendarID=116&Date=04/01/2014&View=Listview.

to change the schedule and will be looking at it further in the task force (how fuel costs are reflected) and schedule harmonization.[104]

2.4.4.5 EIPC Efforts

The EIPC study assessing the Eastern Interconnection's multi-regional gas-electric coordination of major interstate, intrastate, and local natural gas infrastructure is underway (and covers ISO-NE, NYISO, PJM, MISO, Ontario IESO, and TVA). Stakeholders are represented through a multi-sector Stakeholder Steering Committee, whose members include Interstate Natural Gas Association of America (INGAA), NGSA, and AGA, with PJM acting as principal investigator. The study aims to develop a baseline natural gas and electric system, and assess gas-fired generation needs over the next five to ten years, identify system issues that could affect either natural gas or electric systems, and estimate the costs and benefits of dual-fuel capabilities (compared with firm gas transportation).[105]

2.4.5 Southeast

2.4.5.1 Southeast Area Issues

The U.S. Southeast has traditionally relied on coal and nuclear for power generation. Thus, the region has experienced few gas-electric coordination issues. As natural gas prices recovered from the lows seen in 2012, coal became more economical in regions such as the Southeast, leading to some power generation fuel-switching.[106] Over the 2013–2014 cold snap, many utilities in the Southeast set peak demand winter records, requiring conservation measures. Duke Energy Progress and South Carolina Electric and Gas (SCE&G) reduced voltage at times in early January 2014, with several generators tripped in the SCE&G region, leading to rotating outages and load shedding of 300 MW of firm load.[107] The Southeast had a small number of voltage reductions and outages over the winter, although all of the outages were restored the same day.

The Southeast region does not have an RTO or ISO, but is split into two reliability regions[108]:

- Southeastern Electric Reliability Council (SERC), which includes western Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina, and parts of Missouri, Kentucky, and Texas.
- Florida Reliability Coordinating Council (FRCC), which includes most of the state except western Florida.

[104] Helm, G. "PJM Gas-Electric Interface." Statement on behalf of PJM. Presented at FERC Technical Conference. 17 October, 2013. Available at: http://www.ferc.gov/CalendarFiles/20131017102539-5-PJM.pdf.

[105] FERC. "Gas-Electric Coordination Quarterly Report to the Commission" (4). DOE, 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[106] Ibid., 15.

[107] FERC. "Recent Weather Impacts on the Bulk Power System" (9). FERC, 16 January 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

[108] FERC. Electric Power Markets: Southeast. Available at: http://www.ferc.gov/market-oversight/mkt-electric/southeast.asp.

2.4.5.2 Southeast Efforts

The power sector in the Southeast is dominated by vertically integrated utilities. These utilities determine fuel needs, the costs for which are calculated into power rates. Across the Southeast, particularly in states such as Florida, power generation is the primary use for natural gas, whereas the residential, commercial, and industrial sectors account for significant proportions of gas use in other regions of the country. Because power generation makes up the bulk of gas use in the Southeast, pipeline capacity is built based on the region's power generation demand needs. For this reason, this region does not have any significant natural gas supply access issues.

2.4.6 Central

The section below discusses gas-electric coordination in more detail by region.

2.4.6.1 MISO Area Issues[109, 110, 111]

MISO saw consistently cold weather throughout the 2013–2014 winter, and was the first region impacted by the polar vortex, setting a new winter peak of 110 GW in January 2014.[112] The region consistently made heavy natural gas storage withdrawals between December 2013 and March 2014. Despite the region's extensive planning, the 2013–2014 winter was a one-in-20-years event (power sector planners plan for one-in-10-years events). The extreme weather affected supply access, but not power grid resiliency.[113]

2.4.6.2 MISO Efforts

MISO began field trials over the 2013–2014 winter to gain information from natural gas pipelines on flows and to increase situational awareness. The field trials were valuable during the coldest winter days in assessing fuel supply issues and identifying alternate generation needs. In addition, MISO efforts to ensure reliability included improving communications with generation transmission owners, improved coordination with pipelines, better use of demand response, and enhanced communication with generation owners. Communication with generation owners allowed MISO more time to proactively address supply-demand issues. In addition, the reliability measures allowed MISO to assess certain local areas more carefully. Although there were no issues related to the integration of the MISO South region over the winter, coordinators

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[109] Doying, R." Winter 2013-2014 Operations and Market Performance." Statement on behalf of MISO. Presented at FERC Technical Conference.1April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401083952-Doying,%20MISO.pdf.

[110] FERC. "Gas-Electric Coordination Quarterly Report to the Commission," Docket No. AD12-12-000 (19 December 2013). Available at: http://www.ferc.gov/legal/staff-reports/2013/dec-report.pdf.

[111] FERC. "Recent Weather Impacts on the Bulk Power System." FERC, 16 January 2014. Available at: https://www.ferc.gov/legal/staff-reports/2014/01-16-14-bulk-power.pdf.

[112] FERC. Impacts on the Bulk Power System, Item No: A-4 (8), 16 January 2014.

[113] Doying, R." Winter 2013-2014 Operations and Market Performance." Statement on behalf of MISO. Presented at FERC Technical Conference.1April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401083952-Doying,%20MISO.pdf.

temporarily raised the transfer limit by 500 MW to allow additional power delivery to other regions.[114]

In order to assess locational marginal prices and reliability impacts as a generation fuel, the Electric and Natural Gas Coordination Task Force (ENGCTF) developed a paper in 2013. Initial findings suggest business rules are adequate in MISO. ENGCTF also concurred with recommendations to analyze the impact of Reserve Shutdown hours, capacity accreditation, seasonal resource adequacy, and Generation Availability Data System cause codes. Furthermore, MISO released positive findings from a study examining flow patterns and potential impacts for future gas-fired power generation demand over the next 20 years. Overall infrastructure was deemed adequate but the report identified certain supply and area-specific constraints that would need to be addressed.

MISO's Electric and Natural Gas Coordination Task Force holds monthly meetings to assess gas-electric coordination issues, including Phase III preliminary results of the MISO Gas-Electric Interdependency Analysis. The study assessed MISO's natural gas infrastructure's ability to meet growing demand and identified flow patterns and current and potential pipeline congestion areas. The preliminary results found that recent pipeline capacity additions have helped limit the total days during which pipeline capacity would have been unavailable within the region, and that the region is expected to see more natural gas supply sources. MISO is also conducting a number of white papers to address gas and electric sector coordination issues, resource adequacy, and coordinated operations and communications.[115]

The Phase III gas study, started in late 2011, anticipated that the reliance on gas would not change. The earlier studies suggested that anticipated gas-fired generation foreshadowed reliability concerns. MISO received feedback on details of the Phase II study, published in mid-2012, and kicked off stakeholder meetings. The region gained a lot of knowledge through these meeting that was used to support better study updates. The Phase III study is not yet finalized, although preliminary findings have been released. The study shows that gas availability for the region and reliability is improving and is driven by[116]:

- Production from shale regions (Bakken, Marcellus, other Appalachian)
- Historically came from the western and southern parts of the country and most moved to load centers in the east and Canada
- Flow patterns are now changing this and the Midwest is becoming a hub, increasing supply availability for Midwest end-users

[114] Ibid.

[115] FERC. "Gas-Electric Coordination Quarterly Report to the Commission." DOE. 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[116] Ramsey, T. "MISO Gas-Electric Coordination Update." Statement on behalf of MISO. Presented at FERC Technical Conference. 17 October, 2013. Available at: http://www.ferc.gov/CalendarFiles/20131017102239-MISO-MEETING.pdf.

According to FERC Commissioner Moeller, the MISO region is likely to be 8 GW short of requirements, "Projections are disconcerting," according to Moeller.[117]

In terms of the potential for moving ahead in the day-ahead bidding window, there is not a compelling reason to make the day-ahead market earlier. Market design is flexible to allow operators to make hourly updates to reflect changes in economics. Stakeholders are comfortable with an11 a.m. closing. In terms of MISO South, the subregion is more dependent on natural gas, so this may be an issue in the future.[118]

In terms of the prospects for supply and reliable delivery, MISO will still have many sources. The gas delivery system continues to grow, but the potential for 3–7 GW resource shortfall in MISO Midwest in 2016–17 still exists. Uncertainty surrounding commitments to build capacity is still apparent. MISO is attempting field trials in gas-electric coordination through the ANR pipeline company to further coordinate operator situational awareness and improve reliability. Monthly coordination of outage activities (maintenance activity, availability of gas) is occurring, as well as protocol development for unforeseen events between gas and electric systems. The efforts are coordinated through gas-electric task force.[119]

2.4.6.3 SPP Area Issues

SPP saw extreme winter weather a number of times at the beginning of 2014, establishing a new winter peak of 37 GW and causing SPP to issue an energy emergency warning at one point.[120] Despite the harsh weather, SPP made a number of winter preparations that prepared the region well, particularly in-person meeting with natural gas pipeline operators within the region's footprint to develop planning measures.[121]

2.4.6.4 SPP Efforts

Over the 2013–2014 winter season, SPP consolidated 16 balancing authorities into one through the SPP Integrated Marketplace, which launched on March 1, 2014. This effort occurred during SPP's third cold weather event between March 1 and March 3, 2014. SPP preparations also included gas industry expert trainings to assess natural gas scheduling practices. The 2013–2014 winter highlighted the need for continued improvements in load forecasting, enhanced coordination with neighboring ISOs/RTOs, and improving supply access issues. [122] SPP's Gas-Electric Coordination Task Force conducted a gas-fired generator survey, applied pipeline

[117] Ibid.

[118] Ibid.

[119] Ibid.

[120] FERC. Impacts on the Bulk Power System, Item No: A-4 (8), 16 January 2014.

[121] Rew, B. "Southwest Power Pool: Winter 2013-2014." Statement on behalf of SPP. Presented at FERC Technical Conference.1 April 2014. Available at: http://www.ferc.gov/CalendarFiles/20140401084211-Rew,%20SPP.pdf.

[122] Ibid.

mapping tools to coordination efforts, and conducted training sessions for gas pipeline and marketer personnel. SPP is also discussing a potential study (similar to EIPC) for its region.[123]

SPP is moving toward implementation of a Day 2 Market, turning attention to how gas-electric coordination is changing and what the impacts to SPP will be. SPP did not have gas-electric coordination issues through the summer, allowing it to take on outreach projects, connecting SPP operations personnel with gas supply entities. SPP has selected two primary gas supply entities to provide further feedback, Natural Gas and Southern Star. SPP went to both locations and had productive meetings over winter preparedness protocols. SPP representatives toured operations control rooms to assess how to manage pipeline constraints, improve gas displays in control room, improve situational awareness to operators, associate real time to displays, and develop relevant procedures. SPP created a draft document to use ahead of projected weather events. SPP will have a discussion of upcoming events and constraints. Possible challenges include needing two to three days' preparation for the event, gaining a greater understanding of what each side will face, and allowing them to stay out of each other's way during the crisis (outside of an action call). SPP plans to reach out to a third provider before winter as well.[124]

[123] FERC. "Gas-Electric Coordination Quarterly Report to the Commission." DOE, 19 September 2013. Available at: https://www.ferc.gov/legal/staff-reports/2013/aug-A-3-report.pdf.

[124] Shipley, D. "Report Regarding Its Summer Experience and Winter Preparedness**."** Statement on behalf of SPP. Presented at FERC Technical Conference. 17 October 2013. Available at: http://www.ferc.gov/CalendarFiles/20131017102614-SPP-statement.pdf

3 Infrastructure Design

This section describes the methodology ICF employed to estimate the amount of natural gas infrastructure that would be needed to adequately supply power plant and other natural gas customer in the year 2030 under each of three future scenarios for the power sector within the Eastern Interconnect. This section also presents the key results of that analysis.

3.1 Power System Analysis Methodology

Using the three Futures scenarios defined in the EIPC Phase II study, as well as previous work by the natural gas industry, ICF developed a natural gas infrastructure build-out to match and support each of the power demand scenarios developed by EIPC previously.[125] These scenarios were used to analyze an infrastructure design that improves coordination and cohesion between the power and natural gas systems. The power sector scenarios were based on those developed by EIPC, which are discussed below. The hourly gas demand, electrical load, capacity by technology, and interregional transfers for each scenario were incorporated into the ICF analysis.

3.1.1 Scenario 1: Nationally-Implemented Federal Carbon Constraint with Increased Energy Efficiency/Demand Response

The EIPC Phase II first scenario (S1), referred to as the "Combined Policy Scenario," models the effect of carbon constraints and a reduction in the demand for energy. This scenario has a CO_2 price that is nationally implemented throughout the country and also reflects accelerated deployment rates for energy efficiency (EE), and demand response (DR).[126] The CO_2 price increases every year in this model according to a schedule prescribed exogenously which results in a 42 percent reduction in CO_2 emissions by 2030. The combination of strong EE/DR deployment coupled with higher energy prices leads to a 19 percent reduction in demand in the Eastern Interconnection. The evolution of electricity demand in the U.S. portion of the Eastern Interconnection (EI) as modeled in the EIPC Phase I scenario analysis cases[127] is shown in Exhibit 3-1. This depicts the demand for electricity as a function of time for each of the sensitivity cases in Phase I which formed the basis of the Scenarios analyzed in Phase II and illustrates clearly the lower power load in the Combined Policy case relative to the other two scenarios.

3.1.2 Scenario 2: Regionally Implemented National Renewable Portfolio Standard (RPS)

Scenario 2 (S2) is characterized by the regional procurement mandates for local renewable energy. It requires that 30 percent of the load in each of seven regions in the EI be met by renewable resources by 2030. Qualified sources for renewable credits include wind, solar,

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125 DOE. "Phase II Report: DOE Draft – Part 1: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios." DOE, December 2012. Available at: http://eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf.

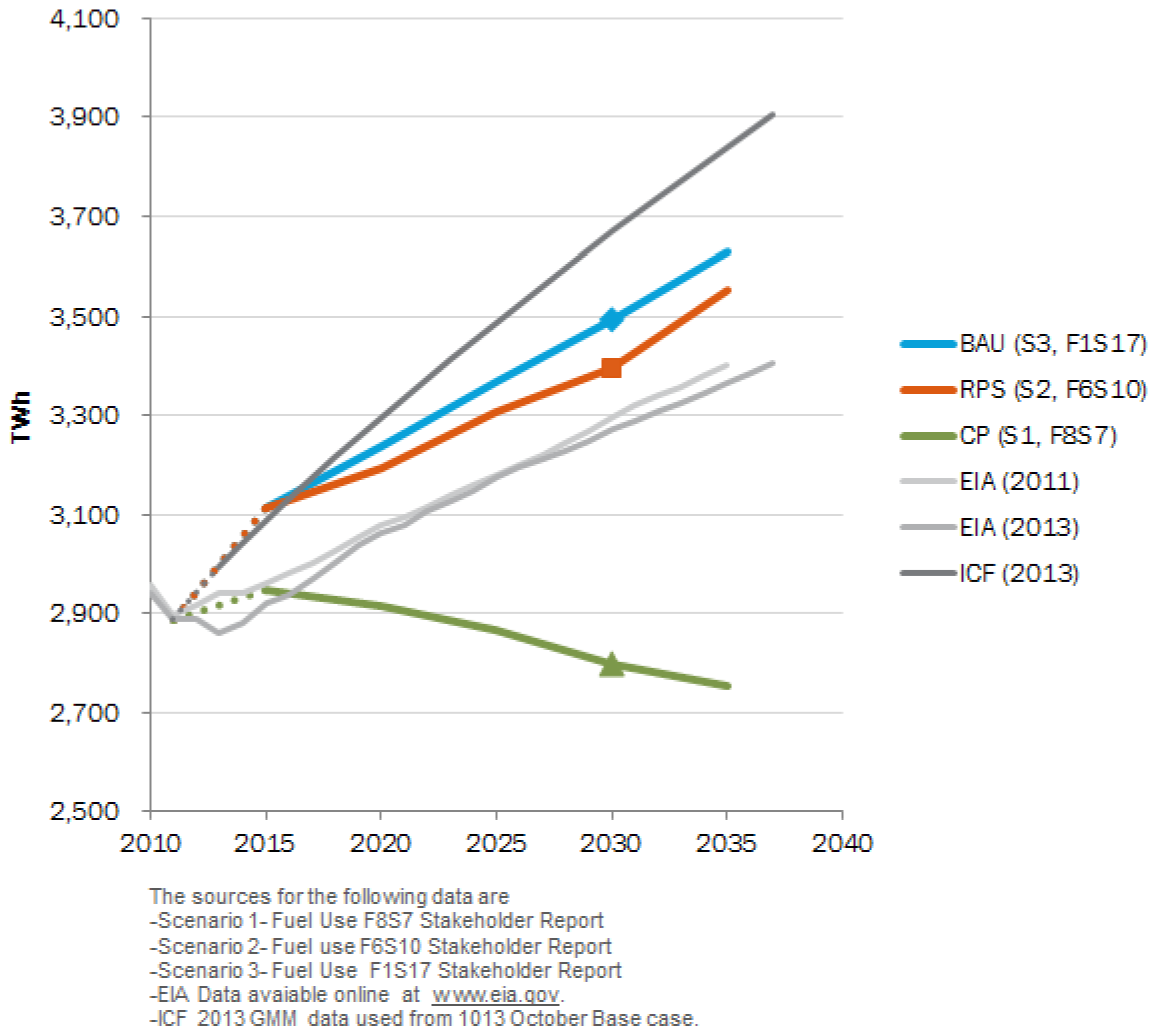
126 Ibid., 5.

127 Eastern Interconnection Planning Collaborative. Phase I Modeling Results. Available at: http://eipconline.com/Modeling_Results.html.

geothermal, biomass, landfill gas, fuel cells using renewable fuels, marine hydrokinetic, and hydropower.[128]

Although the level of electricity demand remained broadly consistent with the business as usual case, changes in the generation mix appreciably impact the fuel use in this scenario. As shown in Exhibit 3-1 below, the increased deployment of renewables displaced generation from other sources such that power sector natural gas use was the lowest among the three scenarios.

Exhibit 3-1: EIPC Phase I Results, Power Generation, U.S. EI (TWh)



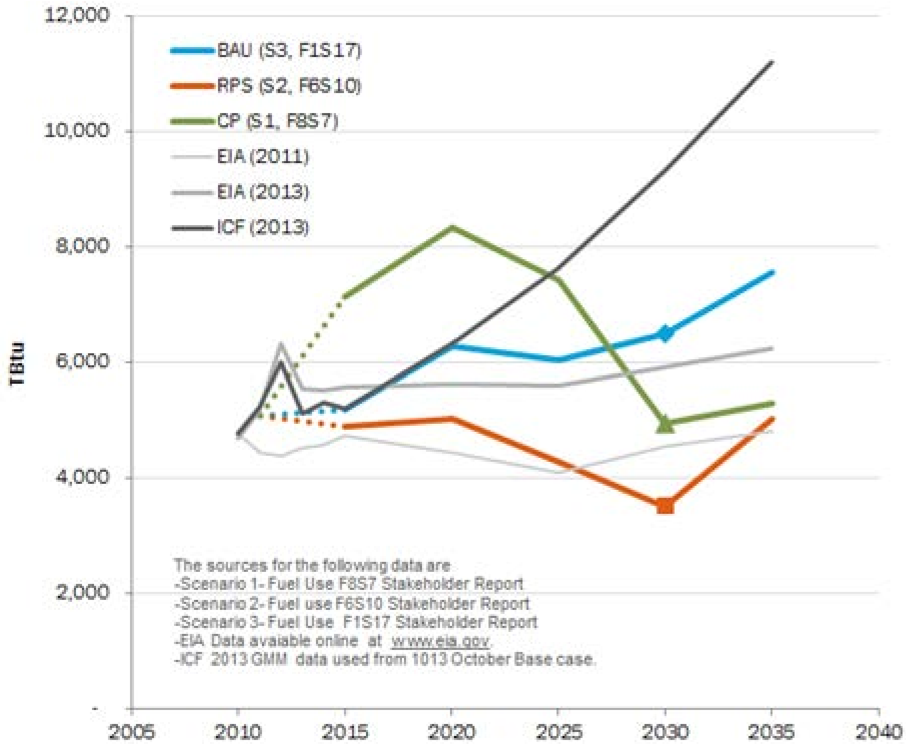
Source: Eastern Interconnection Planning Collaborative. Phase I Modeling Results. Available at: http://eipconline.com/Modeling_Results.html.

[128] Ibid.

3.1.3 *Scenario 3: Business as Usual*

The third scenario (S3), known as the Business as Usual (BAU) Scenario, depicts the effects of continuing energy and environmental policies that were in place during the time of the EIPC study. This scenario constitutes the base case for the EIPC analysis and reflects a continuity of load growth and generation mix trends observed at that time.[129]

Exhibit 3-2: EIPC Phase I Results, Power Sector Gas Use, U.S. EI (TBtu)



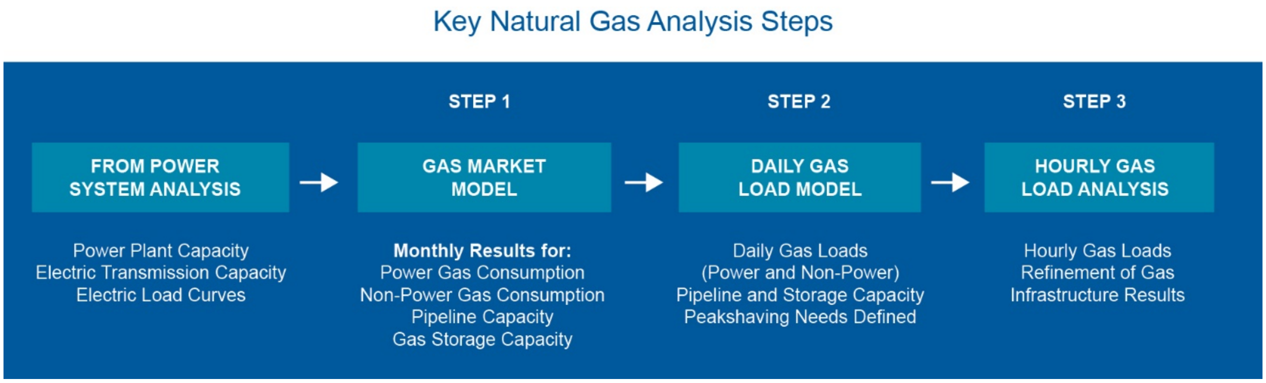
Source: Eastern Interconnection Planning Collaborative. Phase I Modeling Results. Available at: http://eipconline.com/Modeling_Results.html.

3.2 Natural Gas Analysis Methodology

Using the EIPC power gas use scenarios as the basis for the analysis, ICF then translated these power sector assumptions into the Gas Market Model® (GMM) to assess impacts by scenario to the natural gas sector (Exhibit 3-3). The GMM® was used to simulate future month by month natural production, consumption, pipelines flow and storage injections/withdrawals. This Step 1 analysis was further refined in Step 2 by looking at how daily natural gas loads would be met under a range of weather outcomes and in Step 3 by looking at the expected future pattern hourly natural gas loads.

[129] DOE. "Phase II Report: DOE Draft – Part 1: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios." DOE, December 2012. Available at: http://eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf.

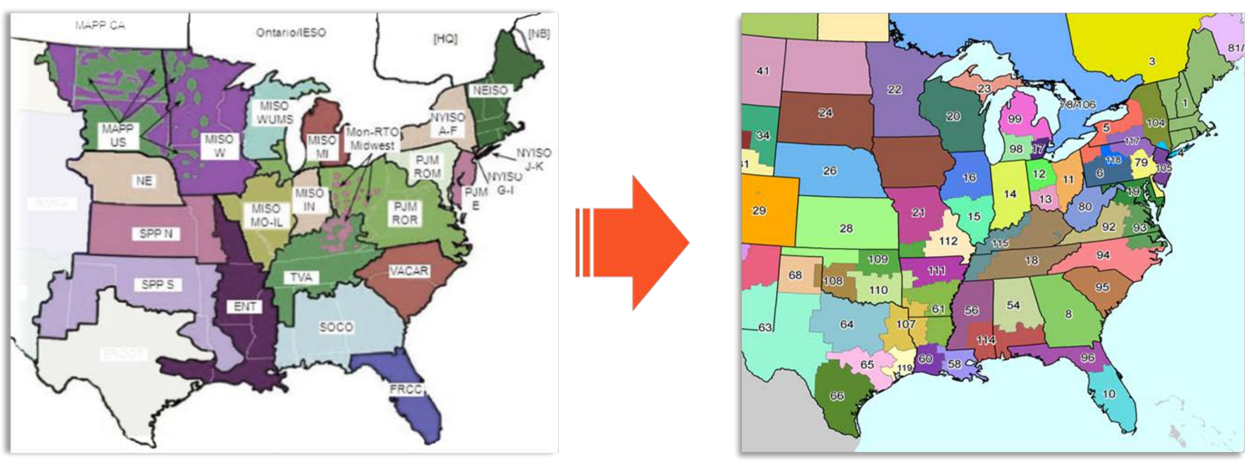
Exhibit 3-3: Key Natural Gas Analysis Steps



3.2.1 2030 Power Sector Gas Use for EIPC Scenarios

Initially, ICF converted EIPC regional distributions to the regions designated in the GMM®, as illustrated in Exhibit 3-4. In order to do this, the hourly dispatch data from the EIPC Phase II analysis was used to determine hourly power sector gas use by NEEM region using an average heat rate for each technology type in each region derived from the same production cost analysis results.[130] This data was further decomposed using a Ventyx database of the same vintage as the one used for the original EIPC scenario in order to map the power sector gas use in each scenario from NEEM regions to GMM® nodes.

Exhibit 3-4: Regional Mapping



CRA NEEM Regions (EIPC Phase I/II Scenarios) ICF Gas Market Model

Source: Left: Eastern Interconnection Planning Collaborative. 2010. Right: ICF. 2014.

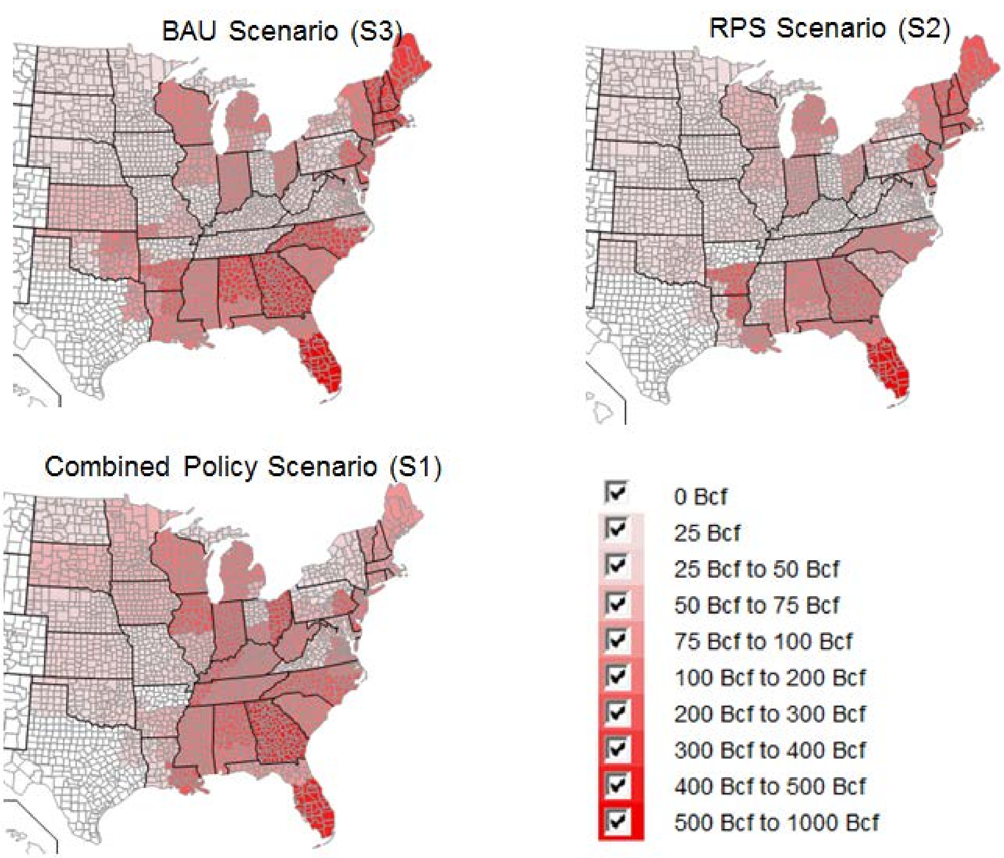
[130] Eastern Interconnection Planning Collaborative. Phase I Modeling Results. Available at: http://eipconline.com/PhaseII_Modeling_Results.html.

Exhibit 3-5: 2030 Power Sector Gas Use Summary by Scenario (Bcf/y)

Region	BAU (S3)	RPS (S2)	Combined Policy (S1)
Mid-Atlantic	737	605	1,256
Midwest	950	633	1,738
Northeast	865	727	271
Producing-Onshore	1,313	818	956
South Atlantic	2,457	1,729	1,426
West	337	98	176
Total	**6,658**	**4,609**	**5,825**

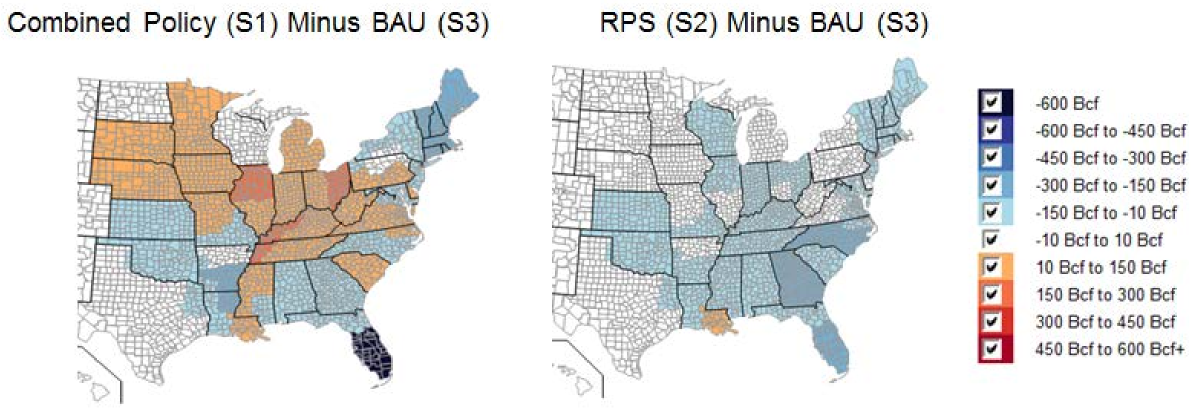
Note: The values above are based on decomposition of EIPC Phase II production cost modeling results for those GMM® nodes corresponding to areas within the Eastern Interconnection. The regions used here are based on GMM® nodes and are defined in Exhibit 9-5 in Appendix A.

Exhibit 3-6: 2030 Power Sector Gas Use by Scenario (Bcf/y)



Note: The county borders shown above are used to show GMM® node interfaces, but the value key corresponds to consumption values on the basis of GMM® nodes shown in Exhibit *3-4* earlier.

Exhibit 3-7: 2030 Power Sector Gas Use Scenario Comparisons (Bcf/y)



Note: The country borders shown above are used to show GMM® node interfaces, but the value key corresponds to consumption values on the basis of GMM® nodes shown in Exhibit 3-4 earlier.

The power sector gas use trajectory in the Combined Policy (CP) case required special consideration. Due to the high rates of coal retirements, power sector gas use increases rapidly in the 2010-2020 time period as shown in Exhibit 3-2 earlier. However, the increases in carbon price post-2020 result in accelerated deployment of renewable resources which increasingly displace gas fired units between 2020 and 2030. As a result, the CP scenario has a local maximum for power sector gas use occurring in 2020 followed by a subsequent decline. This means that the fuel infrastructure built to accommodate this scenario would need to reflect the flows at the 2020 peak and not just the 2030 consumption levels. Although the intermediate years were not analyzed in the Phase II production cost analysis, the Phase I scenario analysis results provided a basis from which to derive the equivalent 2020 consumption levels for Scenario 1.

Exhibit 3-8: 2020 and 2030 Power Sector Gas Use, Combined Policy Case (S1) (Bcf/y)

Region	CP, 2020	CP, 2030	Difference
Mid-Atlantic	1,374	1,256	(118)
Midwest	2,475	1,738	(737)
Northeast	421	271	(150)
Producing-Onshore	1,251	956	(295)
South Atlantic	2,738	1,426	(1,312)
West	68	176	108
Total	**8,328**	**5,825**	**(2,503)**

Note: The values above are based on decomposition of EIPC Phase II production cost modeling results for those GMM® nodes corresponding to areas within the Eastern Interconnection.

3.2.2 Natural Gas Infrastructure Methodology

After converting the EIPC-designated regions to those used in the GMM®, ICF conducted the natural gas analysis in three key steps as shown above in Exhibit 3-3:

Step 1: Developed projections of the natural gas transmission and storage infrastructure required to meet projected gas loads in 2030 for areas throughout the Eastern Interconnection using ICF's GMM®. This was done by looking at monthly natural gas supply, demand and infrastructure utilization through the year 2030 and estimating what new infrastructure would be needed. Infrastructure was assumed to be built as needed to balance the market given where supplies would be originating and the patterns of regional natural gas consumption (assuming average monthly weather patterns).

Step 2: In this step the future infrastructure to be constructed was "fine-tuned" by looking at daily loads throughout the year in the 2011 base year and the years 2020 and 2030 under a variety of weather cases. This step of the analysis determined if additional pipeline, gas storage capability, peak shaving or fuel switching was needed. The daily gas demand under a variety of weather cases were generated using ICF's Daily Gas Load Model (DGLM), wherein seasonal heating and cooling degree days and daily average daily temperature were selected to correspond to specific probabilities of occurrence. The infrastructure to be built was determined through stochastic optimization using ICF's Energy Asset Decision Support System (EADSS).

Step 3: In the third step ICF determined if changes in hourly swings in gas loads would require additional infrastructure (e.g., more line-pack capacity through larger-diameter lateral pipe, high-deliverability market area storage, or onsite liquefied natural gas (LNG) storage).

3.2.3 Cost Assumptions

Each of the three analytic steps described above used the same assumed natural gas infrastructure costs. These are summarized below.

Pipeline Costs: Average pipeline costs are assumed to remain constant at $155,000 per inch-mile, in 2012 U.S. dollars, with regional factors applied to reflect cost variations by region, as shown in Exhibit 3-9.[131]

[131] PennEnergy Research. "Annual Pipeline Economics Special Report, U.S. Pipeline Economics Study 2013." Oil and Gas Journal. Available at: http://ogjresearch.stores.yahoo.net/us-pipeline-economics-study.html.

Exhibit 3-9: Regional Pipeline Cost Factors

Region	Cost Factors for Pipeline
Central	0.69
Midwest	0.85
Northeast	1.46
Southeast	1.09
Southwest	0.68
Western	1.14

Source: PennEnergy Research. "Annual Pipeline Economics Special Report, U.S. Pipeline Economics Study 2013." Oil and Gas Journal. Available at: http://ogjresearch.stores.yahoo.net/us-pipeline-economics-study.html.

Gathering Line Costs: Gathering line is small-diameter pipe that connects oil or gas wells to gas processing plants or to gas pipelines. Cost for gathering line is assumed to remain constant in real term and is size dependent, as shown in Exhibit 3-10.

Exhibit 3-10: Gathering Line Costs by Diameter Size

Diameter (Inches)	Gathering Line Costs (2012 $/inch-mile)
1	$46,228
2	$34,671
4	$28,892
6	$24,164
8	$25,215
10	$39,398
12	$68,291
14	$110,316
16	$122,135

Source: ICF analysis of historical costs from various industry sources.

Compression and Pumping Costs: Gas compressors are used in transporting natural gas through pipelines, at gas processing plants and at underground gas storage fields. Compression and pumping costs are assumed to remain constant at about $2,600 per HP, in 2012 U.S. dollars, with regional factors applied to reflect cost variations by region, as shown in Exhibit 3-11.[132]

[132] Oil & Gas Journal Regional Compression Costs 1999–2012.

Exhibit 3-11: Gathering Line Costs by Diameter Size

Region	Cost Factors for Compression
Central	1.06
Midwest	1.16
Northeast	1.24
Southeast	1.00
Southwest	0.98
Western	1.07

Source: Oil & Gas Journal Regional Compression Costs 1999–2012.

Lease Equipment Costs: Cost for lease equipment is assumed constant in real-term at an average of about $88,000 per well for gas wells, in 2012 U.S. dollars. The costs are area/play dependent.[133]

Gas Processing Costs: Gas processing costs (does not include compression cost component) are assumed to remain constant at roughly $520,000 per MMcfd, in 2012 U.S. dollars for cryogenic gas processing plants to separate natural gas liquids (ethane, propane, butanes and pentanes plus), with additional costs for non-hydrocarbon gas removal.

Natural Gas Storage Costs: Cost for gas storage projects (excludes pipeline connection cost), in dollars per Bcf of Working Gas Capacity, remains flat in real-terms, with costs by field type included in Exhibit 3-12.

Exhibit 3-12: Natural Gas Storage Costs (2012$ Million per Bcf of Working Gas Capacity)

Field Type	Expansion	New
Salt Cavern	$26	$31
Depleted Reservoir	$15	$18
Aquifer	$30	$37

Source: ICF analysis of historical gas storage field costs and current drilling and compressor costs.

3.2.4 Demand-side and Other Assumptions[134]

As was described above, the future demand for natural gas from the power sector was adopted for this study from the EIPC's three main scenarios: BAU (S3), RPS (S2) and Combined Policy (S1). The natural gas demand assumptions used in this study for non-power demand and for gas demand outside of the Eastern Interconnect came from the ICF standard forecast assumptions, which are discussed below.

Natural Gas Use for Commercial, Industrial and Residential Sectors: Other assumptions include that the U.S. population will increase at an average rate of approximately 1 percent per

[133] U.S. Energy Information Administration (EIA). Oil and Gas Lease Equipment and Operating Costs data.

[134] ICF International. "North American Midstream Infrastructure through 2035: Capitalizing on Our Energy Abundance." The INGAA Foundation, Inc. 18 March 2014. Available at: http://www.ingaa.org/File.aspx?id=21498.

year. The U.S. gross domestic product (GDP) increased 2 percent in 2013 and it is expected it will increase 2.8 percent in 2014 and 2.6 percent in 2015 and onward. Electric load will grow at 1.5 percent a year from 2013 to 2020, and at 1.1 percent per year 2021 and onward. Other assumptions are that industrial production growth will average 2.3 percent per year, consistent with the GDP assumption, and that the expect or “P50” weather conditions are similar to average weather during the past 20 years.

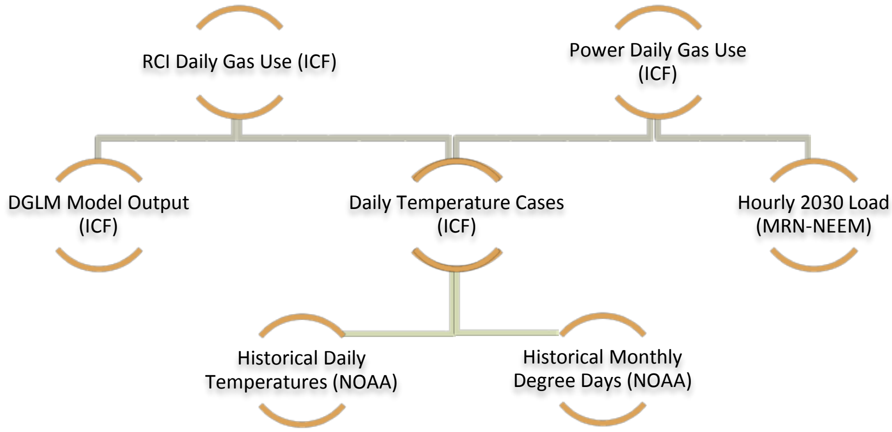
Natural Gas Resource and Supply Estimates: Gas production in Canada and the United States is originating from more than 300 trillion cubic feet (Tcf) of proven gas reserves. The total North American natural gas resource base is estimated at 4,000 Tcf when unproved gas resources are added to discovered-but-undeveloped ones. At current consumption levels, this total resource base could supply U.S. and Canadian gas markets for nearly 150 years. Gas supply development is expected to continue at recent levels, and no new significant production restrictions are anticipated.

New Pipelines and Other Midstream Infrastructure Construction: ICF includes various types of natural gas projects with reasonable level of certainty (either under construction or sufficiently advanced in the development process) in the near-term midstream infrastructure development pipeline. These projects are assumed to go forward without significant barriers to balance the market. ICF also expects some unplanned projects to come online as new demand comes along. The projection does not include the Alaska and Mackenzie Valley gas pipelines, and shows net LNG exports from Western Canada and the United States.

3.2.5 Seasonal and Daily Temperature Cases Analytic Approach

As was mentioned above, all runs with the GMM® to simulate monthly natural gas supply, demand and infrastructure utilization were conducted assuming monthly heating and cooling degree days consistent with an average for the last 20 years. However for the daily analysis alternative weather cases were analyzed to estimate the impact that weather has on natural gas consumption, ICF produced regional residential, commercial, industrial, and power sector daily gas use estimates for years 2020 and 2030 across nine separate weather case scenarios. The examined weather case scenarios ranged from 3rd percentile (least severe) to 99th percentile (most severe) weather cases. Each weather case was developed on regional basis from NOAA’s historical degree day and temperature series.

Exhibit 3-13: Data Source Overview



ICF first in developing weather cases was estimating the regional degree day distribution characteristics. The degree day distributions were based on 30 years of monthly degree day series for each of the Census Division regions as provided by NOAA. ICF tested for normality of each regional degree day series by examining its skew and kurtosis statistics and undergoing formal normality tests such as Kolmogorov-Smirnov and Cramer-von Mises tests. We found that in most cases normal distribution provided adequate approximation of the actual distribution of degree day series. Once appropriate distribution was determined, ICF was able to specify a probability of exceeding any specified total winter-time heating degree day or any total summer-time cooling degree day levels. Based on those distributions, ICF chose nine separate heating and cooling degree days for each region and season combination that represented a specific probability percentile. For example, the 99th percentile (P99) for total winter-time HDD, which can be expected to be exceeded once each 100 years, could be calculated as the regional total winter-time mean HDD plus 2.326 standard deviations. The results for winter HDD and summer CDD are shown in Exhibit 3-15 and Exhibit 3-16 for the nine probability levels used for analyses in this study.

Exhibit 3-14: Sample Degree Day Distribution Fit

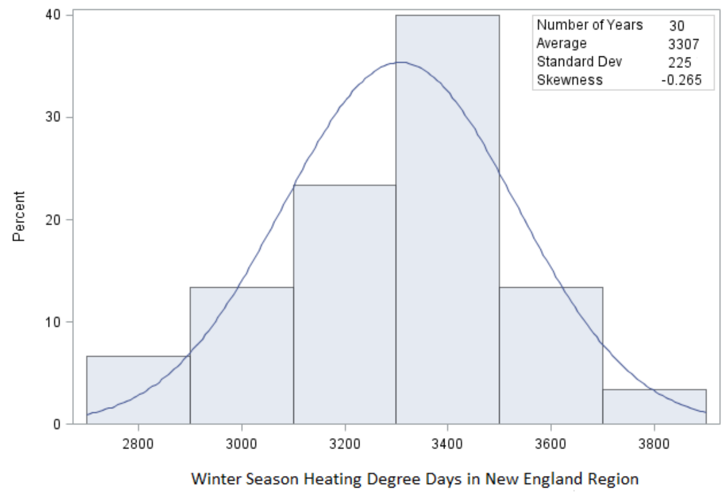


Exhibit 3-15: Winter Season Heating Degree Days

EIA Region	Census Division	P03	P10	P30	P50	P70	P90	P95	P97	P99
Northeast	New England	2,883	3,019	3,190	3,307	3,424	3,596	3,679	3,731	3,833
Northeast	Middle Atlantic	2,607	2,749	2,929	3,052	3,175	3,355	3,442	3,497	3,603
Northeast	South Atlantic	1,344	1,442	1,566	1,651	1,736	1,860	1,921	1,958	2,032
Southeast	East South Central	1,714	1,834	1,987	2,091	2,196	2,348	2,422	2,469	2,559
Southeast	South Atlantic	1,344	1,442	1,566	1,651	1,736	1,860	1,921	1,958	2,032
Midwest	East North Central	2,889	3,048	3,250	3,388	3,526	3,727	3,826	3,887	4,006
Midwest	West North Central	2,994	3,185	3,427	3,592	3,758	4,000	4,118	4,191	4,334
Central	West North Central	2,994	3,185	3,427	3,592	3,758	4,000	4,118	4,191	4,334
Southwest	West South Central	1,133	1,239	1,372	1,464	1,555	1,689	1,754	1,794	1,873

Source: ICF analysis of historical weather data from NOAA.

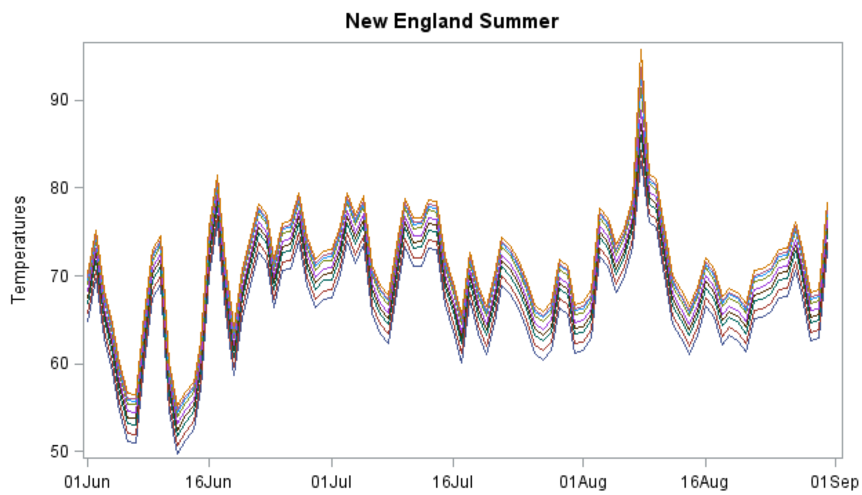
Exhibit 3-16: Summer Season Cooling Degree Days

EIA Region	Census Division	P03	P10	P30	P50	P70	P90	P95	P97	P99
Northeast	New England	260	316	386	434	482	552	587	608	650
Northeast	Middle Atlantic	416	482	566	623	680	764	805	830	880
Northeast	South Atlantic	1,024	1,078	1,145	1,191	1,237	1,305	1,338	1,358	1,398
Southeast	East South Central	905	977	1,069	1,132	1,194	1,286	1,331	1,358	1,413
Southeast	South Atlantic	1,024	1,078	1,145	1,191	1,237	1,305	1,338	1,358	1,398
Midwest	East North Central	373	453	554	623	692	793	843	873	933
Midwest	West North Central	531	610	711	779	848	948	997	1,027	1,087
Central	West North Central	531	610	711	779	848	948	997	1,027	1,087
Southwest	West South Central	1,318	1,394	1,491	1,557	1,623	1,720	1,767	1,797	1,854

Source: ICF analysis of historical weather data from NOAA.

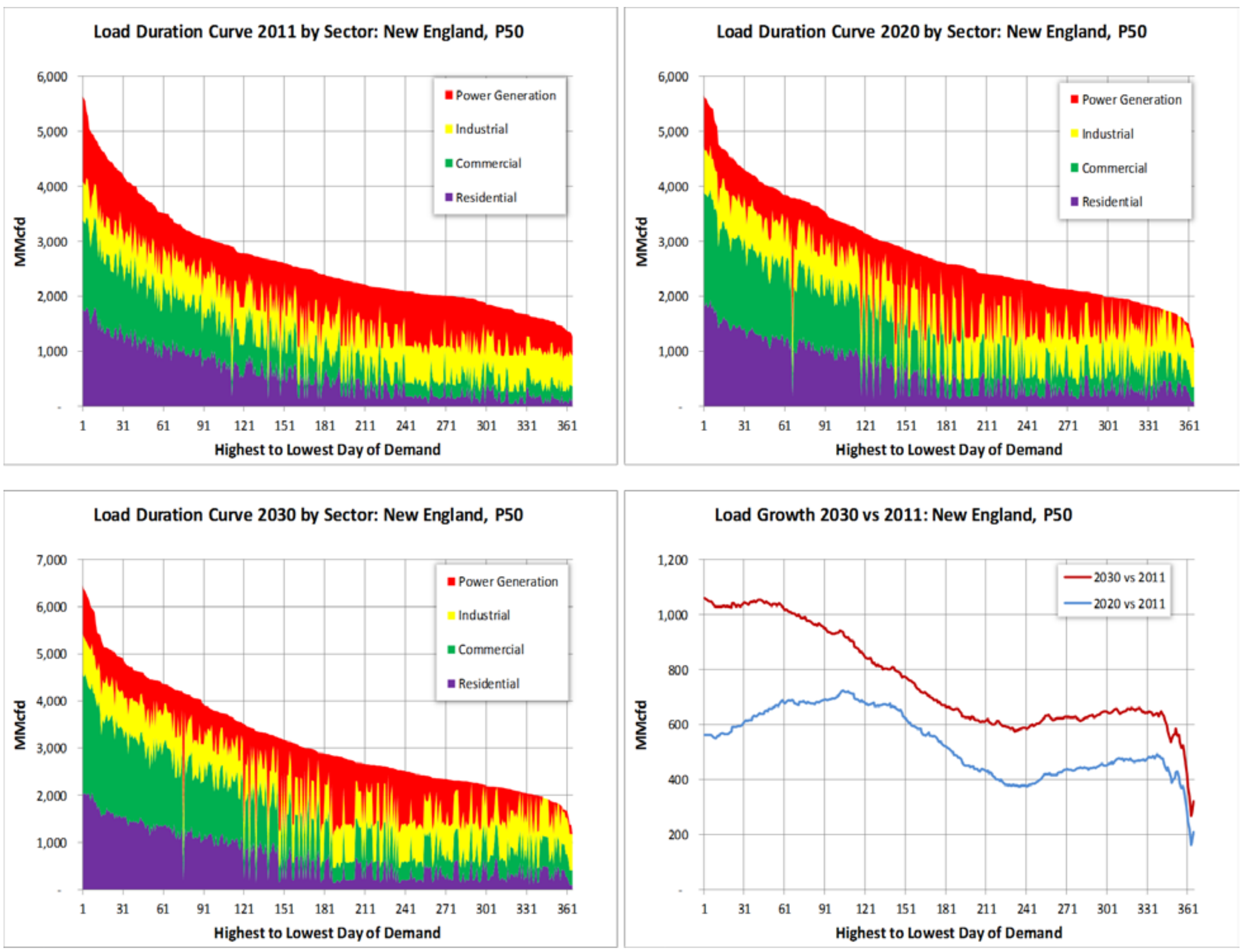
The second step of the process was a creation of daily temperatures for each of the specified nine weather cases. ICF collected daily temperatures for a representative weather station in each region and estimated their means and standard deviations on a seasonal basis. Next, ICF used those summary statistics to estimate seasonal maximum and minimum temperatures for a number of different percentile points using Monte Carlo simulation. Finally, we then shifted the original daily historical temperature series to match both the (a) distribution based degree day levels at specified probability of occurrence, and (b) distribution based extreme average daily temperature at the same specified probability of occurrence. The result of those calculations was a regional daily temperature series for nine weather cases. An example of these daily temperature series is shown in Exhibit 3-17.

Exhibit 3-17: Sample Daily Temperature Weather Cases



The daily temperature data was used in ICF's Daily Gas Load Module to project daily gas demand by sector for each node in the GMM® for the years 2011, 2020 and 2030. These daily load profiles can be depicted graphically in chronological order (for example, starting from January 1st and going to December 31st) or they can be sorted from the day of highest demand to the day of lowest demand. The resulting sorted graph is usually referred to as a natural gas load duration curve in that it can be read to indicate the number of days per gas load is equal to greater than a given value. Examples of such curves are shown in Exhibit 3-18 for the expected (P50) weather case for New England. There are curves for the years 2011, 2020 and 2030 and the last chart is difference between 2020 versus 2011 and between 2030 versus 2011. The P50 load duration curves for all gas nodes are shown in Appendix C.

Exhibit 3-18: Natural Gas Load Duration Curves: New England



Source: ICF analysis.

3.2.6 Representation of Alternative Options for Meeting Daily Gas Demand

The ICF analysis of daily demand for natural gas included the application of ICF's Energy Asset Decision Support System (EADSS) to determine the optimal mix of infrastructure that would most economically meet the weighted average demand of the nine weather cases. EADSS was set up to represent the same node-to-node gas pipeline network depicted in GMM® and was initialized with the same gas storage capacity and deliverability data. To meet daily demand under the nine weather cases EADSS was given the option of:

- Expanding node-to-node pipeline capacity,
- Adding depleted reservoir or aquifer underground storage (where feasible),
- Building high deliverability underground storage (where feasible),
- Adding LNG peak-shaving plants,
- Expanding fuel switching at power plants or industrial facilities,
- Curtailing demand when the cost of meeting demand exceeded the presumed customer's willingness to pay.[135]

The cost of meeting demand with these options was based on the gas infrastructure cost algorithms discussed earlier in this section. The application of those cost algorithms leads to different infrastructure development in each region due to such difference as:

- Existing infrastructure and its utilization for local and downstream gas consumption,
- Geology that impacts the feasibility, design and cost of underground storage, and the distance to any such suitable storage sites,
- Location of and distance to gas supply basins,
- Regional gas pipeline construction costs,
- Existence of and/or maximum capacity potential for each option,
- Volume and temporal distribution of incremental gas loads.

[135] Industrial customers were assumed to have a willingness to pay up to $150/MMBtu and power generators were assumed to have a willingness to pay of up to $300/MMBtu. These assumptions had relatively little effect on model results because installing fuel switching was usually a more economic option. Curtailment of consumption only occurred to a limited degree in the industrial sector in the P97 (coldest winter in ~30 years) and P99 (coldest winter in ~100 year) cases.

One way of representing the relative economics of different infrastructure options to meet daily gas demands is to create a “cost duration curve.” As shown in the two examples presented below, the x-axis of the cost duration curves represents how many days each year a given level of gas load exists. (This is the same concept as the x-axis in the natural load duration curve shown above except that it is shown in log scale.) The y-axis of the cost duration curve shows dollars per MMBtu of energy service. Options with relatively high capital costs and relatively low variable costs (such as gas pipelines) will tend to be the lowest cost option for loads that last for 100 days or more per year. This is because the high capital costs can be spread over more days (more Btus of energy service) resulting in a low $/MMBtu cost. On the other hand options with low capital costs, but high variable costs (such as fuel switching to No. 2 distillate oil) tend to be the lowest cost options for loads of short duration.

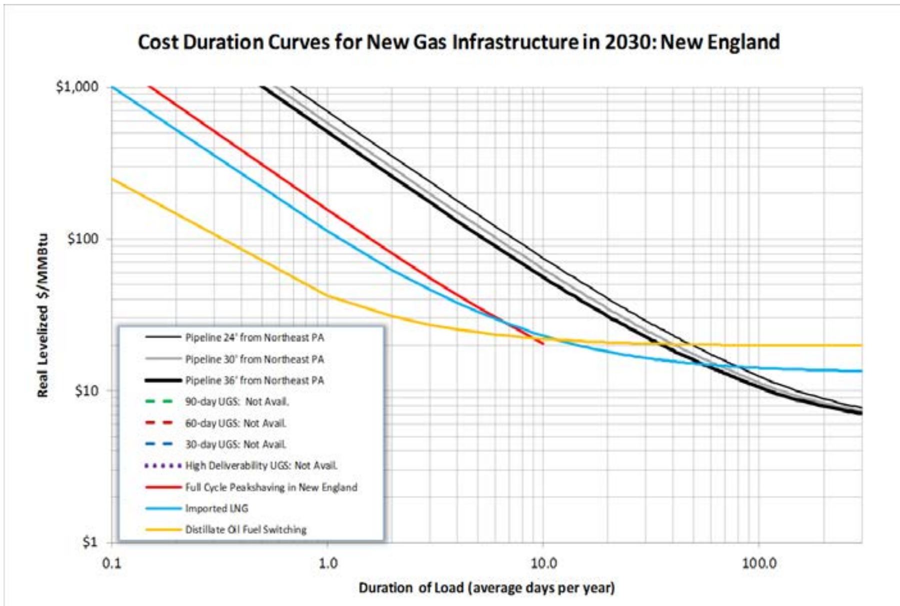
Energy Asset Decisions Support System (EADSS) Model

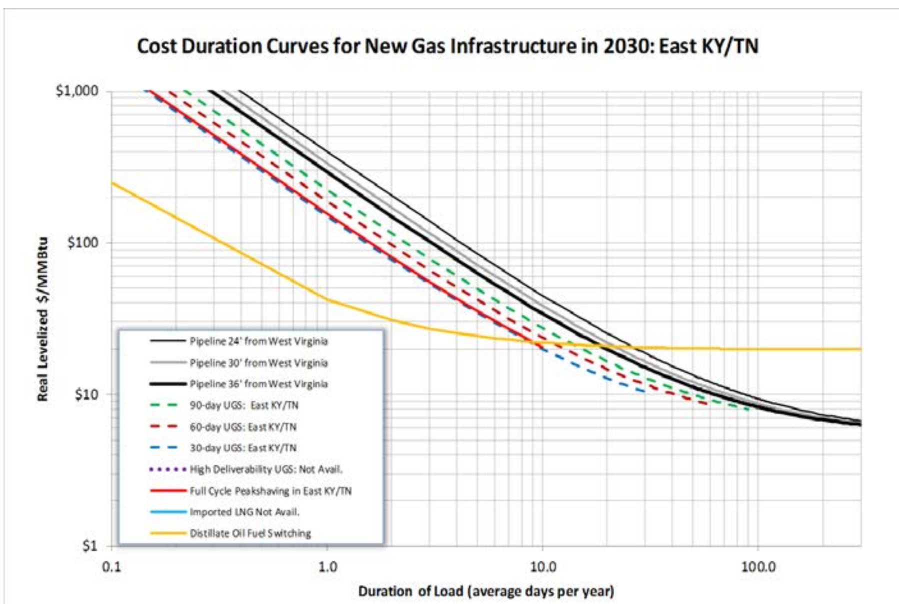
ICF designed the EADSS model to look at energy asset decisions that require an analysis of local constraints, system economics, multiple assets and end-use environment options, and/or uncertainty. EADSS includes stochastic modeling, combined with stochastic optimization, to address decision making under uncertainty and can simultaneously model power generation assets, natural gas infrastructure, energy storage, and emission allowance markets. We have used EADSS to evaluate regional pipeline and storage assets for system security purposes and evaluate high-deliverability storage fields.

Historically, both the electric and natural gas sectors have relied on mathematical-model-based tools to support infrastructure and resource planning. Such planning is typically performed separately by the two sectors. However, as natural gas-fired generation captures an increasing share of the generation mix, the electric power and natural gas sectors are becoming increasingly interdependent. To plan a robust energy future and to address the challenges of the gas-electric interdependency described in preceding sections, it could be advantageous to coordinate infrastructure planning across the electric and natural gas sectors.

Co-optimization models offer the greatest degree of such cross-sector coordination by facilitating joint planning of the two systems, subject to a set of coordinated constraints. However, due to the very-large-scale requirements on data and computation, this type of functionality is only now beginning to be integrated into system planning models. A few notable examples of such models include ICF’s proprietary models—IPM® and the Energy Asset Decisions Support System (EADSS), Brookhaven National Laboratory’s (BNL’s) MARKAL model, and the European models (MESSAGE and LIBEMOD).

Exhibit 3-19: Examples of Cost Duration Curves





The two example of cost duration curves shown in Exhibit 3-19 show the GMM® node for New England (wherein underground storage is not feasible but imports of LNG are) and the GMM® node for East Tennessee/Kentucky (wherein some kinds of underground storage are available, but LNG imports are not). Cost duration curves for all nodes are contained in Appendix D. The different size pipelines are represented by black lines in the cost duration curves. Various types of underground storage are represented by dashed lines. The solid red line represents LNG peak-shaving plants, the solid blue line is LNG imports and the solid yellow line is fuel switching to Number 2 fuel oil.

Where feasible, underground storage is often a lower cost option than gas pipelines for loads lasting fewer than 100 days per year. Underground storage remains the lowest cost option down to about 15 or 10 days of duration, at which point other options such as fuel switching, imported LNG or peak shaving are the most economic options. Note that the x-axis goes down to 0.1 days per year. This represents a load that is expected to occur one day every 10 years. Meeting such infrequent loads cost several hundreds of dollars per MMBtu because the capital cost are allocated to only a few units of energy leading to very high costs per unit.

3.2.7 Natural Gas Consumption Hourly Profiles

In order to investigate the degree to which changes in consumption patterns might make more difficult the serving of hourly loads within a day, ICF developed hourly gas consumption profiles for the examined regions by the key gas consumption sectors: residential, commercial, industrial, and power. The hourly gas consumption profiles provided a basis for projecting trends in regional hourly gas consumption patterns summed across all sectors. In particular, the hourly profiles allowed ICF to measure the hourly gas consumption levels that were above daily average consumption, called hourly “swing” volumes, and how they are expected to change in the future. The examination of the patterns in projected hourly swing levels is important because it identifies the amount of daily gas consumption that may need to be met through high deliverability market area storage or by short-term line-packing.

3.2.7.1 Methodology

ICF developed hourly gas consumption profiles for the examined regions for three gas consumption sectors: residential, commercial, and industrial. The power sector profiles were based on hourly model output from GE-MAPS model. The aggregate residential and commercial sector regional hourly profiles were based on the hourly gas use profiles of 11 typical commercial and two typical residential region-specific structure types. Hourly energy consumption patterns were generated for each building type with ICF’s Building Energy Analysis Console® (Beacon)[136] energy simulation and analysis modeling platform.

The typical commercial and residential building structures selected for this analysis were medical office building, warehouse, supermarket, small office building, secondary school building, restaurant, hospital, large hotel, strip mall, stand-alone retail building, mid-size apartment building, single-family homes, and apartment buildings. These building type specific profiles were then aggregated into single regional residential and commercial profiles with the help of the U.S. Energy Information Administration’s (EIA) RECS and CBECS surveys, both of which provided regional counts of each building type.

The industrial sector profile was based on ICF's research on typical industrial profiles in one, two, and three shift industries. The regional differences in hourly industrial profile were largely based on ICF’s assessment of predominance of these industries in each of the examined

[136] Beacon is an energy simulation tool that uses state-of-the-art simulation engines DOE-2 and EnergyPlus for estimating building energy performance.

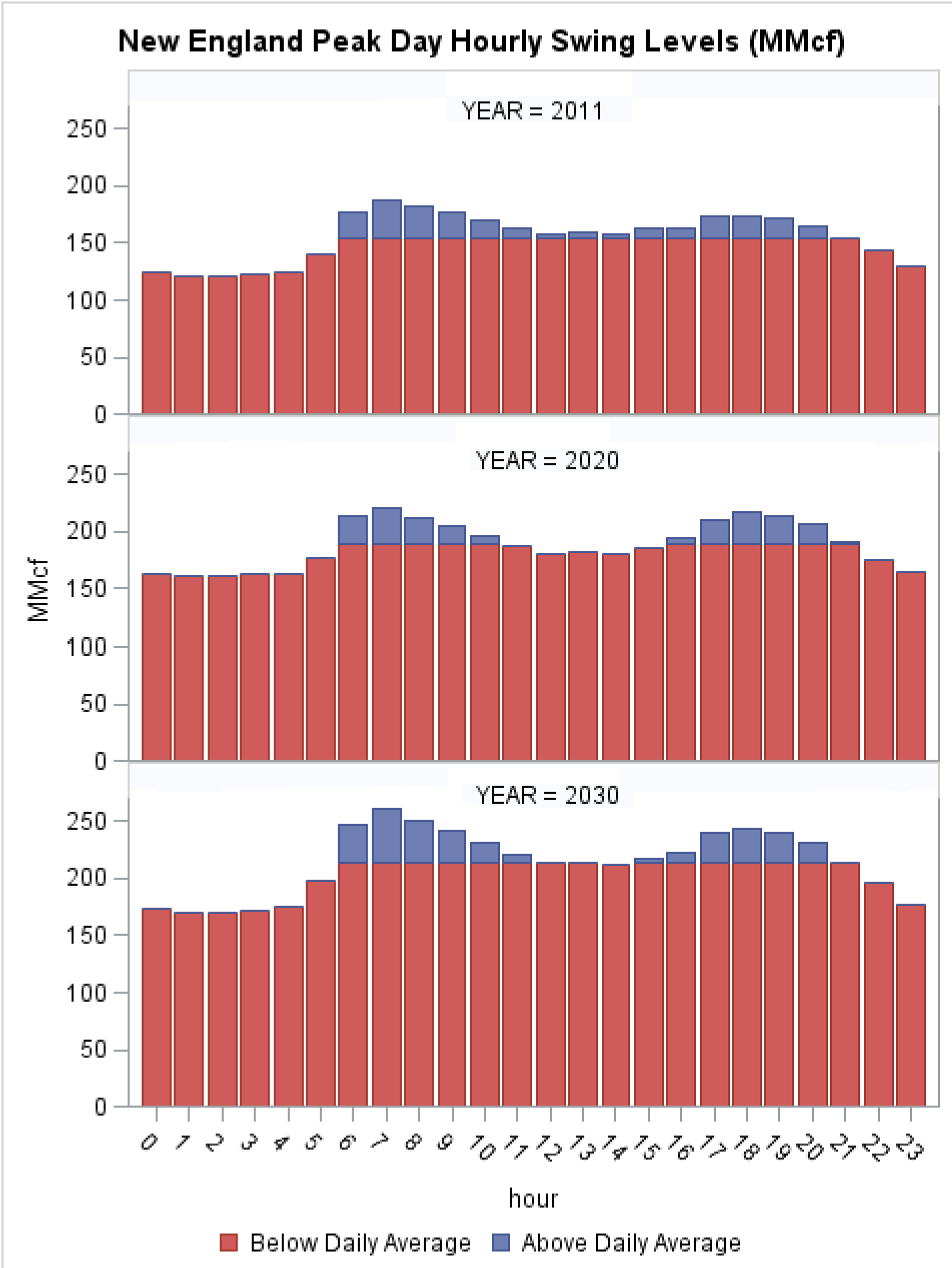
regions. The industrial profiles were also broken out by temperature sensitive and baseload profiles and by weekday and weekend profiles.

3.2.7.2 Hourly Profile Results: New England Example

Exhibit 3-20 shows New England peak winter day hourly profile for years 2011, 2020, and 2030. The exhibit shows that during winter peak day, New England's natural gas consumption rises above average hourly levels at 6:00 a.m. and falls below that level after 8:00 p.m. with distinct morning and afternoon peaks.

The average hourly natural gas consumption during New England winter peak day during 2011, 2020, and 2030 is estimated to be 155, 188, and 214 MMcf for those three years respectively. The total of hourly natural gas consumption that is above the daily average level is 215, 207, and 284 MMcf for 2011, 2020, and 2030, respectively.

Exhibit 3-20: New England Peak Day Hourly Swing Levels

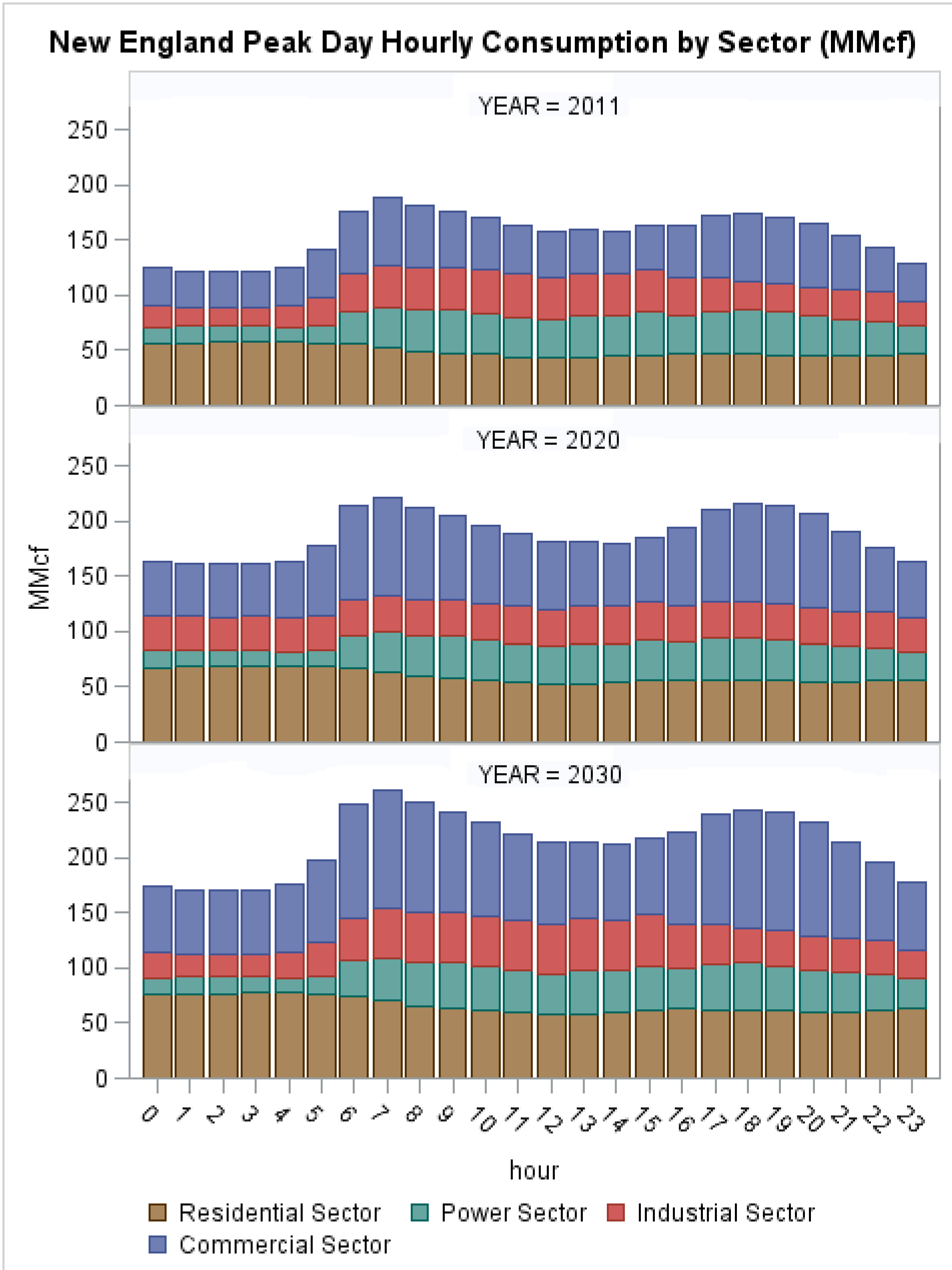


Source: ICF.

Note: Daily Swing Levels defined as sum of hourly demand levels that are above average daily demand (blue bars above).

Exhibit 3-21 shows the same New England winter peak day data broken out by sector.

Exhibit 3-21: New England Peak-Day Hourly Consumption by Sector (MMcf)

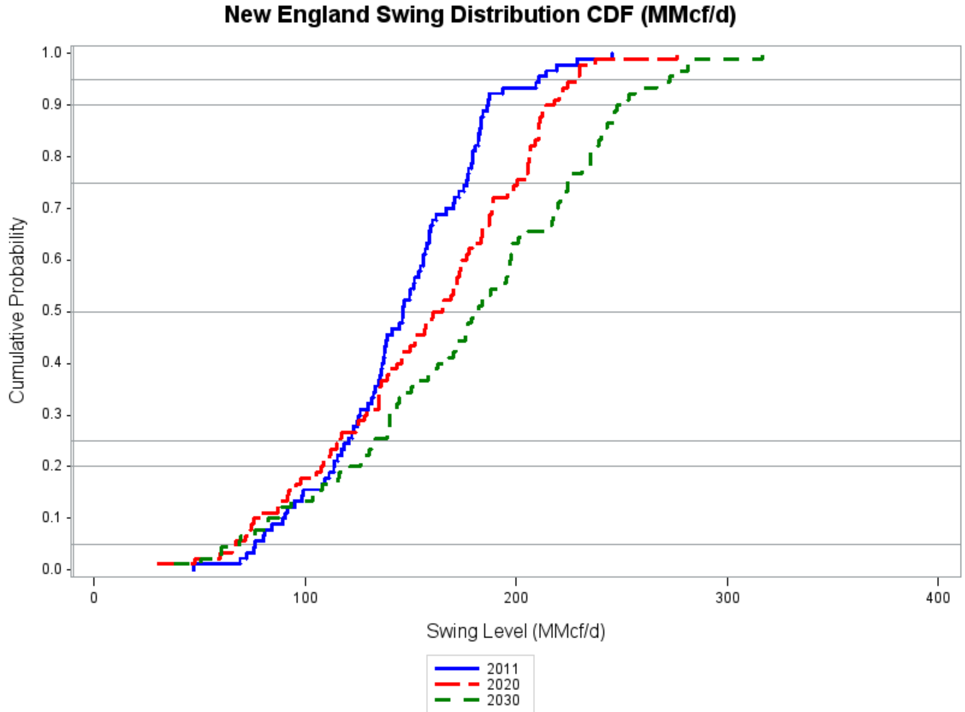


Source: ICF.

Note: Daily Swing Levels defined as sum of hourly demand levels that are above average daily demand.

The growth in winter hourly swing levels is not limited to winter peak days. Exhibit 3-22 below shows the cumulative distribution of New England's winter swing levels across all winter days. The exhibit shows a distinct increase in the size of the swing level across the years for each cumulative probability level above 20 percent.

Exhibit 3-22: New England Winter Daily Swing Distribution CDF

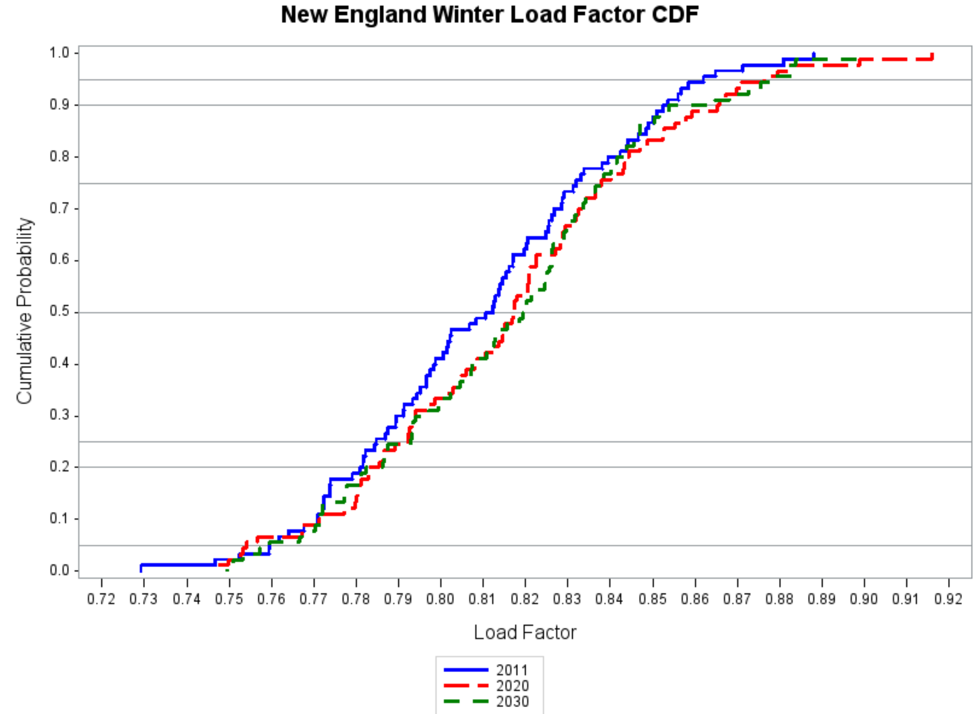


Source: ICF.

Note: Daily Swing Levels defined as sum of hourly demand levels that are above average daily demand.

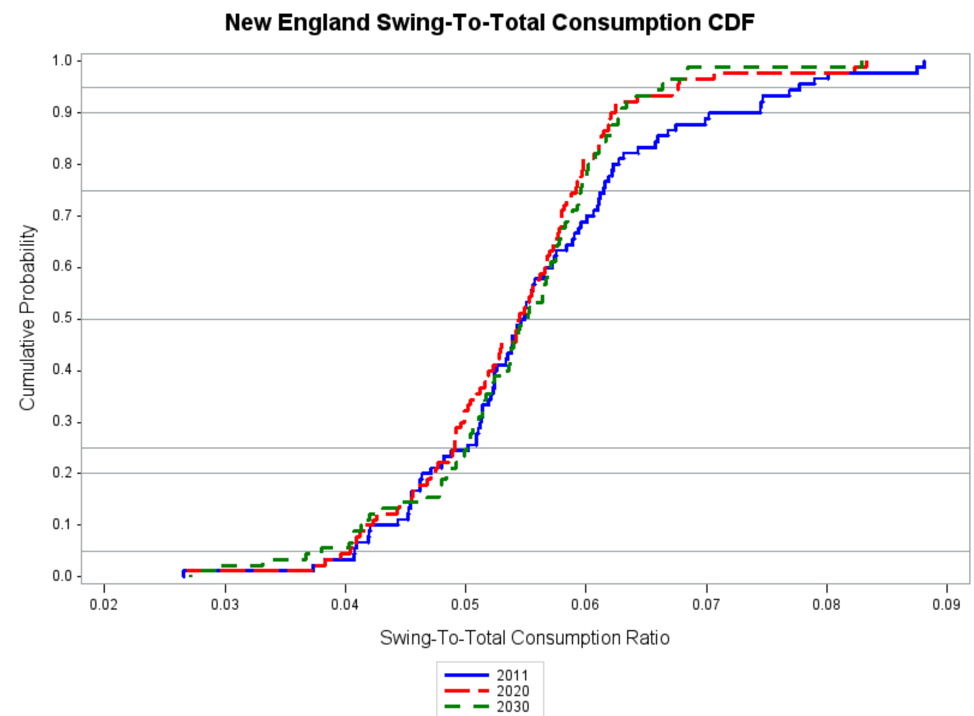
However, the growth in New England's winter swing levels across the years is not as strong as the overall growth in the daily total gas consumption. As shown in Exhibit 3-23 the load factor, defined as an average load to peak load ratio, is lower in 2020 and 2030 as compared to 2011, which suggests less variable load profile in those two years. Alternatively, as shown in Exhibit 3-24, a ratio between daily swing level and total daily gas consumption is expected to decline in 2020 and 2030 as compared to 2011, especially during the winter days with relatively higher than average daily gas consumption.

Exhibit 3-23: New England Winter Load Factor CDF



Source: ICF.

Exhibit 3-24: New England Winter Daily Swing-To-Total Daily Consumption CDF



Source: ICF.

Note: Daily Swing Levels defined as sum of hourly demand levels that are above average daily demand.

3.2.7.3 Regional Swing Level Trends

ICF examined three key statistics to assess the growth in the potential regional swing levels under the BAU scenario. The first statistic was a sum of hourly gas consumption that was above average hourly consumption during a given day. This swing level was measured in MMcfd. The second statistic used in the hourly analysis was a daily load factor, which was calculated by dividing a given day's average hourly gas consumption by that day's hourly peak gas consumption. Finally, the third statistic was a ratio of the daily swing level divided by the total daily gas consumption.

These statistics were examined for each region, season, and projected year under peak day, maximum swing day, and average swing day conditions. The first of these three conditions looked at the "swing" statistics during seasonal peak day, defined as the day with the highest daily gas consumption in a given season. The following two conditions represented days within a given season with the highest maximum hourly swing and average hourly swing levels.

A review of regional swing levels revealed that the peak day swing was typically lower than maximum swing during winter season as shown in Exhibit 3-25. The reason for this trend is that the average hourly gas consumption during peak days is already driven up by more extreme weather conditions minimizing any up-swing potential.

Exhibit 3-25: Winter Gas Consumption Swing Summary for 2011, 2020, and 2030 (MMcfd)

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day	Max Swing Day	Average Swing Day	Peak Day	Max Swing Day	Average Swing Day	Peak Day	Max Swing Day	Average Swing Day
Northeast	New England	214	245	145	207	276	156	284	316	177
Southeast	South Florida	333	341	142	304	477	298	342	537	336
Midwest	North Illinois	363	493	211	462	489	264	492	568	285
Southwest	Eastern Louisiana Hub	167	168	99	64	175	109	166	170	112

Source: ICF.

Note: Peak Day, Max Swing Day, and Average Swing Day Swing Levels defined as sum of hourly demand levels that are above average daily demand during winter peak day, winter day with the highest daily swing levels, and a winter day with an average daily swing levels respectively.

As can be seen in Exhibit 3-25 above, average daily swing levels grow across years from 2011 to 2030. This indicates a need for the natural gas infrastructure to have an increasing ability to follow swings in hourly loads within a day.

A review of the regional load factors across examined years allowed ICF to assess whether peak and average hourly load factors are projected to grow at the same rate. The load factor trend shown in Exhibit 3-26 below revealed no significant trend in load factor growth for most regions indicating that peak hour demand for natural in a day was growing at about the same rate as average hourly demand.

Exhibit 3-26: Winter Load Factor Summary for 2011, 2020, and 2030

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day	Max Swing Day	Average Swing Day	Peak Day	Max Swing Day	Average Swing Day	Peak Day	Max Swing Day	Average Swing Day
Northeast	New England	0.83	0.73	0.81	0.85	0.75	0.82	0.82	0.75	0.82
Southeast	South Florida	0.78	0.67	0.80	0.79	0.67	0.78	0.78	0.67	0.78
Midwest	North Illinois	0.76	0.65	0.80	0.76	0.63	0.79	0.76	0.64	0.79
Southwest	Eastern Louisiana Hub	0.85	0.85	0.90	0.91	0.83	0.89	0.84	0.84	0.89

Source: ICF.

Note: Load Factor during winter peak day, winter day with the highest daily swing levels, and a winter day with an average daily swing levels respectively.

ICF also examined the trend in the ratio of hourly swing to total daily gas consumption during the 2011 to 2030 period. This statistic separates out the impact of overall growth in gas consumption from daily swing levels. Exhibit 3-27 below shows that the expected daily swing levels as a share of total daily demand. The exhibit shows examined regions' swing level as a share of total daily demand is expected to remain fairly flat.

Exhibit 3-27: Winter Daily Swing to Total Gas Consumption Ratio Summary for 2011, 2020, and 2030 (%)

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing
Northeast	New England	9.0%	8.8%	5.6%	8.0%	8.3%	5.4%	8.0%	8.3%	5.4%
Southeast	South Florida	13.0%	13.4%	8.2%	15.0%	15.3%	9.1%	15.0%	15.2%	9.2%
Midwest	North Illinois	11.0%	10.6%	5.5%	13.0%	12.6%	5.8%	11.0%	11.1%	5.8%
Southwest	Eastern Louisiana Hub	6.0%	6.3%	4.1%	6.0%	6.4%	4.2%	6.0%	6.1%	4.4%

Source: ICF.

Note: Daily swing to total daily consumption ratio during winter peak day, winter day with the highest daily swing levels, and a winter day with an average daily swing levels respectively.

Given that the above tables use the same temperature assumptions for each of the examined years, and a single hourly profile pattern for each non-power sector, the changes in the swing levels as a percentage of total daily demand are explained by the shifts in the sectoral makeup of the regional gas consumption and changes in hourly gas burn in the power sector.

Exhibit 3-28 and Exhibit 3-29 below show swing level as a share of total gas demand and load factor for each of the four key sectors in 2030. The exhibits illustrate that residential and power sectors tend to have the highest share of swing as a percentage of the total consumption but those results are region specific. As natural gas use grows in the power sector, natural gas is used to meet a greater share of baseload electric load, meaning natural gas hourly loads are more likely to somewhat flatten.[137] This means that residential and in some regions, commercial sectors, remain important sources of future daily swing levels along with the power sector.

Exhibit 3-28: Winter Average Daily Swing to Total Gas Consumption Ratio by Sector in 2030 (%)

EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Northeast	New England	9.0%	8.8%	5.6%	8.0%
Southeast	South Florida	13.0%	13.4%	8.2%	15.0%
Midwest	North Illinois	11.0%	10.6%	5.5%	13.0%
Southwest	Eastern Louisiana Hub	6.0%	6.3%	4.1%	6.0%

Source: ICF.

Exhibit 3-29: Winter Average Daily Load Factor by Sector in 2030

EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Northeast	New England	0.71	0.72	0.81	0.69
Southeast	South Florida	0.65	0.70	0.88	0.76
Midwest	North Illinois	0.73	0.63	0.84	0.67
Southwest	Eastern Louisiana Hub	0.60	0.66	0.88	0.77

Source: ICF.

3.3 Key Results

3.3.1 Infrastructure Needed to Connect Demand-Supply Regions

ICF employed the GMM® and EADSS to analyze how transport and storage dynamics are likely to change as supply grows and markets change. For each of the three scenarios studied in the model, ICF assessed the following through 2030:

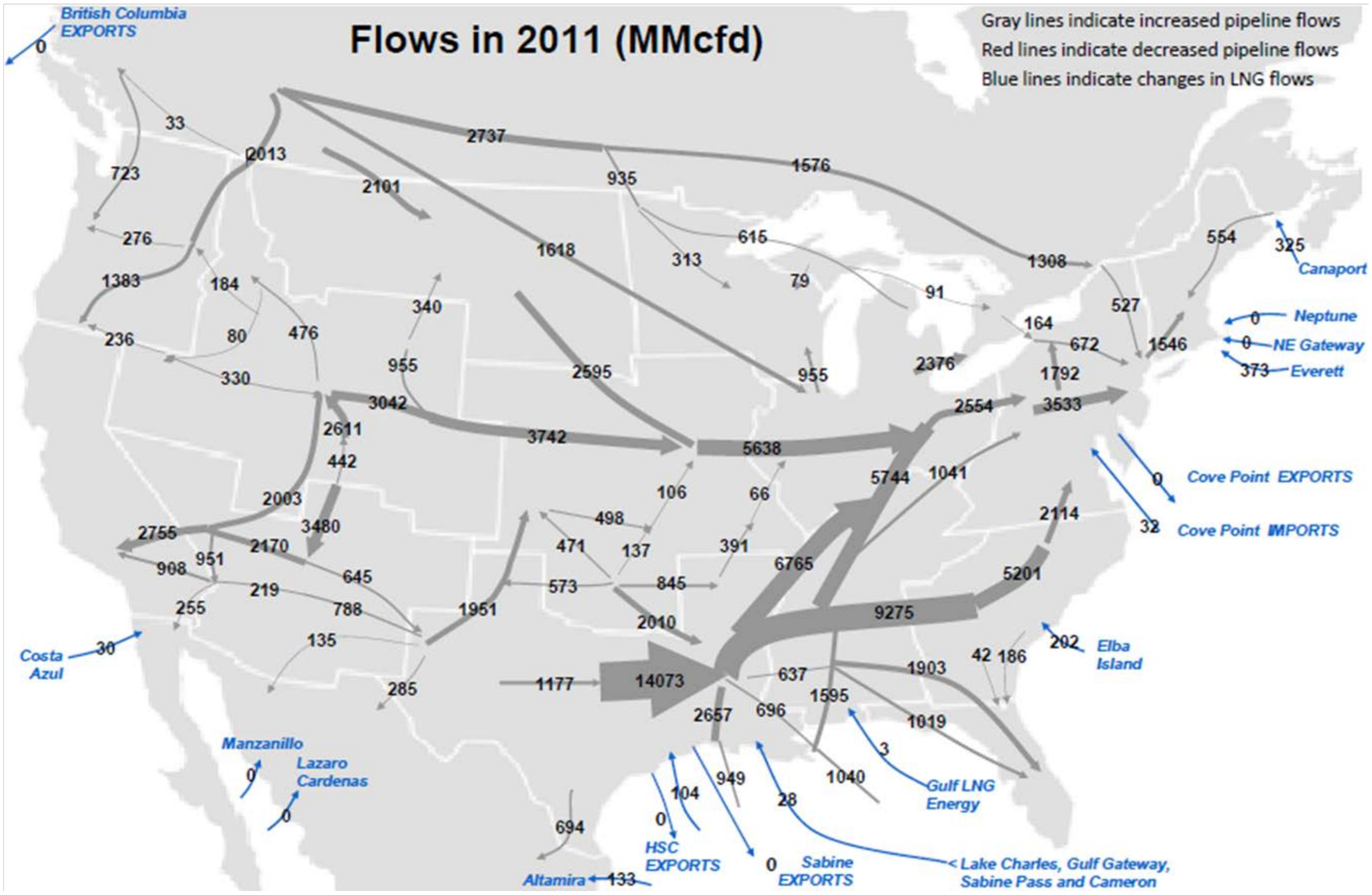
- Projected characteristics of natural gas monthly, daily and hourly demands throughout the Eastern Interconnection.
- Requirement for new gas pipeline capacity (e.g., mileage by diameter and type, including gathering systems, long-haul transmission, laterals to power plants).
- Pipeline compression added on new and existing pipelines.
- Underground storage capacity additions, including high-deliverability storage through 2030.

[137] The hourly natural gas use profiles in power sector were based on EIPC business as usual case scenario produced by CRA with GE-MAPS model. ICF did not make any further changes to these profiles to account for variability of the renewable generation resources.

- LNG peak shaving through 2030.
- On-site alternative fuel backup.
- Cumulative capital expenditures for natural gas and alternative fuel infrastructure.

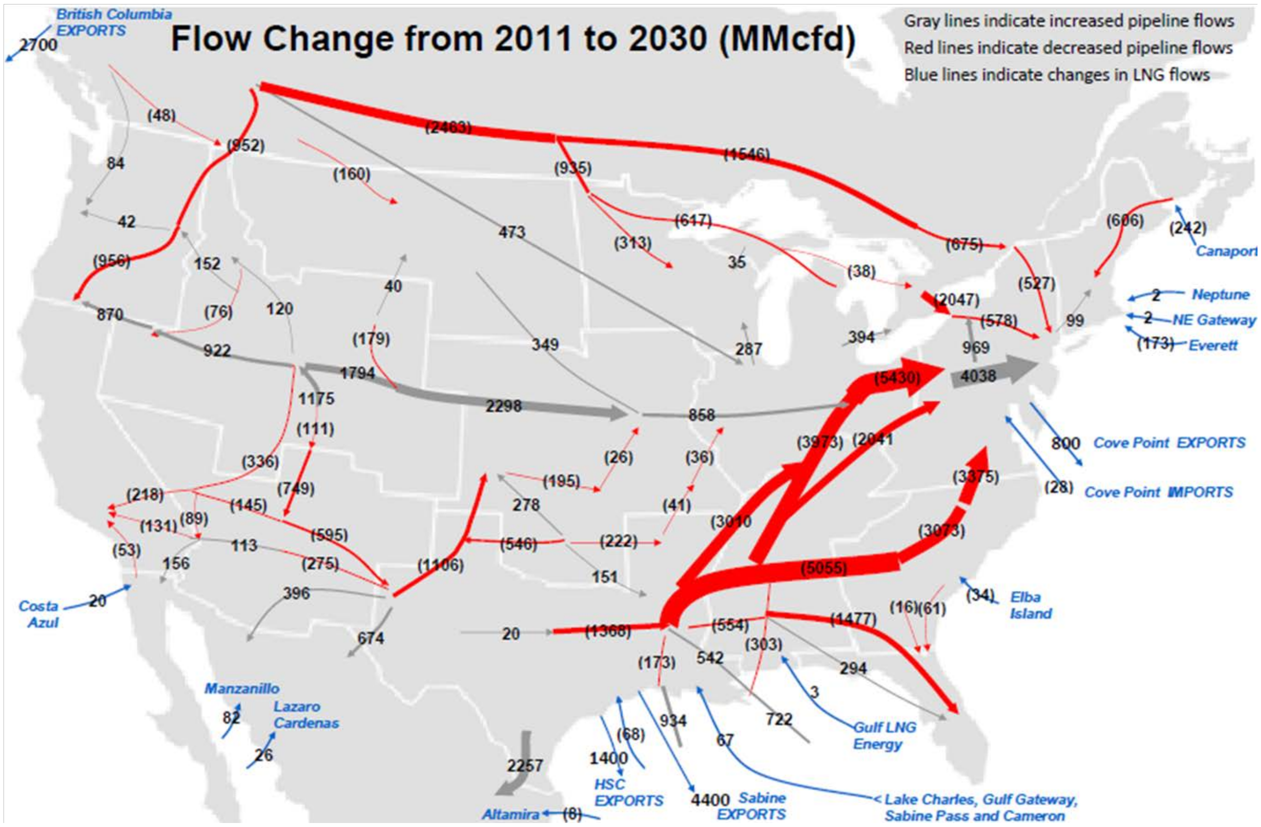
In terms of similarities between the three scenarios, because of Marcellus and Utica production growth, all three scenarios show a large decline in flows from the Gulf Coast and Western Canada to the Northeast. By 2030, gas will flow out of Marcellus/Utica to Ontario, the Midwest, the South Atlantic, and toward the Gulf Coast. In addition, flows from Western Canada to Pacific Northwest will decrease, while flows from the Rockies westward will increase. However, differences in the Combined Policy (S1) include a greater net decrease in flows to Northeast, with less gas consumed in the region, and more gas flowing out. In addition, there is a net decrease in flows to Florida in the Combined Policy (S1) Scenario, whereas flows increase in other cases. S1 also shows increased flows east out of Rockies, while flows are flat or reduced in other cases. The maps in Exhibit 3-30, Exhibit 3-31, Exhibit 3-32, and Exhibit 3-33 show pipeline flow changes throughout North America. Exhibit 3-30 shows interregional flows in 2011, with gray lines illustrating increasing flows, red lines showing a decline in pipeline flows, and blue lines indicating changes in LNG flows with arrows. Exhibit 3-31, Exhibit 3-32, and Exhibit 3-33 show the *change* in flows between 2011 and 2030 for each of the three cases.

Exhibit 3-30: 2011 Interregional Pipeline Flows (Base Year)



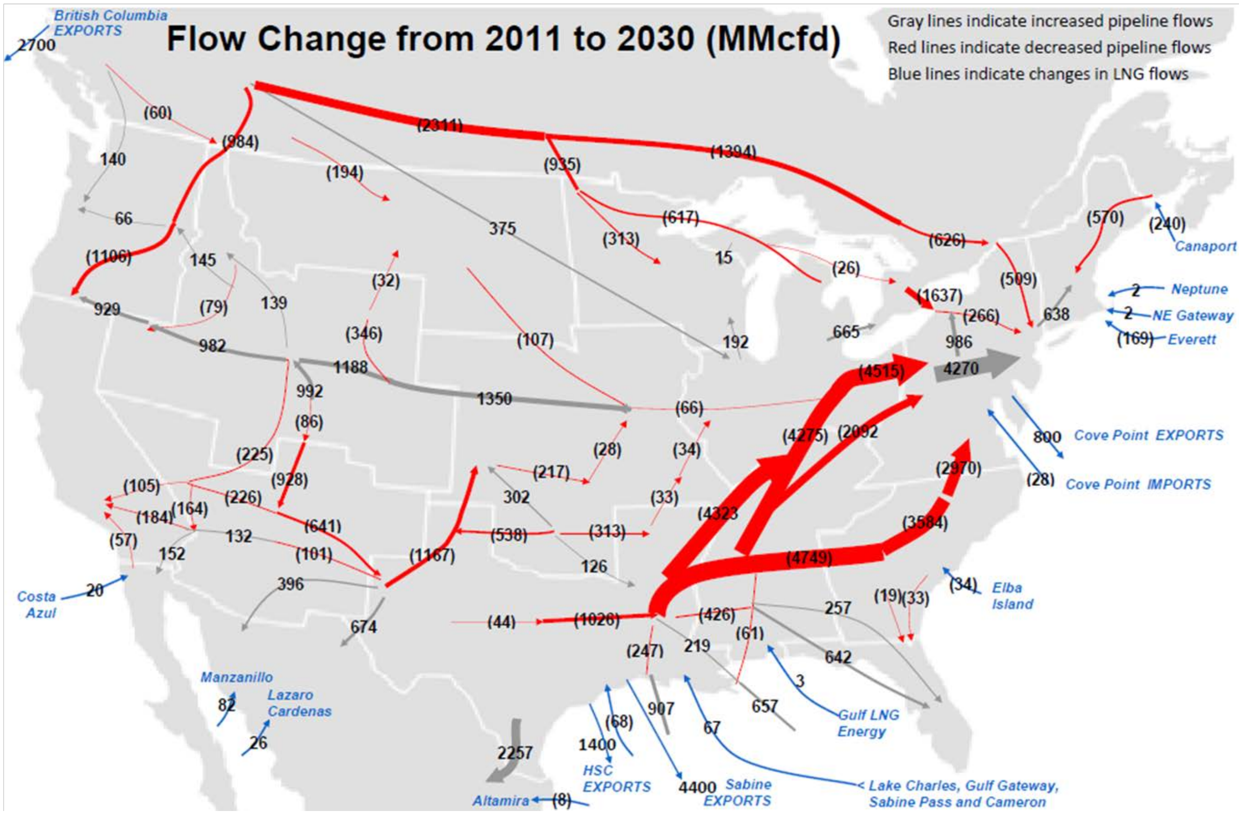
Source: ICF GMM®.

Exhibit 3-31: 2011–2030 Combined Policy (S1) Changes in Interregional Pipeline Flows



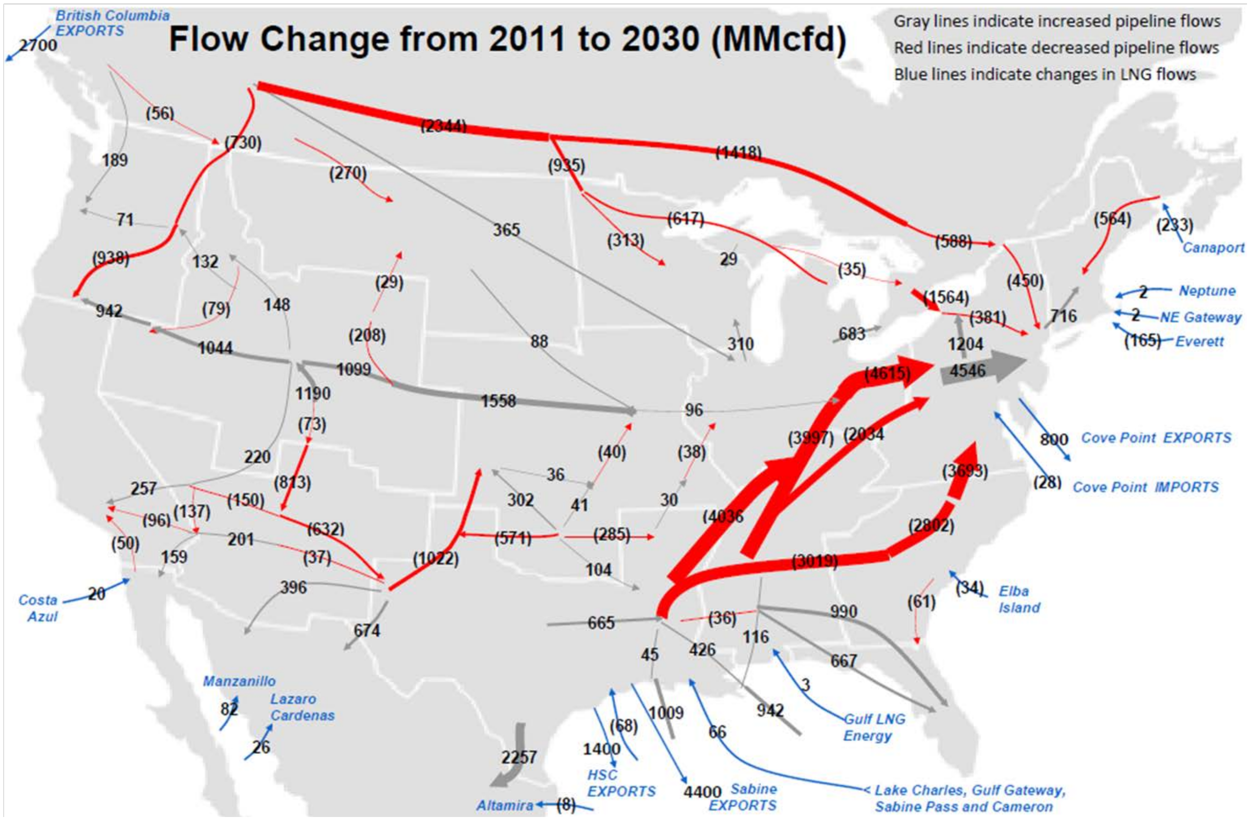
Source: ICF GMM®.

Exhibit 3-32: 2011–2030 RPS (S2) Changes in Interregional Pipeline Flows



Source: ICF GMM®.

Exhibit 3-33: 2011–2030 BAU (S3) Changes in Interregional Pipeline Flows



Source: ICF GMM®.

Pipeline infrastructure development reflects new patterns of supply and demand across North America, particularly the new supply growth in the Northeast and Southwest. In the Northeast, more pipeline projects will connect the Marcellus and Utica to power plants in the region, which is seeing increasing appetite for natural gas. Historically, gas flows south to north, with the Gulf Coast supplying New England. However, ICF expects this flow to reverse in the future. The Southwest is also seeing substantial load growth, especially in the form of gas exports to Mexico and at LNG terminals, and increasing petrochemical gas use. The southeastern and central states will see sizable capacity increases, primarily because a significant number of coal plants are expected to be retired, and gas-fired capacity will be serving as the primary replacement.

Most capacity increase will occur over the next 10 years to balance market supply and demand. The Combined Policy Scenario requires highest levels of infrastructure investment. Depending on the scenario, the Lower 48 will see between 686,000 and 763,000 new well completions and 9,400 and 14,200 miles of transmission mainline. This capacity increase will require other supporting infrastructure such as gathering lines, laterals, and processing capacity.. Exhibit 3-34 and Exhibit 3-35 show the infrastructure requirements by scenario.

Exhibit 3-34: 2014–2030 Lower 48 Natural Gas Infrastructure Requirements

Infrastructure Requirement by Type	Combined Policy (S1)	RPS (S2)	BAU (S3)
Total Well Completions	763,073	686,484	725,062
Miles of Transmission Mainline	14,153	9,369	11,527
Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants	8,826	5,014	7,676
Miles of Gas Gathering Line	190,219	170,807	180,619
Inch-Miles of Transmission Mainline	446,098	285,900	354,089
Inch-Miles of Laterals to/from Power Plants, Storage Fields and Processing Plants	153,328	83,804	125,818
Inch-Miles of Gathering Line	703,485	637,274	670,484
Compression for Pipelines (1000 HP)	4,186	2,423	2,852
Compression for Gathering Line (1000 HP)	5,537	4,672	5,329
Gas Storage (Bcf Working Gas)	581	349	488
Processing Capacity (MMcfd)	21,557	18,552	21,016

Source: ICF GMM® and EADSS.

To support the incremental gas movements that are anticipated, substantial investment is required. Exhibit 3-35 summarizes new gas transmission investment by type, including new mainlines, natural gas storage fields, laterals to/from storage, power plants and processing facilities, gas lease equipment, processing facilities, and LNG export facilities. These infrastructure needs between 2014 and 2030 are projected to total $182.6B in the Combined Policy (S1) Scenario, $131.7B in the RPS (S2) Scenario, and $156.9B in the BAU (S3) Scenario, the bulk of which is comprised of gas transmission lines, as shown in Exhibit 3-35.

Exhibit 3-35: 2014–2030 Lower 48 Natural Gas Infrastructure Investment Expenditures (2012$ Million)

Infrastructure Requirement by Type	Combined Policy (S1)	RPS (S2)	BAU (S3)
Gas Transmission Mainline Pipe	$66,540	$43,289	$53,212
Laterals to/from Power Plants, Gas Storage and Processing Plants	$23,862	$13,361	$19,728
Gathering Line (pipe only)	$22,531	$20,350	$21,450
Gas Pipeline & Storage Compression	$11,034	$6,416	$7,556
Gas Gathering Line Compression	$15,647	$13,273	$15,104
Gas Lease Equipment	$16,843	$14,815	$15,865
Gas Processing Capacity	$17,380	$14,982	$16,960
Gas Storage Fields	$8,788	$5,226	$7,029
Lower-48 U.S. States	**$182,624**	**$131,712**	**$156,904**

Source: ICF GMM®.

Exhibit 3-36 shows the regional distribution of natural gas infrastructure expenditures for the three scenarios.

Exhibit 3-36: Regional Natural Gas Infrastructure Investment Expenditures by Scenario

2012$ Million	2014–2020	2021–2030	2014–2030
Combined Policy (S1) Scenario			
Central	$19,422	$18,952	$38,374
Midwest	$9,808	$2,073	$11,880
Northeast	$25,333	$16,996	$42,329
Southeast	$24,097	$6,460	$30,556
Southwest	$33,547	$22,603	$56,150
Western	$2,886	$448	$3,334
Lower 48	**$115,093**	**$67,531**	**$182,624**
RPS (S2) Scenario			
Central	$14,779	$15,129	$29,907
Midwest	$3,580	$2,925	$6,505
Northeast	$21,880	$12,930	$34,809
Southeast	$7,369	$7,361	$14,729
Southwest	$21,589	$21,373	$42,962
Western	$2,399	$401	$2,800
Lower 48	**$71,594**	**$60,118**	**$131,712**
BAU (S3) Scenario			
Central	$15,656	$17,062	$32,718
Midwest	$3,732	$4,023	$7,755
Northeast	$22,669	$19,519	$42,188
Southeast	$7,697	$12,561	$20,258
Southwest	$23,871	$26,262	$50,133
Western	$1,862	$1,990	$3,851
Lower-48 U.S. States	**$75,487**	**$81,417**	**$156,904**

Source: ICF GMM®, and EADSS

3.3.2 Infrastructure Costs by State

Exhibit 3-37 below shows total infrastructure expenditures by state. Appendix E includes state-level expenditure findings by type.

Exhibit 3-37: 2014–2030 Total Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$5,893	$3,089	$3,406
Arkansas	$2,208	$1,288	$1,650
Connecticut	$766	$192	$765
Delaware	$697	$642	$690
District of Columbia	$0	$0	$0
Florida	$8,111	$4,257	$7,134
Georgia	$2,038	$633	$442
Illinois	$3,288	$1,698	$1,809
Indiana	$1,148	$248	$575
Iowa	$713	$424	$408
Kansas	$3,842	$3,328	$3,736
Kentucky	$2,172	$643	$626
Louisiana	$14,823	$10,519	$12,894
Maine	$2	$13	$14
Maryland	$920	$488	$958
Massachusetts	$766	$192	$765
Michigan	$2,649	$2,885	$3,249
Minnesota	$134	$23	$35
Mississippi	$6,619	$4,195	$5,074
Missouri	$1,874	$44	$44
Montana	$545	$616	$539
Nebraska	$2,941	$1,525	$1,526
New Hampshire	$1	$6	$7
New Jersey	$1,630	$1,498	$1,595
New Mexico	$2,485	$2,317	$2,521
New York	$5,299	$4,263	$5,902
North Carolina	$759	$297	$707
North Dakota	$3,628	$3,507	$3,247
Ohio	$6,667	$3,937	$4,381
Oklahoma	$4,518	$3,944	$5,124
Pennsylvania	$21,258	$19,712	$21,311
Rhode Island	$1	$6	$7
South Carolina	$2,672	$520	$1,340
South Dakota	$568	$323	$323
Tennessee	$952	$439	$398
Vermont	$0	$0	$0
Virginia	$2,469	$1,097	$1,671
West Virginia	$6,292	$4,369	$6,058
Wisconsin	$560	$84	$197
Eastern Interconnect	***$121,904***	***$83,260***	***$101,125***
Non-Eastern Interconnect	***$59,614***	***$47,810***	***$54,656***
Lower-48 U.S. States	**$181,518**	**$131,070**	**$155,781**

Source: ICF GMM®, and EADSS

4 Co-Optimization of Gas and Power Sector Infrastructure

4.1 Evaluation of Planning Tools

4.1.1 Introduction

This section will provide detailed review and analysis of existing mathematical models/tools for long-term resource planning, with emphases on natural gas sector models and co-optimization models that can determine infrastructure expansion plans for multiple sectors. Different approaches for addressing the interaction between the power and gas sectors will be presented, followed by comparisons among different approaches. Next assessed are the gaps in capability between the current co-optimization approaches and the new requirements and challenges that emerged from the more interconnected electric and natural gas sectors, including large-scale and fast computation capability, data requirements, and validation processes. Based on the in-depth review and analysis, recommendations are proposed to reduce such gaps, including identifying practical yet feasible analytic approaches, data acquisition, and establishing validation protocols. The purpose of such recommendations is to advise EISPC stakeholders on the best practice for coordinating electric and natural gas infrastructure to achieve both an economically efficient and reliable energy network.

4.1.2 Review of Practice and Literature of Resource Planning Modeling

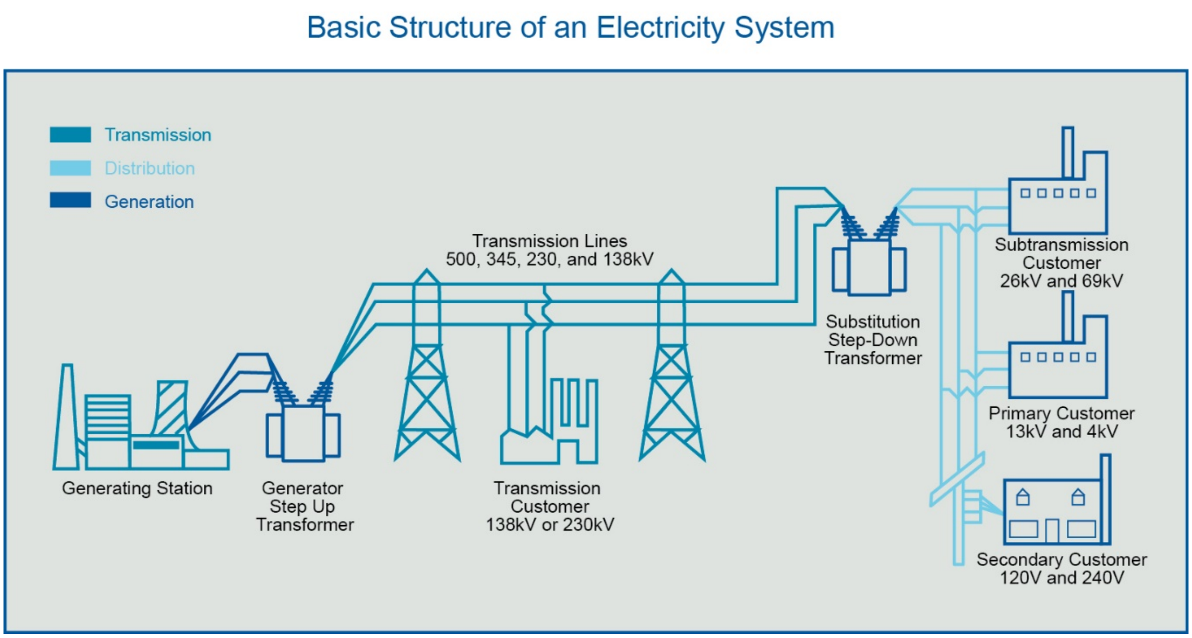
This section will review the literatures and practices of modeling for resource planning in both the electric power and natural gas sectors, and then survey the models and methods that can determine optimal options to meet demand in both the electric power and natural gas sectors, while explicitly considering the interdependence between the two sectors.

The primary motivation is to provide insights as to whether recent advancements in modeling and computational methods could provide better decision support to ease the future risks of fuel supply shortage under various conditions. Since surveys on electricity planning models have been abundant, the focus is on natural-gas-sector models, and more importantly models (or modeling frameworks) that can endogenously consider both sectors.

4.1.2.1 Resource Planning Models in the Power Sector

An electric power system has historically consisted of four components: generation, transmission, distribution and consumption, as illustrated in Exhibit 4-1. In a vertically integrated market regime, an electric utility company usually owns all the physical assets from generation to distribution, and has a specified area of customers to serve. In such a regime, utilities forecast future demand and are responsible for investing in generation, transmission, or distribution infrastructure to meet the projected demand. While the utilities can pass the investment costs to their consumers, they need to demonstrate to the states' utility commissioners that least-cost options in meeting demand are chosen, with the options including investments in generation, transmission or demand-side resources. Such a process is sometimes referred to as integrated resource planning. For such purposes, optimization problems, usually cast as cost-minimization problems, subject to a series of engineering and reliability constraints, have been widely used in the utility industry. In a deregulated market, electricity generation is separated from transmission and distribution, creating independent generation companies (Gencos) and utilities that focus on serving their customers (load serving entities, or LSEs); while the bulk transmission networks are operated by the independent system operators (ISOs). While integrated resource planning is no longer a requirement in most restructured electricity markets, long-term resource planning models are still useful. For example, ISOs could employ such tools in order to ensure that the market is sending the right price signals to market participants to invest in the most efficient resources at the right location. ISOs can also suggest new transmission solutions to transmission line owners based on system needs, and anticipate how generation asset dispatch would alter as a result of new transmission projects. Long-term resource planning models for the electricity sector can be applicable in both the regulated and deregulated markets (under the assumption that the deregulated market is perfectly competitive). An extensive review of such models has been provided in another study to EISPC,[138] and hence will be omitted here.

Exhibit 4-1: Basic Structure of an Electricity System



Source: ICF.

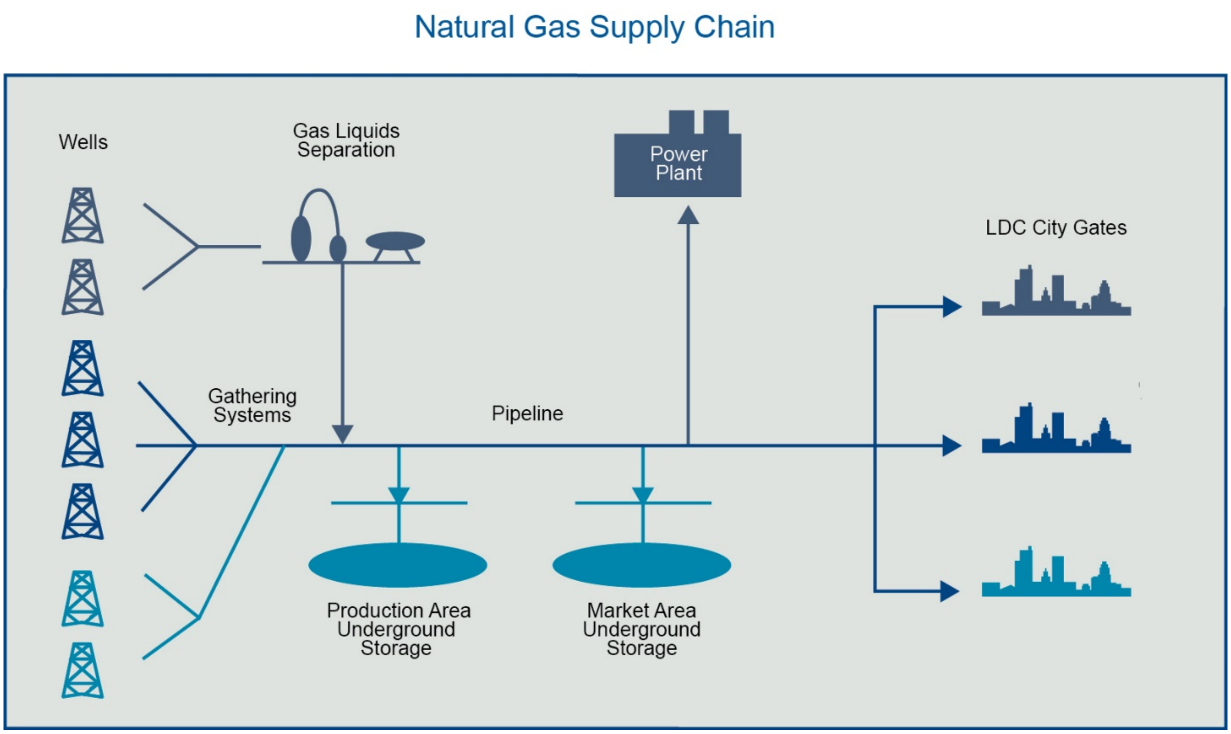
4.1.2.2 <u>Resource Planning Models in the Natural Gas Sector</u>

The natural gas supply chain typically consists of exploration and production (E&P), transportation (pipelines), distribution, and consumption, as illustrated in Exhibit 4-2. Unlike the electric power sector, the natural gas sector is highly segmented in terms of ownership, largely

[138] Liu, AL et al. "Co-optimization of Transmission and Other Supply Resources." September 2013. Available at: http://www.naruc.org/Grants/default.cfm?page=7.

due to deregulation of the industry. Since natural gas utilities typically do not own all the physical components from wellheads to burner tips, mathematical models for the natural gas sector are much more diverse in terms of their modeling objectives, scope and methodologies. The preponderance of such models are designed to project infrastructure expansion and to forecast natural gas prices based on supply-demand fundamentals, or for policy makers to study the impacts of various market and environmental policies on the natural gas markets. Such models usually cover large geographical areas in order to capture the major natural gas supply and demand regions, and are of (relatively) long time horizon to allow investments in major infrastructure.

Exhibit 4-2: Natural Gas Supply Chain



Source: ICF.

4.1.3 Model Survey

<u>Mathematical Programming-based Models:</u> Mathematical programming (or optimization) is a mathematical tool to help decision-makers choose a set of solutions to optimize (minimize or maximize) a specific objective function, while such solutions have to simultaneously satisfy a list of constraints. Mathematical programming models have been widely employed in constructing natural gas models. For more physical-asset-focused models, the objective functions can be to minimize the costs of constructing or developing specific infrastructure, such as natural gas pipelines, or storage facilities. For more market-oriented models, the objective functions can be total system costs (capital costs of adding new physical assets, transportation costs, contract costs, among others) of meeting the projected demand, from a planning coordinator or a natural gas utility company's perspective, or to maximize profits for asset owners, investors, or marketers.

The constraints in natural gas-related models vary substantially. These models are designed to help owners or operators optimize the utilization of specific physical assets, such as a gas reservoir, pipelines, or storage facilities. In such models, the constraints usually capture greater physical and engineering details of gas operations, such as the interaction between gas withdrawal rates and pressure at the wellheads or the Weymouth panhandle equations depicting gas flows in pipelines.[139] For market-oriented models built upon the dynamics between supply and demand, the constraints are more focused on flow balancing over (often simplified) natural gas transportation networks, such as the total outflows from gas suppliers match the inflows to all the demand regions/sectors. A prototype of such models is shown in Exhibit 4-3.

Exhibit 4-3: Prototype Natural Gas Market Long-term Resource Planning Model

Minimize: The discounted sum of future investment and operating costs (including reservoir exploration and production costs, pipeline capital and variable costs, storage capital and variable costs, LNG capital and variable costs)

Subject to:

- Gas supply constraints (e.g., drilling and production capacity)
- Gas pipeline constraints (e.g., pipeline capacity; flow balancing)
- Gas storage constraints (e.g., storage capacity; injection and withdraw balancing)
- LNG constraints (e.g., LNG facility and transportation capacity)
- Supply-demand balancing constraints

If the functions appearing in both the objective and the constraints are all linear functions (with respect to the decision variables), the corresponding mathematical programming models are referred to as linear programming (LP). A nonlinear function appearing anywhere in the objective or in the constraints would make the model a nonlinear programming problem (NLP). In addition, certain decisions may exhibit "lumpiness," usually associated with large-scale, infrequent investment decisions. For example, decisions on retiring certain assets are usually lumpy, since partial retirement (or mothball) may not be feasible. Integer decision variables (namely, decision variables can only assume integer values, such as 0 or 1) are the most convenient means to model such decisions in an optimization problem, and mathematical programming problems with mixed continuous and integer decision variables are referred to as mixed-integer programming (MIP). While LP, NLP, and MIP-based natural-gas related models all exist in the literature, the predominant models are LP, mainly due to the fact that NLP and MIP are fundamentally more difficult to solve than LP. While commercial LP solvers capable of

[139] More modeling details can be found in: Q. P. Zheng, S. Rebennack, N. A. Iliadis, and P. M. Pardalos. "Optimization Models in the Natural Gas Industry." *Handbook of Power Systems I* , edited by Panos M. Pardalos, Steffen Rebennack, Mario V. F. Pereira, and Niko A. Iliadis. Springer, 2010.

handling extremely large-scale problems have been well established,[140] solving large-scale NLP and MIP is still at the frontier of academic research and lacks commercial implementation. Exhibit 4-4 provides a summary of existing natural gas market models that employ various modeling techniques. A brief comparison of the different modeling approaches precedes the summary table. Note that the summary does include co-optimization models (that is, two- or multi-sector models that include at least both the power and natural gas sectors), which are summarized later in Exhibit 4-7.

Equilibrium Modeling (Complementarity)-Based Models: Optimization-based models designed to project market outcomes in an equilibrium all assume that the market in consideration is perfectly competitive; namely, all the market participants are price takers. In another words, no one in the market intentionally manipulates supply or demand of a certain commodity to impact the market prices in order to earn unjustifiably high profits (also known as market power abuse). However, in certain markets, there may be dominant participants who can indeed affect market prices, such as through withdrawing supply to inflate a product's price. In modeling a perfectly competitive market, optimization models with cost-minimization or profit-maximization as their objective functions will both lead to the same set of solutions, which are also socially optimal in the sense that social surplus (consumer surplus plus producer surplus) is maximized. In an imperfectly competitive market, however, the set of solutions from different objective functions will differ. To project market outcomes in such markets, each individual participant's profit maximization problem needs to be modeled explicitly (as opposed to a single optimization problem representing social-surplus maximization under perfect competition).

To solve the resulting model, which now consists of multiple optimization problems, optimality conditions[141] are written out explicitly as a complementarity problem and has the general form of $0 \leq x \perp f(x) \geq 0$ where the $\perp$ sign means that the product between *x* and *f(x)* is zero. Complementarity problems are extensions of optimization problems, and can be solved by specialized algorithms and solvers, such as PATH.[142] Gas market models that explicitly consider imperfectly competitive markets—including COUMBUS, GASMOS, NATGAS, and World Gas Model—are also summarized in Exhibit 4-4.

Stochastic Programming-based Models: While the predominant models related to natural gas markets are deterministic, meaning that all the input data are assumed to be fixed, in reality the markets face multiple uncertainties, especially for long-term resource planning. While using scenario-based analysis to account for future uncertainties is a common practice, stochastic programming (or simply SP) goes one step further in dealing with decision-making under uncertainties. The biggest difference between the scenario-based approach (or Monte Carlo approach, which uses advanced simulation methods to generate future scenarios) and SP is that the former is not a decision tool, while the later can produce solutions that inform decision-

[140] Such as CPLEX from IBM (http://www-01.ibm.com/software/commerce/optimization/cplex-optimizer/), Xpress from FICO (http://www.fico.com/en/products/fico-xpress-optimization-suite/), and Gurobi from Gurobi Optimization (http://www.gurobi.com/).

[141] Very roughly speaking, the optimality condition of an optimization problem is achieved by adding the first derivative of the objective function and the constraints together, and equating the resulting functions to 0.

[142] More information about the PATH solver is available at: http://pages.cs.wisc.edu/~ferris/path.html.

makers about what decisions to make. For example, in natural gas resource planning, a scenario-based approach will produce a set of solutions corresponding to each scenario under consideration (such as high demand growth versus low demand growth). One set of solutions may not even be feasible under the other scenario. For instance, the infrastructure expansion plan may correspond with the low demand-growth scenario, but may not meet demand in the high-demand-growth scenario. SP models, on the other hand, will only produce one set of solutions, which will not only be feasible, but also optimal, with respect to all possible realizations of future uncertainties (given that the probability distributions of the uncertainties are known[143]). While SP is certainly a more useful decision tool than scenario-based analysis, it also has certain disadvantages that will be discussed further in the following section. ICF's EADSS model and Energy Exemplar's PLEXOS® model (to be introduced in the co-optimization modeling section) are known to have stochastic programming capabilities.

[143] This assumption may or may not be reasonable. For example, for weather related uncertainties, such as heating degree days (HDD) in future years, historical data may be abundant to derive the underlying probability distribution of the number of HDDs (e.g., in a month). On the other hand, Earth may be experiencing climate change, making historical data less useful in predicting future events. In addressing such concerns, the field known as robust optimization has received increasing attention due to its goal to help people make robust decisions without assuming specific probability distributions of uncertainties. However, current efforts in this regard are mainly limited to academia, and the applicability of robust optimization to energy market modeling is under active research. See, for example, D. Bertsimas, D. B. Brown, and C. Caramanis, "Theory and Applications of Robust Optimization," SIAM Review, 53(3) (461–501) 2011.

Exhibit 4-4: Summary of Natural Gas Market Models (Excluding Models with Co-Optimization Capability)

Model	Developer	Model Types	Natural Gas Segments Modeled	Capacity Expansion	Time-step/Horizon	Region Scope
COLUMBUS	U. of Cologne, Germany	Complementarity model	Production, pipeline, storage, LNG, fixed demand	Yes	Monthly/20-year	Global
EADSS	ICF	Stochastic optimization	All segments of gas industry and (optionally) the power sectors	Yes	Daily or any other defined period	Varies by application
GASMOD	DIW Berlin	Complementarity model (imperfect competition)	Production, pipeline, LNG,	No	A market snapshot	Europe
GASTALE	ECN, Netherlands	Complementarity model	Gas producers, traders, LDCs	No	A market snapshot	Europe
GMM®	ICF (formerly EEA)	Nonlinear programming	Gas Production, transport, storage and demand. Power plant dispatch	Yes, by rule	Monthly through 2035	North America
GRIDNET	RBAC	Linear programing	Producers (supply contracts), pipelines, fixed demand	No	A market snapshot	North America
GPCM®	RBAC, Inc.	Linear programming	Production, pipelines, storage, LNG, marketers, fixed demand	Yes	Seasonal/ multiple periods	North America
MAGELAN	U. of Cologne, Germany	Linear programming	Production, pipeline, storage, LNG, fixed demand	Yes	Yearly/20-year	Global
NARG	MarketPoint, Inc./Deloitte	Linear programming	Supply, transportation, processing, demand	Yes	Yearly/40-year	North America
NATGAS	CPB, Netherlands	Complementarity model	Production, pipeline, storage, LNG, demand curves	Yes	5-year (2-season/year)/multiple periods	Europe
RIAMS	ICF	Linear programming	Production, pipeline, storage, processing, demand	No	Daily	Regional
RWGTM	Rice University	Linear programming	Production, pipeline, LNG transportation network, demand	Yes	Yearly/multiple-year	Global
TIGER	U. of Cologne, Germany	Linear programming	Production, pipelines, storage, fixed demand	No (dispatch only)	Monthly/10-year	Europe
World Gas Model	U. of Maryland/DIW Berlin	Complementarity model (imperfect competition)	Production, pipelines, storage, marketers, demand curves	Yes	Season, year/30-year	Global

4.1.4 Model Comparison

Mid-term vs. Long-term Models: Mid-term refers to models that do not endogenously determine infrastructure expansion plans. Two prominent mid-term natural gas market models are ICF's GMM® and RBAC's GRIDNET, while all the other models surveyed in Exhibit 4-4 are long-term models with endogenous resource planning. GMM® and GRIDNET themselves differ greatly: GMM® is a market equilibrium model that can project monthly natural gas prices based on calibrated supply and demand curves (see Appendix A for more details on ICF's GMM®). On the other hand, GRIDNET is based on minimum-cost flow problems. More specifically, the model finds the minimum-cost routes to transport natural gas to fulfill the contracts subject to a given set of constraints determined by supply and demand contracts.[144] Despite the different modeling approaches, both GMM® and GRIDNET share the benefit of simpler decision variables (i.e., no investment decisions), which allows the models to work more efficiently and to represent natural gas markets in greater detail.

Most of the long-term models would have to rely on spatial and temporal aggregation to reduce the models' sizes. Consequently, long-term models would not be able to provide price forecasts of the same locational or temporal resolution as GMM® can, nor provide detailed gas flow feasibility studies as GRIDNET can. On the other hand, although mid-term models can be used to compare different infrastructure expansion plans (by taking different plans as inputs and running the models multiple times), long-term models are more likely to find more efficient resource planning solutions while satisfying the various system reliability and environmental constraints..

<u>Mathematical Programming vs. Equilibrium-based Models</u>: The biggest advantage of an equilibrium-based model is its ability to project market outcomes in a market with imperfect competition (i.e. undue concentration of market power). Whether market power is a concern highly depends on the specific markets in consideration. While some European gas markets are more vulnerable to market power abuse, the U. S. natural gas industry's deregulation—coupled with abundant supply from shale gas—makes imperfect competition less of a concern. In this case, mathematical programming-based (especially LP-based) models are recommended since computational capability of current equilibrium solvers (i.e., complementarity-problem solvers) still lags far behind of the commercial-grade optimization solvers.

<u>Deterministic vs. Stochastic Models</u>: While conceptually SP is superior to both its deterministic-version of models and to scenario-based analysis—since it can provide decision-makers a uniform set of optimal solutions that have endogenously incorporated future uncertainties—several reasons have contributed to the lack of real-world application of SP models. First and foremost, SP models are computationally expansive. This issue becomes more serious for multiple-period models as the number of possible future scenarios may grow exponentially, making the resulting model quickly unsolvable by even the most advanced computers. Second, SP models may produce overly conservative (and hence, costly) solutions in trying to maintain system feasibility even for some of the most extreme events. There are modeling techniques that address such an issue, such as relaxing certain constraints in extreme events or using risk measures to explicitly account for the trade-off between costs and reliability. However, these techniques would require the modelers to have advanced mathematical knowledge and stochastic simulation skills to produce reasonable results. Third, endogenously accounting for uncertainty in SP models complicates the process of debugging, validation, and results interpretation. For example, for planning coordinators to demonstrate the validity of the modeling results from an SP model, they need to have all the stakeholders agree on the

[144] Brooks, RE; Neill, CP. GRIDNET: Natural Gas Operations Optimizing System. 2010. Available at: http://rbac.com/Articles/GRIDNETNaturalGasOperationsOptimizingSystem/tabid/67/Default.aspx.

probability distributions of all the uncertainties considered in the model—which may not be possible as perspectives on future uncertainties may be a subjective matter, depending on the stakeholders' roles and positions in the market.

4.1.4.1 Resource Planning in Interdependent Natural Gas and Electric Power Industries: Iterative Approaches

Most of the above-surveyed models only focus on either the power or the natural gas sector, and assume no interactions across sectors. With the increasing reliance on natural gas in the power sector, to maintain both sectors' reliability, it becomes more important to understand the impacts of one sector's operation on the others, both from a long-term and a short-term perspective.

However, two difficulties exist that prevent simply merging the electricity and natural gas resource planning models. First and foremost, the size of the optimization problems resulting from a combined-sector model (in terms of the number of variables and constraints) may be beyond today's computational capabilities. Second, the planning processes and market operations in the power and natural gas sectors differ in many aspects, such as time scales, spatial resolution, physical laws determining electricity and gas flows, to name a few. As a result, special attention is needed in connecting the two sectors' models to produce meaningful results.

4.1.4.1.1 Iterative Approaches to Cross-Sector Optimization

Despite these challenges, there have been significant efforts in developing an integrated power and natural gas model. These include the use of ICF's Integrated Planning Model® (IPM®) together with the ICF Gas Market Model® (GMM®) to produce a fully developed model of both the power and natural gas sectors. IPM® is ICF's engineering/economic capacity expansion and production-costing model of the power and industrial sectors supported by an extensive database of every boiler and generator in the nation. It is a multi-regional model that endogenously determines capacity and transmission expansion plans, unit dispatch and compliance decisions, and power, coal, and allowance price forecasts, all based on power market fundamentals. The results of IPM®'s optimization of the power sector can be fed directly into the GMM® which provides a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions. Section 3.2 provides a detailed description of this iterative approach for cross-sector optimization.

The National Energy Modeling System, known as the NEMS model, is a module-based comprehensive energy system modeling framework that has 12 modules, representing all energy sectors' activities. The Electricity Market Module (EMM) is a multi-year, linear programming-based model to determine the least cost investments possible and dispatch of various technologies to meet future electricity demand. Transmission networks are modeled as transportation networks, without modeling of AC or DC flows (i.e., no Kirchhoff's Laws). The temporal resolution of the EMM for short-term dispatch operations is by slices of the seasonal load duration curve at each of the 22 regions. Each seasonal load duration curve covers a period of four months, and is divided into three segments. Since the model is a deterministic linear program, no uncertainties or contingencies related to a power grid are explicitly handled in the model. The upstream natural gas sector is represented in the Oil and Gas Supply Module (OGSM) and the midstream is captured in the Natural Gas Transmission and Distribution Module (NGTDM). The NGTDM models the system as a trans-shipment model, without nonlinear equations to determine gas flow and produces yearly outputs (except for the gas prices for electricity sectors, which have finer resolution of on/off-peak).

NEMS uses an initial set of variables that represent current market conditions (fuel prices, electricity prices, demand, etc.) to initiate the solution process. Each module (of the 12 modules in NEMS) solves a single sector optimization, while keeping other sectors' variables fixed and the process stops once convergence occurs (meaning when no changes of solutions occur between the last iteration and the next to the last iteration) or a pre-specified number of iteration limits is reached.

Similar iterative approaches have been used in other studies and regions as well. The California Energy Commission (CEC) has used the PROSYM and NARG models to implement an iterative approach to assess the reliability of California's energy system.[145] PROSYM is an electricity unit commitment and economic dispatch model that balances electricity supply and demand on an hourly level; it also considers reserve requirements. It has much higher temporal and spatial resolution in terms of electricity market modeling than the electricity module in NEMS. However it is a short-term model and cannot determine capacity expansion plans. NARG, on the other hand, is similar to NEMS' natural gas modules in terms of modeling inputs/outputs and capability.

In a recent study by Black & Veatch,[146] an Integrated Market Modeling is proposed, with iterations run between an electricity production costing model—PROMOD and a natural gas market model—GPCM.

Von Weizsäcker and Perner[147] used a similar iterative approach to study the interdependence of power and natural gas markets in Europe. Both power and natural gas sector models are multi-period, linear programming problems. Outputs from the natural gas model (referred to as European Gas Supply Model, or EUGAS) include infrastructure investments, gas production, transport flows, and gas supplies; outputs from the electric power model include investments/retirements of power plants, transmission lines, power transportation, and

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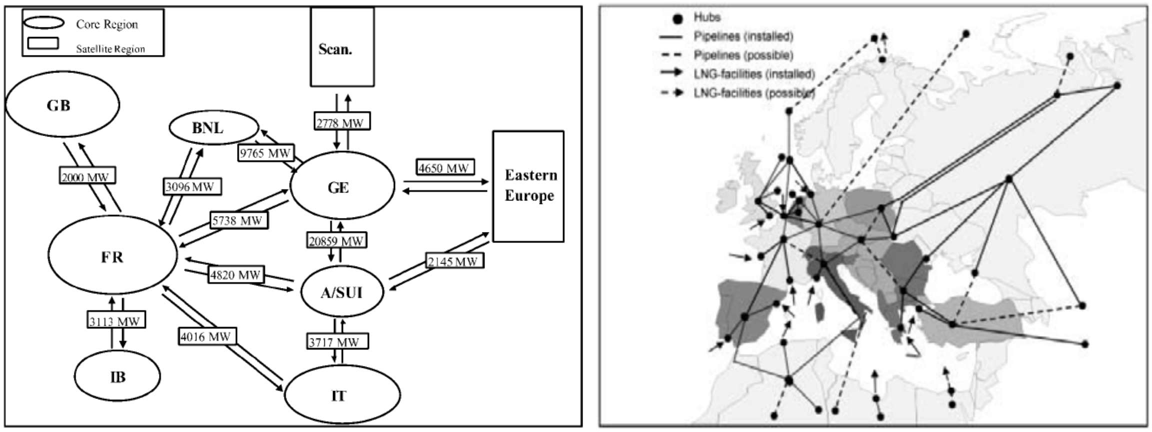
[145] California Energy Commission. "California Integrated Natural Gas/Electric Risk Methodology." Consultation report P700-02-008F. December, 2002.

[146] Black & Veatch. "Natural Gas Infrastructure and Electric Generation: Proposed Solutions For New England." Prepared for the New England States Committee on Electricity. B&V Project No. 178511. 26 August 2013. Available at: http://www.nescoe.com/uploads/Phase_III_Gas-Elec_Report_Sept._2013.pdf.

[147] Von Weizsäcker, CC; Perner, J. "An integrated simulation model for European electricity and natural gas supply." *Electrical Engineering*, Volume 83, Issue 5–6 (265–270). November 2001.

generation. The power and natural gas networks are highly aggregated, as illustrated in Exhibit 4-5.

Exhibit 4-5: Representation of Europe Transmission (left) and Natural Gas Networks (right)



Source: Von Weizsäcker, CC; Perner, J. "An integrated simulation model for European electricity and natural gas supply." Electrical Engineering*, Volume 83, Issue 5–6 (265–270). November 2001.*

4.1.4.1.2 Benefits and Drawbacks of Iterative Approaches

One of the major advantages of the iterative approach (as compared to a co-optimization approach, to be discussed in the next section) is that the computational requirement is less demanding than a co-optimization model that seeks to simultaneously find optimal solutions for all the modules in consideration. The lesser computational requirement would allow each individual module in an iterative approach to capture finer spatial or temporal resolutions of a system than its counterpart in a co-optimization model or to allow more sectors to be considered in the optimization process. For example, in Black & Veatch's study of power and natural gas interdependence, PROMOD[148] is used to represent the power grid. PROMOD is a production-costing model that chooses economic dispatch decisions of 8,760 hours in a year, with DC transmission line representations. Such detailed power grid modeling is not possible for existing long-term co-optimization approaches that jointly model the power and natural gas sectors. Another example is the NEMS model, which covers all the energy sectors, along with all the demand sectors. Although MARKAL is also a multi-sector model, it does not have the same detailed representation of all the fuel sectors' modeling from upstream to downstream to demand response as in NEMS.

The other major benefit of the iterative approach is that it may provide insights on how a market equilibrium is reached. The iteration process is essentially the process of plotting the supply and demand curves for the goods (commodities) in consideration. Solutions from each iteration (namely, from a single-sector model) indicate how a particular section will respond to the price and demand changes from other sectors, such as how electricity prices would change in

148 Ventyx, Product Overview: Promod IV. Available at: http://www.ventyx.com/~/media/files/brochures/promod_data_sheet.ashx?download=1.

response to higher natural gas prices. Such insights may not be easily obtained in a co-optimization framework. This is because changes in one factor may lead to responses from many other factors, and the dynamics among such interactions may be masked in the final solution of a co-optimization model, which only gives solutions to the equilibrium state of a market. For example, a more stringent air quality regulation may accelerate coal plants retirements, thereby reducing coal demand and putting downward pressure on coal prices. However, lower coal prices may stimulate the consumption of coal by the more efficient coal plants or increase coal export to other parts of the world (assuming international coal prices are higher), thus putting upward pressure on coal prices. Such price dynamics will not be revealed in a co-optimization solution, but can be observed through the iterative process. This process is also amenable to explicitly considering demand response in both power and natural gas sectors, which otherwise is difficult to incorporate endogenously in a single optimization model.[149].

The biggest disadvantage of an iterative approach lies in the fact that such solution mechanisms are not guaranteed to converge to a market equilibrium. Since a market equilibrium is equivalent to social welfare maximization, under the perfectly completive market assumption, failing to converge to a market equilibrium means that the iterative approach may provide solutions that are sub-optimal. Sub-optimal solutions would lead to inefficient resource allocation, such that more efficient power plants may not be fully utilized before less efficient ones are dispatched. Consequently, the resulting market prices may be higher than in a true market equilibrium.

From the implementation perspective, a user would not know beforehand how many iterations an iterative approach would need to converge (if it converges at all). If the iteration has to be terminated due to time constraints, the quality of the solutions from the last iteration cannot be gauged; that is, not only may the solutions be sub-optimal, but how close the solutions are to the optimal solutions cannot be known either.

4.1.4.2 Resource Planning in Interdependent Natural Gas and Electric Power industries: Co-optimization

In contrast to the iterative approach, a co-optimization approach seeks to cast the overall problem of finding least-cost investment and operation strategies across multiple energy sectors as a single model and solves the resulting model just once to find a system-optimal solution.150 Due to the complexities involved in modeling the power and the natural gas sector, co-optimization resource planning models that can simultaneously determine least-cost investment

[149] De Jonghe, C; Hobbs, BF; Belmans, R. “Optimal generation mix with short-term demand response and wind penetration.” IEEE Transactions on Power Systems. 27(2). 830–839. 2012. Refer to this reference for detailed discussions of incorporating demand response in resource planning models, which almost always lead to nonlinear functions in the optimization problem.

[150] Note that the term “co-optimization” is indeed a rather generic and vague term (as opposed to a well-defined or a commonly-understood terminology). In a recent study prepared to EISPC on surveying co-optimization resource planning models in the power sector (http://www.naruc.org/Grants/default.cfm?page=7), two definitions of co-optimization are given, with a stricter definition stressing the requirement of simultaneous optimization of two or more different yet related resources within one model, while the more relaxed definition to include the iterative approach. In this work the stricter definition of “co-optimization” is used to emphasize the distinction between simultaneous optimization and an iterative approach.

and operation options of various technologies to meet demand in both the power and natural gas sector are relatively rare, compared to the large number of single sector resource planning models.151 This section attempts to provide a complete survey of all existing co-optimization resource planning models that cover at least the power and natural gas sector.

Multi-sector Partial Equilibrium Models: Most of the co-optimization models that cover multiple sectors fall into the category of partial equilibrium models (also referred to as bottom-up models). A partial equilibrium is a market state in which the supply and demand of certain goods are balanced, independent of other markets' supply and demand activities or the income level of consumers. In the context of electricity and natural gas co-optimization, a partial equilibrium model finds the least-cost supply options to meet the demand of electricity and natural gas, while assuming all other commodities' prices are fixed (such as coal, oil, emissions allowances, etc.) and that the changes of electricity and natural prices will not affect end consumers' income level. (Otherwise the fundamental shapes of the demand curves for electricity and natural gas would be changed.) With the assumption that the energy markets are perfectly competitive, a co-optimization, partial equilibrium model can usually be written as a single optimization problem, as illustrated in the following generation formulation in Exhibit 4-6.

Under certain conditions on the specific function forms of production costs (and other related functions), the above formulation often results in a large-scale linear program. To explicitly account for lumpiness of investments (for example, if a new nuclear plant is to be built, its capacity cannot be lower than 500 MW), integer variables are needed to represent the "either/or" type of decisions; that is, either a particular type of technology of a specific size is constructed or it is not built at all. Integer variables would drastically increase the resulting optimization model's complexity, making it much more difficult to solve than a linear programming model. Exhibit 4-7 provides a summary of existing co-optimization models of power and natural gas sectors.

[151] For example, 37 electricity sector resource planning models are surveyed in "A review of computer tools for analysing the integration of renewable energy into various energy systems," by D. Connolly, H. Lund, B. V. Mathiesen, and M. Leahy. *Applied Energy* 87. 1059–1082. 2010.

Exhibit 4-6: Co-optimization, Partial Equilibrium Model Generation Formulation Example

Minimize the discounted sum of future investment and operating costs of both electricity and natural gas assets.

Subject to:

- Electricity sector constraints:
  - Total electric energy production of all power generation units = Electricity demand for each period
  - Electric power generation constraints (such as capacity constraints)
  - Electricity transmission constraints
  - Natural gas consumption from power sector = sum of natural gas consumption of gas-powered generation plants in each period
- Natural gas sector constraints:
  - Natural gas production constraints
  - Natural gas transportation/flow constraints (such as pipeline capacity constraints)
  - Total gas produced (in upstream) = total gas delivered through pipeline to consumers/city gates in each period
- Natural gas and electricity linkage constraints:
  - Total gas delivered = sum of gas demand from industrial, commercial, residential and electricity sector in each period

4.1.4.2.1 Hybrid Computable General Equilibrium Models*.* While a key justification for using a partial equilibrium model is that the specific market in consideration may have little impact on the rest of the economy, such reasoning may be challenged when both electricity and natural gas sectors are considered. The usage of electricity and natural gas is so pervasive in all sectors, and their combined costs to individual users (such as to a household, a small business, or a manufacturer) may be significant enough to impact their other spending-related decisions. Computable general equilibrium (CGE) models (also known as top-down models) are designed to capture the interaction among all economic sectors. Since all sectors of the economy are captured in the model, traditional CGE models cannot have detailed technology representations of a single sector. Only technology curves indicating the relationship between the amount of outputs and the level of inputs are used in each sector. As a result, such models are mainly used by policy makers to study taxation and other economic policy issues, and are not suitable for the purpose of long-term resource planning. However, recent efforts have tried to combine the technology-rich feature of partial equilibrium models with the all-sector CGE models to produce better market and economic forecasts. A notable example among such efforts is to integrate the CGE model known as EPPA, developed at MIT, and the multi-sector partial equilibrium model, MARKAL, through an iterative approach.[152] The two models are also used in MIT's recent report on the future of natural gas.[153] Since most hybrid CGE models rely on a technology-detailed partial equilibrium model,[154] Exhibit *4-7* focuses on partial equilibrium models with explicit modeling of the electricity and natural gas sectors and excludes hybrid CGE models.

[152] Schäfer, A; Jacoby, HD. "Experiments with a Hybrid CGE-MARKAL Model." *The Energy Journal*, Vol. 27, Special Issue: Hybrid Modeling of Energy-Environment Policies: Reconciling Bottom-up and Top-down.,171–177. Massachusetts Institute of Technology. 2006.

[153] Massachusetts Institute of Technology. "The Future of the Natural Gas -- An Interdisciplinary MIT Study." 2011. Available at: http://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

[154] There are truly integrated CGE and partial equilibrium models without relying on iterations among two models, such as the model and methodology described in "Integrated assessment of energy policies: Decomposing top-down and bottom-up," by C. Böhringer and T. F. Rutherford, in the *Journal of Economic Dynamics and Control,* Volume 33, Issue 9, 1648–1661, 2009. However, such models all lead to complementarity-based models. The computational complexity of complementarity problems, coupled with the data requirements in running the hybrid CGE models, makes them more suitable to study policy issues than addressing long-term resource adequacy issues.

Exhibit 4-7: Summary of Power and Natural Gas Co-optimization Models

Model	Developer	Model Types/Solution methods	Time-step/Horizon	Electricity flow	Natural gas flow	Natural gas segments modeled
GEP	Federal University at Itajubá, Brazil	Mixed-integer optimization	Load blocks/multiple-period	Transshipment model	Linear flow	Production, pipeline, LNG, storage
Iowa State Model	Iowa State University	Network flow models (linear optimization)	Multi-period (flexible)	Transshipment model	Linear flow	Production, pipeline,
IPM	ICF	Linear optimization	Time blocks per season, year/ decades	Transshipment model	Linear flow	Gas reservoirs, E&P, pipeline, storage, LNG
LIBEMOD	The Frisch Centre, Norway	Complementarity	2-season (day, night)/year for electricity, annual for gas	Transshipment model	Linear flow	Production, pipeline
MARKAL	ETSAP/IEA	Linear optimization	Season (peak, off-peak)/40-50 years	Transshipment model	Linear flow	Supply (supply curves), pipeline, LNG
MESSAGE	IIASA, Austria	Linear optimization	Multi-year grouping (e.g., 10-year/up to 100 year)	Transshipment model	Linear flow	Supply (supply curves), pipeline
NETPLAN	Iowa State University	Linear optimization (with decomposition and parallelization techniques)	Chronological order (electricity); monthly (NG)/40-year	Transshipment or AC/DC model	Linear flow	Production, pipeline, storage, LNG
PLEXOS	Energy Exemplar, LLC	Linear optimization/nonlinear optimization/integer programming	Load blocks or chronological order/multiple-period	Transshipment or AC/DC model	Linear flow	Wellheads (aggregated), pipeline, storage

4.1.5 Potential Benefits of Co-optimization Approaches

Coordinated resource planning in both the power and gas sectors is very rare in the United States, which is due largely to the diverse ownership of the various resources, and the daunting requirements of data collection, computation power, and validation (and not because of a lack of acknowledgement of the benefits of co-planning). One of the key motivations for pursuing co-optimization is to find cost minimizing solutions not attainable through the methods described above. Cost reductions could be realized through such an approach because linking power and gas sector optimizations can yield solutions that would not be found by simply iterating between resource planning solutions between the sectors. The co-optimization approach directly seeks to find an optimal solution of the unified system and therefore could find areas of the parameter space that are not attainable by only varying the composition of one sector at a time. It is estimated in the recent report to EISPC[155] that co-optimization of transmission and generation resources can lead to 5 to 10 percent cost savings when compared to separate transmission and generation planning. Co-optimization between the power and gas sector has the potential to yield similar, if not greater, cost savings. As demonstrated below, this could result from cost reductions from one sector compensating for cost increases in another sector.

In addition, co-optimization models that are capable of explicitly modeling variable-output resources and demand-side resources (such as IPM®, NETPLAN, PLEXOS®, and, to some extent, MARKAL), the models would have already considered all the available options in meeting future demand. As a result, co-optimization could provide more efficient solutions to integrate non-traditional resources.

Finally, co-optimization models with explicit representation of regulatory constraints (such as IPM® and MARKAL) can provide the most complete description of regulatory impacts on both the power and natural gas markets. In addition, such co-optimization models could provide a set of infrastructure expansion and resource mix solutions to comply with the various regulations at a lower total cost.

4.1.6 Limitations of Co-optimization Approaches

The challenges faced by cross-sector co-optimization models largely depend on the objectives of the modeling exercise. If a co-optimization model is used to study the impacts of certain markets or environmental policies on the market outcomes of the power and natural gas sectors, then most of the co-optimization models surveyed in Exhibit 4-7 could be applied, as they can return reliable solutions for these types of scenarios. For example, the IPM® model with integrated gas market model has already been used by EPA for analyzing the impacts various market-based regulatory programs.[156] Similarly, Northeast States Center for a Clean Air Future has used the MARKAL model to study potential policies and programs that can improve the air quality in New England regions, while maintaining energy security and reliability.[157]

If, on the other hand, the main concern is the reliability of the interdependent power and natural gas systems, then a combination of tools might be necessary. This is because combining a power sector and a natural gas sector model—with reasonably realistic representations of each sectors' essential characteristics—will result in an unmanageable level of computational complexity. To be able to solve the resulting models within a reasonable timeframe, even as linear programming problems, spatial and temporal aggregations are needed. For example, 8,760 hours in a year may be grouped into several time blocks, and transmission buses located across multiple states are aggregated as one region. As a result, the modeling resolution may

[155] Liu, AL et al. "Co-optimization of Transmission and Other Supply Resources." September 2013. Available at: http://www.naruc.org/Grants/default.cfm?page=7.

[156] Documentation for EPA Base Case v.4.10, 2010. Available at: http://www.epa.gov/airmarket/progsregs/epa-ipm/BaseCasev410.html#documentation.

[157] Goldstein, GA et al. "NE-12 MARKAL Final Report Structure, Data and Calibration." June 2008. Available at: http://www.nescaum.org/topics/ne-markal-model/ne-markal-model-documents.

be too coarse to capture events happening at the level of transmission buses or gas pipeline compressor stations. Such levels of details are important in addressing reliability concerns caused by the increasing dependence between the power and gas sector.

The complexity of a co-optimization model is further increased due to the different characteristics of different energy sectors. For example, the peaking hours of natural gas and electricity usage in a year are unlikely to coincide. Since peak demand is key in driving investments, a co-optimization, cross-sector model must be able to correctly represent the peak periods in all the sectors, and to link such periods across sectors. The temporal aggregation required for co-optimization models to be computationally feasible may not be able to accurately capture the coincidental peak periods in the power and gas sector (e.g. cold snaps). Despite their short duration, these events pose critical challenges to system operation and reliability. In addition, a fundamental difference between power and natural gas operation is that the latter can be stored while economically viable large-scale storage options for electricity are not typically pursued. The natural flow balancing through injection and withdraw activities usually requires chronological representation of time making non-chronological representation of time in the modeling of natural gas storage facilities a challenge. As a result, some restrictive assumptions have to be made regarding gas storage operations. Furthermore, higher deliverability natural gas storage facilities such as salt domes that can accommodate multiple injection/withdraw cycles in a year—cannot be captured due to the lack of chronological modeling and the coarse time resolution of many models.

Finally, as discussed earlier, a co-optimization model only yields solutions representing an equilibrium state of a market, and does not always provide information on the supply-demand dynamics that determine how such an equilibrium is reached. The lack of this type of information, coupled with the size and complexity of such optimization models, makes debugging and validation extremely challenging.

4.1.7 Recommended Approaches to Resource Planning in Interdependent Power and Natural Gas Sectors

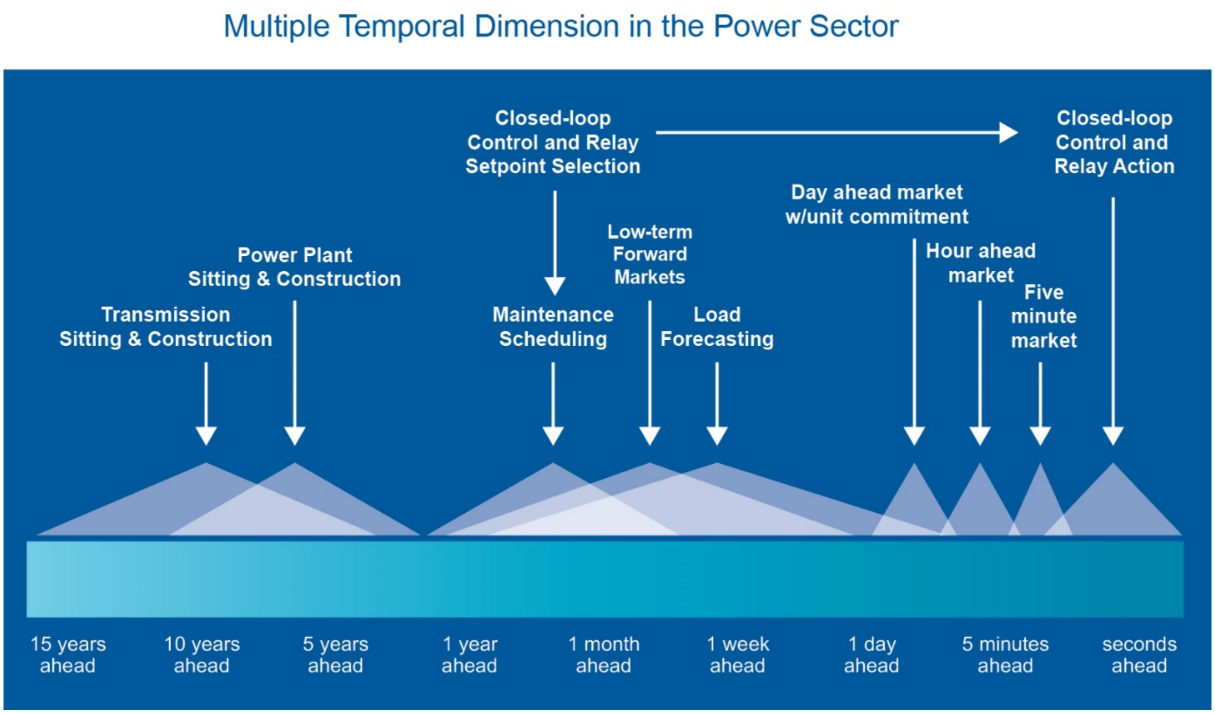
While the objectives of resource planning in both the power and natural gas sectors include finding an efficient resource mix to meet the projected demand, and to maintain or improve system reliability, solutions from a single sector's planning may end up jeopardizing the reliability of the other sector due to their interdependence. Co-planning in the power and gas sectors can therefore be advantageous because of such reliability concerns. However, both the power and natural gas sectors have distinct physical and market characteristics, and different reliability requirements. To simply put together all the constraints in representing such characteristics and requirements in both sectors into a single optimization model would result in an unmanageably complex and cumbersome model. On the other hand, as pointed out in the previous section, existing multi-sector co-optimization models' spatial or temporal resolution might be too coarse to identify reliability issues, which often arise in local areas and across short time scales.

A practical multi-stage modeling procedure is proposed to utilize the strengths of existing co-optimization models, while also addressing their insufficiencies. The detailed steps in the procedure are described below, followed by data requirements for implementing such a procedure.

4.1.8 Recommended Methodology

The essence of the proposed multi-stage approach is to recognize the different spatial and temporal resolutions of various decisions to be made for resource planning and system operation. Regarding the time dimension, Exhibit 4-8 illustrates the different temporal scales of decision-making in the electricity sector. The natural gas sector exhibits a similar range of scales, from decades-long gas reserve exploration and development, to several years of pipeline construction, to monthly gas contracts, to daily market operations. From the spatial dimension perspective, the large geographical areas in the United States—with drastically different weather, natural resource and demographic profiles—ensure very different regional energy supply characteristics. Different regions have different infrastructure and resource mixes, and hence, varying levels of interdependence between the power and gas sectors.

Exhibit 4-8: Multiple Temporal Dimension in the Power Sector



Source: Tang, L; Ferris, M. "A Hierarchical Framework for Long-Term Power Planning Models," IEEE Transactions on Power Systems. Issue 99 (1–11). June 2014.

For the proposed multi-stage approach, each stage corresponds to a particular level of spatial and temporal resolution, and the effects of decisions or events of one dimension on the others are captured through an iterative process. The details are as follows:

Stage 1 (Long-term Stage): Define the regions to be included in the study. Run a deterministic, electricity-natural gas co-optimization model to determine long-term infrastructure needs for a set of projected demand.

Stage 2 (Short-term Stage): Select a particular future year, and take the infrastructure solutions (up to the selected year) from Stage 1 as inputs. Select a representative day (or week, or season) in the year with projected demand under normal conditions. Run an hourly, joint electricity-natural gas economic dispatch model with detailed transmission line and pipeline representations (or an iterative approach between a power unit commitment model and a natural gas dispatch model). (The economic dispatch model of electricity should be able to jointly dispatch energy and operating reserves.)

Stage 3 (Real-time Stage): Take the infrastructure solutions from Stage 1 and power and gas dispatch solutions from Stage 2 as inputs. Simulate scenarios of various weather conditions, demand, and contingency events. Run a Monte Carlo analysis, which is a broad class of computational algorithms that rely on repeated random sampling to obtain numerical results. Use the results of the Monte Carlo analysis to investigate if the solutions from Stage 1 and 2 would violate reliability requirements based on the simulated scenarios.

Iteration Process: If the answer in Stage 3 is negative (e.g., the current infrastructure and resource mix at the chosen year, coupled with the dispatch solutions, will result in a reliability measure below the required level) identify a particular physical asset or a set of assets, (e.g., generation plants, transmission lines, pipelines, or storage facilities) such that the lack of capacity of the asset(s) likely causes the reliability issue. Increase the capacities (and the corresponding dispatch level) of the identified assets, and re-do Stage 3. If the realized reliability measure satisfies the requirement, re-do Stage 1 with an added constraint to the long-run co-optimization model such that the capacities of the identified asset(s) cannot be lower than the levels that lead to the desired reliability measure. This process can be kept repeated (from Stage 1 to Stage 3) until the set of solutions from Stage 1 and 2 will produce a satisfactory reliability level of the joint power-gas system (or until a pre-specified time or computational resource limit is reached).

4.2 Demonstration of Gas and Power Sector Infrastructure Co-Optimization

The discussion below provides a brief demonstration of the cross-sector co-optimization capacity available using ICF's IPM® natural gas module. In order to demonstrate the value of carrying out a planning exercise with co-optimization across the power and natural gas sectors, ICF chose a nominal base case using publicly available inputs and assumptions and solved it using both an iterative approach and a co-optimized approach. The iterative approach is based on a power sector capacity expansion through 2030 using ICF's power sector planning model, IPM® followed by an optimization of the gas sector midstream and upstream infrastructure using ICF's gas market model (GMM®). In this case, GMM® uses the outputs of the IPM® model as an input. For the co-optimization approach, IPM® is run with the natural gas module that solves for both power sector and gas infrastructure in parallel.

4.2.1 Methodology

The runs in both cases solve using the same inputs, cost assumptions, and load growth forecasts. These projections, like the EIPC runs themselves, have a planning horizon to 2030, but because the gas market module is a North American model, results are reported for the continental U.S. instead of just the U.S. portion of the EI as in the EIPC scenario analysis above. In all cases, the inputs for this short demonstration case were based on publicly available data in order to increase the transparency of the results. Electric demand assumptions are based on the NERC 2013 Electric Supply & Demand (ES&D) report that reflects recent load forecasts from all of the regions in the continental U.S.[158] The natural gas assumptions differ between runs due to the differing structures of the models as described below. The remaining assumptions are based on EPA Base Case v5.13 assumptions.[159]

4.2.2 IPM® Natural Gas Module Overview

The gas module is a full supply/demand equilibrium model of the gas market in North America. It consists of 118 supply/demand/storage nodes, 15 LNG regasification (import) facility locations, and three LNG export facility locations that are tied together by a series of links that represent the North American natural gas transmission network. Rather than using exogenous fuel price assumptions, the IPM integrated gas module allows for the natural gas supply, gas demand, transportation, storage, and related costs to be modeled directly and incorporated into the objective function of the optimization.

Supply curves for natural gas are developed for each model region based on undiscovered resource availability or recoverable resource as a function of exploration and development (E&D) cost for 81 supply regions. The resource cost curves are constructed on the basis of

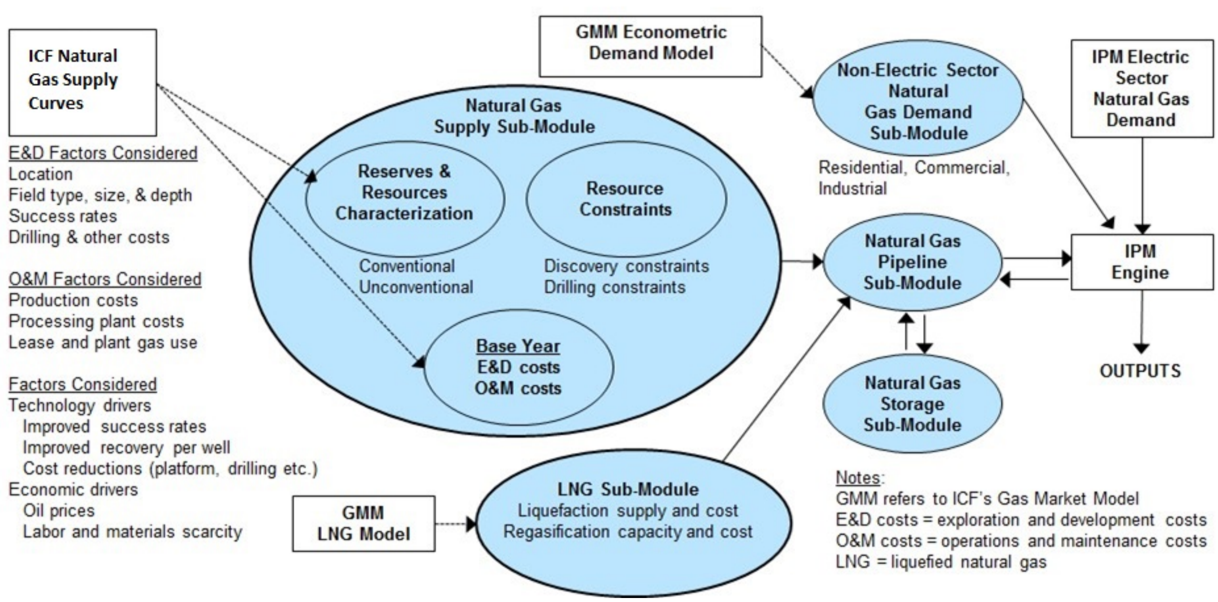
[158] NERC. "Electricity Supply & Demand (ES&D)" 2013. Available at: http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

[159] EPA. "Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model" Air and Radiation (6204J), EPA # 450R13002. November 2013. Available at: http://www.epa.gov/powersectormodeling/docs/v513/Documentation.pdf.

resource assessments and economic evaluations prepared by ICF for the GMM®. This detailed representation of natural gas resources allows the model to solve the natural gas price endogenously and therefore facilitates price response based on the level of fuel consumption and vice versa. This is in sharp contrast to the methodology carried out in the EIPC Phase I analysis whereby a static gas price was imposed that remained fixed and independent of natural gas consumption levels. By reflecting natural supply elasticity and demand elasticity, an equilibrium level of gas production and demand can be reached and allows the model to build less gas generation and infrastructure if production costs rise or to expand utilization of the fuel if cheaper resources are available to the market.

In order to maintain an acceptable complexity scale that will allow for manageable run times, the model design is simplified relative to the full GMM® implementation described in the third section of this report. In particular, the model solves for load blocks in two seasons rather than solving monthly as is typically the case. A schematic diagram of the natural gas module is shown in Exhibit 4-9 below.

Exhibit 4-9: IPM Natual Gas Module



Source: ICF.

4.2.3 Results

Using the assumptions described above, two optimization runs were conducted. The iterative optimization was carried out in two steps by first solving the power sector capacity expansion followed by an optimization of the natural gas infrastructure. In this case, a static natural gas price was used independent of gas consumption levels. The cross-sector co-optimization allowed gas prices and fuel infrastructure builds to respond to levels of power sector gas demand and produced power sector and fuel infrastructure expansion topologies in one step.

Because the exogenous natural gas price trajectory chosen for the fixed price run is somewhat below the equilibrium price solved for in the natural gas module, the average delivered gas prices in the co-optimization run are between \$0.38/MMBtu and \$0.87/MMBtu higher than in the iterative optimization case (Exhibit 4-10). This results in natural gas consumption declines of 1.8 to 8.0 percent over the planning horizon. As a result, the model builds fewer combustion turbines, pursues retrofits on more coal units, and builds less fuel infrastructure with the co-optimization approach.

Despite somewhat higher power sector capital expenditures, the total capital costs of the co-optimized case, when accounting for natural gas infrastructure, were lower by \$7.5 billion (Exhibit 4-12). This corresponds to a net decrease of roughly 1.5 percent relative to the iterative solution. This is in large part due to the considerable savings from reduced natural gas infrastructure as noted in Exhibit 4-11 below.

Exhibit 4-10: Natural Gas Consumption and Price, U.S. Lower 48

Co-optimized Gas and Power Sectors					
	2016	**2018**	**2020**	**2025**	**2030**
Fuel Consumption Annual Gas (TBtu)	33,497	32,345	34,957	38,401	46,100
Fuel Price - Realized Annual Gas (US2012$/MMBtu)	4.97	5.67	5.35	6.80	6.65
Iterative Optimization of Gas and Power Sectors					
	2016	**2018**	**2020**	**2025**	**2030**
Fuel Consumption Annual Gas (TBtu)	36,610	34,423	36,034	39,090	47,144
Fuel Price - Realized Annual Gas (US2012$/MMBtu)	4.27	4.81	4.97	5.93	6.16
Difference					
	2016	**2018**	**2020**	**2025**	**2030**
Fuel Consumption Annual Gas (TBtu)	-3112.5	-2078.0	-1077.5	-689.1	-1043.3
Fuel Price - Realized Annual Gas (US2012$/MMBtu)	0.70	0.86	0.38	0.87	0.49
Percent Change					
	2016	**2018**	**2020**	**2025**	**2030**
Fuel Consumption Annual Gas (TBtu)	-8.5%	-6.0%	-3.0%	-1.8%	-2.2%
Fuel Price - Realized Annual Gas (US2012$/MMBtu)	16.5%	18.0%	7.7%	14.7%	8.0%

Exhibit 4-11: Natural Gas Capital Expenditures through 2030, U.S. Lower 48

Capital Expenditures	Iterative Optimization	Co-Optimization
Gas Transmission Mainline Pipe	$61,652	$43,307
Laterals to/from Power Plants, Gas Storage and Processing Plants	$24,038	$20,712
Gathering Line (pipe only)	$22,188	$21,093
Gas Pipeline & Storage Compression	$8,912	$6,279
Gas Gathering Line Compression	$16,190	$14,894
Gas Lease Equipment	$16,397	$15,537
Gas Processing Capacity	$18,085	$16,688
Gas Storage Fields	$9,743	$8,268
Lower-48 Total	**$177,205**	**$146,778**

Exhibit 4-12: Optimization Capital Expenditure Comparison, U.S. Lower 48

Co-optimized Gas and Power Sectors (Millions of Real 2012 Dollars)						
	2016	**2018**	**2020**	**2025**	**2030**	**Total**
New Capacity Build Costs	$59,780	$26,278	$49,546	$66,907	$97,533	**$300,043**
Capacity Retrofit Costs	$22,410	$4,499	$7,355	$587	$34	**$34,885**
Fuel Infrastructure Costs	$25,902	$18,131	$16,405	$44,033	$42,307	**$146,778**
Total Overnight Construction Costs	$108,092	$48,909	$73,305	$111,528	$139,873	**$481,706**
Iterative Optimization of Gas and Power Sectors (Millions of Real 2012 Dollars)						
	2016	**2018**	**2020**	**2025**	**2030**	**Total**
New Capacity Build Costs	$50,008	$28,217	$56,877	$64,643	$81,146	**$280,892**
Capacity Retrofit Costs	$19,654	$4,013	$6,764	$683	$36	**$31,150**
Fuel Infrastructure Costs	$31,272	$21,890	$19,805	$53,162	$51,077	**$177,205**
Total Overnight Construction Costs	$100,934	$54,121	$83,447	$118,487	$132,259	**$489,248**
Difference (Millions of Real 2012 Dollars)						
	2016	**2018**	**2020**	**2025**	**2030**	**Total**
New Capacity Build Costs	$9,772	-$1,939	-$7,332	$2,264	$16,387	**$19,151**
Capacity Retrofit Costs	$2,756	$486	$591	-$95	-$2	**$3,735**
Fuel Infrastructure Costs	-$5,370	-$3,759	-$3,401	-$9,128	-$8,770	**-$30,428**
Total Overnight Construction Costs	$7,158	-$5,212	-$10,142	-$6,960	$7,614	**-$7,541**
Percent Change						
	2016	**2018**	**2020**	**2025**	**2030**	**Total**
New Capacity Build Costs	19.5%	-6.9%	-12.9%	3.5%	20.2%	**6.8%**
Capacity Retrofit Costs	14.0%	12.1%	8.7%	-13.9%	-6.1%	**12.0%**
Fuel Infrastructure Costs	-17.2%	-17.2%	-17.2%	-17.2%	-17.2%	**-17.2%**
Total Overnight Construction Costs	7.1%	-9.6%	-12.2%	-5.9%	5.8%	**-1.5%**

4.2.4 Conclusions

Using similar model architectures and parallel model assumptions, the ability to endogenously compute gas prices allows lower cost solutions to emerge. It is clear based on this abbreviated analysis that co-optimization has the potential to produce beneficial cost savings even for relatively small adjustments in natural gas price and aggregate gas consumption. In this case an equilibrium price was found above the static values used in the iterative solution. The result is that while power sector capital costs were higher relative to the iterative solution, on the basis of total cost including fuel infrastructure, the co-optimized run yielded significant cost savings.

5 Reliability Metrics

5.1 Resource Adequacy Overview

This section provides brief overview of the resource adequacy concept and how it is implemented in power and natural gas sectors. Overall, resource adequacy is a power sector centric concept. There are relatively clear definitions of metrics and processes for resource adequacy in the power sector. While the formal metrics for gas sector resource adequacy are not defined; natural gas infrastructure design process also contains number of elements that inherently addresses resource adequacy in the sector. Historically, reliability analysis has not been systematically synchronized between two sectors and therefore there was no need to formally define resource adequacy in the natural gas sector in a manner similar to that used in the electric sector.

The power sector relies on a combination of reliability requirements that ultimately drive capacity additions. An integral component of power sector resource adequacy is the level of reserve capacity available. In contrast, resource adequacy in the natural gas industry is driven by the need to meet firm loads under extreme weather conditions. The natural gas industry, particularly gas distribution companies, develops gas supply plans based upon peak (design day) conditions that are typically defined as the coldest day experienced within some historical period such as the last 30 years. Thus, on a typical day (which is much warmer than the design day), natural gas pipelines have a level of capacity available to non-firm customers (which is called interruptible service). The following section discusses in more detail resource adequacy in the power and natural gas sectors.[160]

5.1.1 Power Sector Resource Adequacy

The issue of resource adequacy in the power sector underpins many of the decisions that regulators and utilities regularly make, as the impacts of shedding firm load have repercussions on broad spectrum of issues ranging from security to economics. Different regions across North America have produced a range of assessments to evaluate the benefits and necessary conditions for having enough capacity to meet firm load obligations. But while the different analyses are not directly comparable across regions (due to differences in reserve margin calculations, capacity value attributions for variable and demand side resources, as well as variation in the definition of loss of load events), every grid operator employs a target physical reliability metric.[161]

Resource adequacy is a measure of the ability of the power sector to provide power during peak demand. Loss of Load Expectation (LOLE) is typically used as the standard metric by power sector planners conducting resource adequacy studies, and is the timeframe during which capacity does not meet peak demand. Resource adequacy is one of the six elements of bulk-

[160] NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012.

[161] Ibid.

power system reliability defined by NERC (see Exhibit 5-1). In practice the resource adequacy is closely related with planning reserve margin; and a balancing area is considered to have adequate reserves if the reserve margin target is met.

Exhibit 5-1: NERC's Definition of Adequate Reliability

No.	Metric
1	The System is controlled to stay within acceptable limits during normal conditions;
2	The System performs acceptably after credible contingencies;
3	The System limits the impact and scope of instability and cascading outages when they occur;
4	The System's facilities are protected from unacceptable damage by operating them within facility ratings;
5	The System's integrity can be restored promptly if it is lost; and
6	The System has the ability to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Source: NERC. "Definition of 'Adequate Level of Reliability.'" Available at: http://www.nerc.com/docs/pc/Definition-of-ALR-approved-at-Dec-07-OC-PC-mtgs.pdf.

In context of reserve margin planning, Transmission Security Analysis (TSA) is often used in measuring reliability in addition to resource adequacy. When both TSA and resource adequacy are measured, the more rigorous metric is used. Both Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC) are systems similar to TSA that are used to ensure system security. Security is defined as a system's capability to function during unexpected occasions and its ability to continue to operate in a range of different scenarios. System security analysis is typically a basic picture of peak demand in simplified scenarios. TSA uses AC load flows, however, whereas SCED and SCUC approximate AC by using DC load flows.[162]

5.1.1.1 Commonly Used Metrics to Measure Resource Adequacy

A 1-in-10 LOLE has been the historical standard in the power industry for both resource adequacy requirements and adequate reserve margin level requirements. The term "1-in-10" refers to one day in ten years, with the interpretation being that demand is curtailed only one day in a ten-year window due to insufficient resources. Resource adequacy investigations have found that a 10 percent to 20 percent reserve margin enables a 1-in-10 LOLE. Preferably, reliability should be in a position where there is a diminished desire to pay for electricity caused by increasing costs of reserves.

Some debate exists over how to interpret the 1-in-10 LOLE standard. Some have interpreted it as 2.4 hours per year while others have interpreted it as a singular occurrence over a ten-year period. Industry members have a renewed interest in optimal levels and metrics of reliability, and FERC has also begun to study different interpretations of LOLE. The following three metrics

[162] NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012.

were recommended in a 2010 report by NERC's Generation and Transmission Reliability Planning Models Task Force for reporting in adequacy reports[163]:

- Loss of Load Hours (LOLH): Total hours during a given year that firm demand was not met with available generation.
- Expected Unserved Energy (EUE): Total MWh during a given year that was not met with available generation.
- EUE as a percentage of annual Net Energy for Load (normalized EUE).

5.1.1.2 Resource Adequacy Modeling

Statistical modeling is necessary for calculating resource adequacy metrics, and addresses a wide breadth of possibilities by including variables such as demand, forced outages, and system flexibility needs driven by variable energy resources. The purpose of this modeling practice is to find the reserve margin requirement necessary for the specified reliability level. As uncertainty increases in the model, so too should the required reserves. The minimum scope of these models is outlined in a draft report released by NERC in December 2010.[164] This minimum scope has developed into general industry standards, including:

- Hourly chronological model that factors in uncertainty in load forecasting
- The inclusion of both random outages as random variables
- Capturing transmission constraints (i.e., multi-area modeling)
- LOLH, EUE, normalized EUE should all be outputs

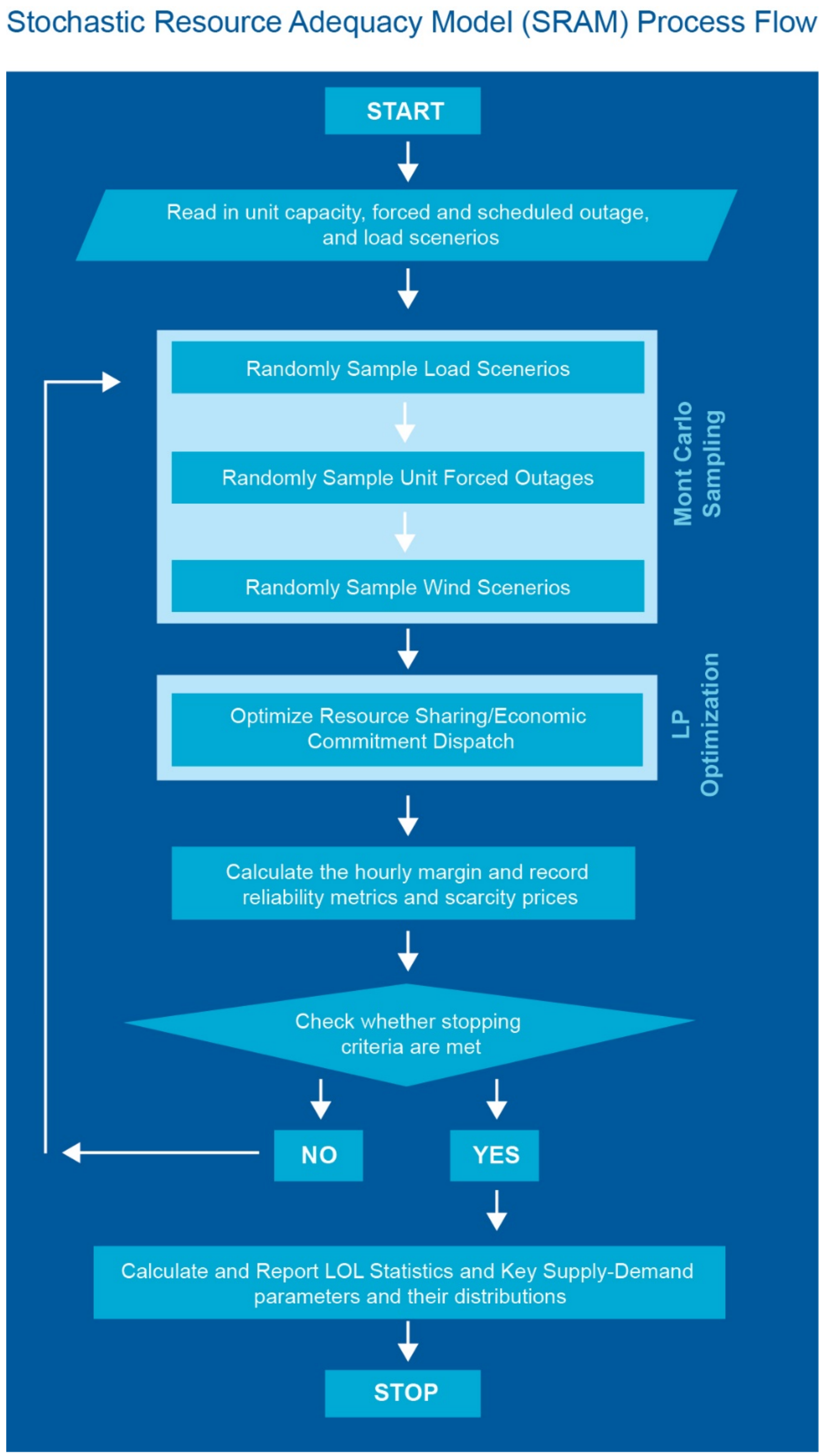
Exhibit 5-2 illustrates the process flow of an ideal resource adequacy model, which first simulates hourly load and wind generation profiles based on the pre-defined stochastic process. The model then randomly determines the generation unit's operating history for each sequential hour (within a year under consideration) based on the historical mean time between failures (MTBF) and mean time to repair (MTTR) statistics for that unit. The model optimizes reserve sharing and/or conducts economic commitment and dispatch for each hour using a linear programming algorithm. After a sufficient number of iterations, the model calculates and documents the constraints of the reliability indices' sampling distribution, along with indices of the fundamental drivers including load, supply, and wind output.[165]

[163] NERC. Generation & Transmission Reliability Planning Models Task Force for the NERC Planning Committee, Final Report on Methodology and Metrics, December 2010.

[164] Ibid.

[165] Ibid.

Exhibit 5-2: Stochastic Resource Adequacy Model (SRAM) Process Flow



Source: ICF, Stochastic Resource Adequacy Model (SRAM).

5.1.1.2.1 Standardization of Resource Adequacy Analysis

Substantial variation exists throughout the United States and Canada when it comes to the modeling of resource adequacy and the selection of reliability criteria. NERC, with FERC's authorization in 2007, took charge of the enforcement of mandatory reliability standards. NERC's Generation & Transmission Reliability Planning Models Task Force released a draft report in December 2010 that included minimum requirements for resource adequacy planning models (see Exhibit 5-3). The report also included all Metric Reporting Areas (MRAs) that are required to file reports that document the results of the probabilistic resource adequacy modeling studies (see Exhibit 5-4). Future resource adequacy modeling studies can reference NERC's draft minimum requirements as the industry standard,[166] however, it should be noted that NERC's authority to set standards does not extend to resource adequacy. Furthermore, FERC does not set resource adequacy standards; such measures are under the purview of the states and regions.

Exhibit 5-3: Minimum NERC Resource Adequacy Modeling and Reporting Requirements[167]

#	Requirement
1	Determine an hourly chronological load model that includes load forecast uncertainty.
2	Assess limitation on generation to be included in modeling. Future generation to be included must have associated transmission.
3	Model random outages for all units as random variables.
4	Incorporate major transmission constraints and limitations, consistent with their planning processes.
5	Use one of three metric results: (i) LOLH, (ii) Expected Unserved Energy (EUE), and (iii) Expected Unserved Energy as a percentage of Net Energy for Load (normalized EUE).
6	Report metrics for Year 2 and Year 5 of LTRA.
7	Document all modeling assumptions.
8	Use common report format.

Source: NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012: Washington, D.C.

[166] Ibid.

[167] NERC. Generation & Transmission Reliability Planning Models Task Force for the NERC Planning Committee, Final Report on Methodology and Metrics, December 2010.

Exhibit 5-4: NERC Metric Reporting Areas[168]

Reporting Area
AESO (CN)
Basin (US)
BC (CN)
CA (US) excluding CAISO
CAISO (US)
Desert SW (US)
ERCOT
FRCC
ICTE1
Maritimes
Mexico (MX)
MISO
MRO (CN) Manitoba
MRO (CN) Saskatchewan
MRO (US) excluding MISO and SPP RTO areas in MRO (US)
New England
New York
NWPP (US)
Ontario
PJM
Quebec
RMPA (US)
SOCO
SPP RTO plus the SPP RE
TVA
VACS excluding PJM areas is VACS

Source: NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012: Washington, D.C.

Market Designs for Resource Adequacy

Markets for resource adequacy in the post-deregulation era continue to evolve. For example, "willingness to pay" for electric service reliability differs significantly across customer classes, a difference that does not accurately reflect the electricity demand curve (which is almost perfectly inelastic). Further, generator offers in the energy markets are capped at $1,000/MWh, except in Texas, and when an administrative action restricts related increases in the market price, the conundrum of "missing money" follows. When the prices of an unregulated market are set by variable costs, the marginal unit cannot recoup its fixed costs. This problem is observed in restructured energy markets where the marginal unit fails to recoup the investment, operations,

[168] Ibid.

and maintenance costs because the price is directly related to the short-run marginal costs. Power market actors in energy-only markets can set a price cap at the VoLL whereas markets with distinct capacity markets (bifurcated: energy and capacity market design) use capacity market revenues to address this issue.[169]

- Energy-Only Market Design: When there is a price shock, firms will recoup fixed costs. This is because the demand for power exceeds the supply, allowing for pricing above the typical variable costs.

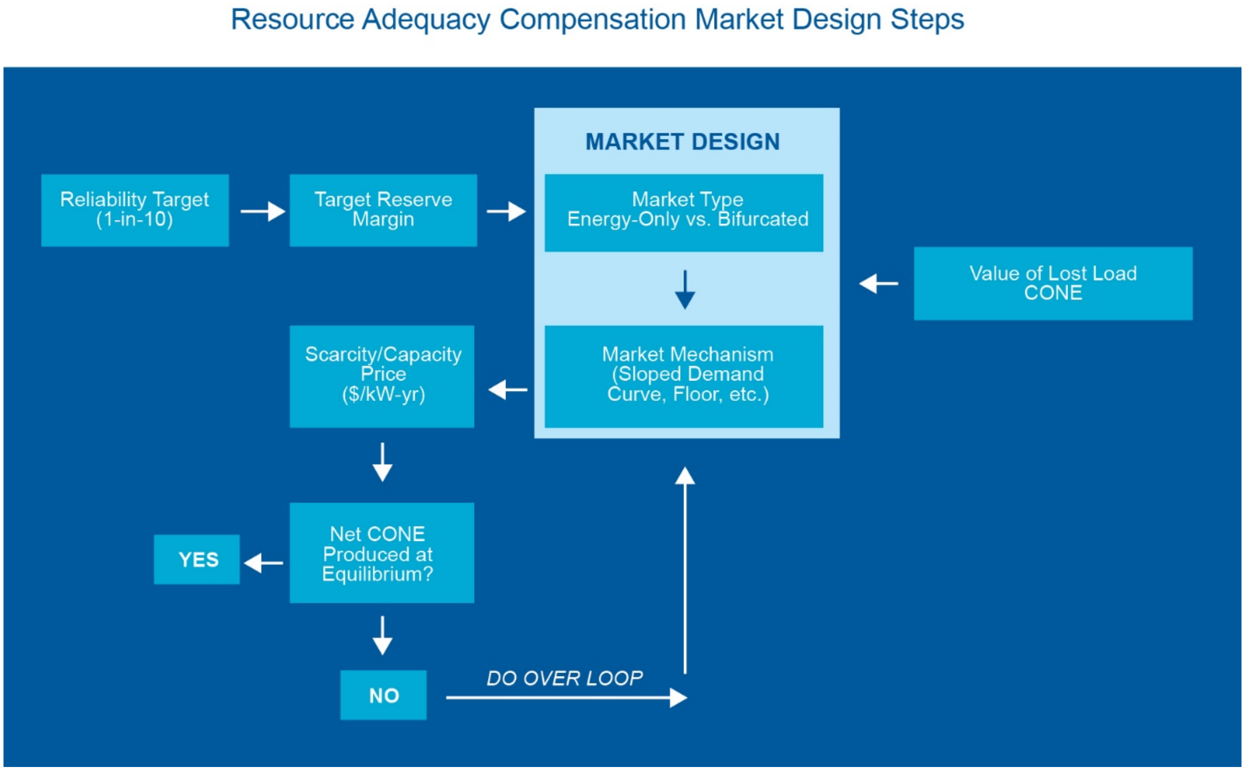
- Bifurcated Market Design: If a capacity market exists, then energy prices are usually set at the short-run variable cost. Power generators are compensated for additional installed capacity, which helps to satisfy resource adequacy. While ERCOT and some other markets utilize the energy-only market design, the majority of eastern RTOs utilize a bifurcated system.

Exhibit 5-5 highlights the path typically followed by market design process. The ultimate goal of resource adequacy compensation in market design is to encourage new resource entries and capital investments (e.g., for life extension or environmental retrofits) on existing resources to meet the planning reserve margin target, which is calculated by loss of load modeling.[170]

[169] Ibid.

[170] Ibid.

Exhibit 5-5: Resource Adequacy Compensation Market Design Steps



Source: ICF.

5.1.2 Natural Gas Sector Resource Adequacy

Resource adequacy as an overarching reliability concept in resource planning does not exist in the natural gas sector, primarily because there is no obligation to serve all customers like there is in the electric power sector. As noted above, elements of resource adequacy inherently exist in natural gas infrastructure planning, which is done on a contractual basis only. Although the natural gas sector's approach to resource planning is not exactly synchronized with the current state of thinking in the power sector there are some common elements in planning. For example, planners in both sectors design their systems or contract for transmission or storage services in preparation for extreme events. Design-day assessments are performed by local natural gas distribution companies (LDCs) in planning for peak demand days, which occur during extremely cold weather conditions. The goal of the design-day analysis is to anticipate demand on these highest flow days, so that LDCs can meet customers' needs year-round. Design-day assessment uses historical demand, weather data, and annual load growth projections to create demand forecasts on the days of extreme weather events.

As discussed above, the power sector uses loss of load modeling for resource planning. Weather-driven load forecast uncertainty is typically the largest source of uncertainty in loss of load models. Therefore, it is possible to say that both sectors mostly rely on their view of extreme weather conditions to plan their systems. Note, however, power sector resource adequacy is more complex and accounts for other contingencies such as plant failures or renewable resource variability. Another point of divergence in planning is that power sector planning is performed to meet all demand whereas natural gas planning satisfies firm demand. In the following sections we further discuss the issue of coordination in resource adequacy planning and introduce a three-layer resource gas-electric adequacy analysis.

5.2 Approaches to Integrated Gas-Power Resource Adequacy

It is possible to analyze implications of power-gas dependence on resource adequacy in two categories. The first category is reliability-based interaction of two infrastructures. Reliability-driven planning does not pay significant attention to economic consequences and focuses on satisfying certain pre-set reliability criterion such as 1-in-10 LOLE. As discussed in the previous section, reliability-based resource adequacy planning is widely used in the U.S. power sector. It is important to connect natural gas infrastructure build-out to conventional power system resource adequacy planning before discussing the more advanced concept of economics-based system resource adequacy planning. In this section we discuss both reliability and economics-based approaches to gas-power resource adequacy planning.

5.2.1 Power system reliability driven gas-power coordination

In general, 1-in-10 LOLE-based resource adequacy studies do not confront the issue of increasing forced outage probabilities that are a consequence of gas-power interdependence. Gas-power interdependence could be partially addressed in a standard loss of load modeling framework by capturing increasing forced outage probabilities of individual natural gas-fired generators. Not only do the increases in individual unit forced outages need to be captured however, but the increasing dependence between forced outages of gas fired generators must also be accounted for. It is paramount to model the dependence between forced outages of natural gas-fired units and to capture the probability of fuel supply disruptions that occur simultaneously in order to create a sound probabilistic resource adequacy model. This is because the sole purpose of a probabilistic resource adequacy model is to be able to capture extreme events. Review of the literature indicates existing resource adequacy models do not address this dependence issue. Asserting an assumption of complete independence between forced outage rates of gas-fired generation would be misleading and likely to produce inaccurate outcomes in resource adequacy modeling.[171]

In theory all resource adequacy planning concepts, such as 1-in-10 LOLE, implemented in the electricity sector could also be implemented in natural gas infrastructure design. Under such a theoretical reliability-driven concept, the amount of firmly supplied natural gas-fired generators would be adjusted to support power system in satisfying the pre-set reliability criterion (e.g., 1-in-10 LOLE). In this context, there would be a need to have representation of the gas infrastructure in a standard loss of load modeling framework. Exhibit 5-6 illustrates the reliability-driven gas-power resource adequacy planning through a comparison of four hypothetical resource adequacy cases.

[171] Ibid.

1) System-1 has 40 percent natural gas-fired capacity. The system is able to meet the 1-in-10 LOLE criterion with 15 percent reserve margin. In this scenario, 5 percent of the total power sector natural gas demand has firm supply.
2) System-2 has same peak demand as System-1. The share of natural gas-fired capacity is 80 percent. System-2 has also a 15 percent planning reserve margin. Note, however, because of increased penetration of the natural gas, a 15 percent reserve margin is no longer sufficient for System-2 to meet its reliability criterion. This could be because increasing dependence between fuel supply disruption probabilities of natural gas plants.
3) System-3 has same peak demand as Systems 1 and 2. The share of natural gas-fired generation capacity in System-3 is 80 percent. To meet its reliability criterion of 1-in-10, operator of System-3 opted for maintaining a higher planning reserve margin.
4) System-4 has the same characteristics as Systems 2 and 3. To meet its reliability criterion, the operator of System-4 opted for increasing the amount of natural gas-generation capacity with firm supply.

Note, although the operators in System-3 and System-4 have opted for different approaches they both meet the reliability criterion. Amounts of required additional reserve margin or firm natural gas supply, in the cases of System-3 and System-4, can be calculated via the loss of load modeling framework.

Exhibit 5-6: Different Reliability Criterion Driven Resource Adequacy Planning Scenarios

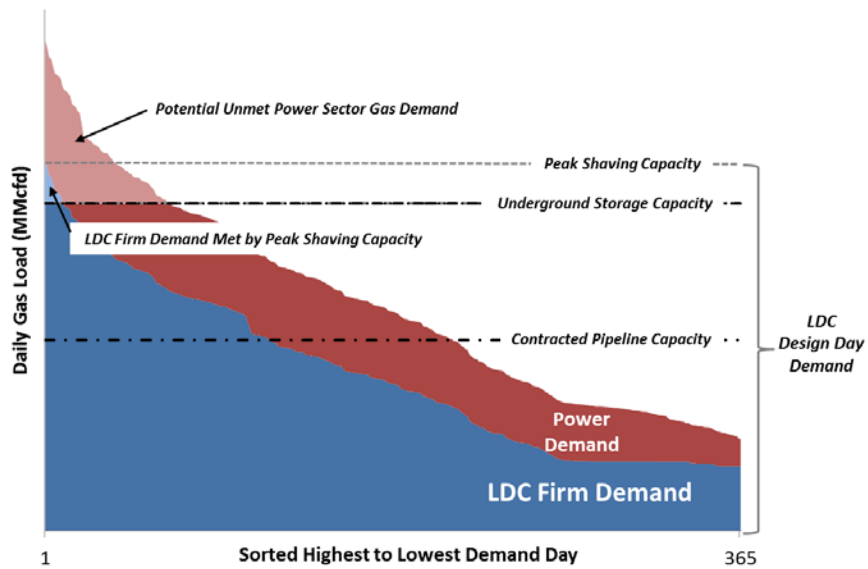
Scenario	System-1	System-2	System-3	System-4
Peak Demand	50 GW	50 GW	50 GW	50 GW
Share of Natural Gas-Fired Capacity	40%	80%	80%	80%
Reliability Target	1-in-10 LOLE	1-in-10 LOLE	1-in-10 LOLE	1-in-10 LOLE
Reliability Level	1-in-10 LOLE	>1-in-10 LOLE	1-in-10 LOLE	1-in-10 LOLE
Planning Reserve Margin	15%	15%	17%	15%
Share of Firm Gas Supply in Total Power Sector Gas Demand	5%	5%	5%	10%

Source: NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012: Washington, D.C.

<u>Reliability Criterion-Driven Integrated Resource Adequacy Modeling Approaches</u>

As discussed in the previous sections, currently implemented natural gas infrastructure capacity design practices are different than power sector planning procedures. Natural gas infrastructure is designed to meet the firm load on the selected design day (e.g., coldest day in 30 years). In many instances where power generators rely on interruptible pipeline capacity, this means that most of the power sector demand is without a firm supply contract and left outside this design criterion. Therefore the natural gas supply for the power sector could be interrupted in periods of cold weather and high firm gas loads. Since high electric loads are also correlated to cold weather, the probability of a natural gas supply shortfalls in the power sector would increase with the increasing interruptible power sector wintertime demand (see Exhibit 5-7). This will consequently increase LOLE of the power system as a result of (1) increasing probability of individual plant outages, and (2) increasing correlations in forced outages throughout the system. Modeling of dependencies between random variables and consequently capturing the probability of extreme events occurring simultaneously is paramount to creating a sound probabilistic resource adequacy model.

Exhibit 5-7: Comparison of Load Duration Curve to Gas Supply Capability



Source: ICF.

While the complete understanding and quantification of power-gas interdependence are only possible with integrated modeling of power and gas networks, recent experience with the certain markets shows a dependency exists and is likely to increase with the increasing penetration of gas-fired units. For example, a recent study[172] has shown that ERCOT may lose 24 percent of its gas generation should the weather pattern of December 1983 repeat itself.

To incorporate fuel system availability into the modeling framework of the resource adequacy model, one first needs to identify common risk factors and direction of data flow. Both power and gas demand uncertainties are mostly driven by weather uncertainty. An integrated model, therefore, needs to have the weather uncertainty as a common random variable, feeding into both fuel supply availability and resource adequacy models. Ultimate output of the fuel supply availability model would be hourly fuel availability information for each and every unit in the grid. Fuel availability is another layer of outage information that will complete the scheduled outage and forced outage history created in the resource adequacy model.

[172] Black & Veatch, ERCOT Natural Gas Curtailment Risk Study, February 2012.

Incorporation of the fuel supply availability model into resource adequacy modeling will fill two gaps in standard resource adequacy models:

1) By modeling the gas network, the probabilistic resource adequacy model will be able to capture the dependence between gas supply risk and power outages.

2) The fact that a significant number of gas-fired plants do not have firm fuel supply contracts is not reflected in the current resource adequacy models. Integrated modeling will create opportunity to examine the risk of non-firm fuel supply on the power grid.

The section below discusses a method to integrate natural gas fuel availability into power sector resource adequacy. Because of the extensive data requirements in assessing the impact of fuel availability on electric system reliability, the approach is split into three layers. **Layer 1** assesses the capacity of the gas infrastructure under normal operating conditions, and compares that capacity to the gas load by developing daily gas load duration curves for a specific set of weather conditions (e.g., 90/10 load). This provides an indication of the potential for fuel-related outages if the gas system is fully operational. **Layer 2** compares the same gas load duration curves to gas infrastructure capacity under assorted gas supply contingencies, such as a compressor station outage. This provides an indication of the additional incremental fuel outages that could be caused by potential large disruptions of the gas system. **Layer 3** performs a Monte Carlo analysis, which examines a wide range of weather and gas supply conditions to determine how often the expected power sector gas demand cannot be served, and the resulting threat of lost electric loads. A more detailed description of each layer follows.[173]

5.2.1.1 <u>Layer 1: Assessing Natural Gas Infrastructure Capacity under Normal Conditions</u>

Layer 1 consists of three steps for a full analysis:

1) What region is being looked at? What are the current as well as projected gas supply capabilities for the region during regular operation conditions?
2) For the region being assessed, what are the current as well as projected gas loads for given weather conditions?
3) Find unmet demand for the region by observing supply volumes and the total projected load.

In the first step, the region that is being investigated must be clearly defined. Is it an entire ISO? Or only a singular market zone? Once the region is established, the gas supply capabilities need to be thoroughly measured.

Future gas supply capabilities should also be forecasted to allow the model to take into account changes in gas supply infrastructure. These changes could include new pipelines or even the decommissioning of current lines.

[173] NERC. “Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments.” NERC, November 2012: Washington, D.C.

The second step is addressing the strong direct proportional relationship between gas demand and weather. Both power generation and non-power generation gas consumption need to be analyzed in order to forecast daily gas loads using historical weather and load information. ICF created the Daily Gas Load Model (DGLM) to forecast expected gas loads on a daily basis by making it a function of average daily temperature. [174]

The final step of Layer 1 is to take the findings on daily gas loads from the second step and compare with the gas supply capabilities measured in step one. Days of peak demand may be met with interruptible service of gas to commercial markets, and possible use of LNG storage as well as other peak storage options. If all options are exhausted, it is possible for supply to fail to keep pace with demand and thereby lead to possible service interruption of non-firm loads.

5.2.1.2 Layer 2: Assessing the Impact of Gas Supply Contingencies

North America has a diverse set of options for natural gas delivery and storage, which makes it a reliable gas market. Pipeline infrastructure is vast and has created strong interconnections for consumers of natural gas. In addition to the pipeline infrastructure, underground storage allows for excess demand to be met during severe weather conditions. Additionally, more expensive options such as LNG and propane-air allow for greater supply storage.

Layer 2 investigates and quantifies factors that may adversely affect the gas supply infrastructure and available gas quantity. Layer 2 is accomplished through three steps:

1) Recognize possible supply contingencies and record their frequency.
2) Quantify the adverse nature of the contingencies found in step one by taking into account the volume of gas that will be impacted as well as the length of time the contingency may last.
3) Finally, take the findings from step two and combine the analysis with the findings from Layer 1 to determine how total gas supply is affected.

In the first step, possible contingencies can be physical and operational, technical and cyber, natural, or man-made.

The second step will take each of these contingencies and use a combination of past data and forecasts to understand what future contingencies might be composed of in terms of both volume and timeframe.

The final step would now combine Layer 2 with Layer 1 and see how all contingencies would affect natural gas supply.

[174] While the regression analysis used for the DGLM is based solely on average daily temperatures, this same type of approach could also include other weather variables that also have an impact on gas and electricity demand, such as dew point, relative humidity, wind speed, cloud cover, precipitation, wind chill, and heat index.

5.2.1.3 Layer 3: Monte Carlo Analysis of Gas and Electric Systems

Since Layer 1 and 2, explained in the previous sections, do not address local conditions that may affect a section within a region as a whole, they do not help to explain frequency of shortages or specified locations. For this reason, ICF recommends the use of a Monte Carlo analysis as Layer 3. The Monte Carlo method uses both gas and electric systems to help forecast the frequency of events, and allows for realistic combinations of events that are correlated with each other.

5.2.1.3.1 Regional Definition and Boundary Conditions

To start with a Monte Carlo analysis, the gas and electric landscape must be mapped out. The mapping needs to be complex enough to encapsulate the relationships that could be affected by gas supply contingencies, but at the same time be manageable so they can be analyzed quickly.

5.2.1.3.2 Sensitivity of Electric and Natural Gas Loads to Weather

It is generally accepted that electric loads both hourly and daily are functions of weather, seasonal components (calendar dates, time of day), and other autoregressive factors.

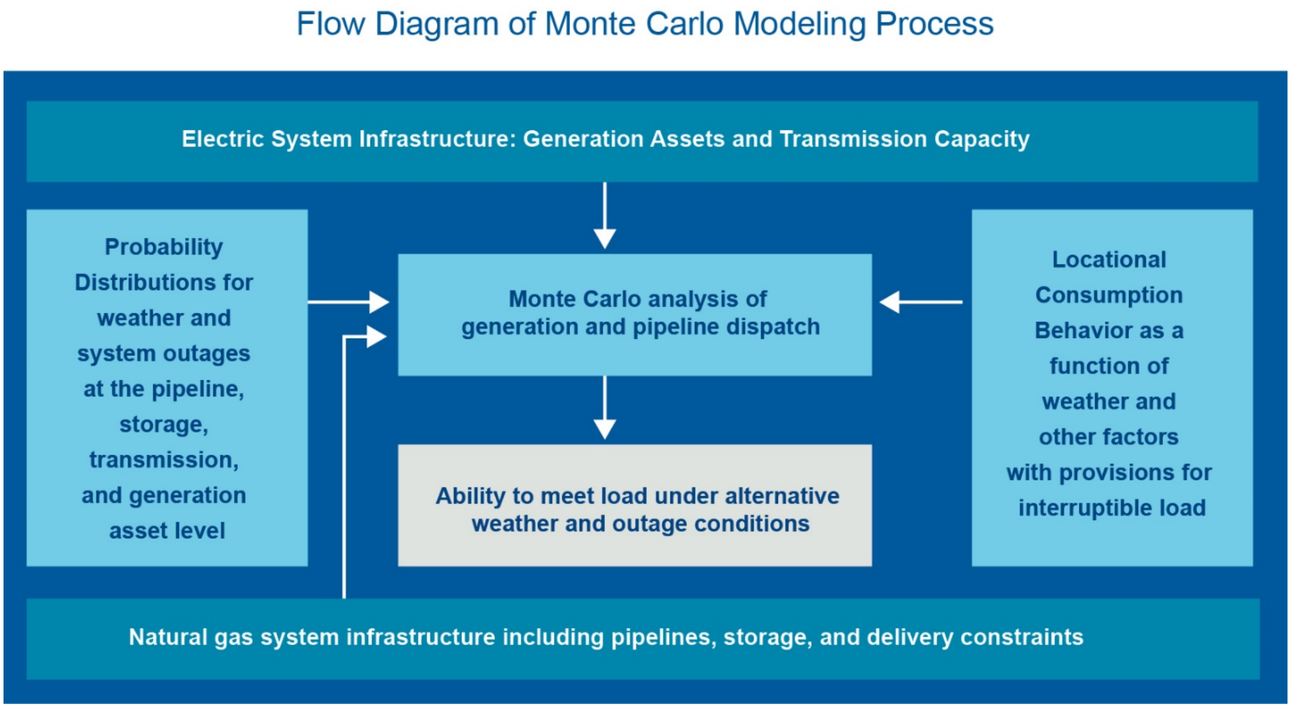
5.2.1.3.3 Modeling Weather Scenarios

While ICF recommends that modeling weather conditions is comprised of using past localized trends, it also acknowledges that there is an upward trend over a long time horizon. ICF looks at 10-year periods instead of 30-year periods to minimize volatility related to this upward trend.

5.2.1.3.4 Monte Carlo Modeling

ICF developed the Stochastic Resource Adequacy Model (SRAM) as a resource adequacy model that utilizes a Monte Carlo simulation on an hourly basis. These Monte Carlo simulations encapsulate the uncertainty and risk connected to unknowns in the supply and demand dynamics. Variables such as weather (including temperature or even wind speed) and other supply contingencies are accounted for in the model as shown in Exhibit 5-8.

Exhibit 5-8: Flow Diagram of Monte Carlo Modeling Process



Source: NERC. "Recommendations for Incorporating Fuel Availability into Electric System Long-term Resource Adequacy and Reliability Assessments." NERC, November 2012: Washington, D.C.

The Monte Carlo simulation would provide estimated Loss of Load Expectation, Loss of Load Hours, and Expected Unserved Energy:

- Loss of Load Expectation: An estimate on the number of days or hours that current capacity is unable to meet peak demand.
- Loss of Load Hours: Forecasted number of hours in a year that existing generation capacity fell short of providing non-interruptible service because of deficient supplies of gas.
- Expected Unserved Energy: The yearly MWh that were unable to be fully met.

While the Monte Carlo model that has been laid out in Exhibit 5-8 provides information on resource adequacy, it does not solve for expanded infrastructure that would be needed to meet adequacy goals. Different potential infrastructure projects would each need to be modeled out and then compared in order to evaluate the different options for natural gas infrastructure expansion.

5.2.1.3.5 Gas System Scheduled Outages and Contingencies for Layer 3 Gas Infrastructure Analyses

The Monte Carlo simulation would be comprised of numerous factors that make up the natural gas infrastructure. It would reflect direct connections between components, and their individual capacity. These components could include sources of production, LNG import terminals, peak shaving plants, as well as others. Additionally, the model would be able to account for scheduled outages by frequency and duration as well as forced outages as represented by their probability of occurrence and a probability density function for the outage duration.

5.2.2 Economics driven resource adequacy planning in the context of gas-power coordination

To put the resource adequacy discussion in perspective, Section 5.2.1 provided overview of how natural gas infrastructure design process could relate to conventional reliability driven resource adequacy planning in power sector. This section provides discussion of economic implications of gas-power integrated resource adequacy planning. Economics driven resource adequacy planning in gas-power integrated resource adequacy framework would focus on economically optimum level in building gas-power infrastructure rather than satisfying reliability criterion; and consider increasing natural gas interdependencies in the power sector.

Power sector resource adequacy planning has long been driven by the reliability related criteria. An alternative, and probably and improvement, would be a planning exercise driven by economic optimization between costs and benefits of reliability. As we discuss below, there are recent indications that economics of current resource adequacy practices, namely 1-in-10 LOLE based planning, is under greater scrutiny of policy makers. An economics-based approach to resource adequacy addresses some of the limitations of the physical reliability perspective provided by the 1-in-10 standard. It provides a framework for reflecting the customers' willingness to pay for varying levels of reliability, as well as the risk-mitigation benefits of higher reliability requirements not accounted for in traditional physical reliability metrics. Thus, in addition to estimating the value of avoided load curtailments, the economics-focused view on reliability considers both the potential to reduce other reliability-related costs, such as expensive energy purchases to meet peak demand, and the insurance value of reducing the likelihood of high cost shortages.

The remainder of the section is organized in following order.

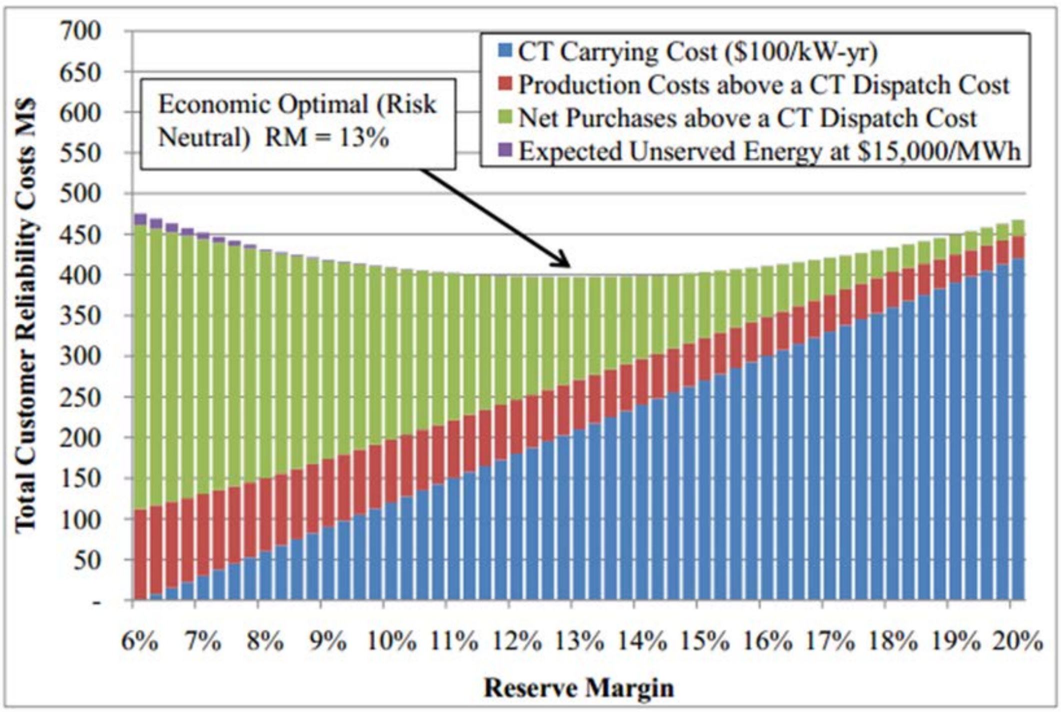
1) The first section introduces the concept of economic resource adequacy analysis in the power sector and provides overview of the recent NARUC/EISPC whitepaper on the topic.
2) The second section discusses the concept of economic resource adequacy in integrated gas-electric planning framework.

5.2.3 EISPC/NARUC White Paper – The Economic Ramifications of Resource Adequacy

The NARUC/EISPC whitepaper "The Economic Ramifications of Resource Adequacy" provides one approach to quantify the economic value provided by reserve margins according to the 1-in-10 standard by balancing the tradeoffs between the economic value of reliability and the cost of carrying the amount of capacity needed to maintain target reserve margins. The paper shows that an economic cost/benefit analysis can help identify more cost-effective solutions to resource adequacy planning and quantify (and justify) the value of paying for reserve capacity from the point of view of the customer.

The focus of the whitepaper is to determine the economically optimal reserve margin at a regional level for a defined base case and a number of sensitivities. The calculation of the optimal reserve margin is based on minimizing total system costs (including the costs of energy production, of importing energy from neighboring regions, as well as the broader societal costs incurred during load shed events) from the perspective of the customers of a vertically integrated utility. The analysis evaluates the trade-offs between the fixed costs of additional marginal capacity and the economic benefits that such supplementary resources would bring, above and beyond the benefits of meeting the physical reliability standard of 1-in-10 (see Exhibit 5-9).

Exhibit 5-9: Economic Optimal (Risk Neutral) Reserve Margin for a Vertically Integrated Utility



Source: EISPC/NARUC White Paper.

The whitepaper uses input data from a recent transmission expansion study performed by the EIPC. The same region definitions, load forecasts, generating resource mixes, and transmission capabilities have been used to build a model of the Eastern Interconnection consisting of 14 regions. While inter-regional interactions and interdependencies are an integral part of the analysis, the main results of the base case and sensitivities are tabulated only for PJM Rest of MAAC. This simplification does not detract from the scope of the analysis, since different planning regions establish their reserves margin targets independent of similar planning efforts in neighboring regions.

The results were compiled under different market constructs assumption. For the purpose of the base case, PJM Rest of MAAC is treated as a vertically integrated utility in order to simplify economic comparisons, even if in reality it is part of the competitive wholesale power market administered by PJM ISO. The same analysis was performed under two structured market scenarios – that of an energy-only market and that of a bifurcated (energy and capacity) market – with a focus on impacts on both consumers and merchant generators. The results of the economic resource adequacy analysis indicate economically optimal reserve margin could vary in a wide range (e.g. from 7 percent to 30 percent) depending on the market structure and design (regulated/deregulated, energy-only/bifurcated).

The Study Methodology

The study employs combination of standard multi-area loss of load modeling with economic dispatch modeling to assess the costs of different reliability levels. For the purpose of capturing the frequency of reliability events, several sources of uncertainty were considered, such as weather variability, load growth forecast errors, and unit performance vis-à-vis forced outages. By sampling amongst the different weather years and load shapes, the model runs discrete scenarios that yield a picture of the system's physical reliability needs and limitations.

The total cost impacts of different target reserve margins (below and above those obtained by applying just the 1-in-10 standard) were analyzed under the range of possible outcomes. The reserve margins for the study region were increased incrementally in two-percent intervals, without changing any other planning reserve margin parameters in the rest of the system. The results recorded at each reserve margin focused on loss of load events (LOLE and LOLH), total system costs, and hourly market prices. System costs consist of production costs above the dispatch costs of a combustion turbine (i.e., the cost of dispatching high cost oil-powered generators), the cost of importing emergency power from adjacent regions, the cost of unserved energy (the value of loss load was assumed to be $15,000/MWh), and the carrying costs of additional capacity. The supplementary capacity was assumed to consist of natural gas-fired combustion turbines.

Reliability-related costs were balanced against the benefit of maintaining infrequently used marginal capacity with the goal finding optimum reserve margin and minimum cost point. The trade-off between volatile reliability energy costs and static fixed costs was risk-adjusted to account for the likely propensity of load serving entities to hedge their costs. Market participants would potentially be willing to make a fixed payment toward installed capacity to insure against an extreme scenario, even if the fixed payment is slightly higher than the average economic benefit. In other words, the study indicated that the benefit of reduced volatility is valuable. This is different from typical approach of focusing only on the expected value of loss of load. If the cost of maintaining slightly higher reserve margin is minimal compared to mitigated risk; all else equal a system operator would opt for higher reserve margins.

Results of the Whitepaper

The results from these simulations reveal that economic optimal reserve margins are contingent on market structure and differ greatly between market constructs (regulated/deregulated) and perspectives (consumers versus producers).

The economic optimal reserve margin for the traditionally regulated utility is 13 percent based on the total system cost. This reserve margin is higher than the level of reserves suggested solely by a 1-in-10 LOLE criterion, calculated to be 9.75 percent. In contrast, in a restructured market the consumer cost would be minimized at reserve margins nearing 30 percent. The study however finds equilibrium reserve margin would be around 7 percent-9.75 percent in a restructured market. The variance in economic reserve margins between the two market structures stems from the different pricing mechanisms and the resulting costs to consumers.

In the case of traditionally regulated utilities, costs are placed into rate base and during high-demand hours only high marginal cost generators receive payments reflecting their high cost of operation. In a long term sense, consumers will ultimately see prices that reflect a blend of low cost baseload unit costs and high cost peaking resources but the baseload units will not benefit from uplift. However, in restructured utilities operating in organized markets, the clearing price paid to all consumers is set by the short run marginal cost of the last incremental unit. During times when the demand for electricity is high, the most expensive units come online which drives up the price paid to all units on the system. Therefore during these times, a clearing price set by the high marginal cost of the peaking units is paid to all facilities dispatched on the system irrespective of their individual cost.

It is possible to extend the methodology employed in this study to cover gas-electric integrated resource adequacy analysis. For example, one of the customer costs associated with gas shortages is gas scarcity pricing that drives power prices to very high levels. Increased natural gas infrastructure capability would not only circumvent load shedding but also avoid gas scarcity pricing. It should also be noted that the concept of the market structure and definition of cost carries significant importance in economic resource adequacy analysis in an integrated gas-power framework. As the study indicates rate of return regulation based approach and pure market driven approach yield completely different results. In addition in a deregulated market setting consumer costs and system costs represent two different perspectives. From consumers' perspective all purchases above and beyond short-run marginal cost represent cost. From system perspective only short run marginal costs count as cost and others are classified as transfers that increase producer surplus. In this context, ICF's approach employed in designing optimal infrastructure is based on total cost minimization that is consistent with regulated utility approach.

5.2.4 Economics of Integrated Gas-Power Resource Adequacy Planning

As we describe in the previous sections, when resource adequacy planning is driven by economics the reliability target is defined by the trade-off between cost of lack of reliability and cost of maintaining reserves. Cost of maintaining reserves includes fixed costs of generation and gas infrastructure investments net of their operational revenues. Cost of lack of reliability includes: (1) economic value lost due to unserved energy; (2) cost of fuel/power pricing above the certain threshold (e.g. marginal production cost) reflective of scarcity or near-scarcity pricing; and (3) cost of any emergency actions to avoid load shedding. Cost of reliability includes cost of maintaining reserve supply capacity.

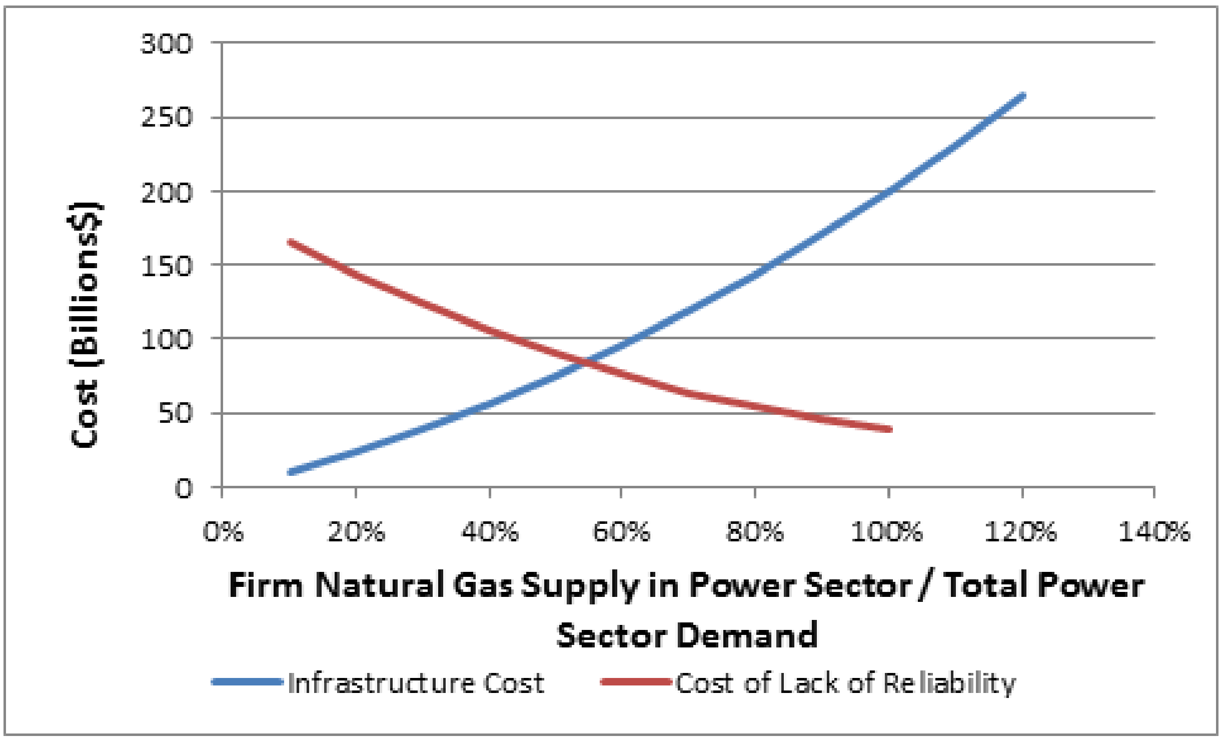
It is important to set the scope of economic analysis when resource adequacy planning involves in two different but interconnected energy infrastructures as benefits of increased reliability would be shared by all sectors and customer classes. For example, increased supply capability would benefit interruptible non-power sector natural gas consumers as increased supply would decrease the level and frequency of natural gas scarcity pricing. Furthermore, resource adequacy goals could be satisfied through a number of different measures including: (1) increasing the amount of firm natural gas supply to the power sector; (2) increasing the share of non-gas generation capacity resources; (3) increasing transmission connectivity; and (4) increasing dual fuel capability. This multidimensional problem could be simplified with following assumptions:

- All additional measures (dual fuel capability, transmission and non-gas generation) are optimally implemented. The only degree of freedom is increasing the amount of firm natural gas supply.
- All costs and benefits are borne by power sector consumers as the demand for added reliability comes from power sector.
- The economic planning is performed to minimize the average total system cost (i.e., the planning attempts to find the optimal reliability level where combined cost of investment and operating expenses is equal to cost of lack of adequate resources).

As discussed above deregulated electrical power markets have various mechanisms for resource adequacy compensation. These mechanisms provide incentives for maintaining reserves above system peak demand allow investors to recover their fixed costs that cannot be recovered in short-run marginal cost based electrical energy market. Similarly, in regulated markets utility companies are allowed earn rate of return for investments to meet the target reserve margin levels. In this context, the firm supply premium paid by firm natural gas load can also be interpreted as payment for reliability, which is determined based on a different criterion than power sector reliability (e.g. loss of load modeling versus design day). Setting aside the differences in reliability planning approaches, as discussed in the previous sections, it is therefore the case that the primary concern is related to gas fired generators without firm natural gas supply. In this context the issues can be summarized as 1) majority of natural gas fired generators do not have firm natural gas supply arrangements and; 2) in regions where gas-power interdependence is highest the resource adequacy compensation mechanisms do not reward firm natural gas supply.

The costs for firming up natural gas supply for gas fired generation potentially include investments at the plant site (e.g. lateral to pipeline) and expansion of regional natural gas supply capacity via increased storage and/or peaking capability. The costs for lack of firm gas supply in the power sector would potentially include value of 1) lost electrical load, 2) natural gas costs above and beyond marginal cost of production and transportation, and 3) imported power costs above and beyond marginal cost of power production. Hypothetical optimization of firm natural gas supply in power sector is presented in Exhibit 5-10. The concept is same as the concept employed in the recent NARUC/EISPC study reviewed in the previous section. It is possible to combine integrated gas-power resource adequacy planning concepts discussed in the "Reliability Criterion-Driven Integrated Resource Adequacy Modeling Approaches" section (Three-layer analysis) with economic concepts shown in Exhibit 5-10 to perform fully integrated economic resource adequacy analysis. It is also possible to perform economic assessment of firm natural gas supply level as one off analysis following the conclusion of the standard power sector resource adequacy study.

Exhibit 5-10: Economic Optimal Firm Natural Gas Supply in Power Sector as Percentage of Total Power Sector Natural Gas Demand



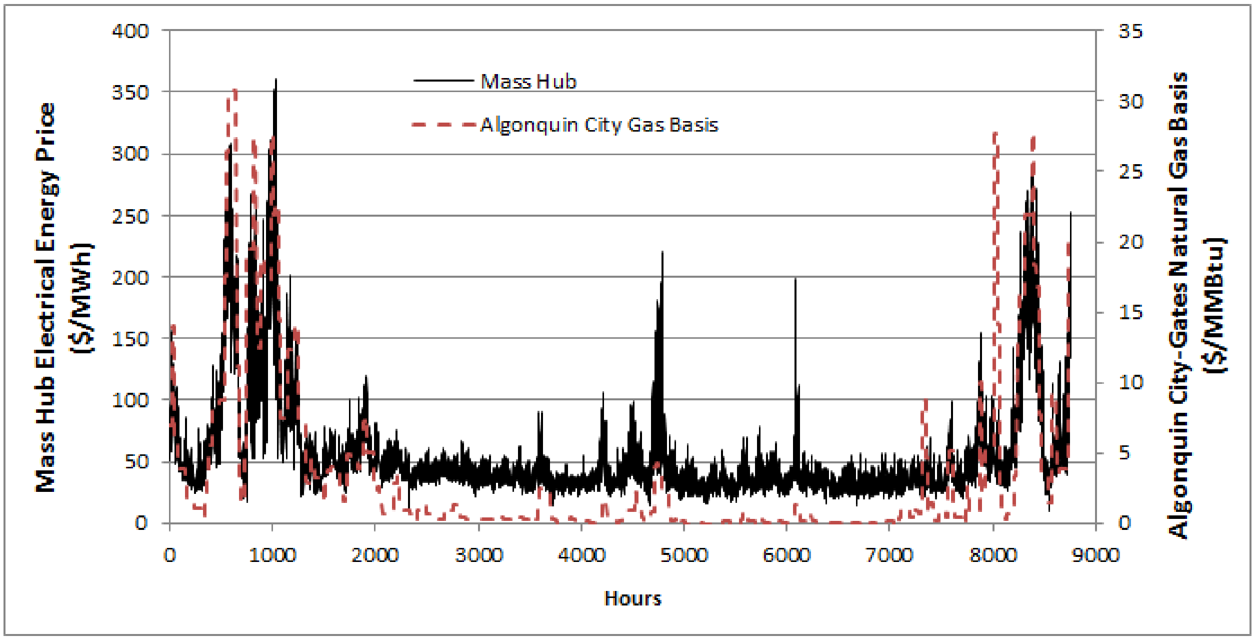
Source: ICF.

As discussed in the previous section the definition of costs due to lack of reliability is key in assessment of optimal reliability level. Exhibit 5-11 provides historical hourly time series of ISO-NE Mass Hub power prices and Algonquin City Gates basis differentials. These two pricing hubs are one of the most –if-not-the-most- liquid power and natural gas trading points in ISO NE footprint. Historically, electrical power prices have been driven by the changes in the natural gas prices. Every time the price of delivered gas price reaches above marginal cost of production and transportation there is a cost associated with not having sufficient natural gas infrastructure in place. The calculated cost for lack of infrastructure would be different for a regulated market and deregulated market. In a deregulated market setting, the case showing in Exhibit 5-11, all electricity customers subject to spot pricing will pay marginal cost of the most expensive unit. In regulated cost based approach the costs would be limited to fuel cost of each individual power plant. For example, assume a system with two power plants, 500 MW combined cycle with 7 MMBtu/MWh heat rate and 200 MW combustion turbine with 10 MMBtu/MWh heat rate. If the delivered gas price is $20/MMBtu above marginal cost of production and transportation of natural gas, for one hour the cost of lack of sufficient natural gas infrastructure would be

1) In the case of deregulated market: Reliability cost = 10*20*500+10*20*200 = $14,000;
2) In the case of cost based regulated market: Reliability cost = 7*20*500+10*20*200 = $11,000.

In reality the calculation would need to be more complex as not all of the power generators are subject to spot prices due to fixed-price contracts and hedging.

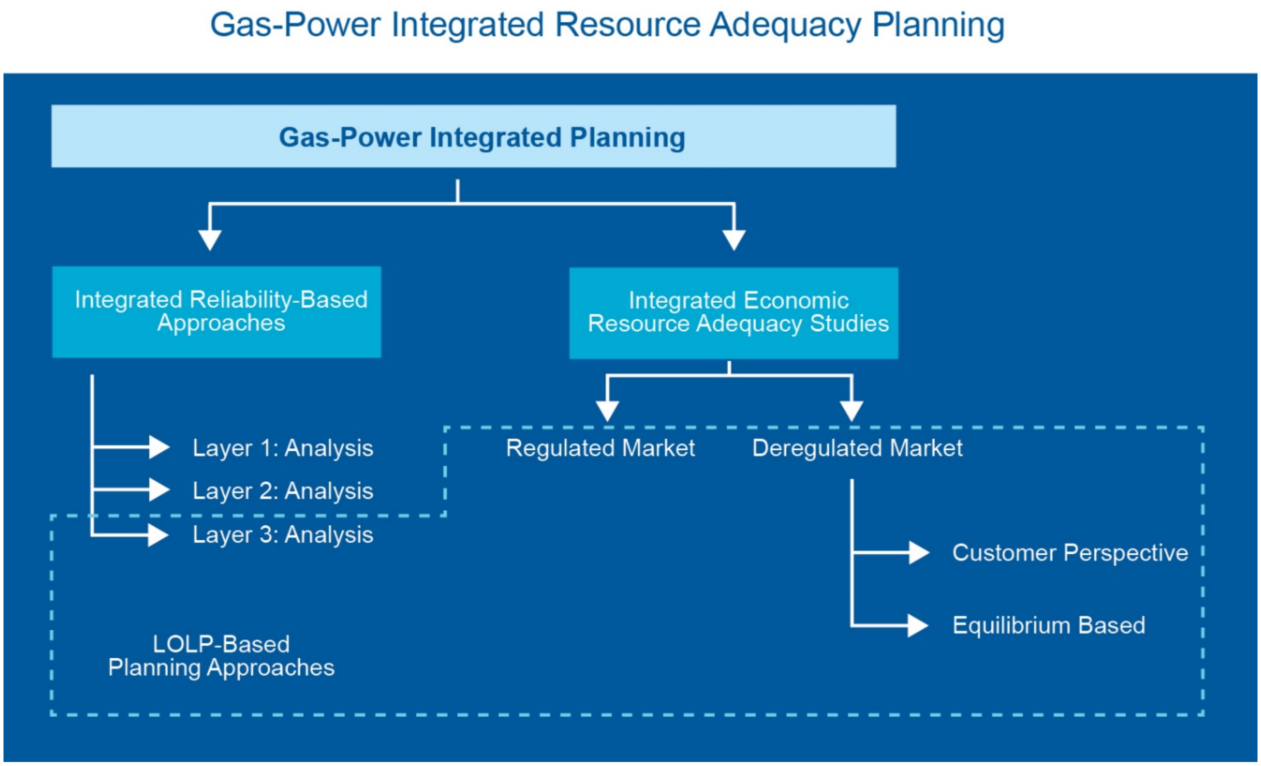
Exhibit 5-11: Mass Hub Day-Ahead Electrical Energy Prices and Algonquin City Gates Natural Gas Price Basis Differences with respect to Henry Hub (Hourly Prices in 2013)



Source: SNL Financial.

As NARUC/EISPC study on economics of resource adequacy in power sector hints planning for end user cost minimization would require significant expansion of natural gas infrastructure expansion to eliminate price spikes in Exhibit 5-10. Note, however, as indicated by the same study the economic optimal at which the average total system cost is minimized would not be necessarily at the point where end users costs are minimized. Exhibit 5-12 summarizes the resource adequacy planning approaches discussed in this section. The potential approaches have multiple degrees of freedoms involving analytical approach, economic perspective and market design.

Exhibit 5-12: Gas-Power Integrated Resource Adequacy Planning



Source: ICF.

6 Siting

6.1 Introduction

The ability to effectively site, and ultimately build, the necessary infrastructure to facilitate increased transportation and storage of gas will be a critical determinant of whether the industry's efforts to address the gas-electric coordination challenge are a success. Siting natural gas pipelines and other natural gas infrastructure requires an understanding of the major impacts and concerns associated with the facilities themselves, as well as an understanding of the permitting, consultation, and environmental review requirements of federal and state agencies. This section largely focuses on natural gas pipelines, as pipeline siting—compared to siting the other energy infrastructure types addressed in this report—requires a much larger environmental footprint and potentially greater environmental impact. The section discusses the other energy infrastructure types throughout, where such discussion is warranted.

Pipeline siting typically proceeds in a two-step process to take all the issues and authorities into account and to avoid undue delays and project opposition. First, there is a screening-level analysis of alternatives to support initial selections of a preferred route and reasonable alternatives. Using the framework employed by FERC, this includes a review of system alternatives (alternatives that could use entirely different pipeline systems to achieve the same objectives), major route alternatives (following different alignments for significant portions of the proposed route), and route variations (relatively short deviations that would avoid or reduce impacts on specific localized resources). Higher priority is always given to feasible alternatives that follow existing rights-of-way to avoid new impacts and community concerns.

Second, there is a more detailed analysis to support final selections and approval. If federal approval is needed, this detailed analysis would include scoping, consultation, and review of impacts and mitigation measures under the National Environmental Policy Act (NEPA). Other federal and state authorities may require related or additional reviews before siting is officially approved. This section focuses on federal and state laws, regulations, and requirements that may pertain to certain types of energy infrastructure projects, primarily those related to natural gas. It then describes how the regulatory framework could affect the infrastructure development necessary to undertake the infrastructure build-out implied in the four energy infrastructure scenarios discussed in this report. The section concludes with recommendations for streamlining the siting and approval process.

6.2 Federal and State Laws, Regulations, and Requirements

6.2.1 Federal

This section discusses the federal laws, regulations, requirements, and associated consultation processes that pertain to energy infrastructure development. It is organized into two subsections: one for environmental and social issues and another for operational safety issues.

6.2.1.1 Environmental and Social

Most of the energy infrastructure projects analyzed in this report would require the involvement of a federal agency. FERC is the only federal agency involved in siting interstate natural gas pipeline and LNG facilities. The only exception is if the project (i.e., pipeline) would cross federal land (e.g., the Bureau of Land Management or U.S. Forest Service would be involved if a pipeline was proposed to cross land under their jurisdiction). Other federal agencies may have permit issuance authority, but would not be the lead agency conducting the environmental review. For example, EPA may be involved for air quality permitting or the Army Corps of Engineers for wetland permitting. Permitting and resource agency consultation is discussed further below for specific resource areas, as applicable.

FERC, under Section 7 of the Natural Gas Act, issues Certificates of Public Convenience and Necessity for construction and operation of facilities associated with interstate natural gas transportation by pipeline. FERC's issuance of this certificate is a federal action, and therefore requires compliance with NEPA. NEPA is a U.S. environmental statute that was developed to establish a national policy for the protection of the human environment, which includes the natural and physical environment and the relationship of people with the environment (40 CFR §1508.14). It ensures that environmental factors are considered in federal decision-making in conjunction with technical and economic considerations. NEPA emphasizes the federal government's leadership role in ensuring impacts are considered through environmental assessment before major decisions are made. According to the statute, federal agencies must use a systematic, interdisciplinary approach to project planning to ensure that unquantifiable environmental resources are given appropriate weight in the decision-making process.

NEPA also established the Council on Environmental Quality (CEQ), a division of the Executive Office of the President whose primary responsibility is to oversee the implementation of NEPA and to ensure that federal agencies meet their obligations under the Act. In 1978, CEQ issued regulations (40 CFR parts 1500–1508) implementing the provisions of NEPA and providing direction to federal agencies regarding the requirements necessary to fulfill their NEPA obligations. The CEQ regulations set the standard for NEPA compliance. These regulations address the procedural provisions of NEPA and the administration of the NEPA process.

The CEQ regulations direct federal agencies to develop their own implementing procedures in order to better address each agency's specific mandates, obligations, and missions. For example, FERC has established its own NEPA implementing regulations (18 CFR Part 380) to supplement the CEQ regulations.

To comply with NEPA, federal agencies must determine if the proposed action would "significantly affect the quality of the human environment." To determine this, federal agencies first determine if the proposed action belongs to a category of actions in which the agency is certain significant impacts would not occur. This is referred to as categorical exclusion. NEPA defines a categorical exclusion as "a category of actions which do not individually or cumulatively have a significant effect on the human environment and which have been found to have no such effect in procedures adopted by a federal agency in implementation of these regulations and for which, therefore, neither an Environmental Assessment [EA] nor an Environmental Impact Statement [EIS] is required" (40 CFR §1508.4). FERC's list of categorical exclusions is provided in its NEPA implementing regulations (18 CFR §380.4). None of the infrastructure projects considered in this report would fall into one of FERC's categorical exclusions.

If the proposed action cannot be excluded categorically from a more detailed environmental review, federal agencies typically prepare an EA, which is a concise public document that helps the agency analyze and determine whether or not the potential environmental impacts of a proposed action and its reasonable alternatives would be significant. Based on the conclusions of the EA, the federal agency will prepare either a Finding of No Significant Impact, which would conclude the NEPA process, or prepare a more detailed EIS. If an EIS is required, the agency's EA concluded that the proposed action would significantly affect the quality of the human environment and further analysis is required. In practice however, the responsible federal agency is often aware early in the process that a proposed action may impact the environment significantly, or is likely to be highly controversial, and chooses to prepare an EIS without first preparing an EA. In its NEPA implementing regulations, FERC identifies projects that typically require preparation of an EA and projects that typically require an EIS (18 CFR §380.5 and §380.6). For example, major pipeline construction projects under Section 7 of the Natural Gas Act using rights-of-way in which there is no existing natural gas pipeline would typically require preparation of an EIS. However, each proposed project is considered on a case-by-case basis for the NEPA analysis.

To help expedite its NEPA review of large and controversial projects, in 2005 FERC established its Pre-filing Environmental Review Process, which must be implemented prior to the filing of an application (18 CFR §157.21). Use of the Pre-filing Process is now the routine approach at FERC for all moderate to large, and/or potentially controversial projects.

6.2.1.2 Federal Energy Regulatory Commission

A FERC Certificate Application for authority to construct and operate the types of jurisdictional facilities identified in this report may proceed in one of three ways: the Traditional Process, the Pre-filing Process, or under a separate set of regulations known as the Blanket Certificate Program. The latter is not normally applied to large infrastructure projects, and therefore will not be addressed. The Traditional Process omits the pre-application steps, requirements, and FERC staff involvement prescribed in the Pre-filing regulations; in effect restricting FERC from initiating any review or scoping before a formal application is filed.

The FERC Pre-filing Process is the agency's preferred process for reviewing major projects. Use of the Pre-filing Process is required for all new LNG projects and is strongly encouraged for all major pipeline and underground storage projects.

During the Pre-filing Process, applicants, their environmental consultants, and FERC staff focus significant effort on preparing and reviewing draft Environmental Resources Reports (see below), conducting scoping and public outreach, addressing emerging issues, finalizing the proposed pipeline routes and aboveground facility sites, and preparing the formal application. FERC staff assist, in various ways, undertaking scoping early, reviewing draft Resource Reports, and facilitating coordination with other permitting agencies and stakeholders.

The federal project review requirements imposed by FERC for interstate natural gas transmission and storage facilities are often the most relevant portions of this process. In particular, Siting and Maintenance Requirements (CFR §380.15) stipulate effects on scenic, historic, wildlife, and recreational values should be minimized in the siting, construction and maintenance of facilities (§380.15(a). In additions, planning, locating, clearing and maintenance of rights-of-way should take into account desires of landowners in the context of construction on their property if the result of that consideration remains consistent with all applicable laws, including land use laws and any FERC requirements (§380.15(b)).

Compliance with the siting and maintenance requirements is addressed in FERC's NEPA document (i.e., an EA or EIS) for a proposed project. To assist FERC with preparing its NEPA analysis for Natural Gas Act applications, an applicant must submit an environmental report along with the application (§380.12). The environmental report can consist of up to thirteen individual Resource Reports and related materials, as described in §380.12. FERC uses the information contained in an applicant's Resource Reports to develop its NEPA document. If the Pre-filing Process was used for the application, and effectively implemented, ideally all substantive environmental issues will have been identified, addressed, and resolved in some manner prior to the formal application filing.

The following resource areas are typically analyzed in FERC NEPA documents: air quality; biological resources (fish, wildlife, and vegetation, including protected species); cultural resources; geological resources; soils; land use, recreation, and aesthetics; noise; socioeconomics and environmental justice; and water resources (water use and quality). A brief discussion of these resources, the regulatory setting associated with the resources, and federal consultation processes (as required by federal statutes associated with the resources) that may be required are provided below. As a general note, FERC staff routinely consult and coordinate with all applicable federal agencies involved in a project review and/or authorization, typically during the Pre-filing Process. FERC is a signatory to the *Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews Conducted in Conjunction with the Issuance of Authorizations to Construct and Operate Interstate Natural Gas Pipelines Certified by the Federal Energy Regulatory Commission*.[175] The other signatories include the U.S. departments of Army, Agriculture, Commerce, Interior, Transportation, and Energy; the Advisory Council on Historic Preservation; CEQ; and EPA. The agreement establishes a framework for early cooperation and participation among the departments and agencies during environmental reviews of proposed interstate natural gas pipeline projects.

[175] FERC. "Interagency Agreement on Early Coordination Of Required Environmental and Historic Preservation Reviews Conducted in Conjunction with the Issuance of Authorizations to Construct and Operate Interstate Natural Gas Pipelines Certificated by the Federal Energy Regulatory Commission." May 2002. Available at: http://www.ferc.gov/industries/gas/enviro/gas_interagency_mou.pdf.

6.2.1.3 Air Quality

Air quality is the measure of the condition of the air expressed in terms of ambient pollutant concentrations and their temporal and spatial distribution. Air quality regulations in the United States are based on concerns that high concentrations of air pollutants can harm human health, especially for children, the elderly, and people with compromised health conditions; as well as adversely affect public welfare by damage to crops, vegetation, buildings, and other property. Air quality impacts (or air emissions) can occur from operation of construction equipment (temporary source) and operation of compressor stations (long-term/permanent source).

Exhibit 6-1 lists the primary statute (the Clean Air Act) related to air quality.

Exhibit 6-1: Statute Related to the Protection of Air Quality

Statute	Location in U.S. Code	Implementing Regulation(s)	Oversight Agency	Summary
Clean Air Act	42 U.S.C. §§7401-7671q	40 CFR parts 6, 9, 50-53, 60, 61, 63, 66, 67, 81, 82, and 93	EPA	Regulates air pollutant emissions from stationary and mobile sources; authorizes EPA to establish NAAQS for criteria pollutants and to regulate HAPs.

Notes: EPA = U.S. Environmental Protection Agency; NAAQS = National Ambient Air Quality Standards; HAPs = Hazardous Air Pollutants.

Under the Clean Air Act, EPA developed the National Ambient Air Quality Standards for six common air pollutants. These criteria air pollutants are carbon monoxide, nitrogen dioxide, ozone, particulate matter, sulfur dioxide, and lead. EPA determined that these criteria air pollutants may harm human health and the environment, and cause property damage. EPA regulates these pollutants to permissible levels through human health-based (primary standards) and environmental-based (secondary standards) criteria.

Consultation with state or local air quality agencies, as well as EPA regional offices, may be necessary when conducting the air quality analysis. For example, if FERC needs to make a General Conformity determination, FERC may need to consult with the EPA regional office and/or the state or tribal air permitting agency early in the environmental review process to discuss which General Conformity determination criteria to use and to identify the most up-to-date models and emissions data for a conformity analysis. Typically this type of consultation coordination is provided in an air quality modeling protocol document, which outlines to the reviewing agencies the proposed approach to demonstrate compliance with all applicable air quality rules and requirements.

The General Conformity Rule sets forth procedures and criteria for making the determination as to whether certain federal actions conform to federal or state air quality implementation plans. Consequently, this rule is only relevant in those instances where actions are proposed to occur in a nonattainment or maintenance area established by EPA. The general conformity requirements should be integrated into the NEPA process in those instances where the federal action is subject to EPA's General Conformity Rule (see 40 CFR Part 93).

6.2.1.4 Biological Resources (Fish, Wildlife, and Vegetation)

Biological resources are valued for their intrinsic, aesthetic, economic, and recreational qualities and include fish, wildlife, plants, and their respective habitats. Typical categories of biological resources include:

- terrestrial and aquatic plant and animal species;
- game and non-game species;
- special status species (state or federally listed threatened or endangered species, marine mammals, or species of concern, such as species proposed for listing or migratory birds); and
- environmentally sensitive or critical habitats.

Impacts on biological resources can result from clearing vegetation/habitat during construction/installation of energy infrastructure (long-term/permanent impact).

Exhibit 6-2 lists the primary statutes related to biological resources and that might apply to the energy infrastructure projects in the Eastern Interconnection.

Exhibit 6-2: Statutes Related to the Protection of Biological Resources

Statute	Location in U.S. Code	Implementing Regulation	Oversight Agency	Summary
Bald and Golden Eagle Protection Act	16 U.S.C. §668 et seq.	50 CFR part 22	USFWS	Protects bald and golden eagles from the unauthorized capture, purchase, or transportation of the birds, their nests, or their eggs.
Endangered Species Act	16 U.S.C. §§1531-1544	50 CFR parts 17 and 402	USFWS; NMFS	Requires all federal agencies to pursue conservation of threatened and endangered species. Section 7(a)(2) requires federal agencies to ensure that any action it authorizes, carries out or funds is not likely to result in the destruction or adverse modification of designated critical habitat or jeopardize the continued existence of a listed species in consultation with the Services (USFWS and/or NMFS),.
Fish and Wildlife Coordination Act	16 U.S.C. §§661-667d	Not applicable	USFWS	Requires federal agencies to consult with the USFWS, NMFS (in some instances), and appropriate state fish and wildlife agencies regarding the conservation of wildlife resources when proposed federal projects may result in control or modification of the water of any stream or other water body.
Migratory Bird Treaty Act (http://www.fsa.usda.gov/FSA/webapp?area=home&subject=ecrc&topic=waf-ma)	16 U.S.C. §703 et seq.	50 CFR part 21	USFWS	Protects migratory birds by prohibiting private parties (and federal agencies in certain judicial circuits) from intentionally taking, selling, or conducting other activities that would harm migratory birds, their eggs, or nests (such as removal of an active nest or nest tree), unless the Secretary of the Interior authorizes such activities under a special permit.

Notes: USFWS = U.S. Fish and Wildlife Service; NMFS = National Marine Fisheries Service.

The most common consultation when analyzing potential impacts to biological resources is Section 7, consultation with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS) under the Endangered Species Act. Under Section 7, if the federal agency determines that an action *may affect* a threatened or endangered species, the agency must initiate consultation with USFWS (for terrestrial and freshwater species) or NMFS (for marine and anadromous species), as appropriate, to ensure that any action the agency authorizes, funds, or carries out is not likely to jeopardize the continued existence of any federally listed threatened or endangered species or result in the destruction or adverse modification of critical habitat. FERC's process for complying with the Act is detailed in 18 CFR §380.13.

6.2.1.5 Cultural Resources

Cultural resources encompass a range of sites, properties, and physical resources relating to human activities, society, and cultural institutions. Such resources include past and present expressions of human culture and history in the physical environment, such as prehistoric and historic archaeological sites, structures, objects, and districts, which are considered important to a culture or community. Cultural resources also include aspects of the physical environment, namely natural features and biota that are a part of traditional ways of life and practices and are associated with community values and institutions. Impacts on cultural resources can occur from construction/installation of energy infrastructure in an area where historic properties or archaeological resources are located (direct or indirect impacts).

Exhibit 6-3 lists the primary statute (the National Historic Preservation Act), related to cultural resources.

Exhibit 6-3: Statute Related to Cultural Resources

Statute	Location in U.S. Code	Implementing Regulation(s)	Oversight Agency	Summary
National Historic Preservation Act	16 U.S.C. §§470-470x-6	36 CFR part 800 (Section 106 process) 36 CFR part 60 (NRHP) 36 CFR part 68 (standards)	NPS ACHP SHPO THPO	Establishes the ACHP, an independent agency, and the NRHP within the NPS. Section 106 of the NHPA requires federal agencies to consider the effects of their undertaking (or action) on properties listed on or eligible for listing on the NRHP.

Notes: ACHP = Advisory Council on Historic Preservation; NHPA = National Historic Preservation Act; NPS = National Park Service; NRHP = National Register of Historic Places; SHPO = State Historic Preservation Officer; THPO = Tribal Historic Preservation Officer.

The most common consultation when analyzing potential impacts to cultural resources is Section 106 consultation with the State Historic Preservation Officer, Tribal Historic Preservation Officer (as applicable), and/or the National Park Service (when National Historic Landmarks are involved) under the NHPA. Section 106 of the NHPA focuses on a specific subset of cultural resources: those properties that are listed on or meet the eligibility criteria for the National Register of Historic Places. Under Section 106, a federal agency is responsible for taking into account the effects of a project (referred to as an “undertaking”) on historic properties and providing an opportunity for the Advisory Council on Historic Preservation to provide comments on these types of undertakings. Although NEPA and Section 106 are distinct and contain separate requirements, they both require scoping, consultations, and public involvement; therefore, coordinating efforts under NEPA and Section 106 can make both reviews more efficient. FERC’s process for complying with the NHPA is detailed in 18 CFR §380.14.

6.2.1.6 Geological Resources and Soils

Geological resources can be discussed in terms of the mineral resources and hazards associated with the project area. Geological hazards are conditions or phenomena that present a risk or are potentially dangerous to life and/or property. Geologic hazards that can affect underground pipelines, underground gas storage, and applicable facilities include seismicity, faults, landslides, and subsidence due to sinkhole development, groundwater withdrawal, or past mining activities. There are no major federal laws or regulations that pertain to the protection of geological resources. However, FERC has comprehensive guidelines[176] it applies to address the U.S. Department of Transportation (DOT) requirements[177] applicable to the siting and seismic design of LNG facilities.

Soil can be discussed in terms of soil associations or series, erosion potential, fertility, and drainage characteristics. The Natural Resources Conservation Service of the U.S. Department of Agriculture can classify soils as unique or prime farmland. Farmlands are defined as those agricultural areas considered important and protected by federal, state, and local regulations. Farmlands of particular import are inclusive of all pasturelands, croplands, and forests (even if zoned for development) that are considered to be unique, prime, or otherwise important on a statewide or local basis. Exhibit 6-4 lists the primary statute (the Farmland Protection Policy Act) related to farmlands.

Exhibit 6-4: Statute Related to Farmlands

Statute or Guidance	Location in U.S. Code	Implementing Regulation(s)	Oversight Agency	Summary
Farmland Protection Policy Act	7 U.S.C. §§4201-4209	7 CFR parts 657-658	NRCS	Administered by the NRCS, the FPPA regulates federal actions with the potential to convert farmland to non-agricultural uses.

Notes: NRCS = Natural Resources Conservation Service; FFPA = Farmland Protection Policy Act.

As noted in Exhibit 6-4 above, the FPPA regulates federal actions with the potential to convert farmland to non-agricultural uses. Specifically, the Act regulates farmland identified as prime, unique, or of state or local importance. FERC may determine whether or not the site of the proposed action or alternative(s) is prime, unique, state, or locally important farmland using criteria provided in 7 CFR §658.5.

[176] FERC. "Draft Seismic Design Guidelines and Data Submittal Requirements for LNG Facilities." 23 January 2007. Available at: http://ferc.gov/industries/gas/indus-act/lng/lng-seis-guide.pdf.

[177] NFPA 59-A 2006 ed., per 49 CFR Part 193.

6.2.1.7 Land Use, Recreation, and Aesthetics

If federal land is involved with a project, the activities must comply with the existing land use plan for the property. If federal land is not involved with the project, compliance with land use, recreation, and visual resources regulations is typically done at the local municipality and county levels. There are no major federal laws or regulations that pertain to land use, recreation, and aesthetics.

6.2.1.8 Noise

Noise is considered unwanted sound that disturbs routine activities and can cause annoyance. Noise associated with energy projects primarily results from construction or installation of facilities and infrastructure as well as the operation of aboveground facilities. FERC limits noise from compressor stations and other permanent project noise sources to day-night average sound level (or Ldn) of 55 A-weighted decibels (or dBA) at any nearby noise sensitive areas.

The compatibility of existing and planned land uses with proposed energy projects is usually determined in relation to the level of construction and operational noise. Federal compatible land use guidelines for a variety of land uses are provided in Table 1 in Appendix A of 14 CFR part 150, *Land Use Compatibility with Yearly Day-Night Average Sound*. There are no major federal laws or regulations that pertain to noise from energy projects.

6.2.1.9 Socioeconomics and Environmental Justice

Socioeconomics is an umbrella term used to describe aspects of a project that are either social or economic in nature. A socioeconomic analysis evaluates how elements of the human environment such as population, employment, housing, and public services might be affected by the project. Socioeconomic impacts from energy infrastructure projects might include temporary/short-term local employment that results in beneficial economic impacts in the community.

Section 1508.14 of the CEQ regulations states that, "economic or social effects are not intended by themselves to require preparation of an environmental impact statement. When an environmental impact statement is prepared and economic or social and natural or physical environmental effects are interrelated, then the environmental impact statement will discuss all of these effects on the human environment." Therefore, the requirement to prepare socioeconomic analysis in an EA or EIS is project specific and is dependent upon the existence of a relationship between natural or physical environmental effects and socioeconomic effects.

Environmental justice involves the meaningful involvement and fair treatment of all people regardless of national origin, race, color, or income as it pertains to the development, implementation, and enforcement of environmental policies, laws and regulations. In this context, *fair treatment* means that the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies should not be borne disproportionately by any group of people. *Meaningful involvement* means the opportunity to participate in decisions about activities that may affect the public's environment and/or health;

their ability to influence the regulatory decisions; consideration of their concerns in the decision making process; and active efforts by decision makers to seek out and facilitate participation by those potentially affected.

Exhibit 6-5 lists the primary statute and Executive Order related to environmental justice impacts.

Exhibit 6-5: Statute and Executive Order Related to Environmental Justice

Statute or Executive Order	Location in U.S. Code or *Federal Register*	Implementing Regulation(s)	Oversight Agency	Summary
Title VI of the Civil Rights Act of 1964, as amended	42 U.S.C §§2000d-2000d-7	28 CFR §42.401	DOJ	Title VI of the Civil Right Act of 1964 states that "No person in the United States shall, on the ground of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity receiving federal financial assistance."
Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*	59 *Federal Register* 7629, (February 11, 1994)	Not applicable	EPA	Requires federal agencies to incorporate environmental justice into their planning processes.

Notes: EPA= U.S. Environmental Protection Agency; CEQ= Council on Environmental Quality; NEPA = National Environmental Policy Act.

6.2.1.10 Water Resources

Water resources are surface waters and groundwater that are vital to society. They are important in providing drinking water and in supporting recreation, transportation and commerce, industry, agriculture, and aquatic ecosystems. Typically, a NEPA analysis considers the potential impacts on wetlands, floodplains, surface waters, water quality, and groundwater.

6.2.1.11 Wetlands, Surface Waters, and Water Quality

For regulatory purposes under the Clean Water Act (CWA), the term wetlands refers to lands saturated or inundated by ground or surface water at a duration and frequency that is sufficient to support a prevalence of vegetation that is most often adapted to saturated soil conditions. Wetlands typically include marshes, swamps, bogs, and the like. Surface waters (excluding wetlands) include streams, rivers (including Wild and Scenic Rivers), lakes, ponds, estuaries, and oceans. Wild and Scenic Rivers are those rivers having remarkable scenic, recreational, geologic, fish, wildlife, historic, or cultural values as defined by the Wild and Scenic Rivers Act. Impacts on water resources can result from filling in a wetland to support the construction of infrastructure (long-term/permanent impact).

Exhibit 6-6 lists the statutes, regulations, and other requirements that may be relevant to wetlands, surface water, and water quality impacts.

Exhibit 6-6: Statutes and Executive Orders Related to the Protection of Wetlands, Surface Waters, and Water Quality

Statute or Executive Order	Location in U.S. Code or *Federal Register*	Implementing Regulation(s)	Oversight Agency	Summary
Clean Water Act	33 U.S.C. §§1251-1387	33 CFR parts 320-332 40 CFR parts 230-233	USACE; EPA	The CWA establishes the basic structure for regulating the discharge of pollutants into waters of the United States which include wetlands. The two primary sections of the CWA relating to wetland impacts and permitting are Section 404 and Section 401. Section 404 establishes a program to regulate the discharge of dredged or fill material into waters of the United States, including wetlands. Section 401 requires that a Water Quality Certificate for a project to ensure it does not violate State or Tribal water quality standards. Section 401 certifications are generally issued by the state or tribe with jurisdictional authority.
Fish and Wildlife Coordination Act	16 U.S.C § 661-667d	Final regulations never issued	USFWS	Requires federal agencies to consult with the USFWS, NMFS (in some instances), and appropriate state fish and wildlife agencies regarding the conservation of wildlife resources when proposed federal or applicants' projects may result in control or modification of the water of any stream or other water body (including wetlands).
Rivers and Harbors Act	33 U.S.C §403 33 U.S.C §401	33 CFR parts 320-332 33 CFR parts 114-118	USACE; USCG	Established to protect the navigability of waters used for commerce in the United States
Safe Drinking Water Act	42 U.S.C. §§300(f)-300j-26	40 CFR parts 141-149	EPA	Prohibits federal agencies from funding actions that would contaminate an EPA-designated sole source aquifer or its recharge area.
Wild and Scenic Rivers Act	16 U.S.C. §§1271-1287	36 CFR part 297, subpart A (USFS)	NPS, USFWS, and BLM	Creates the National Wild and Scenic Rivers System to preserve certain rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations.
Executive Order 11990, *Protection of Wetlands*	42 *Federal Register* 26961, (May 24, 1977)	Not applicable	DOT	Requires federal agencies to "avoid to the extent possible the long and short term adverse impacts associated with the destruction or modification of wetlands and to avoid direct or indirect support of new construction in wetlands wherever there is a practicable alternative." The stated purpose of this Executive Order is to "minimize the destruction, loss or degradation of wetlands, and to preserve and enhance the natural and beneficial values of wetlands."

Notes: CWA = Clean Water Act; DOT = U.S. Department of Transportation; EPA = U.S. Environmental Protection Agency; NMFS = National Marine Fisheries Service; USACE = U.S. Army Corps of Engineers; USFWS = U.S. Fish and Wildlife Service; USCG = U.S. Coast Guard; NPS = National Park Service; BLM = Bureau of Land Management.

Routine coordination among the various federal agencies assists FERC in addressing wetland, surface water, and water quality issues or conflicts early in the NEPA process and in developing ways to resolve them. If an alternative would impact a wetland and/or surface water that is determined to be jurisdictional by the USACE under the CWA and/or the Rivers and Harbors Act, permits and certification may be required depending on the type of activity. If FERC is taking an action that would physically impact resources covered by the Wild and Scenic Rivers Act, there may be consultation requirements under the Act.

6.2.1.12 Floodplains

Floodplains are lowland areas adjoining inland and coastal waters that are periodically inundated by flood waters, including flood-prone areas of offshore islands. Floodplains are often discussed in terms of the 100-year flood. The 100-year flood is a flood having a 1 percent chance of occurring in any given year. The 100-year flood is also known as the base flood. Floodplains are valued for their natural flood and erosion control, enhancement of biological productivity, and socioeconomic benefits and functions. Floodplain impacts can result from constructing aboveground facilities within the floodplain.

In accordance with Executive Order 11988, *Floodplain Management*, the federal agency must, when property in floodplains is proposed for easement, lease, right-of-way, or disposal to non-federal public or private entities, do the following: (1) reference restricted uses that are under floodplain regulations; (2) attach to uses of properties other appropriate restrictions, except where legally prohibited; or (3) withhold the properties in question from conveyance.

Exhibit 6-7 lists the primary federal statute (National Flood Insurance Act) and Executive Order that pertain to floodplains. The National Flood Insurance Act is a voluntary program under the purview of FEMA, and is implemented at the local municipality or county level.

Exhibit 6-7: Statute and Executive Order Related to the Protection of Floodplains

Executive Order	Location in *Federal Register*	Implementing Regulation(s)	Oversight Agency	Summary
National Flood Insurance Act	42 U.S.C §4001 et seq.	44 CFR part 60	FEMA	Established the NFIP, a voluntary floodplain management program for communities (cities, towns, or counties).
Executive Order 11988, *Floodplain Management*	42 *Federal Register* 26951, (May 25, 1977)	Not applicable	Federal action agency	Requires federal agencies to avoid, to the extent possible, the long and short-term adverse impacts associated with the occupancy and modification of 100-year floodplains and to avoid direct or indirect support of floodplain development wherever there is a practicable alternative.

Note: FEMA = Federal Emergency Management Agency, NFIP = National Flood Insurance Program.

6.2.1.13 <u>Groundwater</u>

Groundwater is subsurface water that occupies the space between sand, clay, and rock formations. The term aquifer is used to describe the geologic layers that store or transmit groundwater, such as to wells, springs, and other water sources. Although not common, groundwater impacts can result from excavation below the water table.

Exhibit 6-8 lists the major statute (Safe Drinking Water Act) that may be relevant to groundwater impacts. The Act may not be applicable to every proposed project, and should only be included when relevant.

Exhibit 6-8: Statute Related to the Protection of Groundwater

Statute	Location in U.S. Code	Implementing Regulation	Oversight Agency	Summary
Safe Drinking Water Act	42 U.S.C. §§300(f)-300j-26	40 CFR parts 141-149	EPA	Prohibits federal agencies from funding actions that would contaminate an EPA-designated sole source aquifer or its recharge area.

Note: EPA = U.S. Environmental Protection Agency.

6.2.1.14 Construction and Operational Safety

Under Section 7 of the Natural Gas Act, FERC reviews applications for the construction and operation of natural gas pipelines. In its application review, FERC ensures that the applicant has certified that it will comply with DOT safety standards. FERC has no jurisdiction over pipeline safety or security, but actively works with other agencies with safety and security responsibilities and considers safety-related issues in its siting reviews and NEPA analyses.

During construction, and once natural gas pipelines projects are operating, the DOT Pipeline and Hazardous Material Safety Administration (PHMSA), monitors, regulates and enforces safety through the Office of Pipeline Safety (OPS). The OPS engages in collaboration with partnering departments and agencies in order to ensure compliance. The federal government is responsible for developing, issuing, and enforcing pipeline safety regulations. Nevertheless, most inspections are conducted by state regulatory agencies, because they are responsible for inspection, regulation, and enforcement of pipelines within state boundaries. The stringency of state agency regulations must be greater than or equal to those of the federal regulations. State agencies are certified by OPS annually. Although it retains enforcement responsibilities, OPS can also authorize states to inspect interstate pipelines,.

PHMSA has taken many initiatives in recent years toward increasing safety. Through its Gas Distribution Integrity Management Program, PHMSA develops rules establishing integrity management requirements for gas distribution pipeline systems. For example, PHMSA established the Gas Transmission Integrity Management Rule (49 CFR Part 192, Subpart O), commonly referred to as the “Gas IM Rule,” which specifies how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect High Consequence Areas within the United States. High Consequence Areas include populated areas, areas containing drinking water and ecological resources that are unusually sensitive to environmental damage, and commercially navigable waterways.

Safety and operations oversight of infrastructure projects not under FERC or PHMSA jurisdiction can be accounted for by adherence to industry codes and standards. Environmental requirements would be subject to compliance with applicable permit conditions (e.g., air quality permit, wetland permit, etc.).

6.2.2 State Regulations

Although federal regulations can be the binding restraint with regard to the siting of natural gas infrastructure, state policies and regulations can influence infrastructure siting decisions and provide a more rigorous stringency requirement. For example, although the federal government is responsible for developing, issuing, and enforcing pipeline safety regulations, most inspections are conducted by state regulatory agencies, which are responsible for regulation, inspection, and enforcement of pipelines within state boundaries. The state agency regulations must be at least as stringent as the federal regulations. Each state associated with the Eastern Interconnection has multiple environmental regulations and siting/permitting regulations that could affect the siting and construction of natural gas infrastructure. Many states also have regulations specific to safety and operations of these facilities. Because 39 states and the District of Columbia are associated with Eastern Interconnection, it is outside the scope of this report to discuss in detail the regulations of each state and jurisdiction. However, the number of regulations for each state can provide some insight into the regulatory complexity for siting and constructing natural gas infrastructure.

As part of EISPC's Energy Zone Study, EISPC compiled a list of policies and regulations pertaining to the development of clean energy technologies. Using EISPC's EZ Mapping Tool website,[178] the number of environmental regulations, siting and permitting policies, and safety and operational guidelines that pertain to natural gas development was obtained for each state in the U.S. portion of the Eastern Interconnection (see Exhibit 6-9).

[178] EISPC. EZ Mapping Tool. Available at: http://eispctools.anl.gov/policy_query.

Exhibit 6-9: Number of Environmental Regulations, Siting and Permitting Policies, and Safety and Operational Guidelines Associated with Natural Gas Facilities for States in the Eastern Interconnection

State	Environmental Regulations and Siting & Permitting Policies	Safety and Operational Guidelines[a]	State	Environmental Regulations and Siting & Permitting Policies	Safety and Operational Guidelines[a]
Alabama	17	4	Montana	33	0
Arkansas	14	1	Nebraska	23	1
Connecticut	21	2	New Hampshire	8	1
Delaware	7	1	New Jersey	8	2
District of Columbia	5	0	New Mexico	17	0
Florida	23	3	New York	26	3
Georgia	21	3	North Carolina	14	3
Illinois	15	5	North Dakota	15	1
Indiana	34	1	Ohio	18	2
Iowa	43	0	Oklahoma	15	1
Kansas	10	0	Pennsylvania	16	3
Kentucky	17	3	Rhode Island	23	0
Louisiana	21	1	South Carolina	18	1
Maine	11	3	South Dakota	12	0
Maryland	27	4	Texas	21	6
Massachusetts	9	2	Tennessee	14	3
Michigan	5	0	Vermont	14	0
Minnesota	26	0	Virginia	19	5
Mississippi	20	0	West Virginia	16	4
Missouri	10	3	Wisconsin	11	0

[a] Some or all of the policies and regulations for safety and operation guidelines are also part of the policies and regulations in the environmental regulations and siting & permitting column.

Several of the state regulations, policies, and guidelines represented in Exhibit 6-9 are specific to natural gas infrastructure, while others address a range of issues that are associated with water resources, water quality, multi-state energy compacts, oil and gas commission rules, hazardous waste, air pollution controls/programs, wetlands, threatened and endangered species, and wildlife management areas.

At the local/community level, building permits are usually required for various parts of energy infrastructure projects. These permits normally do not affect siting. Local authorities typically review to ensure compliance with applicable building codes and local ordinances.

6.3 Energy Infrastructure Scenarios

This section discusses the siting considerations associated with the different types of energy infrastructure and describes how the environmental and safety regulations described in Section 6.2 could affect the infrastructure development necessary to undertake the infrastructure build-out implied in the four energy infrastructure scenarios discussed in this report.

The PHMSA is responsible for administering and enforcing all construction, operation, and safety requirements for oil and gas pipelines. Protection of facilities from natural hazards is addressed broadly in the regulations that govern gas and oil pipelines. It is primarily the responsibility of the owner/operator of the facility to properly locate facilities and to adequately evaluate and mitigate impacts that can adversely affect the facilities or cause a safety hazard. PHMSA regulations apply to offshore pipeline facilities as well; however, Bureau of Ocean Energy Management, Regulation and Enforcement oversees and enforces operational and safety requirements. PHMSA has no specific environmental facility-siting requirements for oil or gas pipelines and does not do any preconstruction or NEPA review, nor authorize construction of facilities.

FERC reviews and authorizes proposals for construction and operation of natural gas pipeline facilities operating in interstate commerce. That includes most of the nation's large diameter natural gas transmission pipelines (and associated facilities such as compressor and meter stations), underground storage fields, all import/export LNG terminals, as well as a relatively small number of LNG peak-shaving plants that operate off the interstate pipeline system. There are comprehensive siting requirements for LNG facilities per the DOT requirements (49 CFR Part 193). Siting requirements for pipelines and power lines are more general and performance-based than, for example, LNG terminals or power plants.

The following list summarizes federal regulatory requirements for pipeline (and electric transmission facilities) construction

1. The use, widening, or extension of existing rights-of-way must be considered in locating proposed facilities.
2. In locating proposed facilities, the project sponsor shall, to the extent practicable, avoid places listed on, or eligible for listing on, the National Register of Historic Places; natural landmarks listed on the National Register of Natural Landmarks; officially designated parks; wetlands; and scenic, recreational, and wildlife lands. If rights-of-way must be routed near or through such places, attempts should be made to minimize visibility from areas of public view and to preserve the character and existing environment of the area.
3. Rights-of-way should avoid forested areas and steep slopes where practical.
4. Rights-of-way clearing should be kept to the minimum width necessary.
5. In selecting a method to clear rights-of-way, soil stability and protection of natural vegetation and adjacent resources should be taken into account.

6. Trees and vegetation cleared from rights-of-way in areas of public view should be disposed of without undue delay.
7. Remaining trees and shrubs should not be unnecessarily damaged.
8. Long foreground views of cleared rights-of-way through wooded areas that are visible from areas of public view should be avoided.
9. Where practical, rights-of-way should avoid crossing hills and other high points at their crests where the crossing is in a forested area and the resulting notch is clearly visible in the foreground from areas of public view.
10. Screen plantings should be employed where rights-of-way enter forested areas from a clearing and where the clearing is plainly visible in the foreground from areas of public view.
11. Temporary roads should be designed for proper drainage and built to minimize soil erosion. Upon abandonment, the road area should be restored and stabilized without undue delay.[179]

FERC's requirements for construction of aboveground facilities are[180]:

1. Unobtrusive sites should be selected for the location of aboveground facilities.
2. Aboveground facilities should cover the minimum area practicable.
3. Noise potential should be considered in locating compressor stations, or other aboveground facilities.
4. The exterior of aboveground facilities should be harmonious with the surroundings and other buildings in the area.
5. For Natural Gas Act projects, the site of aboveground facilities which are visible from nearby residences or public areas, should be planted in trees and shrubs, or other appropriate landscaping and should be installed to enhance the appearance of the facilities, consistent with operating needs.[181]

FERC oversees siting and safety of *interstate* LNG facilities (a minority of U.S. LNG facilities) in accordance with PHMSA regulations and its own data submittal requirements (especially Resource Reports 11 and 13). FERC oversight of the interstate natural gas industry is unique in that there is no similar federal agency with exclusive authority to perform pre-construction/NEPA reviews or to regulate the siting of oil and liquid fuels pipelines and storage facilities or fossil fuel-fired electric power plants. Oil and gas production wells and gathering pipelines are also

[179] 18 CFR §380.15(d).

[180] Examples of aboveground facilities under FERC jurisdiction include compressors, regulators, meter stations, communication towers, and other buildings at jurisdictional facilities, such as underground storage fields and LNG plants operating in interstate commerce.

[181] 18 CFR §380.15(f).

outside FERC's jurisdiction, as are local gas distribution systems and certain pipeline systems operating solely with a state borders.

6.4 Recommendations for Streamlining the Siting and Approval Process

6.4.1 Siting

A recommendation for streamlining the siting process involves using EISPC's EZ Mapping Tool. EISPC, in collaboration with the U.S. Department of Energy (DOE), developed a comprehensive mapping tool[182] to facilitate the identification of areas suitable for development of clean energy. The study included an investigation of nine types of clean energy resources that could be considered for the development of clean electricity generation facilities, one of which was natural gas. For each clean energy category, resource data and information were compiled, reviewed, and assembled into a web-based GIS database. Because an energy resource category may comprise multiple technologies for electricity generation that utilize different types of energy inputs, the database includes several clean energy technologies—for natural gas, the technologies include two of the energy infrastructure types considered in this report: underground and aboveground natural gas storage.

Suitability models built into the GIS database allow users to identify areas suitable for the development of a specific clean energy technology. The tool enables users to define resource thresholds for the technology of interest. Unsuitable areas can be identified and screened out through the application of filter criteria related to land use, ecological considerations or other constraints.

Environmental data layers and information have been fully integrated in to the tool. The inclusion of screening layers allows environmental factors to be incorporated early in the planning process in order to reduce the risk of regulatory intervention, public opposition, or litigation downstream in the process. Three model input grouping layers were used for the environmental screening factors: protected lands, habitat, and imperiled species. The protected lands and habitat environmental screening layers are composites made from numerous individual input datasets.

For underground and aboveground natural gas storage, screening criteria for coal and nuclear technology were used as a basis for developing the natural gas screening factors (Exhibit 6-10). The criteria were modified on the basis of the unique characteristics of natural gas technologies.

[182] DOE. 2013. "Energy Zones Study – A Comprehensive Web-based Mapping Tool to Identify and Analyze Clean Energy Zones in the Eastern Interconnection." Argonne National Laboratory, National Renewable Energy Laboratory, and Oak Ridge National Laboratory. September.

Exhibit 6-10: Natural Gas Screening Factors[183]

Natural Gas Technology	Screening Parameter
Underground natural gas storage	Distance to natural gas transmission pipeline (≥12 in) Aquifer area Distance to domal salt formation Population density Land cover area 100-yr flood zone Distance to railroad Distance to major road Proximity to electric transmission (>100kV) Protected Land Habitat Imperiled Species
Aboveground natural gas storage (LNG)	Distance to natural gas transmission pipeline (≥12 in) Population density Slope Land cover area 100-yr flood zone Proximity to electric transmission (>100kV) Protected Land Habitat Imperiled Species

Notes: in = inch; kV = kilovolt; LNG = liquefied natural gas.

6.4.2 Approval

6.4.2.1 Federal

For projects under FERC jurisdiction, (e.g., interstate pipelines), FERC's successful implementation of its Pre-filing Process ensures FERC's public environmental review process is as streamlined as possible, thus avoiding unnecessary delays in the applicant's approval process. Industry groups have put forth proposals for ways in which the federal siting process could be further streamlined. These proposals do not reflect the position of ICF and their inclusion here does not constitute endorsement; they are summarized here for additional context and to provide further insight into federal siting processes. The INGAA Foundation, Inc. (INGAA) commissioned a study[184] that shows the time to obtain required federal authorizations from agencies other than FERC for interstate natural gas pipeline projects has actually increased since the passage of the Energy Policy Act of 2005 (EPAct 2005), a law with the stated intent to streamline and expedite federal authorizations for such projects. In order to streamline and expedite the federal authorizations required for interstate natural gas pipeline projects, EPAct 2005 authorized FERC to establish a schedule for these authorizations.[185] To

[183] Energy Zones Study – A Comprehensive Web-based Mapping Tool to Identify and Analyze Clean Energy Zones in the Eastern Interconnection.

[184] INGAA Foundation, Inc., The. "Expedited Federal Authorization of Interstate Natural Gas Pipelines: Are Agencies Complying with EPAct 2005." Final Report No. 2012.05. 2012. Available: http://ingaa.org/Foundation/Foundation-Reports/EPAct2005.aspx.

[185] Federal authorizations include both authorizations issued by federal agencies and authorizations issued by state agencies acting under federal delegation.

accomplish this, FERC implemented a 90-day deadline for other agencies to issue the federal authorizations required for a pipeline project after completion of FERC's NEPA process. Common federal authorizations include the following, but vary depending on the project:

- National Historic Preservation Act, Section 106 Consultation
- Clean Water Act, Section 404 Permit
- Endangered Species Act, Section 7 Consultation and Incidental Take Permit
- Rivers and Harbors, Section 10 permit
- Coastal Zone Management Act, Consistency Determination
- Bureau of Land Management, Right-of-Way Grant
- U.S. Forest Service, Special Use Permit

INGAA's study revealed that federal agency authorizations are not always completed within FERC's 90-day deadline. INGAA's survey results showed:

1. An increase from 7.69 percent to 28.05 percent of federal authorizations that were delayed;
2. An increase from 3.42 percent to 19.51 percent of federal authorizations that were delayed 90 days or longer beyond the FERC deadline; and
3. An increase in the time federal agencies took to deem an application for a federal authorization "complete."

INGAA concluded that "in order to achieve [EPAct 2005's] goal of streamlined permitting, there must be consequences for agencies that fail to meet deadlines. Additional process improvements, regulatory revisions, and/or legislative actions likely are needed. Based on analysis of the study data, potential options include:

1. Amending the Natural Gas Act to provide effective tools to enforce the federal authorization deadline, such as granting automatic approval if an agency does not respond by the deadline or allowing FERC to grant approval in the agency's stead.
2. Greater FERC involvement in permitting processes to educate and train other federal agencies, facilitate communications with those agencies, and move the permitting processes forward.
3. Encouragement of other federal agencies to recruit staff with specific experience permitting linear projects.
4. Revision of FERC's policy that encourages cooperation with state and local agencies to recognize more definitively that state or local law that overlaps or conflicts with FERC's authority over pipeline facilities is preempted by the Natural Gas Act.
5. Recognition by federal agencies that, as the lead agency, FERC's completion of National Historic Preservation Act Section 106 consultation and Endangered Species Act Section 7 consultation is sufficient for other federal authorizations that require such consultation for interstate natural gas pipeline projects.
6. Explicit direction by [CEQ] to require expedited review for pipeline projects under [NEPA].

7. Statutory amendments to authorize interstate natural gas pipeline companies access to private property for required non-invasive project surveys and to authorize FERC to apply authorization deadlines to non-federal authorizations required from state and local agencies.
8. Congressional or federal court action to address issues and associated delays resulting from [USFWS] requirements under the Migratory Bird Treaty Act, which currently prohibits the take of migratory birds that occurs incidental to otherwise lawful activities, such as interstate natural gas pipeline development."

6.4.2.2 Non-Federal

For projects where a state is involved, state agencies can contribute to project delays as a result of inadequate agency staffing, lack of experience with pipelines, and unclear or uncommon state permitting requirements. Suggestions for improvement outlined in the study include collaborating with FERC earlier in the permitting process so that correct information and advice is shared with the applicant.

7 Recommendations for Future Work

Going forward, the integration of fuel supply availability and interdependence in power sector resource planning carries significant importance for accurate electricity resource planning. Many of the uncertainties surrounding the question of natural gas and alternative fuel adequacy are the same as those that affect other aspects of power systems planning. These include uncertainties in future economic growth, effects of conservation and changes in consumer behavior, the role of renewables, distributed generation, and the status of new environmental rules that can affect coal and other generation. Therefore, continuous monitoring of electric load trends and developments in demand forecasting will be critical. As mentioned in the context of the 2030 infrastructure expansion modeling, the future needs for incremental fuel infrastructure are driven in large part by power sector demand for natural gas and to the extent that significant uncertainty remains around projections of prospective demand for electricity, those will cast considerable uncertainty on the future needs for incremental fuel supply, transmission and storage capacity over the planning horizon. Continued advancements in load tracking, and electric demand forecasting that provide better insight into future needs for electric power needs will greatly enhance understanding of fuel adequacy and infrastructure additions needs.

Recommendations

- Monitor electricity load trend and load forecasting advancements
- Explicitly incorporate fuel adequacy into electric resource adequacy metrics
- Improve databases used in fuel adequacy metrics (e.g., weather probabilities, historical plant outage caused by inadequate fuels, historical reliability of fuel delivery systems).
- Periodically review regional infrastructure needs in the Eastern Interconnection.
- Ensure that market designs are *in sync* with fuel adequacy goals.

Beyond the general concerns about the overall levels of electricity demand, supply, and fuel mix, most accurate integration of natural gas supply into resource adequacy planning would be accomplished by expanding the standard loss of load modeling framework to include the natural gas and alternative fuel supply network. This includes collecting data on their current and expected future capacities and likely future utilization under various weather scenarios.

However, given the state of resource adequacy planning in the power sector (i.e., lack of consensus on metrics and modeling tools), wide-scale development and implementation of such modeling tools may not be feasible in the short term. In this context, the problem can be divided into two phases. The long-term goal should be development of an integrated planning tool as described in the Layer 3 analysis. In the short term, methodologies could be developed to supplement standard loss of load modeling studies. The Layer 1 and Layer 2 analyses described in Section 5 serve this purpose. In addition, in the short term it could also be convenient to incorporate gas supply availability into standard loss of load modeling by employing statistic methodologies. For example, increasing dependence between forced outages of natural gas-fired generation could be potentially modeled as copulas (multivariate probability distributions); or at an even simpler level a Monte Carlo model could increase forced outage probabilities of gas-generators when the draw results in an extremely cold weather pattern. Implementation of such statistical techniques would require in-depth analysis of historical weather patterns and associated outage information across the United States.

Another aspect of load forecasting worthy of further investigation are the impacts of weather distributions and climate trends on fuel infrastructure needs. Although the steady-state operation of the gas and electric systems under normal or design day conditions are well understood, the amplitude and frequency of extreme weather events could have significant impacts on the economics of the system. To the extent that weather scenarios at the edges of the probability distribution curve incur a disproportionate cost on the system, differing treatments of weather variability can produce disparate results. Standardizing this approach would help make results from different studies and models more directly comparable and therefore a well-established methodology for incorporating weather distributions and long term climatic trends should be developed through a stakeholder process.

While databases compiled by the electric power sector by reliability organizations such as NERC currently compile outage and availability data for power plants on the system, this data is typically not disaggregated to account for different sources of outages. Forced unit outages from weather, mechanical failures and other sources are often combined with outage driven by lack of fuel availability. In order to better understand the impact of fuel infrastructure expansion on system economics, it would be advantageous to understand what outages or decisions to switch fuels are attributable to fuel availability issues. This type of historical data would help to produce a much better basis from which to analyze systems costs and benefits with respect to proposed infrastructure expansions.

Similarly, a comprehensive database of reliability and availability for fuel infrastructure in including natural gas pipelines and fuel delivery systems would greatly inform future discussions on this topic.

Finally, a periodic review of regional infrastructure needs in the Eastern Interconnection would help to track developments and trends across the region. To the extent that developments in the extraction of unconventional gas has fundamentally transformed the fuel supply outlook in the U.S. over the past five years, it seems likely that natural gas and electric power infrastructure need projections will continue to evolve as unforeseen technological, economic or political factors come into play. EISPC is in a unique position to develop a periodic review of regional fuel infrastructure needs in cooperation with fuel suppliers and consumers.

As indicated in earlier sections, the resource adequacy planning is the first step in the development of a structured market design. Therefore, if the natural gas dependency is incorporated into the resource adequacy planning and market designs, the capacity markets will start to price the value of firm fuel supply. Generators will be able to reflect their cost of firm fuel supply to the market because resource adequacy requirements would create demand for such capability.

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9 Appendices

Appendix A: ICF's Gas Market Model® (GMM) and Regional

ICF's *Gas Market Model® (GMM)* is an internationally recognized modeling and market analysis system for the North American gas market. The GMM® was developed by Energy and Environmental Analysis, Inc. (EEA), now a wholly owned business unit within ICF International, in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. For example, much of the initial work with the model in 1996–97 focused on assessing the impact of the Alliance pipeline completed in 2000. The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance? If not, when will it support Alliance?
- Will supply be adequate to fill Alliance? If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, GMM® has been used to complete strategic planning studies for many private sector companies. The different studies include:

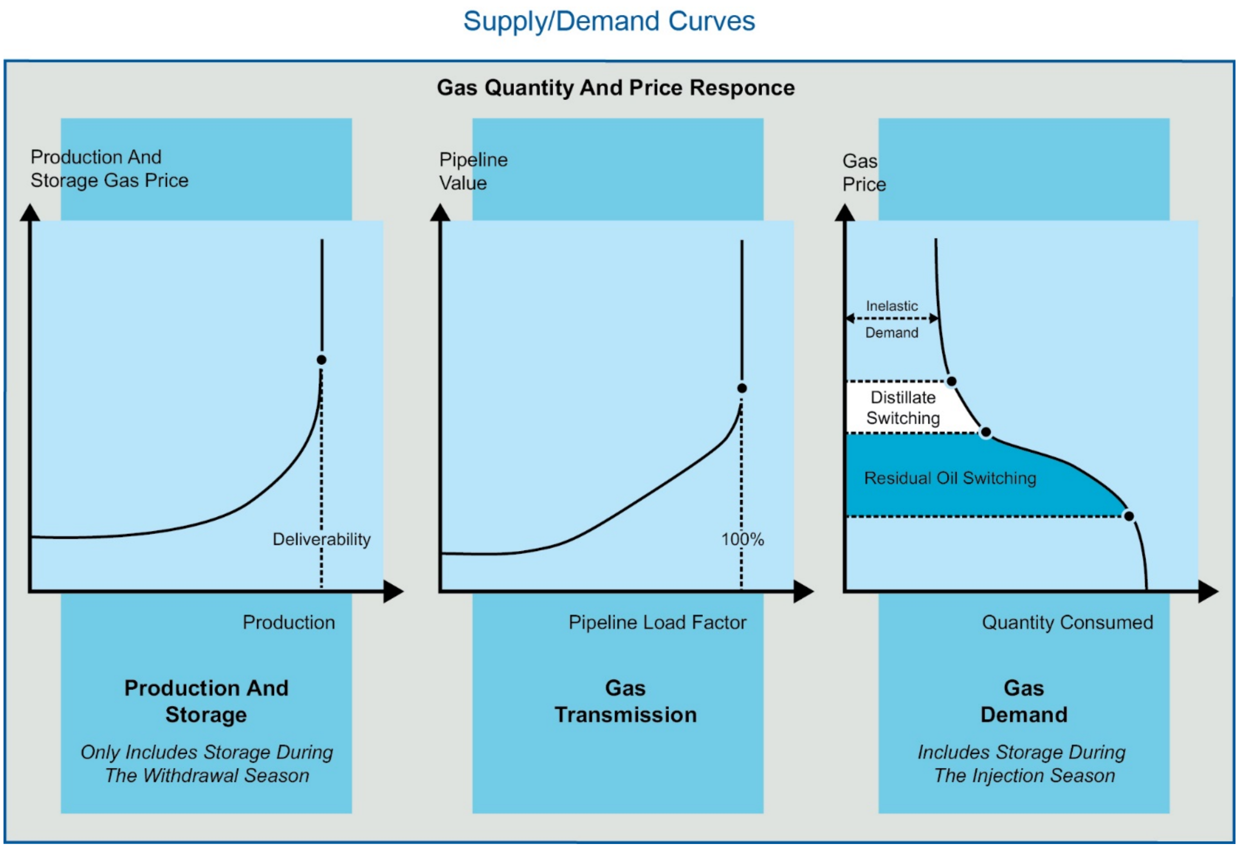
- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including INGAA, which has relied on the GMM® for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003.

GMM® is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (see exhibit below). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

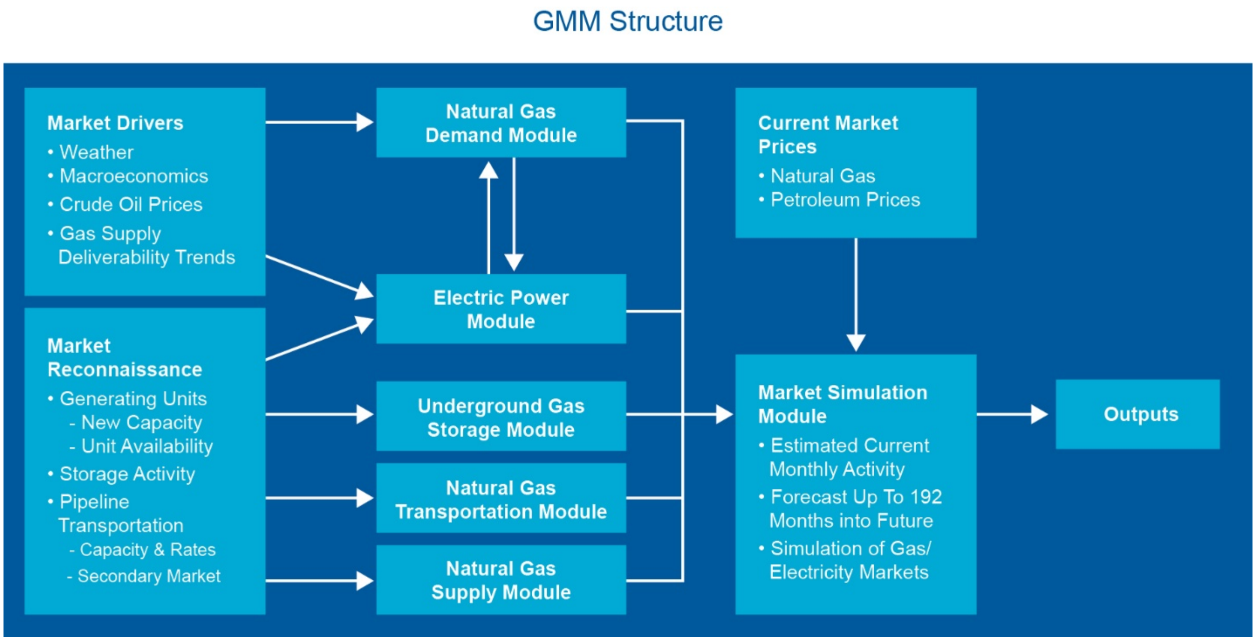
Exhibit 9-1: Supply/Demand Curves



Source: ICF.

There are nine different components of GMM®, as shown in the exhibit below. The user specifies input for the model in the “drivers” spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF’s market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important for maintaining model credibility and confidence of results.

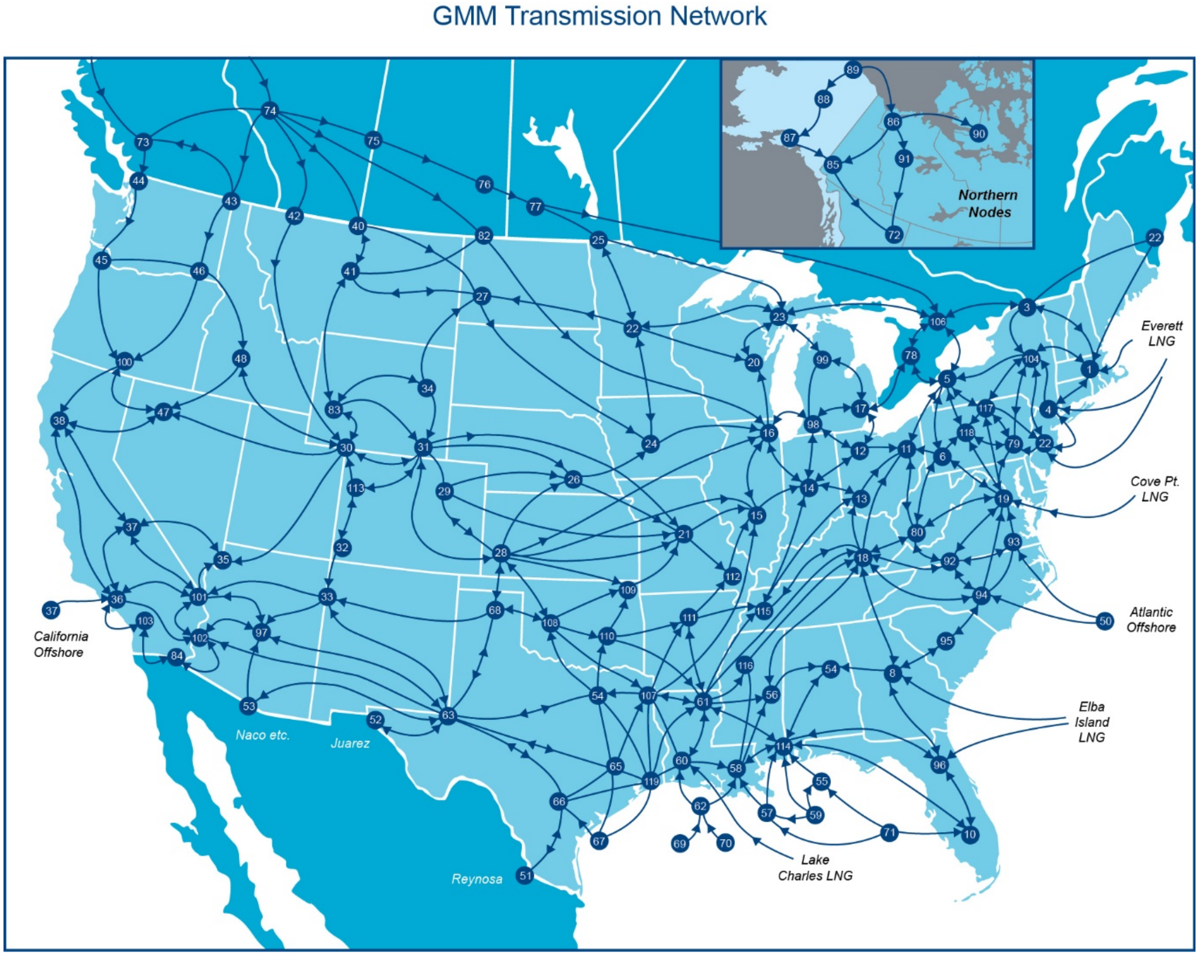
Exhibit 9-2: GMM® Structure



Source: ICF.

The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in the exhibit below. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The Hydrocarbon Supply Model (HSM) may be integrated with the GMM® to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

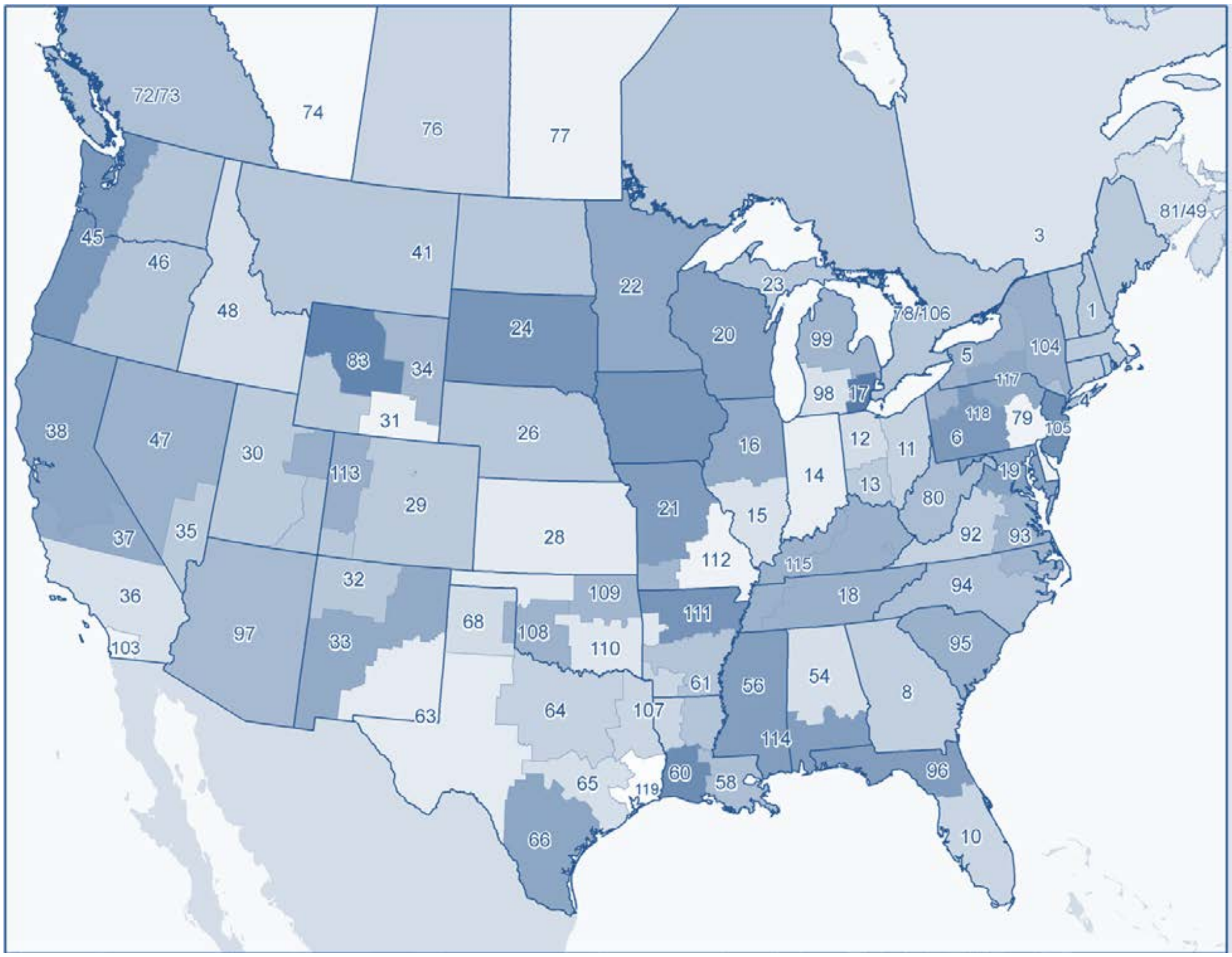
Exhibit 9-3: GMM® Transmission Network



Source: ICF GMM®.

The map below shows GMM®-designated node regions, followed by a description of each node number.

Exhibit 9-4: U.S. and Canadian GMM® Demand Node Map



Source: ICF GMM®.

Exhibit 9-5: U.S. and Canadian GMM® Demand Node Legend

Node Number	Name	EIA Region	Census Region
1	New England	Northeast	NENG
5	Niagara	Northeast	MATL
118	Leidy	Northeast	MATL
104	Eastern New York	Northeast	MATL
4	New York City	Northeast	MATL
105	New Jersey	Northeast	MATL
117	Northeast PA	Northeast	MATL
79	Philadelphia	Northeast	MATL
6	Southwest PA	Northeast	MATL
19	MD/DC/Northern VA	Northeast	SATL
92	Southwest VA	Northeast	SATL
93	Southeast VA	Northeast	SATL
80	West Virginia	Northeast	SATL
94	North Carolina	Southeast	SATL
95	South Carolina	Southeast	SATL
8	Georgia	Southeast	SATL
96	North Florida	Southeast	SATL
10	South Florida	Southeast	SATL
18	East KY/TN	Southeast	ESC
54	North Alabama	Southeast	ESC
56	North Mississippi	Southeast	ESC
114	South MS/AL	Southeast	ESC
115	West KY/TN	Southeast	ESC
11	East Ohio	Midwest	ENC

Node Number	Name	EIA Region	Census Region
12	Maumee/Defiance	Midwest	ENC
13	Lebanon	Midwest	ENC
14	Indiana	Midwest	ENC
15	South Illinois	Midwest	ENC
16	North Illinois	Midwest	ENC
17	Southeast Michigan	Midwest	ENC
20	Wisconsin	Midwest	ENC
23	Crystal Falls	Midwest	ENC
98	Southwest Michigan	Midwest	ENC
99	Northern Michigan	Midwest	ENC
22	Minnesota	Midwest	WNC
21	Northern Missouri	Central	WNC
24	Ventura	Central	WNC
26	Nebraska	Central	WNC
28	Kansas	Central	WNC
112	Southeast Missouri	Central	WNC
58	Eastern Louisiana Hub	Southwest	WSC
60	Henry Hub	Southwest	WSC
61	North Louisiana Hub	Southwest	WSC
108	Southwest Oklahoma	Southwest	WSC
109	Northeast Oklahoma	Southwest	WSC
110	Southeastern Oklahoma	Southwest	WSC
111	Northern Arkansas	Southwest	WSC

Source: ICF GMM®.

Appendix B: Regional Load Factor Metrics

The following section includes daily load curves for nodes within the Eastern Interconnection, and is organized by EIA region.

Exhibit 9-6: Winter Gas Consumption Swing Summary for 2011, 2020, and 2030 (MMcfd)

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing
Northeast	New England	214	245	145	207	276	156	284	316	177
Northeast	Niagara	176	209	84	224	264	110	259	283	127
Northeast	Leidy	8	16	8	14	18	9	15	19	9
Northeast	Eastern New York	41	42	25	57	67	37	76	89	50
Northeast	New York City	162	181	109	207	223	131	234	257	145
Northeast	New Jersey	221	238	118	305	332	171	350	362	194
Northeast	Northeast PA	33	34	17	41	42	21	42	45	22
Northeast	Philadelphia	54	80	46	118	191	96	106	164	95
Northeast	Southwest PA	58	97	50	96	116	61	88	122	65
Northeast	MD/DC/Northern VA	108	134	62	177	197	83	205	223	95
Northeast	Southwest VA	12	23	10	26	30	14	31	36	18
Northeast	Southeast VA	27	34	16	50	52	26	60	62	32
Northeast	West Virginia	37	43	19	57	57	24	62	62	27
Southeast	North Carolina	68	79	45	175	307	161	179	273	157
Southeast	South Carolina	48	59	30	82	128	62	91	155	67
Southeast	Georgia	106	194	87	335	376	150	345	385	160
Southeast	North Florida	86	96	35	45	59	36	49	64	40
Southeast	South Florida	333	341	142	304	477	298	342	537	336
Southeast	East KY/TN	56	56	32	54	82	38	74	93	42
Southeast	North Alabama	61	88	39	121	183	82	130	184	85
Southeast	North Mississippi	31	42	21	57	119	43	61	129	46
Southeast	South MS/AL	62	96	51	65	72	42	69	76	42
Southeast	West KY/TN	72	87	39	94	103	50	103	114	56
Midwest	East Ohio	125	167	86	173	219	113	148	240	128
Midwest	Maumee/Defiance	31	69	35	73	85	41	47	91	45
Midwest	Lebanon	78	94	48	99	115	59	92	131	64
Midwest	Indiana	102	109	60	137	158	90	154	187	109
Midwest	South Illinois	44	79	21	35	84	24	46	58	25
Midwest	North Illinois	363	493	211	462	489	264	492	568	285
Midwest	Southeast Michigan	164	206	83	606	606	118	733	733	131
Midwest	Wisconsin	101	133	71	228	300	159	225	263	147

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing	Peak Day Swing	Max Swing Day	Average Swing
Midwest	Crystal Falls	8	9	4	14	15	9	15	15	8
Midwest	Southwest Michigan	92	106	49	133	137	81	144	145	73
Midwest	Northern Michigan	57	69	32	134	134	75	120	120	61
Midwest	Minnesota	81	112	62	122	148	74	128	140	79
Central	Northern Missouri	36	41	19	28	49	21	30	51	21
Central	Ventura	60	92	44	108	121	53	106	112	53
Central	Nebraska	45	45	20	49	49	24	51	51	25
Central	Kansas	127	127	45	149	149	56	149	149	56
Central	Southeast Missouri	24	42	20	41	64	28	42	60	28
Southwest	Eastern Louisiana Hub	167	168	99	64	175	109	166	170	112
Southwest	Henry Hub	39	44	26	42	70	37	54	62	33
Southwest	North Louisiana Hub	58	58	29	116	130	62	115	120	60
Southwest	Southwest Oklahoma	13	14	7	13	16	8	13	15	8
Southwest	Northeast Oklahoma	55	56	28	89	91	42	88	88	41
Southwest	Southeastern Oklahoma	48	48	24	61	64	27	62	63	28
Southwest	Northern Arkansas	45	47	15	38	55	17	41	61	18

Source: ICF.

Exhibit 9-7: Winter Load Factor Summary for 2011, 2020, and 2030

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Load Factor	Lowest Load Factor	Average Load Factor	Peak Day Load Factor	Lowest Load Factor	Average Load Factor	Peak Day Load Factor	Lowest Load Factor	Average Load Factor
Northeast	New England	0.83	0.73	0.81	0.85	0.75	0.82	0.82	0.75	0.82
Northeast	Niagara	0.72	0.71	0.81	0.71	0.67	0.8	0.71	0.67	0.8
Northeast	Leidy	0.8	0.69	0.79	0.73	0.68	0.78	0.73	0.67	0.78
Northeast	Eastern New York	0.77	0.76	0.83	0.79	0.76	0.83	0.81	0.76	0.84
Northeast	New York City	0.74	0.69	0.79	0.73	0.67	0.79	0.73	0.68	0.78
Northeast	New Jersey	0.75	0.64	0.76	0.77	0.69	0.79	0.76	0.68	0.78
Northeast	Northeast PA	0.71	0.64	0.77	0.71	0.63	0.76	0.72	0.63	0.76
Northeast	Philadelphia	0.8	0.66	0.77	0.78	0.63	0.78	0.8	0.69	0.78
Northeast	Southwest PA	0.78	0.67	0.78	0.73	0.67	0.78	0.76	0.67	0.77
Northeast	MD/DC/Northern VA	0.8	0.63	0.77	0.78	0.66	0.78	0.77	0.66	0.78
Northeast	Southwest VA	0.84	0.65	0.78	0.79	0.7	0.8	0.78	0.67	0.78
Northeast	Southeast VA	0.8	0.62	0.78	0.75	0.64	0.78	0.74	0.65	0.78
Northeast	West Virginia	0.77	0.69	0.82	0.74	0.69	0.82	0.74	0.69	0.81
Southeast	North Carolina	0.74	0.68	0.78	0.75	0.37	0.69	0.74	0.39	0.7
Southeast	South Carolina	0.77	0.68	0.8	0.71	0.58	0.75	0.71	0.6	0.75
Southeast	Georgia	0.85	0.6	0.77	0.74	0.61	0.78	0.75	0.59	0.77
Southeast	North Florida	0.74	0.65	0.84	0.76	0.68	0.84	0.76	0.68	0.84
Southeast	South Florida	0.78	0.67	0.8	0.79	0.67	0.78	0.78	0.67	0.78
Southeast	East KY/TN	0.83	0.72	0.84	0.86	0.74	0.84	0.83	0.72	0.84
Southeast	North Alabama	0.78	0.63	0.82	0.8	0.62	0.8	0.78	0.63	0.81
Southeast	North Mississippi	0.8	0.54	0.79	0.84	0.55	0.76	0.84	0.57	0.76
Southeast	South MS/AL	0.79	0.67	0.81	0.79	0.68	0.82	0.76	0.68	0.82
Southeast	West KY/TN	0.79	0.73	0.81	0.79	0.7	0.81	0.79	0.7	0.81
Midwest	East Ohio	0.78	0.65	0.79	0.78	0.68	0.79	0.8	0.68	0.79
Midwest	Maumee/Defiance	0.84	0.68	0.82	0.78	0.71	0.81	0.82	0.68	0.8
Midwest	Lebanon	0.74	0.61	0.77	0.75	0.61	0.76	0.76	0.61	0.75
Midwest	Indiana	0.73	0.66	0.79	0.74	0.67	0.79	0.74	0.68	0.78
Midwest	South Illinois	0.79	0.68	0.81	0.83	0.69	0.8	0.77	0.68	0.8
Midwest	North Illinois	0.76	0.65	0.8	0.76	0.63	0.79	0.76	0.64	0.79
Midwest	Southeast Michigan	0.74	0.56	0.78	0.42	0.2	0.76	0.4	0.18	0.76
Midwest	Wisconsin	0.8	0.71	0.8	0.82	0.49	0.76	0.81	0.55	0.77
Midwest	Crystal Falls	0.78	0.69	0.79	0.83	0.54	0.78	0.82	0.64	0.79
Midwest	Southwest Michigan	0.78	0.68	0.8	0.79	0.65	0.79	0.77	0.69	0.8
Midwest	Northern Michigan	0.77	0.7	0.79	0.78	0.52	0.78	0.77	0.6	0.79
Midwest	Minnesota	0.84	0.54	0.79	0.81	0.45	0.79	0.81	0.58	0.8

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Load Factor	Lowest Load Factor	Average Load Factor	Peak Day Load Factor	Lowest Load Factor	Average Load Factor	Peak Day Load Factor	Lowest Load Factor	Average Load Factor
Central	Northern Missouri	0.8	0.72	0.83	0.84	0.65	0.78	0.84	0.66	0.78
Central	Ventura	0.85	0.46	0.78	0.83	0.47	0.79	0.82	0.63	0.81
Central	Nebraska	0.77	0.7	0.8	0.81	0.69	0.8	0.81	0.72	0.81
Central	Kansas	0.84	0.69	0.84	0.83	0.71	0.84	0.83	0.71	0.83
Central	Southeast Missouri	0.86	0.69	0.8	0.84	0.73	0.83	0.84	0.75	0.83
Southwest	Eastern Louisiana Hub	0.85	0.85	0.9	0.91	0.83	0.89	0.84	0.84	0.89
Southwest	Henry Hub	0.85	0.81	0.89	0.87	0.78	0.88	0.82	0.78	0.88
Southwest	North Louisiana Hub	0.82	0.76	0.87	0.78	0.71	0.84	0.76	0.72	0.84
Southwest	Southwest Oklahoma	0.79	0.66	0.79	0.8	0.63	0.78	0.8	0.63	0.78
Southwest	Northeast Oklahoma	0.78	0.72	0.83	0.78	0.73	0.83	0.78	0.73	0.82
Southwest	Southeastern Oklahoma	0.78	0.68	0.8	0.78	0.66	0.8	0.79	0.68	0.79
Southwest	Northern Arkansas	0.82	0.69	0.83	0.85	0.67	0.82	0.84	0.69	0.81

Source: ICF.

Exhibit 9-8: Winter Hourly Swing to Total Gas Consumption Ratio Summary for 2011, 2020, and 2030

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio	Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio	Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio
Northeast	New England	9.0%	8.8%	5.6%	8.0%	8.3%	5.4%	8.0%	8.3%	5.4%
Northeast	Niagara	9.0%	9.1%	5.5%	9.0%	9.1%	5.8%	9.0%	9.0%	5.8%
Northeast	Leidy	10.0%	9.8%	6.0%	9.0%	9.1%	6.2%	10.0%	9.8%	6.2%
Northeast	Eastern New York	9.0%	9.0%	5.8%	9.0%	8.8%	5.9%	9.0%	8.9%	5.9%
Northeast	New York City	9.0%	8.6%	5.9%	9.0%	8.8%	5.8%	8.0%	8.2%	5.9%
Northeast	New Jersey	10.0%	10.5%	5.9%	8.0%	8.3%	5.3%	8.0%	8.0%	5.5%
Northeast	Northeast PA	8.0%	8.0%	5.4%	8.0%	8.1%	5.6%	8.0%	8.3%	5.6%
Northeast	Philadelphia	9.0%	8.5%	5.6%	13.0%	12.7%	6.8%	11.0%	10.9%	6.8%
Northeast	Southwest PA	9.0%	8.7%	5.5%	9.0%	9.0%	5.8%	9.0%	9.0%	5.9%
Northeast	MD/DC/Northern VA	9.0%	9.4%	5.7%	9.0%	8.7%	5.5%	9.0%	8.8%	5.6%
Northeast	Southwest VA	9.0%	9.0%	5.7%	11.0%	11.1%	5.9%	12.0%	12.5%	6.3%
Northeast	Southeast VA	10.0%	10.3%	5.5%	11.0%	11.3%	6.0%	12.0%	12.2%	6.3%
Northeast	West Virginia	10.0%	9.7%	4.9%	8.0%	8.3%	5.1%	10.0%	9.7%	5.3%
Southeast	North Carolina	9.0%	9.3%	5.7%	33.0%	33.2%	10.4%	30.0%	29.6%	9.8%
Southeast	South Carolina	10.0%	10.0%	5.5%	14.0%	14.3%	7.4%	13.0%	13.3%	7.6%
Southeast	Georgia	16.0%	15.6%	6.7%	13.0%	13.2%	6.0%	14.0%	13.5%	6.1%
Southeast	North Florida	9.0%	9.1%	5.8%	8.0%	8.2%	5.9%	9.0%	8.6%	5.9%
Southeast	South Florida	13.0%	13.4%	8.2%	15.0%	15.3%	9.1%	15.0%	15.2%	9.2%
Southeast	East KY/TN	9.0%	9.3%	3.9%	9.0%	8.9%	3.9%	8.0%	7.6%	4.0%
Southeast	North Alabama	11.0%	10.7%	5.2%	11.0%	11.1%	5.7%	11.0%	10.7%	5.7%
Southeast	North Mississippi	16.0%	15.7%	6.2%	16.0%	16.4%	7.4%	17.0%	16.8%	7.6%
Southeast	South MS/AL	14.0%	13.8%	5.7%	10.0%	10.0%	5.1%	10.0%	10.1%	5.0%
Southeast	West KY/TN	9.0%	8.5%	4.6%	8.0%	7.8%	4.7%	8.0%	8.1%	4.8%
Midwest	East Ohio	11.0%	11.3%	5.6%	9.0%	9.3%	5.9%	10.0%	9.9%	6.1%
Midwest	Maumee/Defiance	10.0%	10.4%	5.5%	9.0%	8.5%	5.6%	10.0%	9.5%	5.7%
Midwest	Lebanon	15.0%	15.0%	6.4%	16.0%	15.6%	6.8%	14.0%	13.8%	6.8%
Midwest	Indiana	10.0%	10.0%	5.9%	12.0%	12.0%	6.4%	13.0%	12.8%	6.9%
Midwest	South Illinois	10.0%	10.4%	4.6%	10.0%	9.7%	4.8%	9.0%	8.6%	5.0%
Midwest	North Illinois	11.0%	10.6%	5.5%	13.0%	12.6%	5.8%	11.0%	11.1%	5.8%
Midwest	Southeast Michigan	9.0%	9.1%	5.3%	18.0%	18.2%	5.8%	20.0%	19.8%	6.0%
Midwest	Wisconsin	9.0%	8.8%	5.3%	22.0%	21.8%	8.3%	17.0%	17.2%	7.4%
Midwest	Crystal Falls	11.0%	10.7%	5.3%	18.0%	18.3%	7.2%	12.0%	12.0%	6.4%
Midwest	Southwest Michigan	10.0%	10.0%	5.2%	11.0%	11.4%	6.0%	8.0%	8.4%	5.5%
Midwest	Northern Michigan	10.0%	9.5%	5.4%	19.0%	19.5%	6.8%	14.0%	13.9%	6.1%

EIA Region	Sample Gas Node	2011			2020			2030		
		Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio	Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio	Peak Day Hourly Swing Ratio	Maximum Hourly Swing Ratio	Average Hourly Swing Ratio
Midwest	Minnesota	8.0%	7.9%	5.3%	9.0%	9.4%	5.2%	10.0%	9.6%	5.2%
Central	Northern Missouri	8.0%	8.2%	4.9%	14.0%	13.6%	6.1%	13.0%	13.3%	6.0%
Central	Ventura	8.0%	8.0%	4.9%	8.0%	8.0%	4.9%	6.0%	6.4%	4.7%
Central	Nebraska	7.0%	7.1%	4.6%	8.0%	8.4%	4.8%	9.0%	8.6%	4.9%
Central	Kansas	10.0%	10.2%	4.2%	9.0%	9.4%	4.6%	10.0%	9.5%	4.5%
Central	Southeast Missouri	13.0%	13.5%	5.4%	10.0%	9.7%	4.7%	8.0%	8.1%	4.7%
Southwest	Eastern Louisiana Hub	6.0%	6.3%	4.1%	6.0%	6.4%	4.2%	6.0%	6.1%	4.4%
Southwest	Henry Hub	7.0%	7.0%	4.0%	7.0%	7.3%	4.4%	7.0%	6.9%	4.4%
Southwest	North Louisiana Hub	7.0%	6.8%	4.1%	9.0%	8.9%	5.1%	9.0%	8.5%	5.0%
Southwest	Southwest Oklahoma	19.0%	18.7%	5.9%	15.0%	15.4%	6.4%	17.0%	16.5%	6.4%
Southwest	Northeast Oklahoma	9.0%	9.4%	4.6%	10.0%	9.6%	5.0%	10.0%	10.5%	5.0%
Southwest	Southeastern Oklahoma	14.0%	14.2%	5.4%	12.0%	12.0%	5.4%	12.0%	12.0%	5.4%
Southwest	Northern Arkansas	9.0%	9.4%	4.3%	9.0%	8.5%	4.5%	9.0%	8.8%	4.6%

Source: ICF.

Exhibit 9-9: Winter Average Hourly Swing to Total Gas Consumption Ratio by Sector in 2030 (%)

EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Northeast	New England	13.3%	9.9%	9.1%	12.3%
Northeast	Niagara	10.9%	14.9%	9.3%	8.2%
Northeast	Leidy	14.4%	15.0%	9.3%	25.5%
Northeast	Eastern New York	10.6%	14.9%	9.2%	6.4%
Northeast	New York City	10.6%	14.9%	9.3%	9.1%
Northeast	New Jersey	11.5%	14.5%	9.3%	6.4%
Northeast	Northeast PA	11.1%	14.9%	9.3%	8.0%
Northeast	Philadelphia	14.0%	14.5%	9.3%	13.5%
Northeast	Southwest PA	14.4%	15.0%	9.3%	19.9%
Northeast	MD/DC/Northern VA	14.3%	9.9%	9.1%	13.6%
Northeast	Southwest VA	19.9%	10.1%	9.1%	14.4%
Northeast	Southeast VA	19.9%	10.1%	5.0%	15.1%
Northeast	West Virginia	13.7%	10.2%	5.4%	14.5%
Southeast	North Carolina	21.4%	10.2%	5.0%	20.2%
Southeast	South Carolina	23.5%	9.0%	4.9%	18.5%
Southeast	Georgia	21.7%	9.9%	5.0%	9.0%
Southeast	North Florida	16.1%	8.1%	5.1%	10.0%
Southeast	South Florida	16.1%	8.1%	5.1%	10.0%
Southeast	East KY/TN	14.2%	8.6%	5.8%	17.5%
Southeast	North Alabama	22.9%	9.2%	5.4%	9.4%
Southeast	North Mississippi	22.9%	9.2%	5.4%	13.5%
Southeast	South MS/AL	22.9%	9.2%	5.4%	8.7%
Southeast	West KY/TN	13.0%	8.6%	7.5%	17.9%
Midwest	East Ohio	12.6%	15.0%	8.1%	14.3%
Midwest	Maumee/Defiance	12.6%	15.0%	7.9%	14.5%
Midwest	Lebanon	12.6%	15.0%	8.1%	14.5%
Midwest	Indiana	13.3%	15.6%	7.9%	14.4%
Midwest	South Illinois	12.7%	15.3%	7.9%	8.3%
Midwest	North Illinois	12.7%	15.3%	7.7%	14.5%
Midwest	Southeast Michigan	9.1%	15.5%	8.4%	24.2%
Midwest	Wisconsin	12.1%	15.6%	8.0%	24.4%
Midwest	Crystal Falls	9.1%	15.5%	8.0%	23.6%
Midwest	Southwest Michigan	9.1%	15.5%	8.4%	11.4%
Midwest	Northern Michigan	9.1%	15.5%	8.3%	11.4%
Midwest	Minnesota	10.7%	10.7%	7.4%	46.3%
Central	Northern Missouri	14.1%	10.7%	7.9%	8.2%

EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Central	Ventura	12.5%	10.5%	7.1%	43.2%
Central	Nebraska	14.7%	10.8%	6.9%	5.8%
Central	Kansas	15.4%	11.2%	5.3%	20.8%
Central	Southeast Missouri	14.1%	10.7%	8.1%	8.2%
Southwest	Eastern Louisiana Hub	19.4%	9.7%	5.0%	8.2%
Southwest	Henry Hub	19.4%	9.7%	4.8%	7.6%
Southwest	North Louisiana Hub	21.2%	10.9%	5.1%	8.2%
Southwest	Southwest Oklahoma	22.9%	12.4%	5.2%	8.2%
Southwest	Northeast Oklahoma	18.2%	11.2%	7.1%	7.7%
Southwest	Southeastern Oklahoma	21.2%	12.0%	5.1%	8.2%
Southwest	Northern Arkansas	21.7%	11.4%	4.9%	8.2%

Source: ICF.

Exhibit 9-10: Winter Average Hourly Load Factor by Sector in 2030

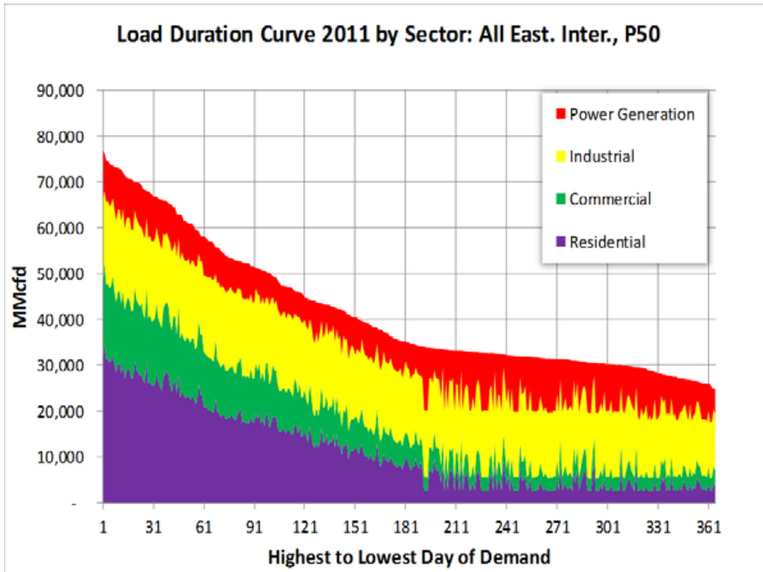
EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Northeast	New England	0.71	0.72	0.81	0.69
Northeast	Niagara	0.75	0.64	0.81	0.74
Northeast	Leidy	0.7	0.63	0.81	0.55
Northeast	Eastern New York	0.75	0.64	0.81	0.81
Northeast	New York City	0.75	0.64	0.81	0.78
Northeast	New Jersey	0.74	0.63	0.81	0.83
Northeast	Northeast PA	0.75	0.64	0.81	0.75
Northeast	Philadelphia	0.71	0.64	0.81	0.67
Northeast	Southwest PA	0.7	0.63	0.81	0.59
Northeast	MD/DC/Northern VA	0.7	0.68	0.81	0.68
Northeast	Southwest VA	0.62	0.67	0.81	0.67
Northeast	Southeast VA	0.62	0.67	0.88	0.66
Northeast	West Virginia	0.72	0.68	0.87	0.67
Southeast	North Carolina	0.59	0.67	0.88	0.58
Southeast	South Carolina	0.56	0.69	0.88	0.59
Southeast	Georgia	0.59	0.66	0.88	0.72
Southeast	North Florida	0.65	0.7	0.88	0.75
Southeast	South Florida	0.65	0.7	0.88	0.76
Southeast	East KY/TN	0.7	0.73	0.86	0.61
Southeast	North Alabama	0.55	0.73	0.87	0.72
Southeast	North Mississippi	0.55	0.73	0.87	0.66
Southeast	South MS/AL	0.55	0.73	0.87	0.73
Southeast	West KY/TN	0.72	0.73	0.84	0.61
Midwest	East Ohio	0.73	0.63	0.83	0.67
Midwest	Maumee/Defiance	0.73	0.63	0.83	0.67
Midwest	Lebanon	0.73	0.63	0.83	0.65
Midwest	Indiana	0.72	0.62	0.83	0.66
Midwest	South Illinois	0.73	0.63	0.83	0.31
Midwest	North Illinois	0.73	0.63	0.84	0.67
Midwest	Southeast Michigan	0.79	0.63	0.83	0.06
Midwest	Wisconsin	0.73	0.65	0.83	0.57
Midwest	Crystal Falls	0.79	0.63	0.83	0.58
Midwest	Southwest Michigan	0.79	0.63	0.83	0.72
Midwest	Northern Michigan	0.79	0.63	0.83	0.72
Midwest	Minnesota	0.76	0.69	0.84	0.22
Central	Northern Missouri	0.7	0.68	0.83	0.76
Central	Ventura	0.74	0.69	0.85	0.22

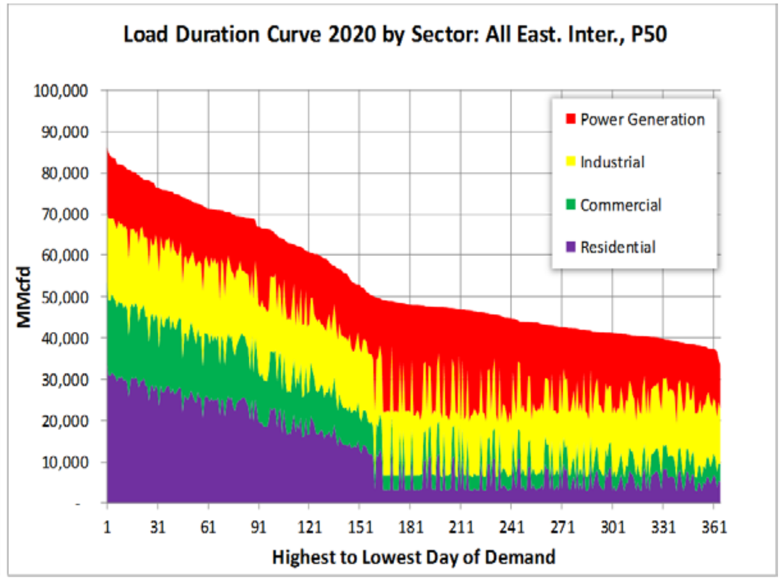
EIA Region	Sample Gas Node	2030			
		Residential Average	Commercial Average	Industrial Average	Power Average
Central	Nebraska	0.71	0.68	0.85	0.31
Central	Kansas	0.69	0.66	0.87	0.6
Central	Southeast Missouri	0.7	0.68	0.83	0.77
Southwest	Eastern Louisiana Hub	0.6	0.66	0.88	0.77
Southwest	Henry Hub	0.6	0.66	0.88	0.77
Southwest	North Louisiana Hub	0.61	0.66	0.88	0.77
Southwest	Southwest Oklahoma	0.6	0.63	0.87	0.75
Southwest	Northeast Oklahoma	0.64	0.66	0.85	0.77
Southwest	Southeastern Oklahoma	0.61	0.64	0.87	0.75
Southwest	Northern Arkansas	0.61	0.65	0.88	0.77

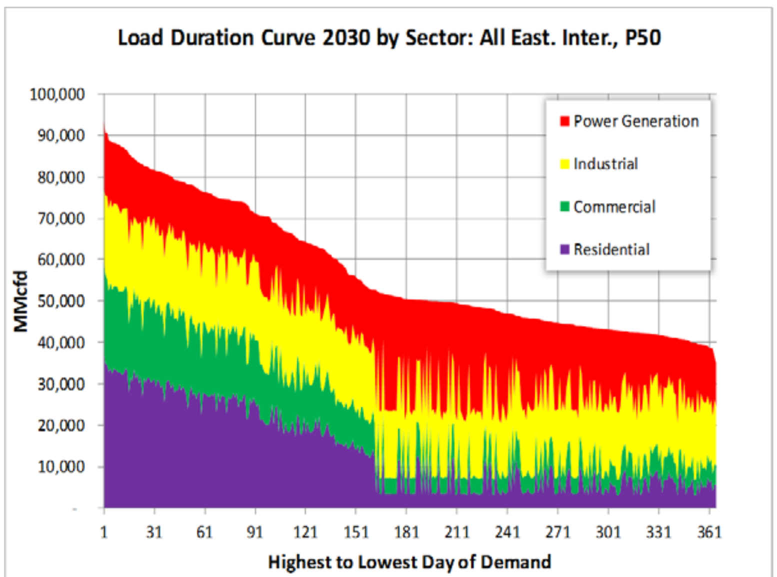
Source: ICF.

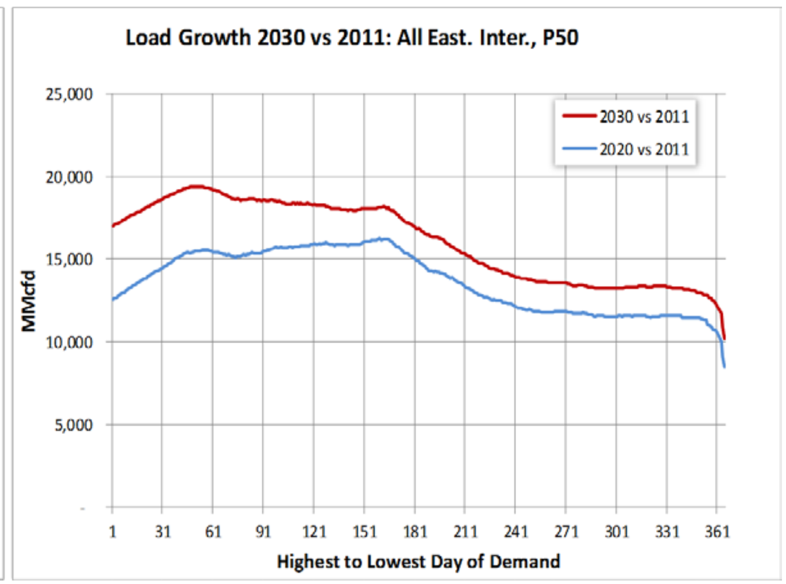
Appendix C: Regional Load Duration Curves

The following section includes load duration curves for nodes within the Eastern Interconnection, and is organized by EIA region.

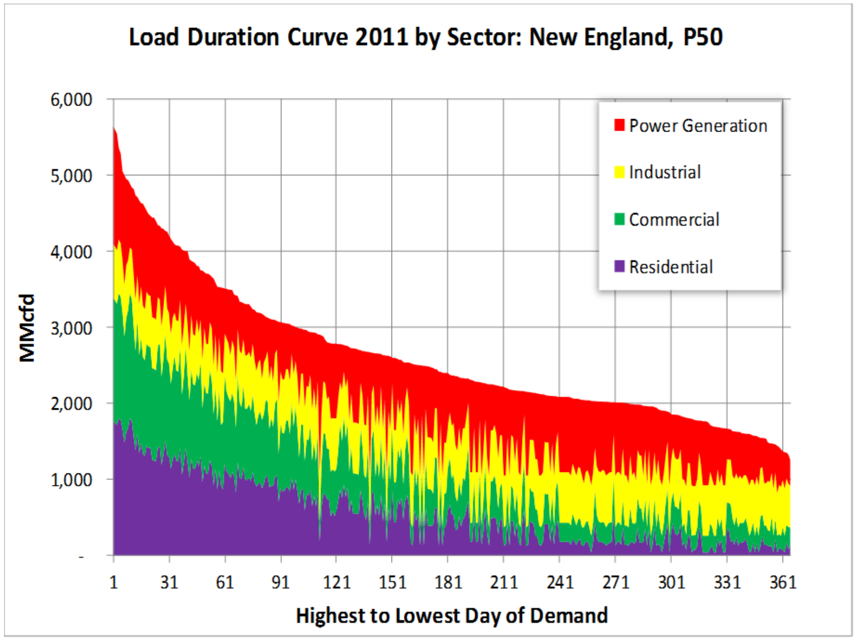

Load Duration Curve 2011 by Sector: All East. Inter., P50
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

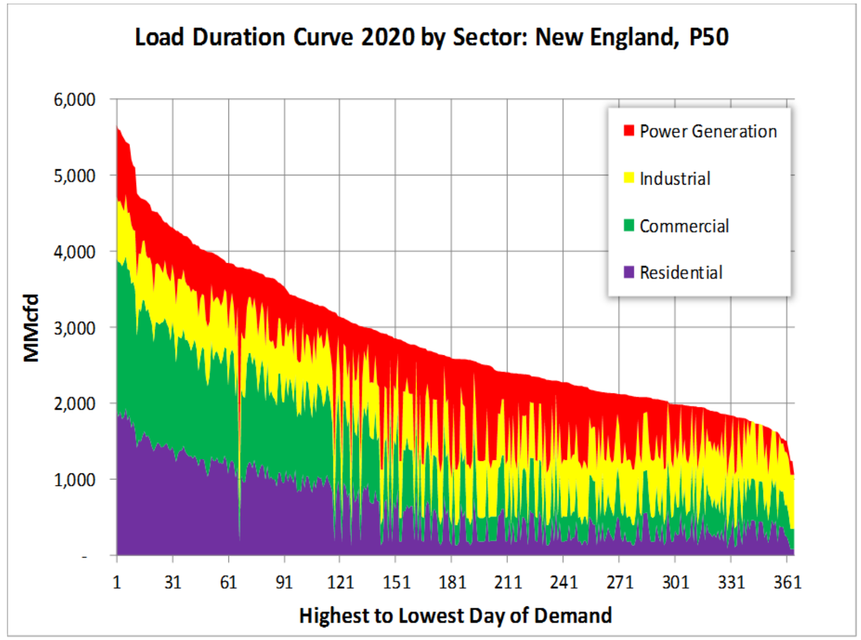

Load Duration Curve 2020 by Sector: All East. Inter., P50
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

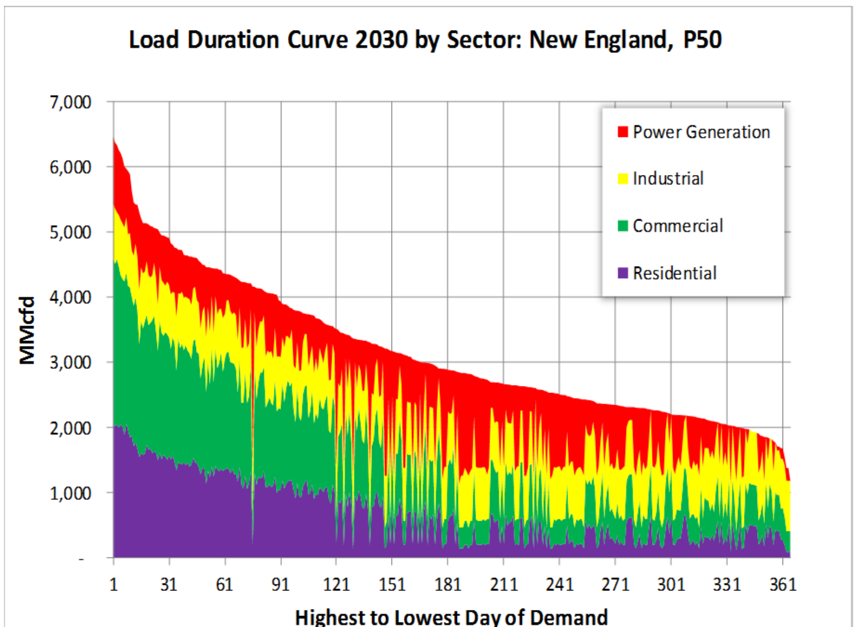

Load Duration Curve 2030 by Sector: All East. Inter., P50
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

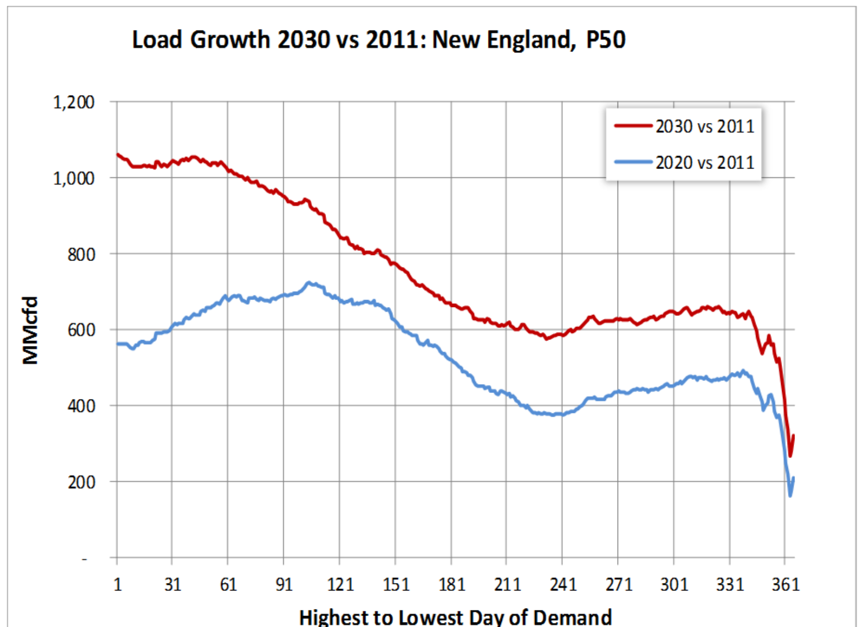

Load Growth 2030 vs 2011: All East. Inter., P50
25,000
20,000
15,000
10,000
5,000
-
MMcfd
2030 vs 2011
2020 vs 2011
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

9.1.1 Northeast

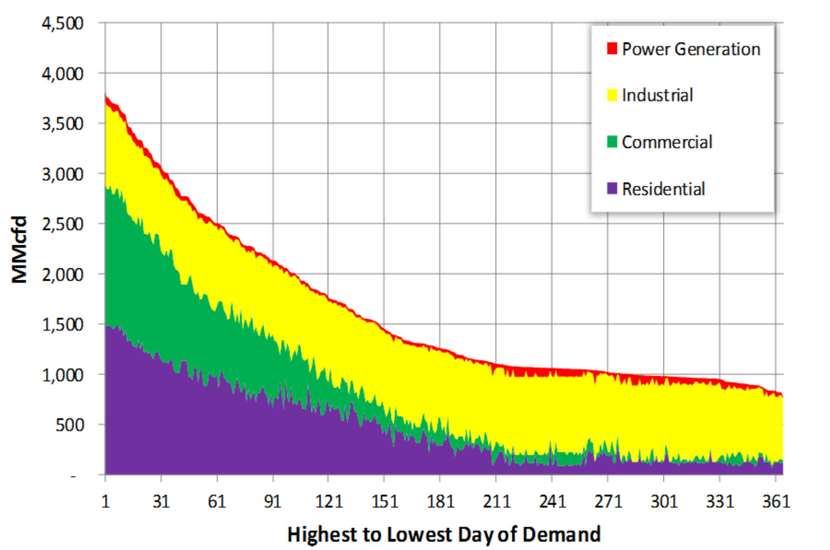

Load Duration Curve 2011 by Sector: New England, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand


Load Duration Curve 2020 by Sector: New England, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

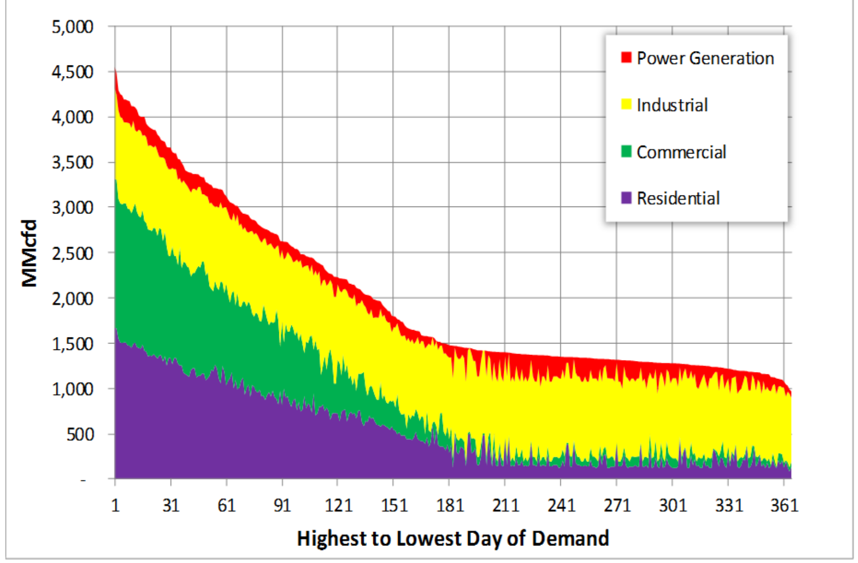

Load Duration Curve 2030 by Sector: New England, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand


Load Growth 2030 vs 2011: New England, P50
2030 vs 2011
2020 vs 2011
MMcfd
Highest to Lowest Day of Demand

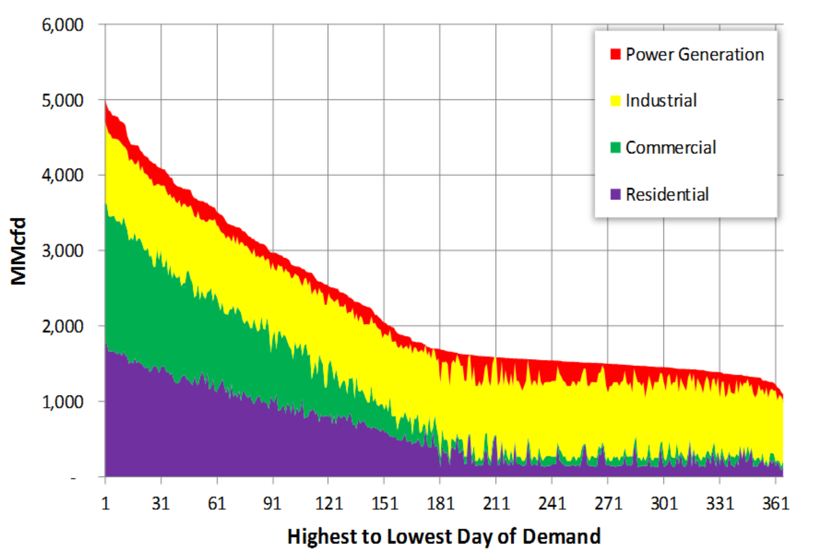
Load Duration Curve 2011 by Sector: Niagara, P50



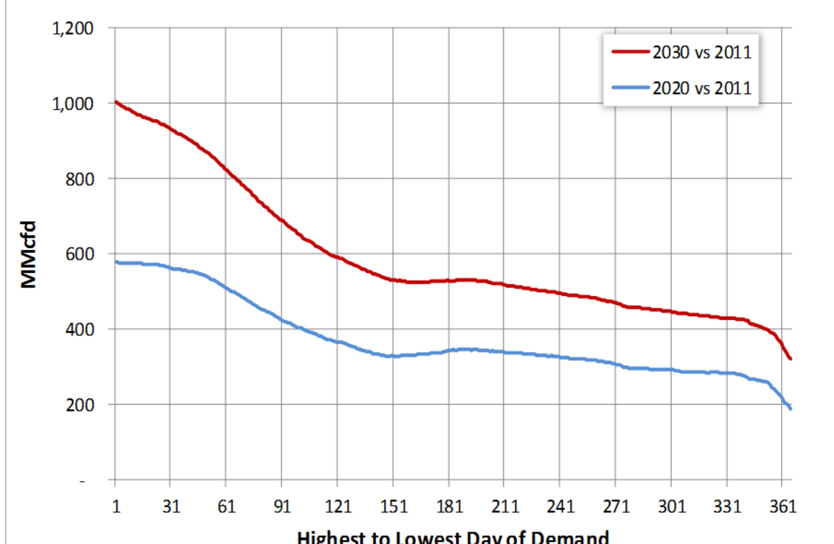
Load Duration Curve 2020 by Sector: Niagara, P50

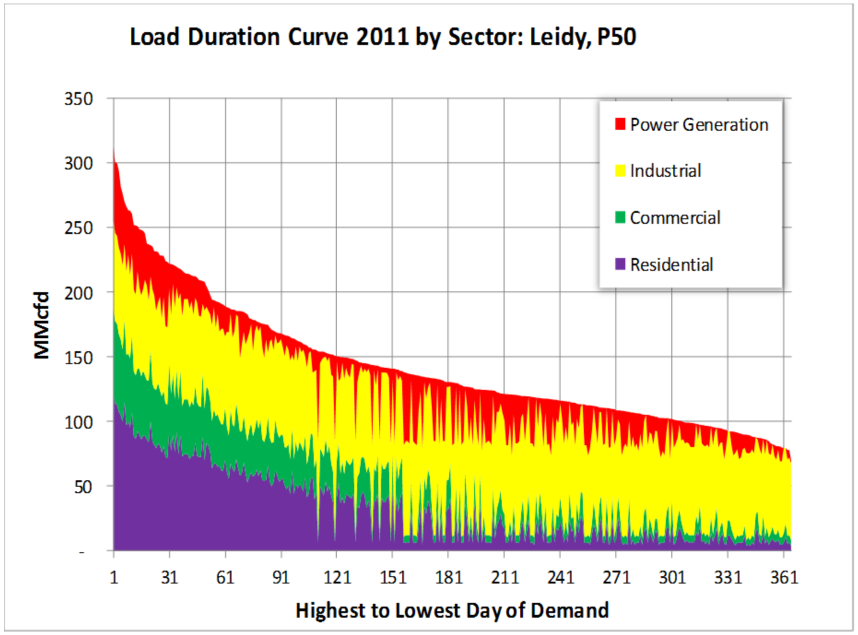


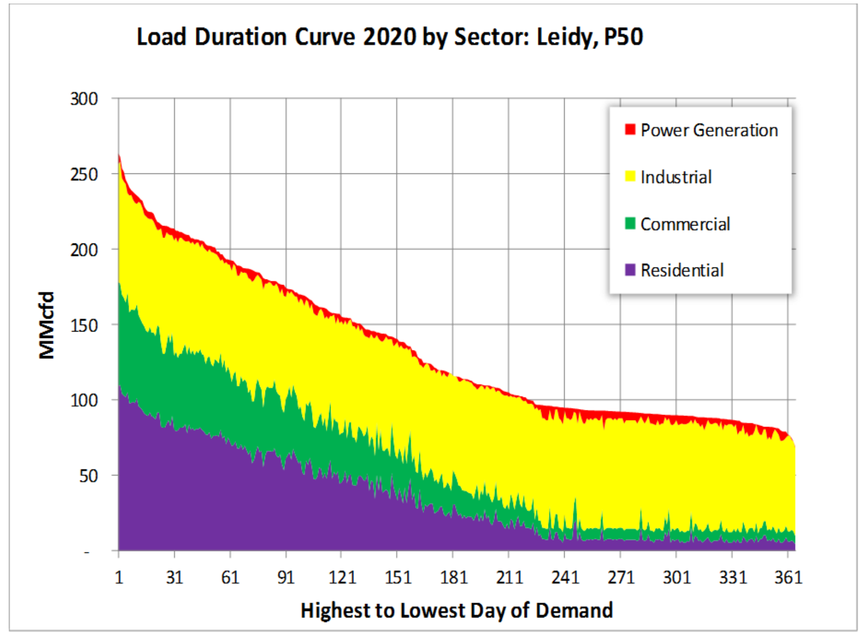
Load Duration Curve 2030 by Sector: Niagara, P50

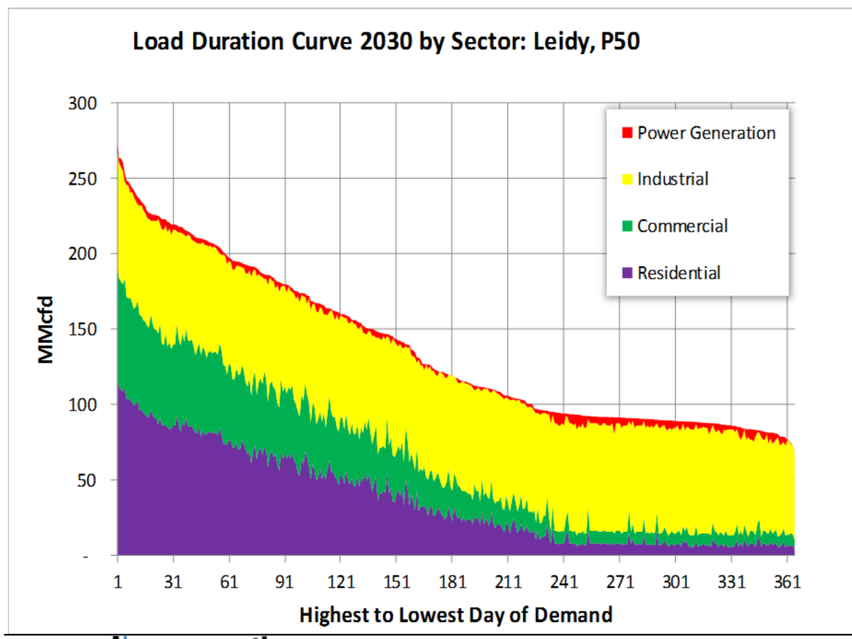


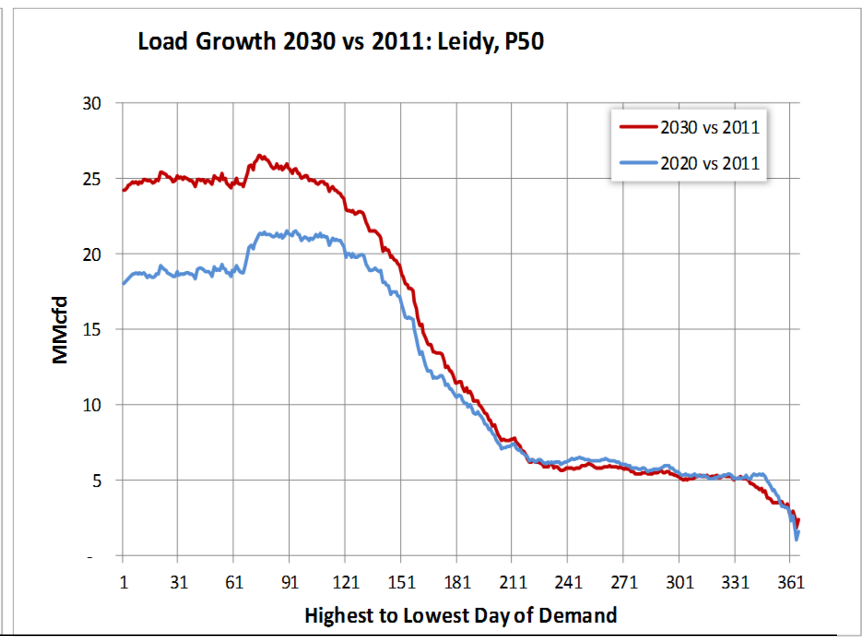
Load Growth 2030 vs 2011: Niagara, P50

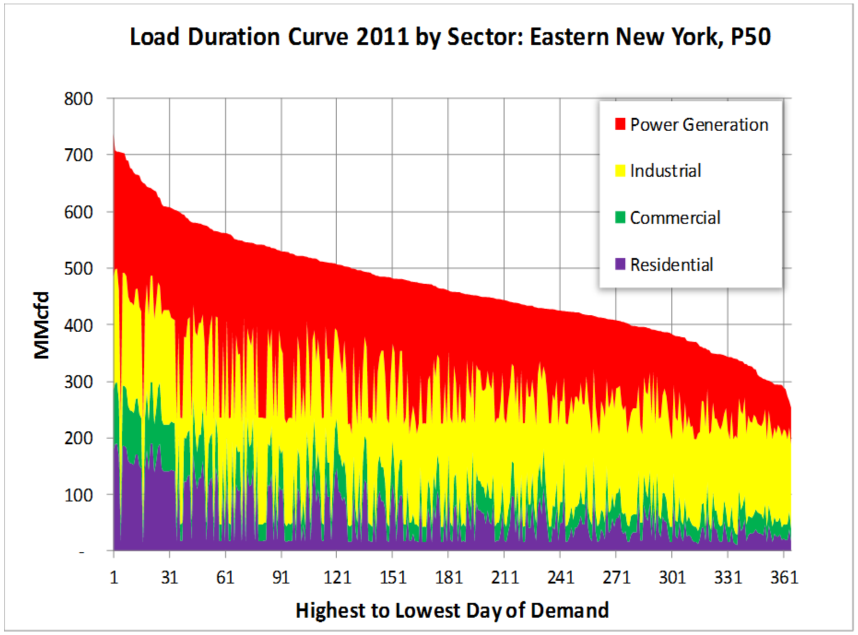


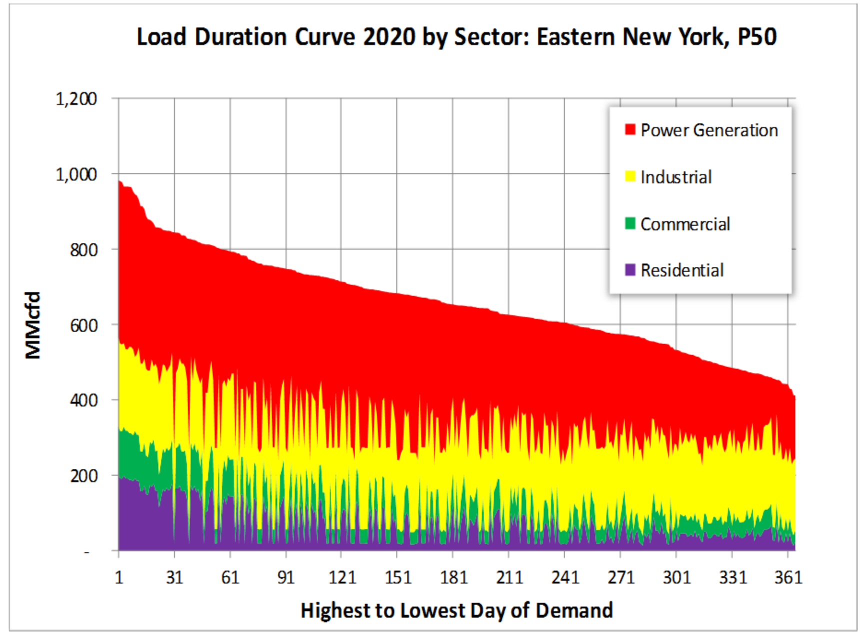

Load Duration Curve 2011 by Sector: Leidy, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
350
300
250
200
150
100
50
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

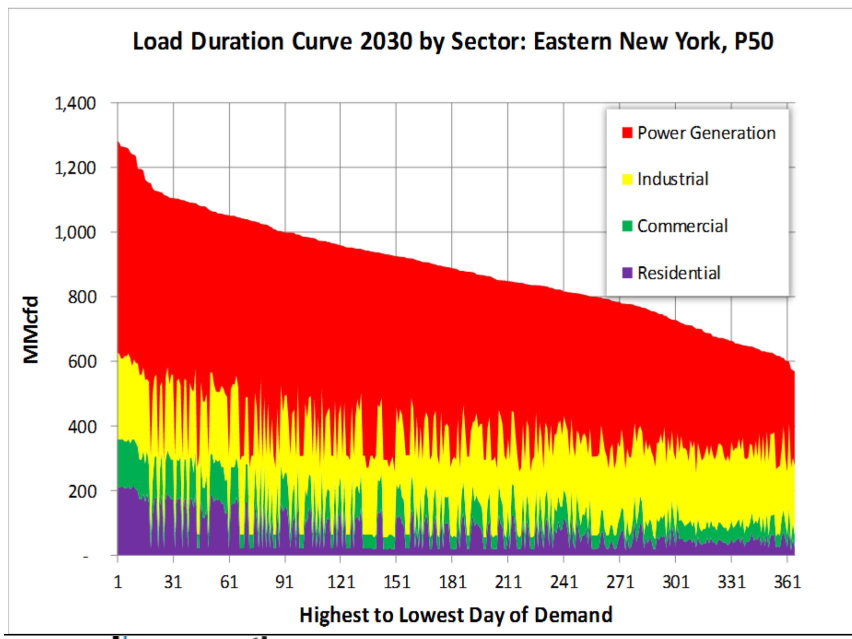

Load Duration Curve 2020 by Sector: Leidy, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
300
250
200
150
100
50
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

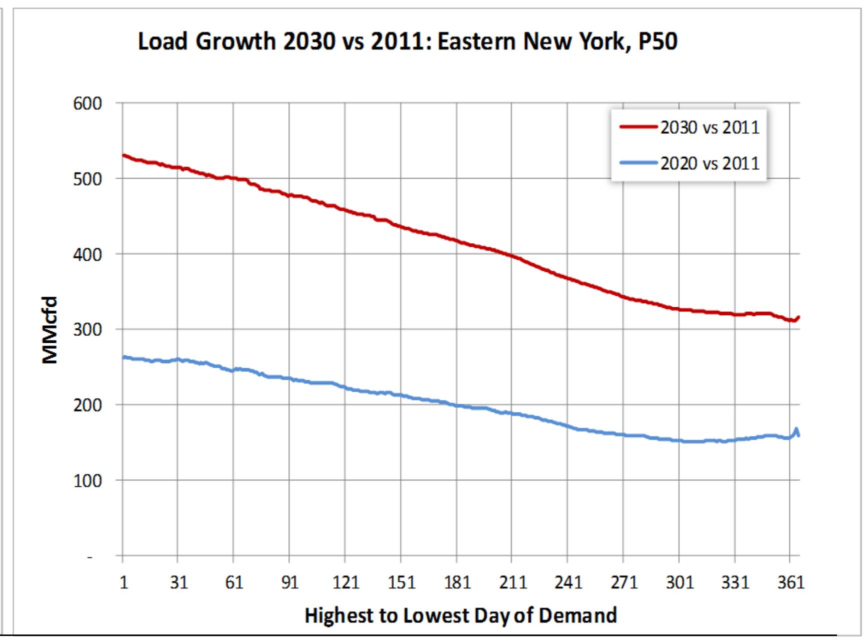

Load Duration Curve 2030 by Sector: Leidy, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
300
250
200
150
100
50
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

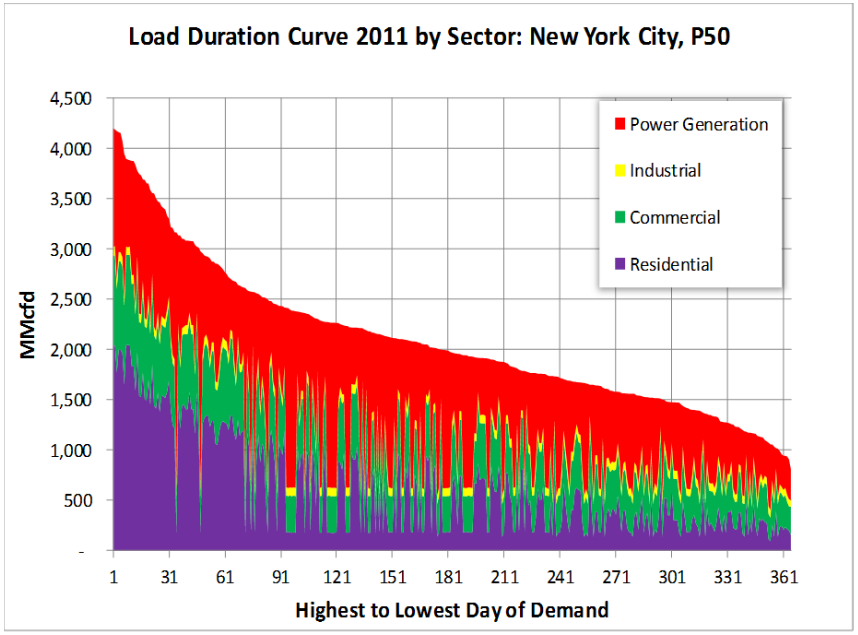

Load Growth 2030 vs 2011: Leidy, P50
2030 vs 2011
2020 vs 2011
MMcfd
30
25
20
15
10
5
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

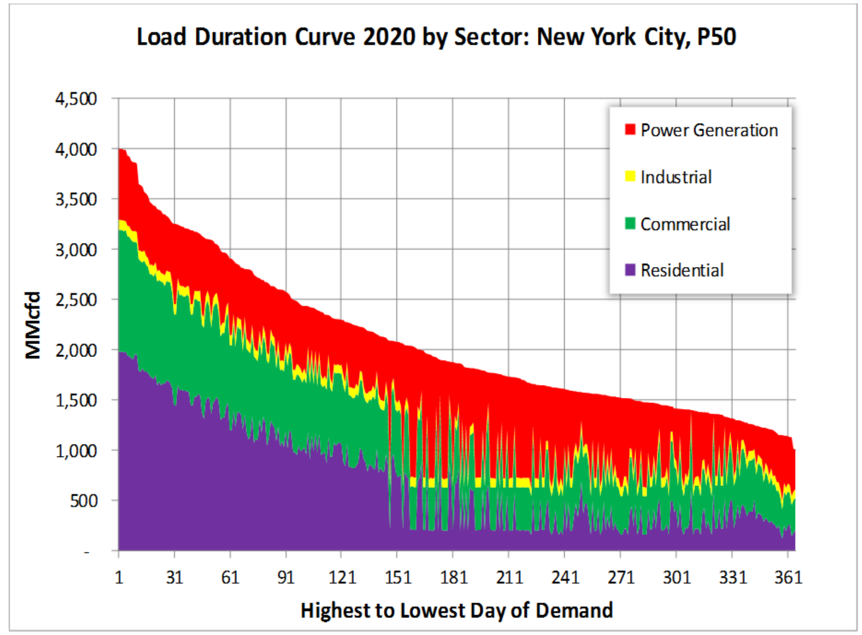

Load Duration Curve 2011 by Sector: Eastern New York, P50
800
700
600
500
400
300
200
100
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

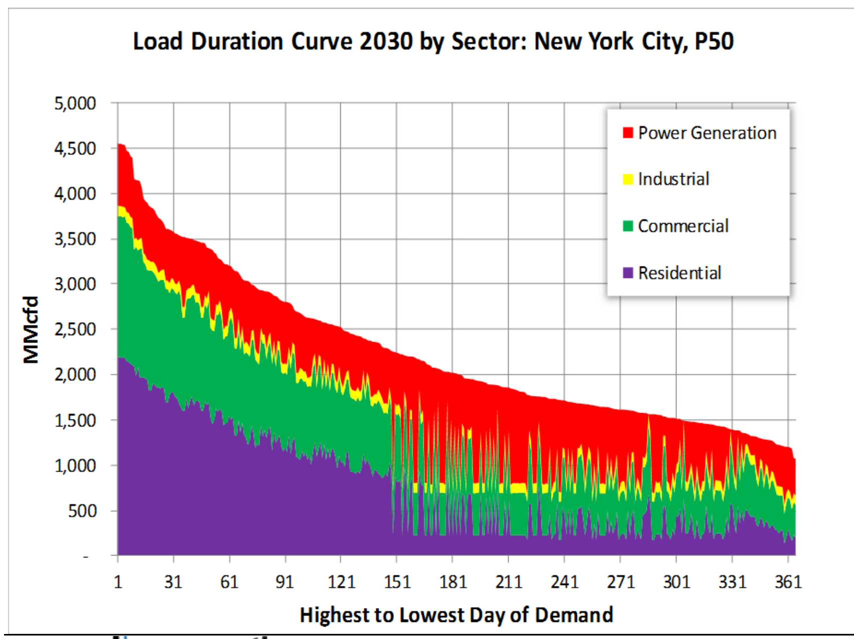

Load Duration Curve 2020 by Sector: Eastern New York, P50
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

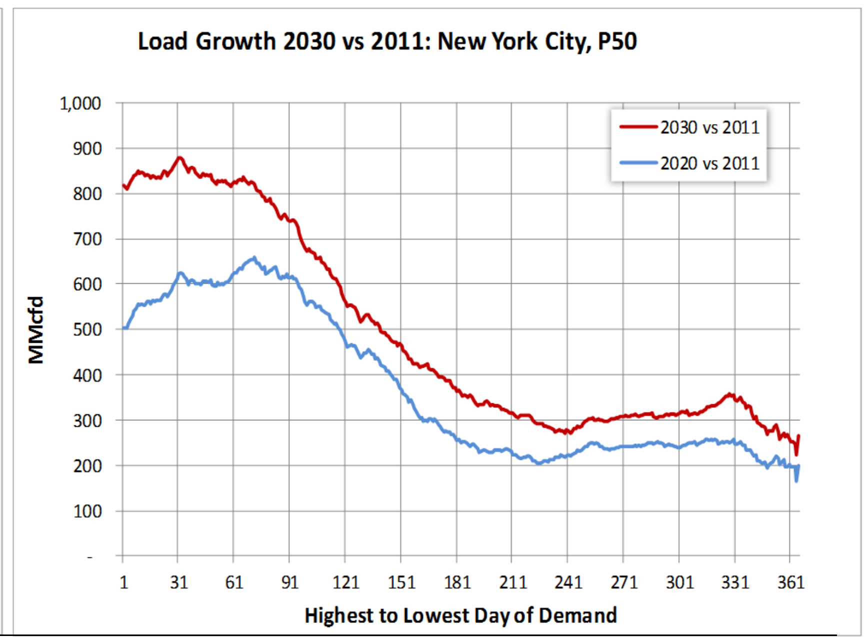

Load Duration Curve 2030 by Sector: Eastern New York, P50
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

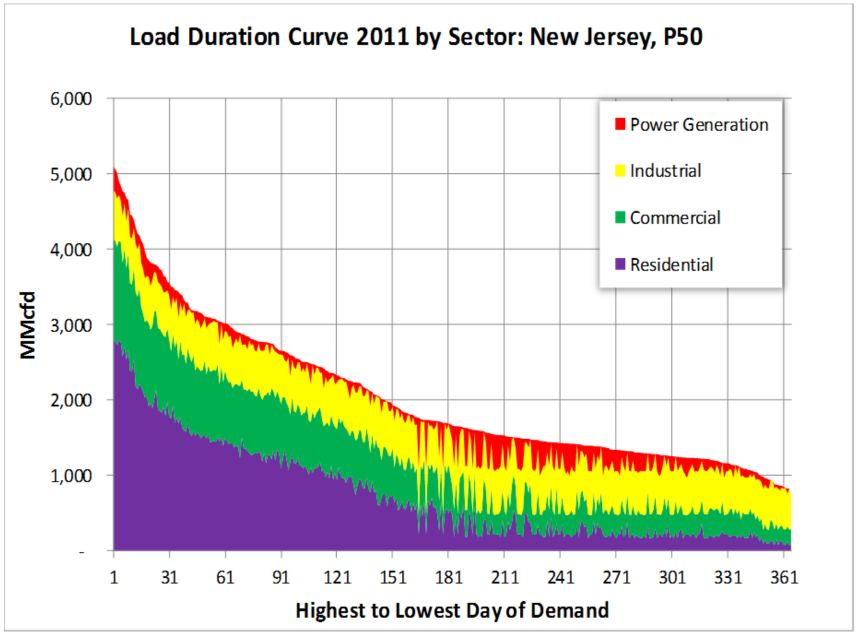

Load Growth 2030 vs 2011: Eastern New York, P50
600
500
400
300
200
100
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

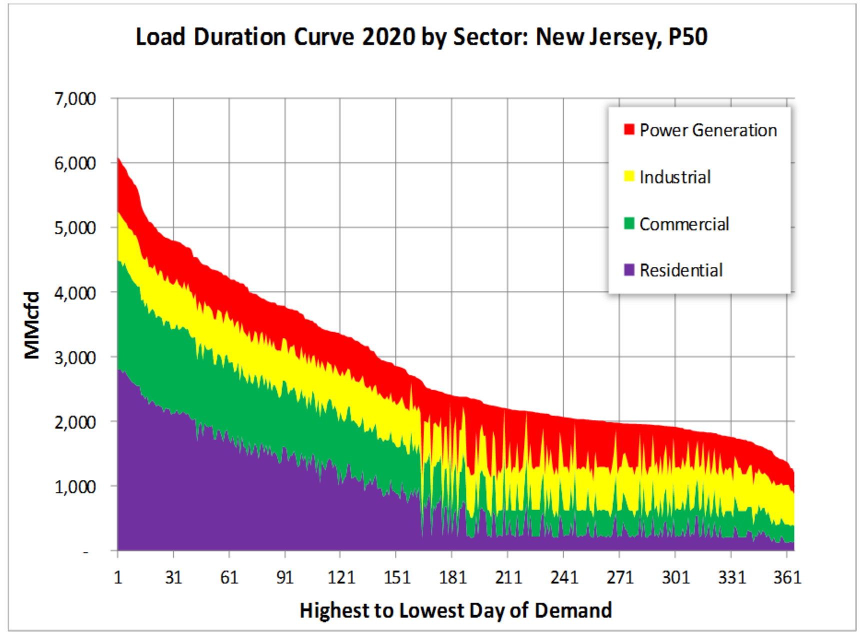

Load Duration Curve 2011 by Sector: New York City, P50
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

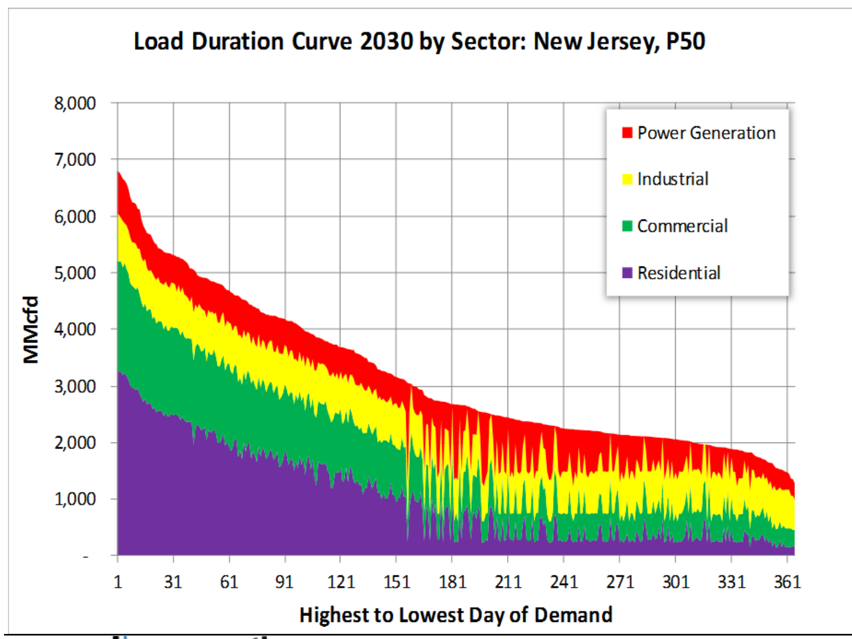

Load Duration Curve 2020 by Sector: New York City, P50
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

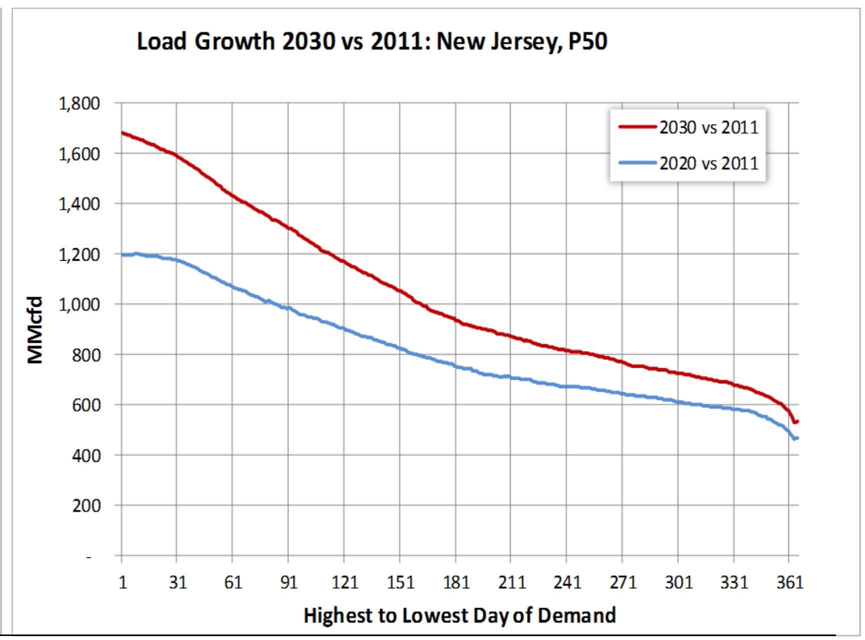

Load Duration Curve 2030 by Sector: New York City, P50
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

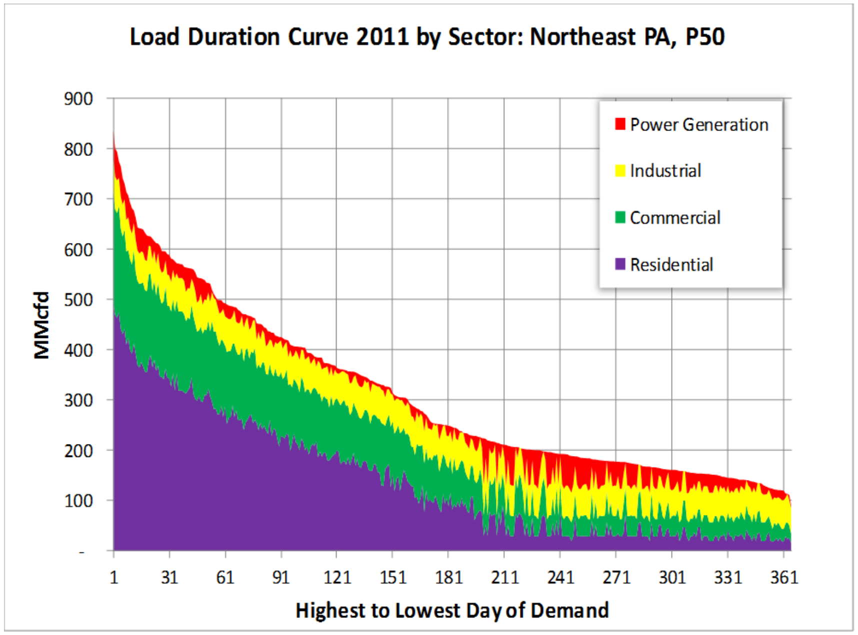

Load Growth 2030 vs 2011: New York City, P50
1,000
900
800
700
600
500
400
300
200
100
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

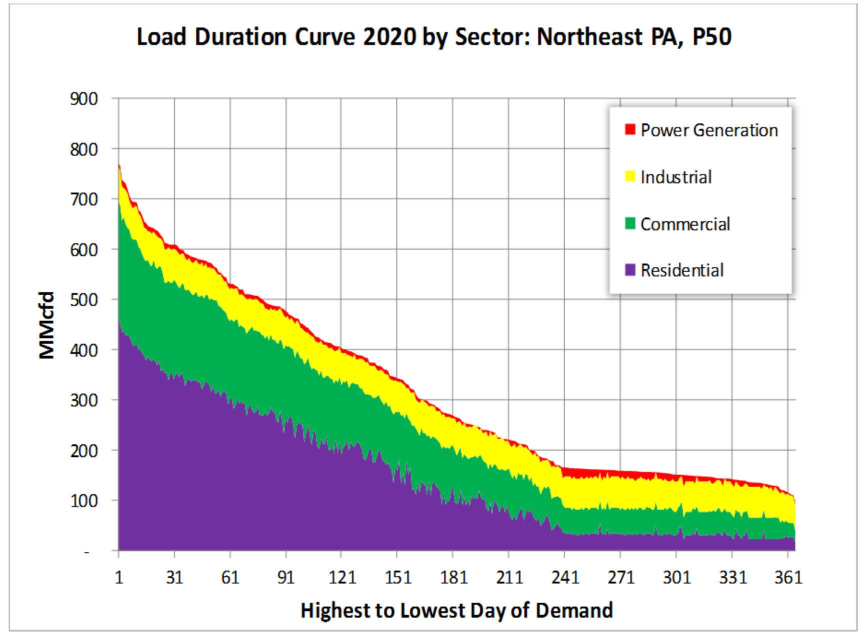

Load Duration Curve 2011 by Sector: New Jersey, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

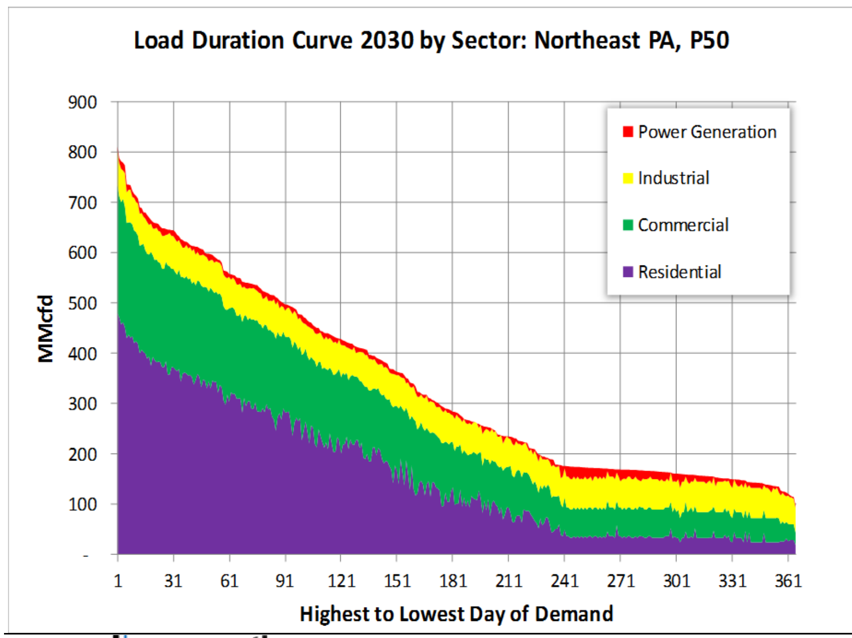

Load Duration Curve 2020 by Sector: New Jersey, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

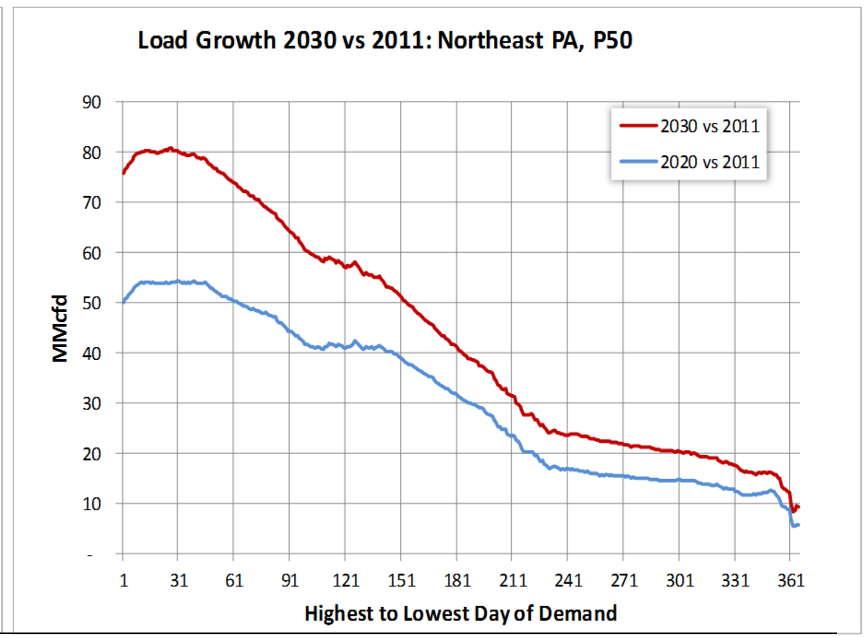

Load Duration Curve 2030 by Sector: New Jersey, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

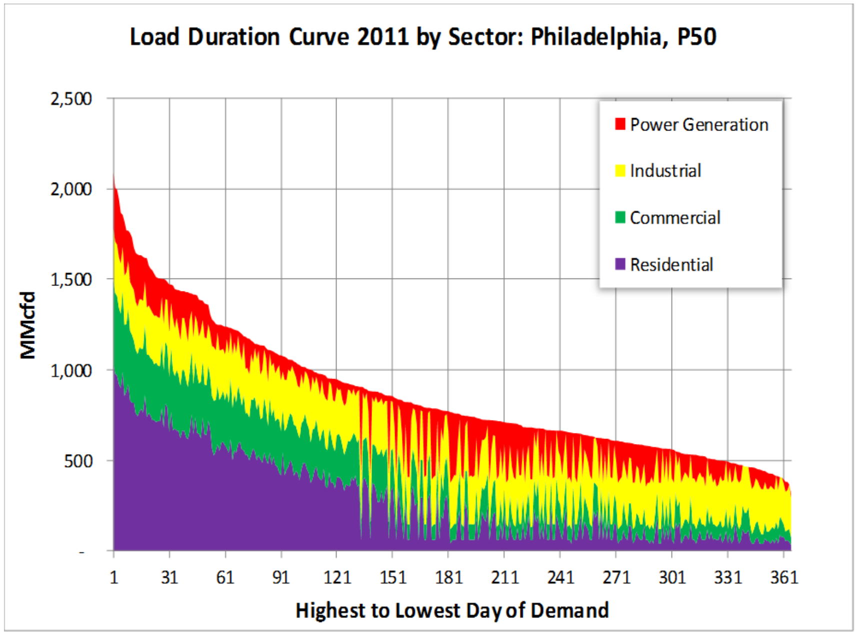

Load Growth 2030 vs 2011: New Jersey, P50
2030 vs 2011
2020 vs 2011
MMcfd
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

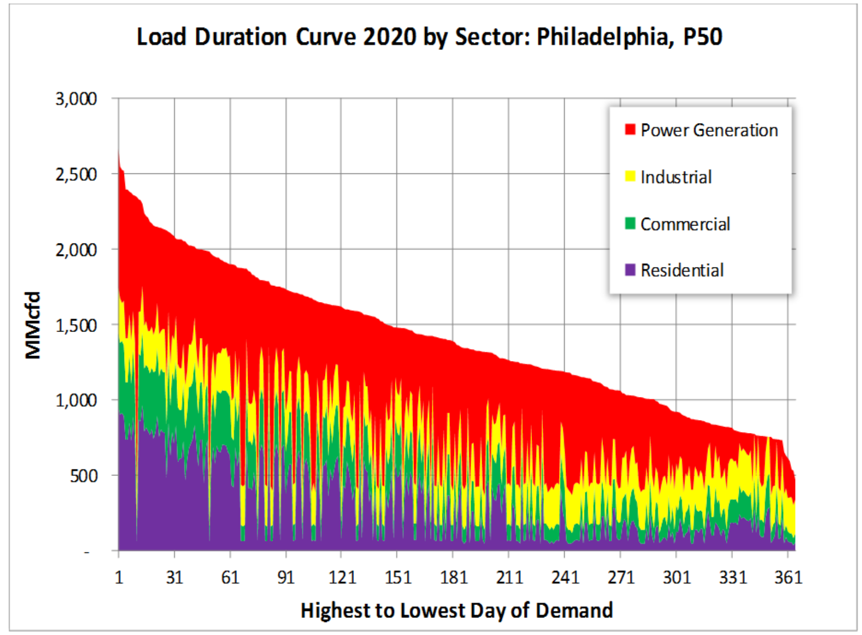

Load Duration Curve 2011 by Sector: Northeast PA, P50
MMcfd
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

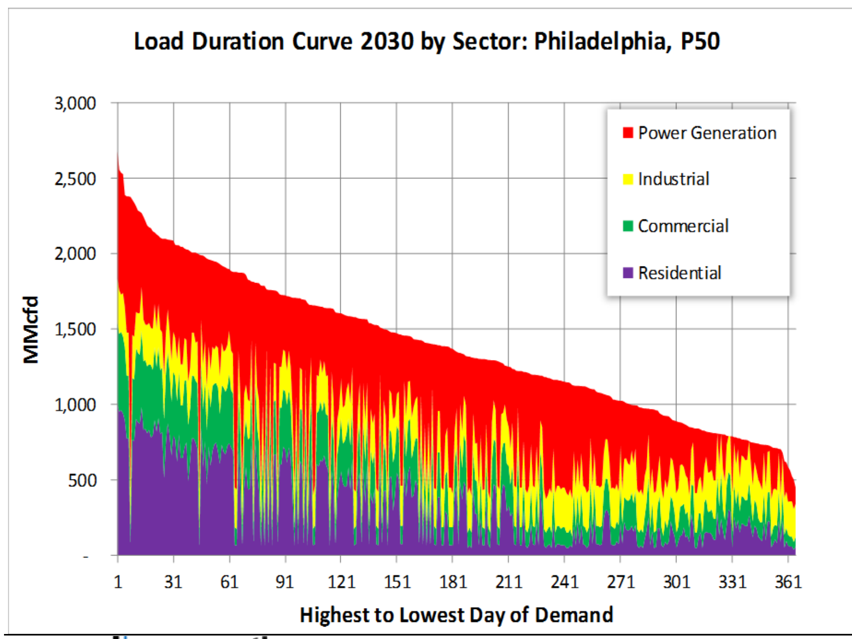

Load Duration Curve 2020 by Sector: Northeast PA, P50
MMcfd
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

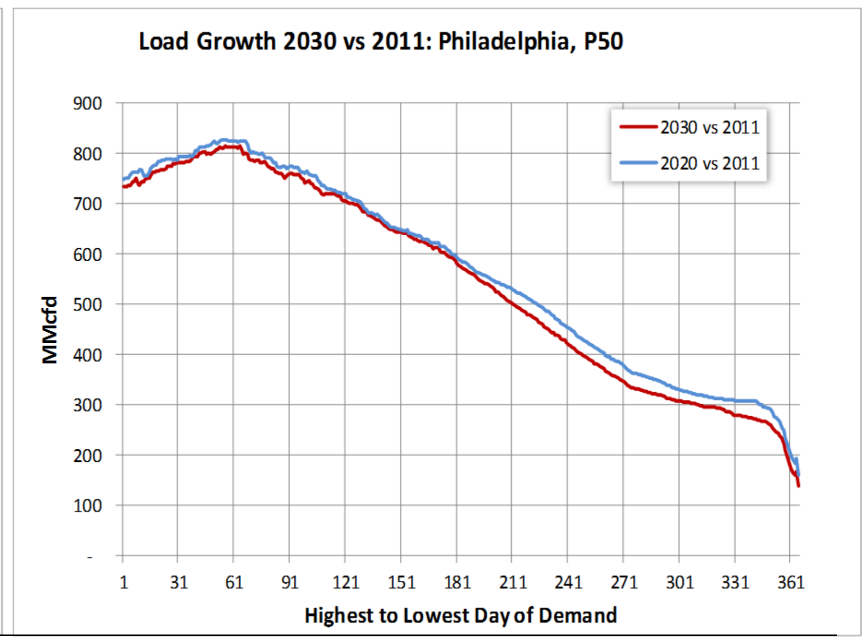

Load Duration Curve 2030 by Sector: Northeast PA, P50
MMcfd
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

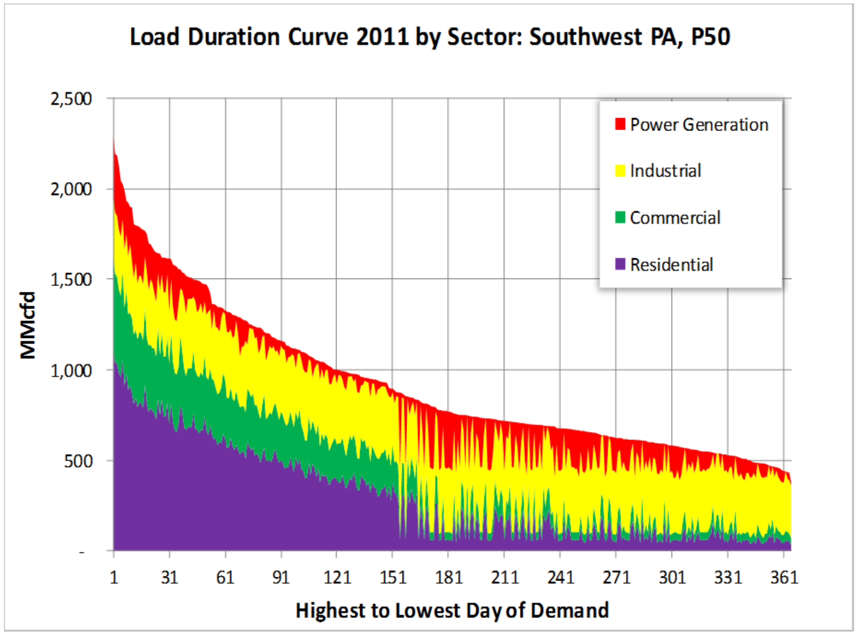

Load Growth 2030 vs 2011: Northeast PA, P50
MMcfd
90
80
70
60
50
40
30
20
10
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

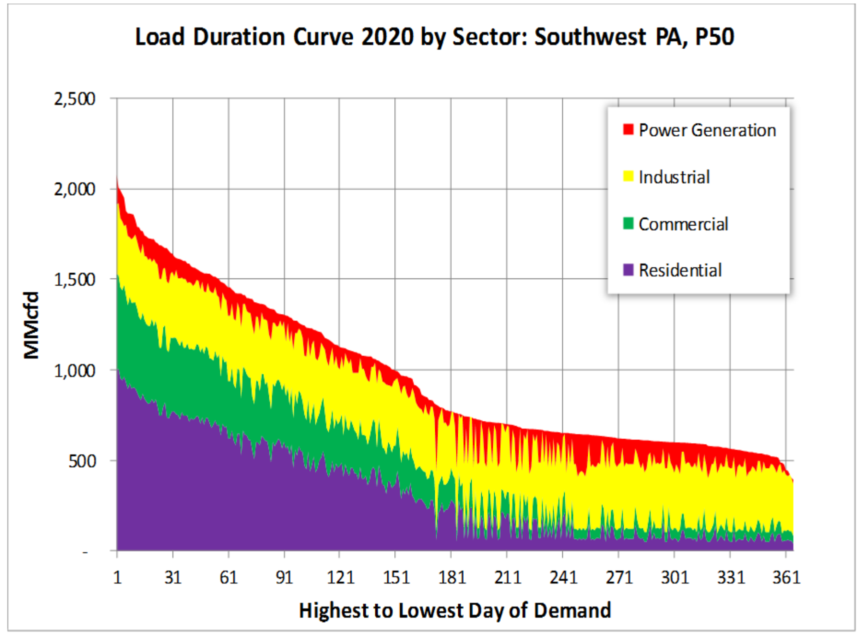

Load Duration Curve 2011 by Sector: Philadelphia, P50
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

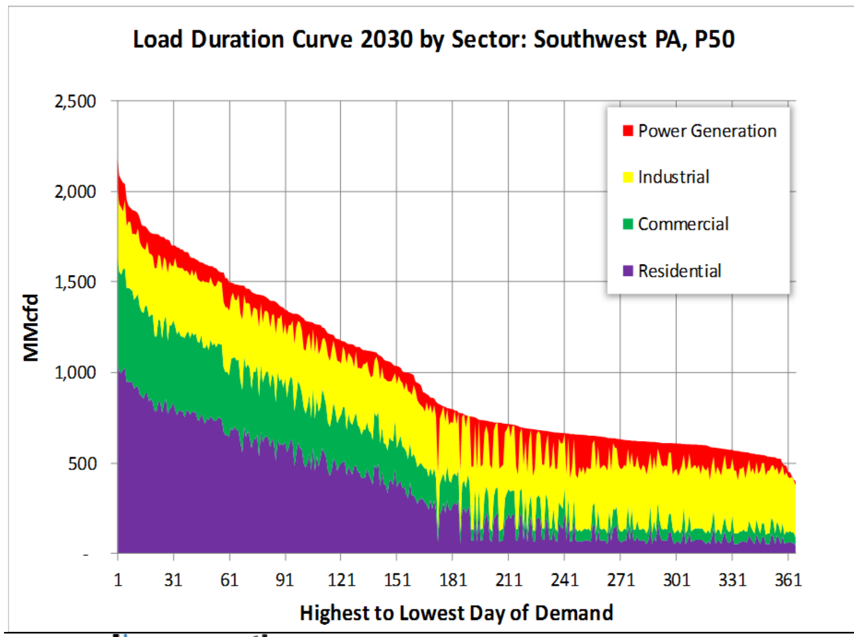

Load Duration Curve 2020 by Sector: Philadelphia, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

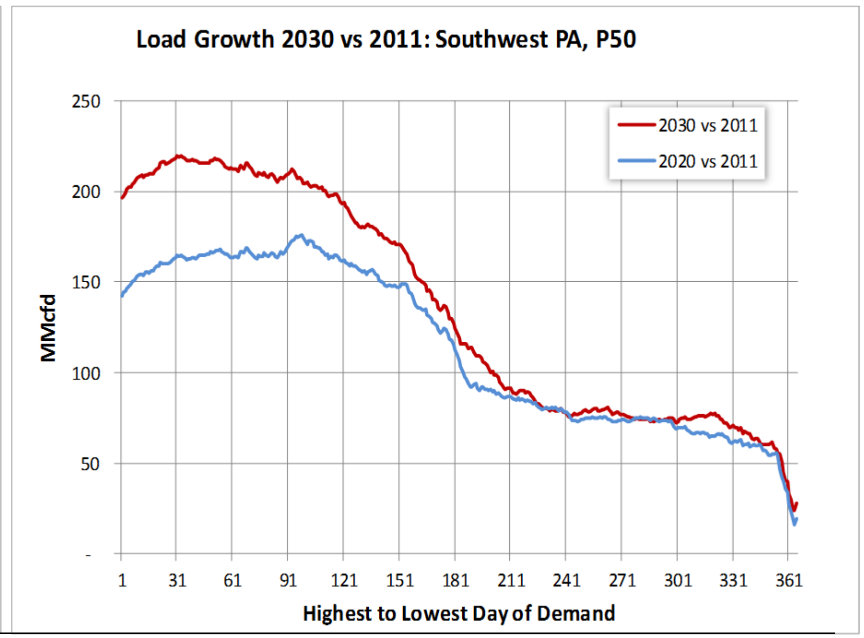

Load Duration Curve 2030 by Sector: Philadelphia, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

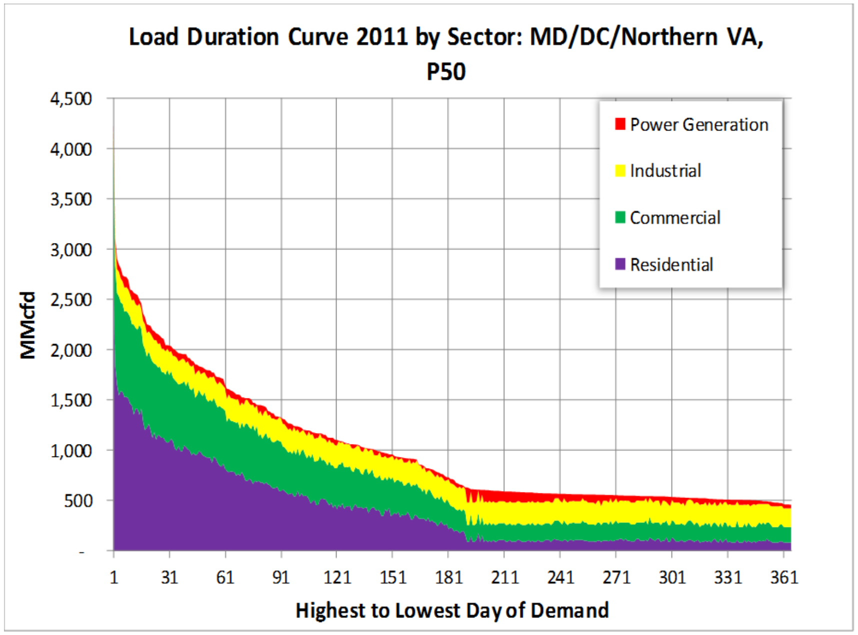

Load Growth 2030 vs 2011: Philadelphia, P50
900
800
700
600
500
400
300
200
100
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

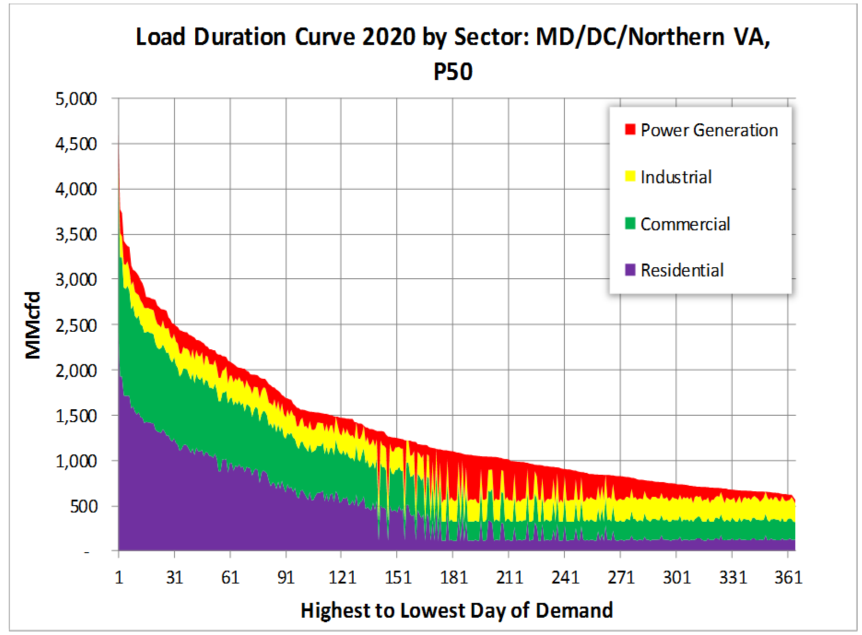

Load Duration Curve 2011 by Sector: Southwest PA, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

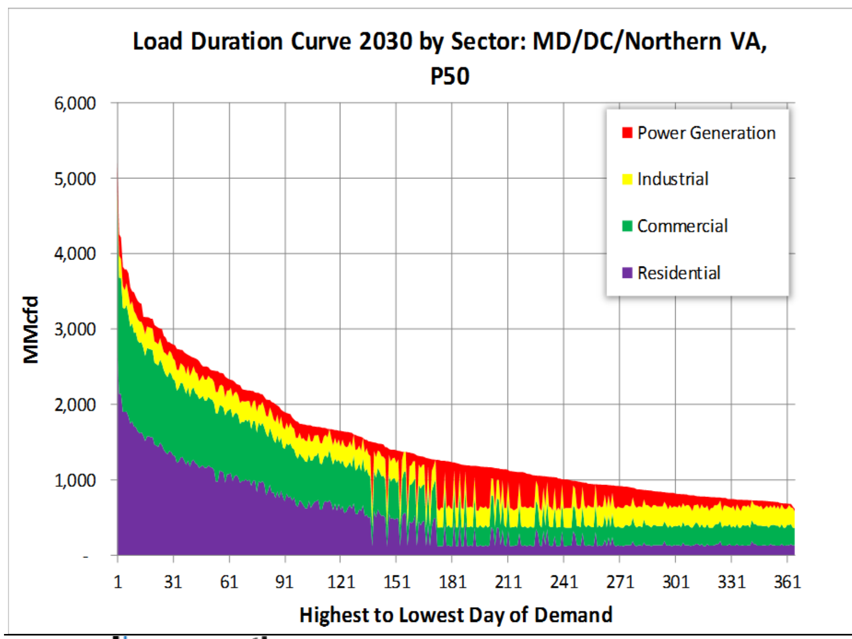

Load Duration Curve 2020 by Sector: Southwest PA, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

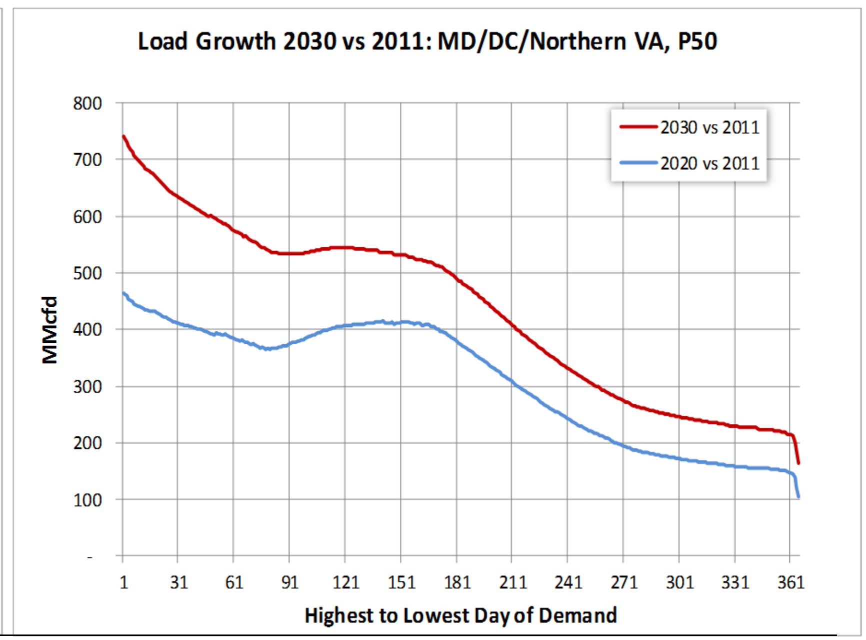

Load Duration Curve 2030 by Sector: Southwest PA, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

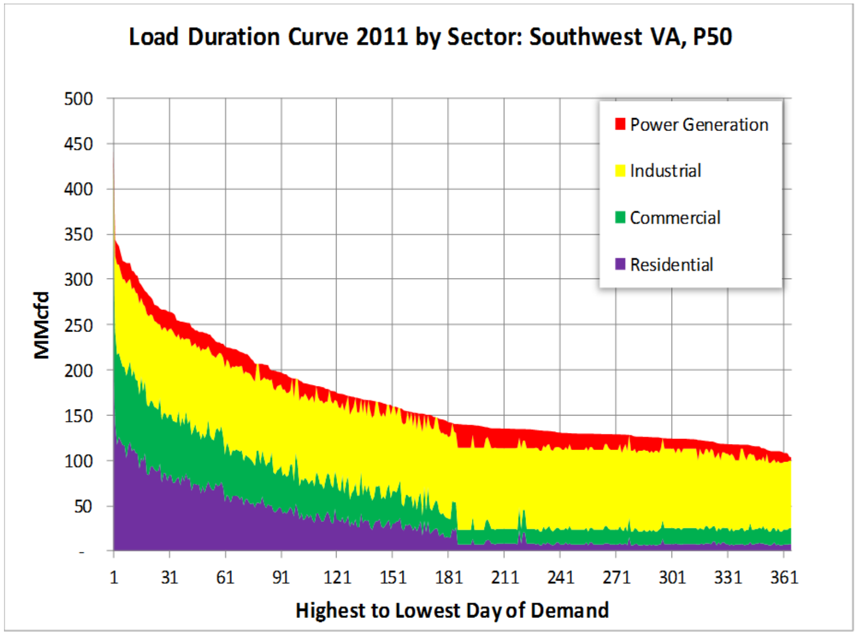

Load Growth 2030 vs 2011: Southwest PA, P50
2030 vs 2011
2020 vs 2011
MMcfd
Highest to Lowest Day of Demand


Load Duration Curve 2011 by Sector: MD/DC/Northern VA, P50
MMcfd
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

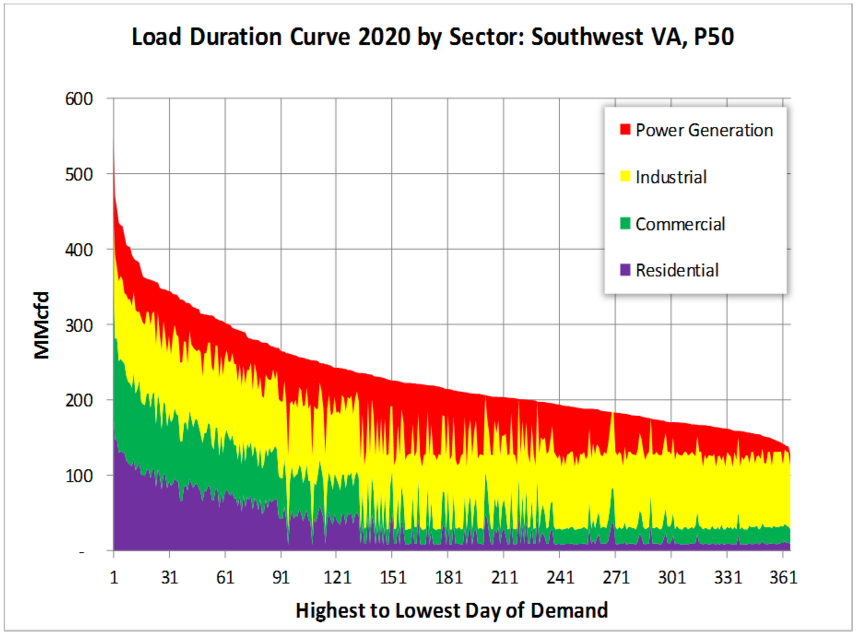

Load Duration Curve 2020 by Sector: MD/DC/Northern VA, P50
MMcfd
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential


Load Duration Curve 2030 by Sector: MD/DC/Northern VA, P50
MMcfd
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

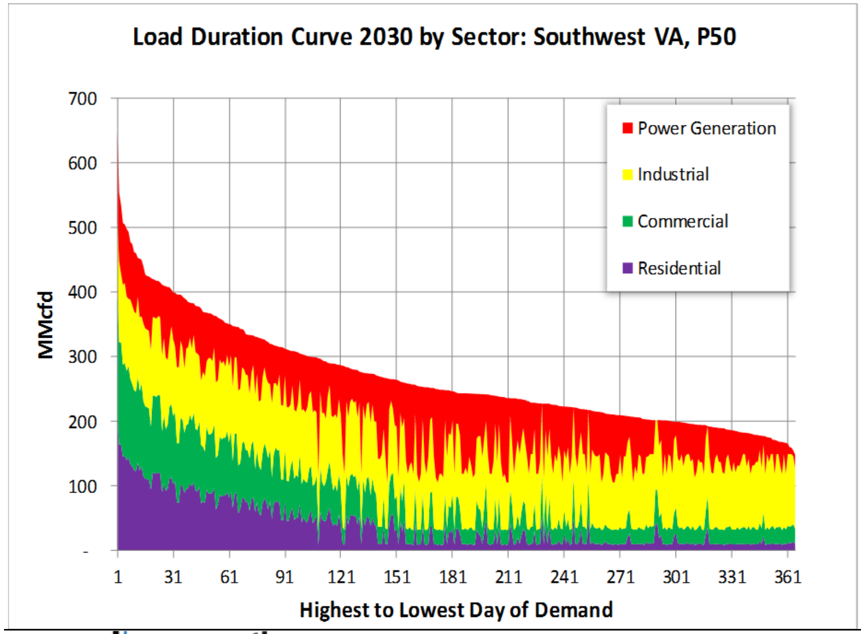

Load Growth 2030 vs 2011: MD/DC/Northern VA, P50
MMcfd
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011



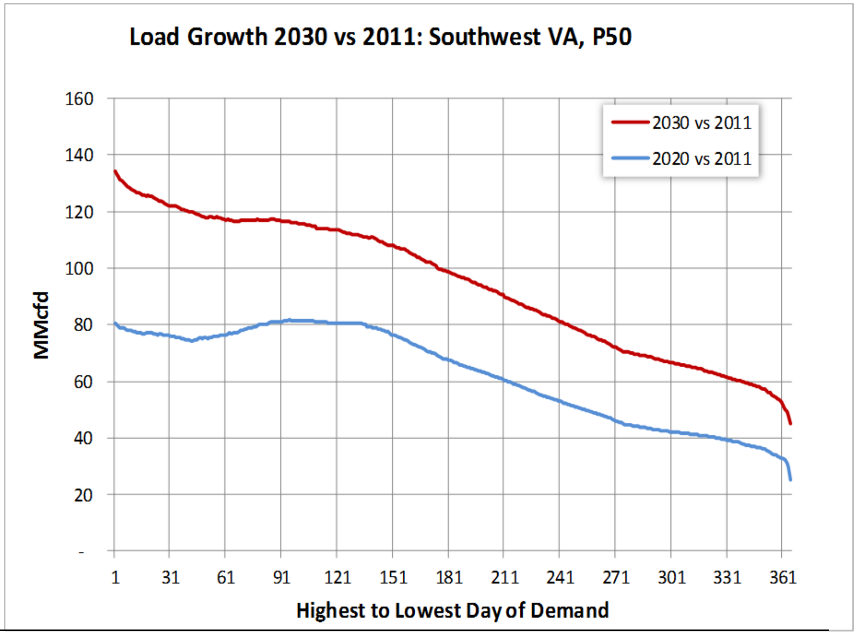
Load Duration Curve 2011 by Sector: Southwest VA, P50
MMcfd
500
450
400
350
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential



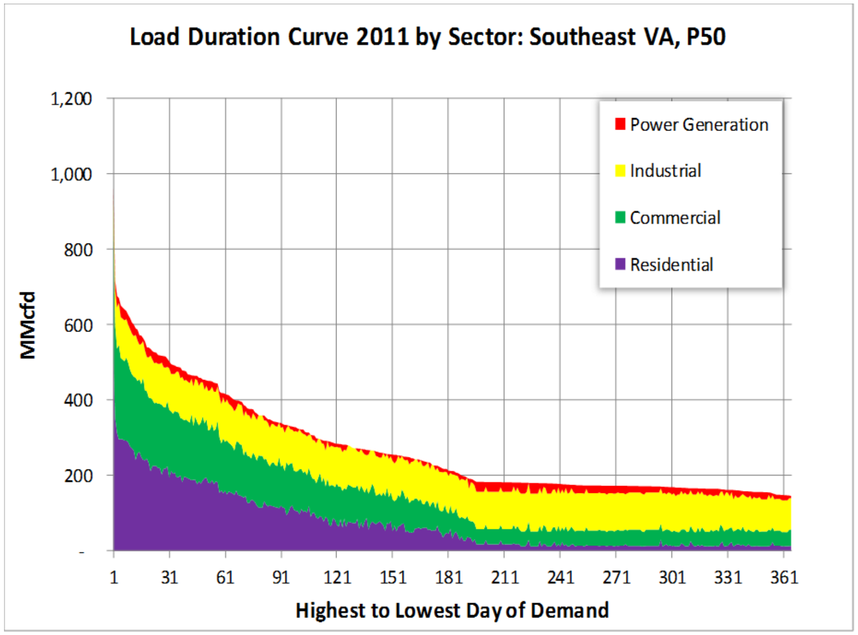
Load Duration Curve 2020 by Sector: Southwest VA, P50
MMcfd
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

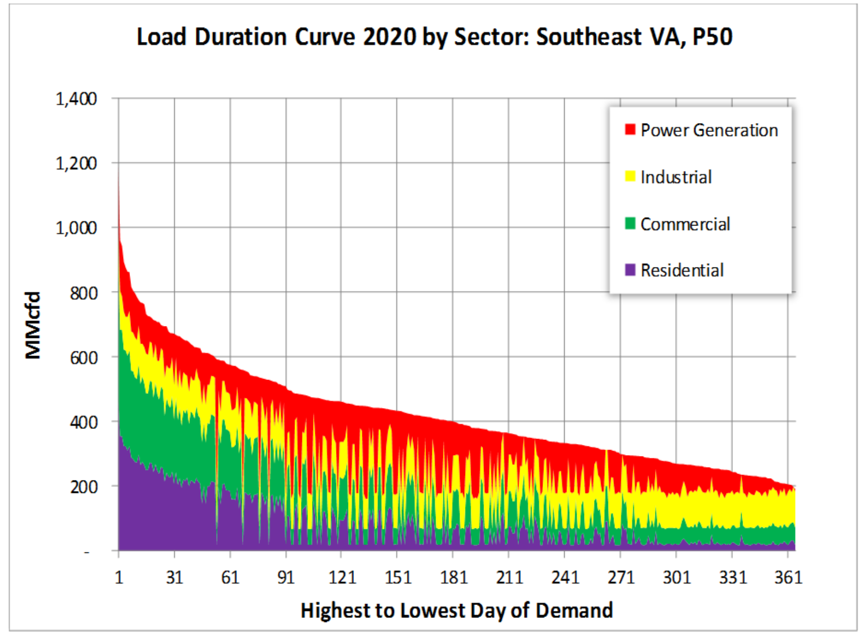


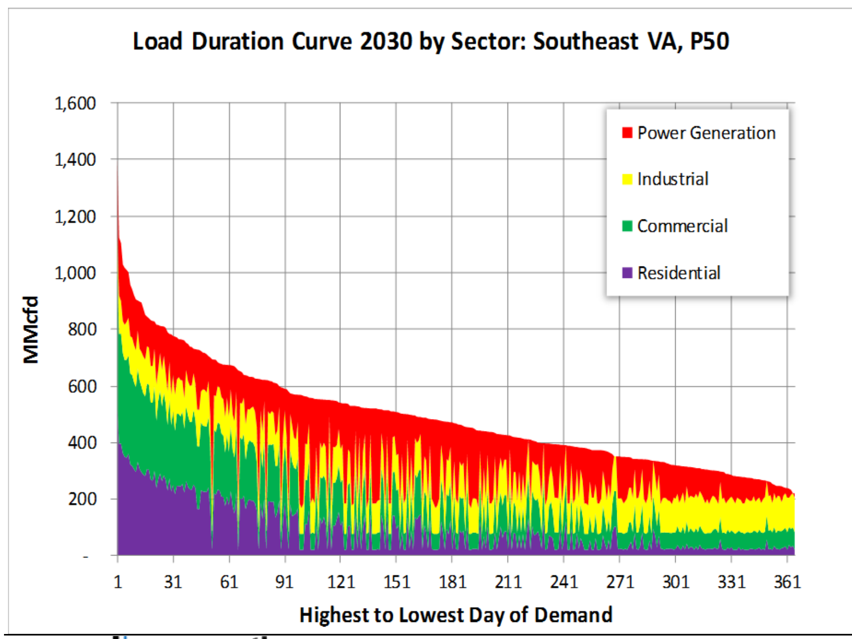
Load Duration Curve 2030 by Sector: Southwest VA, P50
MMcfd
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

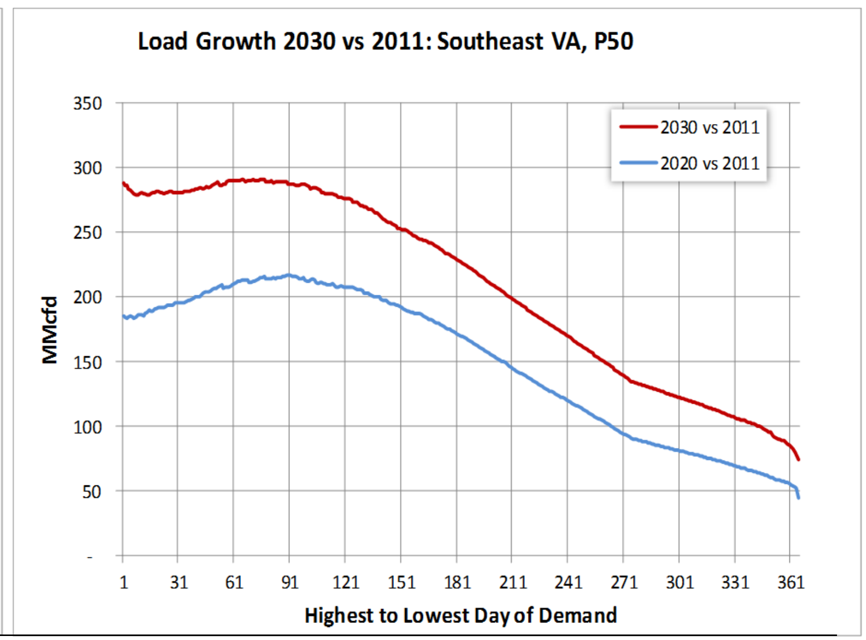


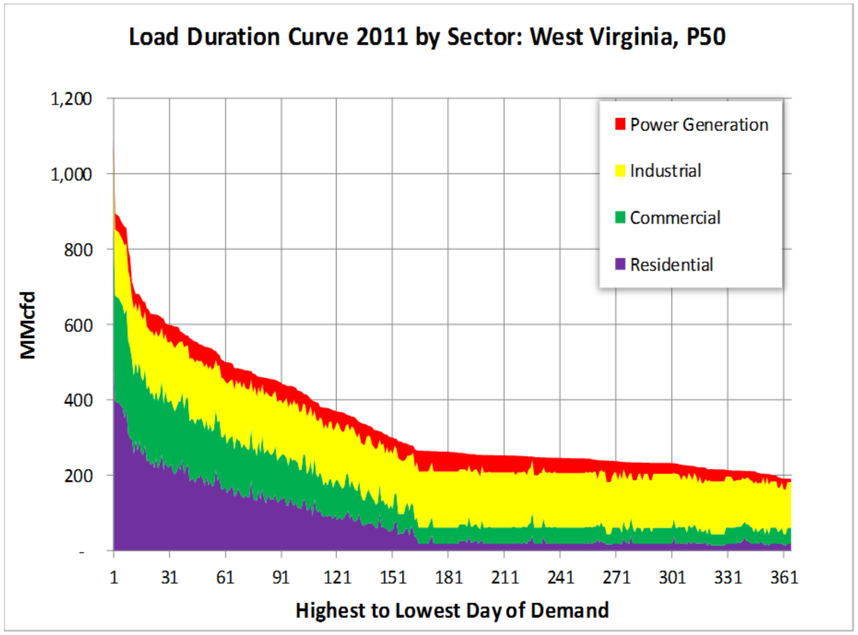
Load Growth 2030 vs 2011: Southwest VA, P50
MMcfd
160
140
120
100
80
60
40
20
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

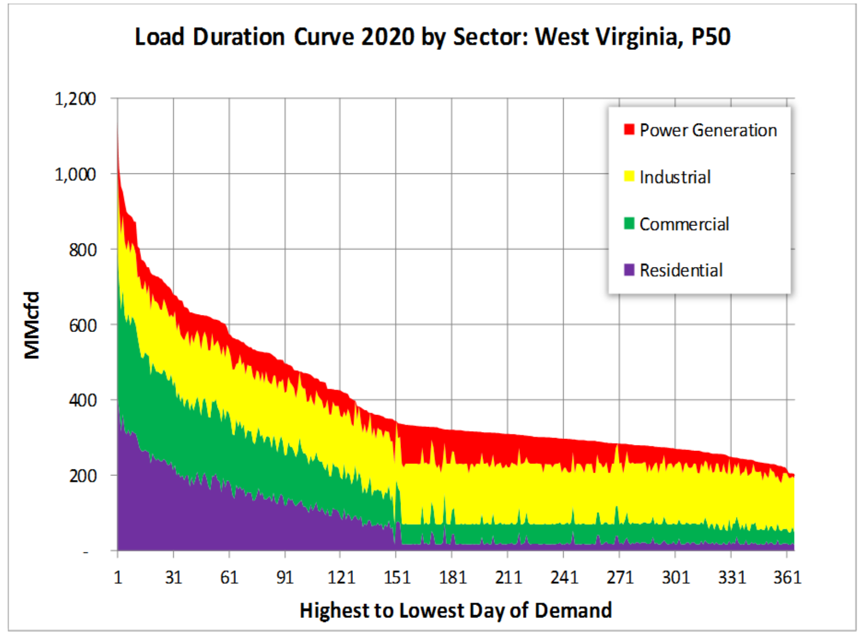

Load Duration Curve 2011 by Sector: Southeast VA, P50
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

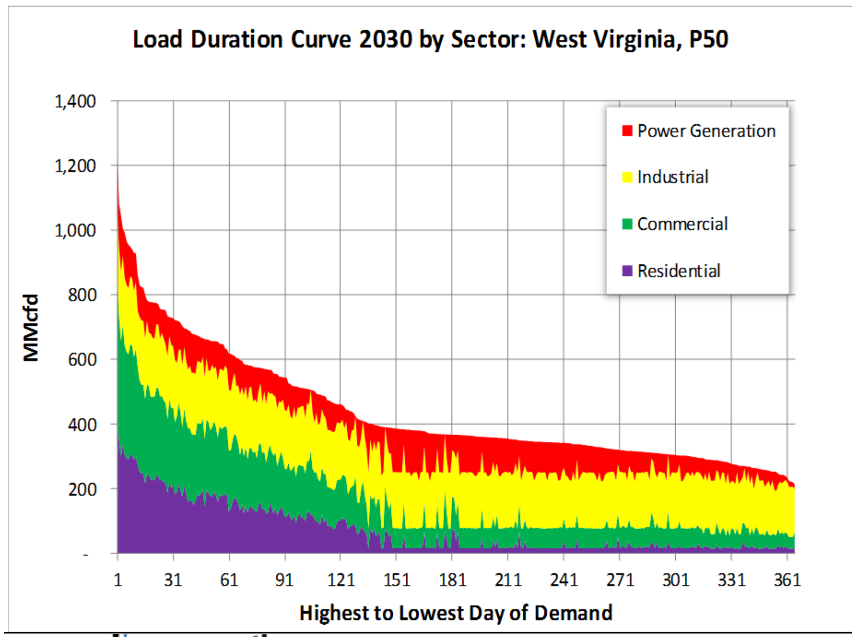

Load Duration Curve 2020 by Sector: Southeast VA, P50
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

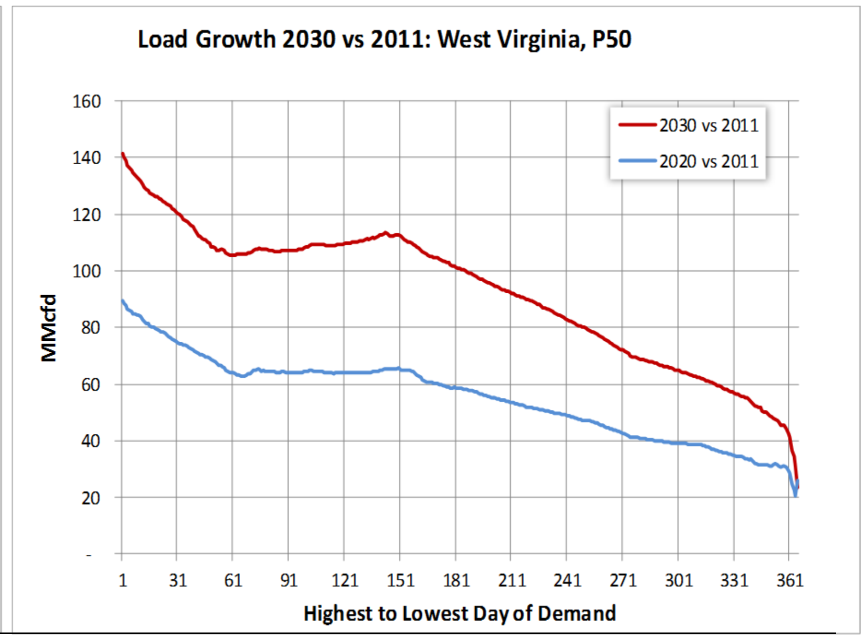

Load Duration Curve 2030 by Sector: Southeast VA, P50
MMcfd
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential


Load Growth 2030 vs 2011: Southeast VA, P50
MMcfd
350
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

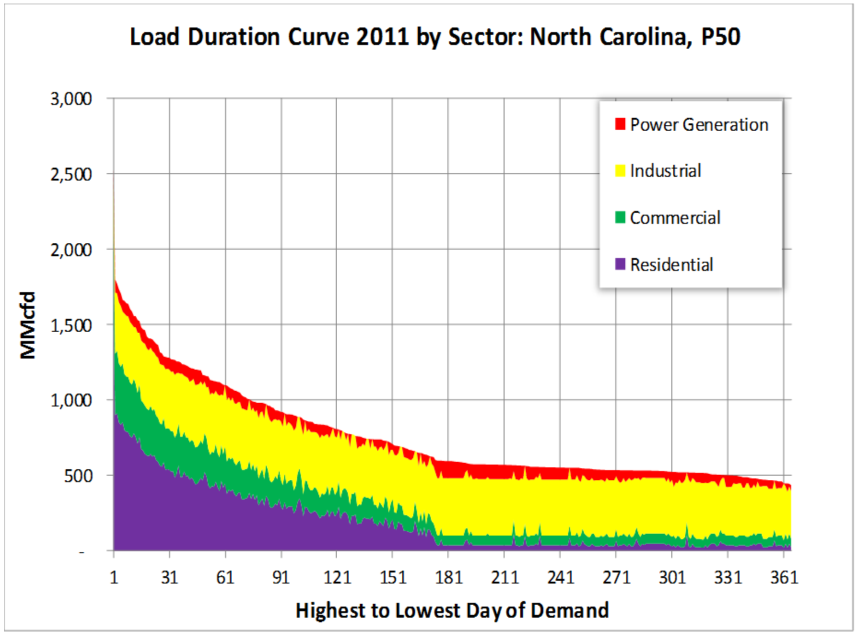

Load Duration Curve 2011 by Sector: West Virginia, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

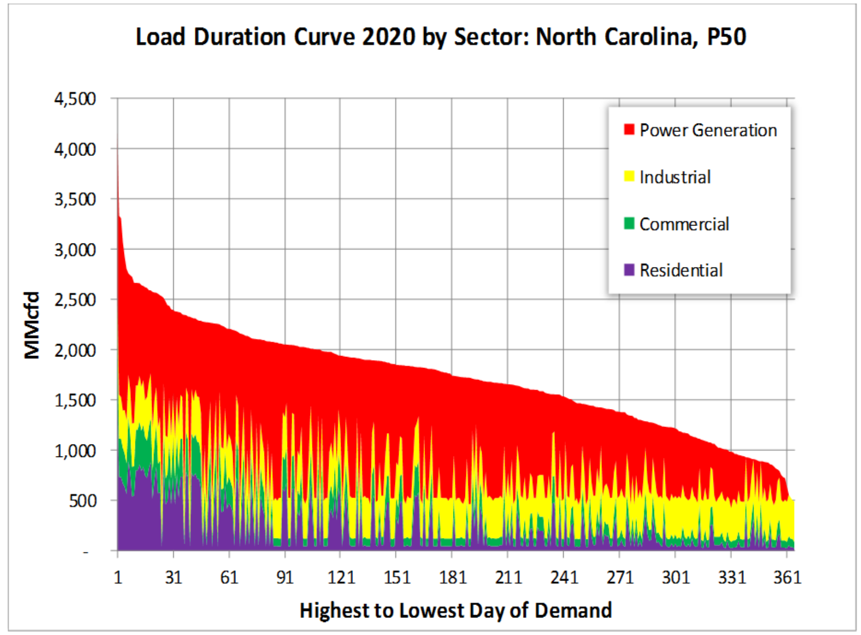

Load Duration Curve 2020 by Sector: West Virginia, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

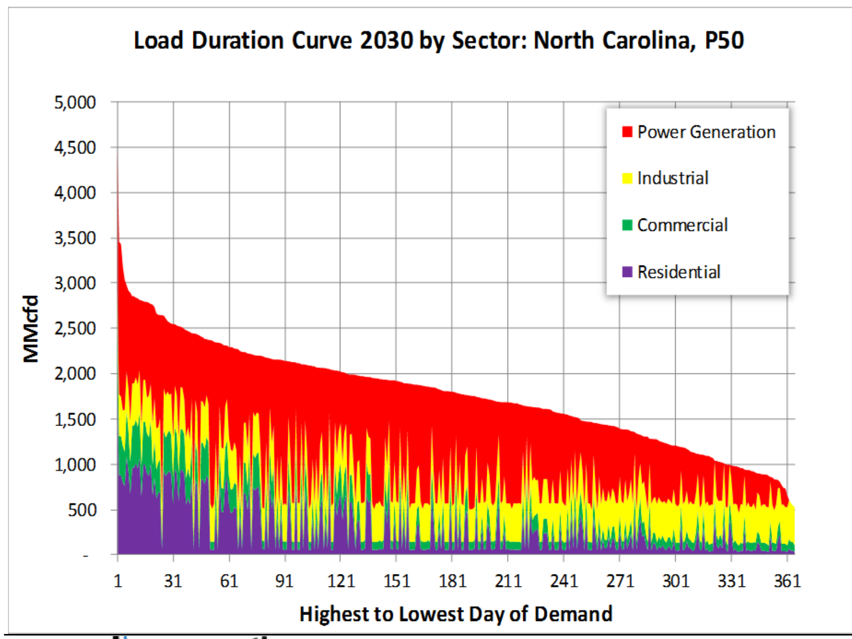

Load Duration Curve 2030 by Sector: West Virginia, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

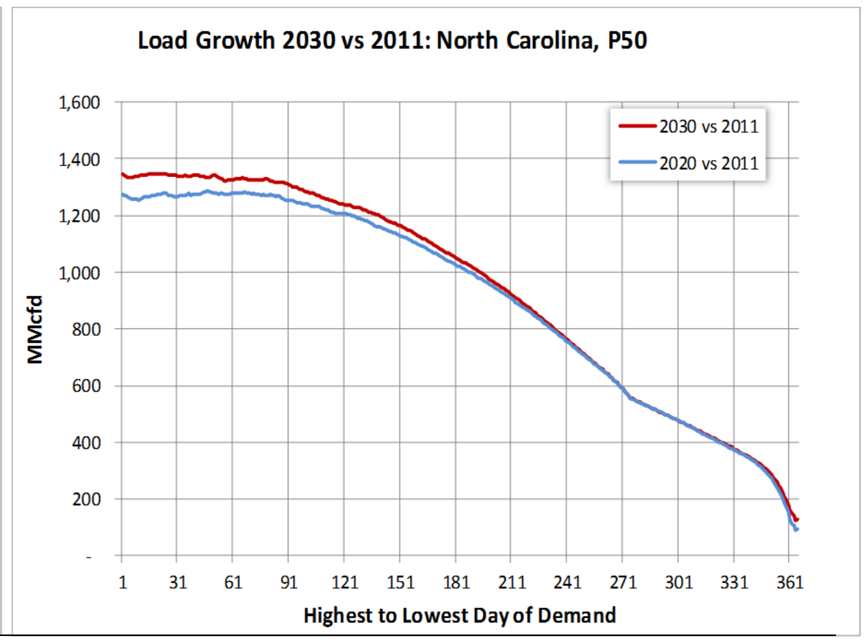

Load Growth 2030 vs 2011: West Virginia, P50
2030 vs 2011
2020 vs 2011
MMcfd
160
140
120
100
80
60
40
20
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

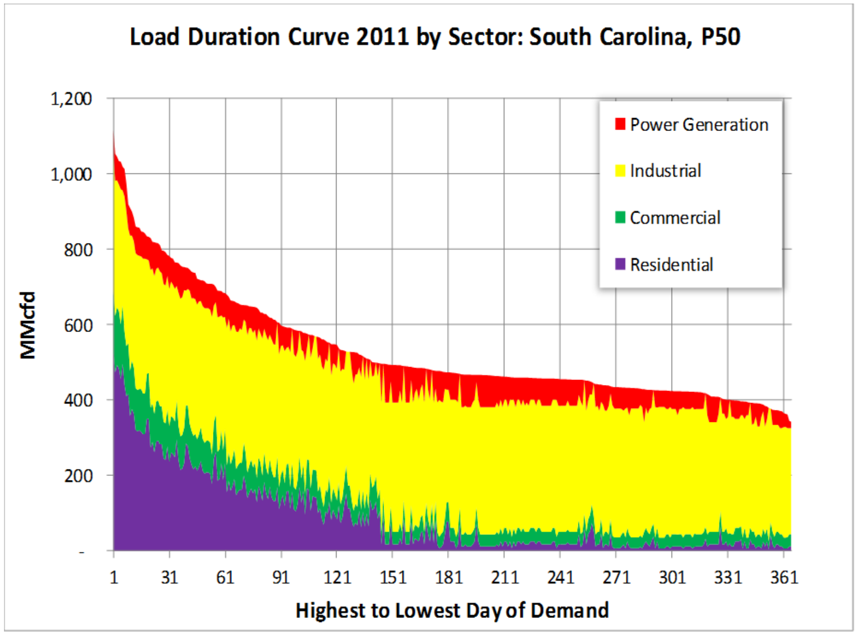
9.1.2 Southeast

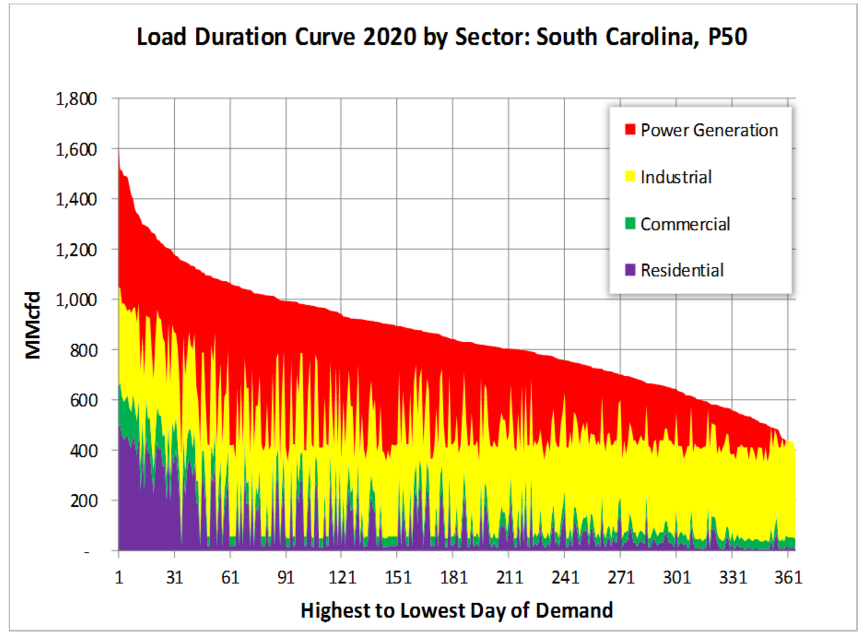

Load Duration Curve 2011 by Sector: North Carolina, P50
MMcfd
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

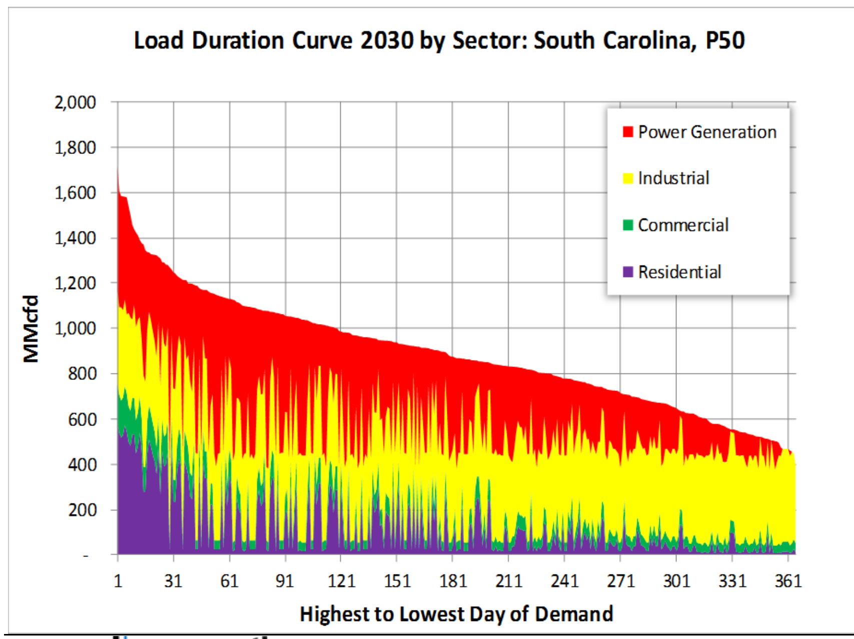

Load Duration Curve 2020 by Sector: North Carolina, P50
MMcfd
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

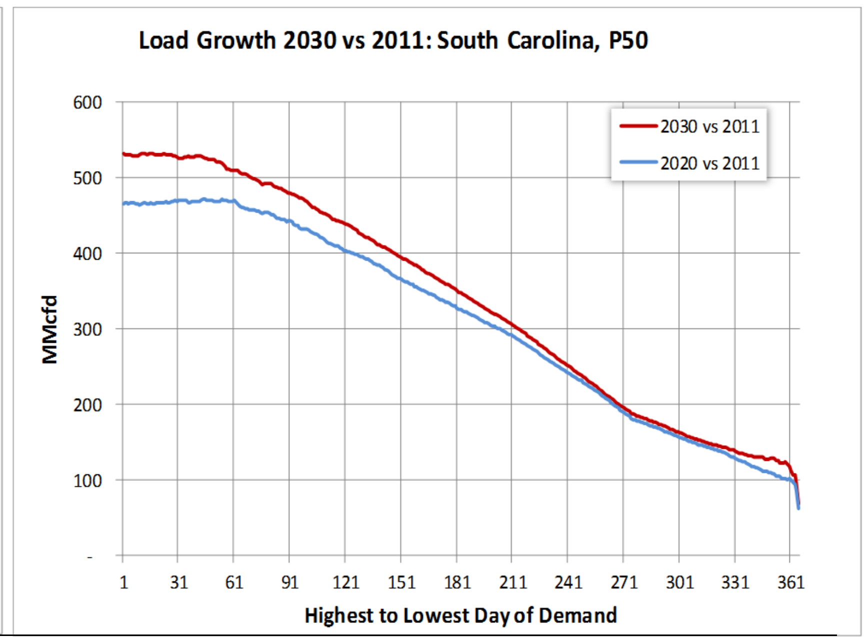

Load Duration Curve 2030 by Sector: North Carolina, P50
MMcfd
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

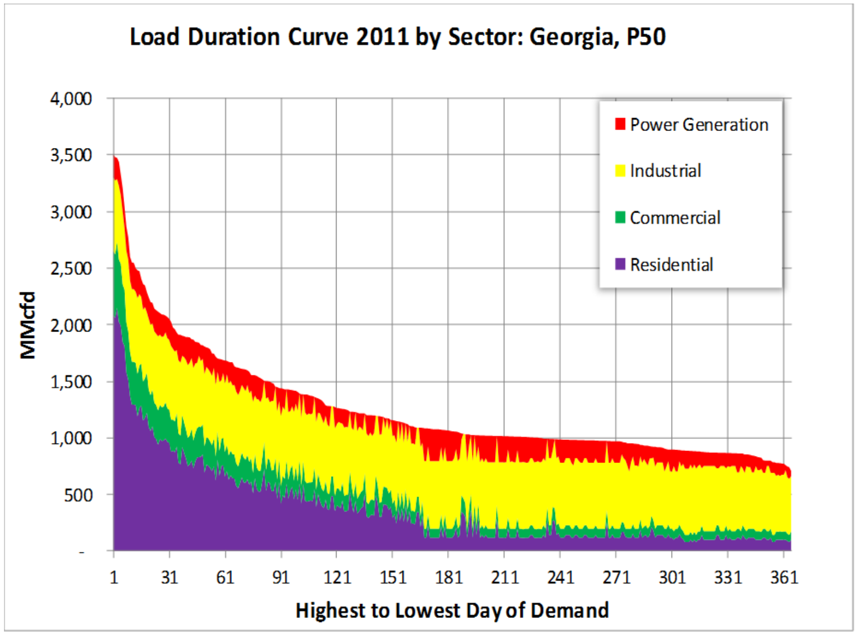

Load Growth 2030 vs 2011: North Carolina, P50
MMcfd
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

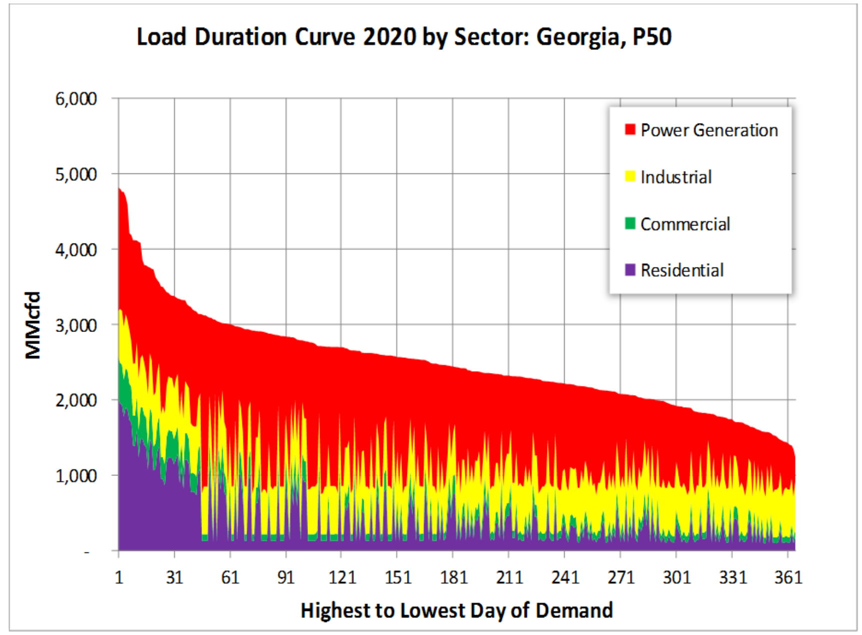

Load Duration Curve 2011 by Sector: South Carolina, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

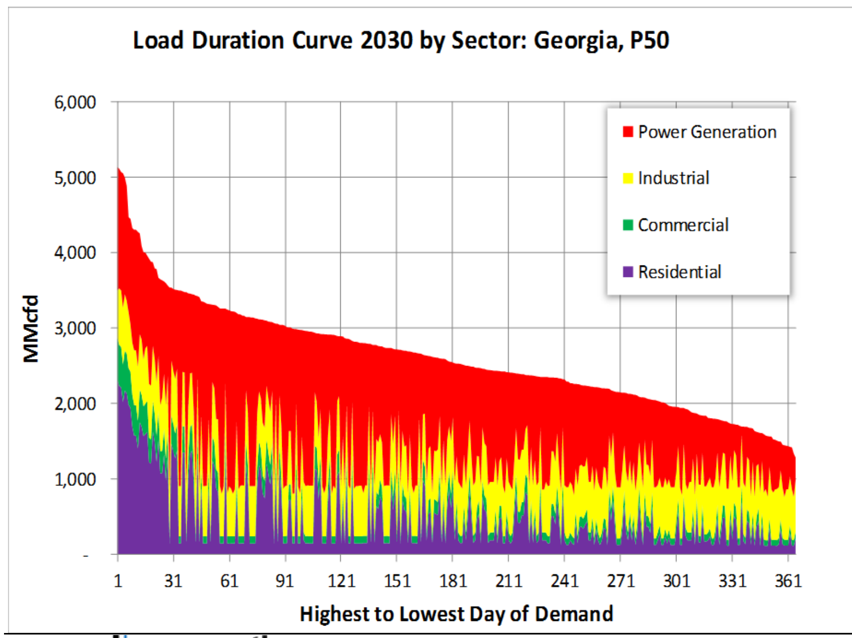

Load Duration Curve 2020 by Sector: South Carolina, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

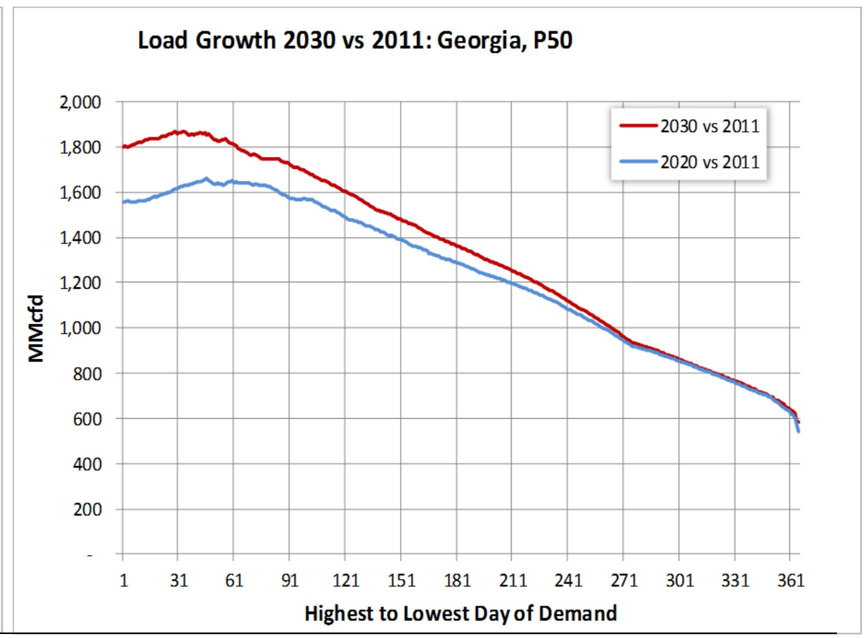

Load Duration Curve 2030 by Sector: South Carolina, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

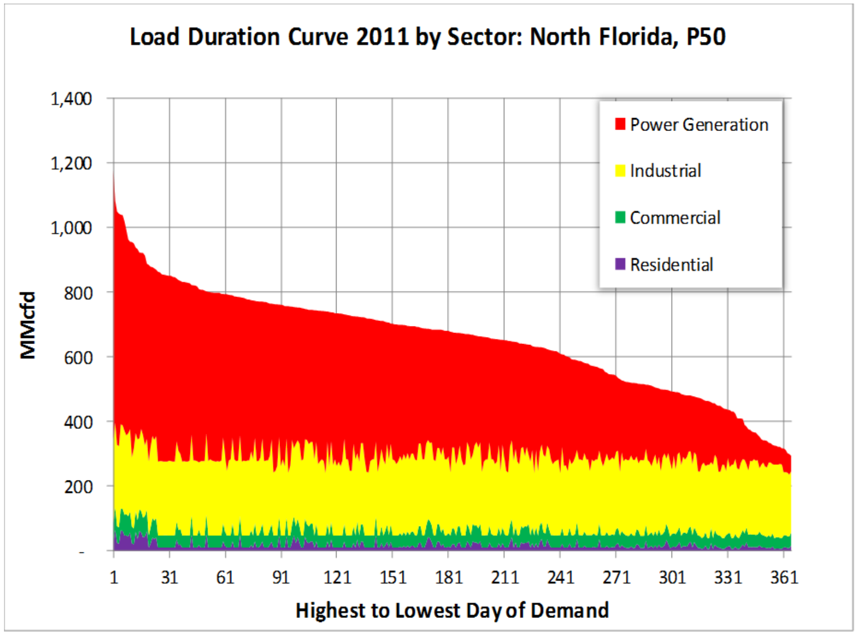

Load Growth 2030 vs 2011: South Carolina, P50
2030 vs 2011
2020 vs 2011
MMcfd
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

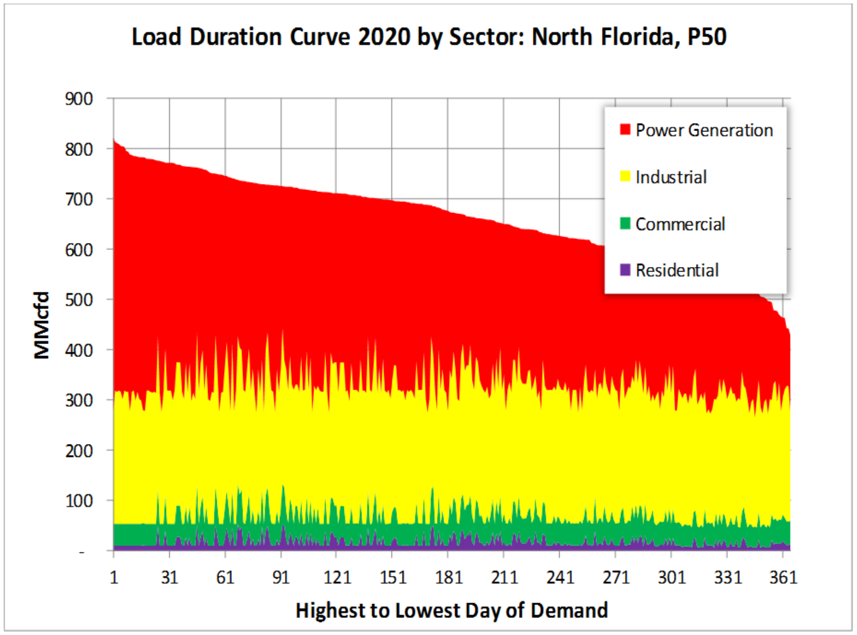

Load Duration Curve 2011 by Sector: Georgia, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

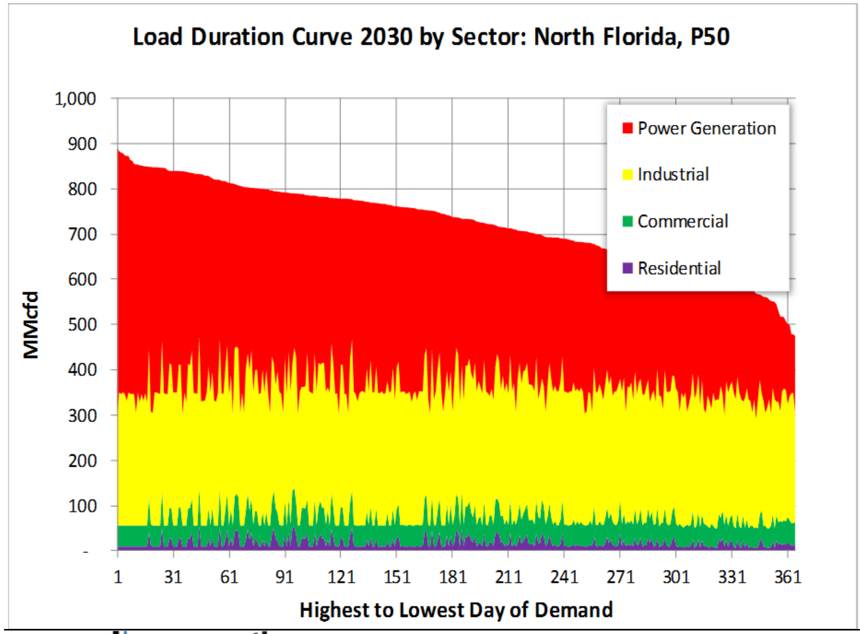

Load Duration Curve 2020 by Sector: Georgia, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

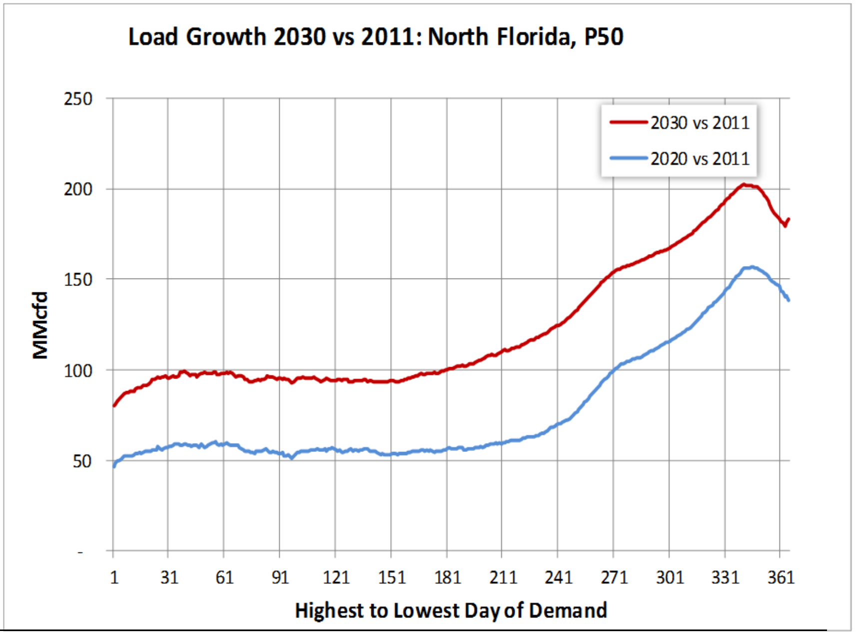

Load Duration Curve 2030 by Sector: Georgia, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

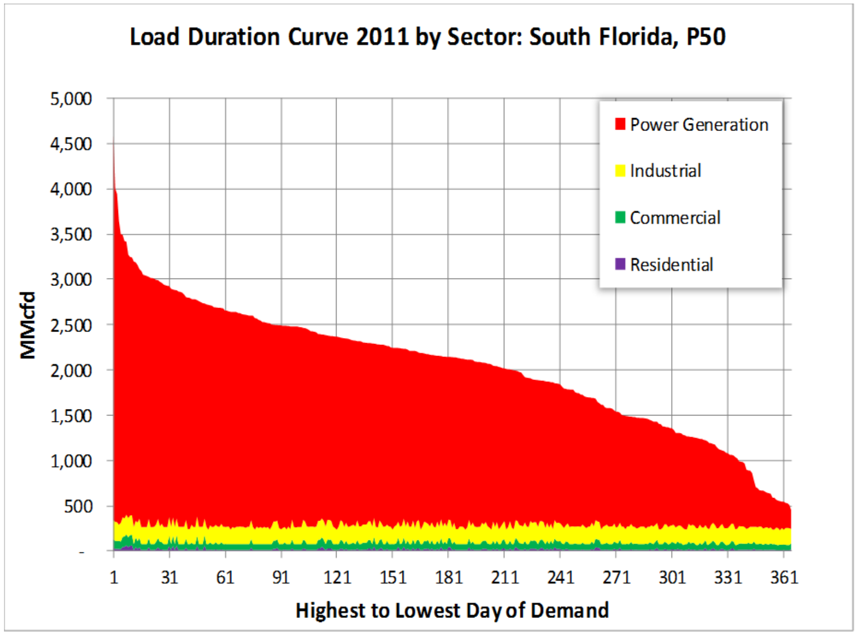

Load Growth 2030 vs 2011: Georgia, P50
MMcfd
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

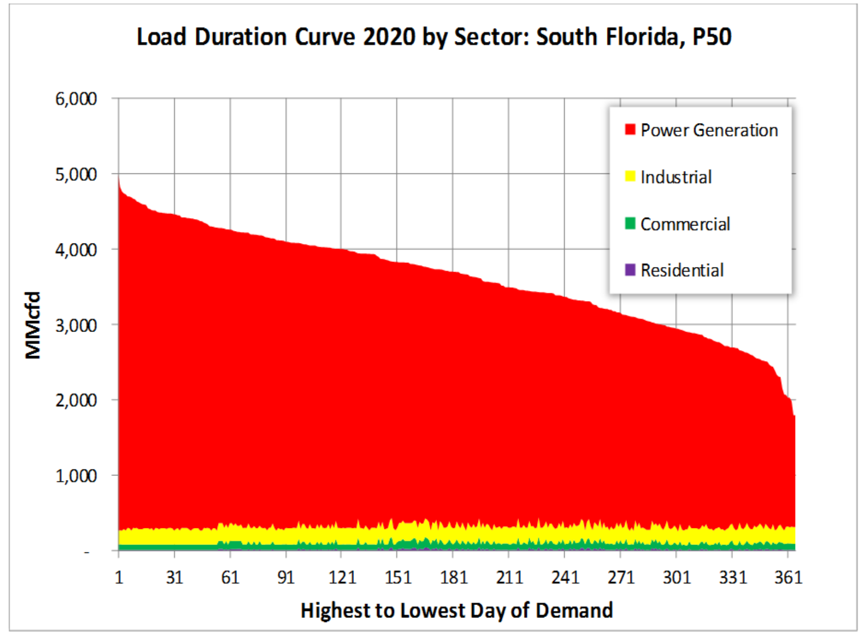

Load Duration Curve 2011 by Sector: North Florida, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

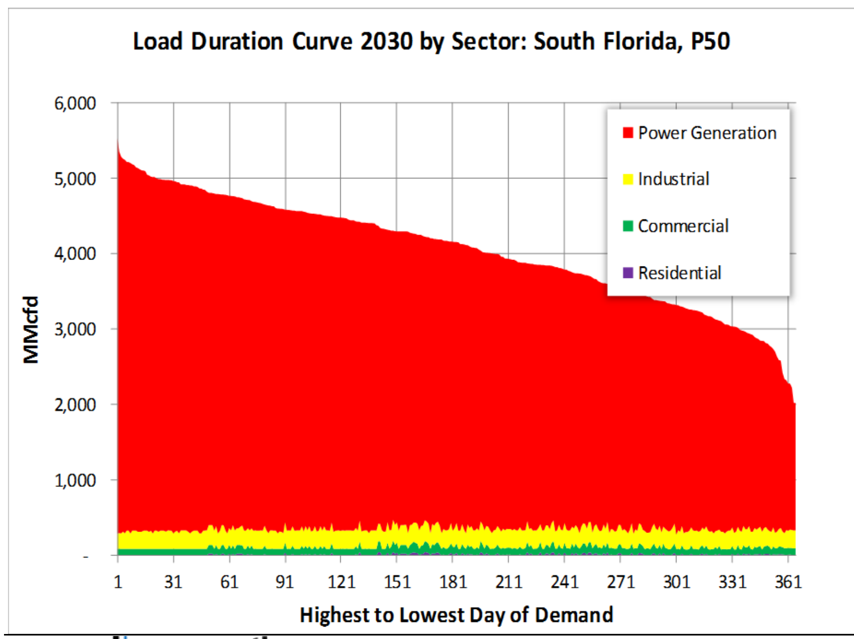

Load Duration Curve 2020 by Sector: North Florida, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

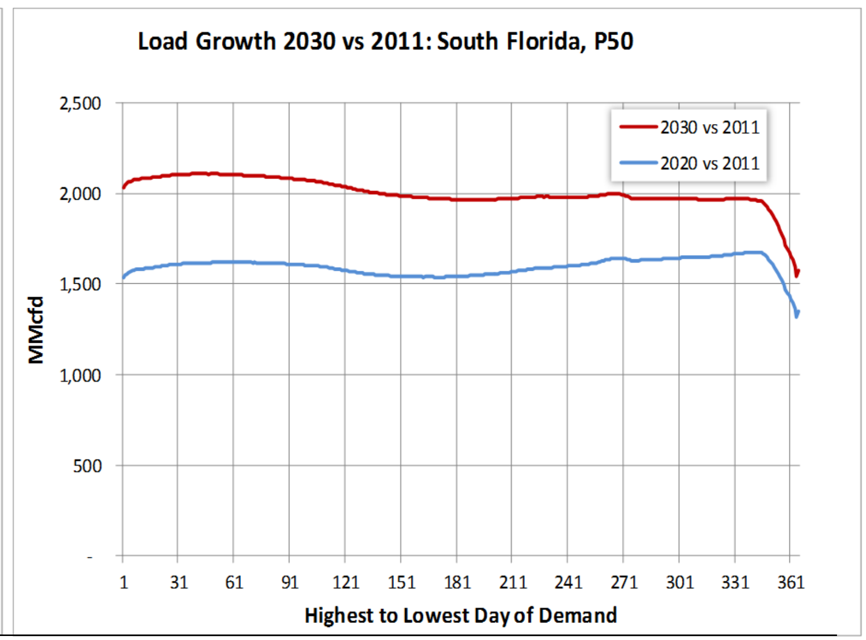

Load Duration Curve 2030 by Sector: North Florida, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,000
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

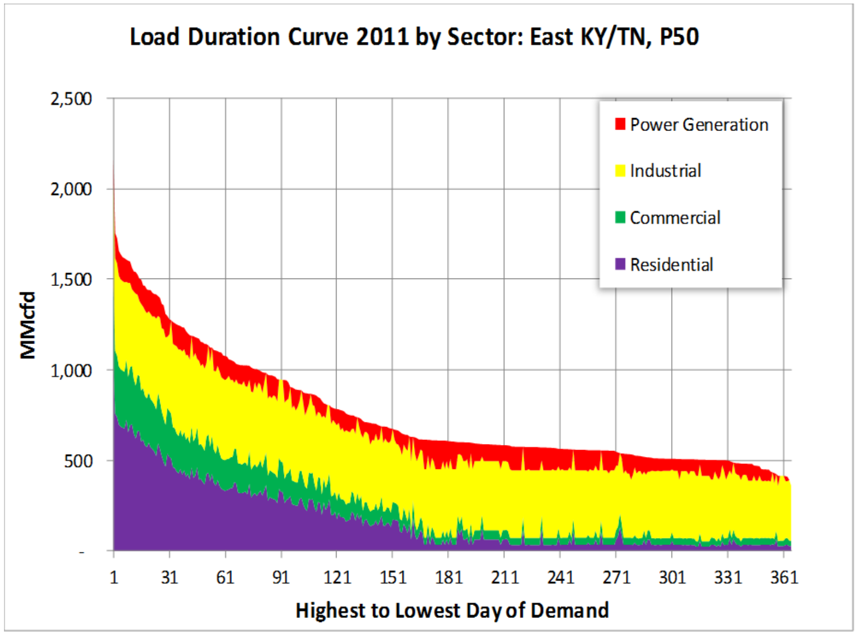

Load Growth 2030 vs 2011: North Florida, P50
2030 vs 2011
2020 vs 2011
MMcfd
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

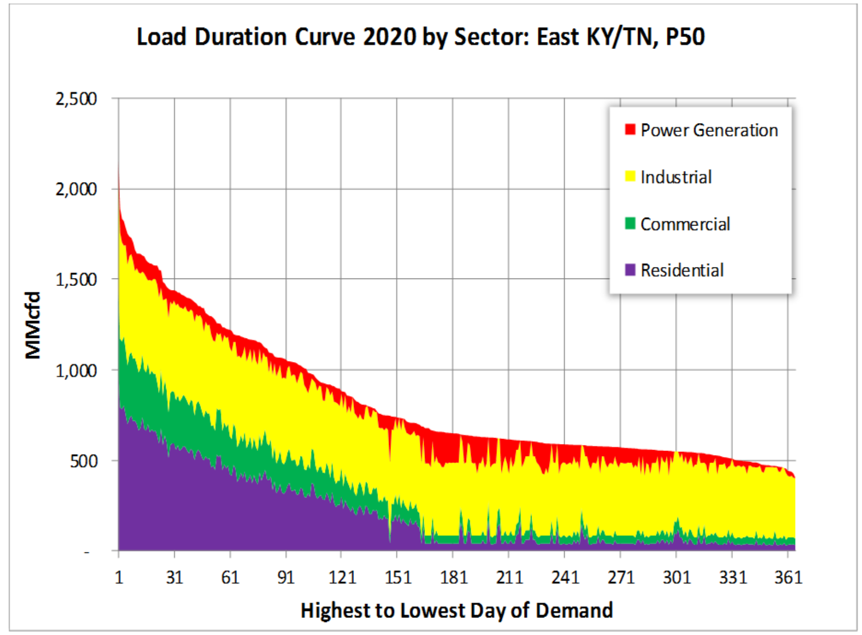

Load Duration Curve 2011 by Sector: South Florida, P50
MMcfd
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

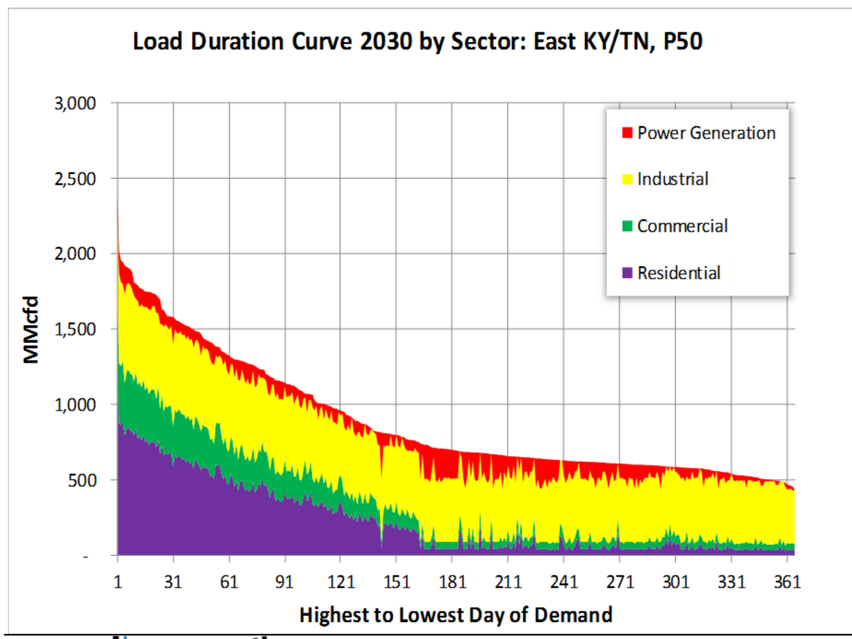

Load Duration Curve 2020 by Sector: South Florida, P50
MMcfd
6,000
5,000
4,000
3,000
2,000
1,000
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

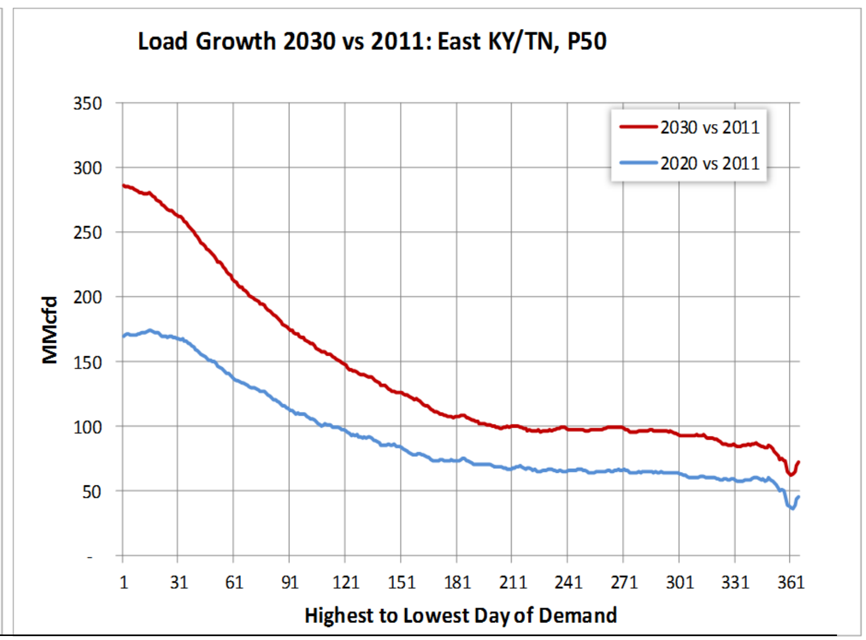

Load Duration Curve 2030 by Sector: South Florida, P50
MMcfd
6,000
5,000
4,000
3,000
2,000
1,000
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

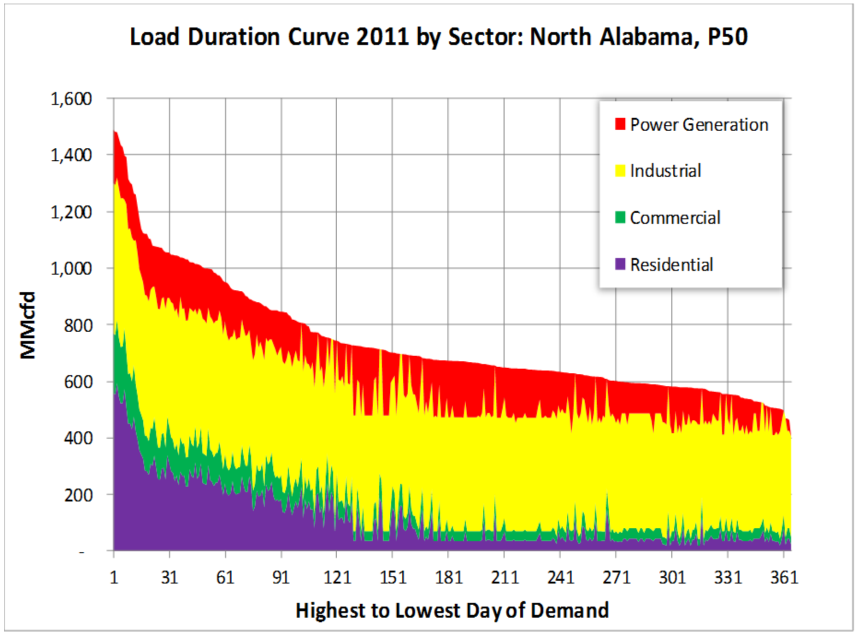

Load Growth 2030 vs 2011: South Florida, P50
MMcfd
2,500
2,000
1,500
1,000
500
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

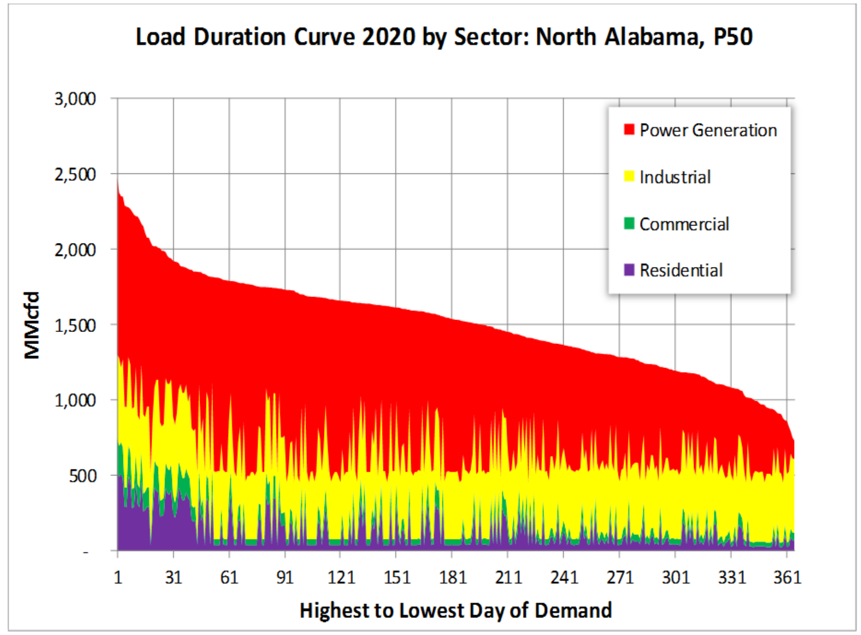

Load Duration Curve 2011 by Sector: East KY/TN, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand

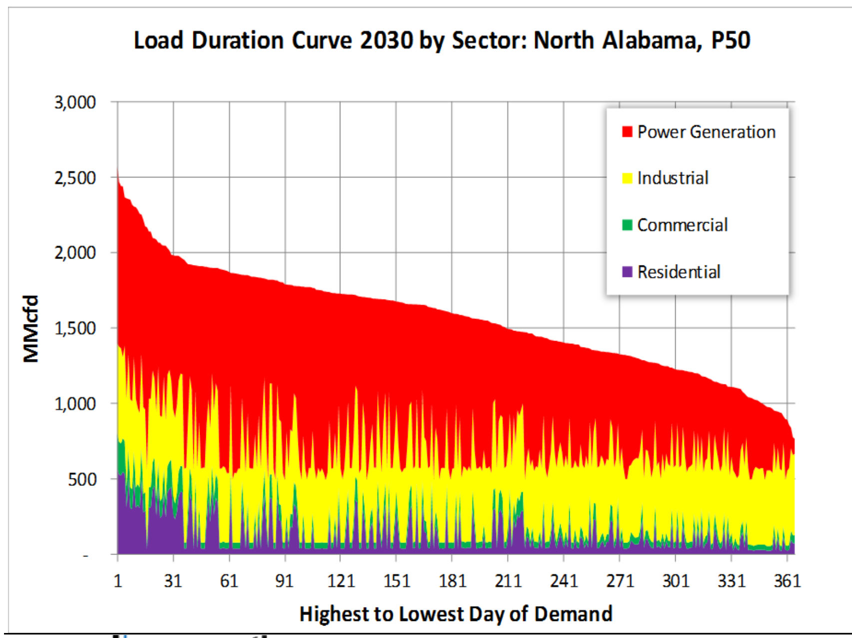

Load Duration Curve 2020 by Sector: East KY/TN, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand

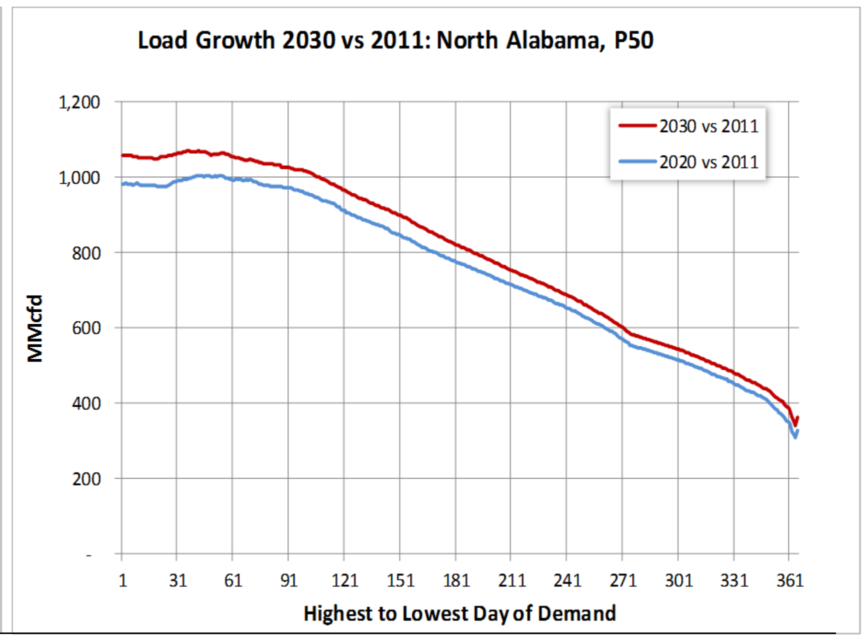

Load Duration Curve 2030 by Sector: East KY/TN, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand

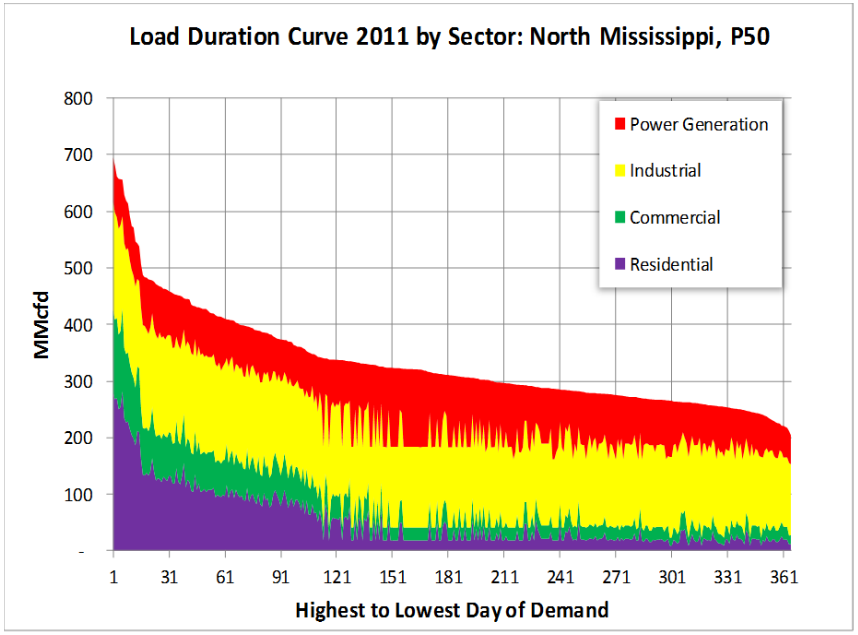

Load Growth 2030 vs 2011: East KY/TN, P50
MMcfd
2030 vs 2011
2020 vs 2011
Highest to Lowest Day of Demand

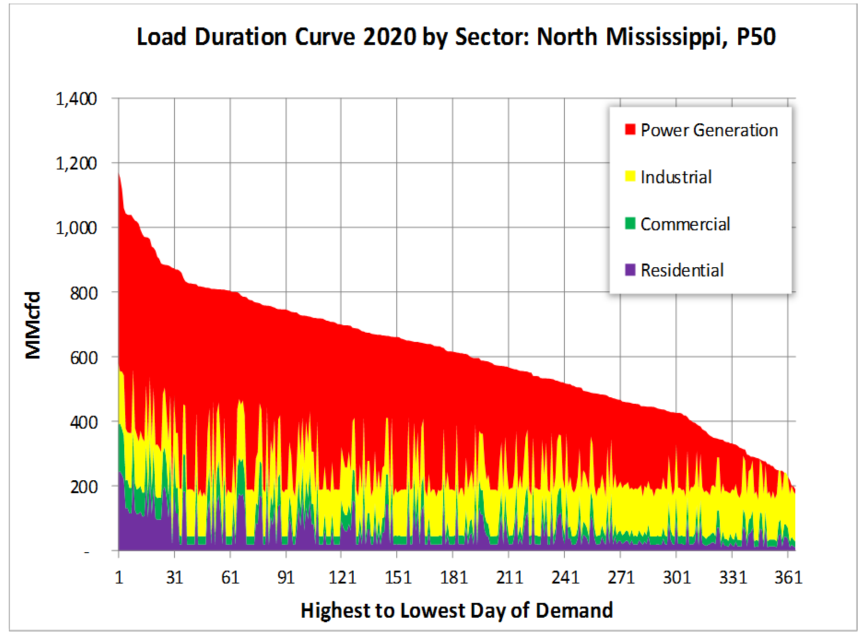

Load Duration Curve 2011 by Sector: North Alabama, P50
1,600
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

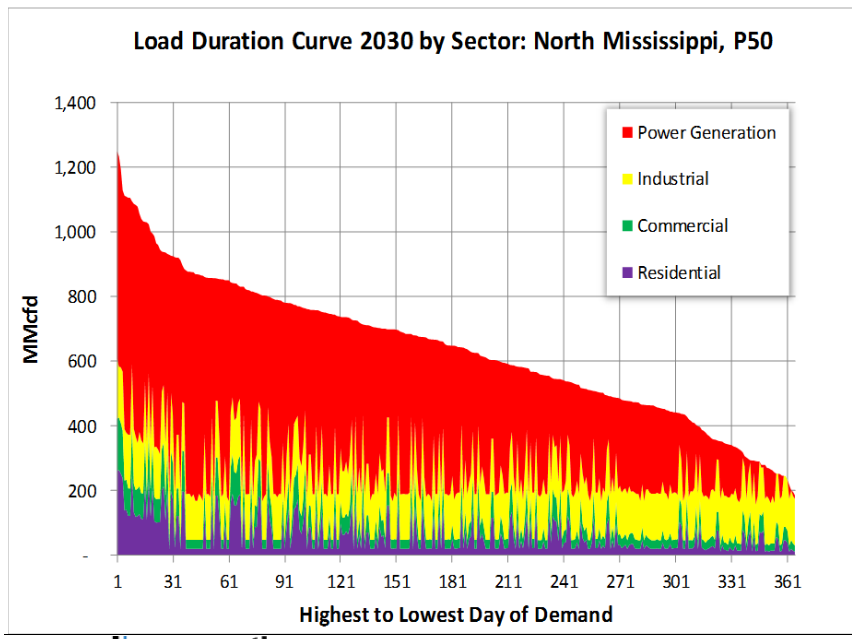

Load Duration Curve 2020 by Sector: North Alabama, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

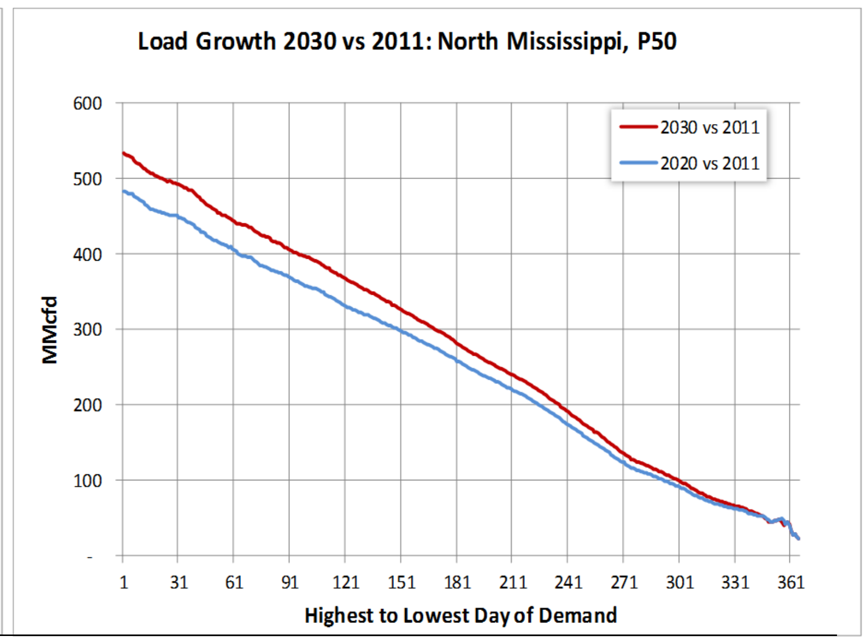

Load Duration Curve 2030 by Sector: North Alabama, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

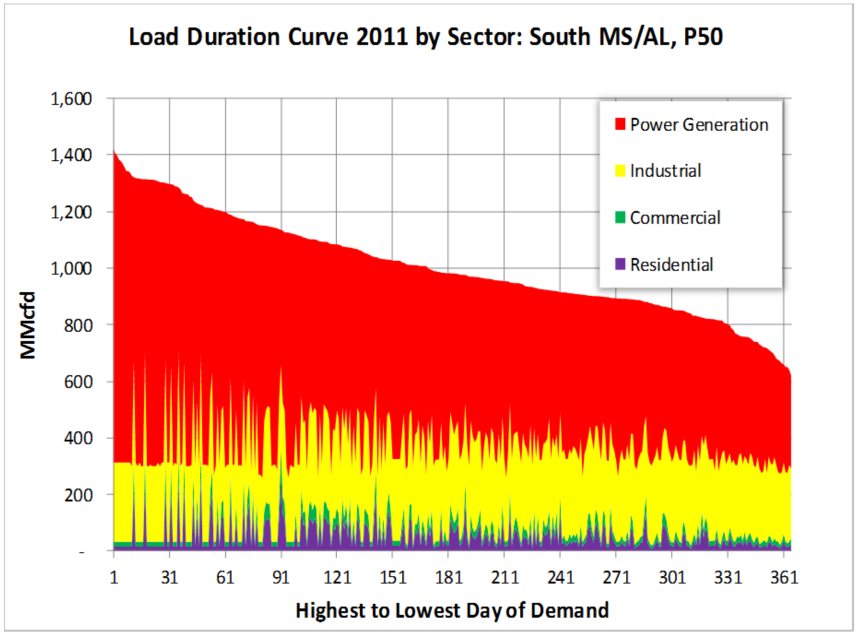

Load Growth 2030 vs 2011: North Alabama, P50
1,200
1,000
800
600
400
200
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

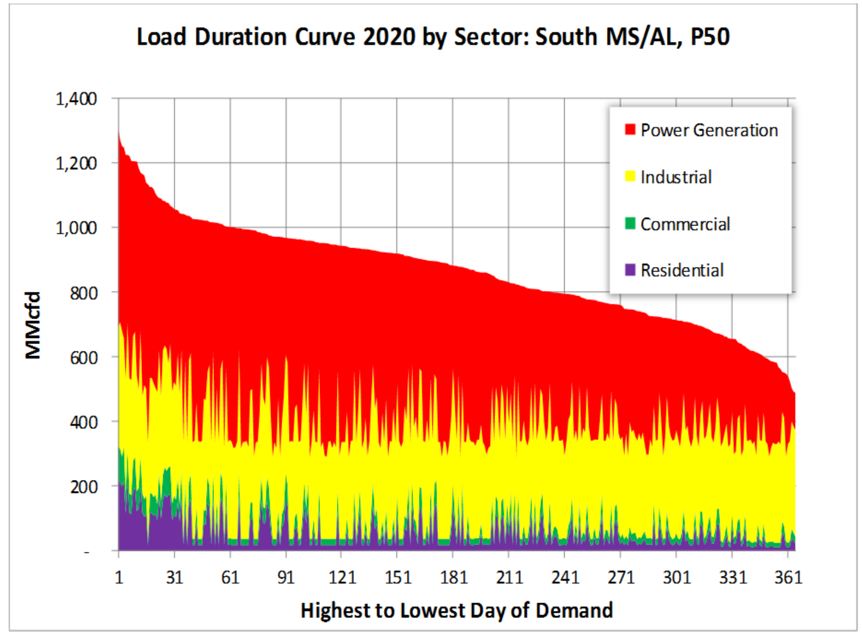

Load Duration Curve 2011 by Sector: North Mississippi, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

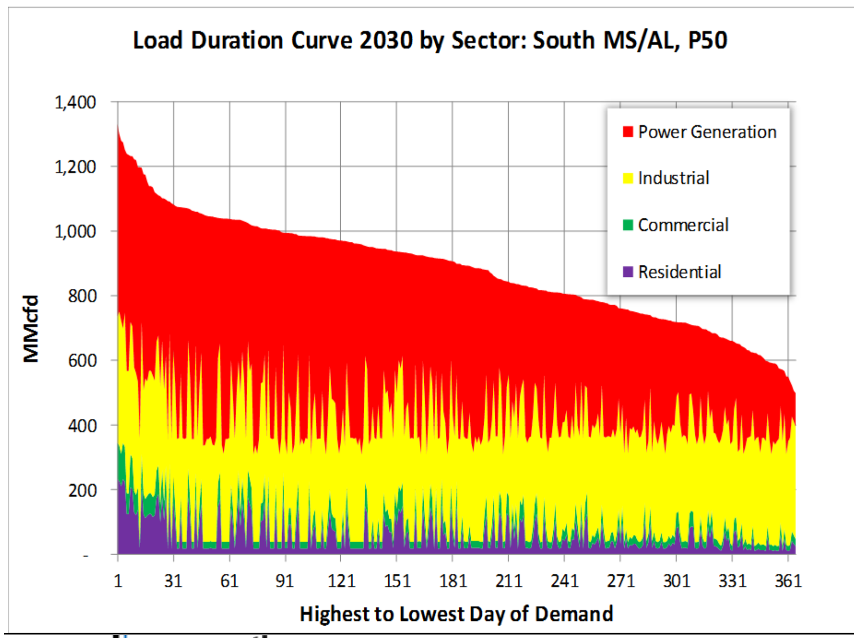

Load Duration Curve 2020 by Sector: North Mississippi, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

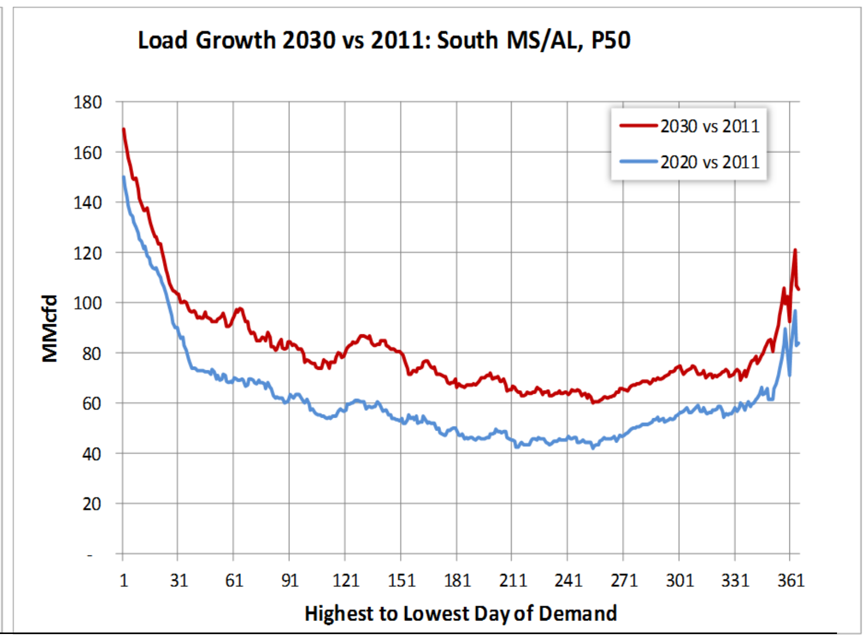

Load Duration Curve 2030 by Sector: North Mississippi, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

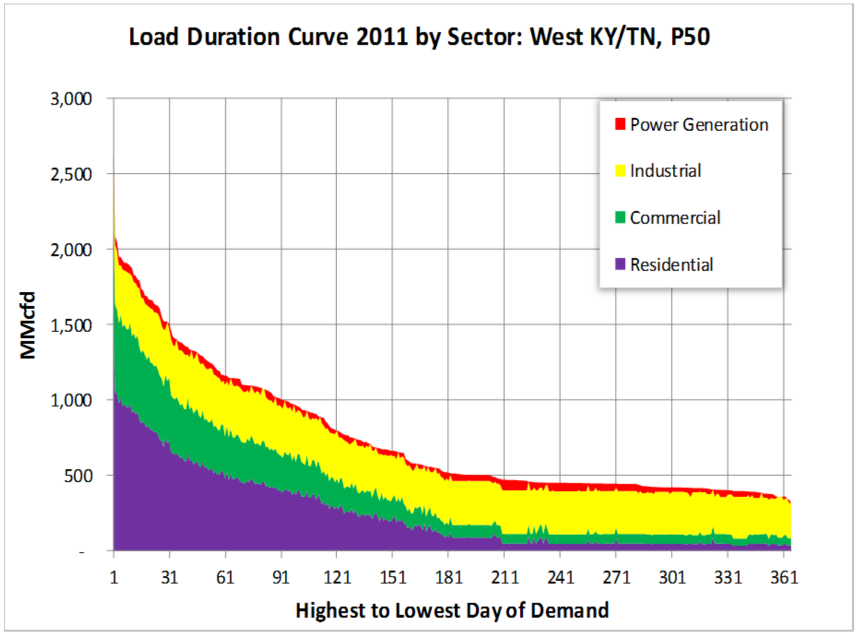

Load Growth 2030 vs 2011: North Mississippi, P50
MMcfd
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

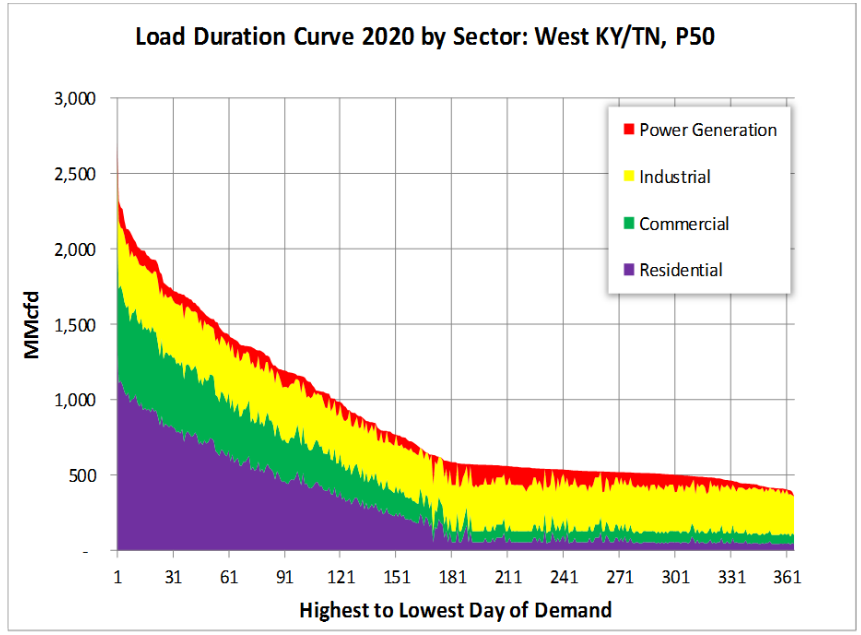

Load Duration Curve 2011 by Sector: South MS/AL, P50
1,600
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

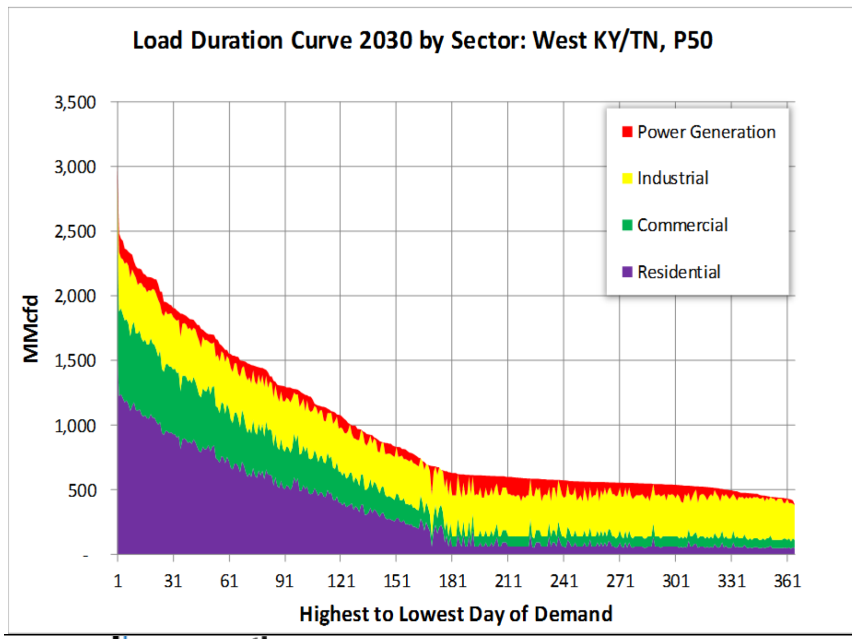

Load Duration Curve 2020 by Sector: South MS/AL, P50
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

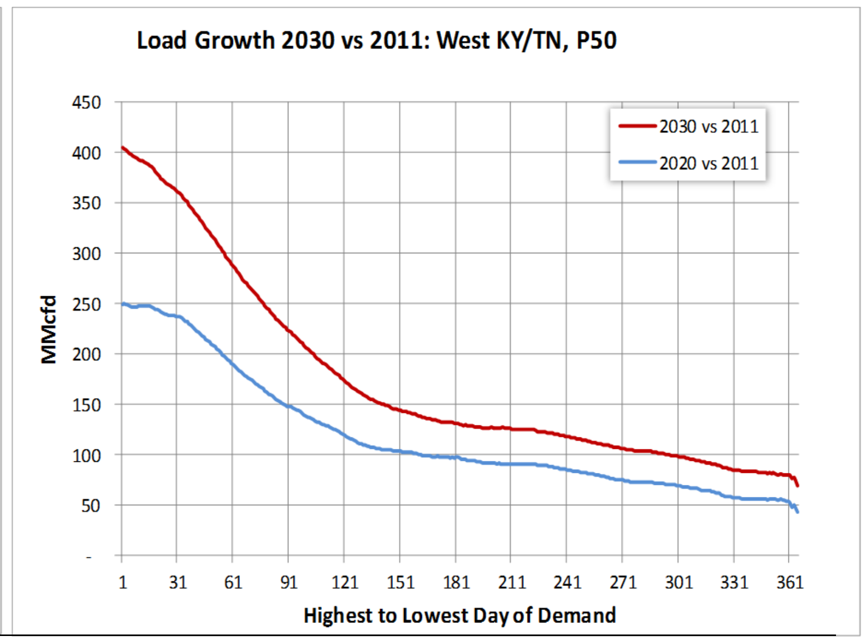

Load Duration Curve 2030 by Sector: South MS/AL, P50
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand


Load Growth 2030 vs 2011: South MS/AL, P50
180
160
140
120
100
80
60
40
20
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

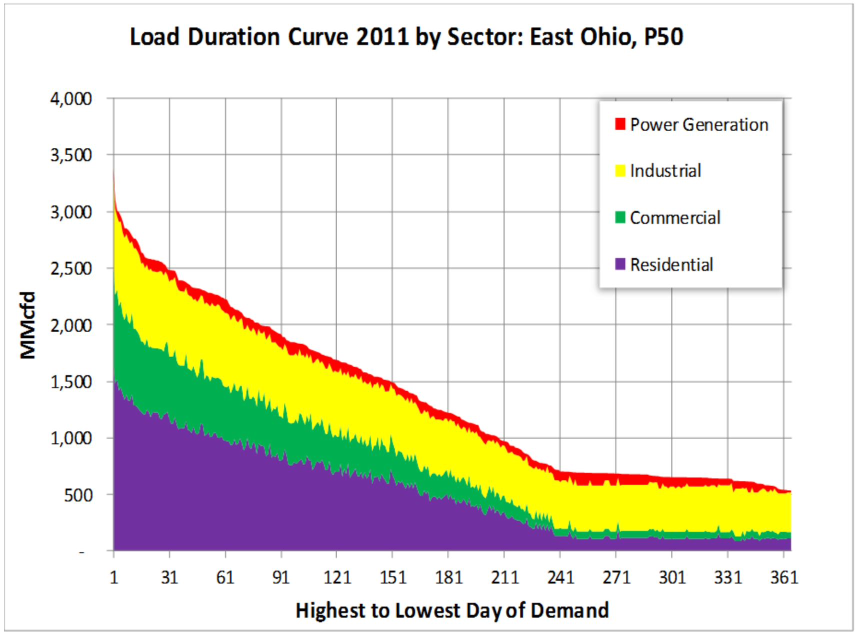

Load Duration Curve 2011 by Sector: West KY/TN, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

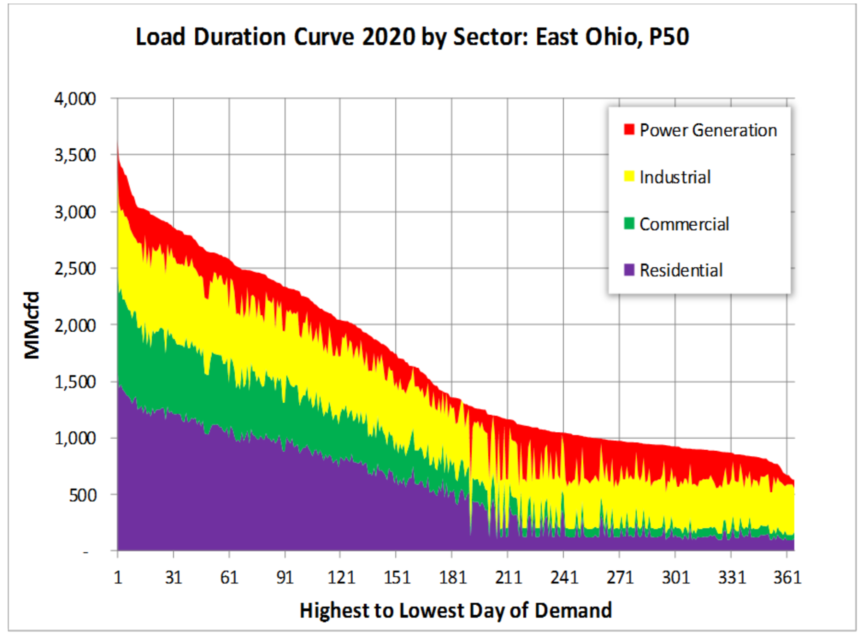

Load Duration Curve 2020 by Sector: West KY/TN, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

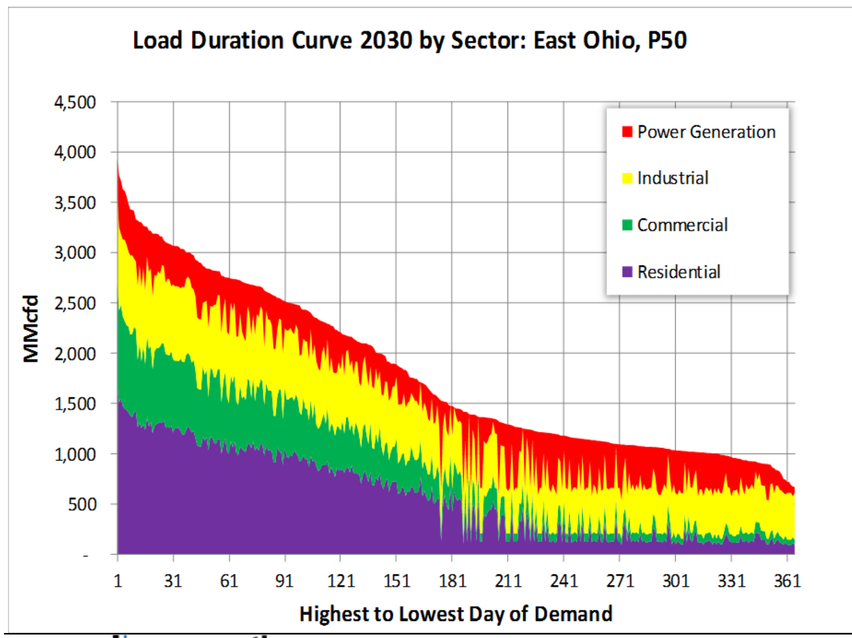

Load Duration Curve 2030 by Sector: West KY/TN, P50
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

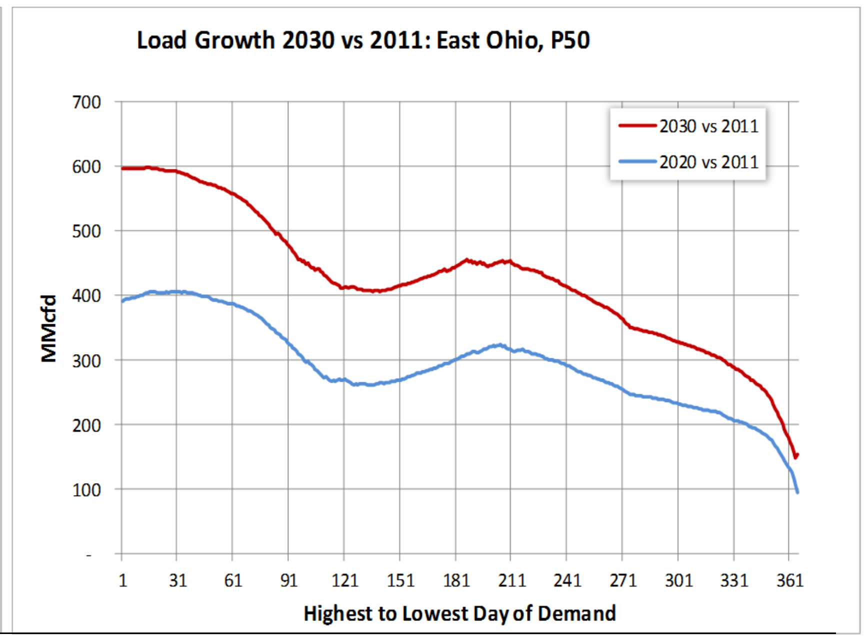

Load Growth 2030 vs 2011: West KY/TN, P50
450
400
350
300
250
200
150
100
50
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

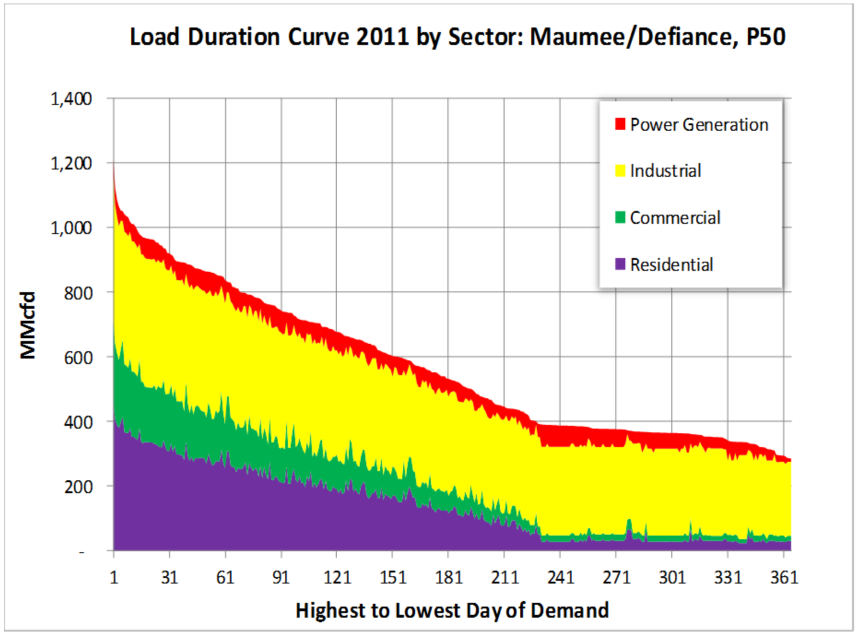
9.1.3 Midwest

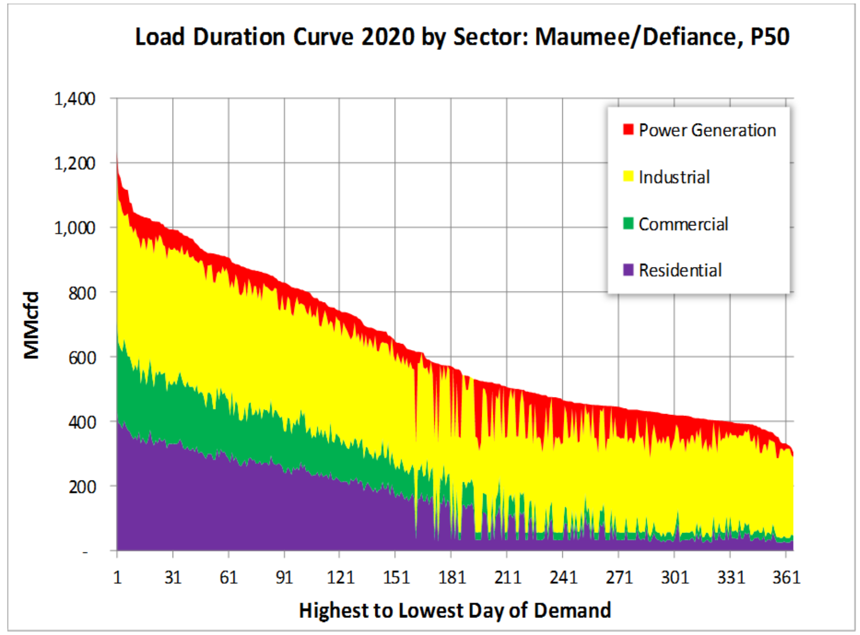

Load Duration Curve 2011 by Sector: East Ohio, P50
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

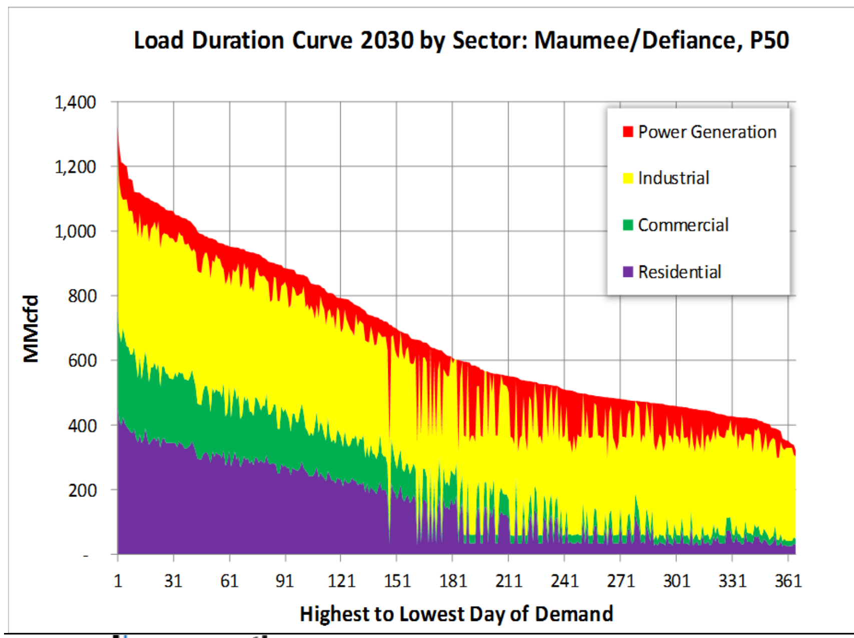

Load Duration Curve 2020 by Sector: East Ohio, P50
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

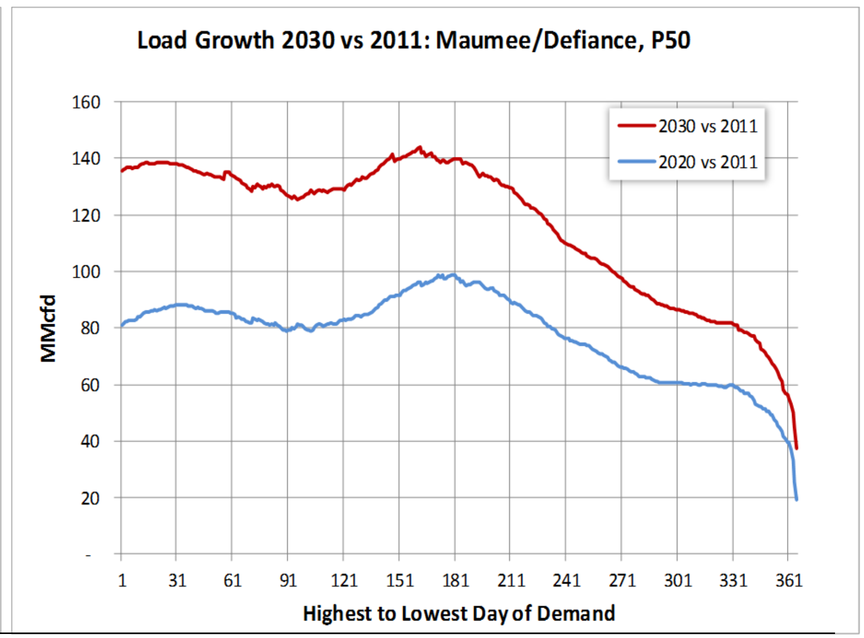

Load Duration Curve 2030 by Sector: East Ohio, P50
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

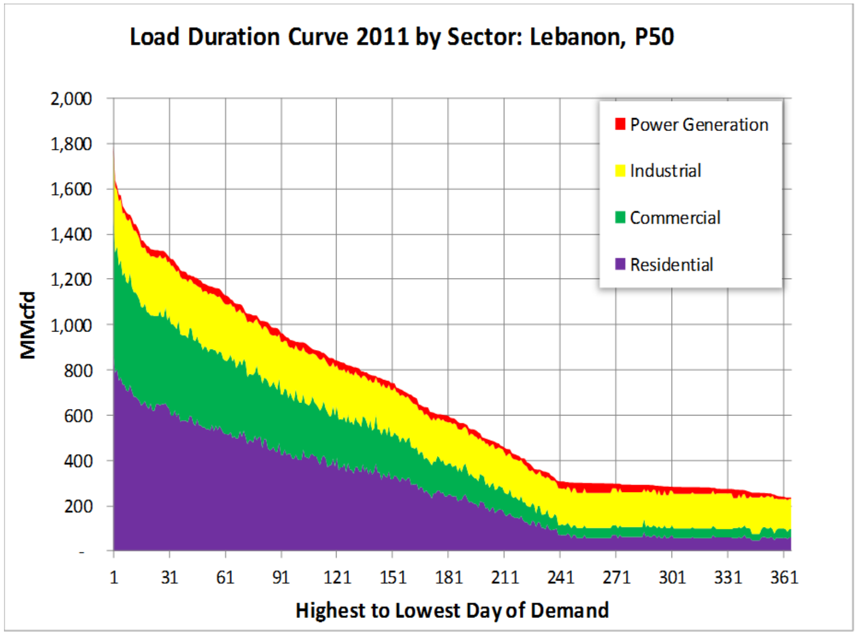

Load Growth 2030 vs 2011: East Ohio, P50
700
600
500
400
300
200
100
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

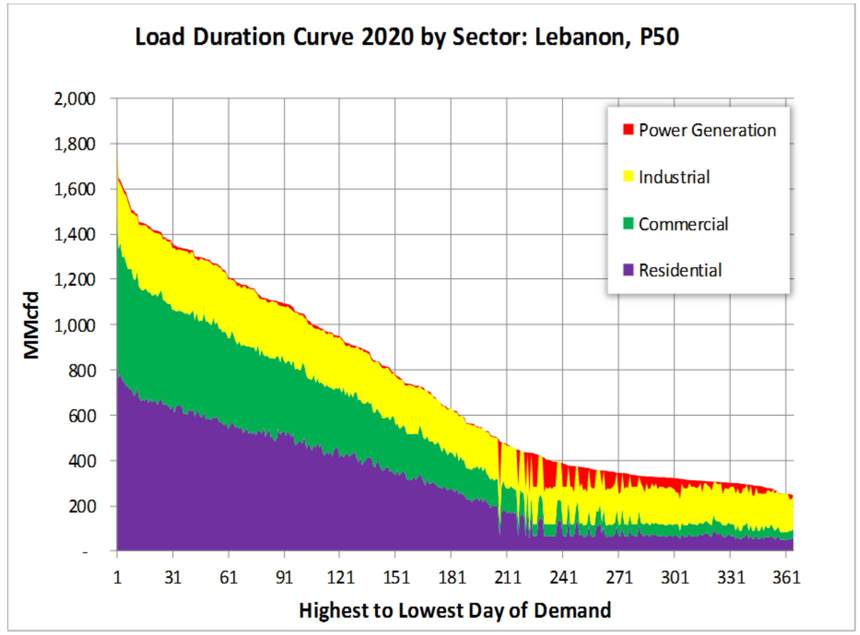

Load Duration Curve 2011 by Sector: Maumee/Defiance, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

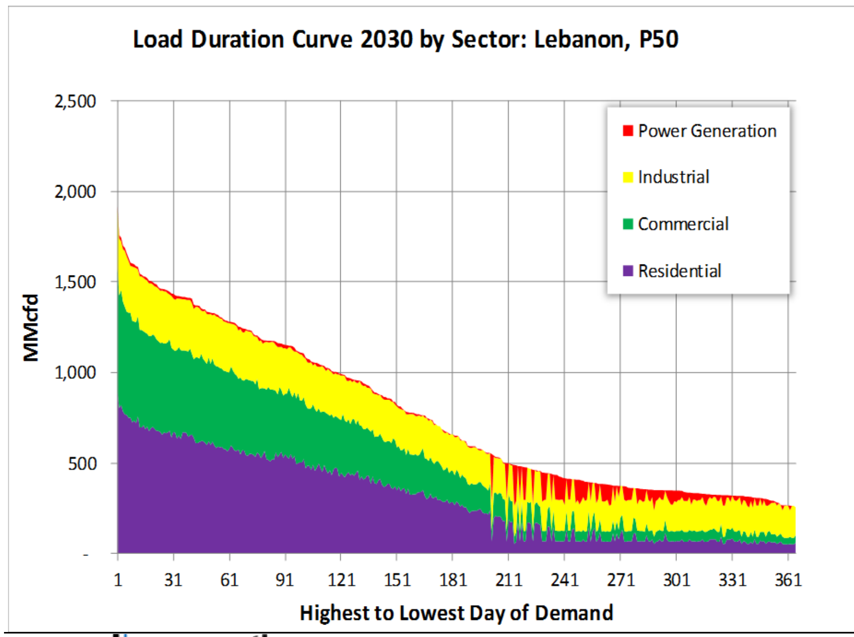

Load Duration Curve 2020 by Sector: Maumee/Defiance, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

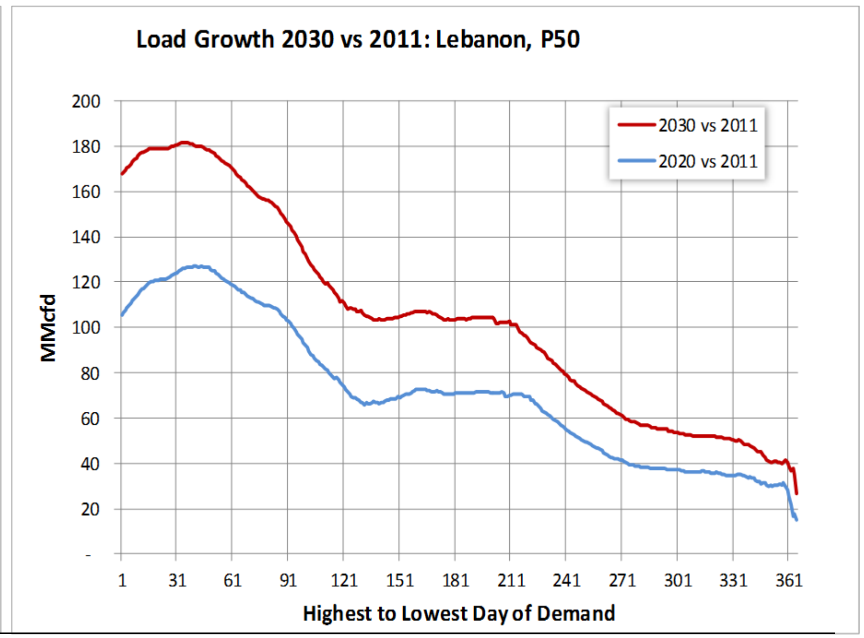

Load Duration Curve 2030 by Sector: Maumee/Defiance, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand


Load Growth 2030 vs 2011: Maumee/Defiance, P50
2030 vs 2011
2020 vs 2011
MMcfd
160
140
120
100
80
60
40
20
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

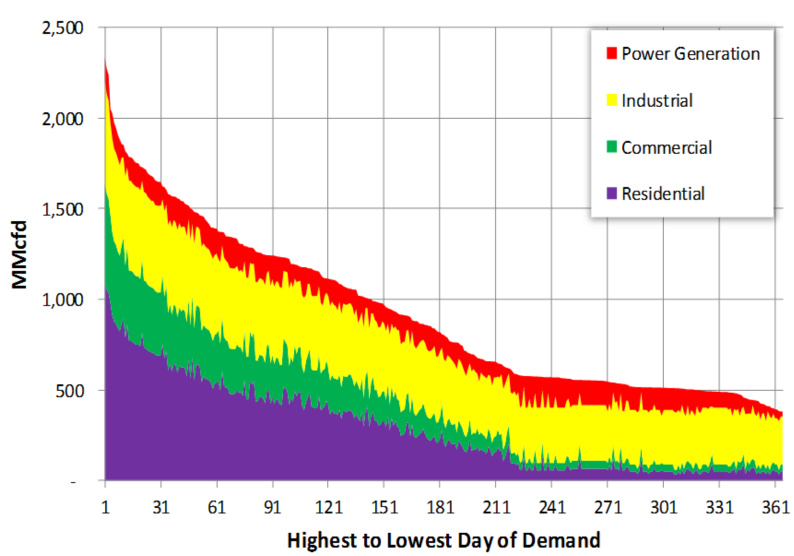

Load Duration Curve 2011 by Sector: Lebanon, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand


Load Duration Curve 2020 by Sector: Lebanon, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

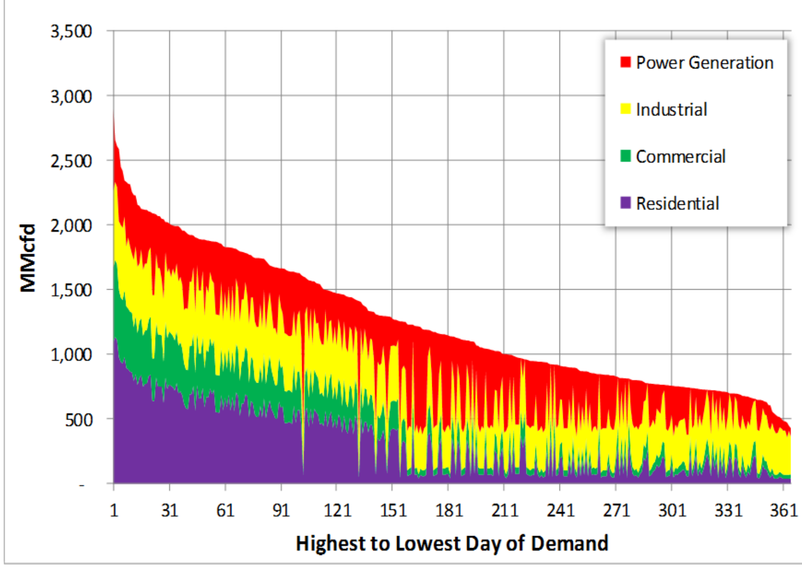

Load Duration Curve 2030 by Sector: Lebanon, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand


Load Growth 2030 vs 2011: Lebanon, P50
2030 vs 2011
2020 vs 2011
MMcfd
200
180
160
140
120
100
80
60
40
20
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

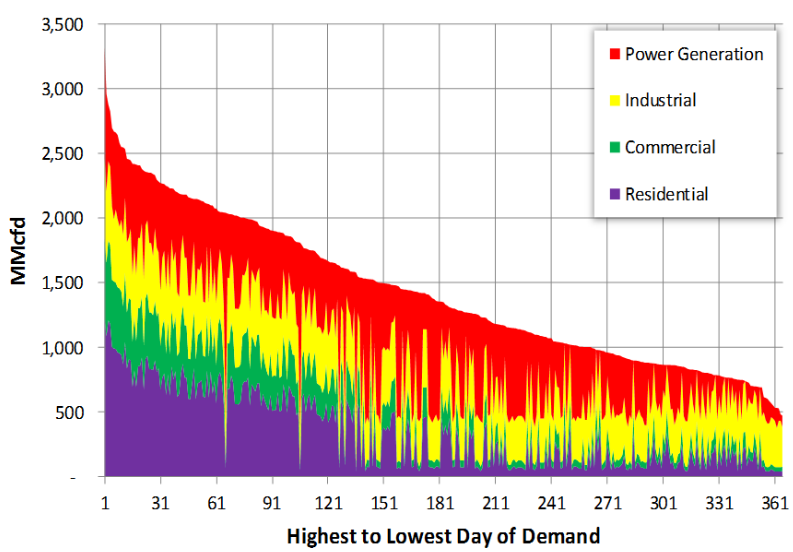
Load Duration Curve 2011 by Sector: Indiana, P50



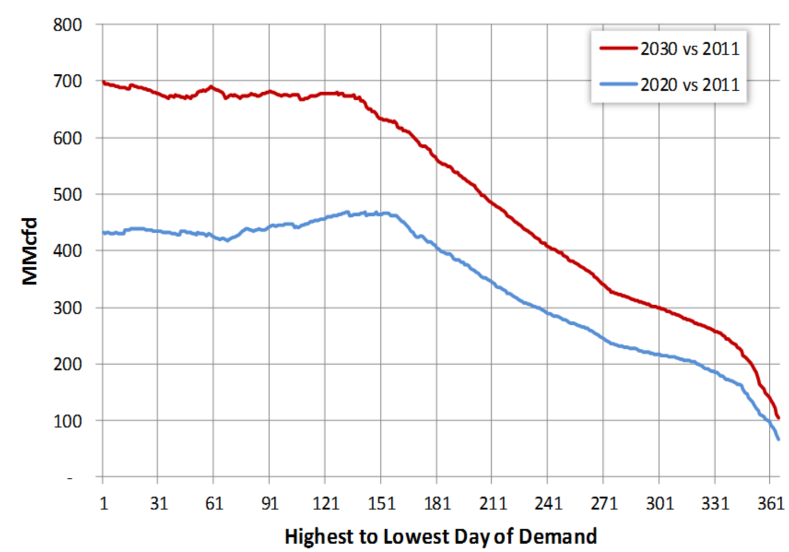
Load Duration Curve 2020 by Sector: Indiana, P50

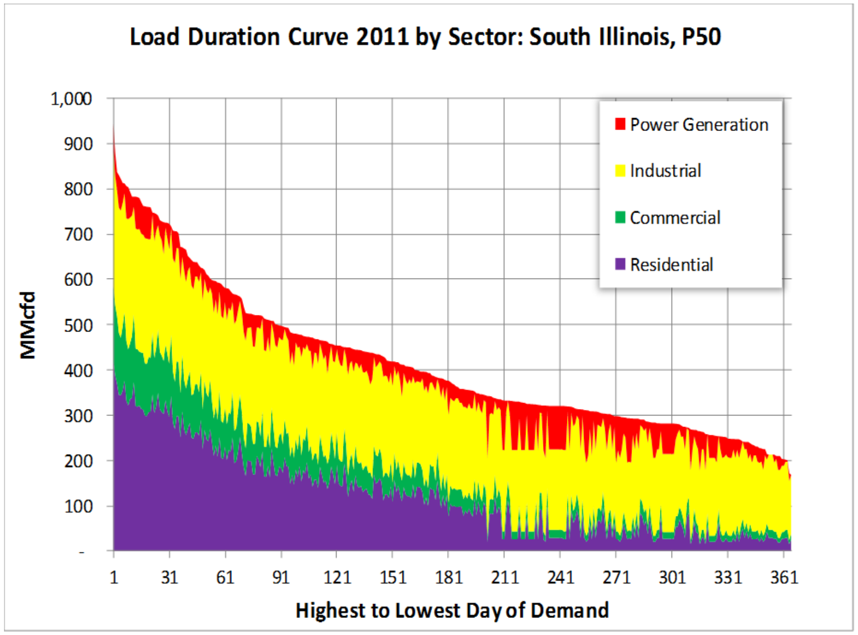


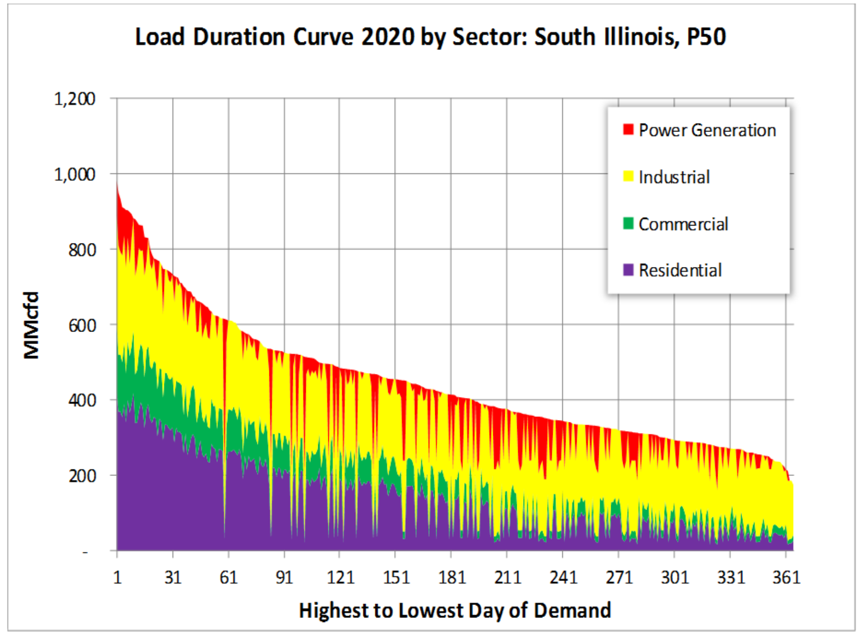
Load Duration Curve 2030 by Sector: Indiana, P50

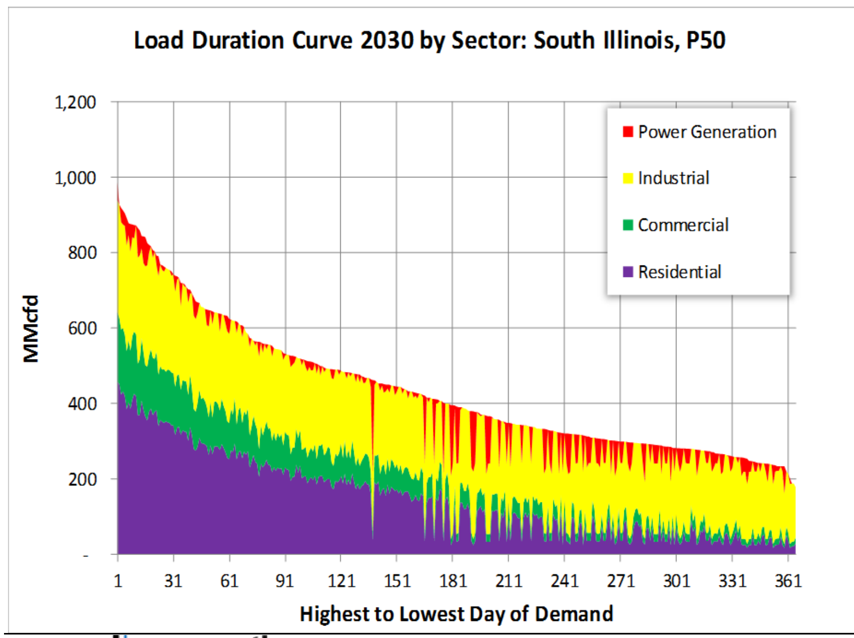


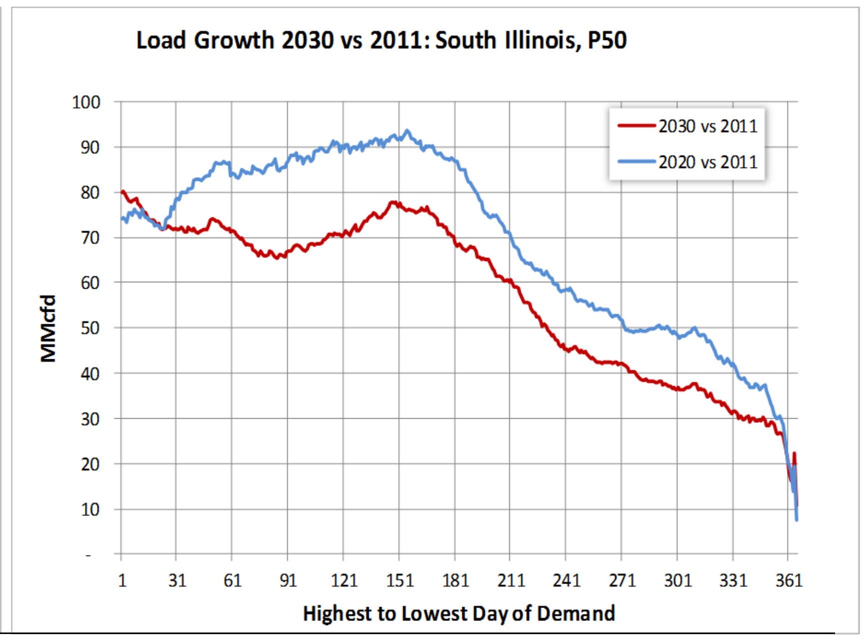
Load Growth 2030 vs 2011: Indiana, P50

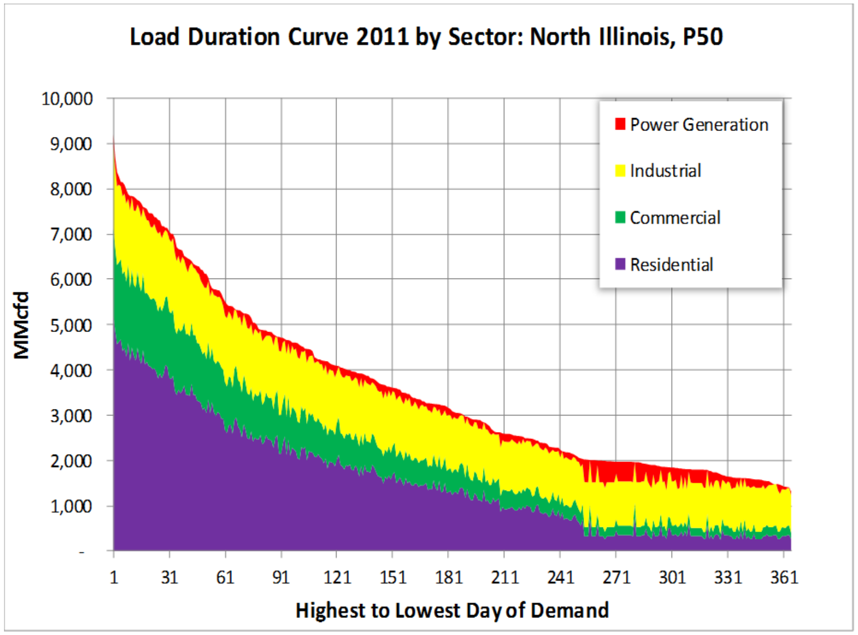


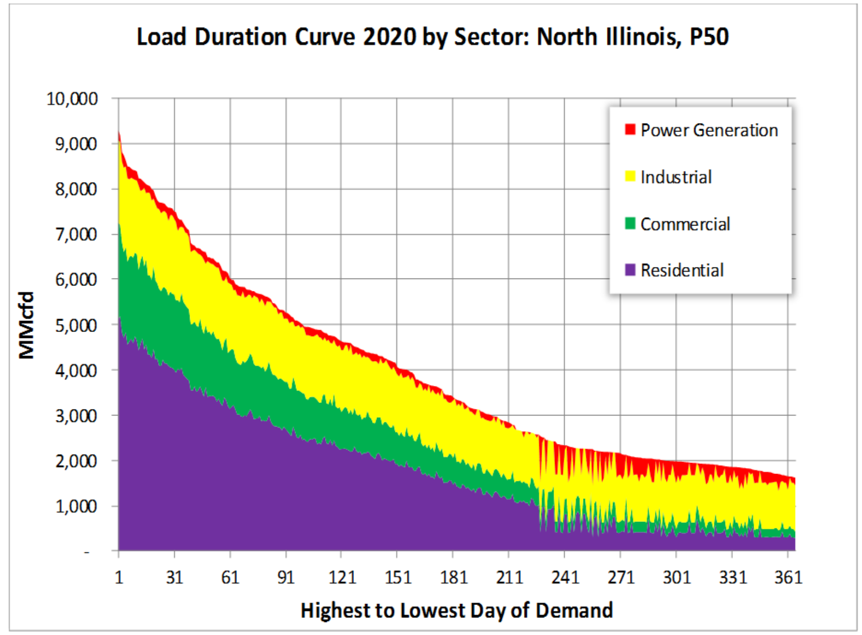

Load Duration Curve 2011 by Sector: South Illinois, P50
1,000
900
800
700
600
500
400
300
200
100
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

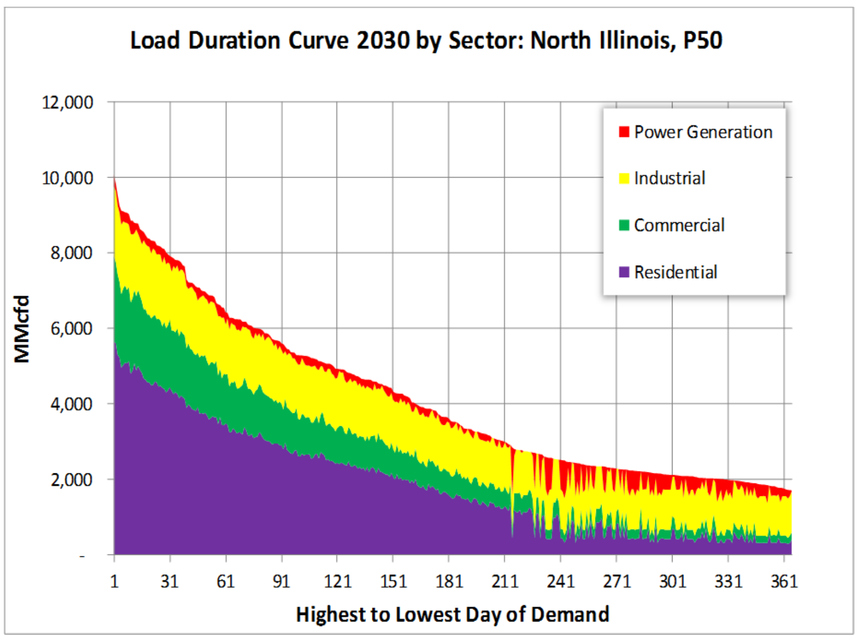

Load Duration Curve 2020 by Sector: South Illinois, P50
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

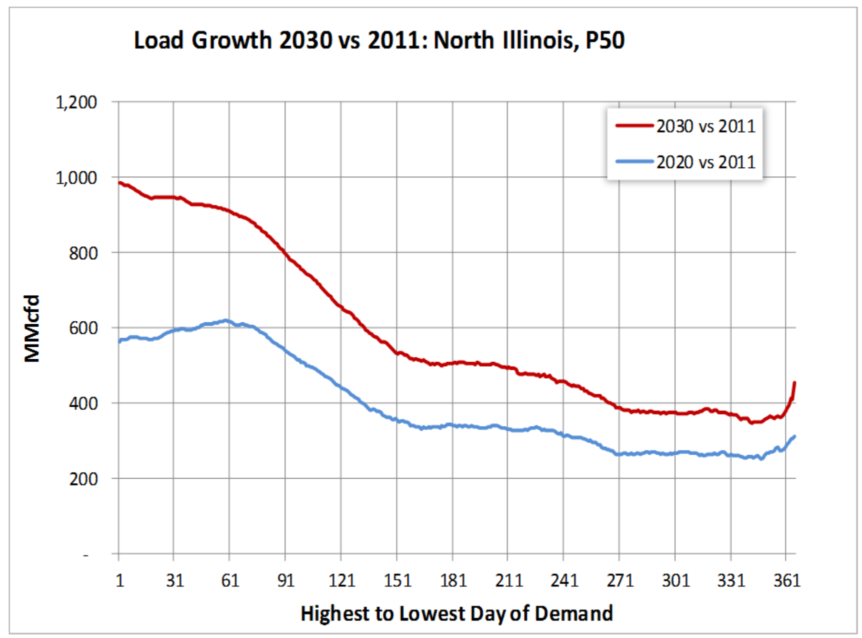

Load Duration Curve 2030 by Sector: South Illinois, P50
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

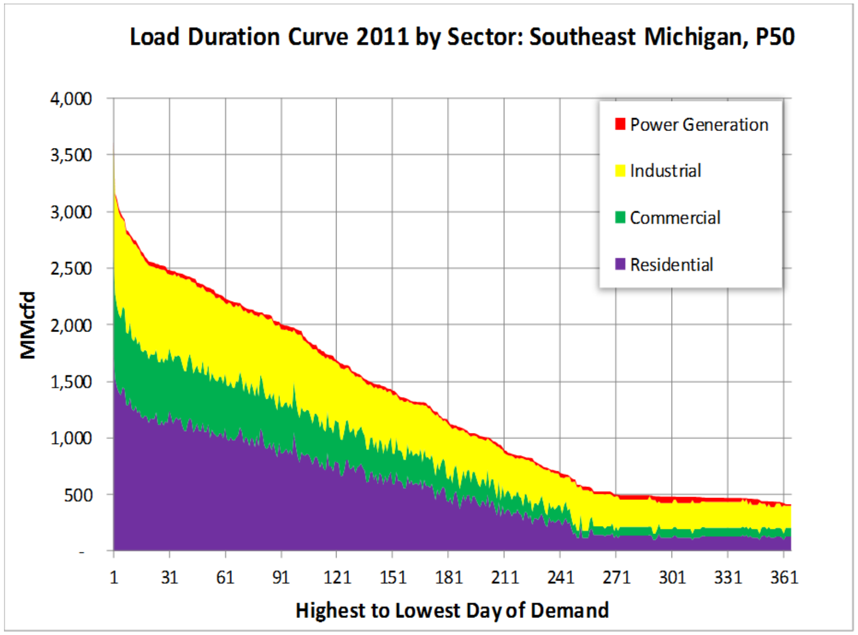

Load Growth 2030 vs 2011: South Illinois, P50
100
90
80
70
60
50
40
30
20
10
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

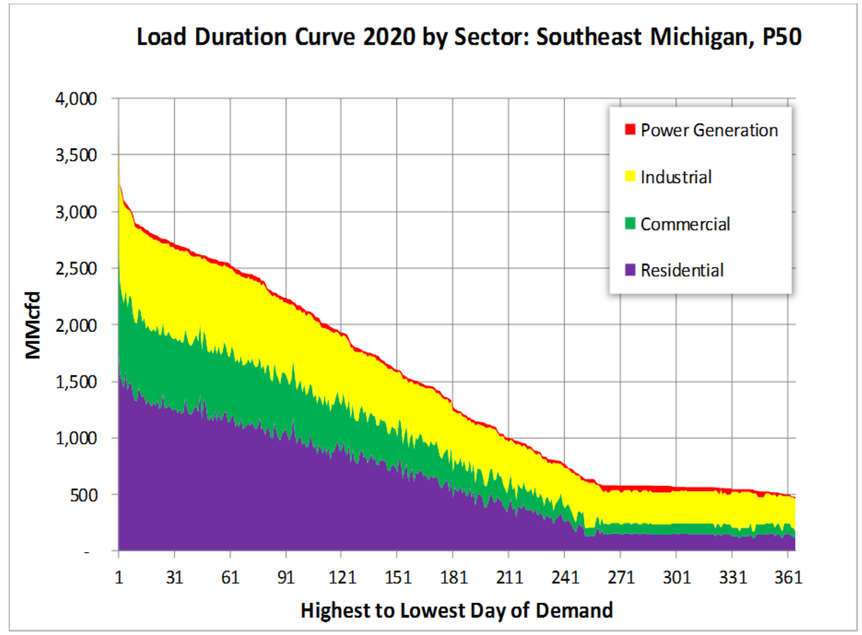

Load Duration Curve 2011 by Sector: North Illinois, P50
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

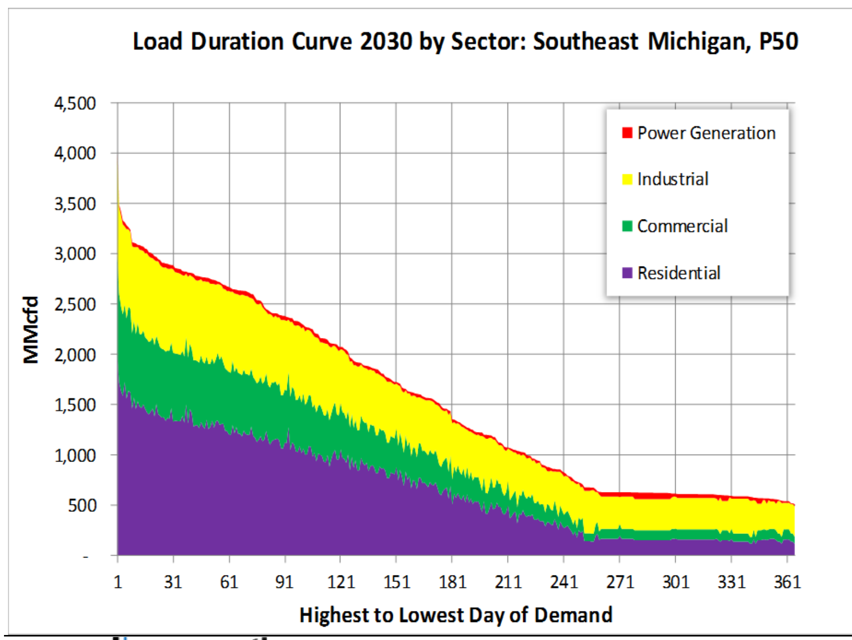

Load Duration Curve 2020 by Sector: North Illinois, P50
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

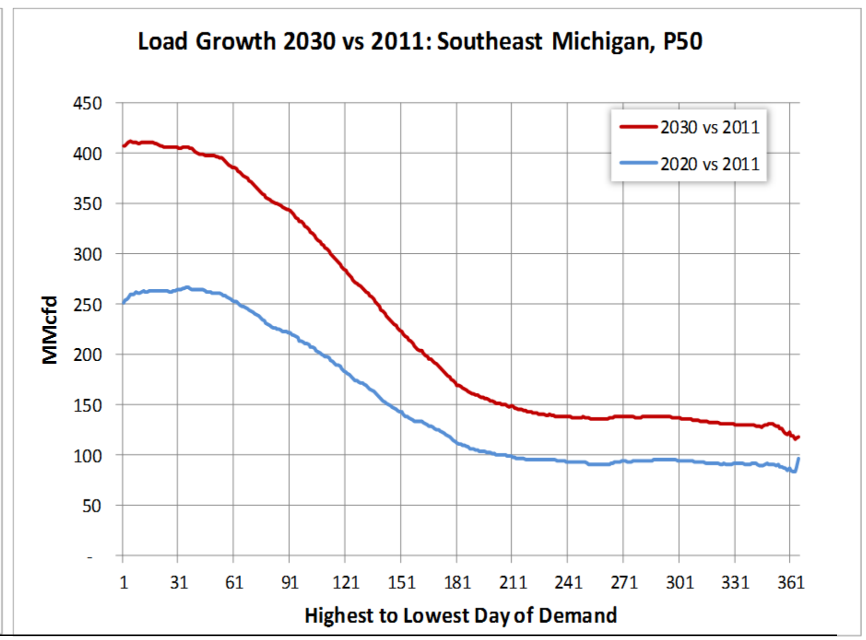

Load Duration Curve 2030 by Sector: North Illinois, P50
12,000
10,000
8,000
6,000
4,000
2,000
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

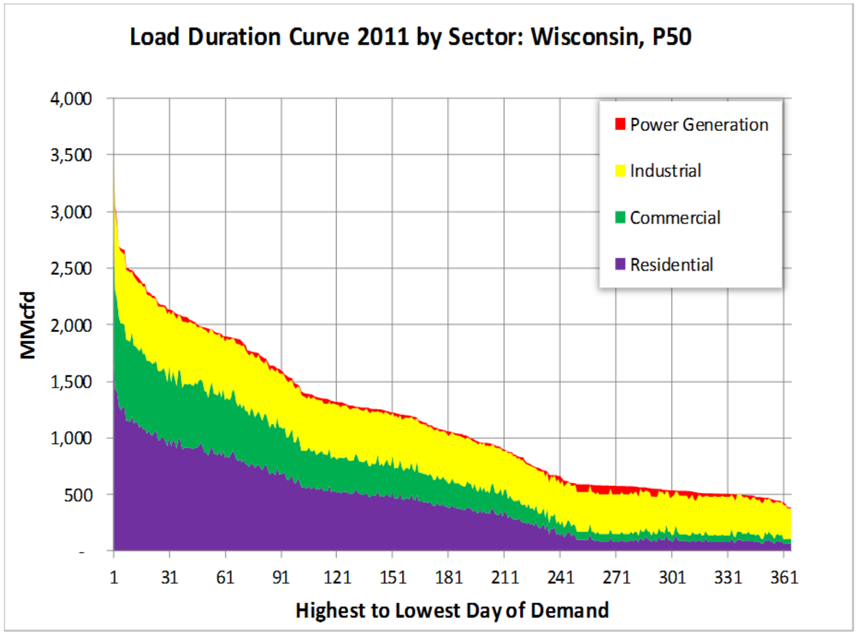

Load Growth 2030 vs 2011: North Illinois, P50
1,200
1,000
800
600
400
200
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

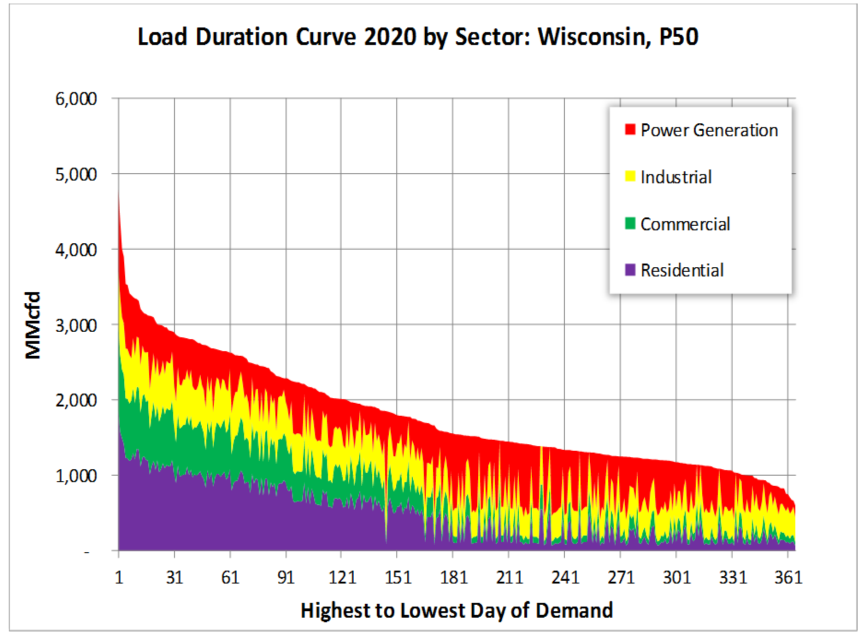

Load Duration Curve 2011 by Sector: Southeast Michigan, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

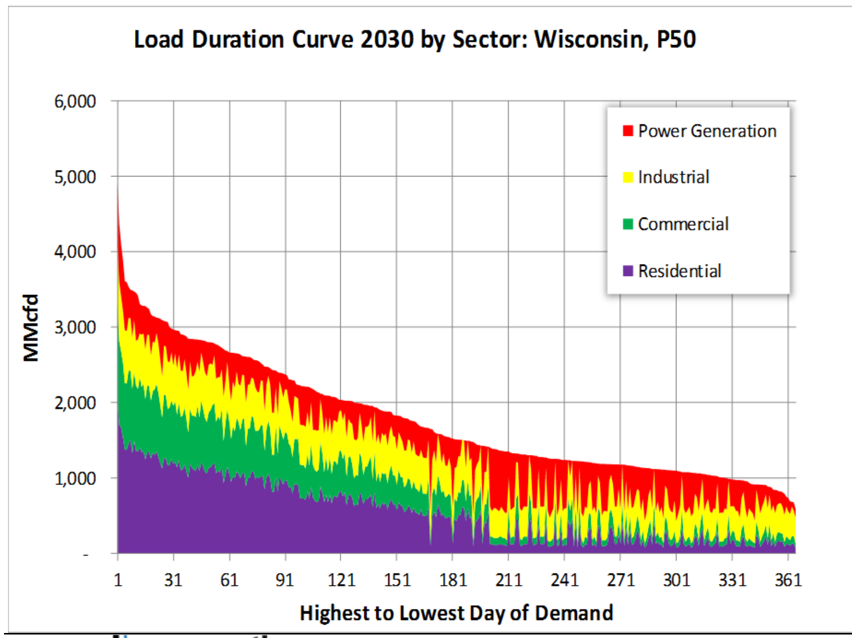

Load Duration Curve 2020 by Sector: Southeast Michigan, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

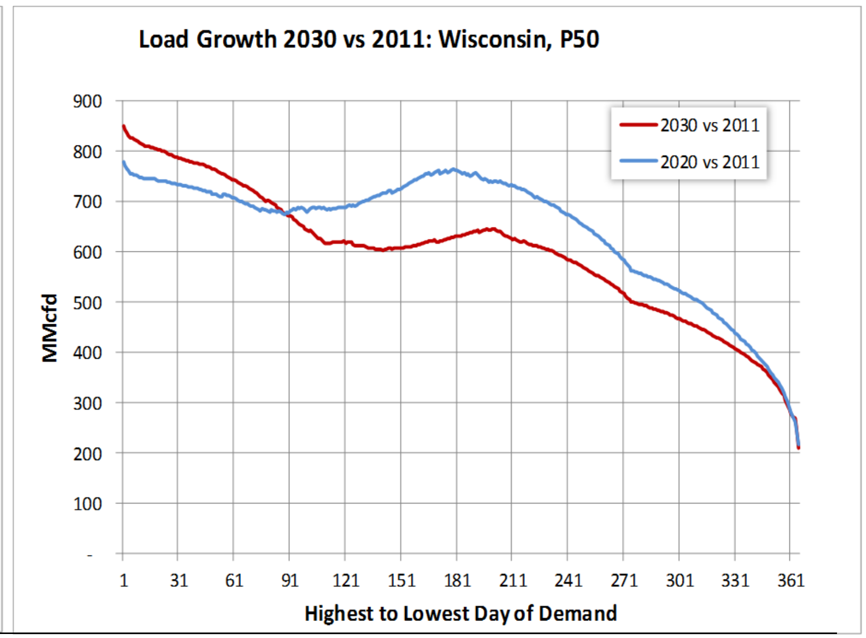

Load Duration Curve 2030 by Sector: Southeast Michigan, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

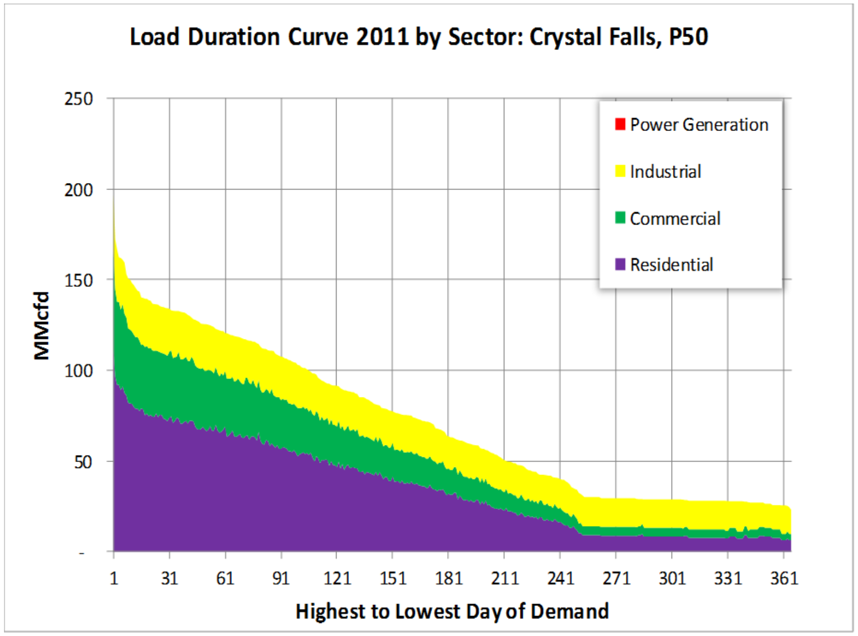

Load Growth 2030 vs 2011: Southeast Michigan, P50
2030 vs 2011
2020 vs 2011
MMcfd
450
400
350
300
250
200
150
100
50
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

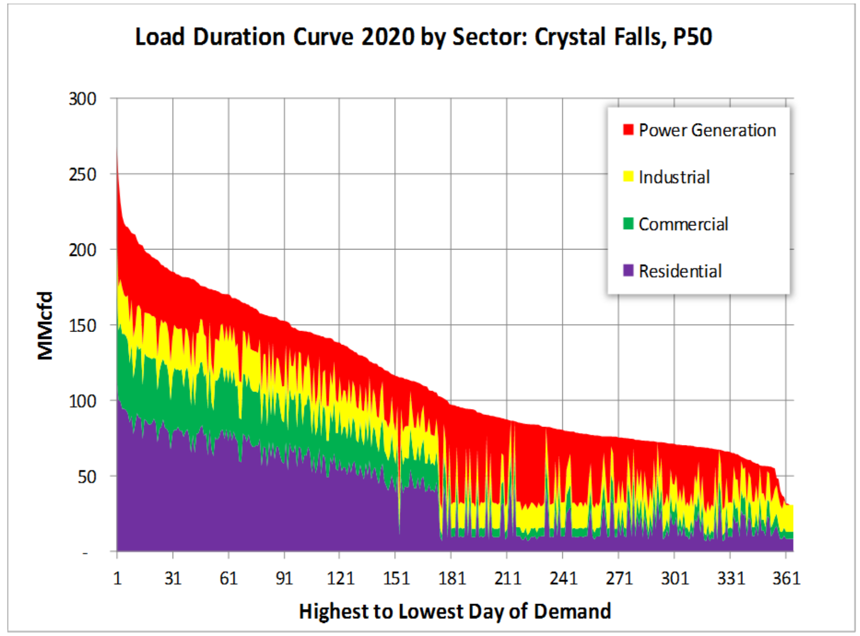

Load Duration Curve 2011 by Sector: Wisconsin, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361

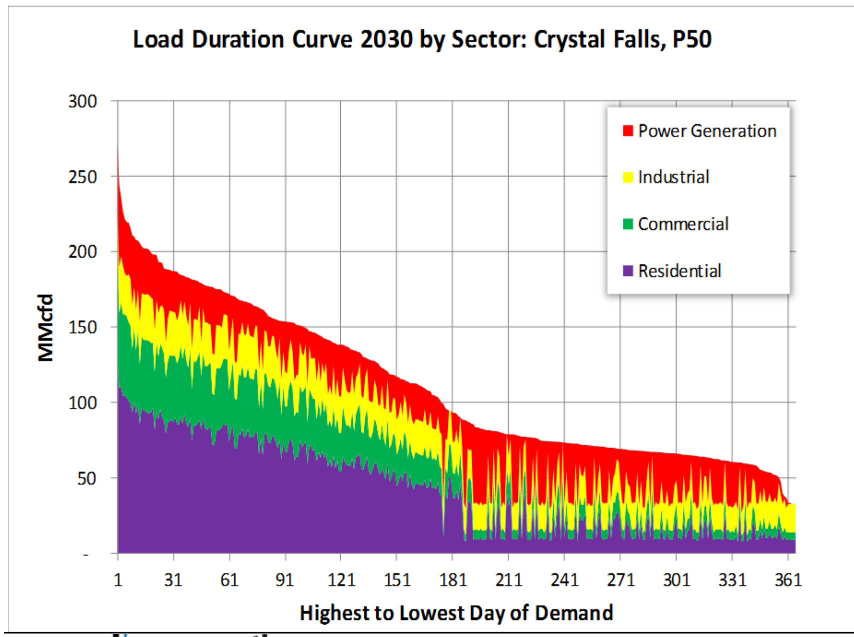

Load Duration Curve 2020 by Sector: Wisconsin, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361

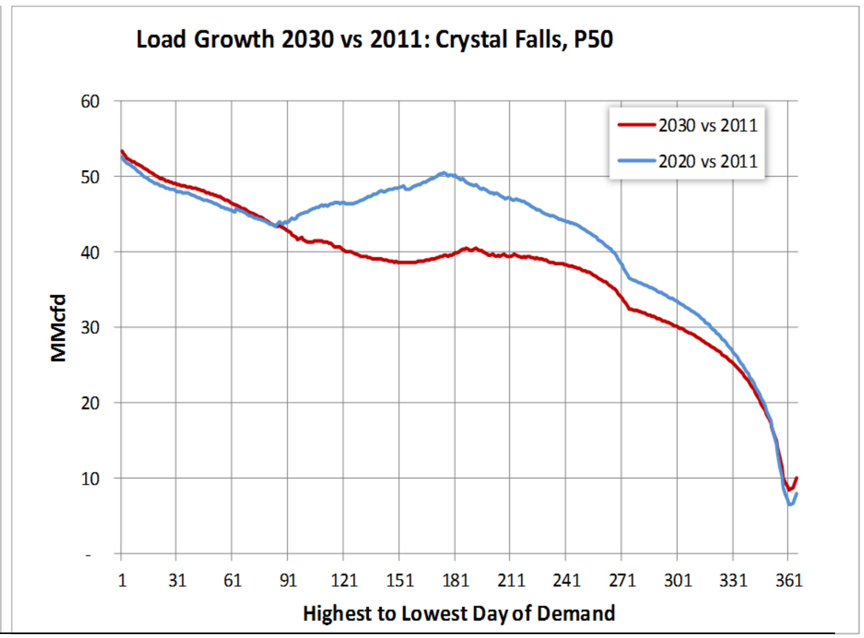

Load Duration Curve 2030 by Sector: Wisconsin, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
6,000
5,000
4,000
3,000
2,000
1,000
-
1
31
61
91
121
151
181
211
241
271
301
331
361

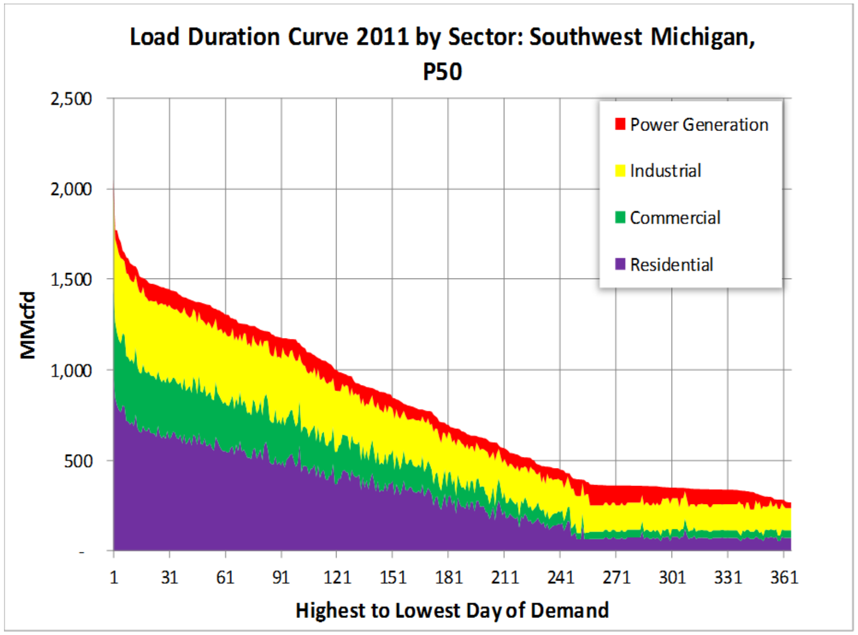

Load Growth 2030 vs 2011: Wisconsin, P50
MMcfd
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361

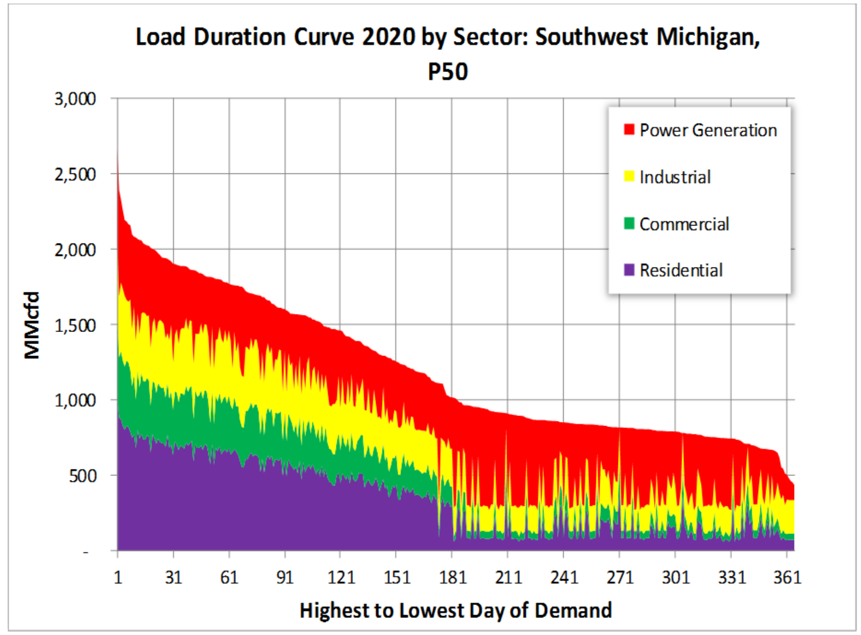

Load Duration Curve 2011 by Sector: Crystal Falls, P50
250
200
150
100
50
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

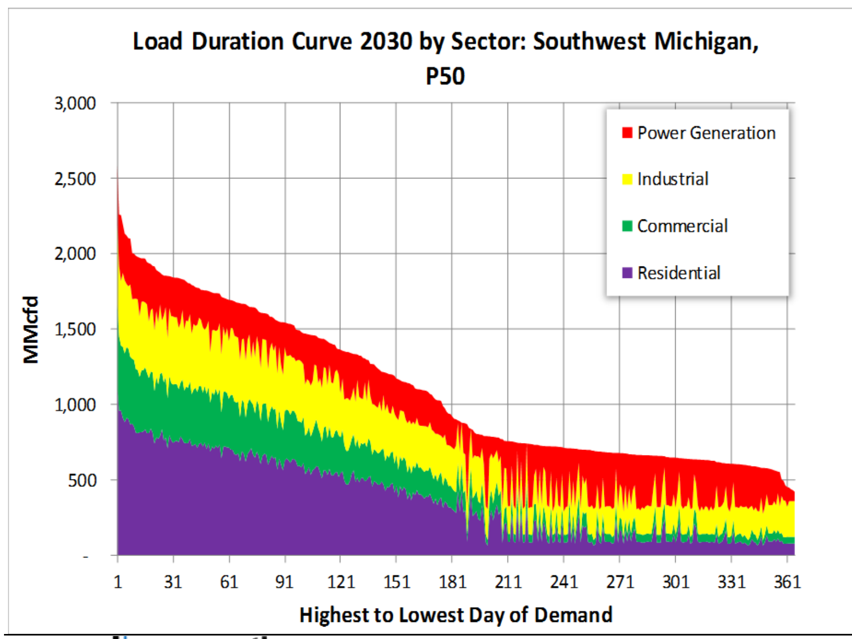

Load Duration Curve 2020 by Sector: Crystal Falls, P50
300
250
200
150
100
50
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

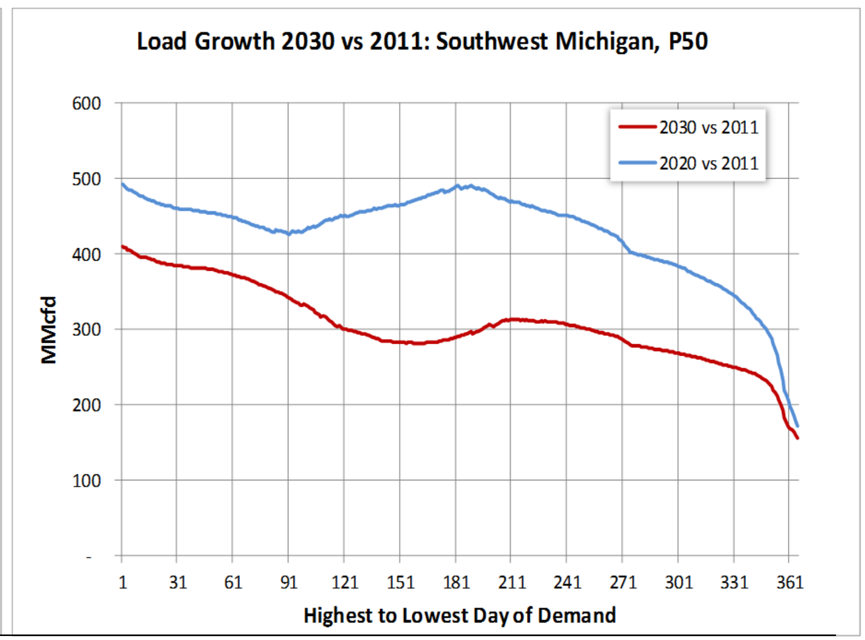

Load Duration Curve 2030 by Sector: Crystal Falls, P50
300
250
200
150
100
50
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

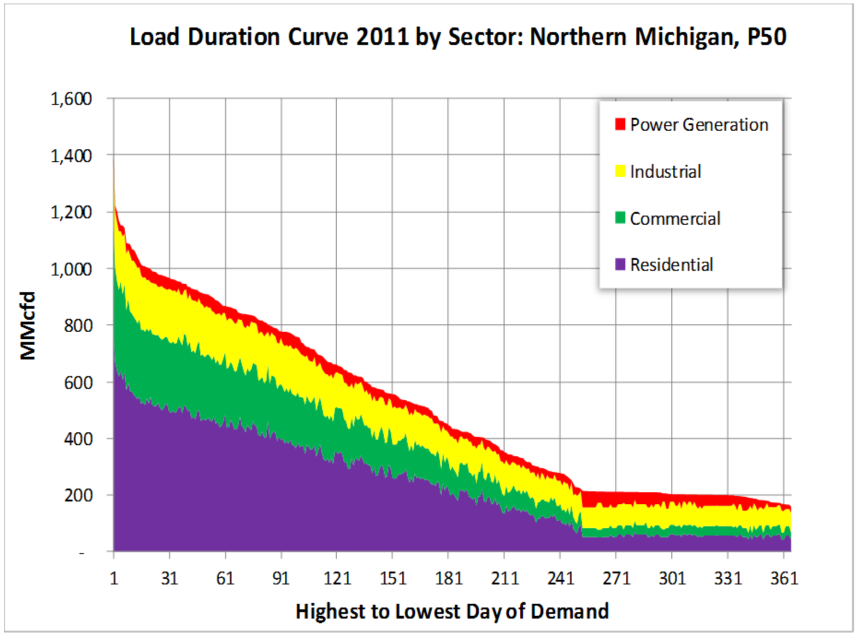

Load Growth 2030 vs 2011: Crystal Falls, P50
60
50
40
30
20
10
-
MMcfd
2030 vs 2011
2020 vs 2011
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

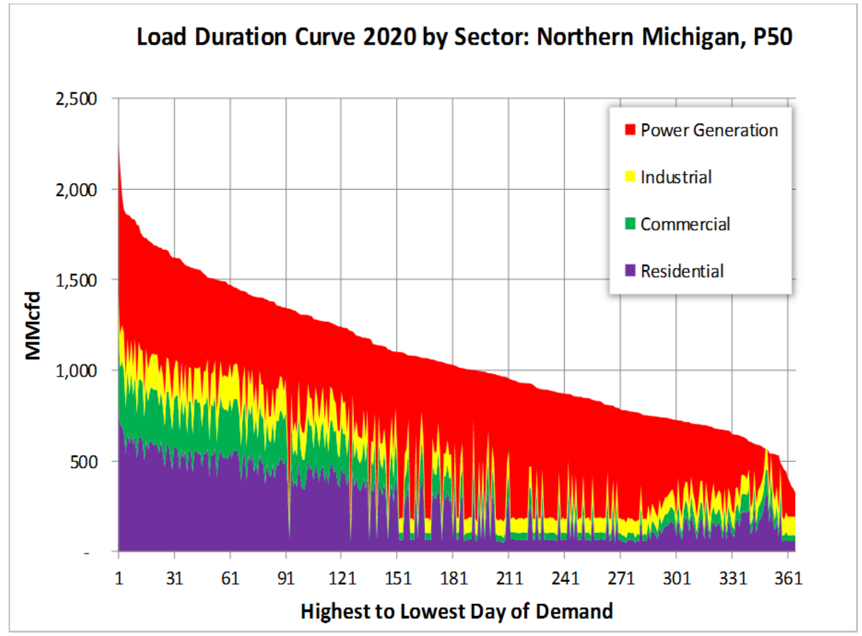

Load Duration Curve 2011 by Sector: Southwest Michigan, P50
MMcfd
2,500
2,000
1,500
1,000
500
-
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

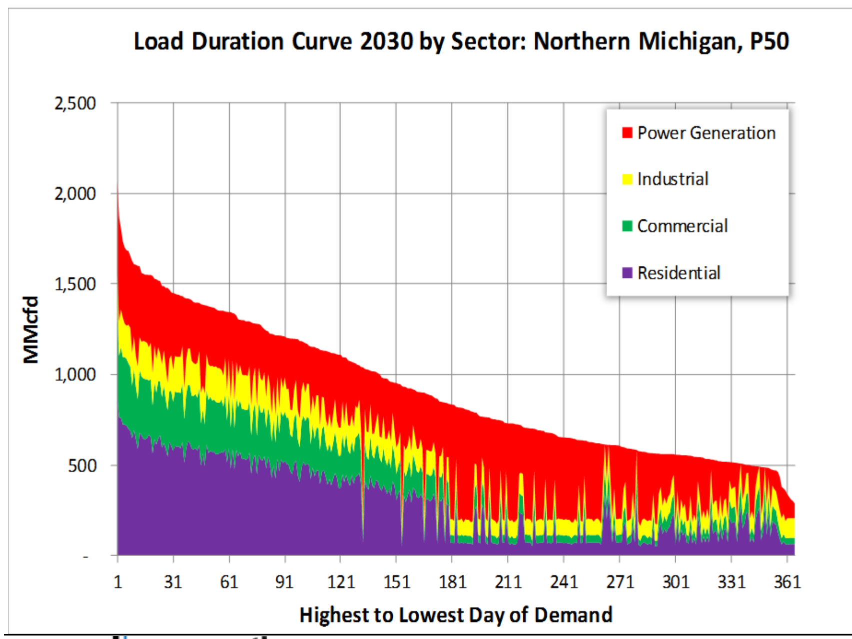

Load Duration Curve 2020 by Sector: Southwest Michigan, P50
MMcfd
3,000
2,500
2,000
1,500
1,000
500
-
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

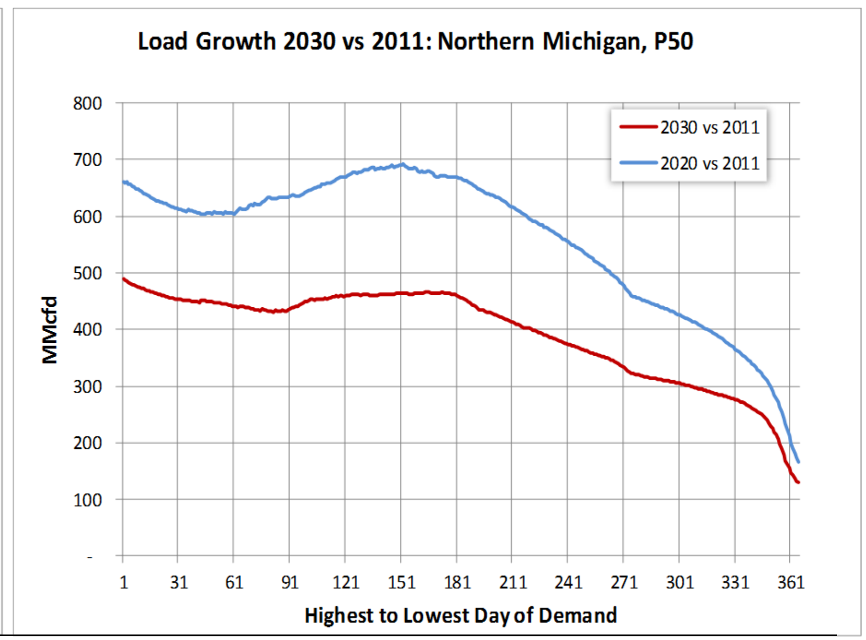

Load Duration Curve 2030 by Sector: Southwest Michigan, P50
MMcfd
3,000
2,500
2,000
1,500
1,000
500
-
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

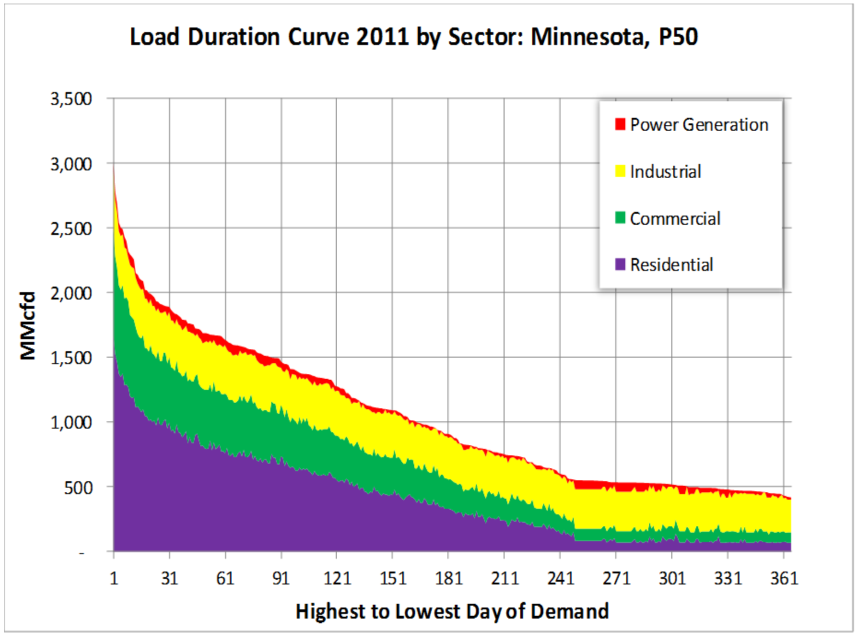

Load Growth 2030 vs 2011: Southwest Michigan, P50
MMcfd
600
500
400
300
200
100
-
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

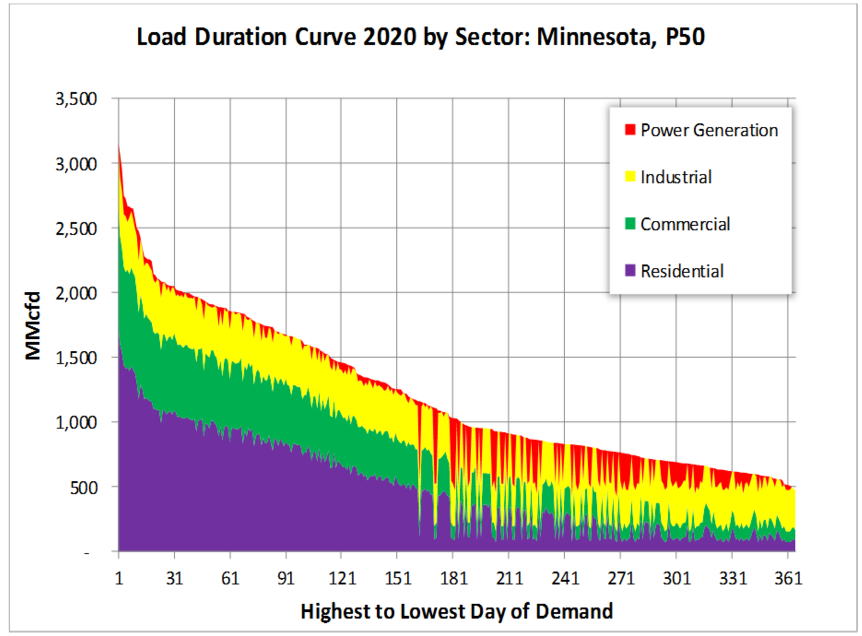

Load Duration Curve 2011 by Sector: Northern Michigan, P50
1,600
1,400
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

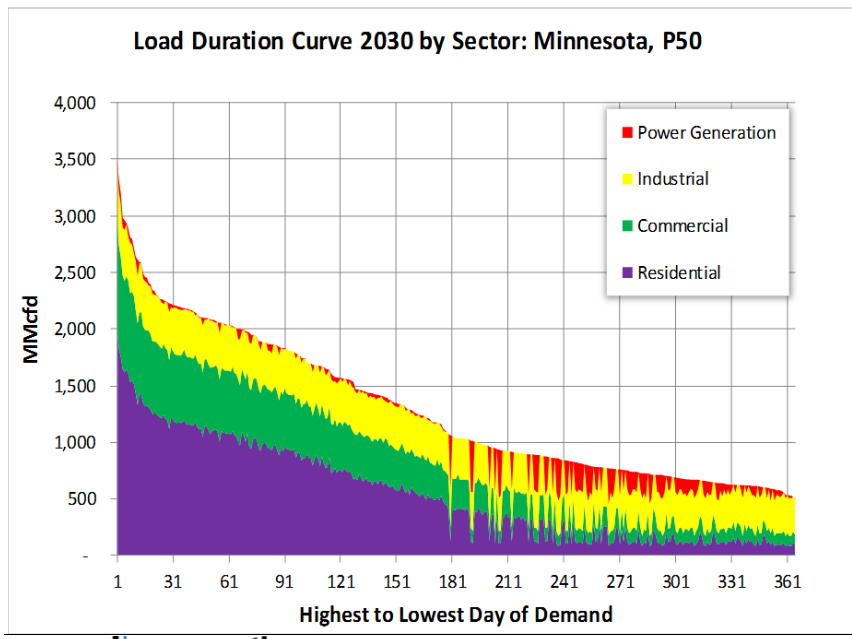

Load Duration Curve 2020 by Sector: Northern Michigan, P50
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

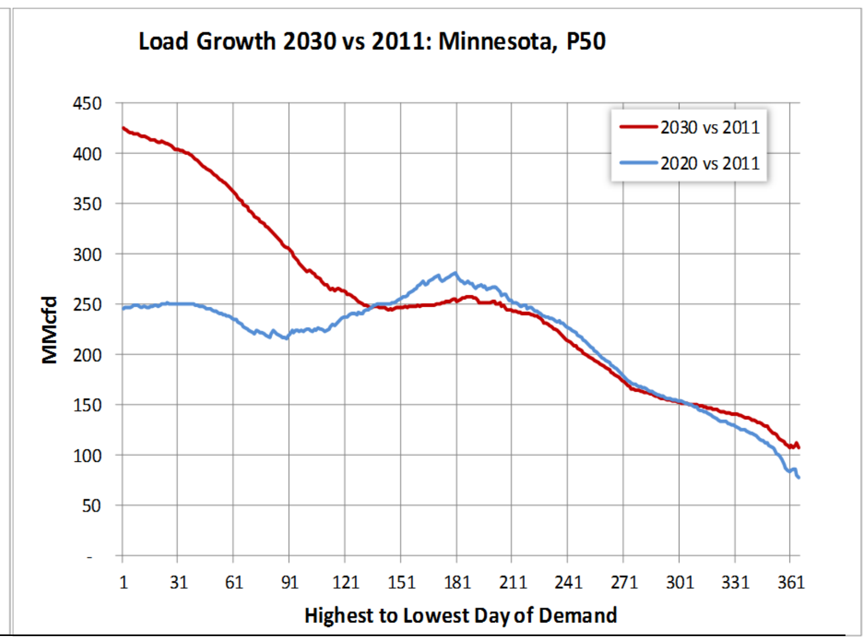

Load Duration Curve 2030 by Sector: Northern Michigan, P50
2,500
2,000
1,500
1,000
500
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand


Load Growth 2030 vs 2011: Northern Michigan, P50
800
700
600
500
400
300
200
100
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

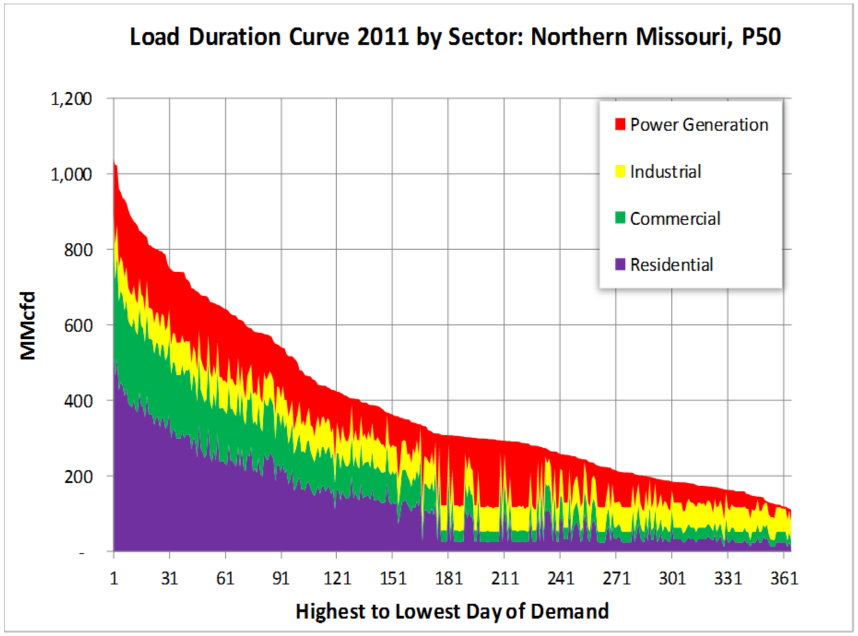

Load Duration Curve 2011 by Sector: Minnesota, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

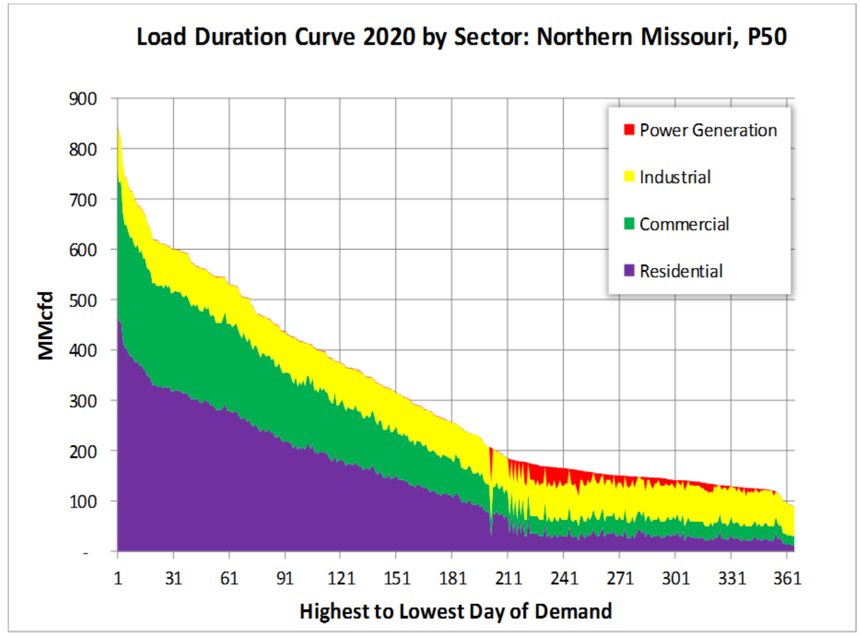

Load Duration Curve 2020 by Sector: Minnesota, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

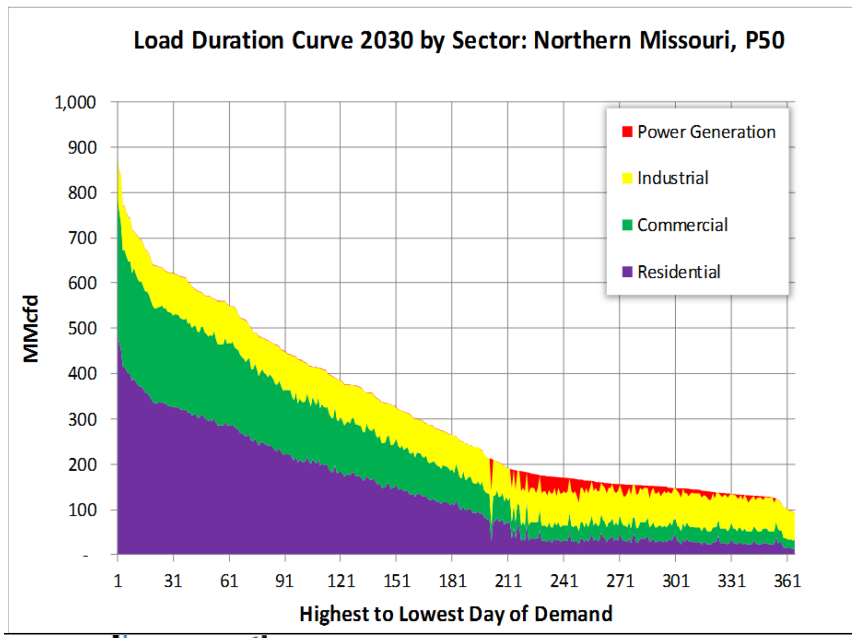

Load Duration Curve 2030 by Sector: Minnesota, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

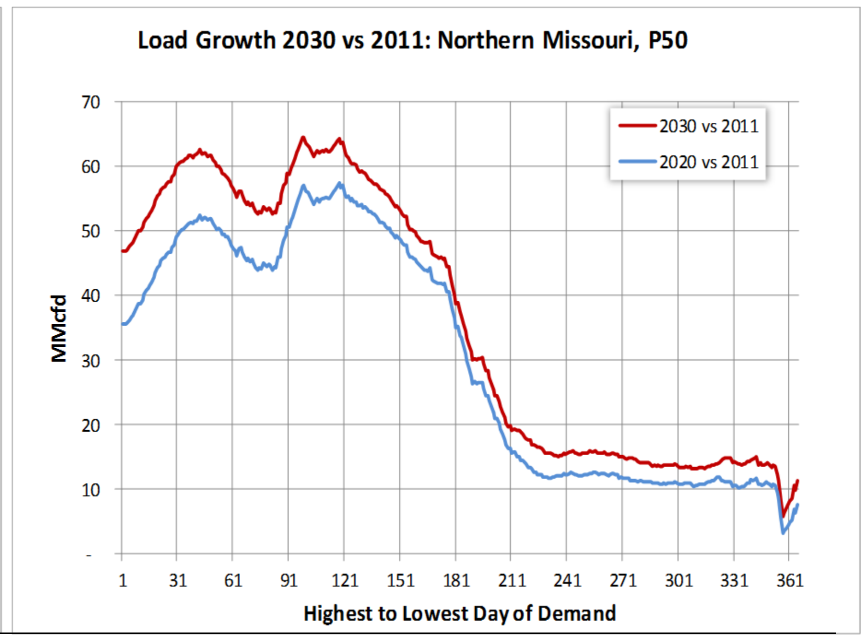

Load Growth 2030 vs 2011: Minnesota, P50
2030 vs 2011
2020 vs 2011
MMcfd
450
400
350
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

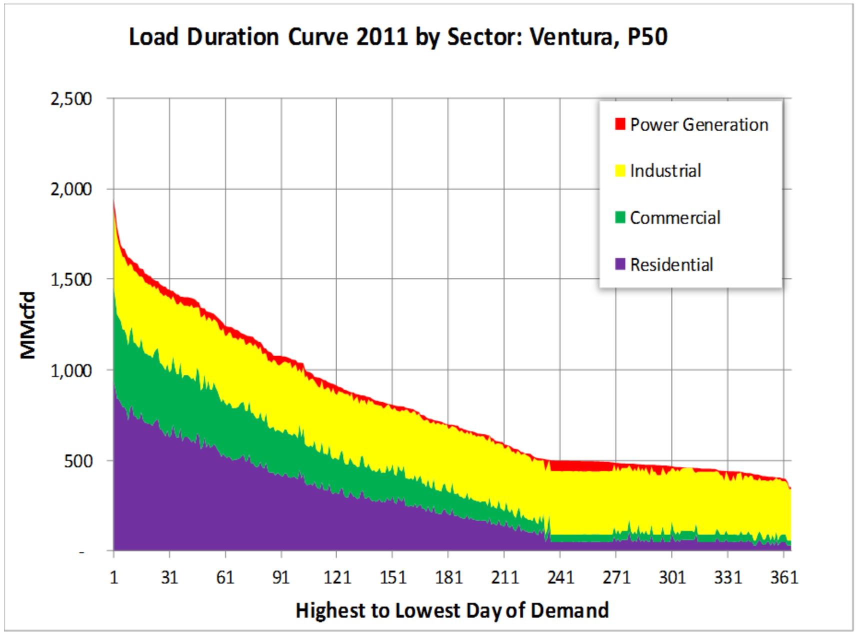
9.1.4 Central

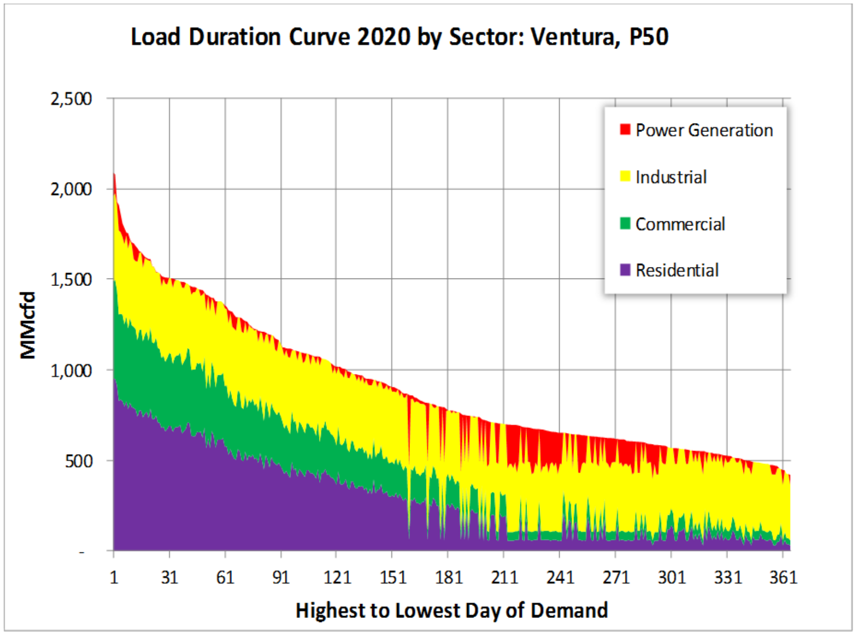

Load Duration Curve 2011 by Sector: Northern Missouri, P50
1,200
1,000
800
600
400
200
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

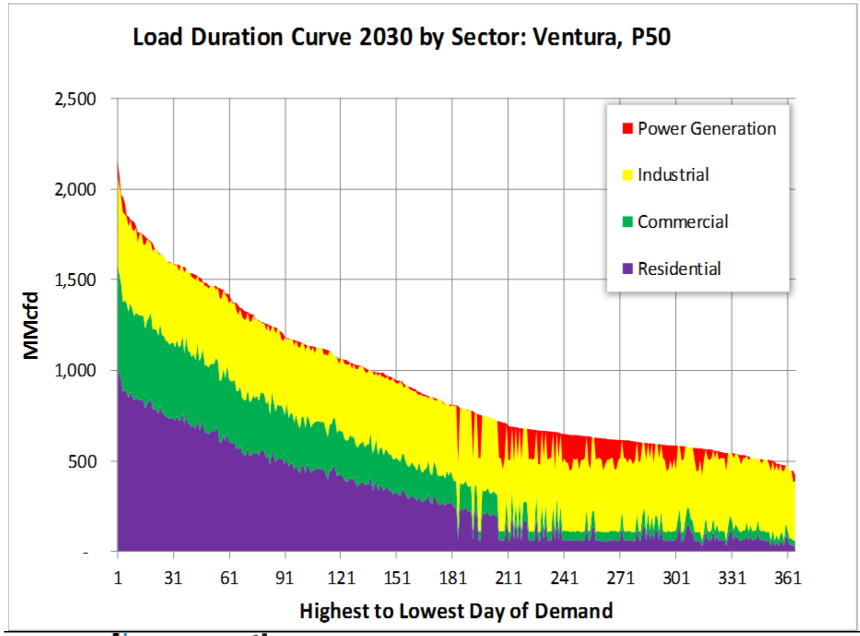

Load Duration Curve 2020 by Sector: Northern Missouri, P50
900
800
700
600
500
400
300
200
100
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

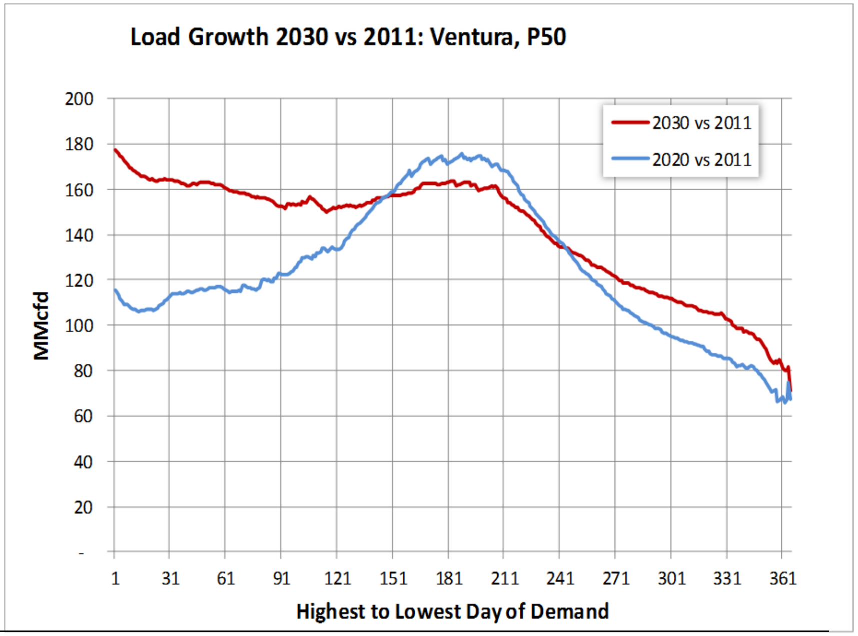

Load Duration Curve 2030 by Sector: Northern Missouri, P50
1,000
900
800
700
600
500
400
300
200
100
-
MMcfd
Power Generation
Industrial
Commercial
Residential
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

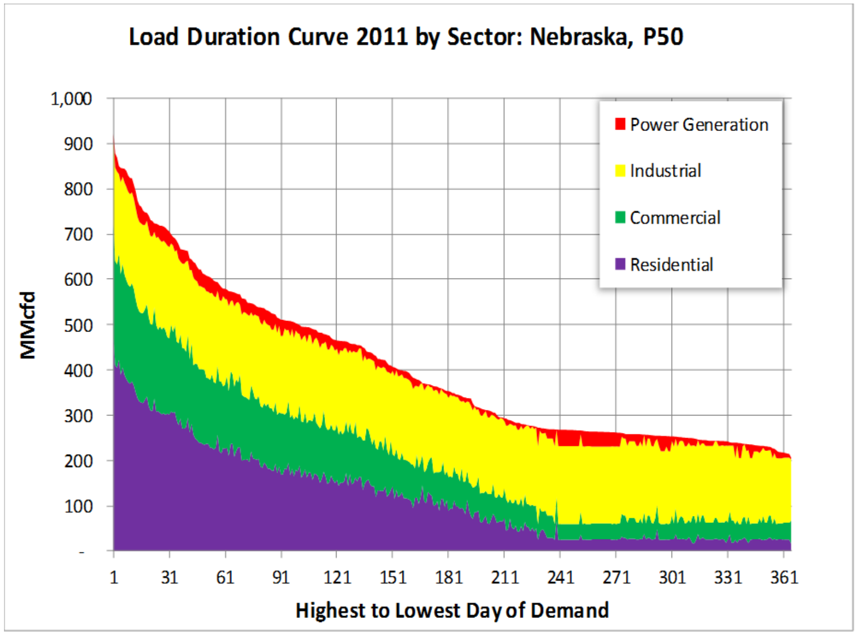

Load Growth 2030 vs 2011: Northern Missouri, P50
70
60
50
40
30
20
10
-
MMcfd
2030 vs 2011
2020 vs 2011
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand

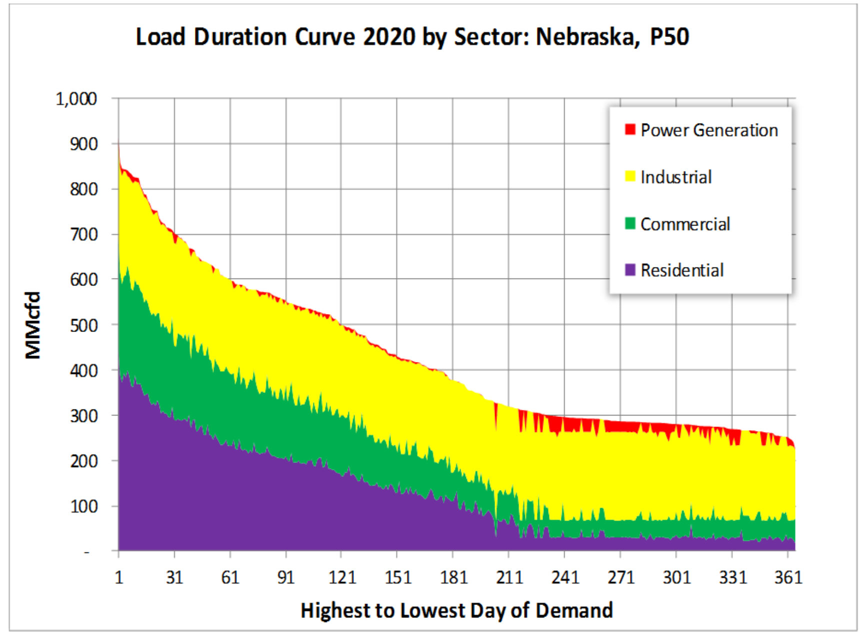

Load Duration Curve 2011 by Sector: Ventura, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

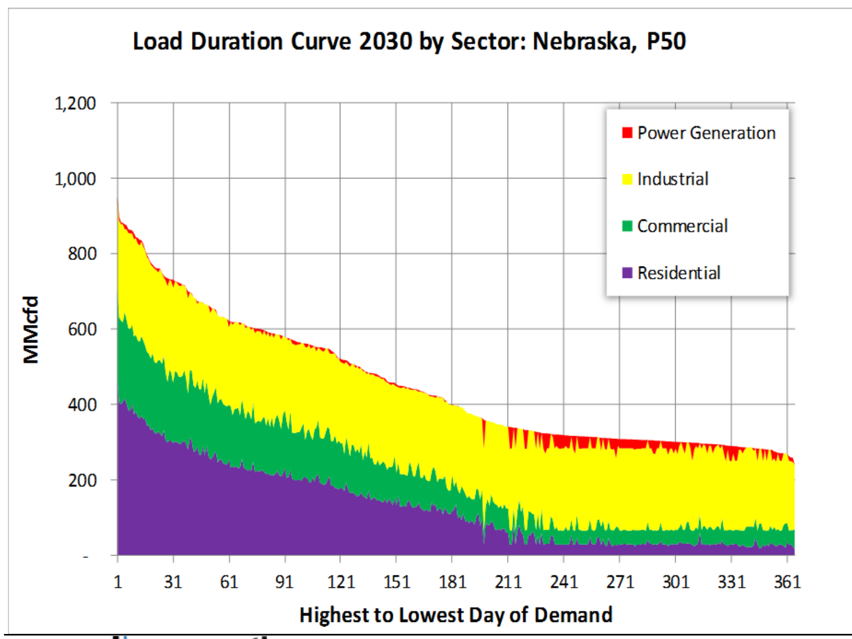

Load Duration Curve 2020 by Sector: Ventura, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

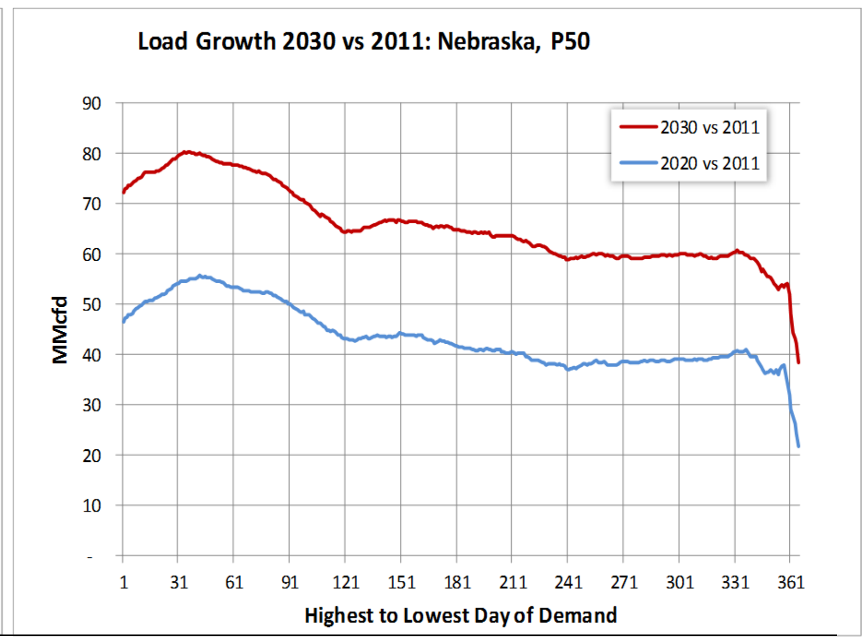

Load Duration Curve 2030 by Sector: Ventura, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

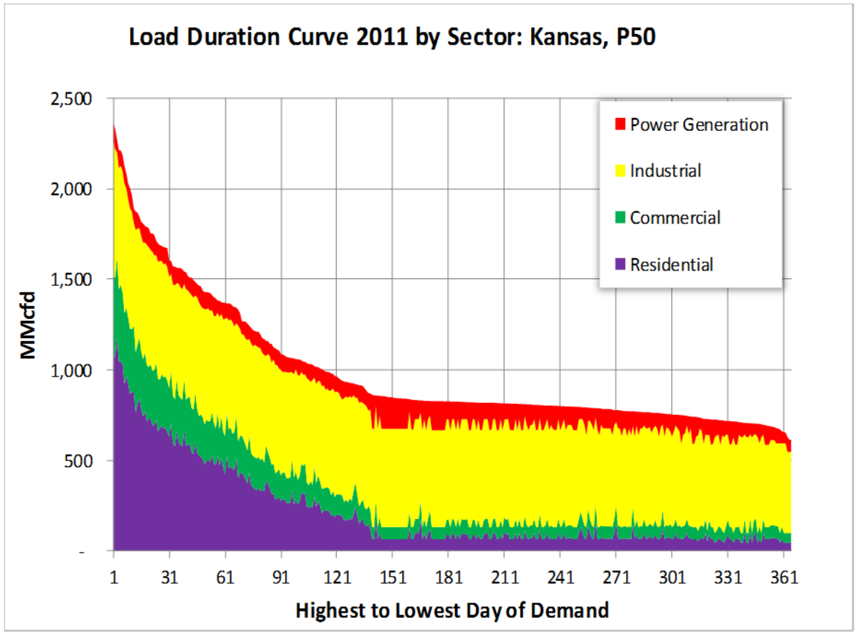

Load Growth 2030 vs 2011: Ventura, P50
2030 vs 2011
2020 vs 2011
MMcfd
Highest to Lowest Day of Demand

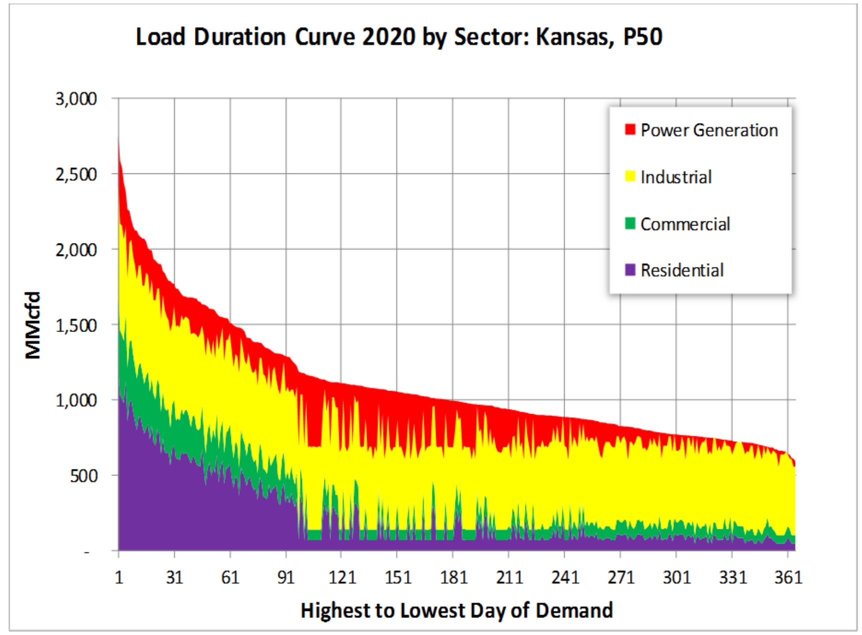

Load Duration Curve 2011 by Sector: Nebraska, P50
MMcfd
1,000
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

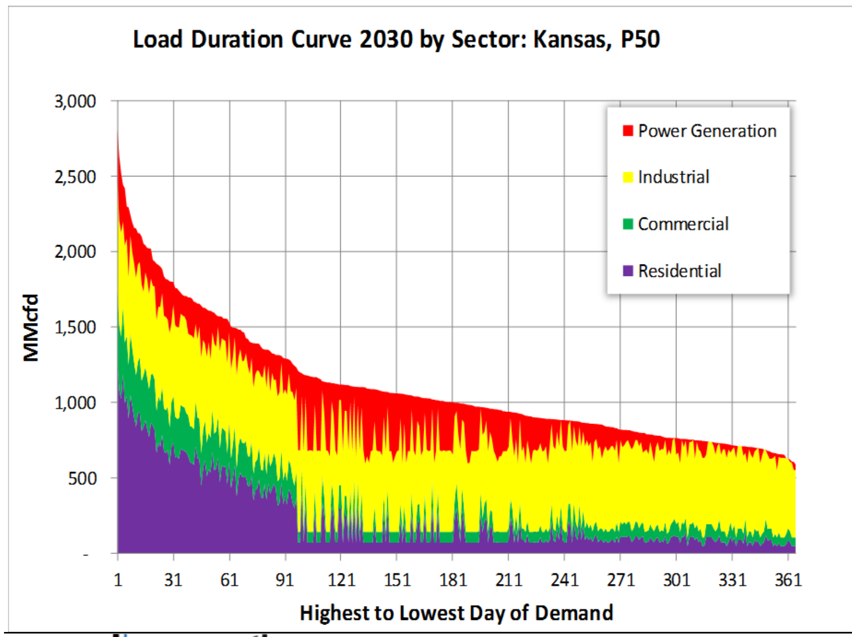

Load Duration Curve 2020 by Sector: Nebraska, P50
MMcfd
1,000
900
800
700
600
500
400
300
200
100
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

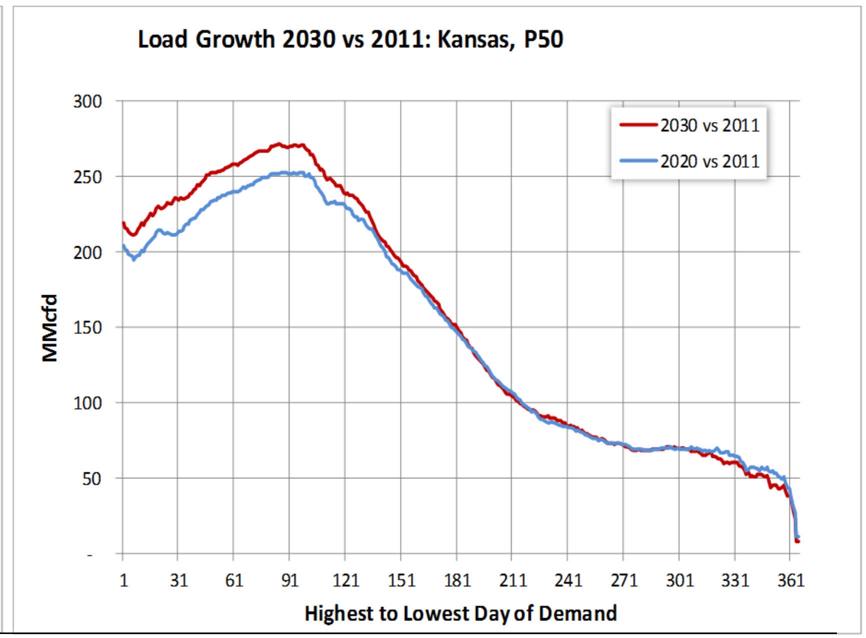

Load Duration Curve 2030 by Sector: Nebraska, P50
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

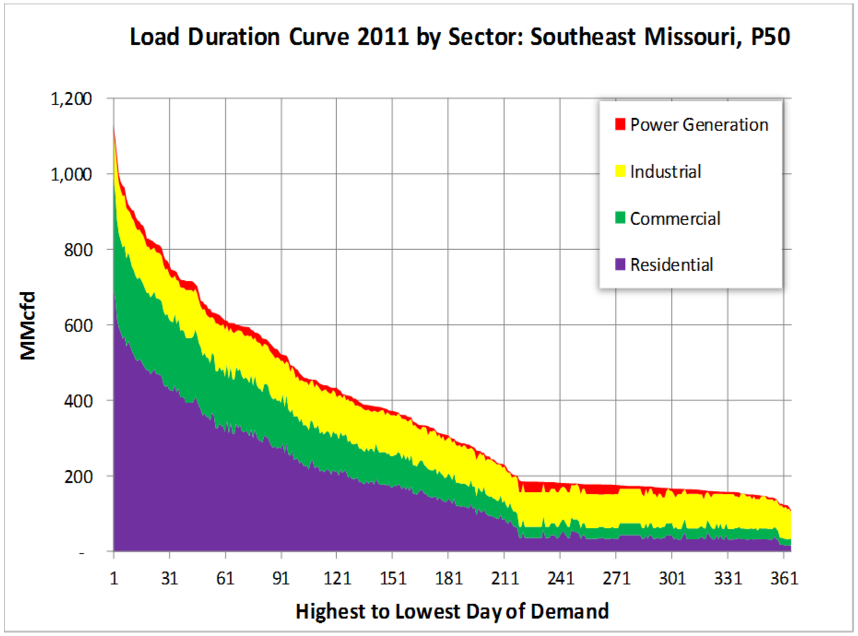

Load Growth 2030 vs 2011: Nebraska, P50
MMcfd
90
80
70
60
50
40
30
20
10
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

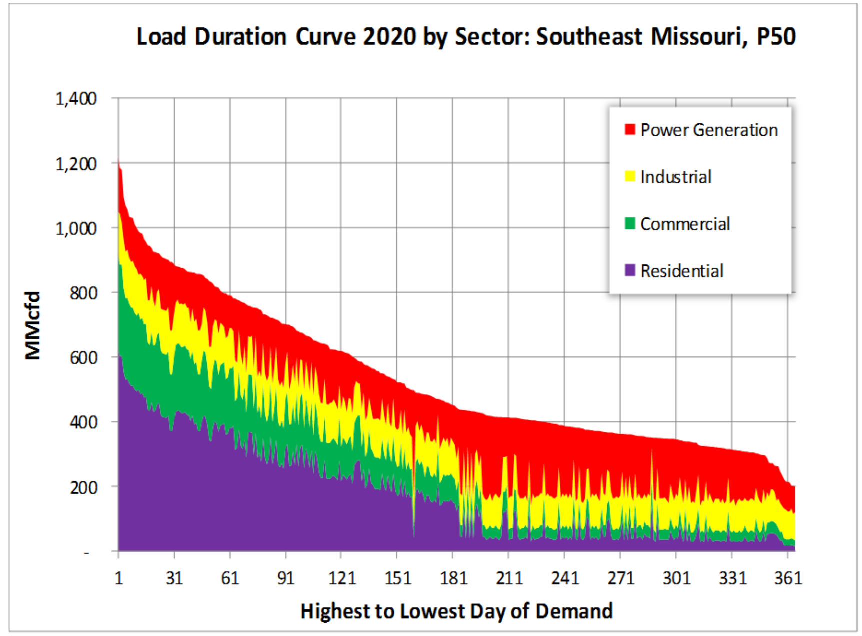

Load Duration Curve 2011 by Sector: Kansas, P50
2,500
2,000
1,500
1,000
500
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

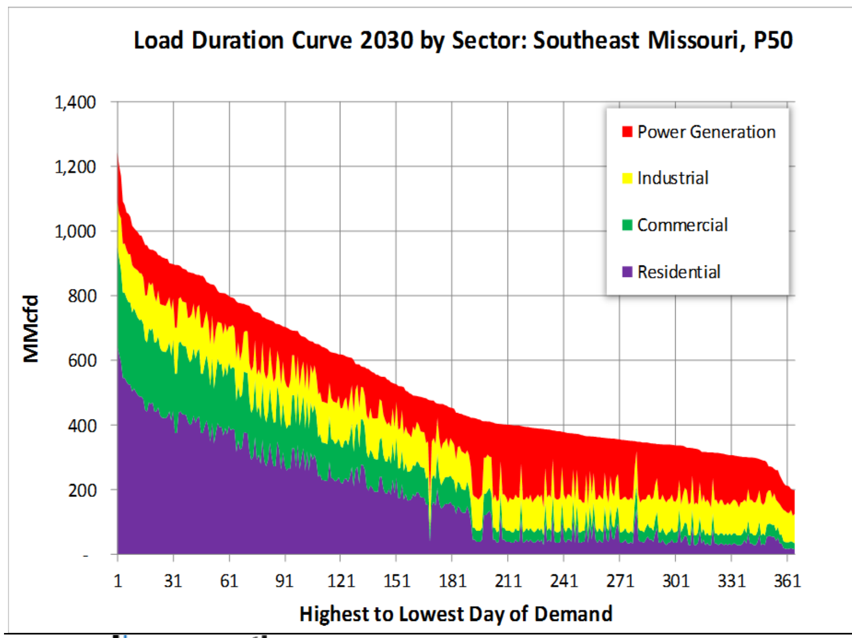

Load Duration Curve 2020 by Sector: Kansas, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

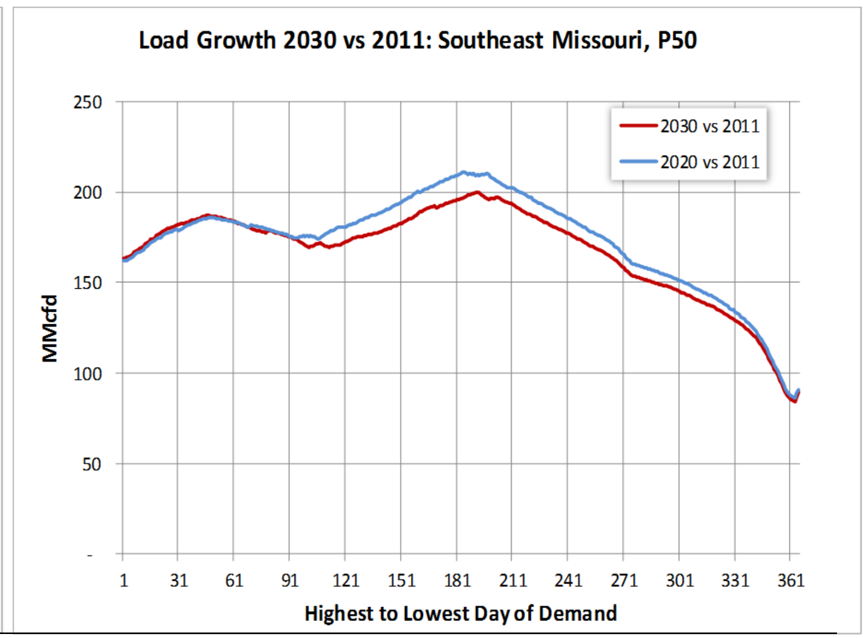

Load Duration Curve 2030 by Sector: Kansas, P50
3,000
2,500
2,000
1,500
1,000
500
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential


Load Growth 2030 vs 2011: Kansas, P50
300
250
200
150
100
50
-
MMcfd
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011

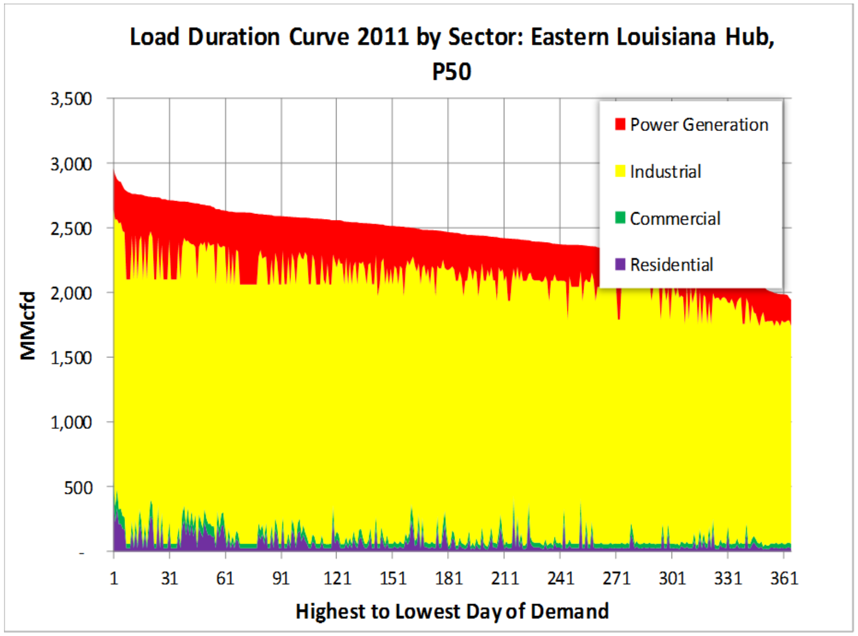

Load Duration Curve 2011 by Sector: Southeast Missouri, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

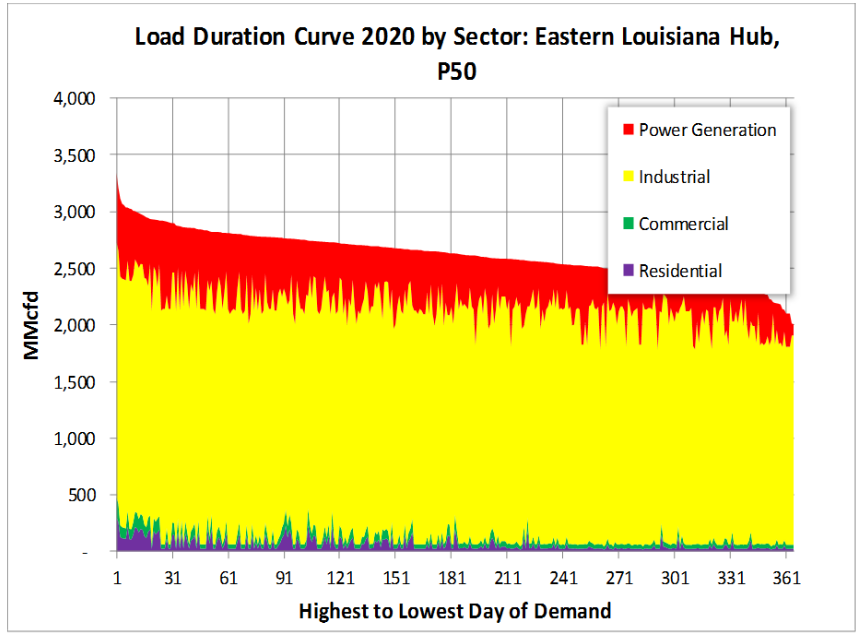

Load Duration Curve 2020 by Sector: Southeast Missouri, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

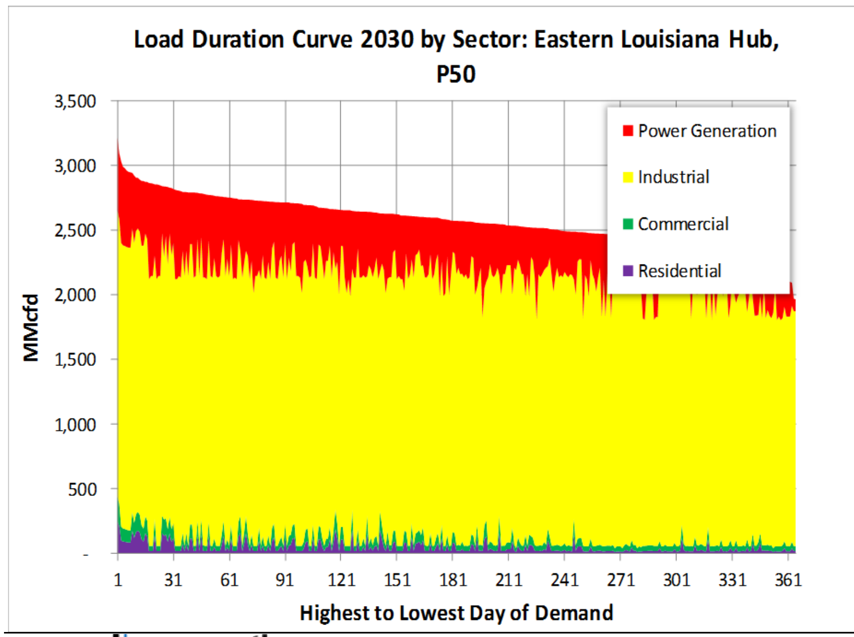

Load Duration Curve 2030 by Sector: Southeast Missouri, P50
Power Generation
Industrial
Commercial
Residential
MMcfd
Highest to Lowest Day of Demand

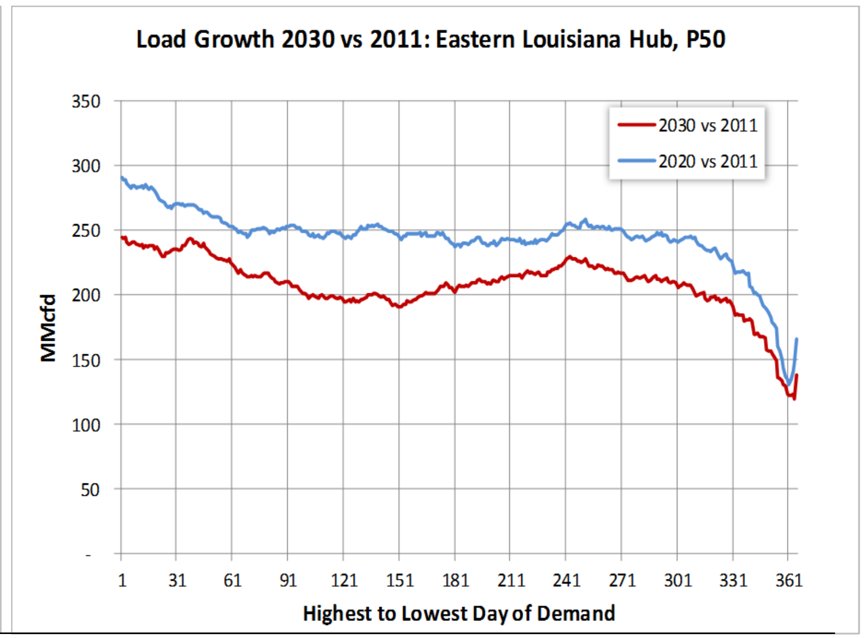

Load Growth 2030 vs 2011: Southeast Missouri, P50
2030 vs 2011
2020 vs 2011
MMcfd
Highest to Lowest Day of Demand

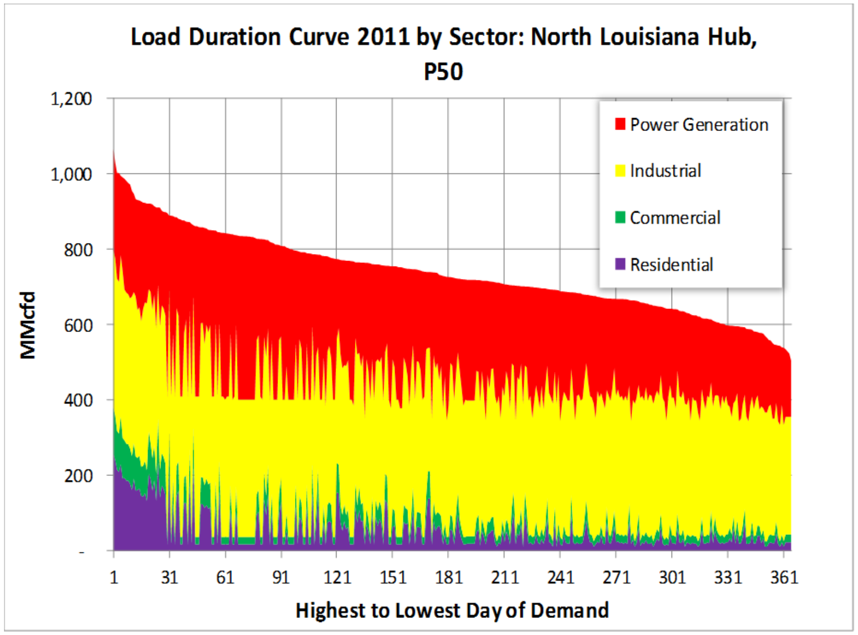
9.1.5 Southwest

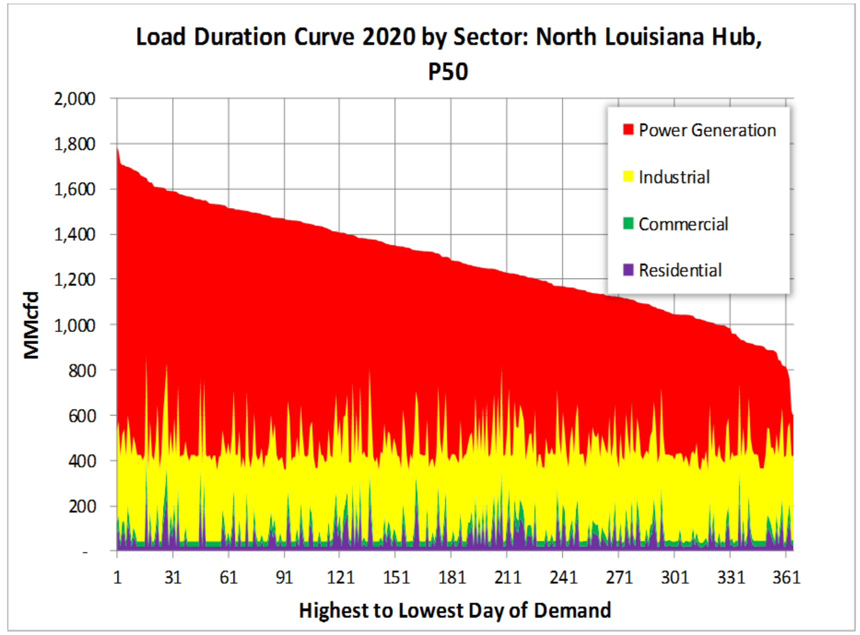

Load Duration Curve 2011 by Sector: Eastern Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361

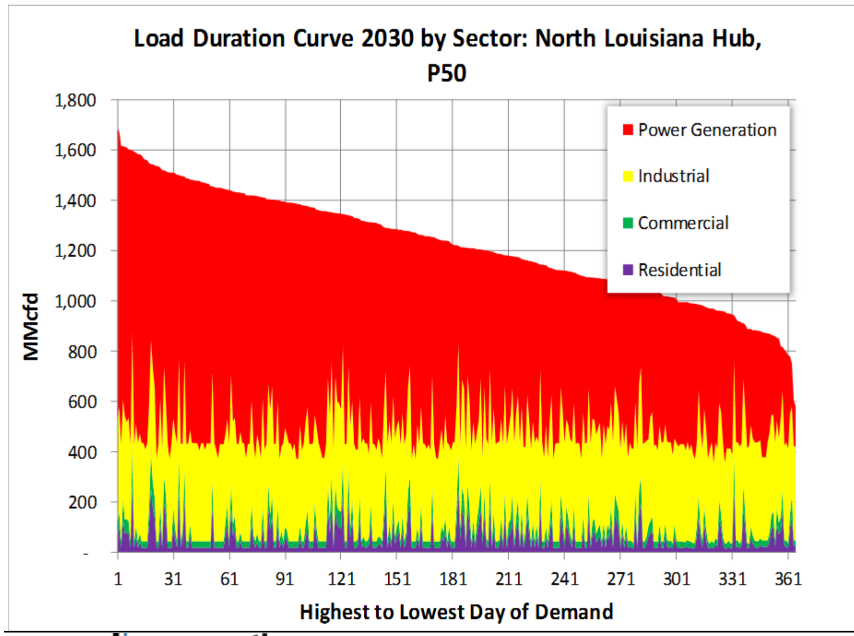

Load Duration Curve 2020 by Sector: Eastern Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361

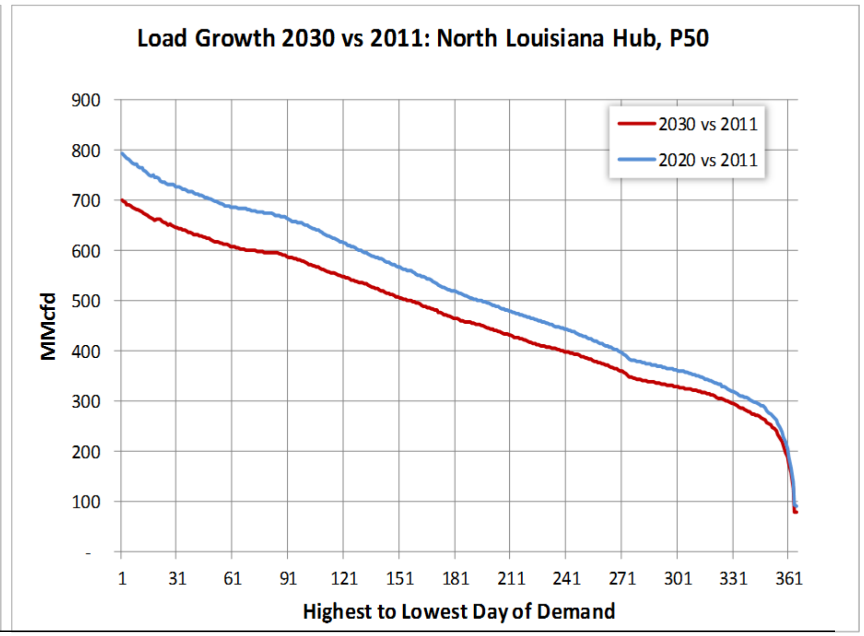

Load Duration Curve 2030 by Sector: Eastern Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential
3,500
3,000
2,500
2,000
1,500
1,000
500
-
1
31
61
91
121
151
181
211
241
271
301
331
361

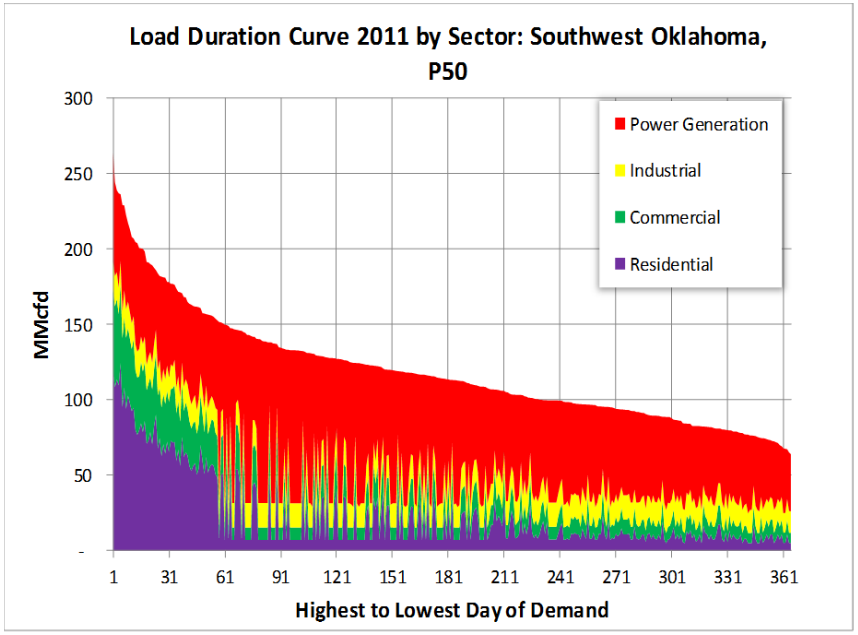

Load Growth 2030 vs 2011: Eastern Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011
350
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361

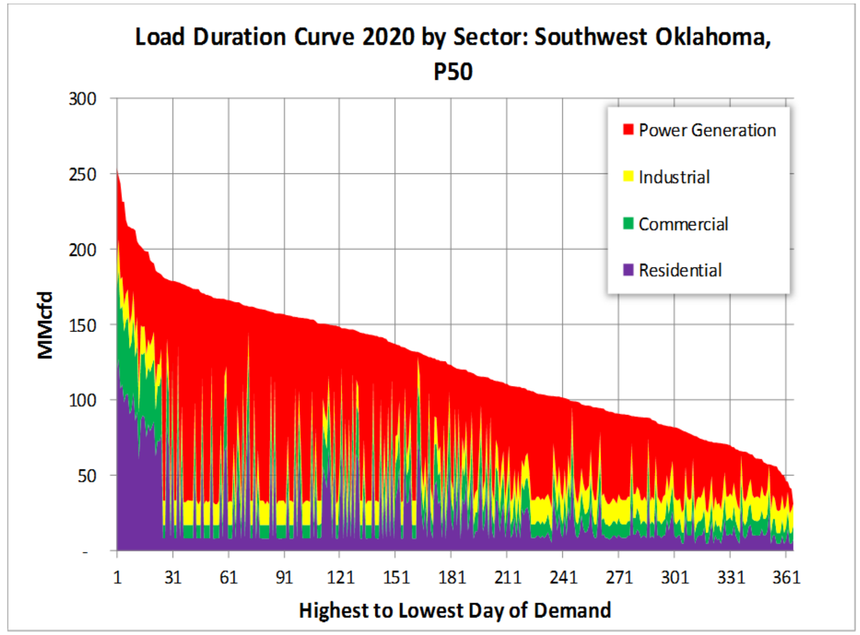

Load Duration Curve 2011 by Sector: North Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

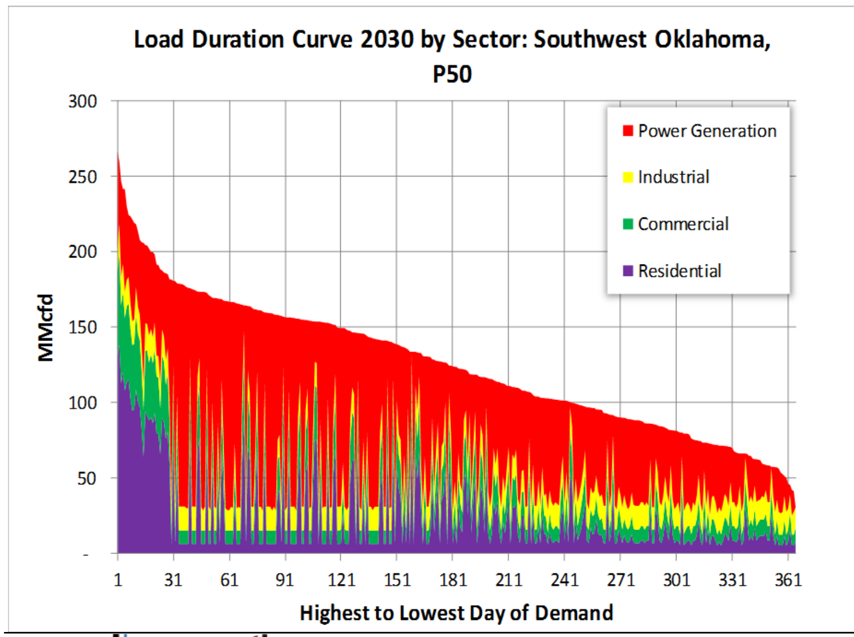

Load Duration Curve 2020 by Sector: North Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

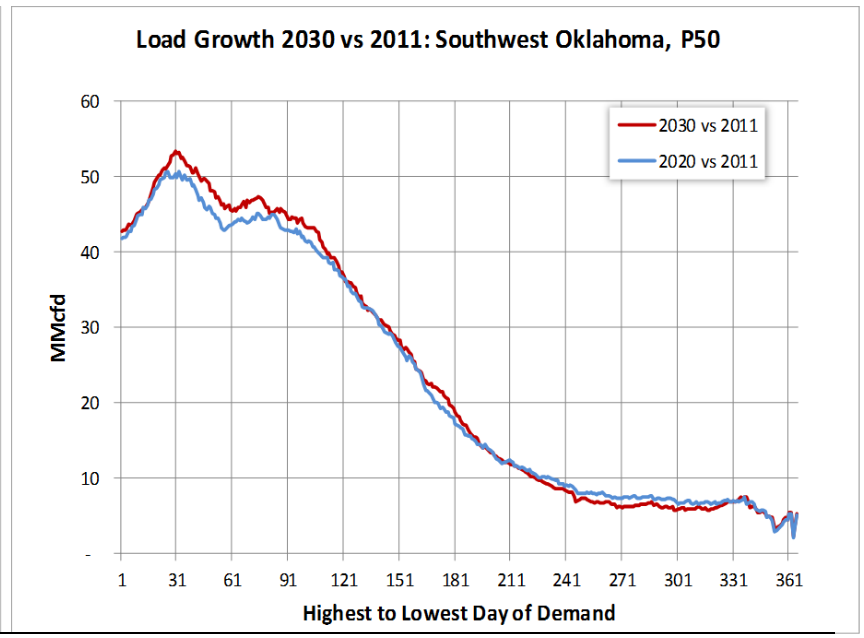

Load Duration Curve 2030 by Sector: North Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

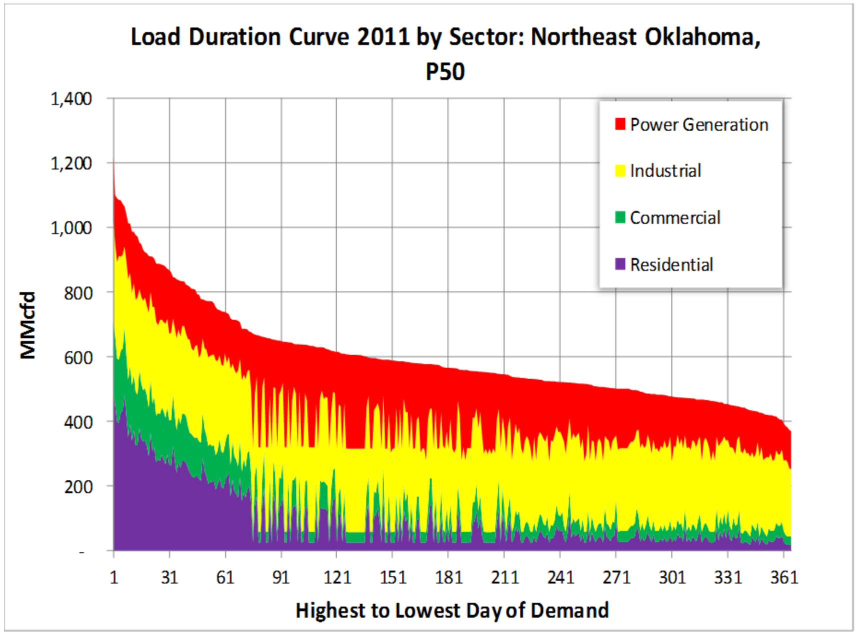

Load Growth 2030 vs 2011: North Louisiana Hub, P50
MMcfd
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011


Load Duration Curve 2011 by Sector: Southwest Oklahoma, P50
MMcfd
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

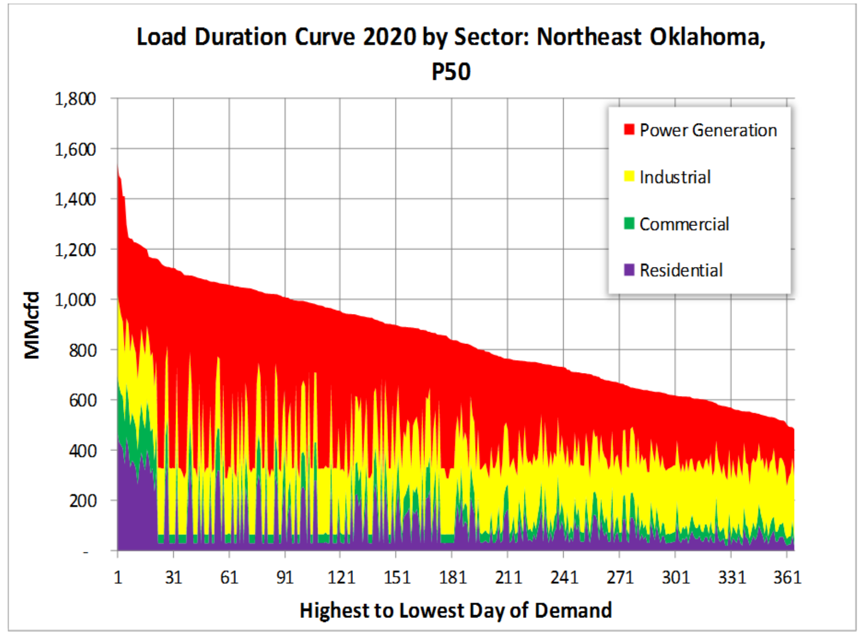

Load Duration Curve 2020 by Sector: Southwest Oklahoma, P50
MMcfd
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential


Load Duration Curve 2030 by Sector: Southwest Oklahoma, P50
MMcfd
300
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

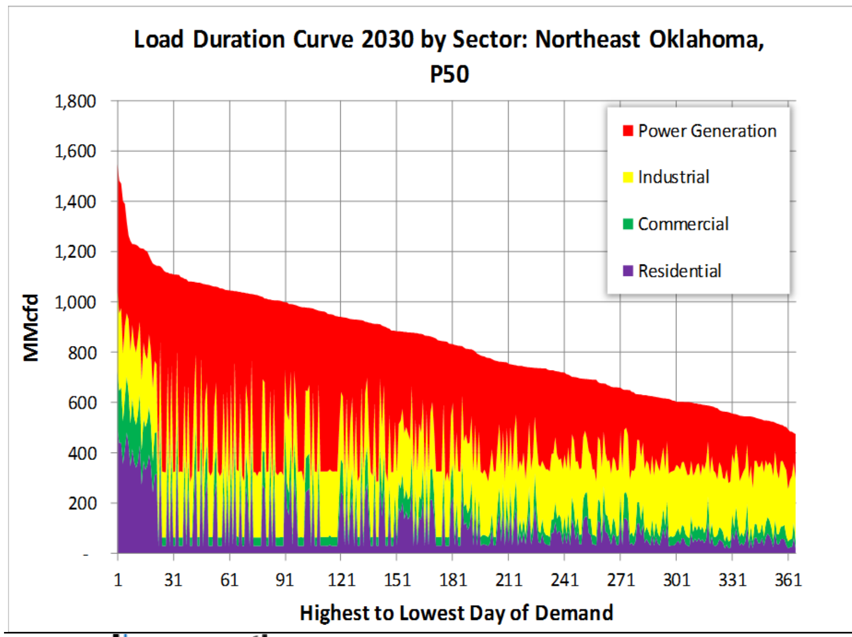

Load Growth 2030 vs 2011: Southwest Oklahoma, P50
MMcfd
60
50
40
30
20
10
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011



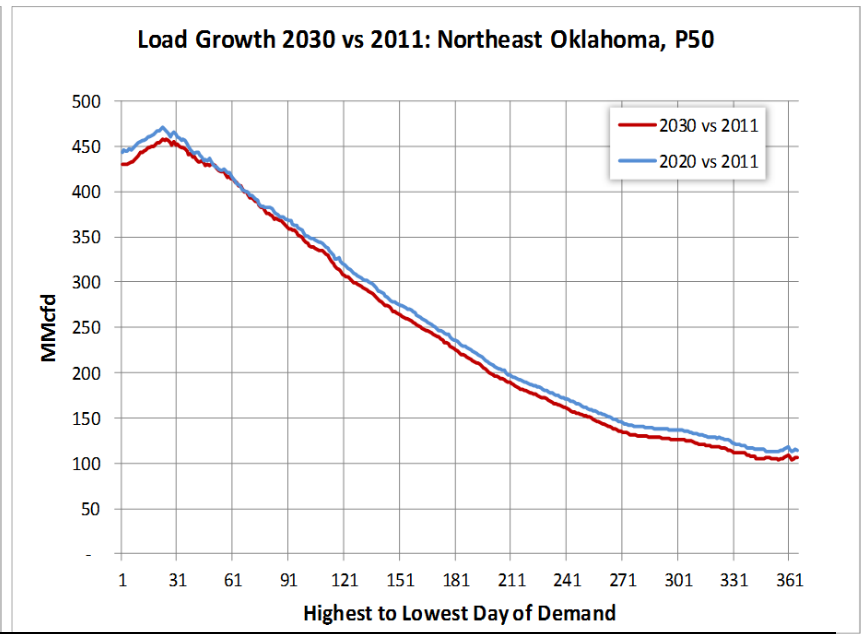
Load Duration Curve 2011 by Sector: Northeast Oklahoma, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand



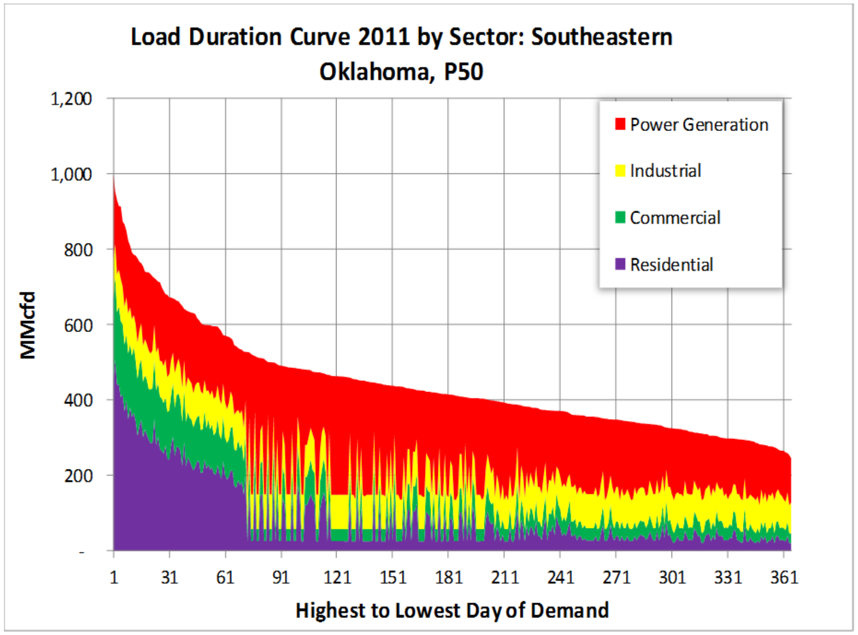
Load Duration Curve 2020 by Sector: Northeast Oklahoma, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand

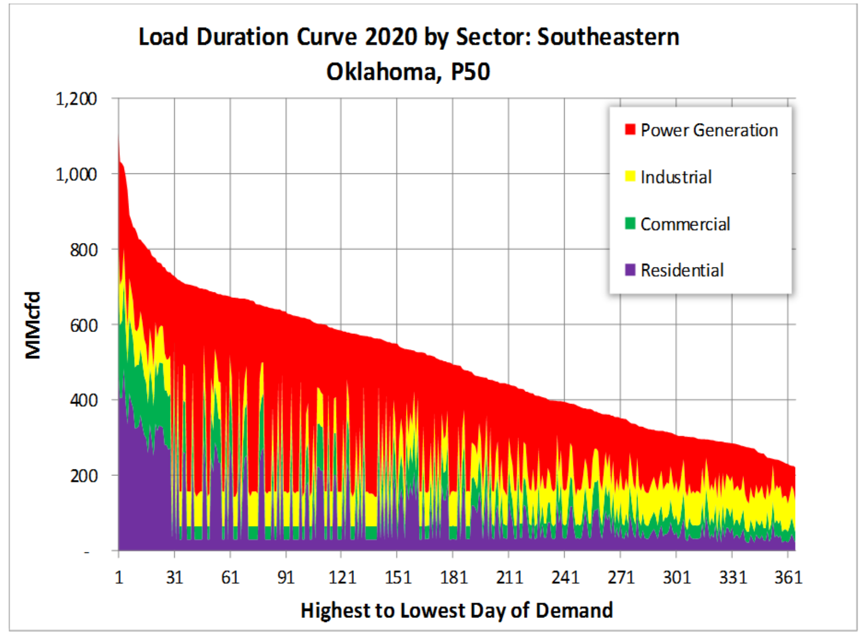


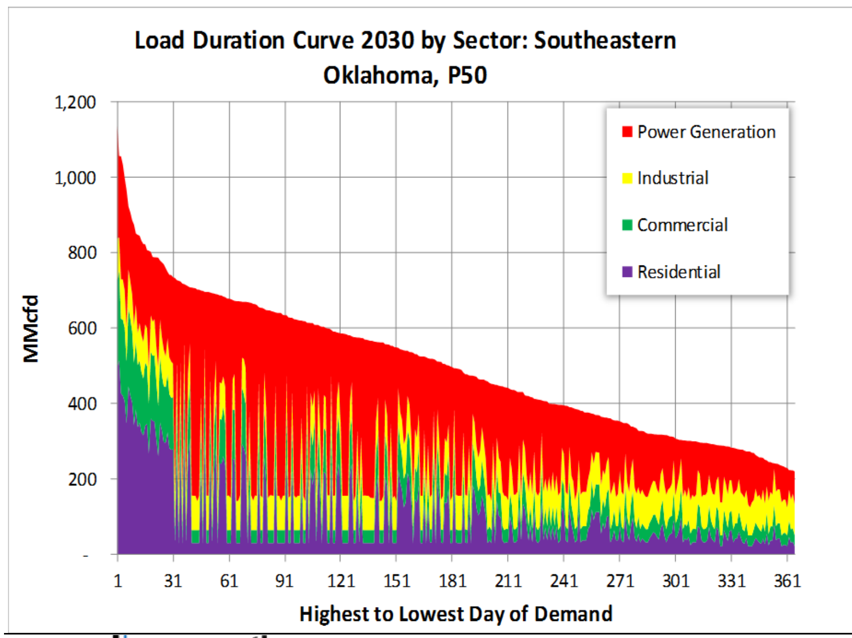
Load Duration Curve 2030 by Sector: Northeast Oklahoma, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
Highest to Lowest Day of Demand

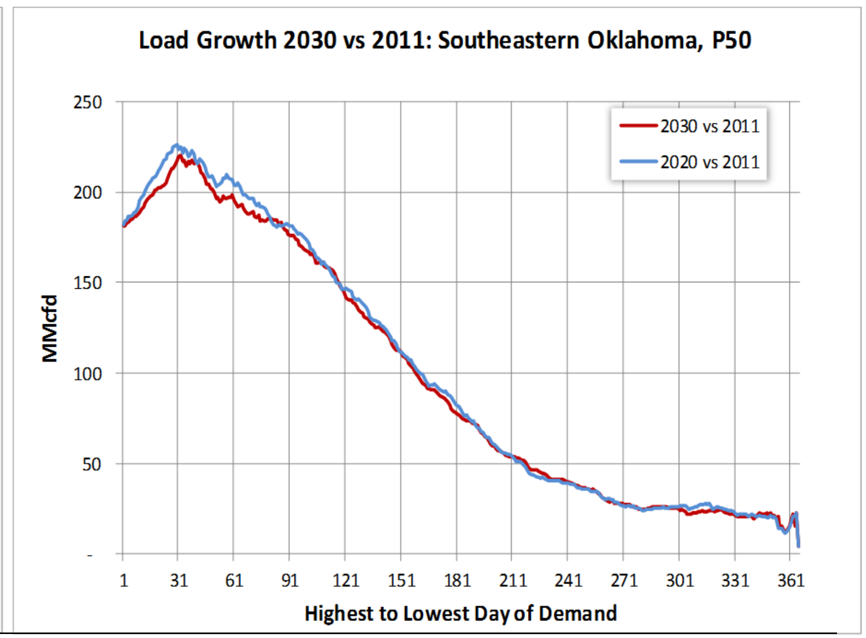


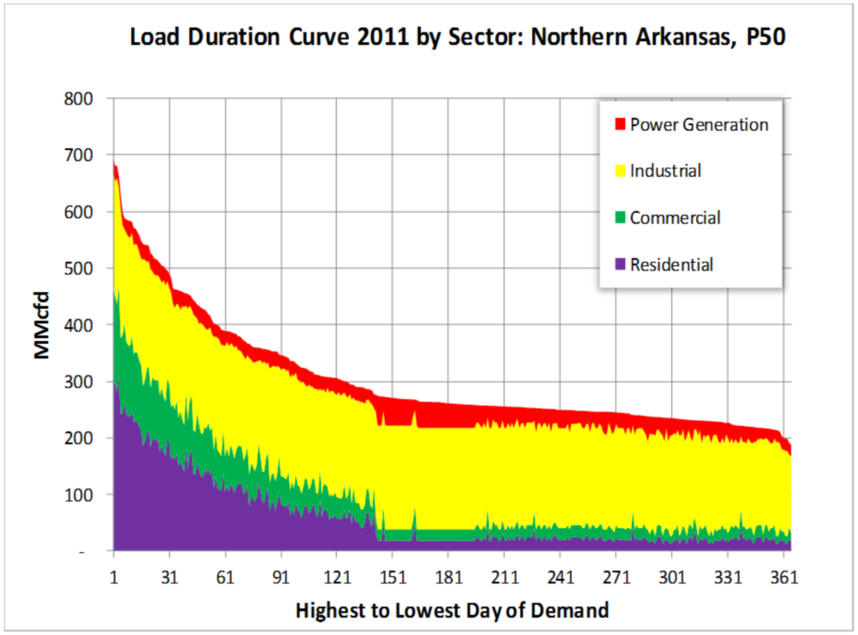
Load Growth 2030 vs 2011: Northeast Oklahoma, P50
MMcfd
2030 vs 2011
2020 vs 2011
Highest to Lowest Day of Demand

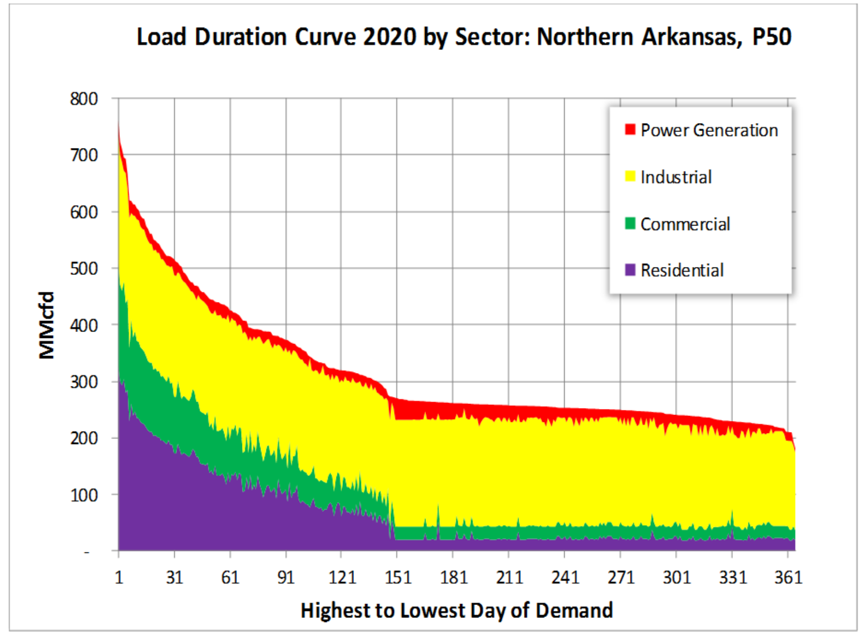

Load Duration Curve 2011 by Sector: Southeastern Oklahoma, P50
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

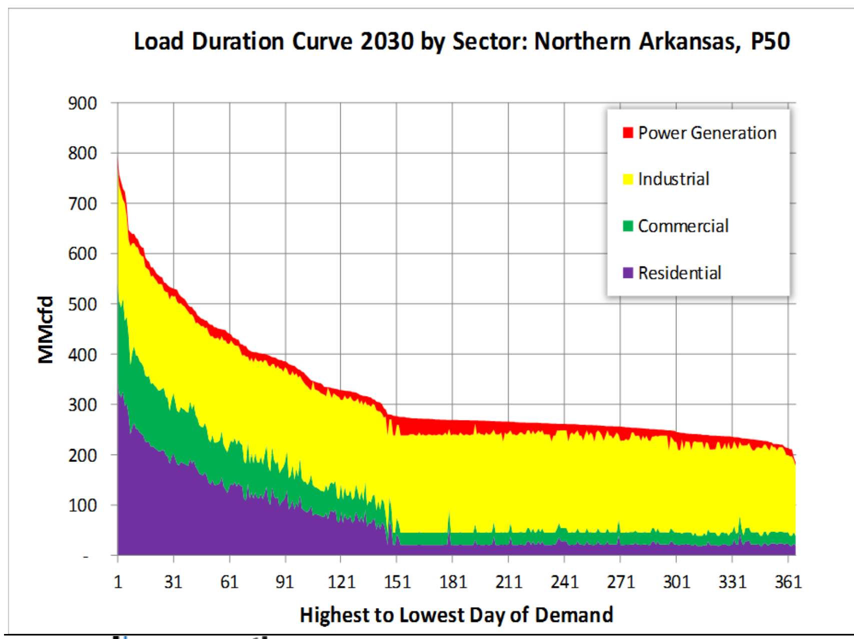

Load Duration Curve 2020 by Sector: Southeastern Oklahoma, P50
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential

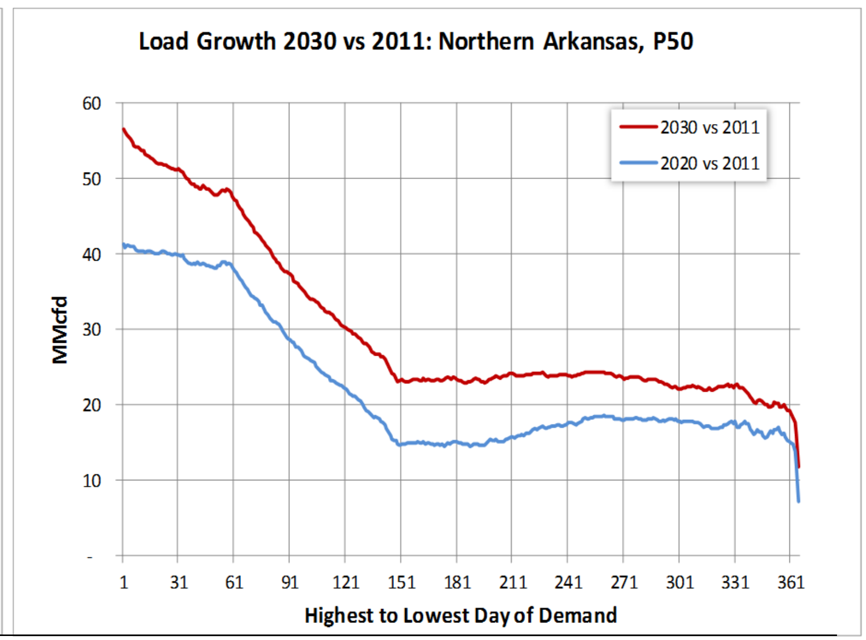

Load Duration Curve 2030 by Sector: Southeastern Oklahoma, P50
MMcfd
1,200
1,000
800
600
400
200
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
Power Generation
Industrial
Commercial
Residential


Load Growth 2030 vs 2011: Southeastern Oklahoma, P50
MMcfd
250
200
150
100
50
-
1
31
61
91
121
151
181
211
241
271
301
331
361
Highest to Lowest Day of Demand
2030 vs 2011
2020 vs 2011


Load Duration Curve 2011 by Sector: Northern Arkansas, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
800
700
600
500
400
300
200
100
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand


Load Duration Curve 2020 by Sector: Northern Arkansas, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
800
700
600
500
400
300
200
100
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

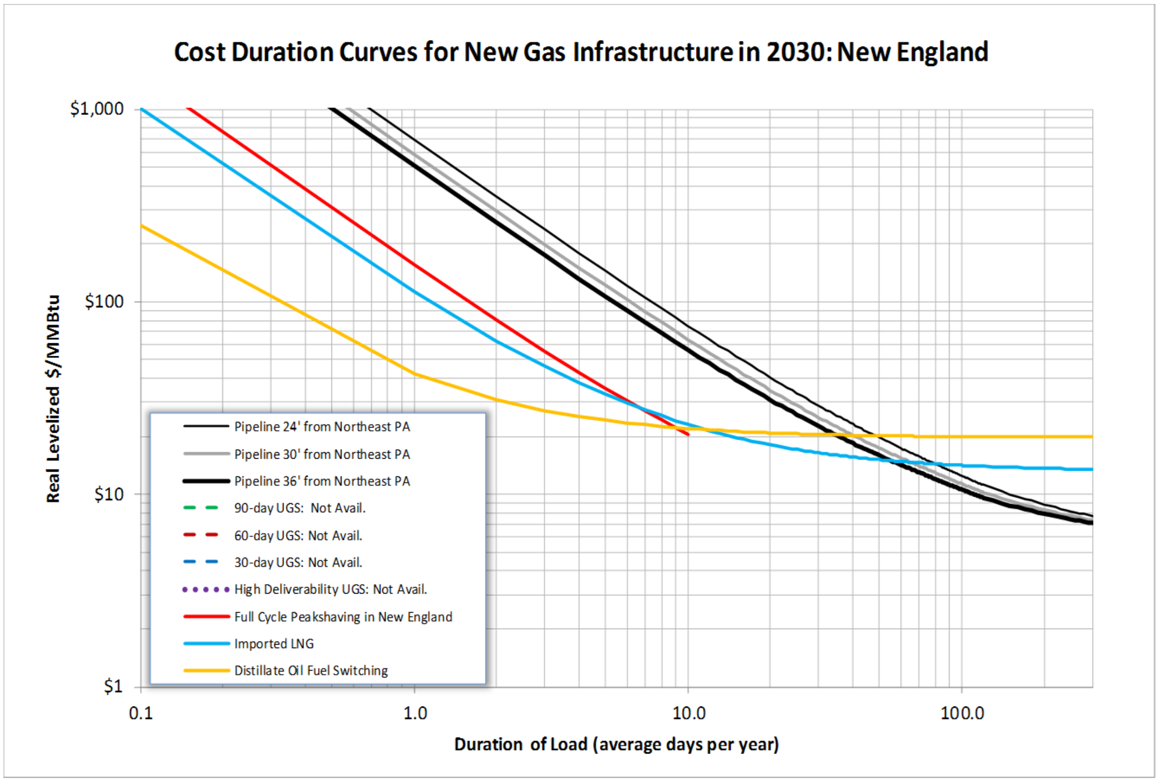

Load Duration Curve 2030 by Sector: Northern Arkansas, P50
MMcfd
Power Generation
Industrial
Commercial
Residential
900
800
700
600
500
400
300
200
100
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

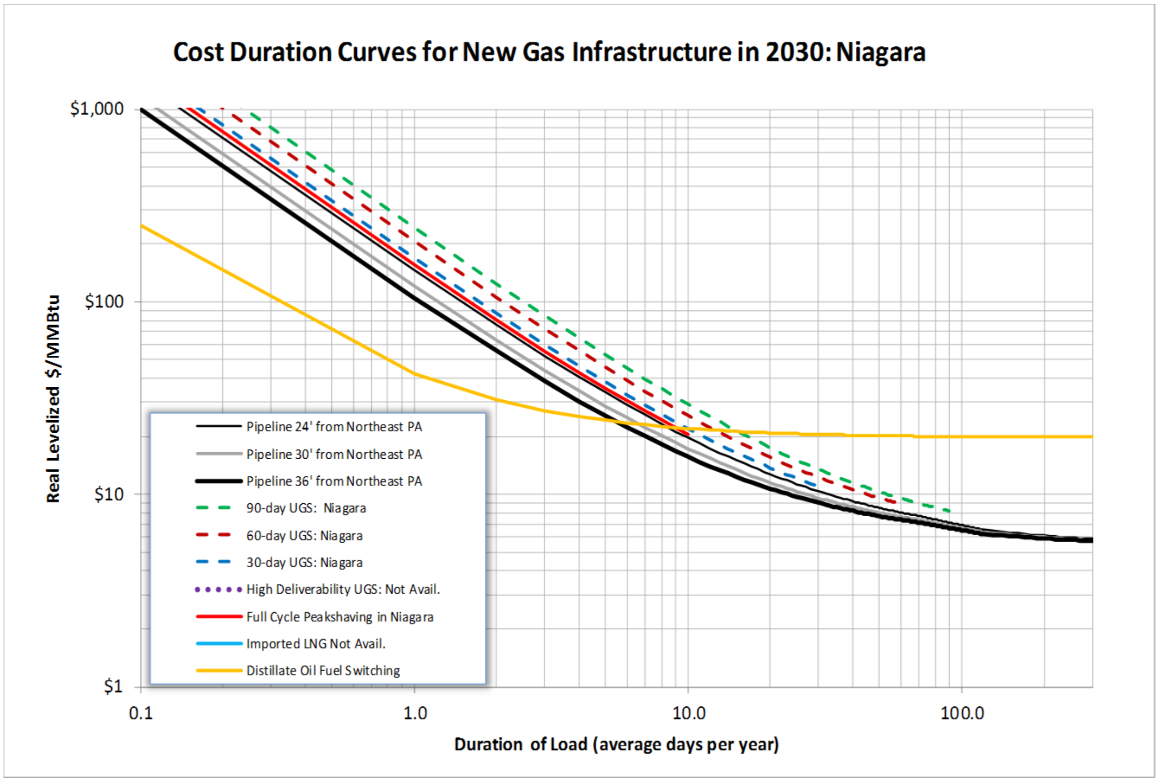

Load Growth 2030 vs 2011: Northern Arkansas, P50
MMcfd
2030 vs 2011
2020 vs 2011
60
50
40
30
20
10
-
1 31 61 91 121 151 181 211 241 271 301 331 361
Highest to Lowest Day of Demand

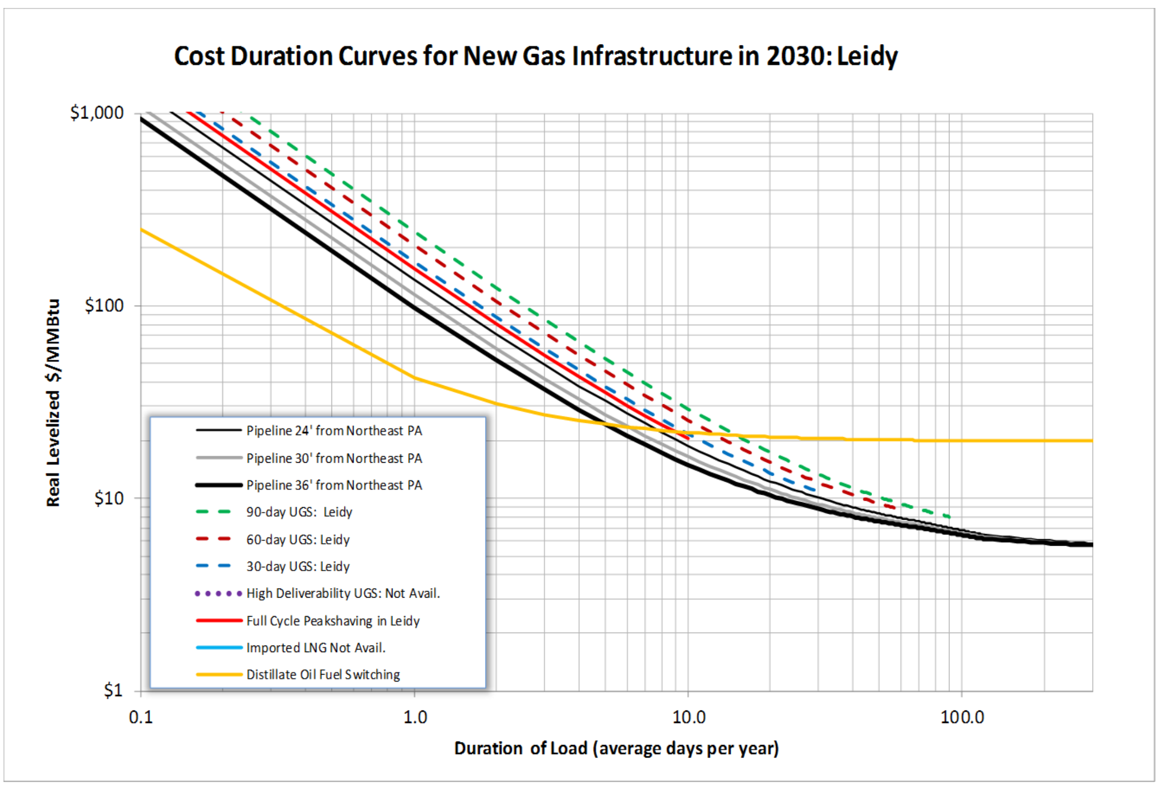
Appendix D: Cost Duration Curves

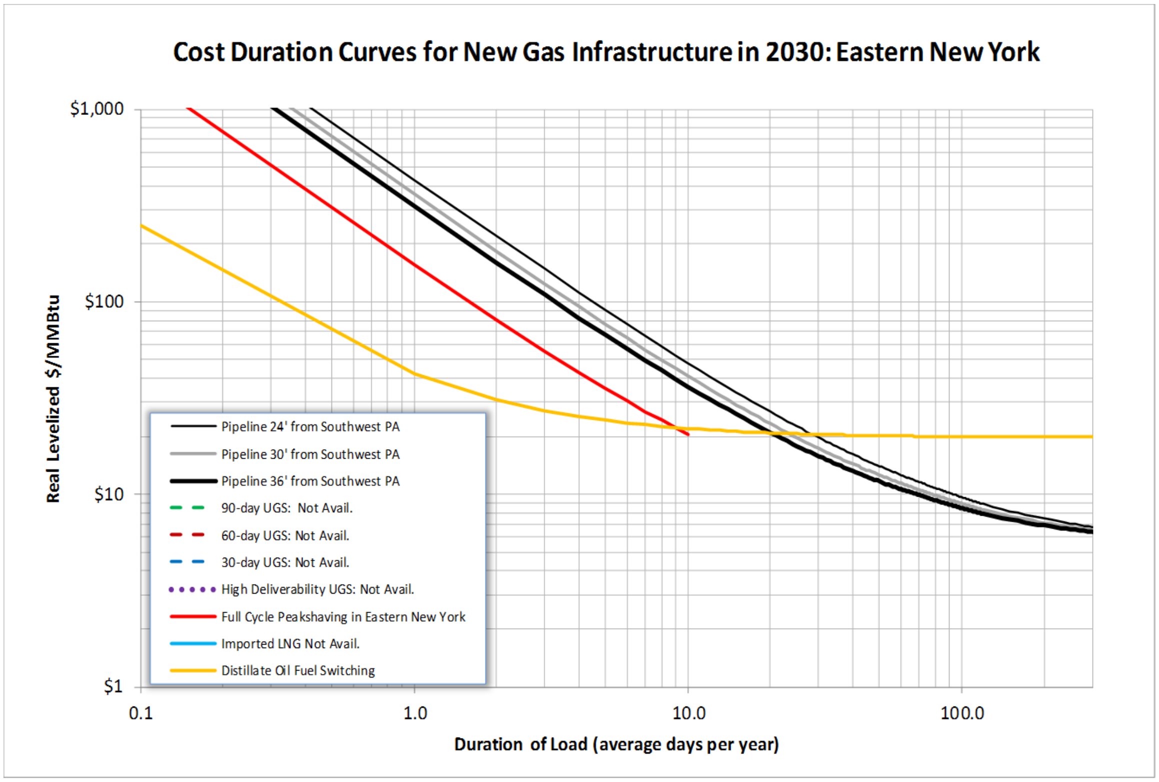
The following section includes cost duration curves for nodes within the Eastern Interconnection, and is organized by EIA region.

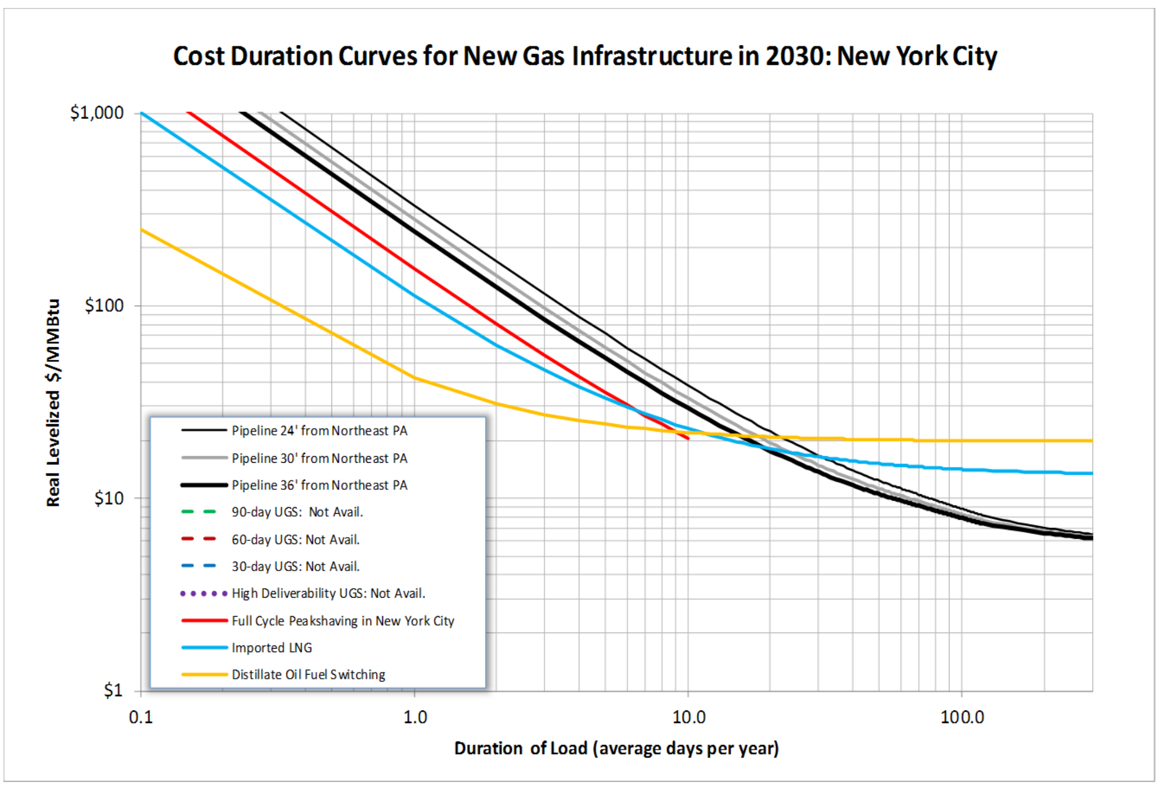
9.1.6 Northeast

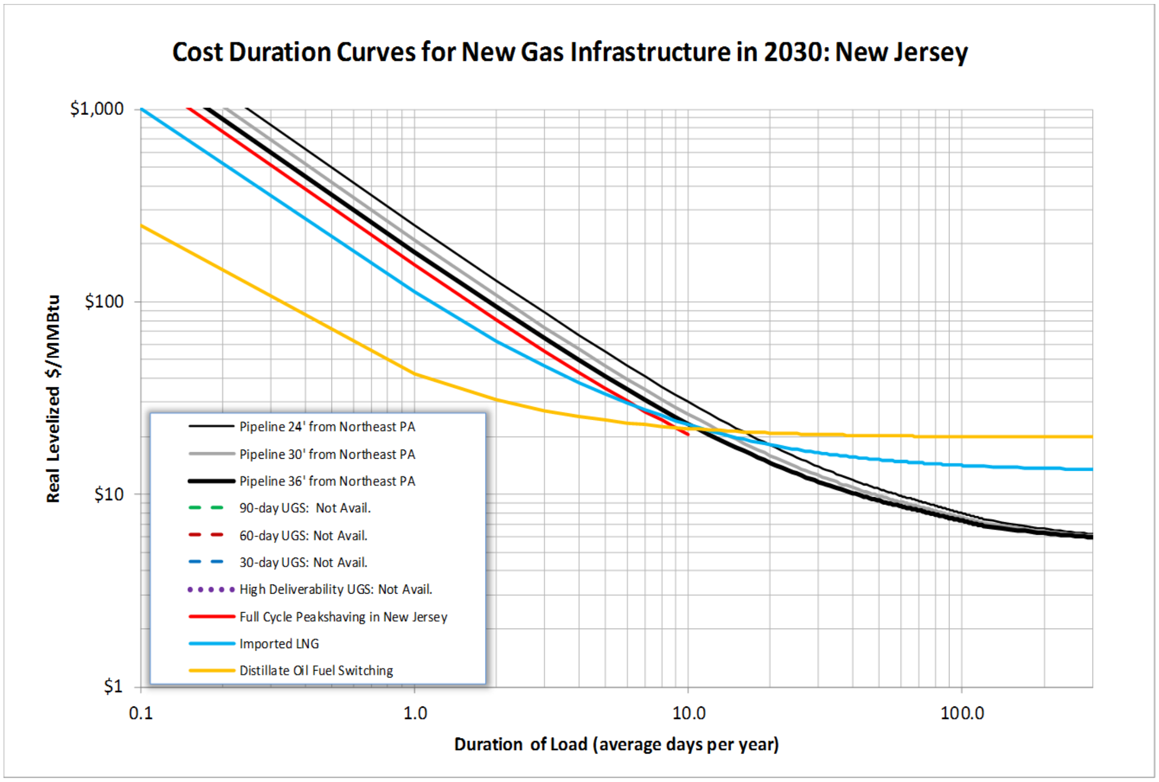


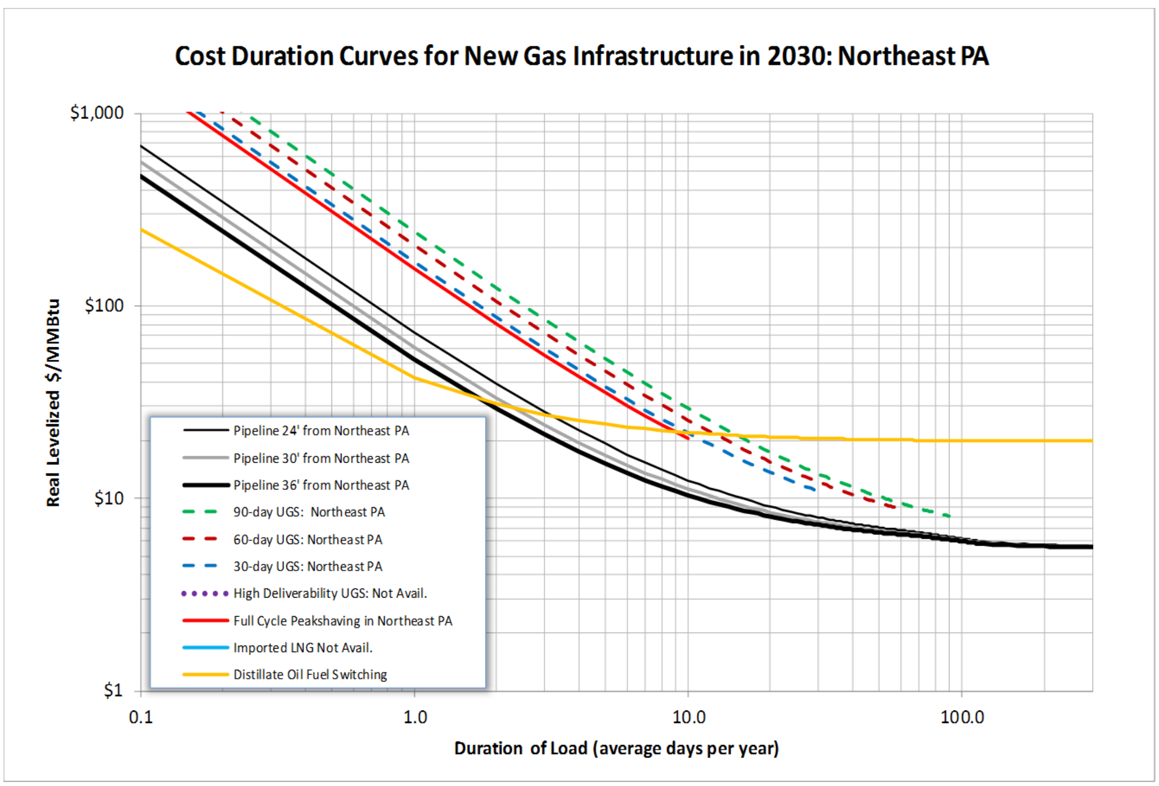

Cost Duration Curves for New Gas Infrastructure in 2030: Niagara
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Niagara
60-day UGS: Niagara
30-day UGS: Niagara
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Niagara
Imported LNG Not Avail.
Distillate Oil Fuel Switching

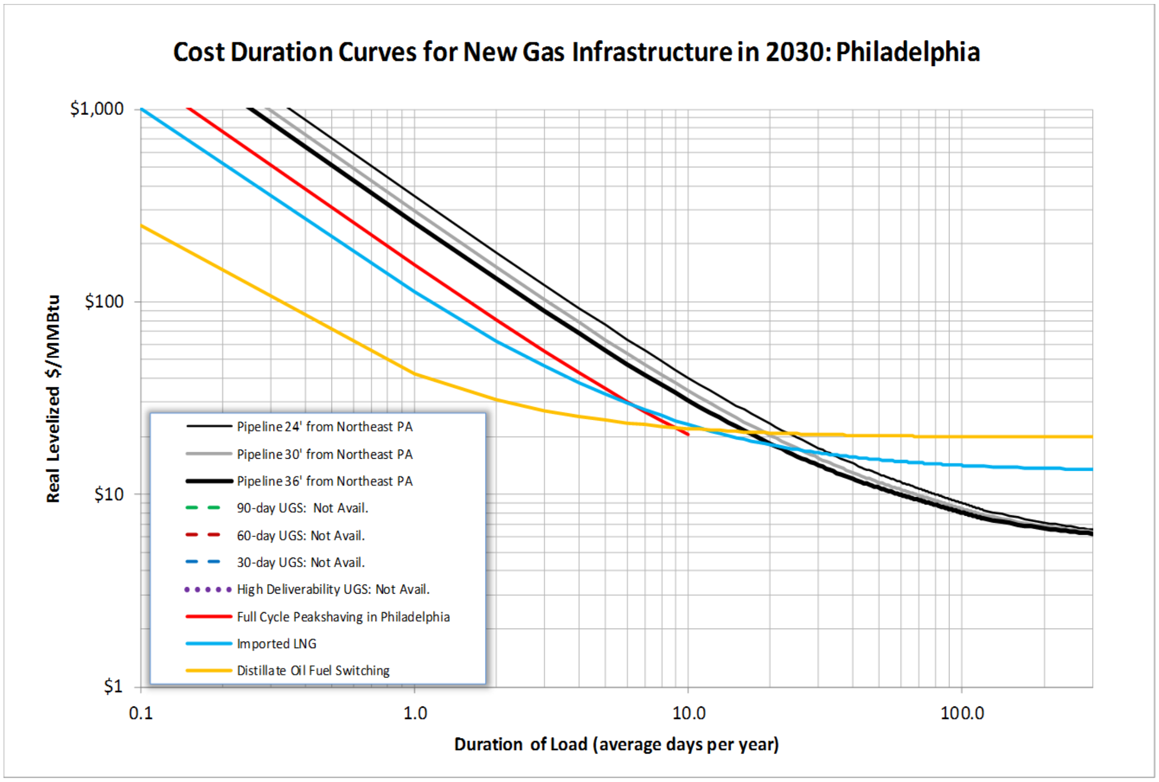

Cost Duration Curves for New Gas Infrastructure in 2030: Leidy
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Leidy
60-day UGS: Leidy
30-day UGS: Leidy
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Leidy
Imported LNG Not Avail.
Distillate Oil Fuel Switching

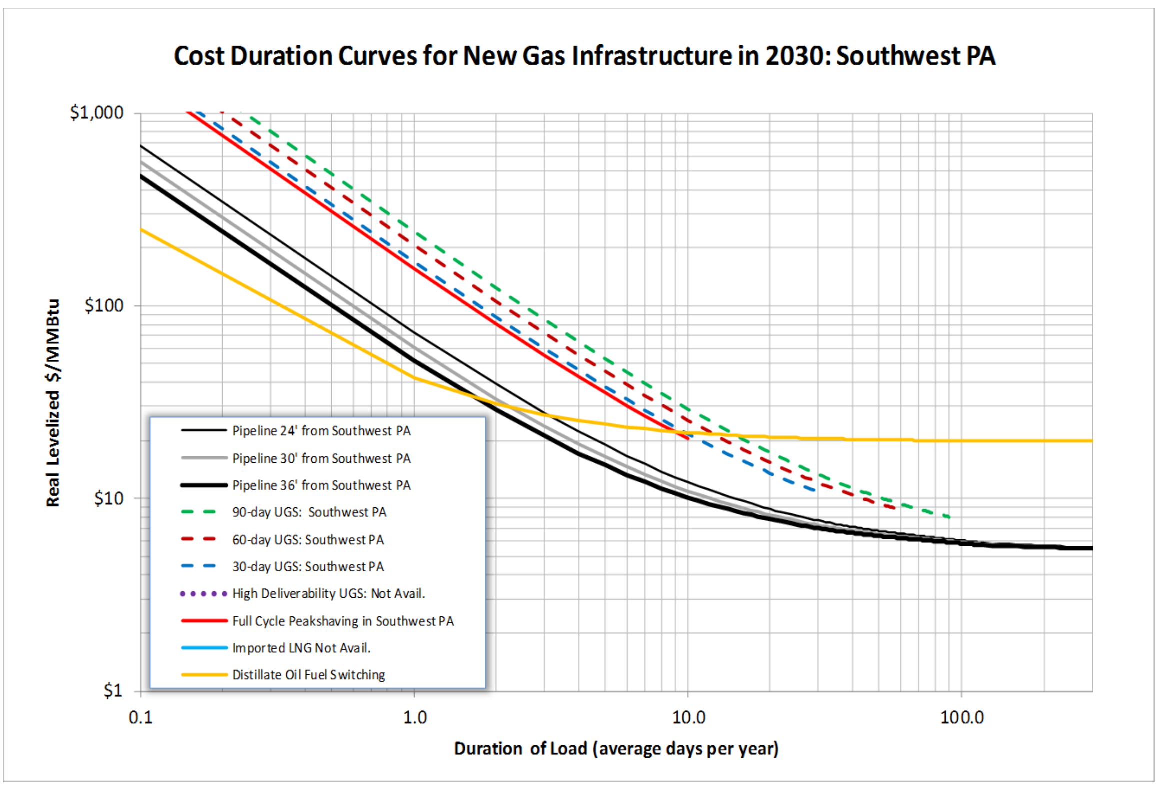

Cost Duration Curves for New Gas Infrastructure in 2030: Eastern New York
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Eastern New York
Imported LNG Not Avail.
Distillate Oil Fuel Switching

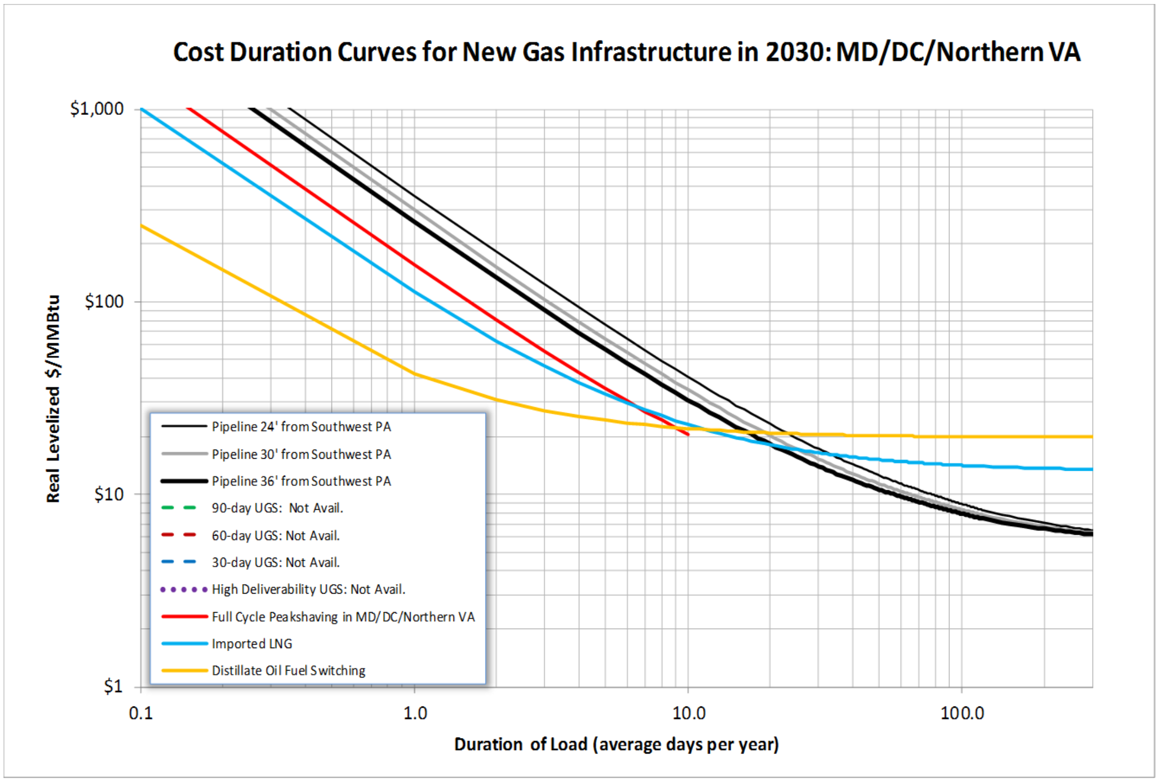

Cost Duration Curves for New Gas Infrastructure in 2030: New York City
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in New York City
Imported LNG
Distillate Oil Fuel Switching

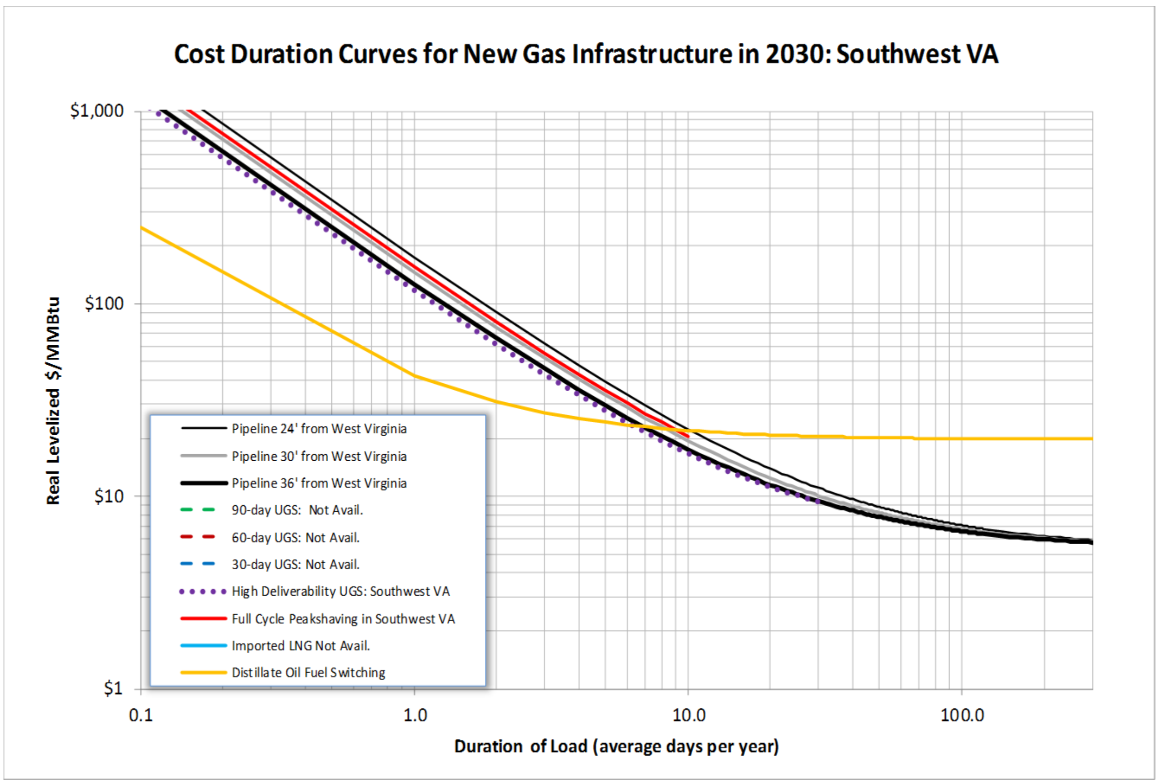

Cost Duration Curves for New Gas Infrastructure in 2030: New Jersey
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in New Jersey
Imported LNG
Distillate Oil Fuel Switching

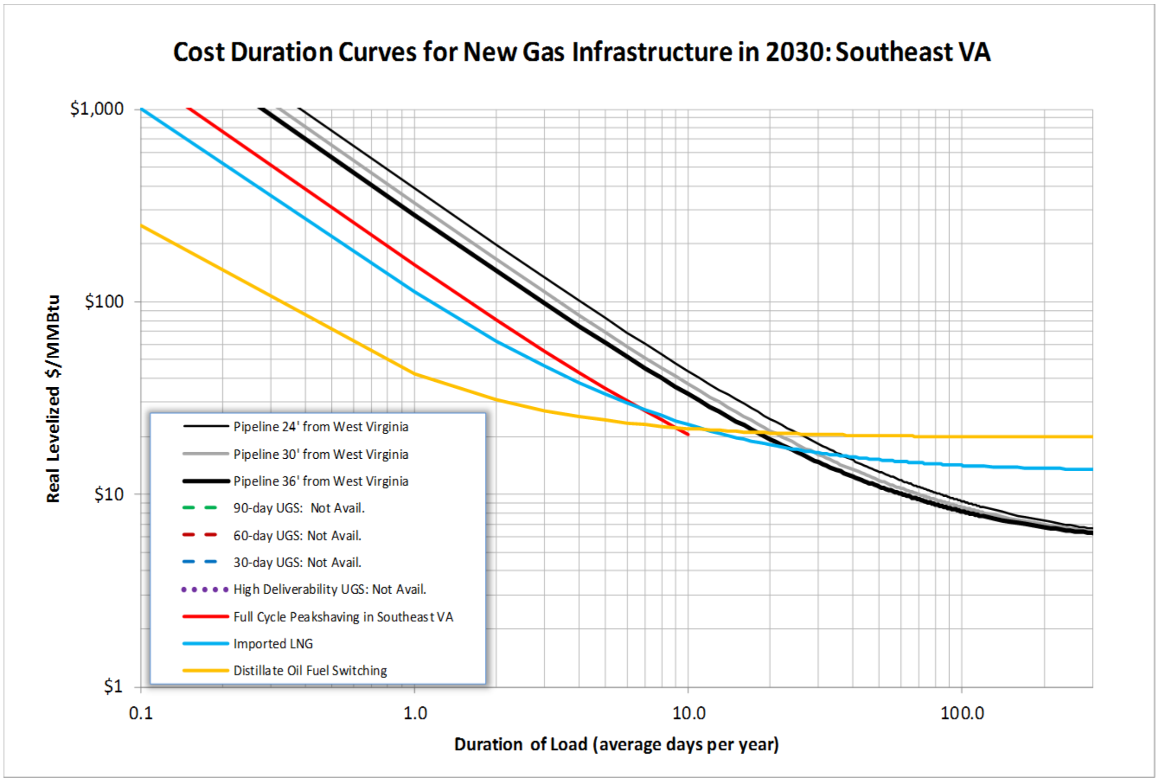

Cost Duration Curves for New Gas Infrastructure in 2030: Northeast PA
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Northeast PA
60-day UGS: Northeast PA
30-day UGS: Northeast PA
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Northeast PA
Imported LNG Not Avail.
Distillate Oil Fuel Switching

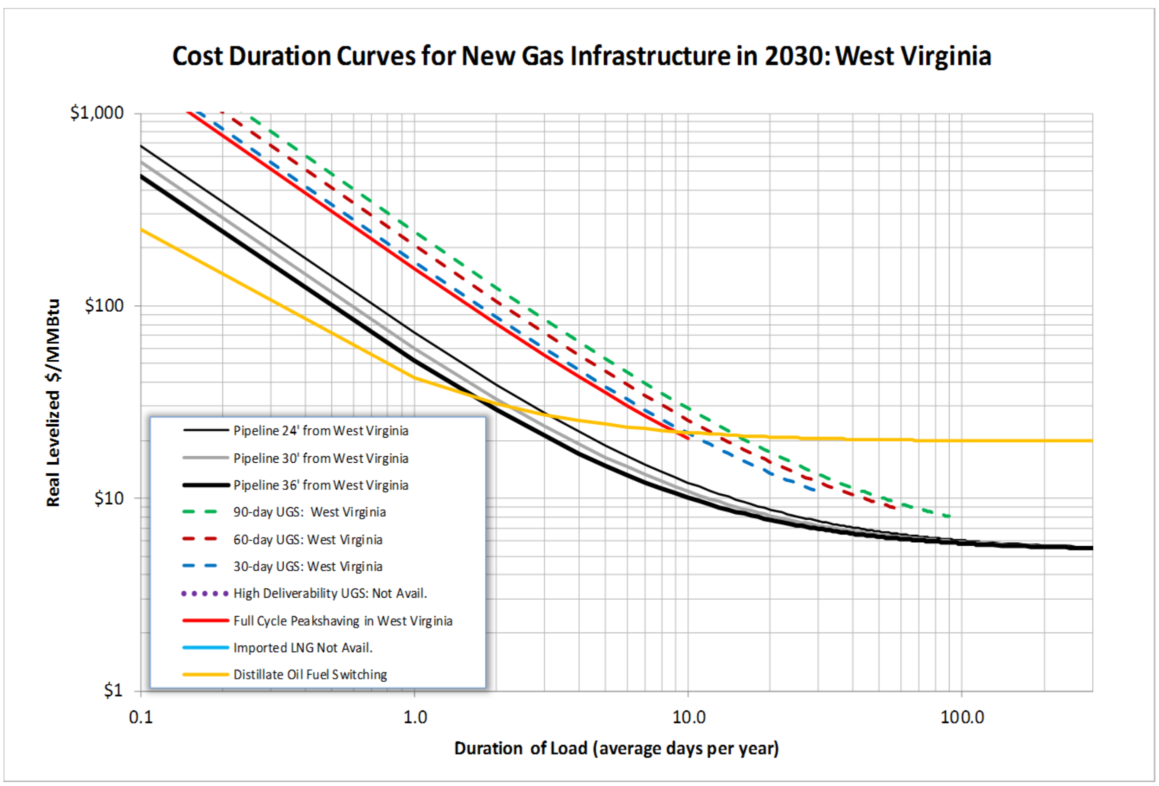

Cost Duration Curves for New Gas Infrastructure in 2030: Philadelphia
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northeast PA
Pipeline 30' from Northeast PA
Pipeline 36' from Northeast PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Philadelphia
Imported LNG
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: Southwest PA
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Southwest PA
60-day UGS: Southwest PA
30-day UGS: Southwest PA
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southwest PA
Imported LNG Not Avail.
Distillate Oil Fuel Switching

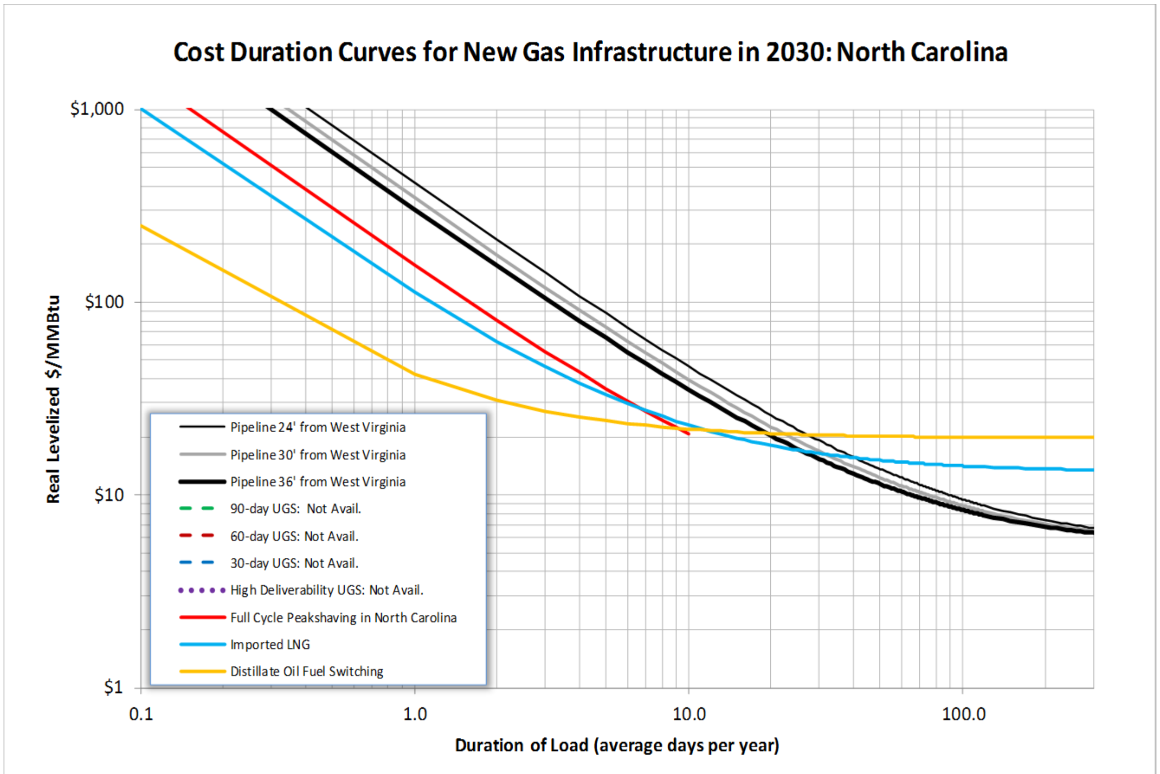

Cost Duration Curves for New Gas Infrastructure in 2030: MD/DC/Northern VA
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in MD/DC/Northern VA
Imported LNG
Distillate Oil Fuel Switching

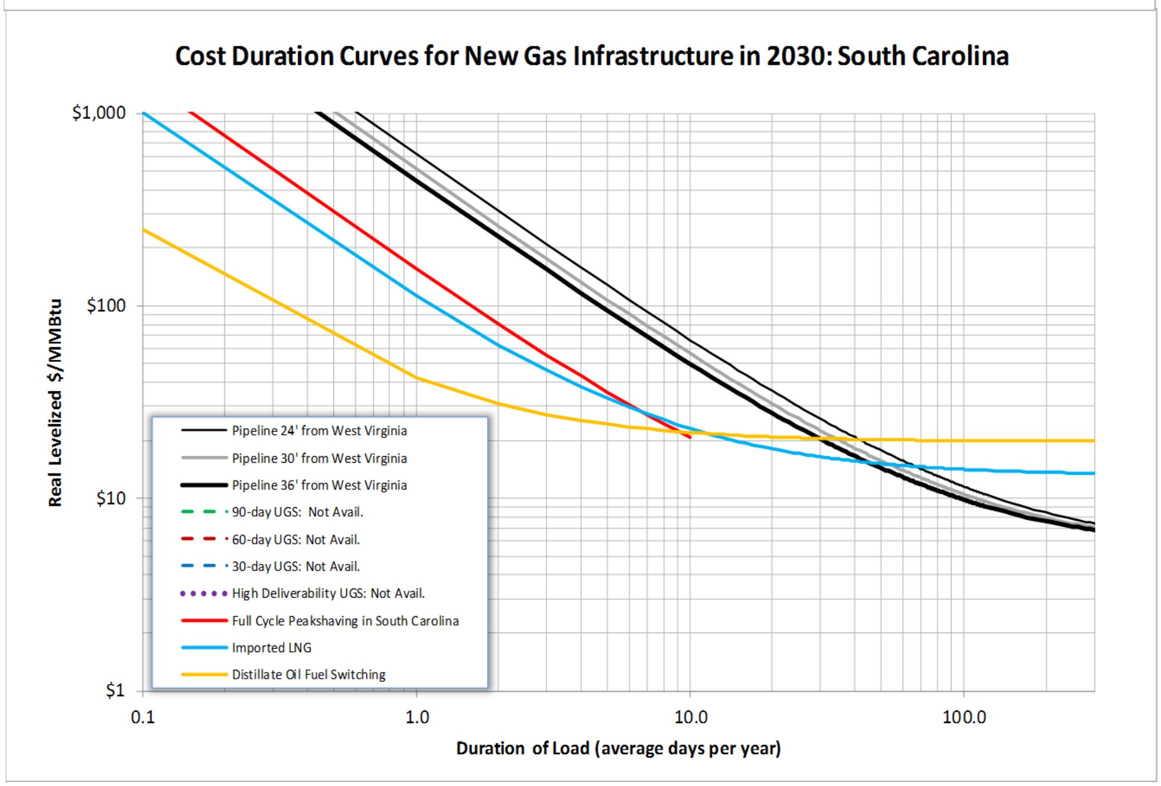

Cost Duration Curves for New Gas Infrastructure in 2030: Southwest VA
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Southwest VA
Full Cycle Peakshaving in Southwest VA
Imported LNG Not Avail.
Distillate Oil Fuel Switching

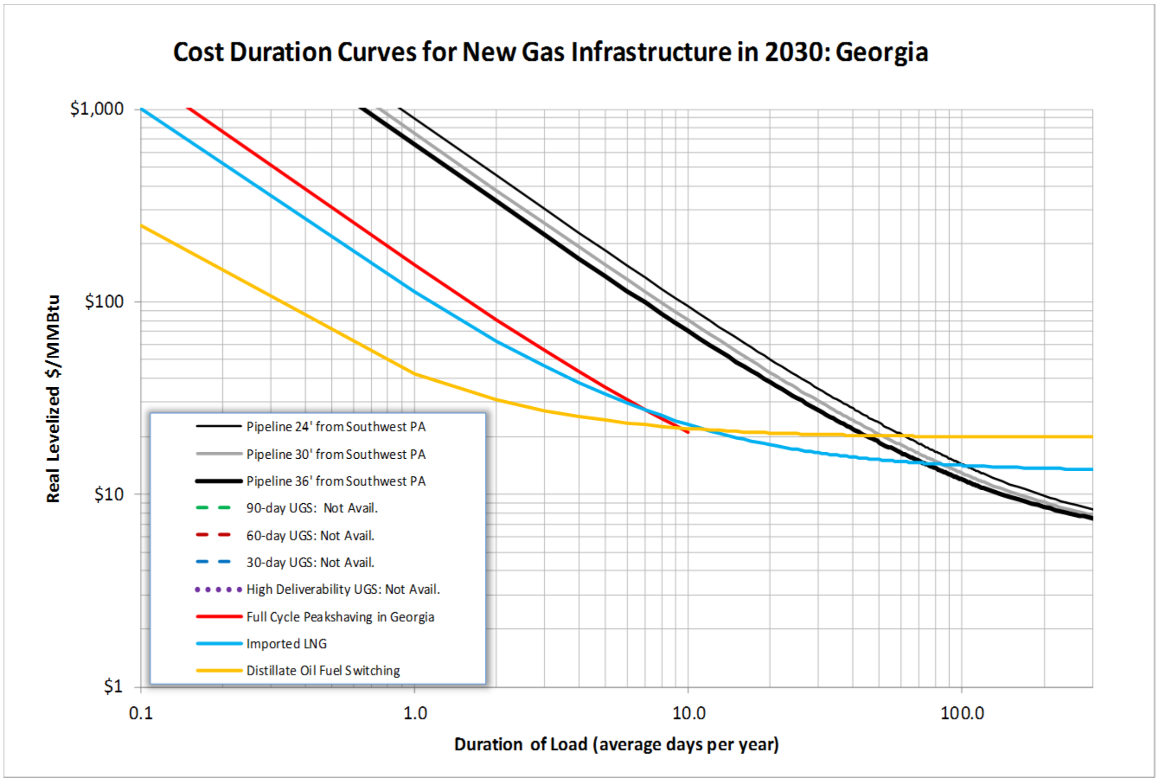

Cost Duration Curves for New Gas Infrastructure in 2030: Southeast VA
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southeast VA
Imported LNG
Distillate Oil Fuel Switching

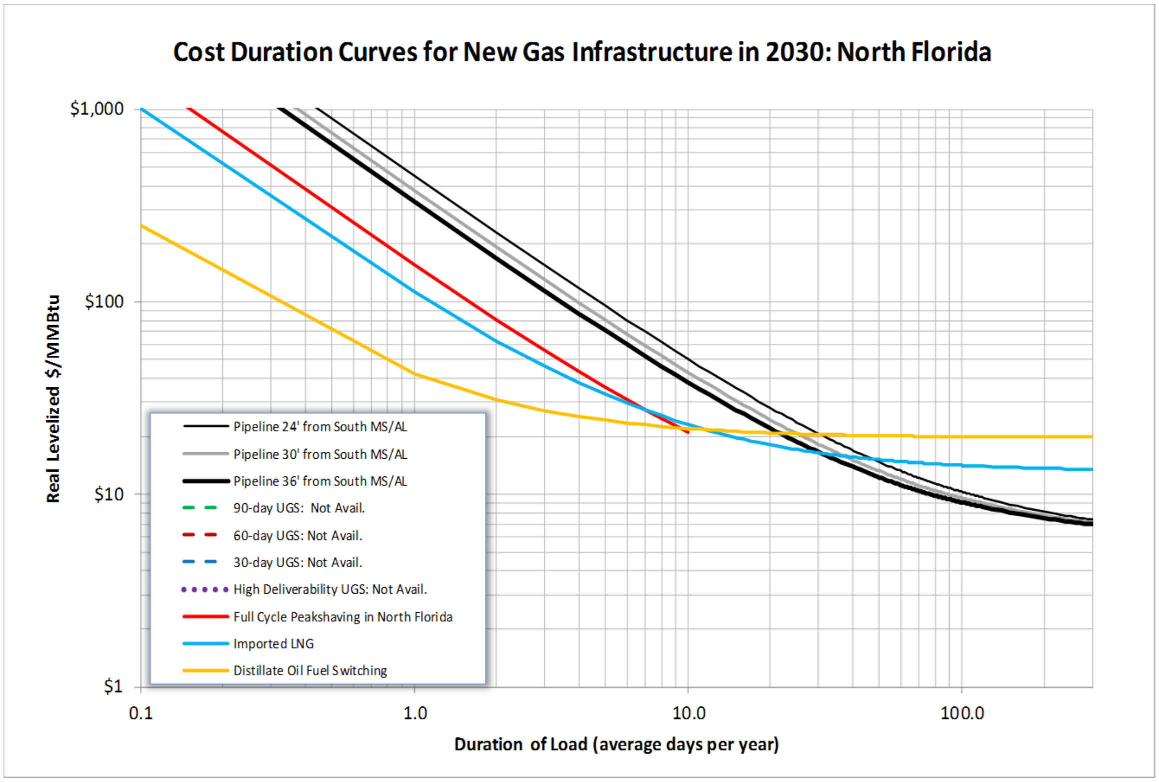

Cost Duration Curves for New Gas Infrastructure in 2030: West Virginia
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: West Virginia
60-day UGS: West Virginia
30-day UGS: West Virginia
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in West Virginia
Imported LNG Not Avail.
Distillate Oil Fuel Switching

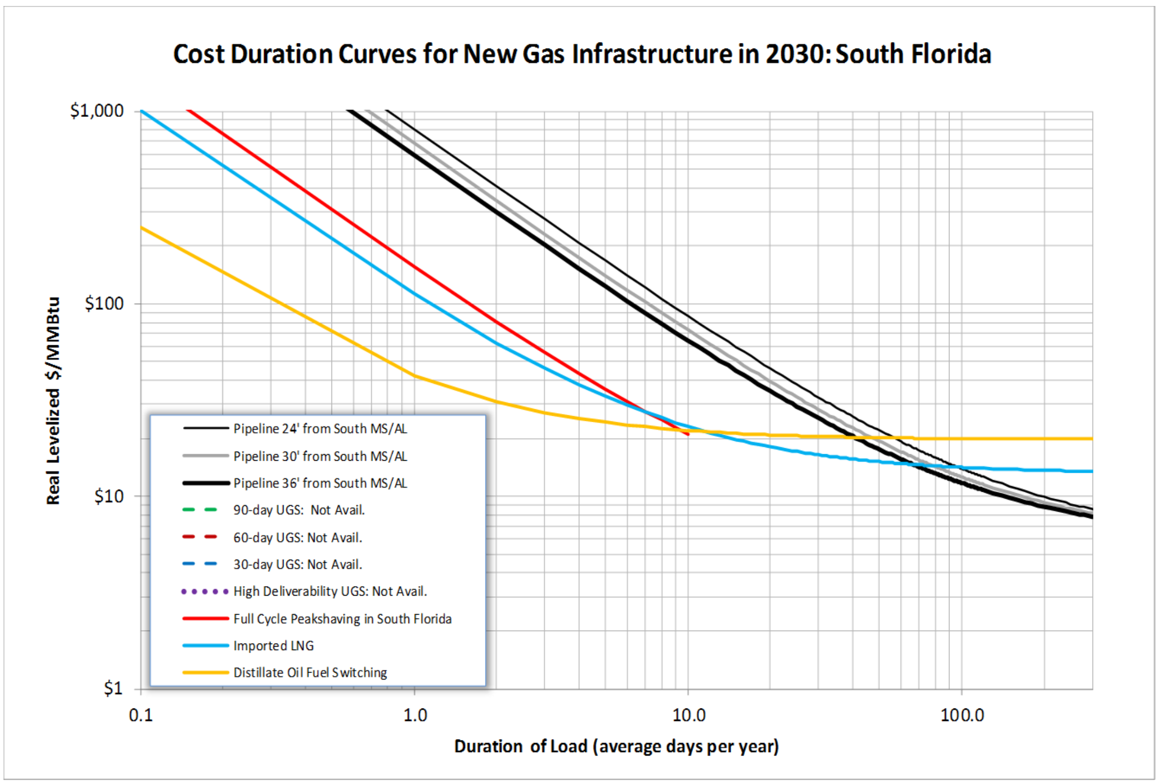
9.1.7 Southeast

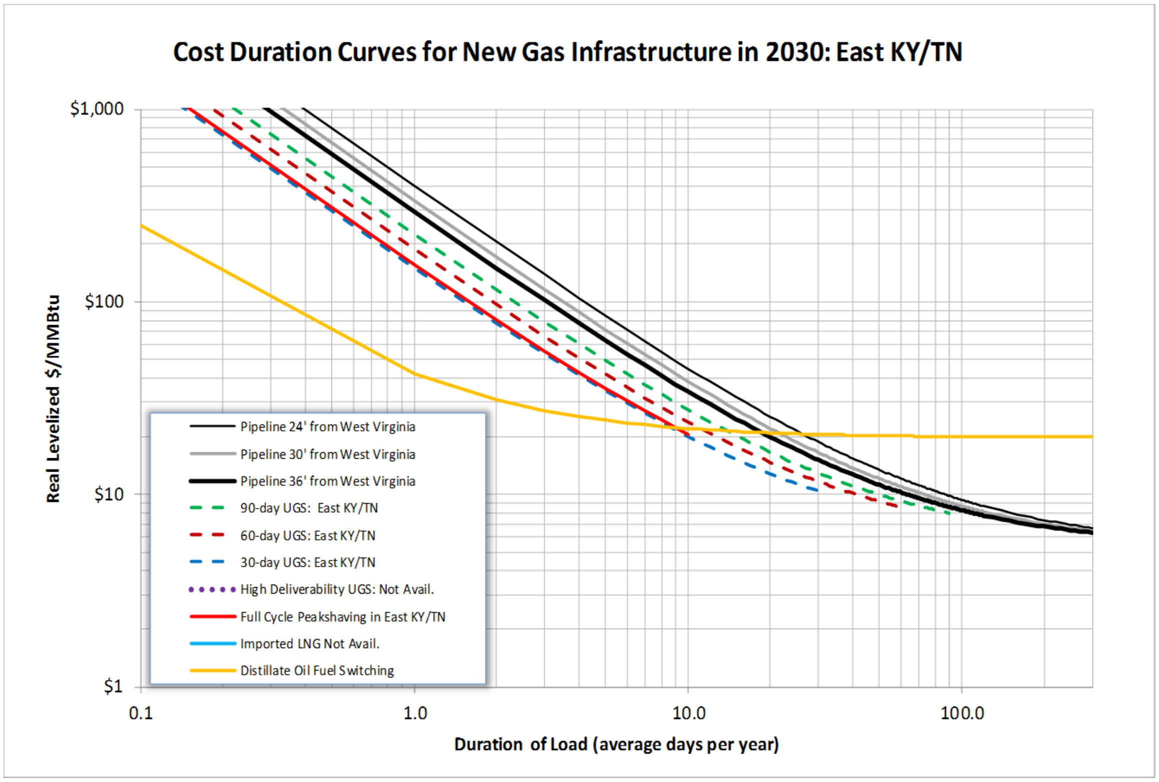

Cost Duration Curves for New Gas Infrastructure in 2030: North Carolina
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Carolina
Imported LNG
Distillate Oil Fuel Switching

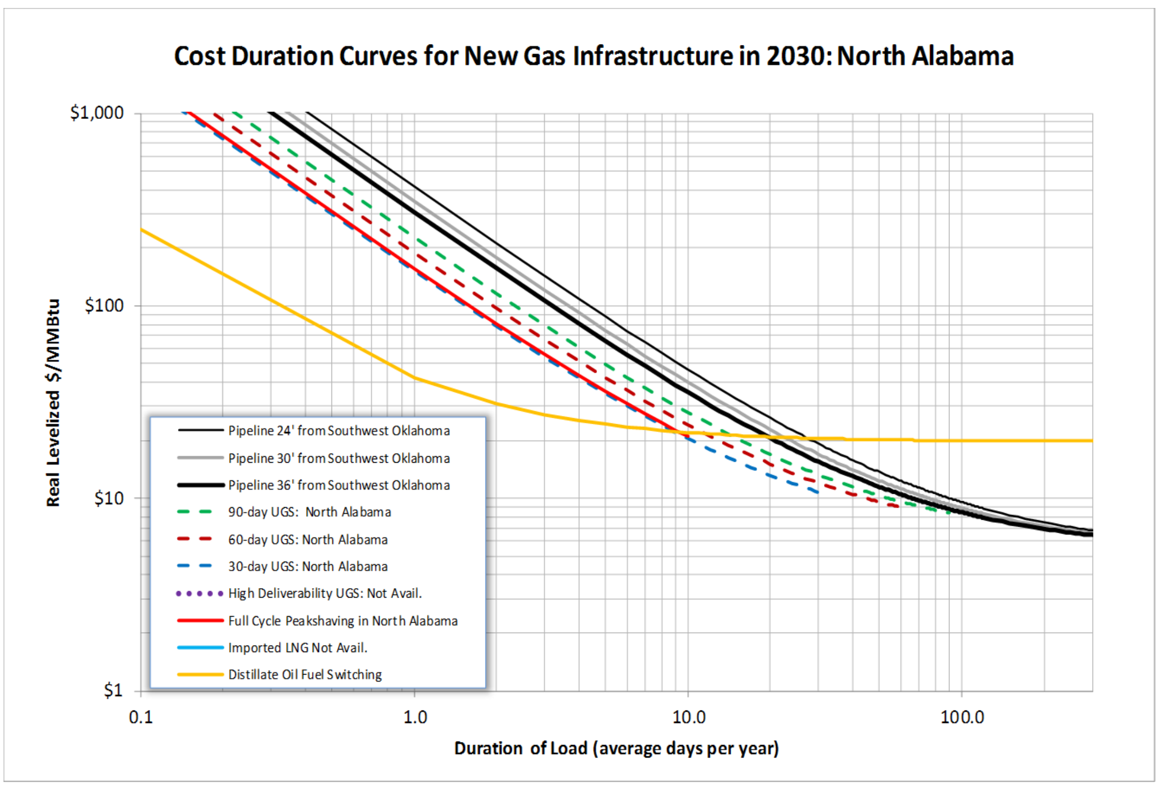

Cost Duration Curves for New Gas Infrastructure in 2030: South Carolina
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in South Carolina
Imported LNG
Distillate Oil Fuel Switching

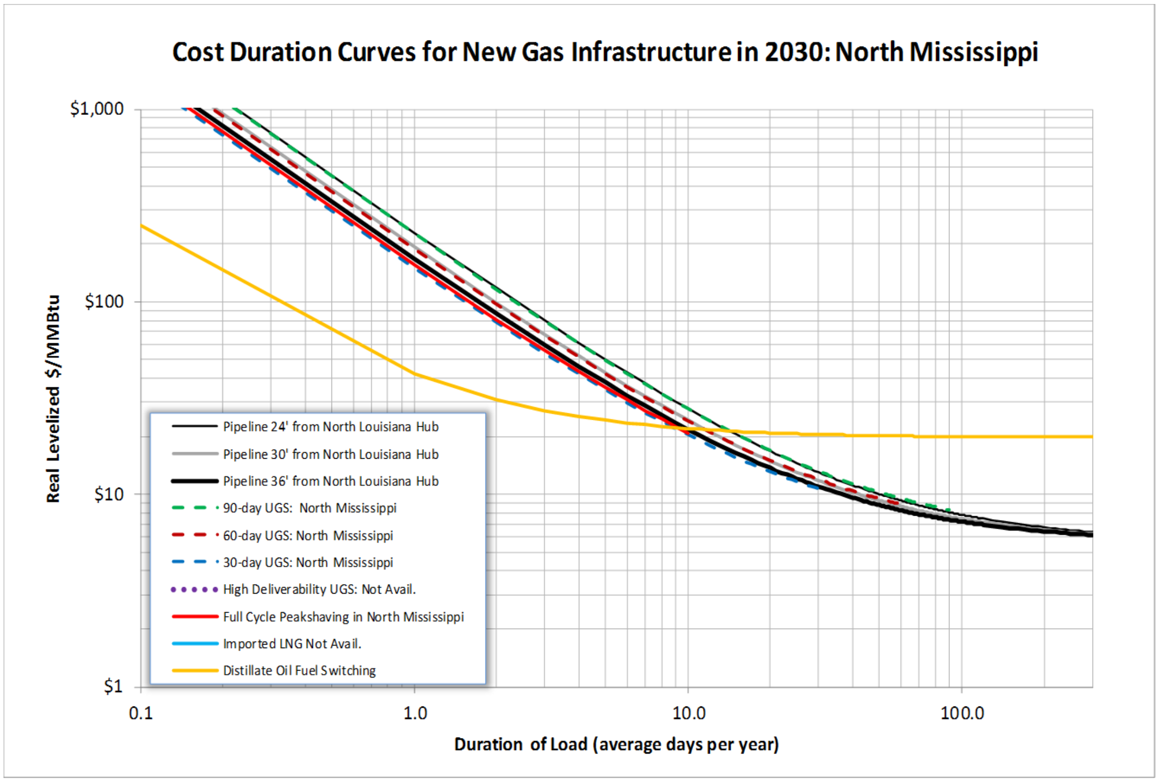

Cost Duration Curves for New Gas Infrastructure in 2030: Georgia
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Georgia
Imported LNG
Distillate Oil Fuel Switching

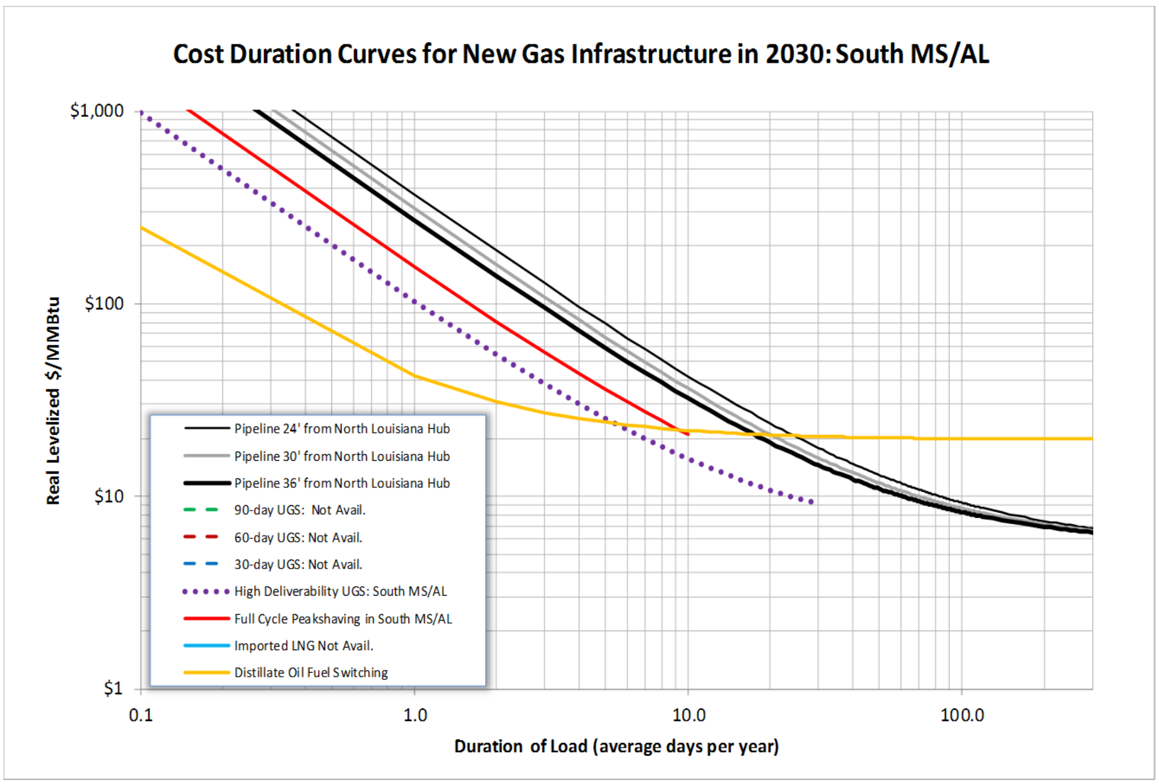

Cost Duration Curves for New Gas Infrastructure in 2030: North Florida
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from South MS/AL
Pipeline 30' from South MS/AL
Pipeline 36' from South MS/AL
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Florida
Imported LNG
Distillate Oil Fuel Switching

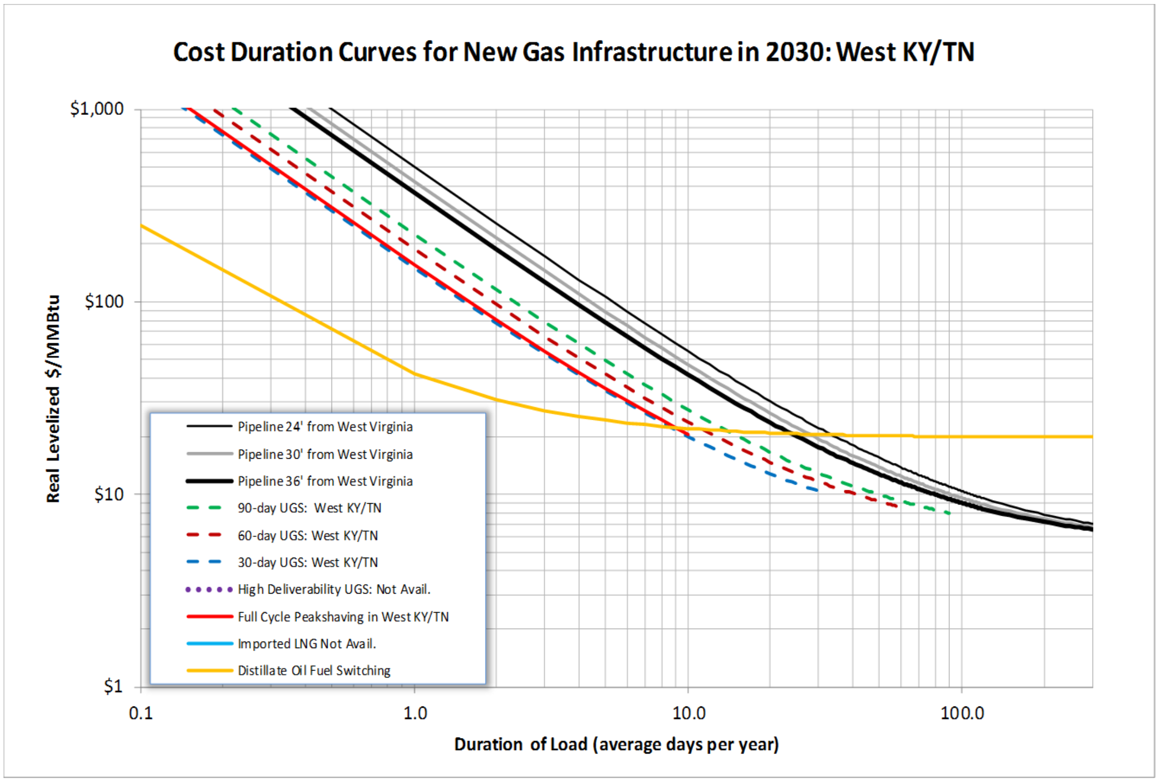

Cost Duration Curves for New Gas Infrastructure in 2030: South Florida
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from South MS/AL
Pipeline 30' from South MS/AL
Pipeline 36' from South MS/AL
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in South Florida
Imported LNG
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: East KY/TN
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: East KY/TN
60-day UGS: East KY/TN
30-day UGS: East KY/TN
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in East KY/TN
Imported LNG Not Avail.
Distillate Oil Fuel Switching

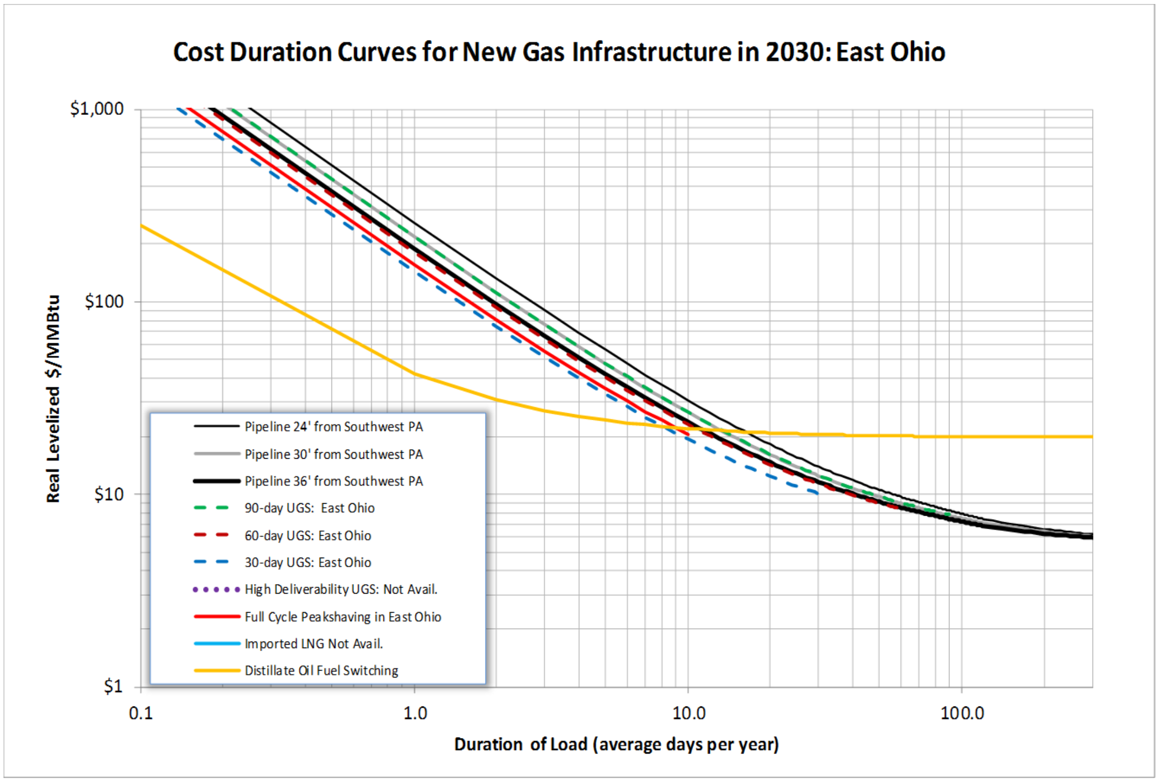

Cost Duration Curves for New Gas Infrastructure in 2030: North Alabama
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: North Alabama
60-day UGS: North Alabama
30-day UGS: North Alabama
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Alabama
Imported LNG Not Avail.
Distillate Oil Fuel Switching

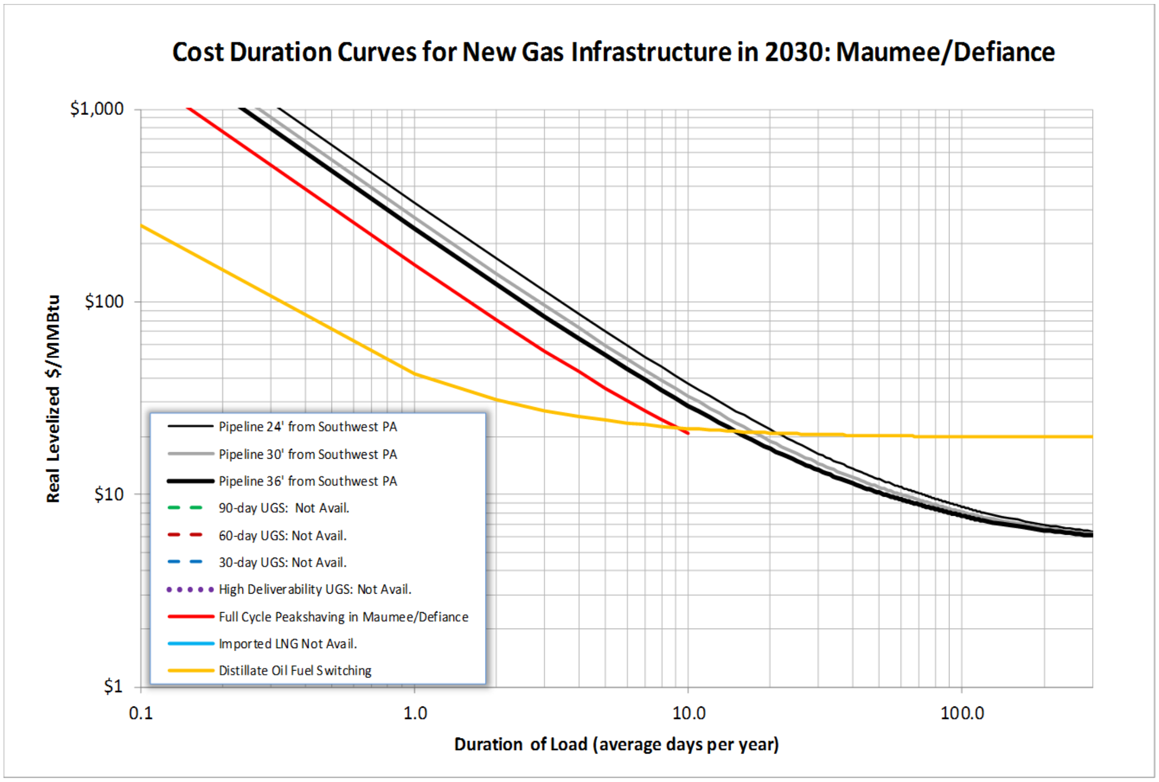

Cost Duration Curves for New Gas Infrastructure in 2030: North Mississippi
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from North Louisiana Hub
Pipeline 30' from North Louisiana Hub
Pipeline 36' from North Louisiana Hub
90-day UGS: North Mississippi
60-day UGS: North Mississippi
30-day UGS: North Mississippi
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Mississippi
Imported LNG Not Avail.
Distillate Oil Fuel Switching

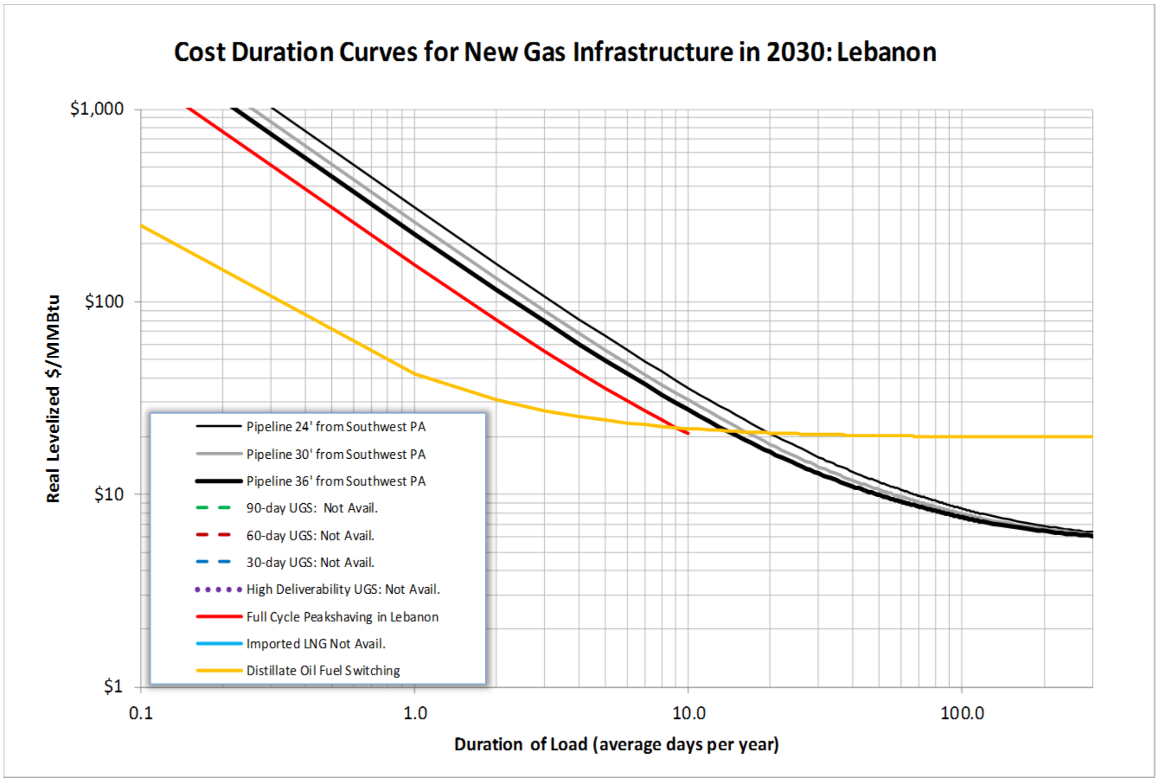

Cost Duration Curves for New Gas Infrastructure in 2030: South MS/AL
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from North Louisiana Hub
Pipeline 30' from North Louisiana Hub
Pipeline 36' from North Louisiana Hub
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: South MS/AL
Full Cycle Peakshaving in South MS/AL
Imported LNG Not Avail.
Distillate Oil Fuel Switching

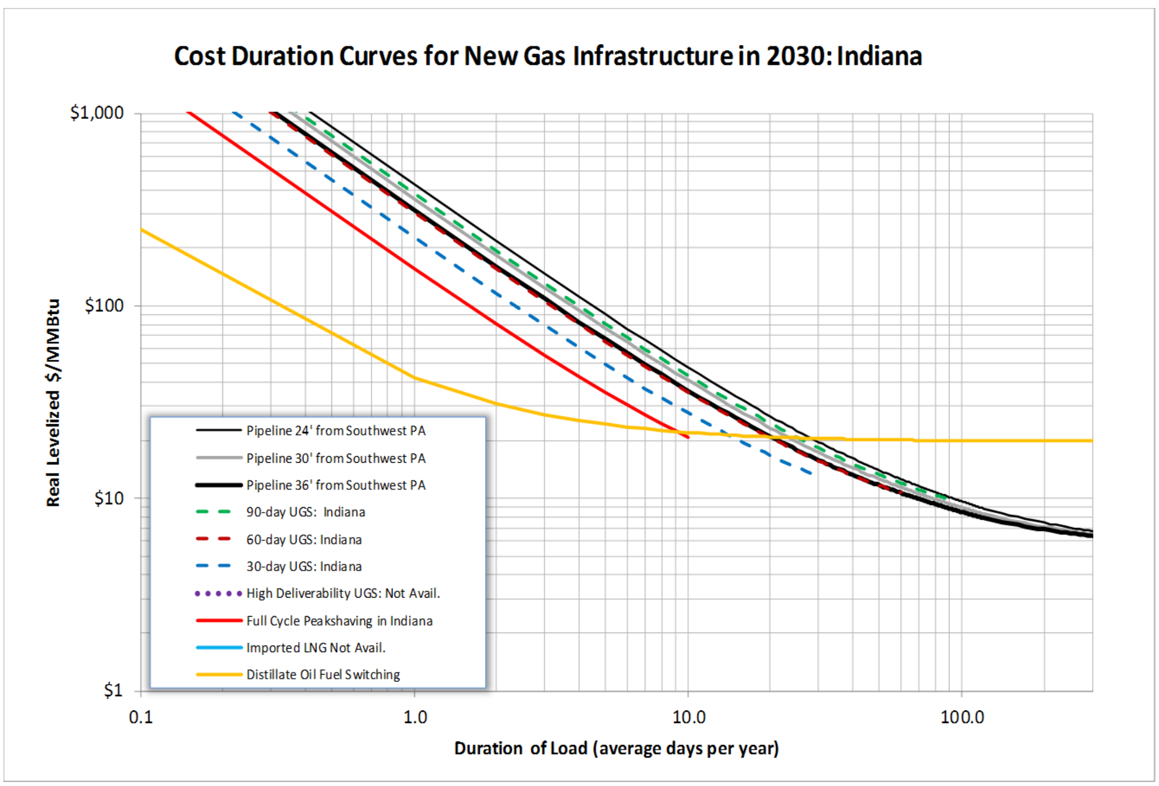

Cost Duration Curves for New Gas Infrastructure in 2030: West KY/TN
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from West Virginia
Pipeline 30' from West Virginia
Pipeline 36' from West Virginia
90-day UGS: West KY/TN
60-day UGS: West KY/TN
30-day UGS: West KY/TN
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in West KY/TN
Imported LNG Not Avail.
Distillate Oil Fuel Switching

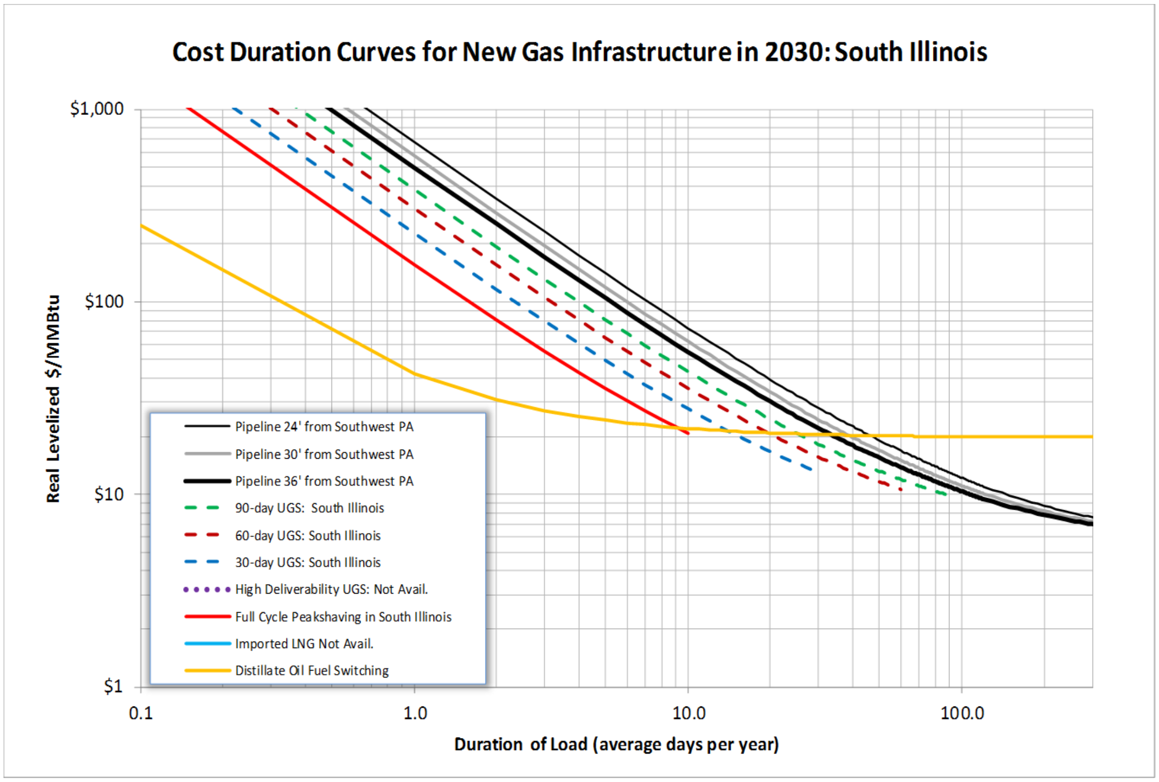
9.1.8 Midwest

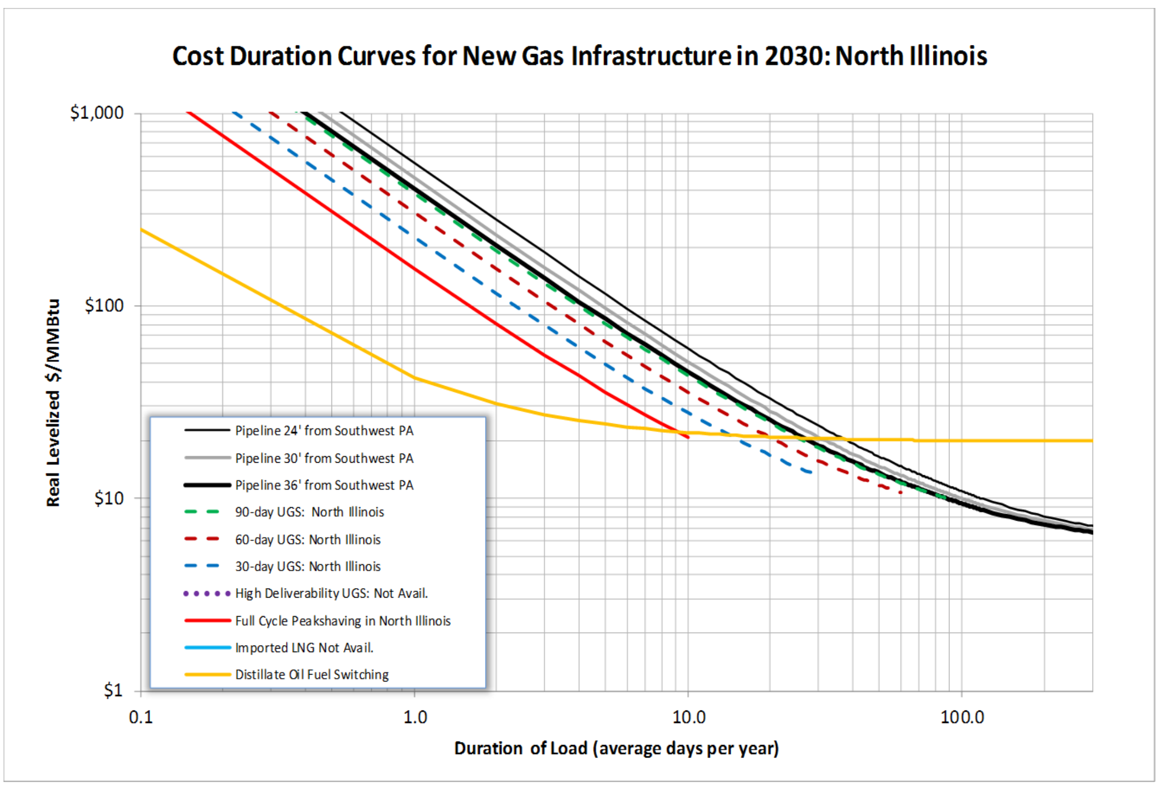

Cost Duration Curves for New Gas Infrastructure in 2030: East Ohio
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: East Ohio
60-day UGS: East Ohio
30-day UGS: East Ohio
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in East Ohio
Imported LNG Not Avail.
Distillate Oil Fuel Switching

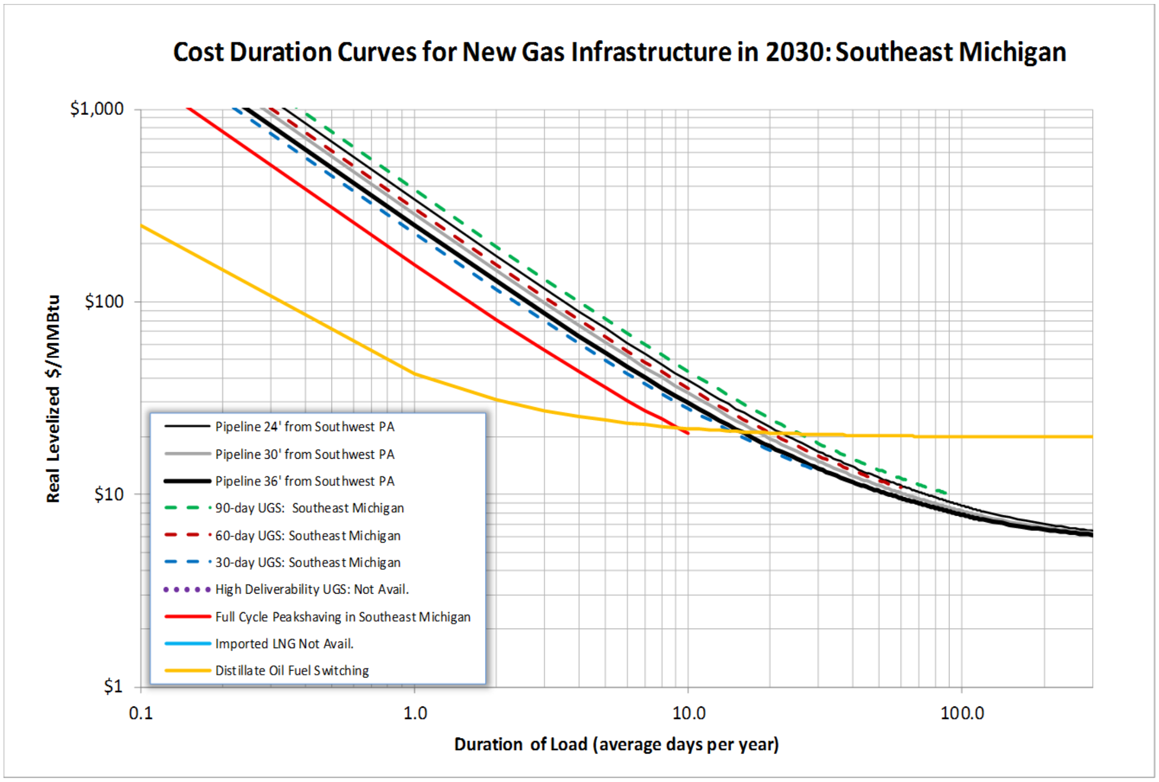

Cost Duration Curves for New Gas Infrastructure in 2030: Maumee/Defiance
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Maumee/Defiance
Imported LNG Not Avail.
Distillate Oil Fuel Switching

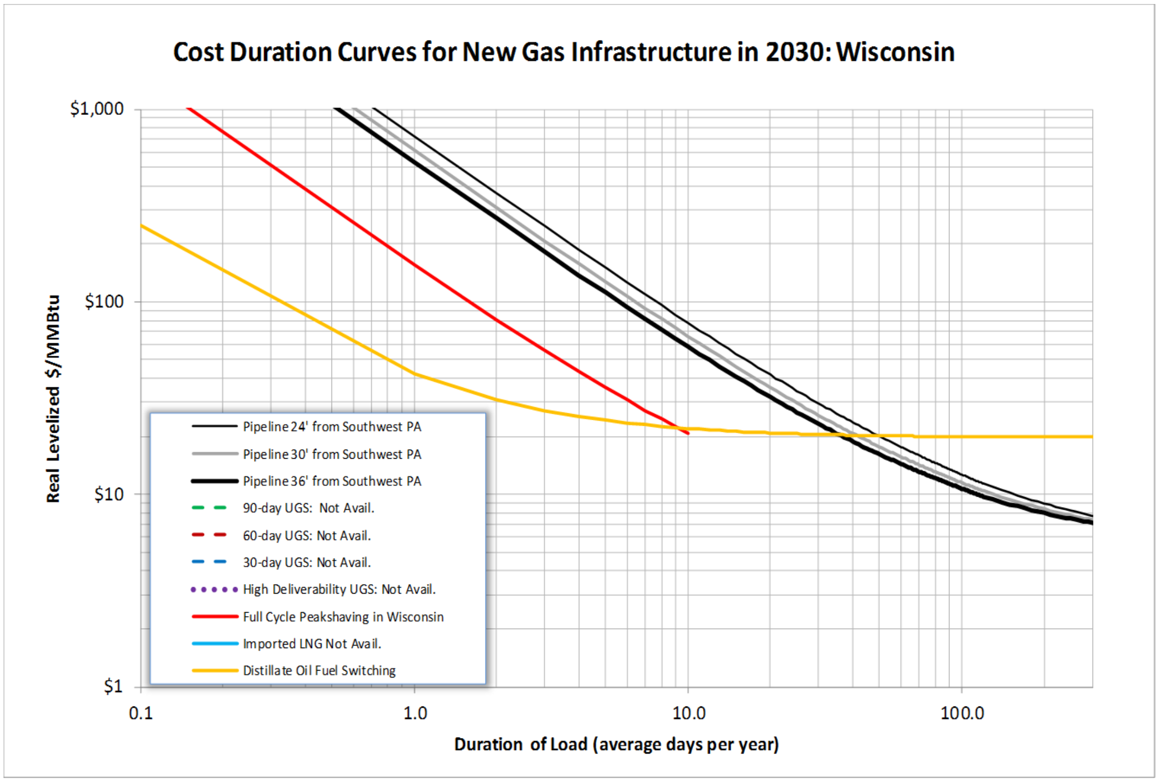

Cost Duration Curves for New Gas Infrastructure in 2030: Lebanon
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Lebanon
Imported LNG Not Avail.
Distillate Oil Fuel Switching

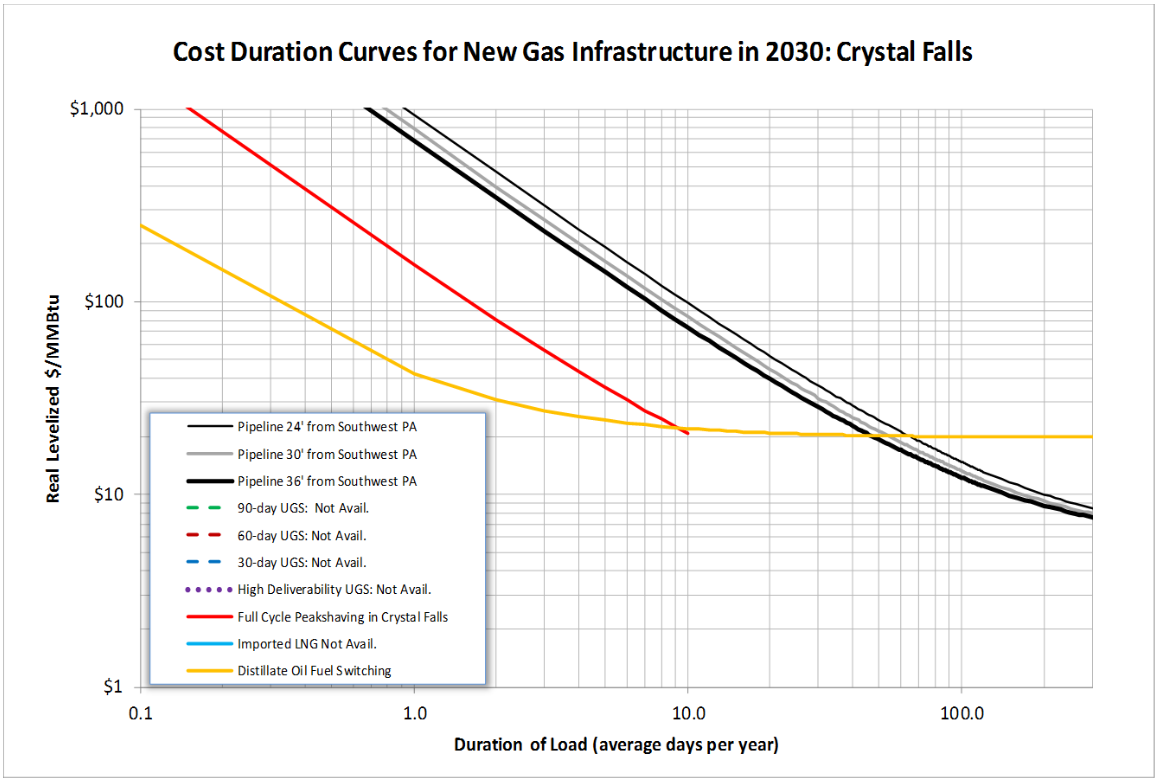

Cost Duration Curves for New Gas Infrastructure in 2030: Indiana
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Indiana
60-day UGS: Indiana
30-day UGS: Indiana
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Indiana
Imported LNG Not Avail.
Distillate Oil Fuel Switching

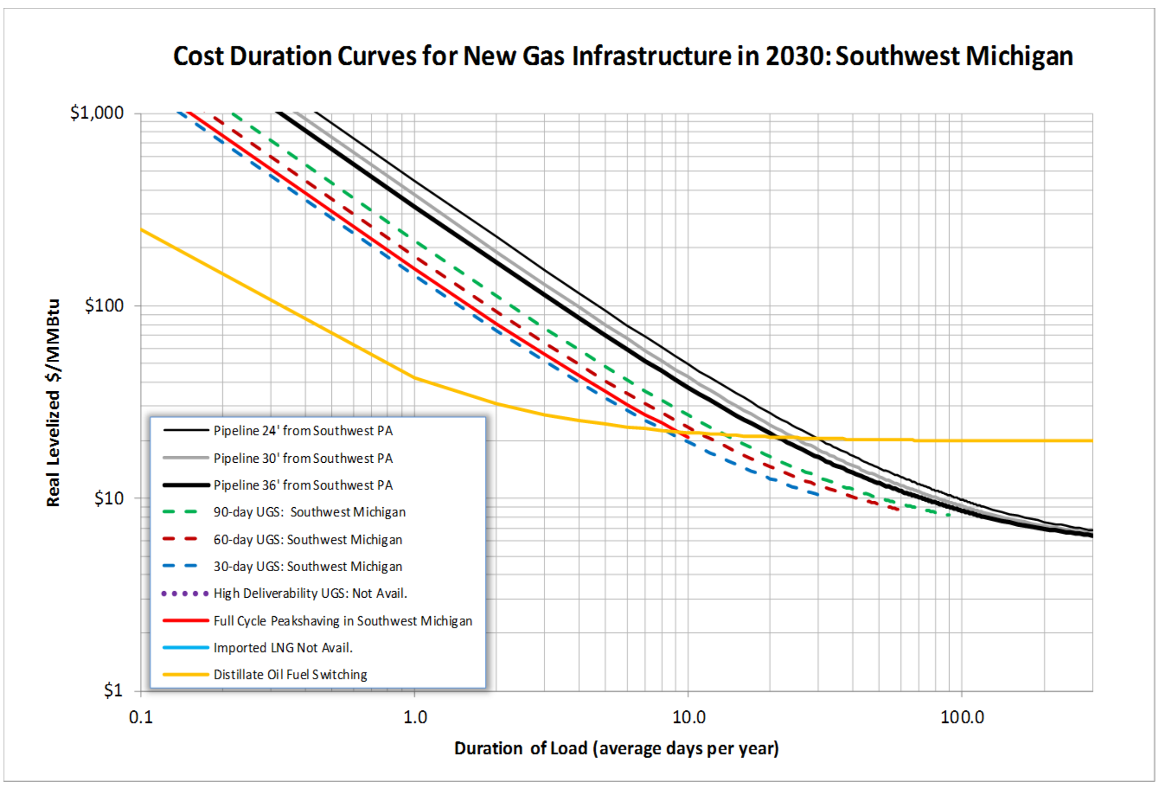

Cost Duration Curves for New Gas Infrastructure in 2030: South Illinois
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: South Illinois
60-day UGS: South Illinois
30-day UGS: South Illinois
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in South Illinois
Imported LNG Not Avail.
Distillate Oil Fuel Switching

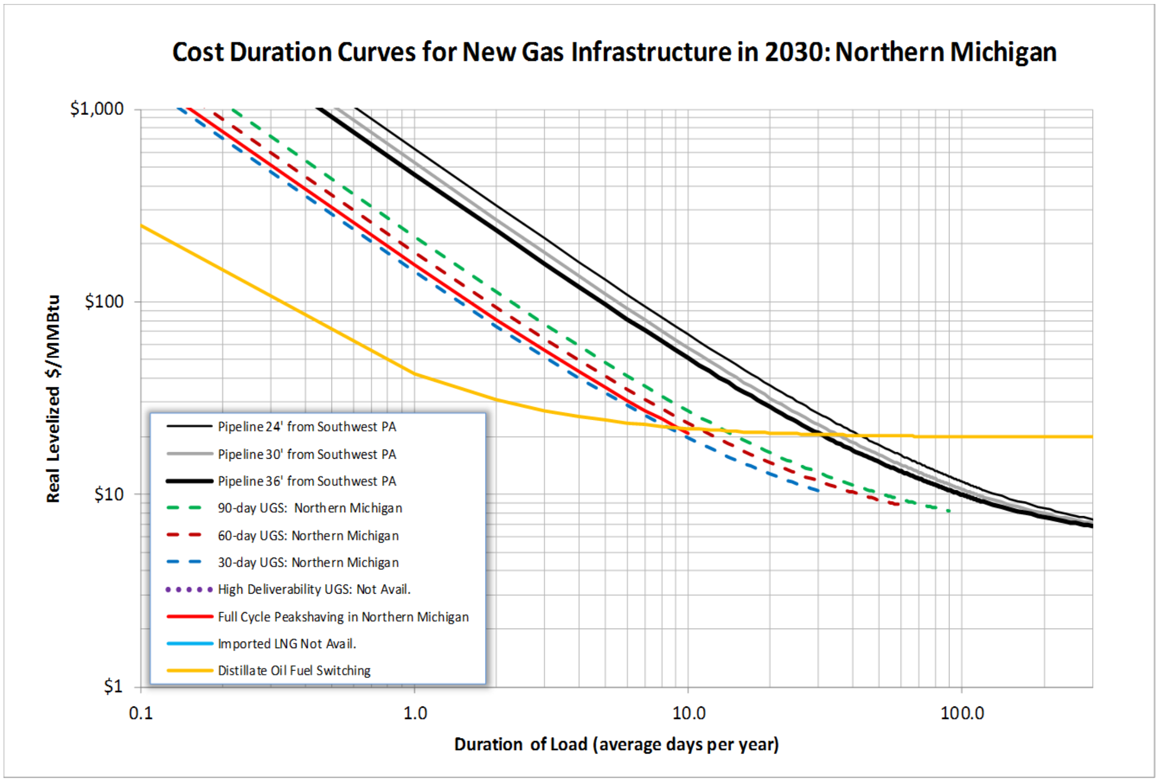

Cost Duration Curves for New Gas Infrastructure in 2030: North Illinois
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: North Illinois
60-day UGS: North Illinois
30-day UGS: North Illinois
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Illinois
Imported LNG Not Avail.
Distillate Oil Fuel Switching

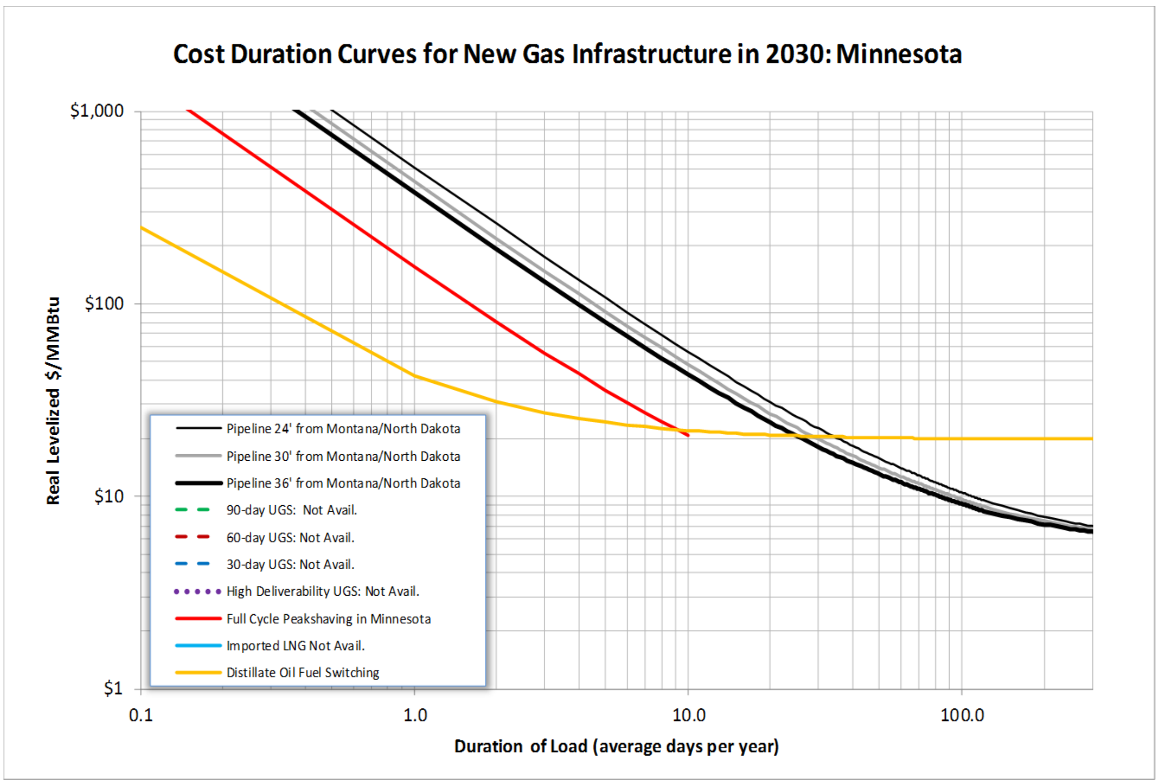

Cost Duration Curves for New Gas Infrastructure in 2030: Southeast Michigan
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Southeast Michigan
60-day UGS: Southeast Michigan
30-day UGS: Southeast Michigan
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southeast Michigan
Imported LNG Not Avail.
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: Wisconsin
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Wisconsin
Imported LNG Not Avail.
Distillate Oil Fuel Switching

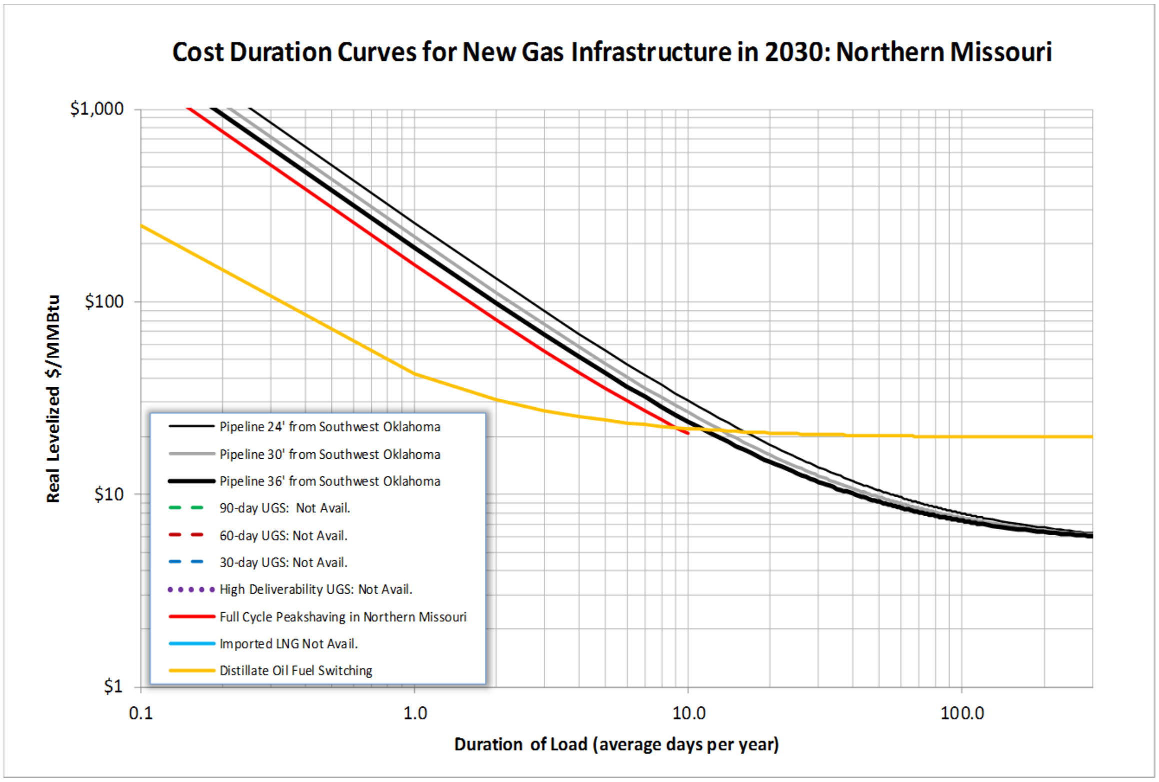

Cost Duration Curves for New Gas Infrastructure in 2030: Crystal Falls
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Crystal Falls
Imported LNG Not Avail.
Distillate Oil Fuel Switching

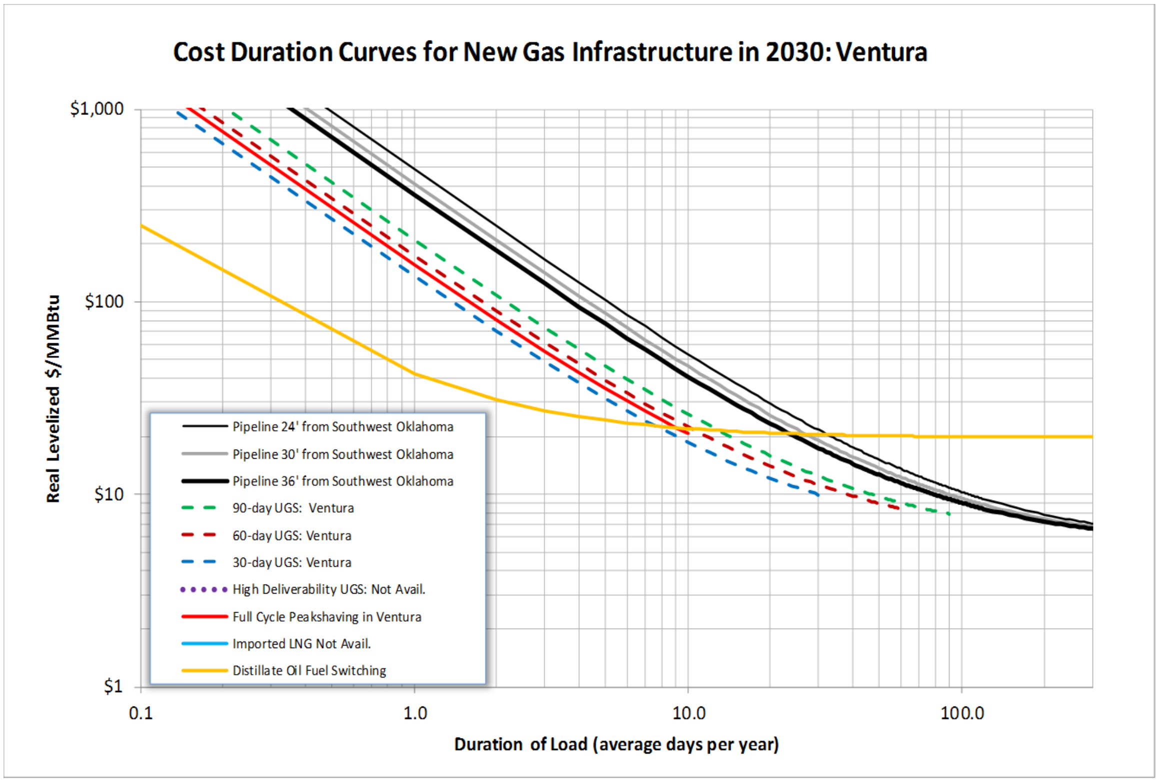

Cost Duration Curves for New Gas Infrastructure in 2030: Southwest Michigan
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Southwest Michigan
60-day UGS: Southwest Michigan
30-day UGS: Southwest Michigan
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southwest Michigan
Imported LNG Not Avail.
Distillate Oil Fuel Switching

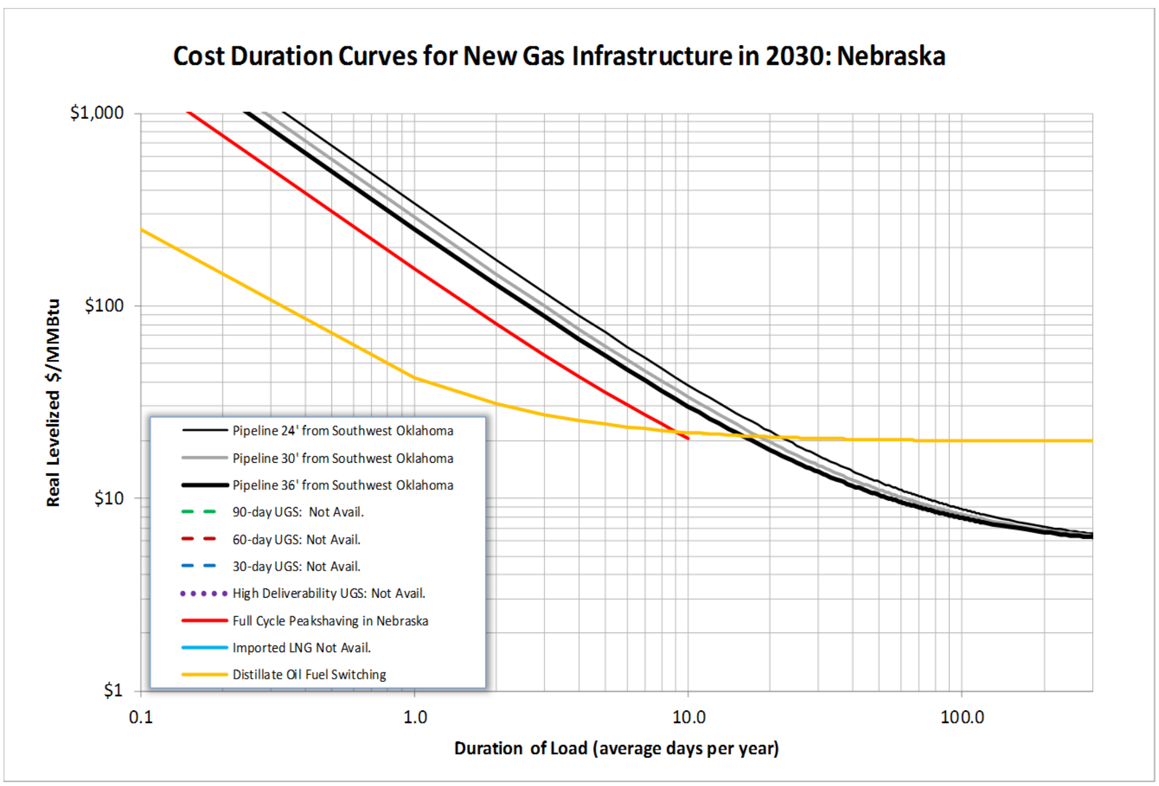

Cost Duration Curves for New Gas Infrastructure in 2030: Northern Michigan
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest PA
Pipeline 30' from Southwest PA
Pipeline 36' from Southwest PA
90-day UGS: Northern Michigan
60-day UGS: Northern Michigan
30-day UGS: Northern Michigan
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Northern Michigan
Imported LNG Not Avail.
Distillate Oil Fuel Switching

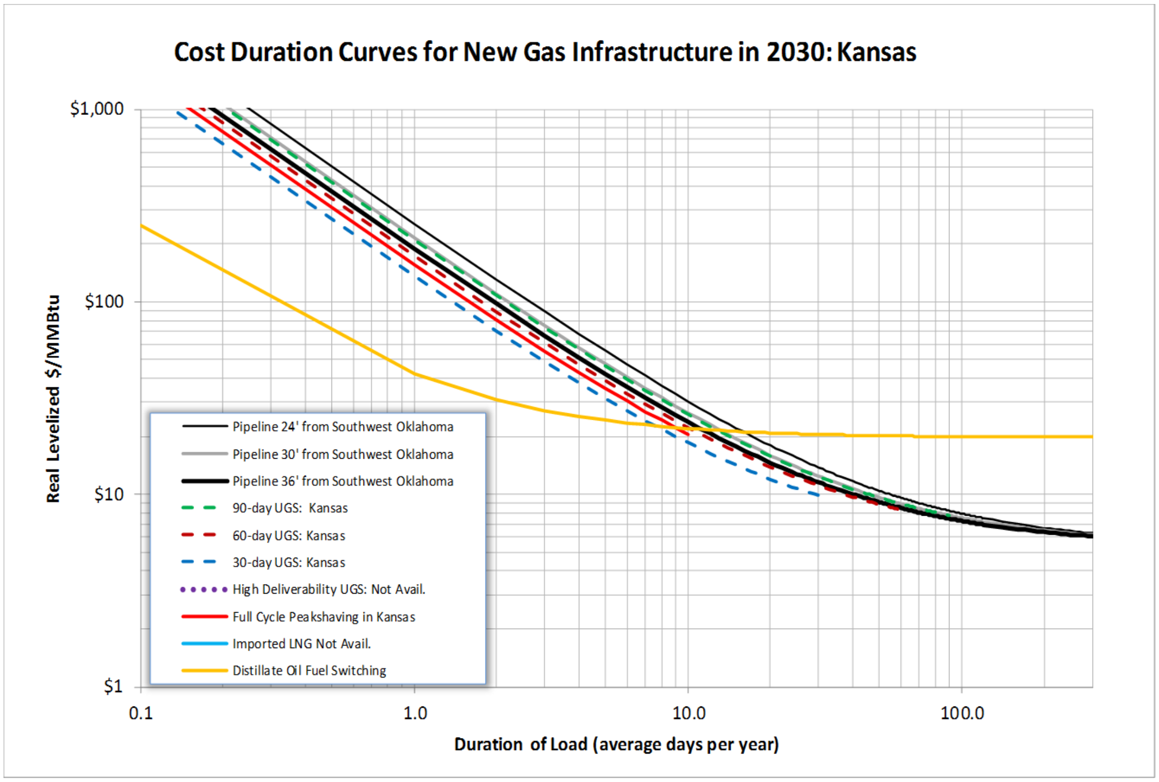

Cost Duration Curves for New Gas Infrastructure in 2030: Minnesota
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Montana/North Dakota
Pipeline 30' from Montana/North Dakota
Pipeline 36' from Montana/North Dakota
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Minnesota
Imported LNG Not Avail.
Distillate Oil Fuel Switching

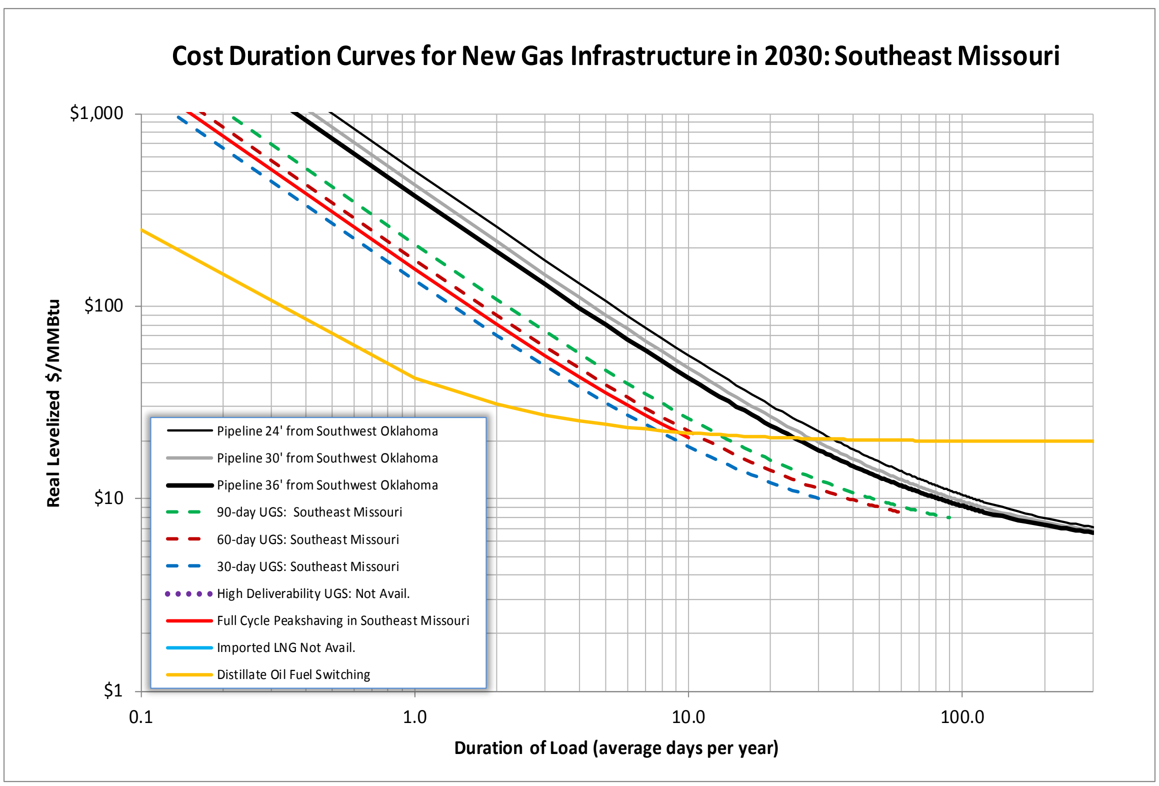
9.1.9 Central


Cost Duration Curves for New Gas Infrastructure in 2030: Northern Missouri
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Northern Missouri
Imported LNG Not Avail.
Distillate Oil Fuel Switching

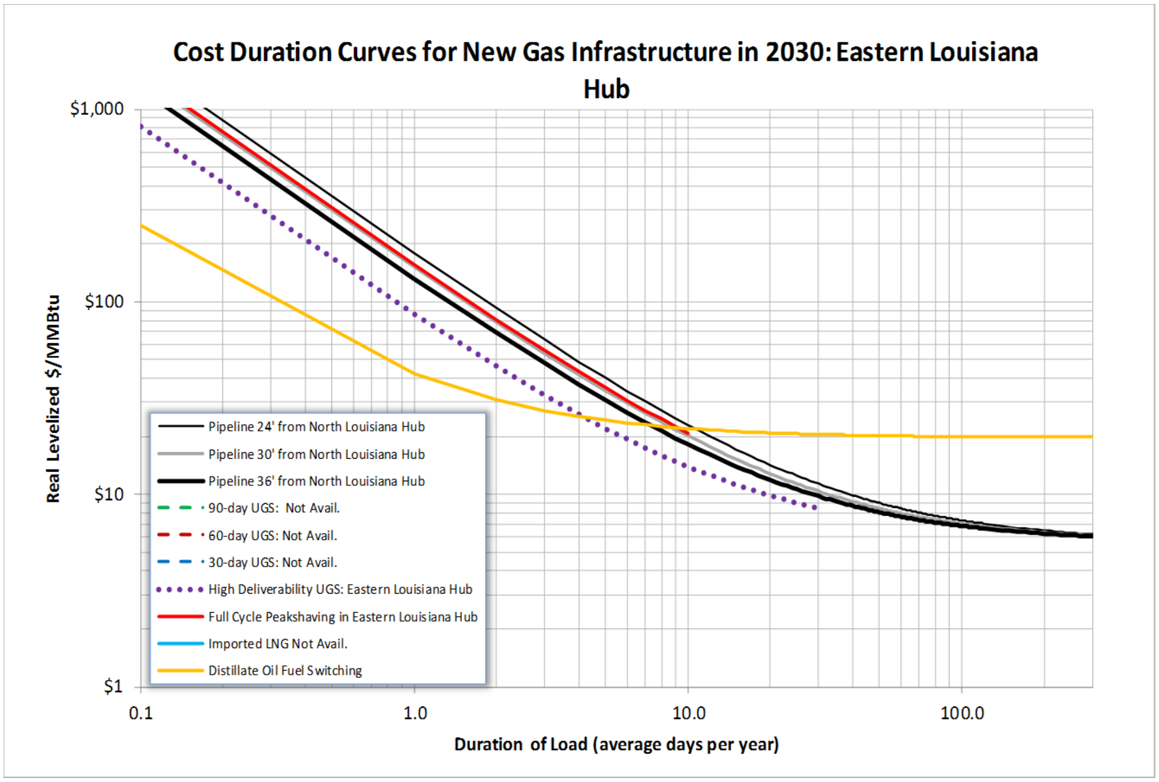

Cost Duration Curves for New Gas Infrastructure in 2030: Ventura
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Ventura
60-day UGS: Ventura
30-day UGS: Ventura
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Ventura
Imported LNG Not Avail.
Distillate Oil Fuel Switching

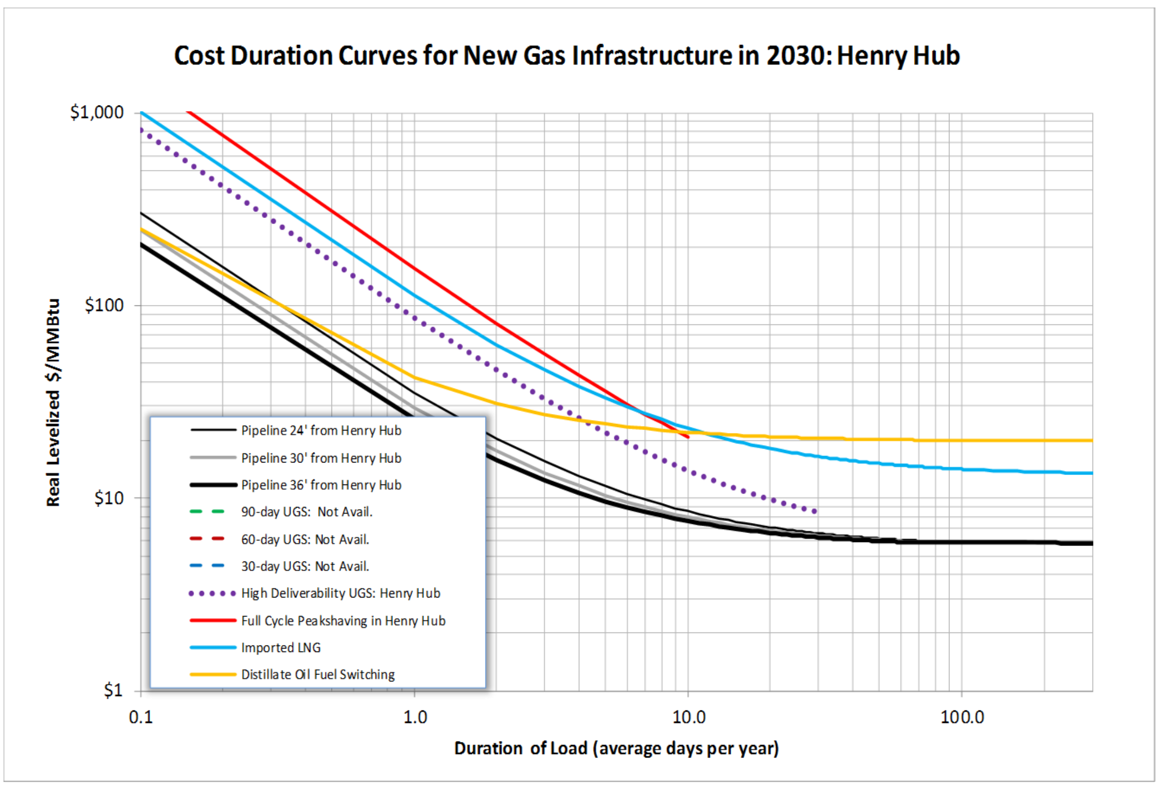

Cost Duration Curves for New Gas Infrastructure in 2030: Nebraska
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Nebraska
Imported LNG Not Avail.
Distillate Oil Fuel Switching

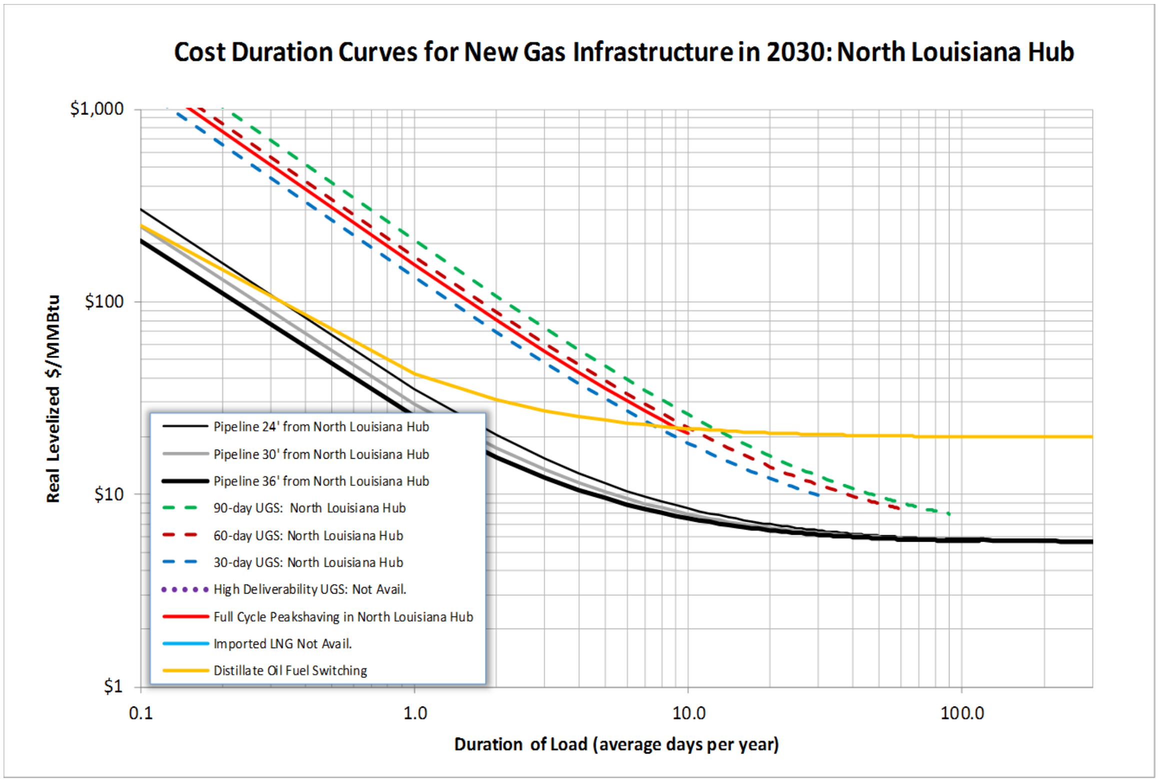

Cost Duration Curves for New Gas Infrastructure in 2030: Kansas
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Kansas
60-day UGS: Kansas
30-day UGS: Kansas
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Kansas
Imported LNG Not Avail.
Distillate Oil Fuel Switching

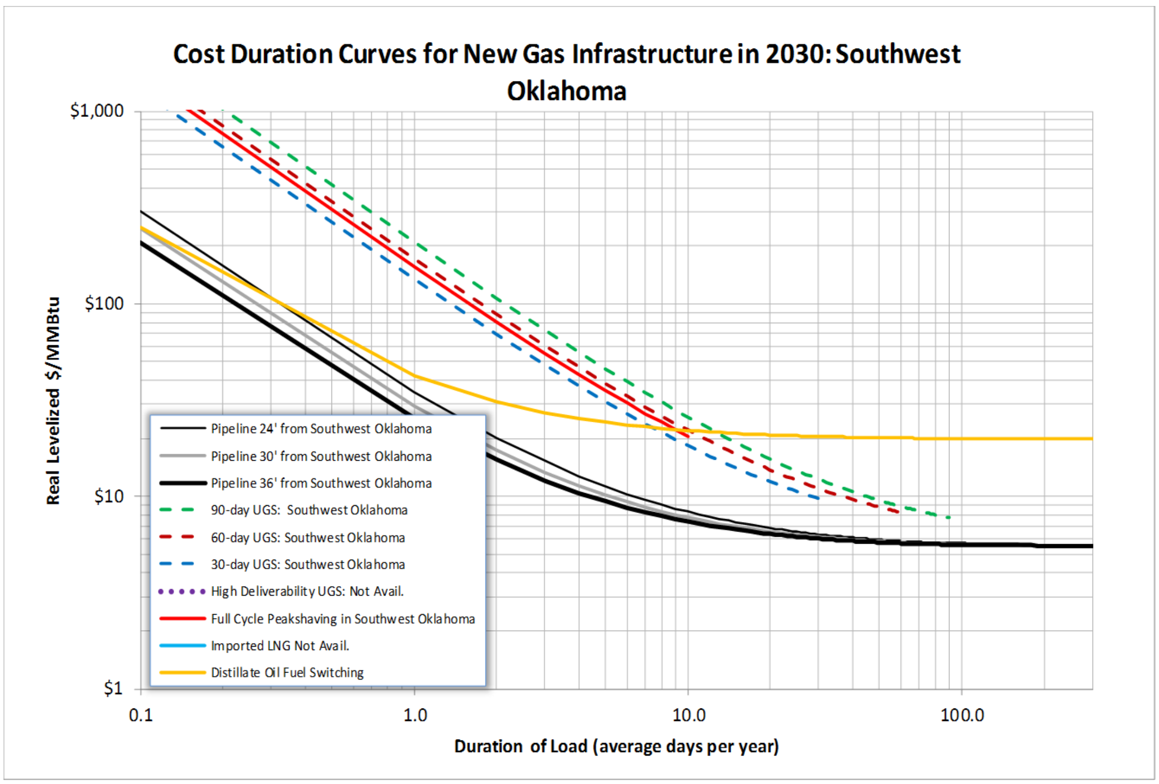

Cost Duration Curves for New Gas Infrastructure in 2030: Southeast Missouri
Real Levelized $/MMBtu
$1,000
$100
$10
$1
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Southeast Missouri
60-day UGS: Southeast Missouri
30-day UGS: Southeast Missouri
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southeast Missouri
Imported LNG Not Avail.
Distillate Oil Fuel Switching

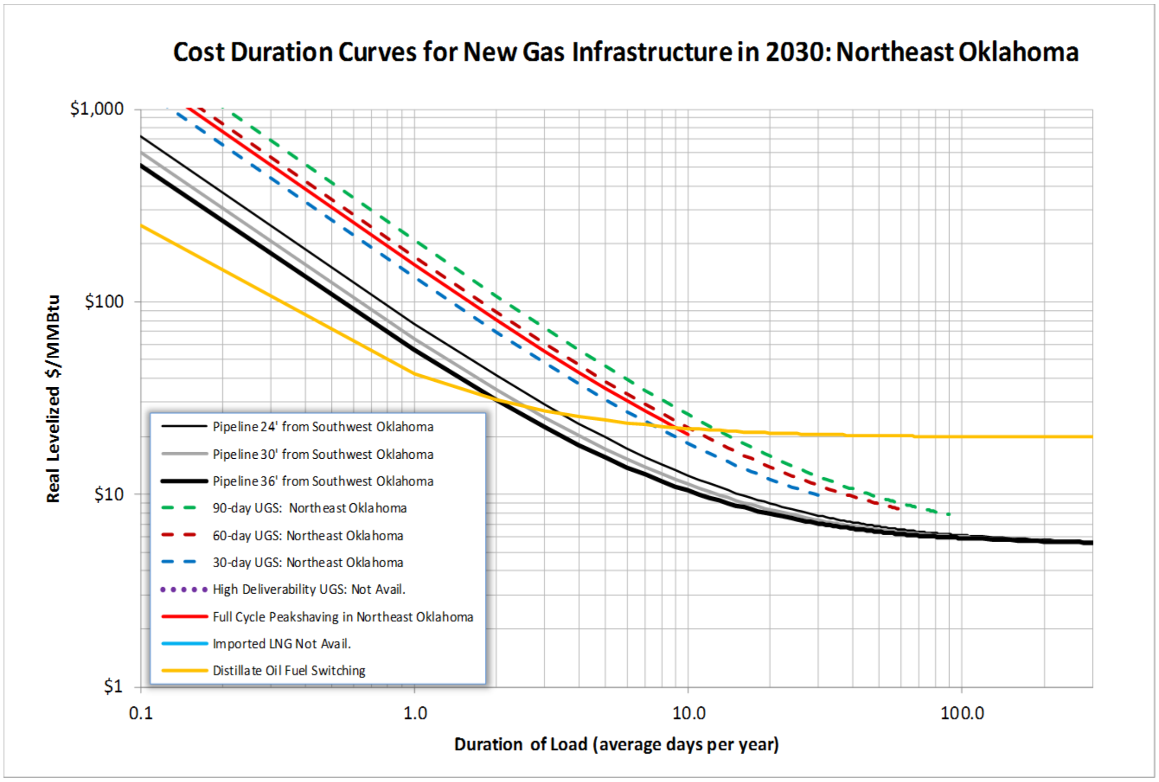
9.1.10 Southwest

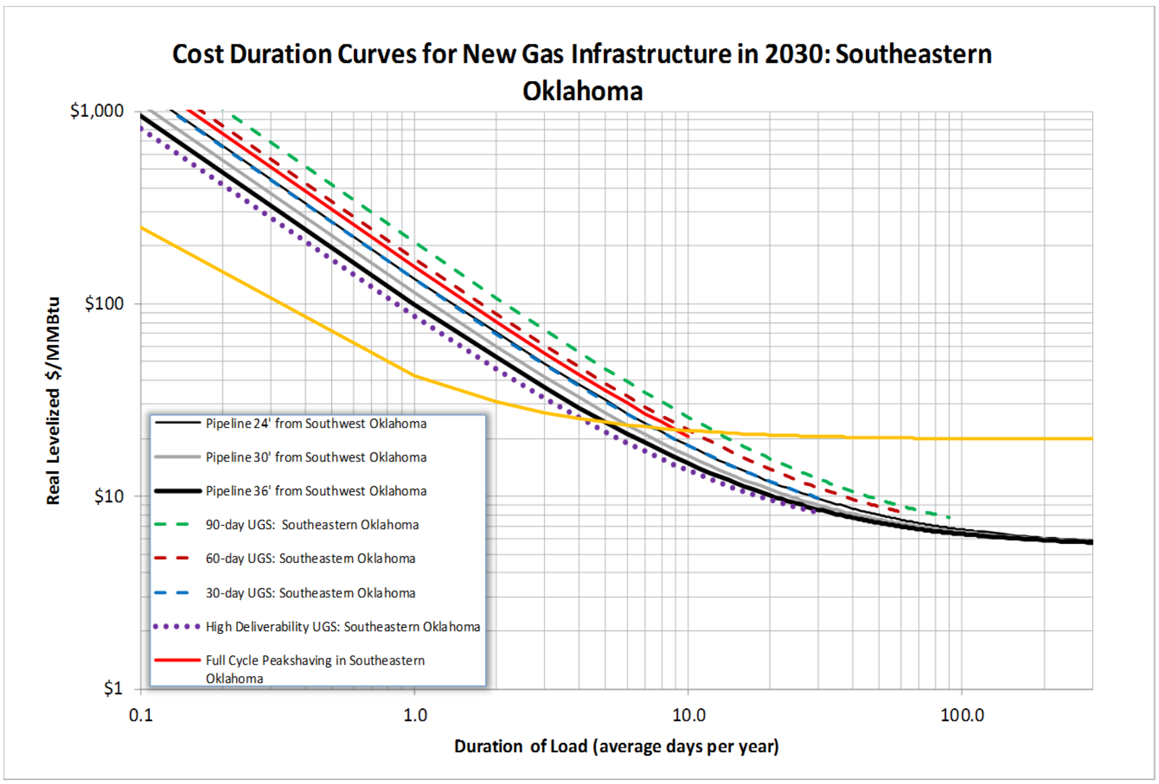


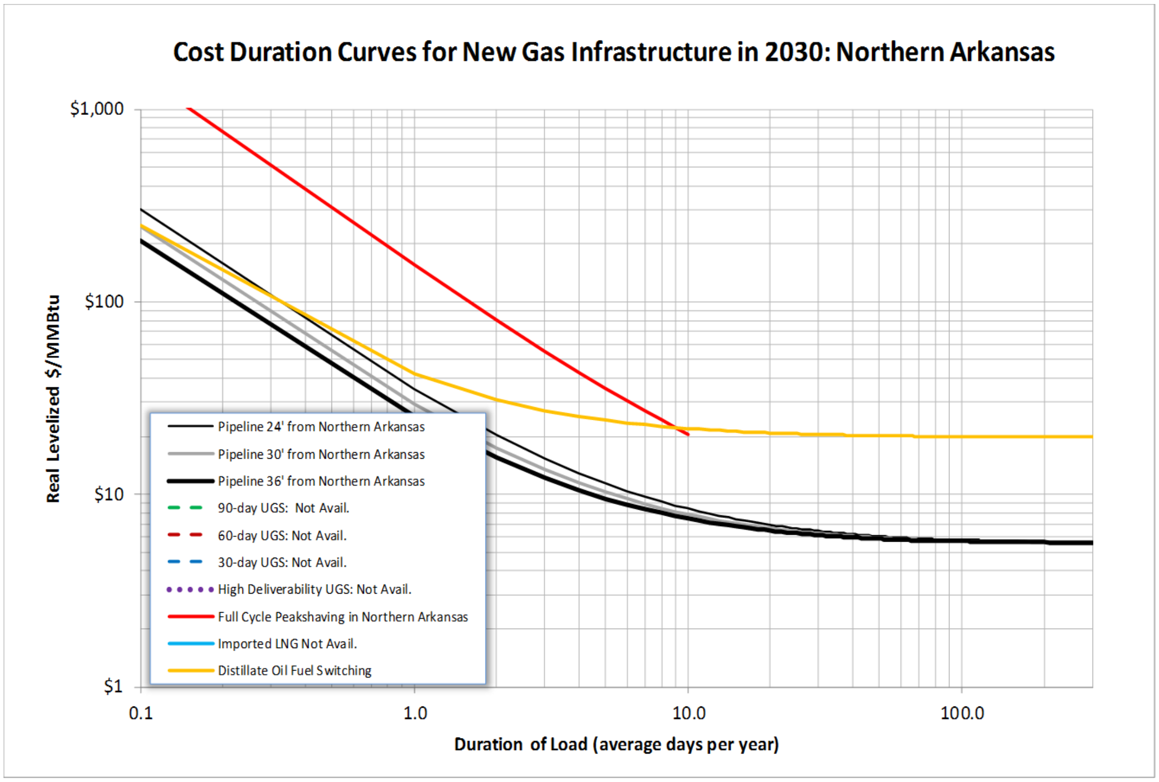



Cost Duration Curves for New Gas Infrastructure in 2030: North Louisiana Hub
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from North Louisiana Hub
Pipeline 30' from North Louisiana Hub
Pipeline 36' from North Louisiana Hub
90-day UGS: North Louisiana Hub
60-day UGS: North Louisiana Hub
30-day UGS: North Louisiana Hub
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in North Louisiana Hub
Imported LNG Not Avail.
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: Southwest Oklahoma
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Southwest Oklahoma
60-day UGS: Southwest Oklahoma
30-day UGS: Southwest Oklahoma
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Southwest Oklahoma
Imported LNG Not Avail.
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: Northeast Oklahoma
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Northeast Oklahoma
60-day UGS: Northeast Oklahoma
30-day UGS: Northeast Oklahoma
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Northeast Oklahoma
Imported LNG Not Avail.
Distillate Oil Fuel Switching


Cost Duration Curves for New Gas Infrastructure in 2030: Southeastern Oklahoma
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Southwest Oklahoma
Pipeline 30' from Southwest Oklahoma
Pipeline 36' from Southwest Oklahoma
90-day UGS: Southeastern Oklahoma
60-day UGS: Southeastern Oklahoma
30-day UGS: Southeastern Oklahoma
High Deliverability UGS: Southeastern Oklahoma
Full Cycle Peakshaving in Southeastern Oklahoma



Cost Duration Curves for New Gas Infrastructure in 2030: Northern Arkansas
$1,000
$100
$10
$1
Real Levelized $/MMBtu
0.1
1.0
10.0
100.0
Duration of Load (average days per year)
Pipeline 24' from Northern Arkansas
Pipeline 30' from Northern Arkansas
Pipeline 36' from Northern Arkansas
90-day UGS: Not Avail.
60-day UGS: Not Avail.
30-day UGS: Not Avail.
High Deliverability UGS: Not Avail.
Full Cycle Peakshaving in Northern Arkansas
Imported LNG Not Avail.
Distillate Oil Fuel Switching

Appendix E: State-level Infrastructure Expenditure and Other Metrics by Type

The following section includes state-level infrastructure expenditures and other natural gas metrics.

Exhibit 9-11: Gas Transmission Mainline and Laterals Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$5,006	$2,537	$2,712
Arkansas	$280	$119	$167
Connecticut	$673	$139	$710
Delaware	$613	$559	$607
District of Columbia	$0	$0	$0
Florida	$7,855	$4,211	$6,991
Georgia	$1,954	$608	$425
Illinois	$2,588	$1,065	$1,132
Indiana	$1,104	$219	$544
Iowa	$277	$177	$160
Kansas	$1,793	$1,500	$1,669
Kentucky	$901	$464	$339
Louisiana	$6,013	$4,274	$5,299
Maine	$1	$12	$14
Maryland	$856	$430	$891
Massachusetts	$673	$139	$710
Michigan	$1,068	$1,678	$1,727
Minnesota	$94	$22	$33
Mississippi	$5,407	$3,919	$4,774
Missouri	$1,796	$44	$43
Montana	$244	$329	$253
Nebraska	$2,404	$1,256	$1,258
New Hampshire	$1	$6	$7
New Jersey	$1,559	$1,428	$1,516
New Mexico	$175	$199	$297
New York	$4,095	$3,044	$4,618
North Carolina	$701	$284	$666
North Dakota	$873	$1,132	$877
Ohio	$4,167	$1,740	$1,964
Oklahoma	$1,455	$1,135	$1,788
Pennsylvania	$6,880	$6,659	$7,100
Rhode Island	$1	$6	$7
South Carolina	$2,633	$515	$1,331
South Dakota	$117	$62	$61
Tennessee	$757	$417	$292
Vermont	$0	$0	$0
Virginia	$2,029	$755	$1,281
West Virginia	$3,298	$1,735	$3,144
Wisconsin	$548	$81	$193
Eastern Interconnect	***$70,887***	***$42,900***	***$55,599***
Non-Eastern Interconnect	***$18,409***	***$13,121***	***$16,226***
Lower-48 U.S. States	**$89,296**	**$56,020**	**$71,825**

Source: ICF GMM®.

Exhibit 9-12: Gas Gathering Line Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$185	$156	$169
Arkansas	$500	$385	$444
Connecticut	$0	$0	$0
Delaware	$0	$0	$0
District of Columbia	$0	$0	$0
Florida	$0	$0	$0
Georgia	$0	$0	$0
Illinois	$13	$11	$12
Indiana	$0	$0	$0
Iowa	$0	$0	$0
Kansas	$1,287	$1,101	$1,190
Kentucky	$54	$46	$49
Louisiana	$1,062	$916	$994
Maine	$0	$0	$0
Maryland	$0	$0	$0
Massachusetts	$0	$0	$0
Michigan	$281	$248	$262
Minnesota	$0	$0	$0
Mississippi	$29	$25	$27
Missouri	$0	$0	$0
Montana	$160	$157	$159
Nebraska	$0	$0	$0
New Hampshire	$0	$0	$0
New Jersey	$0	$0	$0
New Mexico	$1,363	$1,262	$1,313
New York	$45	$42	$43
North Carolina	$0	$0	$0
North Dakota	$1,008	$999	$1,003
Ohio	$281	$266	$275
Oklahoma	$1,060	$963	$1,010
Pennsylvania	$1,732	$1,575	$1,649
Rhode Island	$0	$0	$0
South Carolina	$0	$0	$0
South Dakota	$11	$11	$11
Tennessee	$0	$0	$0
Vermont	$0	$0	$0
Virginia	$128	$106	$116
West Virginia	$426	$383	$403
Wisconsin	$0	$0	$0
Eastern Interconnect	***$9,626***	***$8,652***	***$9,128***
Non-Eastern Interconnect	***$12,905***	***$11,698***	***$12,322***
Lower-48 U.S. States	**$22,531**	**$20,350**	**$21,450**

Source: ICF GMM®.

Exhibit 9-13: Gas Pipeline, Gathering Line, and Storage Compression Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$247	$74	$93
Arkansas	$541	$116	$258
Connecticut	$92	$52	$55
Delaware	$84	$82	$83
District of Columbia	$0	$0	$0
Florida	$256	$46	$142
Georgia	$83	$26	$16
Illinois	$679	$452	$462
Indiana	$44	$29	$31
Iowa	$436	$247	$248
Kansas	$233	$201	$229
Kentucky	$291	$33	$117
Louisiana	$3,358	$2,427	$2,970
Maine	$0	$0	$0
Maryland	$64	$58	$67
Massachusetts	$92	$52	$55
Michigan	$286	$339	$393
Minnesota	$40	$1	$2
Mississippi	$427	$178	$199
Missouri	$78	$1	$1
Montana	$78	$69	$65
Nebraska	$537	$269	$269
New Hampshire	$0	$0	$0
New Jersey	$71	$70	$79
New Mexico	$207	$186	$199
New York	$493	$443	$402
North Carolina	$58	$13	$40
North Dakota	$1,302	$935	$922
Ohio	$1,010	$779	$939
Oklahoma	$499	$430	$553
Pennsylvania	$4,559	$4,180	$4,519
Rhode Island	$0	$0	$0
South Carolina	$39	$5	$8
South Dakota	$438	$249	$249
Tennessee	$196	$23	$106
Vermont	$0	$0	$0
Virginia	$123	$78	$103
West Virginia	$946	$806	$935
Wisconsin	$12	$2	$4
Eastern Interconnect	***$17,901***	***$12,951***	***$14,813***
Non-Eastern Interconnect	***$8,780***	***$6,737***	***$7,847***
Lower-48 U.S. States	**$26,681**	**$19,688**	**$22,660**

Source: ICF GMM®.

Exhibit 9-14: Gas Lease Equipment Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$296	$250	$272
Arkansas	$867	$655	$765
Connecticut	$0	$0	$0
Delaware	$0	$0	$0
District of Columbia	$0	$0	$0
Florida	$0	$0	$0
Georgia	$0	$0	$0
Illinois	$7	$6	$6
Indiana	$0	$0	$0
Iowa	$0	$0	$0
Kansas	$469	$401	$434
Kentucky	$56	$47	$51
Louisiana	$869	$759	$813
Maine	$0	$0	$0
Maryland	$0	$0	$0
Massachusetts	$0	$0	$0
Michigan	$193	$172	$181
Minnesota	$0	$0	$0
Mississippi	$25	$21	$23
Missouri	$0	$0	$0
Montana	$12	$10	$11
Nebraska	$0	$0	$0
New Hampshire	$0	$0	$0
New Jersey	$0	$0	$0
New Mexico	$561	$495	$532
New York	$65	$61	$63
North Carolina	$0	$0	$0
North Dakota	$9	$9	$9
Ohio	$419	$398	$411
Oklahoma	$917	$839	$878
Pennsylvania	$2,319	$2,110	$2,209
Rhode Island	$0	$0	$0
South Carolina	$0	$0	$0
South Dakota	$1	$1	$1
Tennessee	$0	$0	$0
Vermont	$0	$0	$0
Virginia	$189	$157	$171
West Virginia	$549	$496	$520
Wisconsin	$0	$0	$0
Eastern Interconnect	***$7,823***	***$6,888***	***$7,350***
Non-Eastern Interconnect	***$9,019***	***$7,928***	***$8,514***
Lower-48 U.S. States	**$16,843**	**$14,815**	**$15,865**

Source: ICF GMM®.

Exhibit 9-15: Gas Processing Capacity Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$12	$12	$12
Arkansas	$20	$13	$16
Connecticut	$0	$0	$0
Delaware	$0	$0	$0
District of Columbia	$0	$0	$0
Florida	$0	$0	$0
Georgia	$0	$0	$0
Illinois	$1	$1	$1
Indiana	$0	$0	$0
Iowa	$0	$0	$0
Kansas	$59	$59	$59
Kentucky	$8	$8	$8
Louisiana	$977	$766	$1,065
Maine	$0	$0	$0
Maryland	$0	$0	$0
Massachusetts	$0	$0	$0
Michigan	$166	$158	$166
Minnesota	$0	$0	$0
Mississippi	$4	$4	$4
Missouri	$0	$0	$0
Montana	$51	$50	$51
Nebraska	$0	$0	$0
New Hampshire	$0	$0	$0
New Jersey	$0	$0	$0
New Mexico	$179	$176	$180
New York	$114	$108	$114
North Carolina	$0	$0	$0
North Dakota	$435	$431	$435
Ohio	$791	$754	$793
Oklahoma	$587	$526	$584
Pennsylvania	$5,161	$4,572	$5,147
Rhode Island	$0	$0	$0
South Carolina	$0	$0	$0
South Dakota	$1	$1	$1
Tennessee	$0	$0	$0
Vermont	$0	$0	$0
Virginia	$0	$0	$0
West Virginia	$1,017	$908	$1,014
Wisconsin	$0	$0	$0
Eastern Interconnect	***$9,582***	***$8,548***	***$9,649***
Non-Eastern Interconnect	***$7,798***	***$6,434***	***$7,311***
Lower-48 U.S. States	**$17,380**	**$14,982**	**$16,960**

Source: ICF GMM®.

Exhibit 9-16: Gas Storage Field Expenditures (Millions of Real 2012 Dollars)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	$147	$60	$148
Arkansas	$0	$0	$0
Connecticut	$0	$0	$0
Delaware	$0	$0	$0
District of Columbia	$0	$0	$0
Florida	$0	$0	$0
Georgia	$0	$0	$0
Illinois	$0	$163	$196
Indiana	$0	$0	$0
Iowa	$0	$0	$0
Kansas	$0	$66	$156
Kentucky	$862	$45	$61
Louisiana	$2,544	$1,376	$1,754
Maine	$0	$0	$0
Maryland	$0	$0	$0
Massachusetts	$0	$0	$0
Michigan	$654	$291	$520
Minnesota	$0	$0	$0
Mississippi	$726	$48	$48
Missouri	$0	$0	$0
Montana	$0	$0	$0
Nebraska	$0	$0	$0
New Hampshire	$0	$0	$0
New Jersey	$0	$0	$0
New Mexico	$0	$0	$0
New York	$488	$565	$662
North Carolina	$0	$0	$0
North Dakota	$0	$0	$0
Ohio	$0	$0	$0
Oklahoma	$0	$51	$312
Pennsylvania	$608	$616	$688
Rhode Island	$0	$0	$0
South Carolina	$0	$0	$0
South Dakota	$0	$0	$0
Tennessee	$0	$0	$0
Vermont	$0	$0	$0
Virginia	$0	$0	$0
West Virginia	$56	$41	$43
Wisconsin	$0	$0	$0
Eastern Interconnect	***$6,084***	***$3,322***	***$4,587***
Non-Eastern Interconnect	***$2,703***	***$1,892***	***$2,435***
Lower-48 U.S. States	**$8,788**	**$5,214**	**$7,021**

Source: ICF GMM®.

Exhibit 9-17: Gas and Oil Well Completions

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	6,477	5,463	5,922
Arkansas	13,119	10,283	11,729
Connecticut	-	-	-
Delaware	-	-	-
District of Columbia	-	-	-
Florida	1	1	1
Georgia	-	-	-
Illinois	674	591	625
Indiana	-	-	-
Iowa	-	-	-
Kansas	75,458	64,507	69,729
Kentucky	2,118	1,796	1,916
Louisiana	18,713	16,180	17,450
Maine	-	-	-
Maryland	-	-	-
Massachusetts	-	-	-
Michigan	13,586	11,942	12,629
Minnesota	-	-	-
Mississippi	1,227	1,036	1,118
Missouri	-	-	-
Montana	5,707	5,615	5,659
Nebraska	-	-	-
New Hampshire	-	-	-
New Jersey	-	-	-
New Mexico	51,126	46,729	48,965
New York	1,238	1,152	1,196
North Carolina	-	-	-
North Dakota	34,708	34,411	34,547
Ohio	7,436	7,020	7,257
Oklahoma	43,759	39,639	41,608
Pennsylvania	28,227	25,586	26,805
Rhode Island	-	-	-
South Carolina	-	-	-
South Dakota	431	426	428
Tennessee	-	-	-
Vermont	-	-	-
Virginia	3,443	2,857	3,120
West Virginia	9,265	8,232	8,668
Wisconsin	-	-	-
Eastern Interconnect	***316,714***	***283,465***	***299,372***
Non-Eastern Interconnect	***446,359***	***403,019***	***425,690***
Lower-48 U.S. States	**763,073**	**686,484**	**725,062**

Source: ICF GMM®.

Exhibit 9-18: Inch-Miles of Transmission Mainlines and Laterals

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	31,535	16,363	17,401
Arkansas	2,627	1,104	1,558
Connecticut	4,268	740	4,429
Delaware	3,182	2,899	3,148
District of Columbia	-	-	-
Florida	50,957	28,114	45,629
Georgia	12,352	3,810	2,526
Illinois	17,805	7,145	7,658
Indiana	8,380	1,665	4,133
Iowa	2,585	1,650	1,499
Kansas	12,160	9,924	11,497
Kentucky	5,825	2,916	2,162
Louisiana	44,848	31,277	39,224
Maine	7	56	60
Maryland	5,388	2,643	5,412
Massachusetts	4,268	740	4,429
Michigan	7,574	10,964	11,419
Minnesota	878	207	309
Mississippi	34,605	25,681	30,946
Missouri	11,797	407	400
Montana	1,763	2,292	1,846
Nebraska	15,867	8,223	8,238
New Hampshire	3	28	30
New Jersey	7,414	6,703	7,098
New Mexico	1,323	1,553	2,462
New York	22,634	15,997	25,148
North Carolina	4,916	1,755	4,734
North Dakota	5,699	7,337	5,740
Ohio	28,481	11,120	12,779
Oklahoma	10,982	8,261	14,382
Pennsylvania	35,719	34,914	36,764
Rhode Island	3	28	30
South Carolina	15,969	3,080	7,950
South Dakota	1,092	575	568
Tennessee	4,763	2,694	1,853
Vermont	-	-	-
Virginia	11,257	4,235	7,705
West Virginia	18,816	9,647	17,915
Wisconsin	4,162	616	1,464
Eastern Interconnect	***451,903***	***267,360***	***350,546***
Non-Eastern Interconnect	***142,603***	***99,545***	***124,401***
Lower-48 U.S. States	**594,506**	**366,904**	**474,947**

Source: ICF GMM®.

Exhibit 9-19: Inch-Miles of Gathering Line

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	5,900	4,962	5,391
Arkansas	16,098	12,404	14,302
Connecticut	-	-	-
Delaware	-	-	-
District of Columbia	-	-	-
Florida	1	1	1
Georgia	-	-	-
Illinois	390	341	361
Indiana	-	-	-
Iowa	-	-	-
Kansas	36,301	31,048	33,555
Kentucky	1,636	1,387	1,481
Louisiana	26,467	22,846	24,695
Maine	-	-	-
Maryland	-	-	-
Massachusetts	-	-	-
Michigan	8,497	7,495	7,915
Minnesota	-	-	-
Mississippi	885	744	804
Missouri	-	-	-
Montana	5,525	5,427	5,475
Nebraska	-	-	-
New Hampshire	-	-	-
New Jersey	-	-	-
New Mexico	45,845	42,651	44,225
New York	1,441	1,352	1,400
North Carolina	-	-	-
North Dakota	34,707	34,412	34,547
Ohio	9,137	8,657	8,941
Oklahoma	31,747	28,867	30,261
Pennsylvania	41,830	38,024	39,809
Rhode Island	-	-	-
South Carolina	-	-	-
South Dakota	379	375	376
Tennessee	-	-	-
Vermont	-	-	-
Virginia	4,309	3,575	3,905
West Virginia	11,090	9,962	10,462
Wisconsin	-	-	-
Eastern Interconnect	***282,184***	***254,532***	***267,906***
Non-Eastern Interconnect	***421,300***	***382,743***	***402,578***
Lower-48 U.S. States	**703,485**	**637,274**	**670,484**

Source: ICF GMM®.

Exhibit 9-20: Compression for Pipelines and Gathering Line (1,000 HP)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	94	28	35
Arkansas	209	45	100
Connecticut	35	20	21
Delaware	32	31	32
District of Columbia	-	-	-
Florida	98	17	54
Georgia	32	10	6
Illinois	259	171	174
Indiana	17	11	12
Iowa	167	94	94
Kansas	86	74	84
Kentucky	111	13	45
Louisiana	1,299	938	1,149
Maine	0	0	0
Maryland	24	22	25
Massachusetts	35	20	21
Michigan	96	120	138
Minnesota	15	1	1
Mississippi	163	68	76
Missouri	30	0	0
Montana	29	25	24
Nebraska	205	102	103
New Hampshire	0	0	0
New Jersey	27	27	30
New Mexico	80	72	76
New York	178	159	142
North Carolina	22	5	15
North Dakota	490	350	345
Ohio	340	254	313
Oklahoma	194	167	213
Pennsylvania	1,428	1,317	1,413
Rhode Island	0	0	0
South Carolina	15	2	3
South Dakota	167	95	95
Tennessee	75	9	41
Vermont	-	-	-
Virginia	45	29	38
West Virginia	304	257	300
Wisconsin	5	1	2
Eastern Interconnect	***6,407***	***4,556***	***5,222***
Non-Eastern Interconnect	***3,316***	***2,539***	***2,958***
Lower-48 U.S. States	**9,723**	**7,094**	**8,181**

Source: ICF GMM®.

Exhibit 9-21: Gas Storage (Bcf Working Gas)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	6	3	7
Arkansas	-	-	-
Connecticut	-	-	-
Delaware	-	-	-
District of Columbia	-	-	-
Florida	-	-	-
Georgia	-	-	-
Illinois	-	12	15
Indiana	-	-	-
Iowa	-	-	-
Kansas	-	6	15
Kentucky	55	3	3
Louisiana	204	111	143
Maine	-	-	-
Maryland	-	-	-
Massachusetts	-	-	-
Michigan	50	22	40
Minnesota	-	-	-
Mississippi	31	2	2
Missouri	-	-	-
Montana	-	-	-
Nebraska	-	-	-
New Hampshire	-	-	-
New Jersey	-	-	-
New Mexico	-	-	-
New York	21	24	28
North Carolina	-	-	-
North Dakota	-	-	-
Ohio	-	-	-
Oklahoma	-	5	30
Pennsylvania	26	26	29
Rhode Island	-	-	-
South Carolina	-	-	-
South Dakota	-	-	-
Tennessee	-	-	-
Vermont	-	-	-
Virginia	-	-	-
West Virginia	2	2	2
Wisconsin	-	-	-
Eastern Interconnect	***395***	***216***	***314***
Non-Eastern Interconnect	***186***	***132***	***173***
Lower-48 U.S. States	**581**	**348**	**487**

Source: ICF GMM®.

Exhibit 9-22: Processing Capacity (MMcfd)

State	Combined Policy (S1)	RPS (S2)	BAU (S3)
Alabama	16	16	16
Arkansas	26	17	21
Connecticut	-	-	-
Delaware	-	-	-
District of Columbia	-	-	-
Florida	0	0	0
Georgia	-	-	-
Illinois	1	1	1
Indiana	-	-	-
Iowa	-	-	-
Kansas	74	74	74
Kentucky	9	9	9
Louisiana	1,258	986	1,370
Maine	-	-	-
Maryland	-	-	-
Massachusetts	-	-	-
Michigan	203	192	202
Minnesota	-	-	-
Mississippi	5	5	5
Missouri	-	-	-
Montana	64	63	64
Nebraska	-	-	-
New Hampshire	-	-	-
New Jersey	-	-	-
New Mexico	229	225	230
New York	135	129	135
North Carolina	-	-	-
North Dakota	546	542	546
Ohio	939	895	942
Oklahoma	758	679	754
Pennsylvania	6,126	5,427	6,110
Rhode Island	-	-	-
South Carolina	-	-	-
South Dakota	1	1	1
Tennessee	-	-	-
Vermont	-	-	-
Virginia	-	-	-
West Virginia	1,207	1,078	1,204
Wisconsin	-	-	-
Eastern Interconnect	***11,597***	***10,341***	***11,684***
Non-Eastern Interconnect	***9,960***	***8,211***	***9,332***
Lower-48 U.S. States	**21,557**	**18,552**	**21,016**

Source: ICF GMM®.

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